Exhibit No.: _________________
Commissioner: Diane Grueneich
Administrative Law Judge: Charlotte TerKeurst
Witness: Anjali Sheffrin, Ph.D.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of Southern California Edison Company (U 338-E) for a Certificate of Public Convenience and Necessity Concerning the Devers-Palo Verde No. 2 Transmission Line Project.	Application 05-04-015 (Filed April 11, 2005)
Order Instituting Investigation on the Commission's Own Motion into Methodology for Economic Assessment of Transmission Projects.	Investigation 05-06-041 (Filed June 30, 2005)

PHASE 1 OPENING TESTIMONY ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR

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October 21, 2005

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OPENING TESTIMONY ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR

I. Supporting Witness

My name is Anjali Sheffrin, Ph.D. I serve as Acting Vice President of Market Development and Program Management and Director of Market and Product Development for the California Independent System Operator Corporation (CAISO) and I am submitting this testimony on its behalf. My job duties and qualifications are set forth as Attachment 11 to this testimony.

II. Testimony Overview

This testimony is submitted pursuant to the "Administrative Law Judge's Ruling Addressing Schedule and Other Procedural Matters" distributed in the above-referenced matters on September 27, 2005 ("ALJ Ruling"). The ALJ Ruling stated, "it is reasonable to require that the CAISO submit direct testimony no later than October 21, 2005 including at least the CAISO's June 2004 TEAM report and its economic analysis of [Devers-Palo Verde #2 or DPV2]" (Ruling at 6.) The testimony complies with this directive and includes several other documents relating to the CAISO's analysis of DPV2. Accordingly, the purpose of my testimony is largely procedural, rather than substantive, and will not attempt to duplicate or elaborate on the contents of the attached materials. Specifically, my testimony will:

a. Set forth the structure of the June 2004 Team Report, the DPV2 economic analysis, and its accompanying technical appendices, and identify the sponsoring witnesses for particular chapters of those respective documents, and

b. Authenticate the (1) the Memorandum to the CAISO Board of Governors, dated November 5, 2004, entitled "Update on the Palo Verde-Devers #2 500 kV Transmission Project," (2) the Memorandum to the CAISO Board of Governors, dated February 14, 2005, entitled "Palo Verde-Devers #2 500 kV Transmission Project," and (3) the Opinion of the CAISO Market Surveillance Committee, entitled "Assessment of an Economic Analysis of the Palo Verde Devers Transmission Network Upgrade," dated February 22, 2005.

III. Description of June 2004 Team Report and Witnesses

The June 2004 Team Report is divided into nine primary chapters and includes an executive summary and appendices. A true and correct copy of the June 2004 Team Report is identified as attachment 1 to this testimony, while true and correct copies of Appendices A through D to the Team Report are identified separately as attachments 2 through 5, respectively. The following is a list of the chapters and appendices, the identity of the sponsoring witness, and the location of the sponsoring witnesses' qualifications in parentheses:

i. Executive Summary
ii. Introduction
iii. Chapter 1 - Overview of Transmission Assessment Process – Anjali Sheffrin (Attachment 11)
iv. Chapter 2 – Quantifying Benefits – Mingxia Zhang (Attachment 12)
v. Chapter 3 – Network Model Requirements – John Kyei (Attachment 13)
vi. Chapter 4 - Market Price Derivation – Mingxia Zhang
vii. Chapter 5 - Sensitivity Case Selection – Mingxia Zhang
viii. Chapter 6 - Resource Substitution – Anjali Sheffrin
ix. Chapter 7 - Overview of Analytical Process – Christopher McLean (Attachment 14)

x. Chapter 8 - Base Case Assumptions – Christopher McLean

xi. Chapter 9 - Results

Appendices

1. Appendix A - List of Acronyms
2. Appendix B - Benefits Example for Three Node Model – Mingxia Zhang
3. Appendix C - Base Case Assumptions – Christopher McLean
   a. SSG-WI 2008 Thermal Plant by Technology
   b. SSG-WI Resource Additions since 1/1/2000
   c. WECC Major Path Listing
   d. Inflation and Gas Price Forecasts
   e. WECC 2008 and 2013 Expansion Plans
4. Appendix D - Public Process

IV. Economic Evaluation of the Palo Verde Devers Line No. 2

The CAISO's economic evaluation of the DPV2 line is divided into ten chapters. A true and correct copy of the economic evaluation is identified as attachment 6 to this testimony. The following is a list of the chapters and the identity of the sponsoring witness:

i. Summary – Anjali Sheffrin

ii. Introduction - Anjali Sheffrin

iii. Project Description – Anjali Sheffrin

iv. Public Process – Anjali Sheffrin

v. Overview of Benefits – Anjali Sheffrin

vi. Input Assumptions – Christopher McLean

vii. Results – Anjali Sheffrin and Christopher McLean

viii. Resource Alternatives - Anjali Sheffrin

ix. Recommendation – Anjali Sheffrin

x. Next Steps

V. Technical and Other Appendices to the Economic Evaluation of the Palo Verde Devers Line No. 2

Accompanying the CAISO's economic evaluation of the DPV2 line is a set of technical and other appendices ("Technical Appendices"). The Technical Appendices are identified as Appendix A through R. A true and correct copy of the Technical Appendices is identified as attachment 7 to this testimony. The following is a list of the appendices and the identity of the sponsoring witness:

Appendix A. Scenario Selection – Mingxia Zhang

Appendix B. Network - John Kyei

Appendix C. Loads – Christopher McLean

Appendix D. Resources – Christopher McLean

Appendix E. Fuel Prices – Christopher McLean

Appendix F. Market Price Derivation – Mingxia Zhang

Appendix G. Project Cost – Christopher McLean

Appendix H. Approved Transmission Projects – John Kyei

Appendix I. Case Summary – Christopher McLean

Appendix J. Estimation of Value of Transmission Loss Reduction – John Kyei

Appendix K. Operational Benefits Estimated for the PVD2 Economic Assessment – Anjali Sheffrin

Appendix L. Transmission Alternatives – John Kyei

Appendix M. Resource Alternatives – Anjali Sheffrin

Appendix N. Alternative Market Paradigms – Anjali Sheffrin

Appendix O. Changes from Original Transmission Expansion Assessment Methodology (TEAM) – Anjali Sheffrin

Appendix P. Public Process – Anjali Sheffrin

Appendix Q. Estimation of Capacity Value – Christopher McLean

Appendix R. Estimation of Value of Emission Reduction – Christopher McLean

VI. Board Memoranda

Under CAISO practice, capital projects over $20 million that will be recovered through CAISO's Transmission Access Charge must be approved by the CAISO Board of Governors. As part of seeking such approval, the CAISO management provided the Board with a memorandum, dated February 14, 2005, describing DPV2 and its economic benefits. A true and correct copy of that memorandum is identified as attachment 8 to this testimony. In addition, also identified as attachment 9 to this testimony is a true and correct copy of an earlier memorandum to the Board, dated November 5, 2004, which provided an update on the progress made in evaluating DPV2.

VII. Market Surveillance Committee Opinion

The Market Surveillance Committee or MSC of the CAISO is an independent advisory group to the CAISO Governing Board. The MSC consists of four industry experts with Prof. Frank Wolak of the Department of Economics at Stanford University as Chairman, and Prof. Brad Barber of the Graduate School of Management at UC Davis, Prof. James Bushnell, Research Director of the University of California Energy Institute, and Prof. Benjamin Hobbs of the Department of Geography and Environmental Engineering at The Johns Hopkins University as members. To ensure independence, none of the MSC members are affiliated with or have any financial interest in any market participant. Their charter allows them to suggest changes in rules and protocols or recommend rules, protocols, sanctions or penalties directly to the CAISO Governing Board. In this regard, the MSC may produce independent reports containing its recommendations.

The MSC has been aware since its inception of the CAISO effort to develop an economic methodology to assess transmission upgrades and has participated in its evolution. As indicated in attachment 9, described above, the MSC was also involved in evaluating the CAISO's assessment of DPV2. Identified as attachment 10 to this testimony is a true and correct copy of the MSC's opinion on the CAISO's DPV2 study results.

ATTACHMENT 1
OF
PHASE 1 OPENING TESTIMONY ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR
October 21, 2005
A.05-04-015
I.05-06-041

CALIFORNIA ISO

Transmission Economic Assessment Methodology (TEAM)

California Independent System Operator

June 2004

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APPENDIX

Introduction

The California System Operator (CAISO) must evaluate all potential transmission upgrades that CAISO ratepayers would be asked to fund. As part of this responsibility, the CAISO has spent the last several years developing and refining a methodology to evaluate the economic viability of these proposed upgrades. We have named our methodology the Transmission Economic Assessment Methodology (TEAM). The purpose of this report is to present application of our methodology in sufficient detail to be evaluated and adopted as a standard for use in examining transmission proposals by regulators, transmission owners, ratepayers, public interest groups, and other interested parties.

The report is divided into nine chapters. In these chapters we first present the methodology: the evaluation principles, model requirements, and our recommended analytical approach. Then we focus on the application of our methodology by performing a transmission feasibility study. Consistent with direction from the California Public Utilities Commission (CPUC), we selected one of the options available for upgrading Path 26 for this study and evaluated its economic viability from multiple perspectives. While we have conducted a complete study, our primary purpose is to demonstrate our methodology. We consider the actual results of secondary importance. Therefore, we concentrate our discussion more on the methodology and its application and less on the study results.

Our report summarizes which components of the methodology we consider essential and should be used in all evaluations without modification, which aspects of the methodology could be improved upon with further research and development, and which areas may benefit from application of the experienced judgment of the user or organization performing the study.

The contents of this report incorporate valuable input and dialogue we received from many organizations and individuals. These include London Economics, the CAISO Market Surveillance Committee (MSC), the California Energy Commission (CEC), the CPUC, the investor- and publicly-owned utilities in California, The Utility Reform Network (TURN), and other interested parties who participated in the stakeholder meetings and technical subgroups.

We do not consider this report to be the final end-all treatise with respect to economic evaluation of transmission upgrades. We do believe this report presents a valuable methodological approach that can be implemented immediately and provide decision-makers with the information needed to make sound economic decisions.

Executive Summary

The CAISO is responsible for evaluating the need for all potential transmission upgrades that California ratepayers may be asked to fund.[1] This includes construction of transmission projects needed either to promote economic efficiency or to maintain system reliability. The CAISO has clear standards to use in evaluating reliability-based projects. To fulfill its responsibility for identifying economic projects that promote efficient utilization of the grid, the CAISO has developed a methodology called the Transmission Economic Assessment Methodology (TEAM)[2].

The CAISO has consulted with many stakeholders including the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and California electric utilities in formulating this methodology. The goal of TEAM is to significantly streamline the evaluation process for economic projects, improve the accuracy of the evaluation, and add greater predictability to the evaluations of transmission need conducted at the various agencies. To this end, the CAISO is filing this methodology for consideration in the CPUC's ongoing transmission investigation preceding commenced pursuant to Assembly Bill 970.[3]

Depending on the environmental and economic attributes of a proposed transmission project and the project sponsor, a number of agencies can have planning, review, oversight and approval roles. These agencies range from the CAISO, the CPUC and the CEC to the boards of municipal districts and utilities. In a number of previous cases, especially in determining project need, the CAISO has seen that the same project has received multiple reviews by various agencies, each seeking to carry out their individual mandates. Both the CEC and CPUC have recognized that this process has led to redundancies and inefficiencies.[4] We believe that accepting the TEAM methodology as the standard for project evaluation by market participants, stakeholders, regulatory and oversight agencies will reduce redundant efforts and lead to faster, less contentious and more widely supported decisions on key transmission investment projects.

ES.1 Purpose of Report

This report presents a detailed methodology for assessing the economic benefits of transmission expansions. It demonstrates the methodology by applying it to a proposed transmission expansion between central and southern California called Path 26. The methodology is intended to be a tool that will provide market participants,

[1] The Legislature, pursuant to Public Utilities Code § 345, assigned the CAISO the responsibility of "ensur[ing] [the] efficient use and reliable operation of the transmission grid." To achieve this goal, the CAISO can compel Participating Transmission Owner's to pursue construction of transmission projects deemed needed either to "promote economic efficiency" or to "maintain system reliability" (CAISO Tariff § 3.2.1.)

[2] The terms TEAM and CAISO methodology are used interchangeably throughout this report.

[3] Phase 5 of "Order Instituting Investigation into Implementation of Assembly Bill 970 Regarding the Identification of Electric Transmission and Distribution Constraints, Actions to Resolve those Constraints, and Related Matters affecting the Reliability of Electric Supply," I.00-11-001.

[4] See, e.g., CPUC's "Order Instituting Rulemaking on Policies and Practices for the Commission's Transmission Assessment Process," R.04-01-026; CEC's "2003 Integrated Energy Policy Report" (Nov. 12, 2003).

policy-makers, and permitting authorities with the information necessary to make informed decisions when planning and constructing a transmission upgrade for reliable and efficient delivery of electric power to California consumers.

Restructured wholesale electricity markets require a new approach for evaluating the economic benefits of transmission investments. Unlike the previous vertically integrated market where one regulated utility was responsible for serving its load, the restructured wholesale electric market is comprised of a variety of parties independently making decisions that affect the utilization of transmission lines. This new market structure requires a new approach to evaluate the economic benefits of transmission expansions. Specifically, the new approach must address what impact a transmission expansion would have on increasing transmission users' access to sources of generation and customers requiring energy, what incentives it would create for new generation investments, and what impact it would have on market competition. The approach must also account for the inherent uncertainty associated with key market factors such as future hydro conditions, natural gas prices, and demand growth. Our challenge has been integrating all of these critical modeling requirements into a comprehensive methodological approach.

The TEAM methodology represents the culmination of over two years of research and development led by the CAISO with support and input from industry experts and the CAISO Market Surveillance Committee. It integrates five key principles for defining quantifiable benefits into a single comprehensive methodology to support decisions about long–term investments required for transmission upgrades. We believe the methodology provided here represents the state-of-the-art in the area of transmission planning in terms of its simultaneous consideration of the network, market power, uncertainties, and multiple evaluation perspectives. This modeling framework provides a template containing the basic components that any transmission study should address. While this methodology specifies what the basic facets of a comprehensive transmission study should be, it makes no specific recommendation on a particular software product to use in its application. It does, however, provide standards on the minimum functional requirements the modeling software should have.

ES.2 Public Process

The TEAM methodology was the subject of a four-month public stakeholder process that had three public workshops and a public CAISO Market Surveillance Committee meeting. In addition, there were three technical subgroups formed. They worked on base case assumptions, the scenario selection, and methods of modeling market prices. In all, there were twelve separate technical sessions. Attachment D provides a list of participating organizations and meeting agendas. During the workshops, we provided the participants with detailed descriptions of our methodology, the key principles guiding it, our modeling effort, the sensitivity cases we were considering and our preliminary results to date. We solicited stakeholder advice and critical review throughout the process. As a result, the final TEAM methodology we present here has benefited from this exposure to various viewpoints and includes modifications prompted by this stakeholder input.

We are continuing the collaborative process by submitting a full report on our methodology to the CPUC. The CPUC has expressed the intent to evaluate, and hopefully endorse, our methodology for performing economic evaluations and reaching conclusions for future use in their regulatory approval process. We believe that our TEAM approach can achieve consensus as the standard for evaluating all future transmission system upgrades. It is comprehensive in its approach and can produce results that are valuable to all involved with proposing and reviewing critical transmission infrastructure upgrades.

ES.3 Major Challenges and Solutions

This evaluation method was developed to capture the quantifiable economic benefits of transmission expansion in the current restructured wholesale market environment. In areas served by ISOs/RTOs, these institutions have the responsibility for providing non-discriminatory access to all parties. Their planning and evaluation of transmission augmentations must be consistent with this objective. It must also account for the fact that investment in new generation resources is made in the market place by private companies or by utilities subject to regulatory oversight, with the focus on the profitability to the investing party. Planners at an ISO or RTO must consider broader objectives that integrate the benefits of the grid to all participants in the region including retail customers, generation owners, and transmission owners.

The experience of many ISO/RTOs that have locational marginal prices (LMP) is that the prices differences between locations may not be sufficient to spur investment in transmission upgrades. The theory behind locational marginal prices is that generation or load would sign contracts to deliver the power to load and those contracts would provide the revenue source for upgrades to the transmission grid. But the reality has been that the LMP differences have not provided enough incentives to upgrade key facilities even after many types of FTR's and CRR's are provided. Our new methodology recognizes that there are many "public goods" aspects to transmission investments, making them similar to investments in the freeway system: (1) they are very lumpy in size, (2) there is non excludability in their use, since an upgrade to an AC grid means many parties who use the grid will benefit, and we cannot exclude parties from benefiting once an upgrade is in place, and (3) there are many positive externalities associated with the upgrade such as generators and consumers in many parts of the network may be affected. A methodology is needed that correctly accounts for the public good aspect of transmission investment.[5]

In a restructured market place, power suppliers are bidding to maximize their profits rather than simply to recover their operating costs. In this market-oriented environment, an ISO/RTO must consider the risk of market power and how a transmission expansion can serve to reduce this risk. Even after considering other market power mitigation measures such as a market price cap, automated mitigation procedures (AMP) on bids, and long-term contracts, a transmission expansion can provide market power mitigation benefits through enlarging the market and reducing the concentration that any one supplier may have under a variety of system conditions.

Uncertainty in load growth, hydro conditions, availability of imports, and new generation entry levels can have significant impacts on the economic benefits of a transmission expansion to different parties and regions. Therefore, it is critical that a

[5] Public goods are defined as a shared good for which it is impractical to make users pay individually and to exclude non- payers.

valuation methodology explore the economic value of a transmission expansion under a number of different assumptions about future market conditions, particularly extremely adverse market conditions (e.g., high demand and low hydro).

To address these challenges, the new transmission valuation methodology we propose here offers five major enhancements to traditional transmission evaluations. It:

1. Utilizes a framework to consistently measure the benefits of a transmission expansion project to various participants. It provides policy makers with several options or perspectives on the distributional economic impacts of an expansion on consumers, producers, transmission owners or other entities entitled to congestion revenues), distinguishing congestion within and between regions
2. Utilizes a network model[6] that can capture the physical constraints of the transmission grid as well as the economic impacts of a project
3. Provides a simulation method that incorporates the impact of strategic bidding on market prices. This allows the benefits of transmission expansions to be not limited solely to reducing the production cost of electricity but also to include consumer benefits from reduced supplier market power
4. Addresses the uncertainty about future market conditions by providing a methodology for selecting a representative set of market scenarios to measure benefits of a transmission expansion and provides a methodology for assigning weighting factors (relative probabilities) to different scenarios so that the expected benefit and range of benefits for a transmission expansion can be determined
5. Captures the interaction between generation, demand-side management, and transmission investment decisions recognizing that a transmission expansion can impact the profitability of new resources investment, so that a methodology should consider both the objectives of investors in resources (private profits) and the transmission planner (societal net-benefits)

Finally, our proposed methodology is intended to be sufficiently general in application so that it can be used by project participants, non-participants, and regulators in evaluating transmission projects over a broad spectrum of energy-industry environments -- ranging from a traditional utility service territory operation to large geographical areas with nodal markets. Although the CAISO may play a central role in transmission expansion by funding the critical expansion through ratepayer grid access charges, the proposed evaluation methodology will not preclude private investment in transmission projects. The TEAM approach will identify all beneficiaries of a proposed upgrade. The question of who should fund it should be dealt with separately.

[6] The “network model” used in this methodology is not an AC model in that it does not explicitly model the reactive power and voltage interactions with real power flow and phase angles. However, it provides for explicit computation of transmission losses (which are allocated based on pre-specified loss allocation factors). In this sense, it can be classified as a DC power flow model. Transmission constraints are enforced explicitly on EHV transmission paths.

Purpose of Report: Establish a standard methodology for assessing the economic benefits of major transmission upgrades that can be used by California regulatory and operating agencies and market participants.

ES.4 Key Principles of the Evaluation Methodology

There are aspects of our methodology we consider critical for any economic evaluation of transmission upgrades. We call these aspects "*key principles*". Other aspects of our methodology are evolving as the modeling and analytical technology improves. We identify and discuss these *"potential enhancements"* in later portions of the report. Many of the evolving components are good candidates for further research and development by the CEC, CPUC, or other parties.

Finally, there are elements that were required for the study, but which were not specified by the CAISO. We refer to these elements as *"user-selected components"* and discuss them in later portions of the report.

Although the specific application of these principles may vary from study-to-study, the CAISO requires that the following five requirements be considered in any economic evaluation of proposed transmission upgrades presented to the CAISO for review.

ES.4.1 Benefit Framework

Decisions on economic-driven transmission investment have suffered due to a lack of a standardized benefit-cost analysis framework. Such a framework would enable users to clearly identify the beneficiaries and expected benefits of any kind of transmission project, for both private and regulated transmission investments. Our benefit framework addresses this problem. It provides a standard for measuring transmission expansion benefits regionally and separately for consumers, producers, and transmission owners for any kind of economic-driven transmission investment. This benefit framework provides decision makers a useful tool for assessing transmission benefits in a consistent and effective manner.

We intend that the benefit framework provide a structure for summarizing the benefits, costs, and risks of the proposed transmission upgrade to the decision makers. The framework should be consistent from one study to another so that alternative project investments can be evaluated against a common standard. The benefit framework should also be able to present the relative economics of a project from a variety of perspectives –consumer, producer, and transmission owner, and on a societal or regional basis.

Consumer benefits in a vertically integrated utility come from three sources -- the reduction in consumer costs, the increase in utility-owned generation net revenue, and the increase in utility-derived congestion revenue. In our methodology, we separated the total change in production costs resulting from a transmission expansion into three separate components – Consumer Surplus, Producer Surplus, and Transmission Owner Congestion Revenue Benefits. Positive benefits indicate an increase in consumer, producer, or transmission owner benefits. Negative numbers indicate a decrease in benefits.

These benefit amounts can be summed and viewed from a Western interconnection-wide societal or sub-regional perspective or California ratepayer perspective. A critical policy question is which perspective should be used to evaluate projects. The answer depends on the viewpoint of the entity the network is operated to benefit. If the network is operated to maximize benefit to ratepayers who have paid for the network, then some may consider the appropriate test to be the ratepayer perspective. Others say this may be a short-term view, which does not match the long-term nature of the transmission investment. In the long run, it may be both the health of utility-owned generation and private supply, which is needed to maximize benefits to ratepayers. Advocates of this view claim that the network is operated to benefit all California market participants (or for society in general) and, therefore, the CAISO participant or Western Electricity Coordinating Council "WECC" perspective of benefits may be the relevant test.

Each perspective provides the policy makers with some important information. If the benefit-cost ratio of an upgrade passes the CAISO participant test, but fails the WECC test of economic efficiency, then it may be an indicator that the expansion will cause a large transfer of benefits from one producer and consumer region to another.

On the other hand, if the proposed project passes the societal test but fails the CAISO participant test, this may be an indication that other project beneficiaries should help fund the project rather than solely CAISO ratepayers. Policy makers should review these differing perspectives to gain useful information when making decisions.

An additional consideration on viewing various perspectives of the benefits of a transmission expansion is how to treat the loss of monopoly rents by generation owners when the grid is expanded. Since monopoly rents result from the exercise of market power that reduces efficiency and harms consumers, the Market Surveillance Committee and the Electricity Oversight Board have argued that it is reasonable to exclude the loss of monopoly rents in the benefit calculations.[7] This is the key difference between the WECC societal test and the WECC modified societal test (based on societal benefits minus monopoly rents). Monopoly rents for California producers are also excluded from the CAISO participant test since it considers only California competitive rents.

ES.4.2 Network Representation

It is important to accurately model the physical transmission flow to correctly forecast the impact of a potential transmission upgrade. Models using a contract path method may be sufficient for many types of resource studies, but that approach is insufficient when analyzing a transmission modification that will impact regional transmission flows and locational prices.

We have recently seen how critical an accurate network representation is to making a correct decision. One California utility proposed a transmission addition and justified its economic viability using a contract-path model. When the CAISO reviewed the case, it found the line to be uneconomical due to its adverse physical impact on the other parts of the transmission system. The simpler transmission model used by the

[7] This does not mean producers collect only variable costs. Since this is a long-run analysis, both variable and fixed cost of production is accounted for. The profitability of generation is assured through a revenue test for all supply.

utility produced inaccurate results, making the upgrade appear economic because the actual physical impact of the upgrade was not correctly modeled.

Accurate physical transmission modeling is also important to ensure that reliability and delivery standards are achieved. Since these standards are based on physical line flows and not contract flows, a detailed, network model is necessary.[8]

There are many different analytical techniques for modeling physical transmission networks. More advanced techniques may provide more accurate information but also increase the data burden and execution time. Recognizing these trade-offs, the CAISO identified the need to model the correct network representation provided in WECC base cases. Any production cost program that utilizes this network model should include at least the following capabilities:

Table ES.1 Production Cost Program Requirements Relating to the Network Model Requirement

No.	Requirement
1	Must use a network model that is derived from a WECC power flow case.
2	Performs either a DC or AC OPF that correctly models the physical power flows on transmission facilities for each specific hourly load and generation pattern.
3	Capable of modeling and enforcing individual facility limits, linear nomograms, and path limits.
4	Capable of modeling limits that vary based on variables such as area load, facility loading, or generation availability.
5	Capable of modeling only those limits of interest (typically only 500 kV and selected 230 kV system limits)
6	Models phase shifters, DC lines, and other significant controllable devices
7	Capable of calculating nodal prices.
8	Capable of plotting the hourly flows (either chronologically or by magnitude) on individual facilities, paths, or nomograms.
9	While not required, it is desirable for the simulations to model transmission losses.

A software tool that can accurately forecast physical flows and nodal prices on the WECC transmission network is critical for computing the economic benefits of a proposed transmission upgrade.

While our methodology requires the use of a network model, a simplified analysis (contract path or transportation models) can be utilized if desired to screen a large number of cases for the purpose of identifying system conditions that may result in large benefits from a transmission expansion. To the extent that cases conducted using a simplified model are critical to the economic support of a transmission project, the results of this analysis should be confirmed using a network model.

[8] For purposes of TEAM, a network model does not necessarily require modeling flows on lower voltages lines (i.e., 69, 115, and some cases 230 kV) or lower voltage constraints.

ES.4.3 Market Prices

Historically, resource-planning studies have typically relied on production cost simulations (i.e., marginal cost pricing) to evaluate the economic benefits of potential generation and transmission investments. Such an approach made sense when utilities were vertically integrated and recovered costs through regulated cost-of-service rates. Assuming marginal cost pricing in a restructured market environment where suppliers are seeking to maximize market revenues may result in inaccurate benefit estimates. In a restructured electricity market, suppliers are likely to optimize their bidding strategies in response to changing system conditions or observed changes in the behavior of other market participants. Because of this, a methodology for assessing the benefits of a transmission project in a restructured market environment should include a method for modeling strategic bidding. Modeling strategic bidding is particularly important because transmission expansion can provide significant benefits to consumers by improving market competitiveness. A new transmission project can enhance market competitiveness by both increasing the total supply that can be delivered to consumers and the number of suppliers that are available to serve load.

There are two approaches to modeling strategic bidding behavior in transmission valuation studies. The first approach involves the use of a game-theoretic model to simulate strategic bidding. A game theoretic model typically consists of several strategic suppliers with each player seeking to maximize its expected profits by changing its bidding strategy in response to the bidding strategies of all other players. The second approach involves the use of estimated historical relationships between certain market variables and some measure of market power such as the difference between estimated competitive prices and actual prices or estimated competitive bids and actual bids (i.e., price-cost markups and bid-cost markups, respectively). Each modeling approach has its advantages and disadvantages. We discuss these in detail in the report. In assessing these two alternative approaches, we believe an empirical approach to modeling strategic bidding is preferable to a game theoretic approach if relevant data is available because it can be adapted to a detailed transmission network representation and has been validated through historical experience.

Energy prices that are determined by strategic bidding, i.e.," market prices", have an impact on societal benefits, and often have a significant impact on the transfer of benefits among participants. Because of this, forecasting of market prices is a critical component of the overall transmission evaluation process.

Forecasting of market prices is a difficult task. It requires us to predict the market behavior of certain suppliers (i.e., strategic bidders) under a variety of system conditions. Our task is further complicated by our decision to use a highly detailed representation of the transmission network (i.e., a network model of the entire WECC). For the most part, software models to date have either focused on transmission modeling and neglected the market behavior side, or focused on the market behavior aspect without the detailed transmission representation.

To the best of our knowledge, no entity has successfully developed and implemented a market simulation model based on dynamic[9] supply bids and incorporating a detailed

9 By "dynamic" we mean that the hourly supply bids change as a function of system conditions. Most of the models that exist currently use a "static" bid strategy (i.e., the bid strategy is set for a period of time such as a month or year and does not change in response to dynamic system conditions such as hourly

physical transmission modeling capability for a reliability region. The CAISO methodology includes these important attributes. The coupling of a dynamic bidding capability with a network model is an important step forward and an essential component of the CAISO methodology. We acknowledge that much research and development remains to be done in this area. We discuss these potential enhancements later in the report.

The CAISO evaluation methodology does not specify the process to be used for forecasting market power. Rather, at this point, the CAISO requires only that a credible and comprehensive approach for forecasting market prices be utilized in the evaluation. We consider the empirical approach of modeling strategic bidding we used in the Path 26 analysis to be one of several useful methodologies for deriving market prices.

ES.4.4 Uncertainty

Decisions on whether to build new transmission are complicated by risks and uncertainties about the future. Future load growth, fuel costs, additions and retirements of generation capacities and the location of those generators, exercise of market power by some generators, and availability of hydro resources are among some of the many factors impacting decision making. Some of these risks and uncertainties can be easily measured and quantified, and some cannot.

There are two fundamental reasons why we must consider risk and uncertainty in transmission evaluation. First, changes in future system conditions can affect benefits from transmission expansion significantly. Historically the relationship between transmission benefits and underlying system conditions was found many times to be nonlinear. Thus, evaluating a transmission project based only on assumptions of average future system conditions might greatly underestimate or overestimate the true benefit of the project and may lead to less than optimal decision making. To make sure we fully capture all impacts the project may have, we must examine a wide range of possible system conditions.

Second, historical evidence suggests that transmission upgrades have been particularly valuable during extreme conditions. Professor Frank Wolak, chair of the CAISO's Market Surveillance Committee, estimated that a large inter-connection between WSCC and the eastern United States during the period June 2000 to June 2001 would have been worth on the order of $30 billion. Had a significant inter-connection between the eastern U.S. and WSCC been in existence, prices in the WSCC would not have risen to levels that existed during the period May 2000 to June 2001. In addition, it would have perhaps avoided the recent blackout in the eastern U.S. that led to significant economic loss in that area of the country.

There are several alternative approaches to assessing the impact of risk and uncertainty on transmission expansion. The most often used in practice are the deterministic approach, the stochastic approach, or a combination of the two. Deterministic analysis is performed using point estimates. These estimates may be, for example, a single set of assumptions about loads, natural gas prices, and the availability of generating plants to meet customer loads. Deterministic analysis is useful for understanding a single set of input forecasts. It does not measure the

demand, supply, and import levels. A static bid strategy has difficulty capturing market power that may exist in times of supply inadequacy.

impact of risk and uncertainty. As such, it is best used for initial analysis of an expansion proposal. A complete transmission evaluation process should incorporate stochastic analysis or scenario analysis. Stochastic analysis models the uncertainty associated with different parameters affecting the magnitudes of benefits to be derived from an expansion project. Stochastic analysis often uses probabilistic representations of the future loads, gas prices, and generation unit availabilities.

The economic assessment of a proposed transmission upgrade can be very sensitive to specific input assumptions. Unless the proposed project economics are overwhelmingly favorable when using "expected" input assumptions, we need to perform sensitivity studies using a variety of input assumptions. We do this to compute the following benefit measures:

- Expected value
- Range
- Contingency value(s)

A significant portion of the economic value of a potential upgrade is realized when unusual or unexpected situations occur. Such situations may include high load growth, high gas prices, or wet or dry hydrological years. The "expected value" of a transmission upgrade should be based on both the usual or expected conditions as well as on the unusual, but plausible, situations.

A transmission upgrade can be viewed as a type of insurance policy against extreme events. Providing the additional capacity incurs a capital and operating cost, but the benefit is that the impact of extreme events is reduced or eliminated.

ES.4.5 Resource Alternative to Transmission Expansion

The economic value of a proposed transmission upgrade is directly dependent on the cost of resources that could be added or implemented in lieu of the upgrade. We consider the following options resources:

- Central station generation
- Demand-side management
- Renewable generation and distributed generation
- Modified operating procedures
- Additional remedial action schemes (RAS)
- Alternative transmission upgrades
- Any combination of the above

In addition to considering the resource alternatives described above, another important issue to consider is the decision where to site new transmission. One perspective is that the transmission should be sited after the siting of new generation. The other perspective is that the transmission should be planned anticipating various generation additions.

We believe the latter perspective is the most efficient approach. Transmission additions have planning horizons that require decisions 8 to 10 years in advance of the line being placed in service. When those decisions are being made, plans to site new generation may not yet have been made. As a result, we believe it best to plan the transmission grid taking into account the profitability of generation additions in various locations. In this way, the transmission planner influences generation decision making, rather than accounting for it after the fact.

The best means to account for the plans of a host of private investment decisions is to model the profitability of the generation decision in the transmission framework. We use a "what if" framework for our standard decision analysis. As an example, if the CAISO were to build a transmission line, what would be the most likely resulting outcomes in the profitability of private generation decisions? Comparing this to a case where we did not build the line, how different would the profitability of generation investment differ? We then optimize generation additions for with and without upgrade cases. The difference in costs between the two scenarios, including both the fixed and variable costs of the new resources, will be the value of the upgrade.

Examining resource alternatives to a transmission upgrade demonstrates that an alternative can either complement the line upgrade or substitute for it.

A third issue we face is whether to credit the proposed transmission upgrade with the benefit of resource alternatives that are economic in the "with upgrade" case, but are not viable in the "without upgrade" case. We have concluded that these benefits are properly attributed to the transmission upgrade that facilitated such investment.

ES.5 Applicability of Methodology

The five key principles of the proposed CAISO methodology do not need to be applied in exacting detail for each study. Rather, the type of study and initial study results will dictate at what level the principles should be applied.

Table ES.2 provides guidelines for the application of key principles. We do not intend these guidelines be applicable to all potential studies, but offer them to provide a foundation for determining analytical requirements.

Table ES.2 Key Benefit Requirements

Requirements	Utility Impact Only	Inter-Regional Impact
- Benefit Framework		Yes
- Network Representation	Yes	Yes
- Market Prices		Possible
- Uncertainty		Possible
- Resource Alternative	Yes	Yes

The application of the five key principles will depend on the specific project. For the evaluation of a major inter- or intra-regional line, all five principles will need to be considered. For smaller projects, only a network representation and resource alternative may be sufficient for the evaluation.

In Table ES.2 we have proposed a minimum analytical threshold. For all transmission upgrade studies, we will require as a minimum, the use of a transmission network model and the consideration of alternative resources. In certain situations where the impact is primarily limited to a single utility, these two requirements may be sufficient. In other cases, a more comprehensive analysis including the full benefit template, forecasting market prices, and understanding the uncertainty of the benefits will be necessary.

For example, suppose a utility wants to evaluate a transmission upgrade internal to its system. If the utility has correctly modeled the impact of this upgrade on outside parties and found that the impact is primarily limited to its system, then the full benefit template would not need to be employed. In this case, a utility perspective would be sufficient.

In those cases where there is a physical or contractual impact on other parties, a full benefit template needs to be developed in order to better understand the economic impact on other participants. If preliminary economic feasibility studies show the proposed upgrade to be strongly economic from both a societal and participant perspective (e.g. the CAISO), then uncertainty analyses may not be necessary. If, however, the economic benefits are marginal, uncertainty analyses may be needed to better understand the distribution of benefits and their root causes.

ES.6 Potential Enhancements

As we stated at the beginning of this summary, the CAISO-proposed methodology is based on five key principles. Although we established these principles as requirements, their exact implementation is not fixed. Our Path 26 study has provided us the initial opportunity to evaluate how to implement our methodology in a realistic situation. It has also given us the experience on which to base suggestions for further enhancements.

Table ES.3 below is a summary of potential enhancements we have identified. While this is not an exhaustive list, it provides an indication of the type of enhancement that could create additional analytical value.

Table ES.3 Potential Areas of Enhancement

	Key Principle	Potential Areas of Enhancement
1	**Benefit Framework**	a.) Enhance methodology to handle companies and sub-regions that will continue to plan on contract path basis (e.g. LADWP).
		b.) Greater disaggregation of participant benefits to company level.
2	**Network Representation**	a.) Review impact and trade-offs involved in modeling select 230 kV lines and develop recommendation for 230 kV line inclusion.
		b.) Develop methodology to Include losses and wheeling charges.
		c.) Develop greater understanding of phase shifter operations and model accordingly.
3	**Market Prices**	a.) Enhance RSI methodology by considering mark-ups in non-CA regions and alternative regression forms.
		b.) Review and test alternative approaches for forecasting market prices including game theory.
4	**Uncertainty**	a.) Evaluate ways to streamline approach so that more sensitivity cases can be run
		b) Develop probabilities for hydro and under- and over-build scenarios.
5	**Resource Alternatives**	a.) Develop more resource alternatives to evaluate including renewable and demand-side resources.
	Other	a) Add unit commitment, short-term load forecast uncertainty, and partial heat rate data
		b) Optimize hydro storage subject to constraints
		c) Disaggregate generator data further to represent generators by unit instead of plant.

In the development of TEAM, we have cataloged areas of enhancement for future research. Our hope is that the research will bring potential improvements over the next few years in the areas of improved analytical approaches for forecasting nodal market prices, valuation of insurance premiums for risk averse policy makers, improvements in databases for WECC and improved modeling of generation for locational prices.

ES.7 User-Specified Components

In addition to identifying what analytical steps we consider required and which ones are evolving, we believe it equally important to note what components of the CAISO methodology we are not specifying in detail. We have intentionally not specified a detailed analytical methodology with respect to certain "user-specified components" of the study, which we believe are best, decided by the end-user or sponsor of the study.

Table ES.4 below summarizes the user-specified components.

Table ES.4 Sample Listing of User-Specified Components

	Key Benefit	User Specified
1	Benefit Framework	a) Number of study years, discount rate, rev. req. calculation
		b) Interpolation or extrapolation of benefits
2	Network Representation	a) Type or vendor of network model
		b) Source of underlying transmission or generation data
3	Market Prices	a) Empirical or game-theory approach
		b) Regression formulation for empirical approach
4	Uncertainty	a) Number and specification of sensitivity studies
		b) Input data and probability for sensitivity studies
5	Resource Alternative	a) Specific resource alternatives
		b) Transmission operating alternatives

The CAISO intends to leave to the user decisions regarding software vendors, sensitivity cases, resource alternatives, data sources, market price methodology, etc. We believe that these decisions are best made by the experienced user who is most familiar with the proposed upgrade project.

ES.8 Reliability and Operational Considerations

ES.8.1 Reliability Evaluations and TEAM Methodology

The TEAM methodology can be applied to both reliability-driven and market-driven transmission expansion/upgrade projects in the following ways.

The reliability-driven projects (called “reliability” projects for short) typically include a set of alternative projects. All are identified as technically viable in addressing an existing or anticipated threat to reliable operation of the power system. At least one of must be selected based on its relative economic merits compared to the other candidate alternatives. Here, the objective of economic analysis is to identify the most cost-effective alternative. This means that even if none of the identified projects has quantified benefits that exceed the quantified costs, we would not reject the most cost-effective alternative solely because it was not economically viable with respect to the identified costs and benefits. This is because “operational reliability” has dimensions that are not uniquely measurable in monetary terms (e.g., the value of avoiding the adverse socio-political ramifications of a system-wide blackout is at best subjective). For the “reliability” projects, the TEAM methodology is intended to complement existing reliability studies and determine the additional economic benefits derived from an upgrade. In general, these benefits can include improvements in market competitiveness, decreases in fuel and capital costs of generation, and decreased probability and severity of service interruptions. The TEAM methodology is designed primarily to assess the first two categories of benefits, termed "economic benefits." In short, for "reliability" projects, the methodology is used to compare relative economic viability of candidate projects, all of which satisfy reliability objectives.

Market-driven projects (called "economic" projects for short) are candidate projects that are not necessary to maintain the reliability of the system operation but are important to facilitate market transactions and help mitigate strategic market behavior. For example, even if adequate resources were available in a load pocket, in the absence of strict regulatory measures, the load in that local area may still face curtailment risk if all local resources belong to a single entity in a position to exercise market power through physical withholding. Alternatively, a local supplier may engage in economic withholding with attendant high costs to the consumer. For "economic" projects, it is essential to quantify the benefits of the project (in monetary terms) with a metric that measures the magnitude of departure from a purely competitive (cost-based) market outcome with and without the project. Moreover, the decision as to whether or not to proceed with a given "economic" project will hinge upon the identified economic benefits of the project exceeding its identified economic costs. If several alternative "economic" projects are identified, the TEAM methodology will assist in determining those candidates that are economically viable, and in identifying the most cost-effective project among them. For projects requiring an economic justification for the upgrade, we assumed that a resource adequacy mechanism is in place to ensure that reliability objectives of the grid were satisfied. Thus, the approach is used to compare relative economic viability of candidate projects, all of which satisfy reliability objectives.

ES.8.2 Cost-Effective Solutions to Operational Concerns

Reliable power system operation requires adequate supply, adequate transmission, and adequate communication and control. In the integrated utility environment, a single entity had the responsibility for infrastructure adequacy. However, in the deregulated environment with transmission open access and reduced control by the power system operator of supply participation in the market, inadequacies or flaws in market design and rules can impact operation of the grid. For example, the inadequacy of the existing CAISO market design allows generation to schedule in the forward market in locations where there is inadequate transmission. By relying on scheduled generation that cannot be delivered due to transmission constraints, the system operator can face a number of daily operational problems that, if not addressed early, can result in increased reliability risk. Strictly speaking, this is not a reliability risk due to inadequate transmission, but due to inadequacy of market design.[10] There may have been adequate supply elsewhere that the operator could

[10]Transmission planning studies for reliability projects start from a base case assuming all resources are available, and then consider conditions arising from credible contingencies such as the loss of the largest generator and an N-1 outage on the transmission grid. If the system is secure under these conditions, then it is expected to be secure under normal, operating conditions. The events considered in these planning studies include more probable multiple simultaneous events: those that have occurred three times within ten years. This criterion is used to determine reliability. Inadequate transmission reliability means the criteria of N-1 contingency is not met. If this were the case, a reliability based upgrade would be requested. Inadequate transmission capacity may have nothing to do with violation of reliability criteria, but be the result of inadequate capacity to meet the demand for lower cost market transactions.

have lined up in the forward market without risking real-time transmission congestion. Although transmission expansion could reduce the operational reliability risk in this case, transmission inadequacy is not the root of the problem, and transmission expansion may not be most the cost-effective response. In this case, the operational concerns arose out of flawed market design. The benefit of the upgrade could be entirely different depending on whether or not the market design flaw is rectified. In order to identify the most cost effective solution to an operational problem it is important to distinguish between a reliability problem on the gird that should be addressed through a reliability upgrade and an operational concern arising from market design flaws.

Another example of distinguishing between reliability problems and poor economic incentives as being the root cause of operational problems is the inadequacy of rules regarding generation interconnection. If policy allows a generator to be built without regard to transmission system adequacy, it is conceivable that after a power plant is constructed, transmission would be inadequate to allow its supply to get out and serve load. A better generation interconnection policy would have had either the generator or another entity responsible for upgrading the transmission system to accommodate the new generation. A combination of inadequate generation interconnection policy and flawed market design can give rise to operational problems that may have nothing to do with transmission inadequacy. Even if generation were built where it could not be delivered in full due to transmission constraints, it may still be possible to entirely avoid operational reliability risk by proper market design (e.g., forward market scheduling taking into account “intra-zonal congestion”) without the need for a transmission upgrade. Insufficient operational reliability due to market design flaws is not a justification for a transmission upgrade when market design improvements (e.g., MD02) are anticipated that will correct the reliability problem. As stated in the previous section, our methodology recognizes the distinction between grid reliability upgrades and economic upgrades needed to accommodate market transaction to bring the most cost-effective solution forward for consideration.

ES.9 CAISO Decision Process

The need for a major transmission upgrade can be identified by a number of parties including utilities; public or private project developers, the CEC through its long-term resource studies, and the CAISO as the transmission operator. We are offering the TEAM framework as consistent means of conducting a project evaluation by any of these parties. If a sponsor does not privately finance a project, and a proposal is submitted to the CAISO for funding through an access charge, the CAISO will utilize the TEAM framework to evaluate project economics. The project must receive a favorable evaluation prior to us recommending the CAISO Board approve it.

We will also evaluate other perspectives to determine if other parties will benefit from the potential upgrade and can contribute to the capital cost of the upgrade. This evaluation will help us identify if large amounts of benefits transfer from one region to another or one market participant to another. Although not everyone may be compensated for a change in regional prices, the ultimate aim of an upgrade is to improve productive efficiency so all load may be served at a lower cost.

The CAISO will primarily rely on two perspectives when evaluating the economic viability of a potential transmission upgrade. These two perspectives are the Modified

Societal and the CAISO Participant. The Modified Societal perspective evaluates whether an upgrade is economic from a regional perspective (excluding the generator profits from uncompetitive market prices). The CAISO Participant perspective evaluates whether an upgrade is economic for the participants in the CAISO market (also excluding the generator profits from uncompetitive market prices). For each of these perspectives, there are expected to be WECC and CAISO winners and losers, but if the overall perspective is positive, then the project is a good candidate for further evaluation incorporating additional decision criteria.

The CAISO will primarily rely on two perspectives when evaluating the economic viability of a potential transmission upgrade. The modified societal test to ensure economic efficacy for the WECC region and the CAISO participant test using only competitive rents for funding decisions.

ES.10 CA Regulatory Framework for Transmission Evaluation

The regulatory process and procedures related to bulk electricity transmission assets can be divided into three sequential categories: planning, siting and ratemaking. The regulatory or oversight body responsible for each category depends on the identity of the particular project sponsor, i.e., public utility or investor-owned utility ("IOU").

Publicly owned utilities, such as municipal and special district utilities, continue to operate under the vertically integrated business-model and obtain planning approval, siting and environmental review, and rate authority from their local regulatory authority ("LRA"). As the result of industry restructuring, IOUs and other utilities that have joined the CAISO ("Participating Transmission Owners" or "PTOs") participate in the CAISO's Grid Coordinated Planning Process. IOU projects identified and approved by the CAISO in the planning phase continue to undergo environmental review and receive siting approval from the CPUC prior to construction. Jurisdiction over PTO transmission rates and terms of service passed to the federal government under restructuring and is administered by the CAISO through the Federal Energy Regulatory Commission ("FERC").

The CAISO's Grid Coordinated Planning Process evaluates transmission expansion projects that serve three main functions:

- Interconnecting generation or load
- Protecting or enhancing system reliability
- Improving system efficiency and flexibility, including reducing congestion

The CAISO intends to apply the TEAM methodology in evaluating interconnection and system efficiency projects. Under established FERC interconnection policy, PTOs must reimburse an interconnecting generator within five years for any "Network Upgrades" paid for by the generator. Because the interconnecting generator receives its money back within five years, the incentive for generators to select the least-cost location from an interconnection perspective is reduced. In response to this perceived inefficiency, the CAISO has proposed to use the TEAM methodology to determine the benefits of network upgrades for purposes of establishing a “cap” on the level of compensation available to the interconnecting party.

For system efficiency projects, the CAISO is authorized to compel PTOs to construct transmission expansion projects that promote economic efficiency. The CAISO tariff only includes general instructions to PTOs and other market participants on providing information, including studies in accordance with “CAISO guidelines,” that enable the CAISO to determine whether a project will promote economic efficiency. The TEAM methodology will serve as the CAISO “guidelines.”

As part of its siting responsibility, the CPUC has historically reviewed whether a project was necessary for reliability or economic reasons. Some have criticized this review as duplicative of the CAISO’ determination reached in its Grid Coordinated Planning Process. The CPUC is currently proposing to eliminate duplicative transmission need determinations by deferring to the need assessments reached by the CAISO to the extent the CAISO applies agreed upon economic and reliability standards. The TEAM methodology represents the anticipated standards to be applied in evaluating economic projects in CPUC proceedings.

ES.11 Path 26 Study

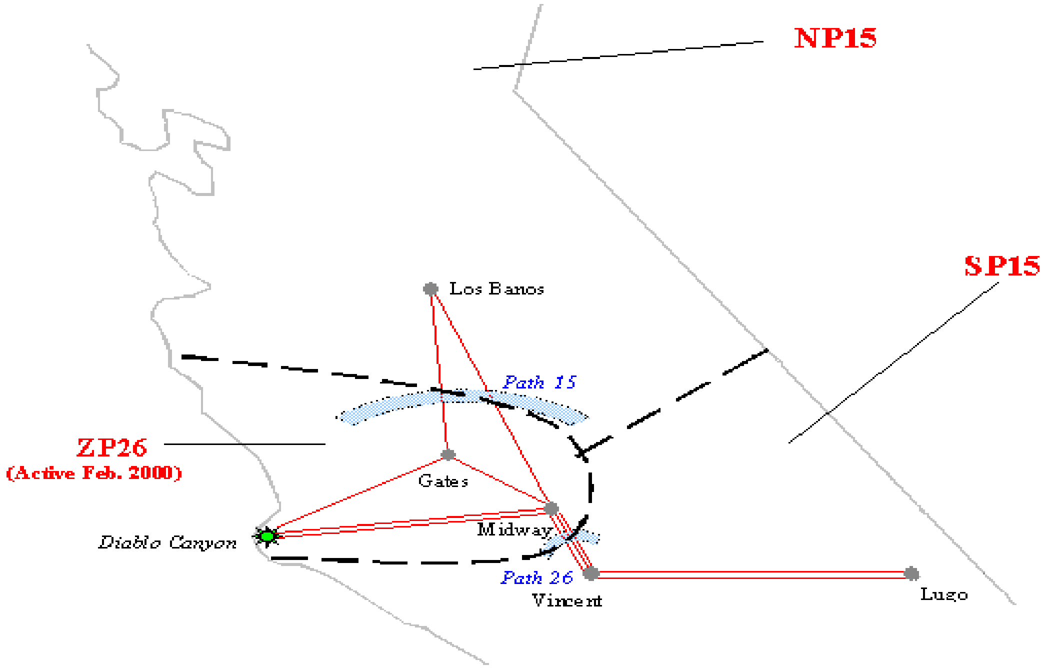
ES.11.1 Study Description

In order to illustrate our methodology, we include a summary of an example study that we conducted using the methodology. The example we selected is a proposed upgrade to a major 500 kV path between central and southern California [Path 26]. Figure ES.1 shows the location of the proposed Path 26 upgrade.

Historically, Path 26 has been frequently congested in the North-to-South direction. We are considering various upgrades to relieve the congestion. For purposes of this study, we defined the Path 26 upgrade project as:

- N-S direction – increase from 3,400 MW to 4,400 MW
- S-N direction – increase from 3,000 MW to 4,000 MW

Figure ES.1 Location of Proposed Path 26 Upgrade



We demonstrate the CAISO methodology by evaluating one of the proposed transmission upgrade options for Path 26. The upgrade being evaluated is the re-conductoring of the third 500 kV Midway-Vincent line.

ES.11.2 Benefit Framework

The CAISO summarizes four perspectives when evaluating the economic viability of a proposed upgrade. Table ES.5 summarizes the benefits for each of the four perspectives. The results shown in Table ES.5 represent one of the scenarios we developed for 2013. This particular scenario indicates the possible distribution of benefits in 2013 for WECC and CAISO assuming baseline input variables for load growth, gas prices, hydrological conditions, and bid mark-ups. In addition to the four perspectives shown, we further subdivided the benefits into Consumer, Producer, and Transmission Owner.

Table ES.5 Benefit Summary for Typical 2013 Scenario[11]

Perspective	Description	Consumer Benefit (mil. $)	Producer Benefit (mil. $)	Trans. Owner Benefit (mil. $)	Total Benefit (mil. $)
Societal	WECC	40.5	(30.1)	(8.2)	2.2
Modified Societal	WECC	40.5	(19.4)	(8.2)	12.9
California Competitive Rent	CAISO Ratepayer	12.5	(4.4)	0.0	8.1
	CAISO Participant	12.5	5.5	0.0	18.0

Definitions:

- **Consumer Benefit** – Reduction in cost to consumers
- **Producer Benefit** – Increase in producer net revenue. For societal perspective, producer benefit includes profit from uncompetitive market prices. For the other three perspectives, this profit is excluded (i.e. monopoly rent).
- **Transmission Owner Benefit** – Increase in congestion revenue
- **WECC Societal** – Sum of Consumer, Producer, and Transmission Owner Benefits in WECC. Also equal to difference in total production costs for the “without” and the “with upgrade” case
- **WECC Modified Societal** – Same as Societal but excludes Producer Benefit derived from uncompetitive market conditions
- **CAISO Ratepayer** – Includes ISO consumers and utility-owned generation and transmission revenue streams
- **CAISO Participant** – Includes ISO Ratepayer plus the CA IPP Producer Benefit derived from competitive market conditions

[11] This scenario is the 2013 market-based reference case, which uses base assumptions for demand, gas price, hydro, and mark-up.

The Consumer, Producer, and Transmission Owner and Total Benefit can be computed for the four perspectives that are the most important to the CAISO – Modified Societal, CAISO Participant, CAISO Ratepayer, and Societal. The Total Benefits at the WECC level equal the difference in total production costs between the "without" and "with upgrade" simulations.

Although the primary purpose of Table ES-2 is to illustrate the benefit framework for one of the scenarios, it is informative to understand the reasons for the benefit distribution. In this particular scenario, the Consumer Benefit was *positive* for all perspectives and the Transmission Owner Benefit was *negative* for all perspectives. The Producer Benefit Revenue was also negative for most perspectives -- except for the CAISO Participant perspective (excluding monopoly rents).

These results appear reasonably intuitive. The consumer benefited significantly from a reduction in market power and the increased transmission capacity resulting in a more efficient generation dispatch.

Since the proposed Path 26 upgrade reduced congestion and associated congestion revenue, transmission owners saw a significant decline in revenue.

The producer benefit was negative for the societal, modified societal, and CAISO ratepayer perspective. The primary reason for this reduction in net revenue was that the increased transmission capability resulted in a more efficient generation dispatch which then resulted in lower prices paid to generators.

The CAISO IPP competitive benefits, however, increased by $12 million. A significant part of the competitive rent increase was due to the increased generation of approximately 120 GWh per year by the IPP's in the CAISO area.[12].

ES.11.3 Impact of Uncertain Variables

The cases we developed encompass a wide range of assumptions for selected input parameters. The benefits in some of these scenarios were significantly impacted as a result of changes in the underlying input variable. In other cases, the benefits did not change nearly as much.

Figure E-2 summarizes the potential impact of the uncertainty of individual variables on the annual CAISO Participant benefits in 2013. This figure is often referred to as a "Tornado Diagram" in that it visually displays the results of a single-factor sensitivity analysis. In a Tornado Diagram, generally the variables with the greatest impact on results are shown in declining order.

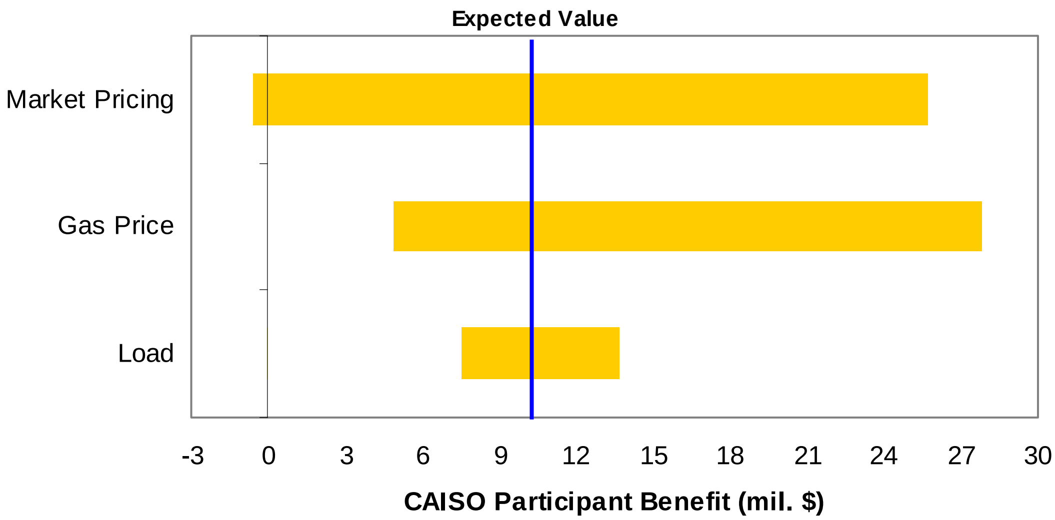
Figure ES.2 shows the impact of three input variables on the 2013 CAISO Participant benefits. The first variable, market pricing, is the level of uncompetitive bidding in the market and ranges from a perfectly competitive market to a highly uncompetitive one.

[12] For a more complete discussion regarding how total producer benefits are subdivided into competitive and monopoly rents, refer to Chapter 2, "Quantifying Benefits", pp. 11-12.

The low and high load-growth scenarios are based on forecast errors for peak and energy that we computed by comparing historical forecasts and actual conditions. The energy requirement ranges from 180,000 to 200,000 gWh per year.

We also developed the gas price low- and high-price scenarios based on an observed forecast error. In 2013, the average burner-tip gas price for WECC is $5.49/mmbtu. The low and high gas prices in 2013 are $2.68/mmbtu and $11.25/mmbtu respectively.

Figure ES.2 Potential Impact of Single Uncertain Variables in 2013[13]



A "Tornado Diagram" can be used to show the relative impact of single, uncertain input variables on the CAISO participant benefits. Based on the above information for 2013, the ratepayer benefits are most sensitive to the market pricing uncertainty and least sensitive to load growth uncertainty.

The potential impact on the annual CAISO Participant benefit from the uncertainty surrounding market pricing was about $26 million in 2013. The impact from uncertain gas prices was approximately $23 million, and the impact from uncertain load growth was $6 million.

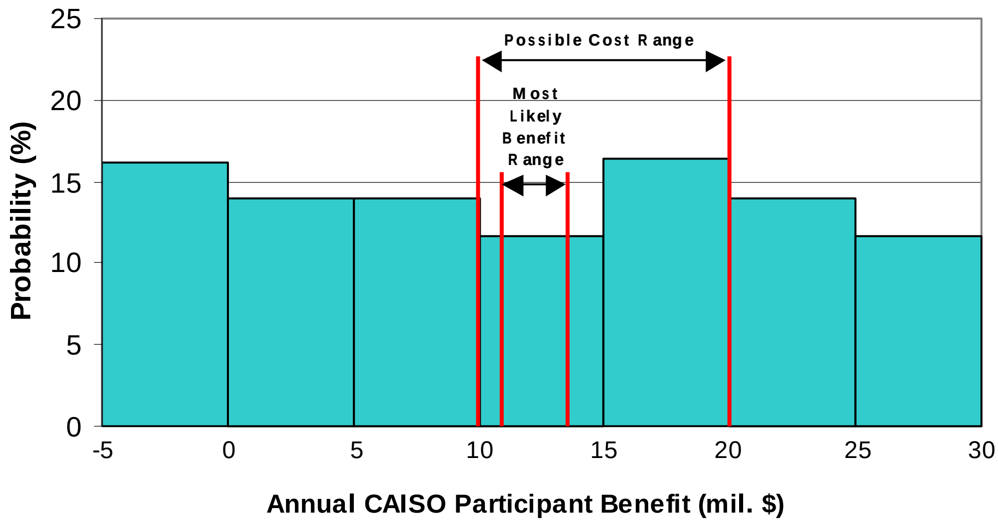
ES.11.4 Probable Benefit and Cost Range in 2013

We have estimated a "most-likely" benefit and a "possible" cost range based on the 22 cases for 2013 that have a probability assigned to them. The probability-weighted results of the scenarios are summarized in the histogram shown in Figure ES.3. The

13 The cases considering the impact of a low and high hydrological condition for 2013 assuming a base mark-up have not been reviewed yet, and are therefore not presented at this time.

annual CAISO participant benefits for the 22 cases are organized into benefit ranges (or "bins"). The benefit range in Figure ES.3 is $5 million nominal dollars. The collective probability for all cases in each benefit range are totaled and shown in Figure ES.3.

Figure ES.3 Potential Range of 2013 Benefits and Costs



We forecast the "most-likely" range of CAISO Participant <u>benefits</u> to be between $11 and $14 million in 2013. This value is based on the 22 scenarios developed and does not include any benefits attributable to an "insurance value" (see discussion in ES 11.5). We estimate the "possible" range of CAISO Participant <u>costs</u> to be between $10 and $20 million in 2013.

A most-likely range of benefits is determined by using the linear programming approach discussed in Chapter 5.

For the possible cost range, we recognize that the levelized revenue requirements could exceed the levelized capital recovery amount by up to 50 percent (or more). In addition, we assumed that there was a 50 percent uncertainty with respect to the capital cost estimate of $100 million. Therefore, we believe that a reasonable range for annual levelized costs is between $10 and $20 million.

ES.11.5 Insurance Value

The benefits in Figure ES.3 are based on the probability-weighted results from the network simulations (i.e. the difference in benefits for the "without" and "with upgrade" cases).

An "insurance value", on the other hand, is a more subjective determination. Developing an appropriate insurance value requires two additional elements: (a) well-defined contingency scenarios to properly understand the extreme-event impacts and associated costs to be avoided; and (b) sufficient input from decision makers to determine their level of risk aversion and their willingness to incur an "insurance" premium to avoid the consequences of these events. Neither of these two elements were sufficiently available in this study to compute an insurance value.

We did, however, have an opportunity to develop a contingency case to illustrate the concept of insurance value. We started with a case for the year 2013 where there is high demand, high gas prices, base hydro, and moderate market pricing mark-up. To this case, we assumed that the DC Intertie was unavailable for the entire year.

We consider the yearlong DC Intertie outage to be a contingency case. It is an extreme event, whose probability is not easily quantified, but the occurrence of such an outage could have huge consequences.

As we would expect, in this situation the Path 26 upgrade has more value than any other case evaluated. The CAISO Participant benefit for the DC-out case was calculated to be $80 million in 2013. Although the <u>value</u> of the Path 26 upgrade is substantial in this case, the <u>expected value</u> of the Path 26 upgrade in this situation is negligible since the probability of the event is so remote. However, in order to avoid the full consequences of a yearlong DC outage, the additional fee that ratepayers (and decision makers) might be willing to pay as an insurance premium could be significantly larger than the expected value, and may be an important part of the overall benefits.

ES.11.6 Path 26 Recommendation

Based on the results presented in the Executive Summary and Chapter 9 – Results, we can make the following observations on the annual costs and benefits for the proposed Path 26 upgrade:

- The most-likely CAISO Participant benefits in 2013 range from $11 to $14 million
- The possible range of estimated costs in 2013 is from $10 to $20 million
- The expected range of Modified Societal Benefits in 2013 is $7 to $10 million

From these observations, we conclude that the Path 26 upgrade <u>may</u> be economically viable. However, to reach a definite conclusion in this regard, additional analytical refinements need to be performed. Specifically, these additional refinements would include the following:

- A more detailed estimate of capital costs -- preferably with a 20 percent or less margin of error
- An appropriate calculation of annual revenue requirements including capital recovery, relevant taxes, operating costs, and other associated costs
- A more comprehensive evaluation of other Path 26 upgrade alternatives including additional remedial action schemes (RAS)

- A net present value analysis of the benefits which would require additional years of benefits to be calculated beyond those for 2008 and 2013
- Consideration of the potential impact of other projects on the benefits of Path 26 upgrade (and those of other competing projects)

These additional tasks would enable the CAISO and the CPUC to make a more definitive recommendation regarding the economic viability of the proposed Path 26 upgrade.

ES.12 CONCLUSION

Based on our initial use of the TEAM methodology in the case study of Path 26, we conclude that the methodology and its five guiding principles will substantially enhance the CAISO's ability to fulfill its responsibility to evaluate and recommend transmission expansion projects.

The case study results demonstrate that the methodology will produce the comprehensive analytical information project proponents and review and approval authorities need to make informed decisions in shaping California's transmission infrastructure. The TEAM methodology advances this objective by creating a framework to examine a project from multiple viewpoints - from those of the overall western interconnection, to the end consumer or transmission line owner. Equally important, the methodology provides a flexible mechanism to identify a range of risks and rewards associated with the project under diverse contingency and market conditions.

We believe that adopting TEAM as a standard for all parties to use in evaluating the economic need for transmission projects would promote consistency and comparability and eliminate duplicative studies. Accordingly, we are confident in recommending adoption of TEAM by the CPUC.

1. Overview of Transmission Planning and Siting Process

The TEAM methodology is intended to be a tool for providing market participants, policy-makers, and permitting authorities with information necessary to make informed decisions when planning and constructing a transmission network for reliable and efficient delivery of electric power to California consumers. This section of the TEAM report discusses the current transmission planning and siting process and demonstrates how the TEAM methodology enhances that process. It also identifies changes in the regulatory environment that are occurring, or may occur in the near future.

1.1.1 Overview

The regulatory processes and procedures governing bulk electricity transmission assets generally can be divided into three sequential categories: planning, siting and ratemaking. The regulatory or oversight body responsible for each category depends on the ownership of the particular project, i.e., public utility or investor-owned utility ("IOU"). The CAISO, California Public Utilities Commission ("CPUC"), the California Energy Commission ("CEC"), and a myriad of local regulatory authorities ("LRAs") may each have a role in transmission planning and siting.

Before deregulation, vertically integrated utilities, whether publicly or investor owned, individually planned for both transmission and generation to meet their specific native load requirements. Preferred network transmission projects largely emerged from the utilities' engineering and transmission planning departments, which included consultation with regional reliability entities depending on the network transmission project being considered. IOU project siting required obtaining a Certificate of Public Convenience and Necessity ("CPCN") from the CPUC as a precondition to construction. In the CPCN siting proceedings, the CPUC evaluated projects from an economic and reliability perspective as well as on environmental, social and aesthetic factors, pursuant to the California Environmental Quality Act ("CEQA") and Public Utilities Code § §1001, et seq. The costs of approved projects were subsequently incorporated into the IOUs' general rate cases for recovery from ratepayers in the IOU's service territory.

Publicly owned utilities, in contrast, obtained approval, environmental review under CEQA, and rate authority through their particular LRAs, i.e., municipality or special district.

The transmission grid has an expanded role in the restructured electric industry environment. It now must facilitate competitive markets and the pooling of resources to provide for ancillary services, among other things. This role changed the planning and regulatory landscape, resulting in a broadening of expectations under which these entities were to perform. To facilitate the success of these competitive markets independent transmission providers were envisioned to provide non-discriminatory access to the grid and to evaluate and plan transmission expansion projects necessary to maintain a reliable and secure system. Accordingly, Assembly Bill ("AB") 1890, California's restructuring law, transferred responsibility for *transmission planning and grid reliability* from the IOUs to the CAISO. The IOUs, and all other transmission owners choosing to do so, ceded operational control of their network transmission assets to the CAISO ("Participating Transmission Owners" or "PTOs") and became subject to the CAISO's federally approved tariff provisions regarding transmission planning. Merchant transmission developers could also sponsor projects and become PTOs. Currently, the CAISO is responsible for transmission planning for about 80 percent of California's bulk electricity grid.

The recent adoption of Senate Bill ("SB") 1389 introduced additional transmission planning requirements at the state level. SB 1389 directed the CEC, in coordination with the CPUC, CAISO, and other governmental entities, to produce an integrated energy policy report every two years that includes "assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices." (Public Resources Code § 25301 (a)). The CEC's integrated policy report also generally assesses system reliability and the need for resource additions. The CEC, therefore, will provide a high level analysis that will be utilized in refining resource decisions, including transmission planning.

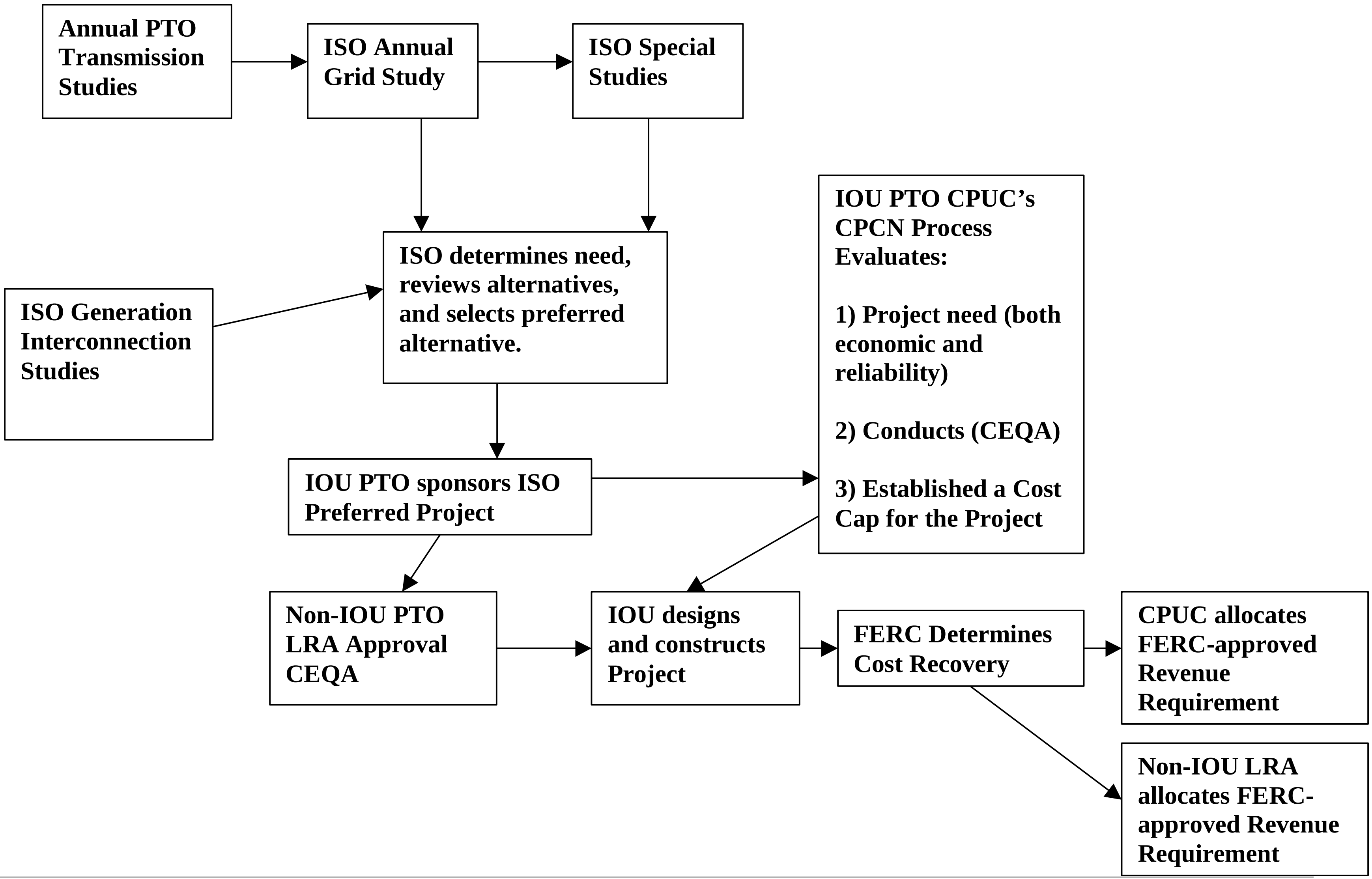
AB 1890 did not, however, revise state law governing transmission facility siting set forth in Public Utilities Code § 1001, et seq. As a result, IOUs continued to be required to obtain a CPCN as a prerequisite to constructing transmission facilities above 200 kV. Because publicly owned utilities were not statutorily obligated to participate in the CAISO, they continue to propose, plan, and build transmission projects to meet their own reliability and economic needs when approved by their LRAs.

Restructuring also altered the primary source of ratemaking authority for transmission assets turned over to the CAISO. By design, the IOUs and other PTOs were to no longer receive ratemaking approval for network facilities at the CPUC through general rate cases or from their LRAs. Instead they were to rely on approval from the CAISO as a precursor to receiving approval for transmission rates from the Federal Energy Regulatory Commission ("FERC"). Under the CAISO's Transmission Access Charge proposal currently pending before FERC, the cost of new network transmission assets approved by the CAISO and part of its controlled grid would be recovered through a phased-in uniform grid-wide charge to all load within the CAISO control area.

Figure 1.1 provides an overview of the current CAISO / PTO transmission planning process.[1]

[1] Figure 1.1 is a modification of Figure 1 of the *Report on the Current Transmission Planning Process for Investor Owned Utilities*, CPUC Division of Strategic Planning (Dec. 29, 2003).

Figure 1.1 Current PTO Transmission Assessment Process



1.1.2 Description of Current Process and TEAM's Role

1.1.2.1. CAISO Grid Planning Process

The current CAISO transmission-planning process is primarily structured around the requirement that PTOs develop, under the oversight of the CAISO and in cooperation with other market participants and stakeholders, annual transmission expansion plans. (CAISO Tariff § 3.2.2.1.) The goal of this annual transmission expansion plan is to identify "needed" transmission upgrades or additions required in the PTO's system to assure that all applicable reliability criteria are met. Need exists where the proposed project "will promote economic efficiency or maintain system reliability." A PTO or any other market participant may propose a transmission system upgrade or addition for consideration in the PTO annual transmission expansion plan review process. (CAISO Tariff § 3.2.1.) In addition to PTO annual transmission plans, the CAISO also conducts or oversees separate focused studies for large or complicated projects.

1.1.2.1.1 Standards

The CAISO Tariff specifies that the CAISO and PTOs must ensure system reliability consistent with "applicable reliability criteria." (CAISO Tariff § 3.2.1.2.) Applicable reliability criteria are the reliability standards established by North American Electric Reliability Council, Western Electric Coordinating Counsel, and local reliability criteria developed by the CAISO as amended from time to time.

Unlike reliability criteria, there are no industry-wide standards or other universally accepted methodology for determining a project's economic efficiency in a competitive market environment. The CAISO Tariff only provides general instructions to PTOs and other market participants for providing information, including studies comporting with "CAISO guidelines," to enable the CAISO to determine whether a project will promote economic efficiency. (CAISO Tariff § 3.2.1.1.) It is the intent of the TEAM methodology to establish industry wide standards within California to serve as the universally accepted methodology through which the CAISO would evaluate economic projects in its grid planning processes. It is also intended that the TEAM methodology will create uniformity of application between "need" determinations at the CAISO and at the CPUC in the context of a CPCN proceeding as well as become a useful tool for any project developer or LRA to evaluate the economic benefits of a proposed transmission upgrade. We further discuss the issue of regulatory coordination below.

1.1.2.1.2 Procedures

As a minimum, the PTO's annual transmission expansion plan provides a detailed, year-by-year analysis for the next five years of projects needed to meet reliability criteria or to promote economic efficiency, plus an analysis of the tenth year. (CAISO Tariff § 3.2.2.1.) The five-year analysis is necessary to fit with the PTOs' budgeting cycles. The tenth-year analysis is required to facilitate identification of longer-term transmission needs that might not be identified in a five-year assessment. These could include projects with permitting and construction timeframes greater than five years and the integration of identifiable short-term transmission needs with projects having a longer planning horizon (e.g., to avoid building three 230kV lines when a single 500kV line would be more efficient). Because the PTOs' transmission plans are produced on an annual basis, they provide a rolling ten-year planning horizon for their systems.

Subsequent to the submission of each PTO's annual plan, and for purposes of developing a CAISO-controlled grid-wide integrated plan, the CAISO initiates its annual CAISO- controlled grid-wide transmission expansion planning study through an open stakeholder process typically initiated in the early part of the calendar year. This is to ensure stakeholders are provided an early opportunity to review and comment on the transmission expansion plans submitted by the PTOs. The CAISO Tariff requires that a Project Sponsor agree to the scope and assumptions of any study addressing the economic feasibility of a transmission upgrade or addition. Disagreements on study scope and assumptions are subject to the CAISO's alternative dispute resolution ("ADR") procedures. (CAISO Tariff § 3.2.3.)[2] The TEAM methodology will establish the study parameters acceptable to the CAISO for determining which projects are economic. However, the stakeholder process will continue to be valuable in addressing those areas of the methodology where the experienced judgment of those participating in the study will be critical to the analysis. In this regard, as illustrated in Figure 8.1, the CAISO anticipates that the stakeholder process will continue to function in a similar capacity under the TEAM methodology by assisting in sensitivity selection and development.

Utilizing initial stakeholder input, the PTOs further refine the studies of their individual systems, hold additional meetings as needed with the CAISO and stakeholders, and coordinate with the CAISO on the final development, execution, and evaluation of the studies. Toward the end of the calendar year, the PTOs hold a final stakeholder meeting to provide a final review of the study report and to address any unresolved comments. Once the CAISO staff has approved the PTOs' transmission expansion plans, their transmission expansion plans are incorporated into the CAISO's Controlled Grid Study to corroborate that all reliability violations have been addressed across the entire CAISO controlled grid, that economic projects do not have any unintended reliability consequences, and to assure that there are no "seams" issues among the PTOs' systems that have not been identified in the PTOs' transmission expansion plans. But for those projects which cost $20 million or more, CAISO Management approves all transmission projects and plans and presents these projects and plans to the CAISO Board of Governors during the first quarter of each year. Projects costing $20 million or more are presented to the CAISO Board of Governors for their approval.

[2] To the extent the scope and basic assumptions included in the TEAM methodology are adopted by the CAISO Governing Board, those elements of a future study may not be open to dispute by a Project Sponsor. The CAISO is continuing to review its Tariff to determine whether modifications are needed to efficiently implement the TEAM methodology.

The determination from a procedural, not substantive, perspective whether a project proposed for economic reasons will promote economic efficiency is currently made in the following ways:

- Except where the PTO Project Sponsor commits to paying the full cost of construction, by ADR if the PTO, CAISO, or any party questions the economic need determination
- Where a non-PTO Project Sponsor commits to pay the full cost of construction and demonstrates financial capability, such commitment is sufficient (PTO can demand security)
- By ADR where the Project Sponsor is unwilling to pay the full costs and the project was not included in the PTO's annual transmission plan for reliability reasons or the PTO's planned operation date is unacceptable to the CAISO or Project Sponsor

The ADR procedures, pursuant to Section 13 of the CAISO Tariff, provide for a mutually agreeable neutral arbitrator, the opportunity to conduct discovery, present evidence, and to cross-examine witnesses. The arbitrator's decision must be issued within six months of initiating the process. The determination, including any determination by FERC or on appeal from a FERC decision, shall be final.

1.1.2.2 CAISO Interconnection Process

A new generator or an existing generator that increases its total capacity must interconnect to the CAISO grid. Under the CAISO Tariff, the PTO in whose service territory the new facility will interconnect, performs system impact studies and facilities studies to determine scope and cost of transmission upgrades necessary to accommodate the new facility or capacity increase and estimate the cost impacts. The CAISO verifies the results, conducts an independent analysis of the transmission impacts, and approves the PTO's studies.

The important factors in understanding the role of TEAM in the interconnection analysis process are how the costs of needed transmission upgrades are allocated under federal law. The CAISO classifies interconnection upgrades as either "interconnection facilities" or "network upgrades." Interconnection facilities are those needed to physically interconnect the generation facility to the first point of interconnection on the grid. Network upgrades consist of either "reliability upgrades" - those necessary to interconnect the facility safely and reliably that would not have been necessary but for the interconnection of the new facility; or "delivery upgrades" - those needed to relieve congestion so that the energy from the facility can reach load. FERC's priority in setting interconnection policy has been to facilitate the ability of generators to interconnect to the bulk electric grid. As a result, FERC policy has consistently been that the PTO must reimburse an interconnecting generator within five years for any network upgrades paid for by the generator. Because the interconnecting generator receives its money back within five years, FERC's approach insulates generators from cost responsibility for network upgrades and thereby reduces the incentive for the generator to select the least-cost location from a transmission perspective. FERC recently reaffirmed this policy in its Order No. 2003.

In response to Order No. 2003, the CAISO has proposed to perform an economic test using the TEAM methodology on network upgrades costing more than $20 million to determine the extent of the benefits resulting from the upgrades and to use the amount of those benefits as a de facto cap on the level of credits that could be offered to the interconnecting generator. The reason for applying the TEAM methodology is to guard against egregiously expensive projects that may otherwise result from the incentives created by current interconnection policies. Without locational price signals, a reasonable backstop is needed to ensure that ratepayers are not paying for uneconomic projects. This CAISO's proposal to apply an economic test to interconnection applications remains pending before FERC.

1.1.2.2.1 CPCN Process

As noted above, after a project has emerged from the CAISO grid planning or interconnection process, an IOU PTO must file an application with the CPUC for a CPCN in order to construct a transmission line above 200 kV. Consistent with the practice prior to restructuring, the CPUC reevaluates the transmission project from both a reliability and economic standpoint in the CPCN proceeding. CPUC staff recently acknowledged the difficulty in performing an economic assessment in a restructured environment without an agreed-upon methodology and acknowledged the role the TEAM methodology would have in providing an analytical solution:

> "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." [3]

The TEAM methodology, if accepted by the CPUC in Investigation No.00-11-001, is intended for universal application in CPCN proceedings. It would fulfill the CPUC's recognized need for a more dynamic model that incorporates market factors.

[3] *Report on the Current Transmission Planning Process for Investor Owned Utilities,* CPUC Division of Strategic Planning (December 2003), at p. 14.

Additionally, pursuant to Public Utilities Code § 1001, the CPUC reviews the project under the provisions of the CEQA, and for its impact on ratepayers and utility capital structure and costs. Given that the CAISO typically approves a transmission project without regard to the exact physical route of the proposed line, it is in the CPCN's CEQA review process that specific project alternatives and routing are considered. The CPCN proceeding also evaluates the proposed project in terms of community values, recreation and park areas, and historic and aesthetic values. (Pub. Utilities Code § 1002.)

1.1.3 Pending Regulatory Changes

In its 2003 Integrated Energy Policy Report, the CEC noted "in the CPCN process, the CPUC often reexamines planning issues, refusing to accept the CAISO's determinations in the planning process. As a result, projects with regional or statewide benefits that could help the state mitigate market power, stabilize electricity prices, and improve the reliability and environmental performance of the electricity system have been denied permits by the CPUC or suffered long delays in the process because of an inadequate assessment of these benefits."[4] The CPUC has proactively responded to this criticism by initiating a rulemaking proceeding to streamline the transmission siting process for IOUs that seeks to achieve a more comprehensive, coordinated infrastructure for California.[5]

The CPUC proposes to eliminate duplicative transmission need determinations by deferring to the need assessments reached by the CAISO in its grid planning process to the extent the CAISO applies agreed upon economic and reliability standards. The TEAM methodology constitutes the CAISO's proposed standards for universal application in evaluating economic projects in CPCN proceedings.

The renewed effort for greater resource planning and coordination builds off of authority granted the CPUC by AB 57 to adopt and approve long-term procurement plans for the IOUs. In the procurement plans, the CPUC would balance competing resource options such as generation, demand management, and transmission. This balancing would be accomplished through a broad spectrum of input from the IOUs, stakeholders, and, in part, on the planning assumptions regarding load and resource capacity developed by the CEC in its biennial Integrated Energy Policy Report process. It is contemplated that once the CPUC approves transmission as a component of the long-term plans, the IOUs would work with the CAISO in its planning process to perform detailed analyses of project options using the CPUC agreed-upon TEAM methodology and reliability criteria to determine "need." If a project requires a CPCN, the CPUC would not revisit the question of need, but rather would simply validate that the economic and reliability criteria were applied.

This pending approach would eliminate existing redundancy in transmission need assessments by assigning to the CAISO responsibility for assessing project "need", and the CPUC responsibility for reviewing the application of the

[4] *2003 Integrated Energy Policy Report*, CEC (date), at p. 19.

[5] *Order Instituting Rulemaking on Policies and Practices for the Commission's Transmission Assessment Process*, R.04-01-026 (Jan. 28, 2004) ("Transmission Rulemaking").

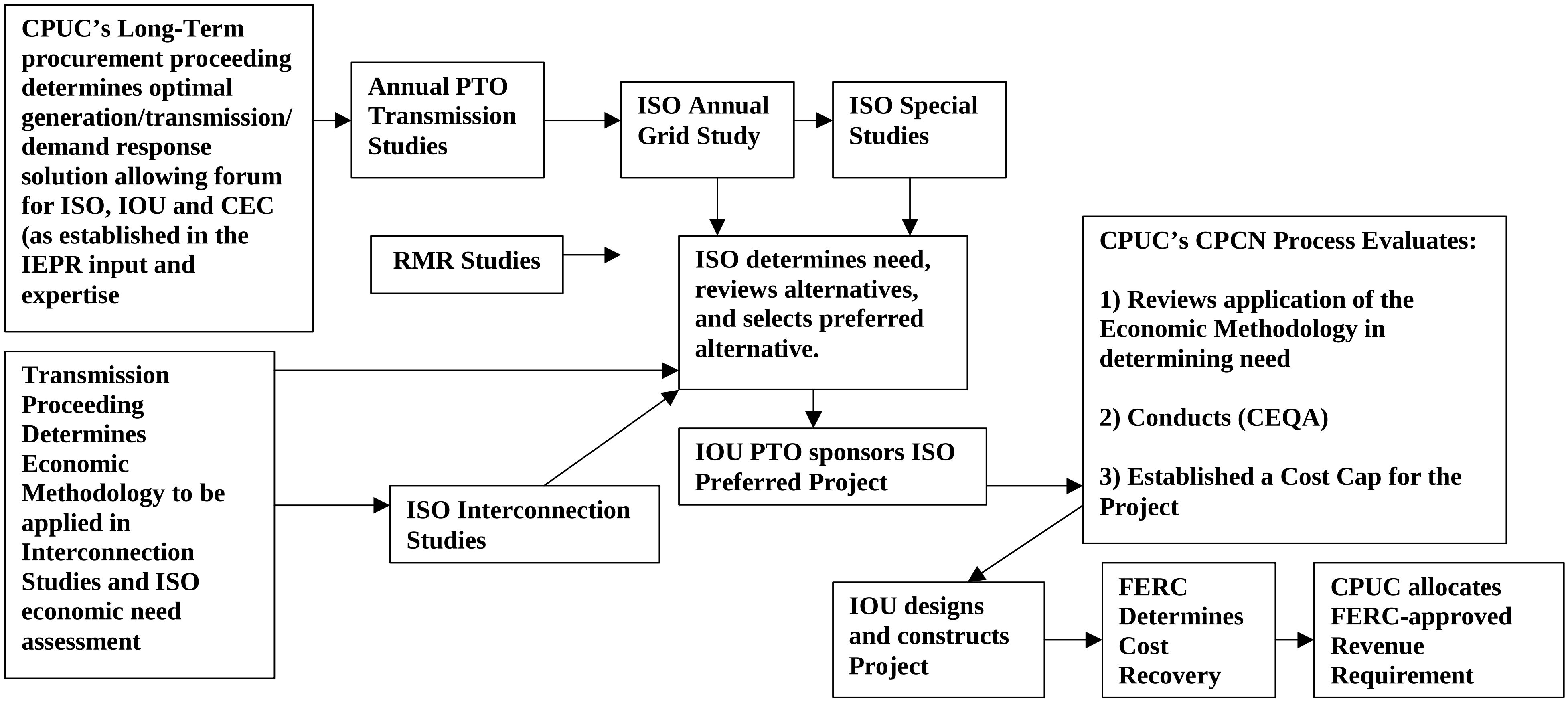
approved TEAM methodology, conducting CEQA review, and implementing more comprehensive resource planning through the IOU's long-term plans. Figure 1.2 outlines the proposed transmission planning and siting process.[6]

Given the emergent status of the IOUs' long-term resource procurement plans with the CPUC, the TEAM methodology presently does not explicitly include consideration of the outcome of that process in determining resource inputs or assumptions to the network topography. However, consistent with the Transmission Rulemaking, the CAISO anticipates incorporating the outcomes of the IOU long-term procurement plans as they become available into the development of the base case assumptions for future studies. Nevertheless, the CAISO recognizes that the Commission may ultimately find that legal or other obstacles preclude adoption of the process amendments proposed in the Transmission Rulemaking.[7] The possible defeat or modification of the Transmission Rulemaking will not eliminate the value of the CPUC's evaluation of the TEAM methodology in this proceeding. The CAISO intends to utilize the TEAM methodology in fulfilling its statutory obligations to provide reliable and efficient transmission service. Accordingly, whether or not formal deference is accorded the CAISO's economic evaluation of a proposed transmission project, the CPUC's evaluation and approval of the methodology will promote regulatory efficiency by imposing on IOUs a uniform assessment methodology.

[6] Figure 1.2 is a modification of Figure 2 of the *Report on the current Transmission Planning Process for Investor Owned Utilities*, CPUC, Division of Strategic Planning (Dec. 29,2003).

[7] In making this statement, the CAISO in this report is not implying or otherwise taking a position on the merits of any legal or policy objections that may have been raised with regard to the Transmission Rulemaking.

Figure 1.2 Proposed Process for Streamlining Transmission Planning and Siting for IOUs



2. Quantifying Benefits

2.1 Challenges in Economic-Driven Transmission Investment Decision Making in a Wholesale Market Regime

Economically efficient investment in transmission is critical to the efficient operation of the transmission system and the competitiveness and efficiency of the electricity wholesale market. Transmission-related capital investment decision-making in the old vertically integrated regime was straightforward. The main goal then was to enhance system reliability and reduce total production cost. The trade-off between generation investment and transmission investment was simply calculated. The parties that funded transmission investment and benefited from its construction were easy to identify and usually were the same entity. The cost of transmission investment in the old paradigm was usually rolled into the electric customer rate base by regulators and could be recovered through regulated electric rates.

In the new wholesale market regime, there could be two types of transmission expansion/upgrade projects: reliability-driven projects and economic-driven projects. The CAISO has existing reliability criteria and standards for evaluating reliability-driven transmission upgrade projects. In contrast, economic-driven transmission investment decision-making in the new wholesale market regime presents a new challenge, in large part, due to the dis-aggregation in the decision-making process of choosing between economic-driven generation and economic-driven transmission investment. Another reason it is a challenge is that changes in market prices rather then production costs will be the basis of transmission benefits. Consequently, a methodology is needed to project how transmission upgrades could affect generator behavior, including the exercise of market power.

In the wholesale market regime, two kinds of economic-driven transmission investment are possible: private investment and regulated investment. Private investment arises if an investor chooses to invest in a transmission upgrade in exchange for the congestion revenue rights for the additional capacity that the upgrade makes available to the market (i.e., investment costs are recovered through the market rather than through a regulated rate of return). There are two significant shortcomings from relying solely on private transmission investments. First, because transmission upgrades reduce the degree and incidents of congestion, the congestion revenue streams are diminished by the upgrade and thus can create a disincentive for investment. This problem can be exacerbated by the lumpy nature of transmission upgrades that limits the investor's ability to choose an optimal upgrade. Second, transmission upgrades have economic implications to a wide range of market participants. A private investment decision does not include these market externalities and therefore will likely result in sub-optimal societal investment decisions. Regulated investments pertain to transmission upgrades for which the investment costs are recovered through a regulated rate of return. It is critical to this process that the regulatory body identifies the beneficiaries as well as benefits of transmission expansion, and that they use their regulatory powers to make beneficiaries pay their fair share.

In dealing with economic-driven transmission investment decision making in the deregulated environment, one primary difficulty facing decision makers is the lack of an appropriate benefit-cost analysis framework; one which enables them to clearly identify the beneficiaries and expected benefits of any kind of transmission project, from private to regulated transmission investment. The methodology we present here addresses this problem. It provides a standard framework to measure transmission expansion benefits regionally and separately for consumers, producers, and transmission owners for any kind of economic-driven transmission investment. This benefit framework provides decision makers a useful tool for assessing transmission benefits in an efficient and cost-effective manner.

The benefit framework presented here focuses primarily on benefits of economic-driven projects. It does not intend to quantify benefits of reliability-driven projects, in part, because it is extremely difficult to quantify in a trustworthy manner changes in the frequency, severity, and duration of service interruptions, or to attach dollar values to such changes. However, this benefit framework can be still used to rank the economic benefits of alternative reliability projects for a given reliability problem. The reliability-driven projects often include a set of alternative projects all of which are identified as technically viable to address an existing or anticipated threat to reliable operation of the power system, at least one of which must be selected based on its relative economic merits compared to the other candidate alternatives. Here, the objective of economic analysis is to identify the most cost-effective alternative. In short, for reliability projects, the TEAM methodology is used to compare relative economic viability of candidate projects, all of which satisfy reliability objectives.

In the following sections we present our methodology. We first discuss ways to identify and define relevant market participants and how to calculate surpluses for those participants. We then discuss the impact of strategic bidding on market participants' surpluses. We discuss how transmission expansion benefits should be measured, both in theory and in practice. Finally we present our decision-making framework and provide several alternative perspectives that decision makers should consider.

2.2 Welfare Measures in Electricity Wholesale Markets

2.2.1 Define Market and Relevant Market Participants

Because of the interconnected nature of the Western electricity system, the relevant geographic area for a transmission expansion project sited primarily in the CAISO controlled area could be much broader than the CAISO control area itself. One approach we might take is to model the entire WECC network explicitly to ensure that power flows in the various modeling scenarios with and without the transmission upgrade are feasible. In this approach, the entire WECC area is modeled as one centralized market. Alternatively, we can model the CAISO controlled area explicitly and the rest of the WECC area in the aggregate, with explicit import and export channels between the two areas. We adopted the former approach in our Path 26 study mainly because of the difficulty in modeling the power flows accurately between the CAISO network and the rest of the WECC area where only the CAISO network is fully modeled.

Any market consists of various market participants. For any transmission project evaluation, we need to capture the potential benefits throughout the whole WECC area and the distribution of those benefits among various geographic regions and across various market participants (i.e., Load Serving Entities (Consumers), Producers, and transmission owners). In our Path 26 study, the WECC area consists of 21 geographic regions, where PG&E service area, SCE service area, and SDG&E service area each is a separate region.[1]

Classical economic surplus measures are used to define the welfare of all participants in the electricity wholesale market.[2] In the electricity wholesale market, participants involved with physical production, transport, and use of electricity may be buyers (i.e., consumers), sellers (i.e., generators), and facilitators (i.e., transmission owners).[3] Consumers are often represented by their electricity distribution companies (public utilities) that purchase power to meet residential and commercial customers' load. The cost of operating such public utilities (i.e., revenue requirement) is often recovered through regulated customer rates. Sellers are electricity generators including both merchant generators and utility-owned generators. Merchant generators are usually un-regulated, selling power for profit. Utility-owned generation is often used to meet the utility's own native load. Revenues from utility-owned generation from power sales surplus to its own customers' needs usually offset the utility's regulated revenue requirement.

As noted above, there are two types of transmission owners – merchant (or private or independent) transmission owner and regulated Participating Transmission Owners (PTOs). The cost of transmission investment for a PTO is rolled into the CAISO's PTO Transmission Revenue Requirements Balancing Account and charged as a Transmission Access Charge (TAC) to the load. Thus the regulated investment cost of a transmission upgrade can be recovered through a regulated customer rate. The private investment cost of a merchant transmission upgrade is often recovered by receiving Congestion Revenue Rights (CRRs) for the incremental transmission capacity resulting from an upgrade.[4] In this case, the merchant transmission will receive no payment other than the FTR or CRR revenues allocated to it.[5]

[1] For more detailed discussion on the network representation of the Path 26 study, see Chapter 4.

[2] As previously mentioned, economic benefits of reliability changes are not the main focus of this methodology.

[3] There are other market participants as well, such as the marketers/traders, but they do not necessarily handle the physical supply, transport, or consumption.

[4] Sometimes CRRs are also referred as Firm (or Financial) Transmission Rights (FTRs), or Transmission Congestion Contracts (TCCs), depending on the markets.

[5] Note that there might be a third category of transmission upgrade in neither of these categories where transmission investment may not be awarded FTRs/CRRs or receive a regulated rate of return. Examples include radial transmission upgrade for specific use of a supplier (to sell into a higher priced market) or for a consumer (to buy from a cheaper source). The party investing in transmission gets its benefits through greater access to the market.

The distinction between private investment and regulated investment is important because it determines who pays for such investment and whose benefits should be considered in transmission expansion cost-benefit analysis. We believe the key elements of any economic-driven transmission investment decision are identifying potential beneficiaries of the investment, quantifying all benefits to the transmission funding participants, and comparing expected benefits of a transmission investment against its cost under a wide range of future system conditions. If a transmission upgrade project is ratepayer funded and the cost will be recovered through regulated cost sharing, the regulatory authorities have to identify exactly who those ratepayers are and how much they benefit. If a project is a merchant transmission investment and the cost will not be recovered by regulated rates, then the merchant transmission company needs to make sure the project meets their financial goals. The CAISO (or any other entities responsible for transmission expansion coordination) has to make sure such project does not jeopardize the stability and reliability of the controlled grid. Although the CAISO's focus is on regulated transmission investment, this methodology is general enough that any market participant can use it to evaluate the effectiveness of its project.

2.2.2 Define Market Participants' Surplus Components

Consumer Surplus

Consumer surplus is the difference between what consumers are willing to pay for a product versus what they actually pay. In an energy market, a consumers' willingness to pay can be measured by Value of Lost Load (VOLL). This measure indicates the approximate value of avoiding involuntary energy curtailments.

Figure 2.1 Consumer and Producer Surplus

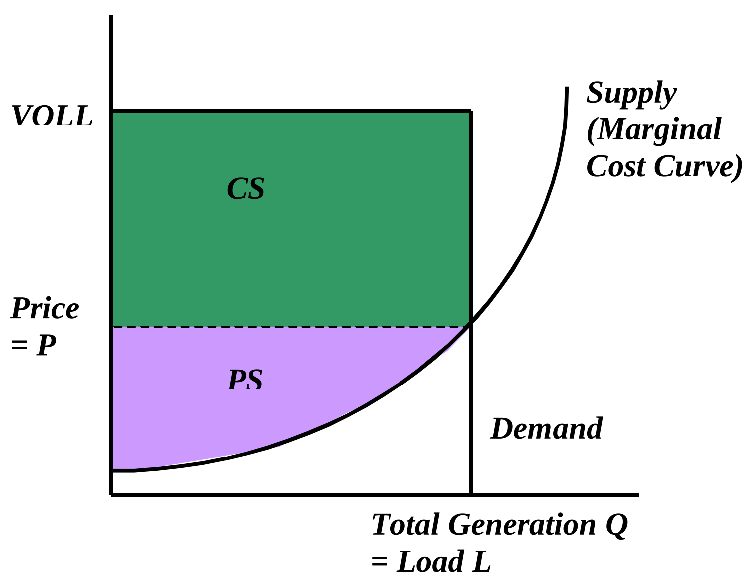


Figure 2.1 graphically depicts consumer and producer surplus under the simple case of an un-congested system where prices are the same across the whole network and all generators bid their marginal costs. The example also assumes that demand is perfectly inelastic and there are no transmission losses or wheeling charges.[6] The green rectangle area marked as CS denotes consumers' surplus. It can be computed as

$$\mathbf{CS = (VOLL - Price)*Load = VOLL*L - CTL,}$$

where VOLL is Value of Lost Load, L is total load (equal to total generation in this case), and CTL is total Cost-to-Load.

If there is congestion in the system, prices will differ by location. However, consumer surplus can be still computed in the same fashion by multiplying load by the price load pays and summing it up for the appropriate geographic region and time horizon. The total WECC consumer surplus is the sum of each region's consumer surplus. In our Path 26 study we calculate each region's annual cost-to-load as the following:

$$\mathbf{CTL_{i,t} = \overline{P}_{i,t} * L_{i,t}}$$

where i (= 1, 2, 3, …, 21) is the ith region in WECC area, t (= 1, 2, …, 8760) is the tth hour per year, and $\mathbf{\overline{P}_{i,t}}$ is quantity-weighted average Locational Marginal Price (LMP) in region i at hour t and $\mathbf{L_{i,t}}$ is total load in region i at hour t. Thus the total WECC consumer surplus summed over all 21 WECC regions is

$$\mathbf{WECC\ CS_t = \sum_{i=1}^{21}(VOLL * L_{i,t} - CTL_{i,t})}$$

We assumed that the same VOLL applies to all loads in all regions. In practice, **VOLL** may be different for different categories of consumers, such as industrial, commercial, residential, etc. But the formula can be generalized if needed, to account for different **VOLL** levels for different regions and consumer classes. However, it is important to note that in the end, we are interested in capturing the change in consumer surplus resulting from a transmission upgrade. If there is no change in reliability (i.e., the total amount of load is served), then when calculating the change in consumer surplus, all VOLL terms will cancel out. Therefore the value used for VOLL is immaterial in the end.

The definition of consumer surplus for the entire WECC area is subject to the following caveats. The WECC area outside of the CAISO controlled area does not currently have a central market and will likely not have one in the near future. As a result, there is no specific price at each load center or generation bus. Transactions are usually accomplished through bilateral agreements. Nevertheless, our defined calculation of consumer surplus indicates how much consumers will gain if the rest of WECC moves into a centralized wholesale market (or several markets). Furthermore, even with the current market structure we can still assume that through price discovery in California's energy market and trading hubs elsewhere in the WECC, the bilateral transaction

[6] The CAISO methodology can be generalized to account for price elastic demand. As demand-response programs based on real-time pricing become more important, such an enhancement should be investigated.

prices throughout the WECC will over time converge in a "long-term expected value" sense to levels that would otherwise result from a seamless centralized WECC market.

Producer Surplus

Producer surplus is the difference between the total payment producers received (Producer Revenue, PR) and the total variable production cost (PC).

$$\mathbf{PS = PR - PC.}$$

In the figure (Figure 2.1), the purple area indicates total producer surplus in the whole system in the case of no congestion and inelastic demand.

But when there is congestion in the system, generators may receive different locational prices. Nevertheless producer revenue can be still computed as output quantity multiplied by price received and summed to the appropriate geographic region. Total WECC producer surplus is the sum of each region's producer surplus. In our Path 26 study we calculate each region's producer surplus as:

$$\mathbf{PS_{i,t} = \sum_{k=1}^{K}(G_{i,k,t} * P_{i,k,t} - VOM_{i,k,t} - G_{i,k,t} * FC_{i,k,t})},$$

where $G_{i,k,t}$ is the dispatch quantity for the kth generator in region i, $P_{i,k,t}$ is the LMP that the kth generator receives, $VOM_{i,k,t}$ is kth generator's non-fuel variable O&M cost, and $FC_{i,k,t}$ is kth generator's fuel cost.[7] Thus the total WECC producer surplus is

$$\mathbf{WECC\ PS_t = \sum_{i=1}^{21} PS_{i,t}}\ .$$

This definition of producer surplus for the outside CAISO area is also subject to the caveats previously discussed.

Congestion Revenue

If there is no congestion in the system, no transmission losses, and no wheeling costs, total cost-to-load will equal total producer revenue at the WECC system level and congestion revenue will be zero. But if there is congestion on any line in the system, what consumers pay will not equal what generators receive in aggregate. This is because consumers are assumed to pay for electricity at their locational prices while generators are paid the prices at their generation buses. The difference between total WECC cost-to-load and total WECC producer revenue is the total WECC congestion revenue:

$$\mathbf{WECC\ CR_t = WECC\ CTL_t - WECC\ PR_t.}$$

Assuming that there are only short-run transmission congestion costs and there are no losses and no wheeling charges, the WECC total congestion

[7] Note that in our Path 26 study, we only simulated a security-constraint economic dispatch, not unit-commitment. Thus start-up costs and no-load costs were not captured in the production cost calculation. Nevertheless this formula can be extended to include such costs if they are specifically modeled.

revenue will equal the sum of shadow prices on congested lines times the flow on the congested lines during any hour.[8]

Figure 2.2 Two-Zone Diagram

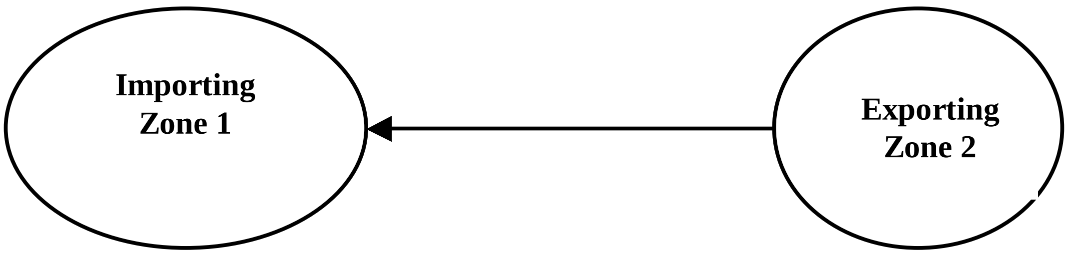
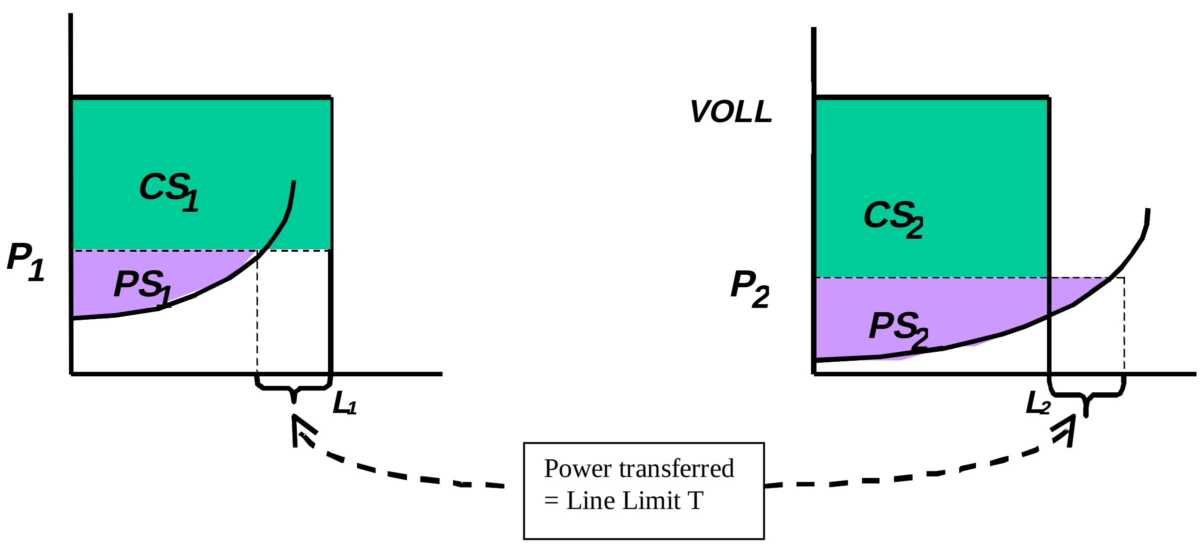


Figure 2.2 above depicts a two-zone example where Zone 1 and Zone 2 are interconnected by a transmission line with limited capacity. Zone 1 is an importing zone due to resource inadequacy or economic reasons (i.e. having more expensive local generation). Zone 2 is the exporting zone due to it having abundant resources or less expansive generation. If the power transfer capability between two zones is T and the line is congested, the following Figure 2.3 shows how consumer surplus and producer surplus in each zone can be computed.

Figure 2.3 A Two-Zone Example



[8] This is a fundamental property of nodal pricing systems on a linearized DC network. See, for example, W.W. Hogan, "Contract networks for electric power transmission," Journal of Regulatory Economics, 4, 211-242. This identity does not hold, however, for a network with losses or for an AC network model.

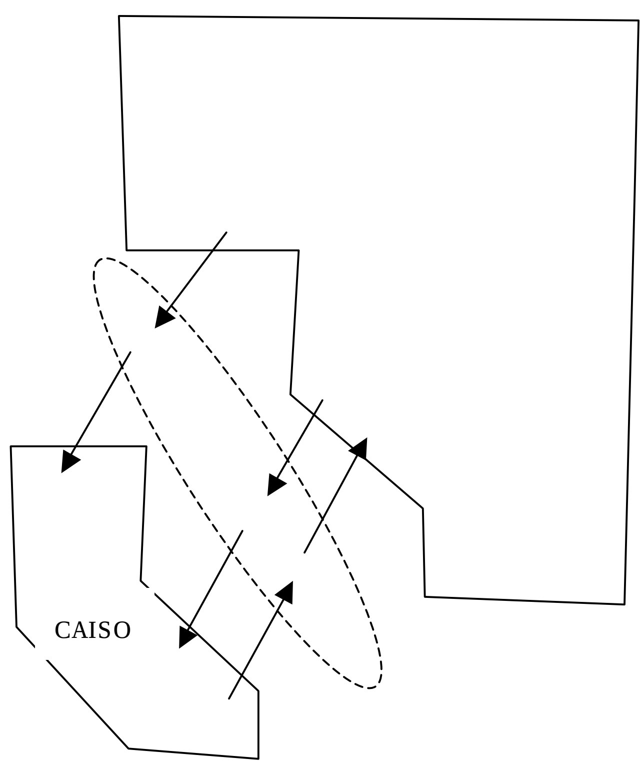
In this case, the congestion revenue is

$$CR = (CTL_1 + CTL_2) - (PR_1 + PR_2) = (P_1 - P_2)*T.$$

Note that the shadow price on a congested line in a radial network is the same as the price difference between two ends of the line. (This is not true, however, for a general meshed network.)

In a system with thousands of buses and transmission lines like the WECC network, computing congestion revenue for each region is not a trivial exercise. Congestion revenue at a regional level is no longer in balance with the difference between regional cost-to-load and producer revenue due to inter-regional exchange (imports and exports). For the sake of simplicity, we assumed that the whole WECC region is a single LMP market and congestion revenues are allocated to congestion revenue rights based on locational price differences and those holding CRR entitlements. In other words, transmission owners are either awarded CRRs or are compensated through TAC payments, and a commensurate set of CRRs are allocated to the entities that pay the TAC. Thus the intra-regional congestion revenue in each hour for an importing region is defined as the difference between the total payment by the regional load and the total payment to generation and net imports into the region, with the inter-regional flows being defined as the exports from one region to the other. Figure 2.4 below shows how the CAISO area's congestion revenue can be partitioned by a scissor-cut at the boundary of the regions.

Figure 2.4 Partitioning Congestion Revenue for CAISO Controlled Area



Therefore, the intra-regional congestion revenue to the CAISO controlled area can be calculated as:

CAISO Intra-CR_t = CAISO CTL_t – (CAISO PR_t + CAISO Cost of Net $Import_t$).

The "Cost of Net Import" term is defined as the nodal price at the bus at which the CAISO is assumed to receive an import via a given path, times the quantity of that import, summed over all paths.

The inter-regional congestion revenue (between the CAISO and the rest of WECC) is the sum of the flow on each interregional path times the LMP difference across the path:

$$\textbf{CAISO Inter-CR}_t = \sum_{i=1, i \neq CAISO}^{21} \sum_{j=1}^{J} L_{i,j,t} * (P_{CAISO,j,t} - P_{i,j,t}),$$

where i = 1, 2, 21 is the ith region in WECC, and j = 1, 2, ..., J represents the *j*th path between CAISO and the outside regions. Here, $P_{i,j,t}$ is the price at the exporting bus in region i for the *j*th path, while $P_{CAISO,j,t}$ is the importing bus for that path. $L_{i,j,t}$ is the MWh flow on that path in time t. If power is being exported from the CAISO region, the formula remains the same except that $L_{i,j,t}$ will be negative.

This approach can be generalized to allocate congestion revenues to other regions within the WECC. This approach of calculating congestion revenues at a regional level is, however, subject to several caveats. First of all, not all regions outside CAISO controlled area have a settlement process for congestion revenue. In the current market design, energy transactions in the RTO West and West Interconnect are all settled by bilateral agreements, in which payments by loads exactly equal receipts received by generators. Congestion is managed in a physical transmission right fashion through transmission reservation. The design filed for implementation in the near future is based on physical transmission rights (Physical FTRs) in the Western Interconnect that must be secured before the entity can submit its schedules. In the case of RTO West, the current filing involves market-based congestion management, but requires an initially balanced schedule from each SC; the SC is charged for congestion management based on its initial schedule. FTRs would be issued only to hedge against congestion charges. Nevertheless, our defined calculation of congestion revenue indicates how much congestion revenue would be allocated to different regions if the rest of the WECC moves towards a locational marginal pricing system for pricing congestion. Second, our calculation of congestion revenue for the CAISO is just an approximation of what would be the case under the initial MD02 LMP implementation that calls for treating inter-ties as radial injections (i.e. no modeling of external loops). The CAISO anticipates keeping an external open loop network until there is a more consistent and seamless market in the rest of the WECC. Under MD02, the CRR revenues in the CAISO-controlled area will be allocated using a network model - which is looped internal to the CAISO while being radial (i.e., scissors cut) to the external region. SCs will schedule at the boundaries of the importing and exporting regions. So, the inter-regional flows may not match the flows computed in the transmission expansion analysis model, which assumes injections and withdrawals at the physical locations of supply and demand outside the ISO control area. The computations assume that, through arbitrage over time, the import-export scheduled flows and prices resulting from SCs' schedules and bids under MD02 will converge in an expected value sense to the inter-regional flows and price differences across inter-regional paths resulting from a seamless WECC market. In other words, market iterations over time with a radial external network will result in a similar outcome (in an expected value sense) as mathematical iterations with a looped external network, yielding similar schedules and bids at physical supply and demand locations outside the CAISO control area.

Total Social Surplus

Total surplus is the sum of consumer surplus, producer surplus, and congestion revenue:

$$\mathbf{TS = CS + PS + CR.}$$

We can compute total social surplus at both the WECC level and regional level.

2.2.3 Impact of Strategic Bidding on Surpluses

In a market environment, suppliers may not necessarily bid their marginal costs. Rather they may bid strategically. Strategic bidding has both efficiency impact (i.e., raising production cost) and distributional impact (i.e., between consumer surplus, producer surplus, and congestion revenue). The efficiency impact at the system level (e.g., WECC) is easy to capture. It is likely the efficiency of the WECC system will be reduced if some generators bid strategically. The reduction in efficiency at a system level (e.g., WECC) can be measured by the difference between total variable production cost without strategic bidding and total variable production cost with strategic bidding. At regional level, efficiency may increase or decrease depending on the specific generator bidding activities within each region and also the power flows across regions.[9]

The distributional impact of strategic bidding is more complicated – some market participants may gain and some may lose if suppliers bid strategically. In the following section, we focus on the distributional impact of strategic bidding.

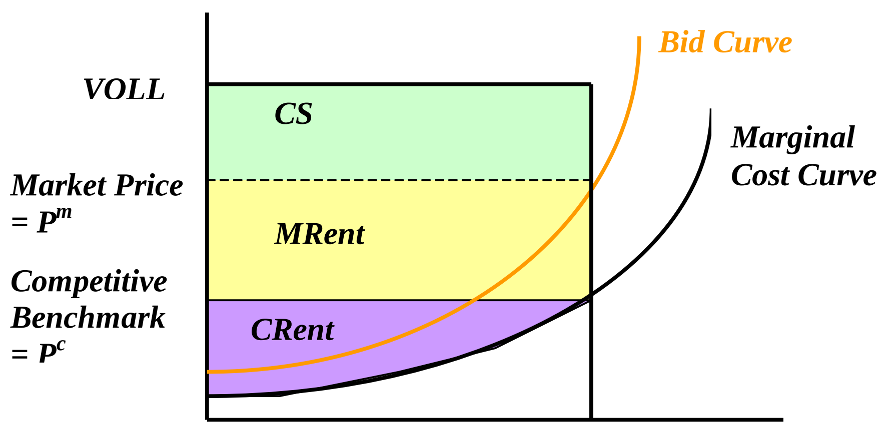
Impact on Consumers

Consumers are likely to be harmed by strategic bidding both in total and in each region, because it is likely that all consumers will face higher prices if some generators bid above their marginal costs. (In a network system, however, it is possible for the opposite to occur.) At a system level, if there is no congestion and no transmission losses, then part of consumers' surplus is transferred to some generators as monopoly rent when some generators bid

[9] In classic oligopoly models, such as the Cournot model, market power results in production inefficiencies because expensive generation from smaller, competitive producers replaces cheaper generation from large producers. This is because the latter restrict output and raise the price above their marginal cost, while non-strategic generators expand their output until their marginal cost equals price.

above their marginal cost. Such shift in surplus is depicted in the Figure 2.5 below.

Figure 2.5 Impact of Strategic Bidding When There is no Congestion



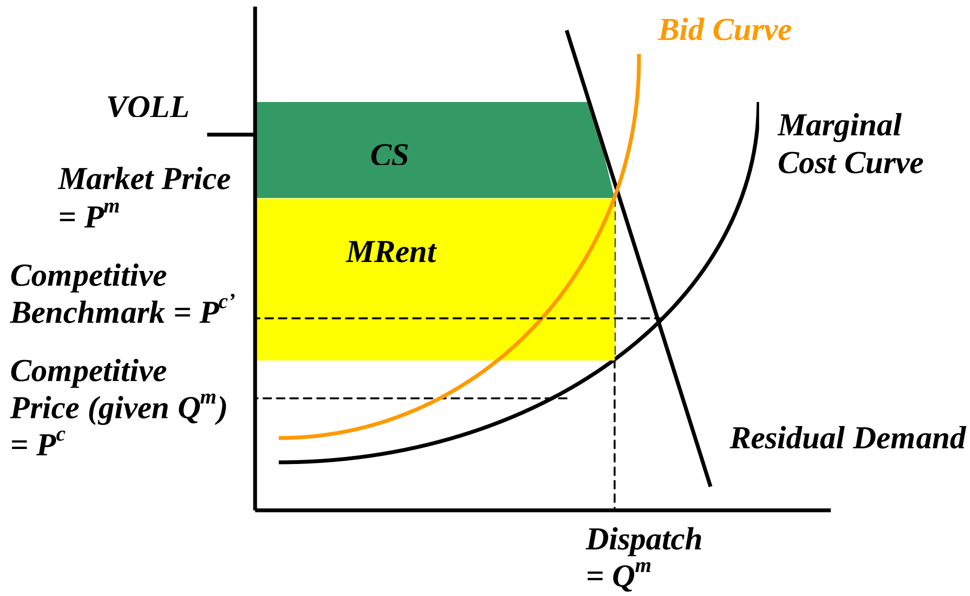
When there is congestion in the system, some consumers may be affected more by suppliers' strategic bidding than other consumers. Nevertheless, the impact of strategic bidding on consumers can still be measured by the reduction in total consumer surplus at the WECC level and at each regional level.

Impact on Producers

Obviously, some producers will have higher profits under strategic bidding than they would if all generators bid marginal costs. We call the excess profit generators capture under strategic bidding, "monopoly rent" (MRent). We call the portion of the producer surplus that producers would receive when all generators bid their marginal costs, "competitive rent" (CRent).

Calculation of monopoly rent in a case with no congestion is straightforward. It is the total load times the difference between the market price with strategic bidding and a competitive benchmark market price, as shown in Figure 2.5. However, when there is congestion in the system, bidding above marginal cost by some generators may lead to a different dispatch than if generators bid their marginal costs. In this case, the calculation of monopoly rent becomes complicated. This is shown in the following example, as depicted in Figure 2.6.

Figure 2.6 Approximate Monopoly Rent When There is Congestion



In this example, there is a load center, which needs imports to meet its load. If the transmission lines connected to this load center have unlimited capacity and there are plenty of inexpensive and competitive generators outside the load center to serve the load, it will force the local generators to always bid their marginal cost. Otherwise they will be excluded from the market. However, if the transmission lines to the load center are congested, the demand curve in the figure is the residual demand curve faced by local generators. If local generators bid above their marginal costs (the orange curve), then part of consumers' surplus is transferred to local generators as monopoly rent (the yellow rectangle). The monopoly rent is calculated as:

$$\mathbf{MRent = (P^m - P^c) * Q^m,}$$

where P^m is the locational marginal price at this load center when some local generators bid above marginal costs, Q^m is local generators' output, and P^c is what the locational price would be if local generators bid their marginal costs given Q^m. Therefore, competitive rent can be calculate as:

$$\mathbf{CRent = PS^m - MRent.}$$

However, obtaining P^c requires fixing the dispatch under markup and re-running the simulation. To avoid the complexity and simulation time of performing a separate run for determining P^c, we approximated monopoly rent using following formula:

$$\mathbf{MRent \cong (P^m - P^{c'}) * Q^m,}$$

where $P^{c'}$ is the competitive benchmark locational price when all generators bid marginal costs. The approximation may under estimate monopoly rent and over estimate competitive rent.

2.3 The Impact of Transmission Expansion on Surpluses

The fundamental benefits of a transmission upgrade are to improve reliability and facilitate commerce; the latter category of benefits is the focus if this CAISO methodology. A transmission upgrade facilitates commerce by creating greater access to regional markets, which may result in greater access to lower cost supply and greater market competition. A transmission upgrade may expand the number of suppliers who can compete to supply energy at any location in a transmission network. With sufficient transmission capacity to all locations in a network, generators will face significant competition from multiple independent suppliers, which will reduce their financial incentive to bid above marginal cost since doing so would more likely result in their bids not being selected.

As we discussed above there are three categories of participants in the market: (1) consumers; (2) producers; and (3) transmission owners or congestion revenue right holders. If one wants to evaluate an upgrade, the benefits for all market participants must be considered and calculated, especially for those parties who will ultimately pay for the transmission upgrade. Since there are many ways to allocate the cost of a transmission investment, decision makers must evaluate all aspects of the benefit components. Moreover, the transmission valuation methodology must provide the building blocks necessary to evaluate the benefits of a variety transmission projects. In the following section, we discuss these benefit building blocks.

2.3.1 Societal Benefit

The fundamental economic impact of transmission upgrade is that it may make the system more efficient and thus lead to more efficient economic dispatch. Thus the societal benefit of a transmission upgrade can be measured as the reduction in total variable production cost of serving load (i.e. the production cost savings).[10] Let $PC_{w/o}$ denote a system's total variable production cost without an expansion project, and let PC_w denotes the total variable production cost with the expansion. Then the total societal benefit (SB) is:[11]

$$\mathbf{SB = PC_{w/o} - PC_w.}$$

It is easy to determine whether a transmission upgrade project is beneficial or not from the societal point of view. However, not all market participants benefit when additional transmission is built to relieve congestion. It is important to

[10] Note that this situation holds only when demand is perfectly inelastic (i.e., zero price elasticity). If demand is not perfectly inelastic, this statement needs to be modified to reflect the substitution effect between price and quantity. In production cost simulation models, demand elasticity is often modeled indirectly by including some dummy generators in the system so that the costs and dispatches of these dummy generators reflect the impacts of demand elasticity on societal benefits. This is what is implemented in the PLEXOS software used for the Path 26 study.

[11] In the presence of price elastic demand, welfare is instead equal to total surplus, equal to total consumer willingness to pay for the electricity consumed minus the cost of providing it. The CAISO methodology does not presently consider elastic demand.

quantify who benefits from expansion and who does not. Further more, total societal benefit, as measured in total variable production cost savings, can be further disaggregated into three components across regions:

- Consumer benefit from upgrade
- Producer benefit from upgrade
- Transmission owner or congestion revenue right-holder benefit

The following sections discuss each component in more detail.

2.3.2 Consumer Benefit, Producer Benefit, and Transmission Owner Benefit

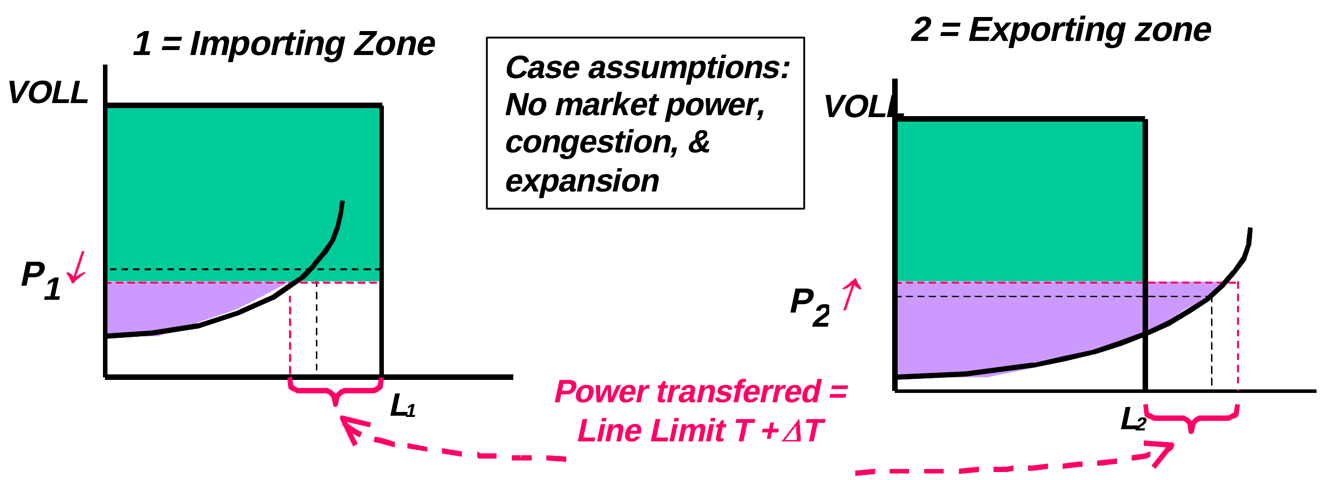
In the two-zone model we discussed before, Zone 1 and Zone 2 are connected by a transmission line with capacity T. Suppose we plan to expand the line limit to T + ΔT and would like to measure the benefit due to this expansion. The line may still be congested after expansion. With the transmission expansion, it is likely that generators in Zone 1 will produce less output and generators in Zone 2 will produce more output than they would without expansion. It is also likely that the Price in Zone 1 will be lower and price in Zone 2 will be higher compared to the no expansion case.

In order to quantify the impact of transmission expansion on welfare, we need to:

- Compute all welfare measurements (i.e., all surpluses) for cases without and with expansion
- Subtract surplus without expansion from surplus with expansion
- Obtain the net impact of transmission expansion on surpluses

We call the change in surpluses caused by a transmission expansion the "transmission benefit". Figure 2.7 shows how consumers and producers in each zone are benefited or harmed by a transmission upgrade in this 2-zone example.

Figure 2.7 Transmission Benefit in the Two-Zone Example



If the amount of power transferred from Zone 2 to Zone 1 is increased, then consumers in Zone 1 may benefit from a lower price and consumers in Zone 2 may be harmed from a higher price.

$$\Delta CS_1 = -\Delta P_1 * L_1 > 0$$

$$\Delta CS_2 = -\Delta P_2 * L_2 < 0$$

However, producers in Zone 1 are harmed due to having less of their output dispatched and from receiving a lower price for their dispatch. On the other hand, producers in Zone 2 benefit from expansion due to having more of their output dispatched and from receiving a higher price for their dispatch.

$$\Delta PS_1 = \Delta PR_1 - \Delta PC_1 < 0$$

$$\Delta PS_2 = \Delta PR_2 - \Delta PC_1 > 0$$

Transmission owners (or CRR holders) of the line may or may not benefit from expansion depending how much the flow is increased and how much the price difference is changed.

$$\Delta CR = CR_w - CR_{w/o} = (\Delta P_1 - \Delta P_2)*T + \Delta T*(P_{1w} - P_{2w})$$

If the line is no longer congested with expansion, TOs (or CRR Holders) may have a net loss.

2.3.3 The Identity and Its Importance

The method of calculating consumer benefit, producer benefit, and congestion revenue benefit can be generalized from the simple two-zone model and applied to the complicated WECC network. One way to check the validity of the partitioning of total benefits among different market participants is to check whether the following identity holds at the system (i.e., WECC) level:

$$\mathbf{SB = -\Delta PC = \Delta CS + \Delta PS + \Delta CR.}$$

Our first step in benefit evaluation of any transmission project is to make sure the total societal benefit calculated can be correctly disaggregated into three major components: consumer benefit, producer benefit, and transmission owner (or CRR holder) benefit. If a transmission project's total societal benefits exceed its total project cost, the project is beneficial to the society as a whole. However, such a project may not benefit everybody, some market participants will benefit and some may not. Thus it is important to further examine the distributional impacts of a transmission project on the various market entities. In the next section we will present our economic-driven transmission expansion evaluation criteria and discuss various different perspectives.

2.4 Economic-Driven Transmission Evaluation Criteria

2.4.1 Overview

We use a traditional cost-benefit framework in deciding whether a proposed project is desirable from varying welfare perspectives. In theory, the optimal investment rule requires that for investment, the evaluator should make sure that each candidate investment satisfies a two-part test, namely

- A project's net present value (NPV), with benefits and costs over the project's lifetime factored into the calculation, that exceeds zero. This can be expressed as

$$\mathbf{NPV} = \frac{\mathbf{B_0 - C_0}}{\mathbf{(1+d)^0}} + \frac{\mathbf{B_1 - C_1}}{\mathbf{(1+d)^1}} + \mathbf{...} + \frac{\mathbf{B_T - C_T}}{\mathbf{(1+d)^T}} > \mathbf{0}.$$

  where the subscript t = 1, 2, …, T represent years during planning period, d is the discount rate, and B and C represent benefits and costs respectively.[12]

- The project selected has the highest NPV

As a practical matter, the second part of the test is often narrowly done by reviewing a limited number of alternatives (alternative timing, alternative transmission project, alternative generation project, or demand-side management projects). Thus the main focus is on the NPV calculation and testing.

The NPV of a transmission upgrade may also hinge on who will ultimately bear the cost of the project. Depending on who ultimately funds the transmission project the applied discount rate could be different. For instance, if the transmission project is funded by CAISO ratepayers then a social discount rate or a regulated discount rate should be applied. However, if an independent merchant entity funds the project, a private discount rate should be applied. Similarly what should be included in the benefit and cost calculation also depends on who ultimately funds the project and who benefits from the project.

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[12] Here, the Bs are the expected benefits of the project calculated considering a wide range system conditions. In Chapter 5 we will discuss how we weight each scenario to calculate the expected benefit.

Fundamentally, net benefits should be the summation of the benefits for all market participants who pay for the project less their costs. Since most projects will enhance the welfare of some market participants while diminishing the welfare of others, a project's acceptability should be judged based on the impact in aggregate.

The annual costs of a transmission project should be evaluated against the estimated annual revenue that a transmission owner would require to undertake the project. Transmission is a long-lived (30 to 50 years), immobile investment with very high initial capital costs and very low operating costs. Thus it is critical to get an accurate estimate of the capital cost of proposed project. Capital cost of a project also includes financing cost of the capital, along with federal and states taxes. Given that benefits of transmission are typically measured only for 5-10 years out[13], we probably have to make some assumptions about benefits for the remaining years. A conservative assumption is that these longer-term benefits are zero. Alternatively, one could extrapolate out the average benefits for the years that they are estimated. In our Path 26 study, due to data limitations and time constraint we only modeled two years: 2008 and 2013, and we compared the benefits in these two years with the levelized annual capital and O&M cost of Path 26 upgrade by assuming an annual carrying charge rate of 10%.

It is important to note that if the benefits of a transmission expansion are adjusted for inflation (i.e., expressed in real dollars versus nominal dollars), then the discount rate should also be adjusted for inflation in order to calculate the inflation-free results. Such an adjustment could be made by comparing the yield on long-term UD Treasury Bonds with the yield on an inflation-indexed Treasury security.

2.4.2 Societal Perspective

The societal perspective focuses on the overall benefit across the entire Western Interconnection. It looks at the societal benefit of a transmission project at a system-wide level with all relevant regions and relevant market participants included. Given that western systems are all inter-connected, a significant transmission project can pass the societal test if the WECC region as a whole benefits from the project. Further more, the societal benefit to the WECC region from a transmission project can be measured as the reduction in total WECC variable production cost of energy:

$$\mathbf{SB_{WECC} = -\Delta PC_{WECC}}.$$

If everyone is part of a RTO, costs of new transmission can be spread across all users of the transmission system and the RTO could be the vehicle through which costs are recovered from all users.

[13] Accuracy of the input assumptions used diminishes significantly when one goes beyond ten years, thus makes longer-term analysis less trustworthy.

2.4.3 Modified Societal Perspective

An alternative societal perspective is the modified societal test. This test excludes generators' monopoly rent in the surplus calculation and the change in monopoly rent in the benefit calculation. More specifically,

$$\textbf{Modified } \mathbf{SB_{WECC} = SB_{WECC} - \Delta MRent.}$$

The rationale for the modified societal test is that if market power profits are given the same weight as consumer benefits (i.e. as in the societal test) then under a transmission upgrade, transfers of market power-derived profits from producers to consumers will net to zero in the social benefit calculation. To the extent policy makers believe there is a value in transferring supplier monopoly profits to consumer surplus, the modified societal perspective will be a more appropriate measure of the value of a transmission upgrade than the pure societal test. Not all economists agree on this argument. We present the modified societal perspective as an alternative measure to the societal benefit so that policy makers can decide for themselves what is appropriate to use on a case-by-case basis.

The CAISO ratepayers are defined as all parties that are responsible for contributing to the transmission revenue requirement balance account for the CAISO Participating Transmission Owners (PTOs). Obviously, these PTOs are acting as agents for the final ratepayers (i.e. retail consumers). Utility-retained generation is also included in the CAISO ratepayer perspective since profits (or negative profits) from this generation flow into the balance account. Furthermore, transmission owners (or CRR/FTR holders) of the CAISO controlled grid are also included in the CAISO ratepayers since congestion revenues flow into the balance account.

The CAISO ratepayer test focuses on the benefits that would accrue to those entities funding the upgrade. The CAISO ratepayers' benefit from transmission upgrade can be expressed as:

$$\textbf{CAISO Ratepayer Benefit} = \mathbf{\Delta CS_{CAISO} + \Delta PS_{CAISO\text{-}URG} + \Delta CR_{CAISO}},$$

where ΔCS_{CAISO} is the change in consumer surplus for load in the CAISO control area, $\Delta PS_{CAISO\text{-}URG}$ is the change to producer surplus for utility-retained generation, and ΔCR_{CAISO} is the change in congestion revenue.

2.4.4 ISO Participant Perspective

The alternative CAISO perspective is to include all CAISO participants' benefits from transmission expansion, including merchant generators' competitive rent benefit but excluding the monopoly rent portion:

$$\textbf{CAISO Participant Benefit} = \mathbf{\Delta CS_{CAISO} + \Delta CRent_{CAISO} + \Delta CR_{CAISO}}.$$

The rationale for this perspective is that if one doesn't account for all generators' competitive profitability in the short-run, then in the long run, they will not invest, and all generation will have to be utility-built. If all the generation internal to the CAISO Control Area is utility owned then the ISO Ratepayer and ISO Participant Perspectives are identical.

In summary, the market-driven projects are candidate projects that might not be indispensable for reliable system operation but will be able to facilitate wholesale energy trade to reduce overall cost of generation. The CAISO's decision as to whether or not to proceed with a given economic-driven project will hinge upon the identified economic benefits of the project exceeding its identified economic costs primarily for CAISO's market participants. In case several alternative market-driven projects are identified, the methodology will assist in determining those candidates that are economically viable, and in identifying the most cost-effective project among them from the perspective of the CAISO's market participants.

In Appendix B of this report we demonstrate how all surpluses, benefits, and benefit tests are calculated using a 3-node prototype model. Readers interested in the details of the calculation can refer to that Appendix.

2.4.5 Merchant Perspective for Private Transmission Expansion

It is possible for unregulated, for-profit entities to build merchant transmission projects. For merchant transmission projects, their perspective is based on the benefit they obtain from the upgrade. Such merchant projects are economic if the benefits from CRR revenues and having greater access to wider regional market exceed the investment costs of the upgrade.

2.5 Additional Benefits of Economic-Driven Transmission Expansion

Above we discussed only the major economic benefits of an economic-driven transmission project. Nevertheless, any economic-driven transmission project may also have additional economic and non-economic benefits such as short-term local reliability benefit, environmental benefits, and others. Some of these additional benefits are often hard to quantify due to data or software limitations. In the following section we list some examples of these additional benefits and potential ways to quantify these benefits.

Reliability Benefits of Economic Projects

Some projects would provide local reliability benefits that otherwise would have to be purchased through reliability-must-run (RMR) contracts. The CAISO pays annual fixed payment to unit owner in exchange for the option to call upon the unit (if it is available) to meet local reliability needs. The CAISO pays a regulated variable cost for energy. RMR units are used for both local reliability and local market power mitigation. The RMR generation units are not modeled as must-run in our Path 26 study. This could potentially under-estimate the benefit of transmission upgrade. Nevertheless the exclusion of RMR reduction benefit in the Path 26 study is mainly due to software limitations and the benefit can be potentially quantified in the future.

New transmission projects could also potentially enhance system reliability by reducing loading on parallel facilities, especially under outage conditions. At the WECC area level, the expansion of the major interconnection will also improve the overall system reliability and reduce the loss-of-load probability of the entire region. These system reliability benefits were not quantified in the Path 26 study and should be further considered as a possible future enhancement.

Benefits from Increased Operational Flexibility

Economic-driven projects may also provide increased operational flexibilities for the CAISO and thus further enhance the reliability of the grid. For instance, new transmission facilities can provide more options for maintenance outages, provide load relief for parallel facilities, and provide additional flexibilities for switching and protection arrangements. The transmission expansion benefits associated with operational flexibilities were not assessed in our Path 26 study.

Strategic Environmental Benefits

As California's demand for electricity grows, competition for air emission offsets and water resources becomes more intense. Under some circumstances, an expansion of the high-voltage transmission system can have substantial environmental benefits by avoiding local air emissions otherwise caused by local generation and by reducing the need to procure local air offsets needed for generation. Such reductions can assist in allowing new industries with higher economic value to enter the local area by avoiding negative impacts to the local water and natural gas supplies otherwise required for local generation. Also transmission upgrade may reduce the construction of additional infrastructures such as gas pipelines and pumping station, and water and waste treatment systems.

The Path 26 study did not internalize the emission costs in the dispatch simulation due to a lack of data on emission rates and emission costs. This is an area that we can potentially improve in the future.

Capacity Benefits of Transmission Upgrade (including A/S Benefits)

A transmission upgrade can potentially increase reserve sharing and firm capacity purchases, and therefore decrease the amount of power plants that have to be constructed in the importing region to meet reserve adequacy requirements. Quantifying these benefits requires simultaneous optimization of the use of capacity, Ancillary Services (A/S) and energy. In our Path 26 study, we did not model capacity or A/S markets specifically due to data limitations. Nevertheless these benefits can be readily quantified if data is available and the software is capable.

Benefits from Reduction in Losses

The impact of loss reduction on the economic benefits is not captured in the Path 26 study. Reduction in system losses can be a significant source of benefits especially when it happens at peak load hours when resources are scarce and prices are high.

2.6 Future Enhancements

As we discussed in the above section, some additional economic and reliability benefits are not included in our Path 26 study due to either data limitations or modeling limitations. In the future we would like to further refine our methodology, our software and our database so that we can quantify these benefits. Examples include quantifying the benefit of a transmission upgrade on emission reductions. This can be easily done if we have emission rate curves and emission costs data available and placed into the market simulation software. Another area for future enhancement is to quantify the RMR reduction benefit due to a transmission upgrade.

Some other benefits may be difficult to quantify. Examples include benefits from increase operational flexibility due to transmission upgrade. Nevertheless we should keep refining the methodology and keep exploring potential ways to quantify these additional transmission benefits.

3. Network Model Requirements

When conducting production cost simulations, several approaches can be used to model the transmission grid in the simulations.

We discuss the two primary approaches below:

1) **Transportation Model –** In this model, nodes are grouped together in a “bubble” in those areas of the grid where we expect few transmission limitations. We then assume each bubble to have no internal transmission limitations and be connected to other bubbles though a transportation path intended to mimic the actual physical limitation of the transmission system. When scheduling power between bubbles, the production cost program schedules power across the paths until they reach their limit. The program ignores actual electrical characteristics of the system and directs power onto any available path in the same way that power is scheduled across a fully controllable DC line

2) **Network Model –** In this model, we import the actual electrical characteristics of the transmission grid from a powerflow program. When the model schedules power from one area to another, it distributes it across the transmission lines based on the actual electrical characteristics of the system

In the past, transportation models were popular because the amount of computer CPU time required to complete a simulation was dramatically less than the time required for a network model. With the advent of modern computers, this has become much less of a concern. While transportation models have had the advantage of computation speed that is their only advantage. On the other hand, they have many disadvantages, including the following:

1) **Transportation models cannot accurately model loop flow limitations** - Loop flow varies by season and time of day. The quantity of loop flow depends on the specific generators being dispatched. Network models will correctly model loop flow as it varies with the load and generation patterns. Transportation models cannot accurately model loop flow. Instead, interfaces need to be artificially derated to account for loop flow impacts

2) **Transportation models do not easily adapt to network changes –** Any change in the physical network, such as the addition or removal of a transmission line, will change the flows on the overall power grid and may change many normal and contingency transmission limits. As a result, many of the limits between the bubbles in a transportation model would need to be recalculated. If a network model is used, individual facility limits would not need to be recalculated. However, path limits and simultaneous limits may need to be recalculated

3) **Transportation models cannot model the detailed interaction between limits** – Over a transmission interface, individual transmission facilities (i.e., a transformer or a line) or a path (i.e., a group of transmission lines) may be the most limiting transmission constraint. There may also be simultaneous interaction betweens lines and/or paths that result in the most limiting transmission constraint. The specific limit may change with the time of day or season. Combining these limits together for modeling convenience into one limiting constraint is not likely to be accurate. On the other hand, a network model can easily simulate these interactions

4) **Outputs from transportation model simulations are inadequate** – Transportation models can produce output showing the flows on the links between bubbles but they cannot plot individual line loadings. As a result, they cannot clearly identify the specific facilities causing the congestion. This makes analysis of the limitation difficult and may lead to incorrect conclusions. In addition, the flows shown on links between bubbles may not be closely related to the physical flows on a path. If a network model is used, the flows on individual facilities can be identified. This enables a much more detailed analysis of the problem

5) **Nodal prices are unavailable in a transportation model** – A transportation model groups individual nodes into a zone. A zone may include a single node or thousands of nodes. With the California ISO transitioning to locational marginal pricing, we have a requirement that the simulations be able to produce nodal prices. The output of a transportation model cannot provide these individual nodal prices while a network model can

Because of the deficiencies identified in the transportation model approach, we believe the CAISO methodology requires that a network model be utilized.

4. Market Price Derivation

4.1 Overview

Historically, resource-planning studies have typically relied on production cost simulations (i.e. marginal cost pricing) to evaluate the economic benefits of potential generation and transmission investments. While such an approach may make sense in a cost-of-service vertically integrated utility paradigm, assuming marginal cost pricing in a restructured market environment where suppliers are seeking to maximize market revenues may result in inaccurate benefit estimates. In a restructured electricity market, suppliers are likely to optimize their bidding strategies in response to changing system conditions or observed changes in the behavior of other market participants. Because of this, a methodology for assessing the benefits of a transmission project in a restructured market environment should include a method for modeling strategic bidding. Modeling strategic bidding is particularly important because a transmission expansion can provide significant benefits to consumers by improving market competitiveness.

A new transmission project can enhance market competitiveness by both increasing the total supply that can be delivered to consumers and the number of suppliers that are available to serve load. Of course, a transmission expansion is just one of several structural options for improving market competitiveness. The addition of new generation capacity, increased levels of forward energy contracting, or the development of price responsive demand can also significantly reduce the ability of suppliers to exercise market power in the spot market. Our methodology provides for consideration of these factors as well. However, a transmission expansion has the additional benefit of improving the competitiveness, of not just the spot market, but also the longer-term forward energy market. This occurs because the transmission expansion creates greater access to a broader regional market and thereby increases the number of sellers that can offer long-term energy contracts.

One of our goals of the CAISO methodology is to perform transmission evaluation based on market prices rather than traditional cost-based analysis. A major challenge we face is to model supplier's strategic bidding behavior, and how their bidding behavior changes with the transmission upgrade. In this methodology we developed a framework that is based on simplified game theoretic models and uses the best available information to establish the linkage between strategic bidding and various system conditions. In the following sections we first discuss some different approaches to modeling strategic bidding in transmission studies, then we explain the particular approach used in our methodology. Finally we identify areas for future improvements to modeling strategic bidding.

4.2 Alternative Approaches to Modeling Strategic Bidding

There are fundamentally two approaches of designing a method for determining suppliers-bidding behavior:

- Game theoretic simulation models
- Empirical-based methods based on actual market outcomes

The first approach involves the use of a game-theoretic model to simulate strategic bidding. A game theoretic model typically consists of several strategic suppliers with each player seeking to maximize its expected profits by changing its bidding strategy in response to the bidding strategies of all other players.

The game theoretic approach is derived independently of observed historical behavior. Its advantage is that it can simulate market power under a variety of future market conditions without the potential bias of being based on observed historical behavior. This could be particularly important if the market conditions assumed in the study period are very different than historical conditions. For example, if a study assumed a much higher level of forward energy contracting or price responsive demand than existed historically, a game theoretic model that explicitly incorporates these elements in determining strategic bidding may be able to better simulate market power than an empirical approach that is based on a period where there was very little forward contracting. However, the game theoretic model's independence from observed historical relationships between market power and specific market conditions raises a significant risk. If the model is not tested and calibrated to replicate historical bidding practices, there will be no guarantee that it will accurately predict strategic bidding in the future. Moreover, it may simply not be possible to calibrate a game theoretic model to match actual market outcomes given that there are a limited number of elements one can incorporate and adjust in such a model. Another risk in simulation-based game theoretic models is that the converged solution may not be truly converged, i.e., it may not represent a true equilibrium. This can happen if the strategy space is too narrowly defined or if the limit on the maximum number of iterations is set too low. It may also happen if the model is simply too complicated to converge to a solution. In order for a game theoretic model to solve in a tractable and timely manner, the model must be fairly simplistic in terms of network representation and the types of bidding strategies. Such simplifications may make the model too abstract to reasonably capture market power.

In summary, this approach faces enormous technical challenges of modeling supplier behavior in equilibrium full-network model. Often times in order to make models converge, simplifications must be made such that only very simple strategy space is considered (e.g., either equilibrium quantities or prices are endogenously determined, but not both.). Furthermore, very simple network model is often used (such as 3 or 4 node radial network). Solving models with more complex strategy spaces – multi-step bid functions or simplified looped network with few zones – is computationally intractable.

The second approach involves the use of estimated historical relationships between certain market variables and some measure of market power such as the difference between estimated competitive prices and actual prices or estimated competitive bids and actual bids (i.e., price-cost markups and bid-cost markups, respectively). Each modeling approach has its advantages and disadvantages.

The advantage of modeling market power through an econometric (empirical) approach is that the approach has a strong historical basis. Estimates of historical relationships between market power (as expressed through bid-cost or price-cost markups) and certain market variables (such as load levels and supply margins) are applied prospectively in the transmission study. Another advantage is that this approach can be applied to a more detailed transmission network representation provided the model can produce the required explanatory variables (i.e. the variables contained in the regression equation(s) at a more detailed level). A potential disadvantage of this approach, because it is based on estimated historical relationships, its predictive capability may be limited if applied to a market where conditions have changed significantly.

In assessing these two alternative approaches, we believe an empirical approach to modeling strategic bidding is preferable to a game-theoretic approach because it can be adapted to a detailed transmission network representation and has been validated through historical experience. In adopting the empirical approach, several measures were taken to improve the model's predictive capability under changing market conditions.

First, when developing the relationship between strategic bidding behavior (markups) and system variables, we purposely included time periods that represented differing market conditions. For this study, we included data from November 1999 to October 2000, a period characterized by little forward contracting, a tight reserve margin, and significant price markups in a number of hours. Our data set also included hourly data from 2003, where a significant portion of load was covered by forward contracts, reserve margins were higher, and price-cost markups were generally lower both in terms of magnitude and frequency. Using data from periods with very different market conditions reduces historical biases and therefore provides for better predictive capability under different future market conditions.

Second, in our regression analysis, we explicitly accounted for contract positions in the market when we constructed different explanatory variables. For instance, when analyzing the impacts that load has on price-cost markups, we focused on load that was not hedged and was therefore exposed to spot market prices. Load under forward contract was treated as hedged and was excluded. By doing this, the changes in contract position during the different historical periods are captured, and model produces more accurate estimates on effects of loads on price-cost markups. We discuss model specifications in more detail later in this section.

Third, due to the nature of the econometric model itself and the myriad of future uncertainties, it is impossible for any econometric model to generate perfect predictions. We did not use just the single point estimates derived from our regression equation. Instead, we used statistical methods to develop high and low markup scenarios to account for the potential range of markups that could exist under alternative future system conditions. Specifically, we considered three scenarios: 1) a perfectly competitive scenario, where every market participant is bidding its marginal cost; 2) the base case markup scenario, where the bid-cost markups are a direct output of our estimation equation; and 3) the high bid-cost markup scenario, where we chose a bid-cost markup based on a upper bound of the 90 percent confidence interval.[1] A probability was assigned to each markup scenario to generate the final expected economic benefits of the upgrade.

4.3 An Empirical Approach to Modeling Strategic Bidding

In the transmission evaluation methodology that the CAISO filed with the CPUC on February 28, 2003[2], the CAISO laid out detailed steps for modeling market power using an empirical approach. The empirical approach adopted here is largely based on the four major steps proposed in that report. However, some modifications and refinements were made to further improve the approach.

In summary, our approach consisted of four major steps:

[1] A 90 percent confidence interval of the bid-cost markup means that 90 percent of predicted markups would be lower than the chosen level of markup.

[2] In Section III of "A Proposed Methodology for Evaluating the Economic Benefits of Transmission Expansions in a Restructured Wholesale Electricity Market", The California ISO and London Economics International LLC, February 28, 2003.

1. We completed a price-cost markup regression analysis using historical data from November 1999 – October 2000 and 2003. In this analysis, the hourly price-cost markup in each zone (j) was regressed against a residual supply index ($RSI_{i,j}$) – a measure of the extent to which the largest supplier is "pivotal" in the market, the percentage of load not hedged by a utility's own generation and long-term bilateral contracts ($PLU_{i,j}$), a dummy variable denoting whether it is a summer month ($SP_{i,j}$), and a dummy variable denoting whether it is a peak hour ($Peak_{i,j}$)
2. For each of the various supply and demand scenarios considered in the prospective study periods, 2008 and 2013, we calculated the following variables for each hour (i) and zone (j):
    a. Residual Supply Index ($RSI_{i,j}$)
    b. Available Supply Capacity of Largest Single Supplier ($LSS_{i,j}$)
    c. Percentage of Load Unhedged ($Pct\_load\_unhedged_{i,j}$)
    d. Dummy variables for summer months and peak hours
    e. We applied the regression equation(s) in Step 1 to the values derived in Step 2 to estimate the bid-cost markups in each region
3. We applied the bid-cost markups to the supply bids on non-utility owned generation and ran the model to determine dispatch and market clearing prices under the various supply and demand scenarios
4. We calculated the different components of societal benefits to be used in the different benefit tests of the upgrade

Each of these steps is described in greater detail below.

4.3.1 Step 1: Price-cost Markup Regression Analysis

4.3.1.1 Definition of Regression Equation

Our regression analysis for determining the relationship between price-cost markups and certain market conditions was based on hourly data for the months November 1999 – October 2000 and the calendar year 2003. Specifically, the following regression equation was estimated:

$$\mathrm{PMU}_{i,j} = a + b\,\mathrm{RSI}_{i,j} + c\,\mathrm{PLU}_{i,j} + d\,\mathrm{S}P_{i,j} + e\,\mathrm{Peak}_{i,j}$$

Where

$PMU_{i,j}$		The price-cost markup for hour (i) in zone (j).
$RSI_{i,j}$	=	Residual Supply Index in hour (i) for zone (j)
$PLU_{i,j}$	=	Percentage of load unhedged in hour (i) for zone (j)
$SP_{i,j}$	=	Dummy for summer periods (May-Oct)
		$Peak_{i,j}$ = Dummy for Peak hours[3]

We describe the price-cost markup, RSI, and the Percentage of load unhedged in greater detail below.

[3] Peak hours are hours between 7am and 10pm for every weekday and Saturday. The rest of hours are off-peak hours.

4.3.1.2 Definition of Variables

Price-Cost Markup (PMU)

The Price-Cost Markup is expressed as the Lerner Index, which is equal to the following:

$$\text{Lerner Index} = ((P_{i,j} - C_{i,j}) / P_{i,j})$$

Where

$P_{i,j}$ = Actual price in hour (i) and zone (j)

$C_{i,j}$ = Estimated competitive price in hour (i) and zone (j)

The Lerner Index denotes the percent of the market-clearing price that is above the estimated competitive level. This specification implies that the explanatory variables in the regression equation have a non-linear relationship with actual market clearing prices. This is important because, historically, market prices tend to increase exponentially when market power is being exercised.

Residual Supply Index (RSI)

The Residual Supply Index (RSIi,j) in each hour (i) and for each zone (j) was calculated according to the following formula:

$$RSI_{i,j} = \frac{TS_{i,j} - Max(TUC_{i,j})}{Load_{i,j}}$$

Where,

$TS_{i,j}$ = Total Available Supply (available import capacity + the available capacity of the internal generation)[4]

$Max(TUC_{i,j})$ = Total Uncommitted Capacity of Largest Single Supplier [5]

$Load_{i,j}$ = Actual regional demand.

The RSI measures the extent to which the largest supplier is "pivotal" in meeting demand. The largest supplier is pivotal if the residual demand cannot be met absent the supplier's capacity and such a case would translate to an RSI value less than 1. When the largest suppliers are pivotal (an RSI value less than 1), they are capable of exercising market power. The first component of the RSI calculation ($TS_{i,j}$) is equal to the aggregate of internal generation capacity and import capacity. The hourly internal generation's available capacity was computed as the difference between the generation' rating and planned and forced outages.

Percentage of Load Unhedged (PLU)

The percentage of load unhedged is defined as:

$PLU_{i,j}$ = ($Load_{i,j}$ – Utility's own available Supply $Capacity_{i,j}$ – load under the forward $contracts_{i,j)}$ / $Load_{i,j}$

[4] For internal generation, the total available generation was computed as the difference between the generation rating and forced and schedule outage. For the import capacity, it was computed differently for different paths (see Capacity on Major inter-Ties on Page 53 in the "A proposed Methodology". However, when we computed the import capacity prospectively, we adopted a more simplified approach. More details are provided in the later section.

[5] The capacity under the long-term contracts was regarded as the committed capacity, and was excluded in the capacity calculation.

As mentioned earlier in this section, the load that is served by long-term bilateral contracts is assumed to be hedged. Also, if a utility's own generation can meet a significant portion of its load, this portion of load is also deemed as the hedged load. In sum, this variable attempts to measure the extent to which the load in a region is exposed to the spot market prices. If most of load is exposed to the market price, suppliers have stronger incentives to bid high in order to increase market prices and collect more market power rent.

4.3.1.3 Regression Results

The regression results for the study period of November 1999 to October 2000 and 2003 are shown below. The regression results indicate that there was a statistically significant relationship between the Lerner Index and RSIs and other explanatory variables. The included variables explain over 46 percent of the variation in the Lerner Indexes during the study period (see R-Squared values in the table). Moreover, the signs of the estimated coefficients were as we expected. A negative coefficient on RSIs indicated that smaller RSI values (i.e. more dominant market shares by the largest supplier) corresponded to higher Lerner Indexes (i.e. higher price-cost markups). On average, an increase in the RSI index of 10 percentage points would decrease the Lerner Index by 5.3 percentage points. A positive coefficient value for PLU indicates that Lerner Indexes increase when more load is exposed to market price. Finally, the effects of two dummy variables also have expected signs. The Lerner Index is larger in summer months and peak hours when the demand is higher and supply margins are relatively lower.

Figure 4.1 Price-cost Markup Regression Results

Dependent: Lerner Index		
Explanatory Variables	Parameter Estimates	t-Statistics
Intercept	0.14	[11.08]
RSI (gross RSI specification)	-0.53	[72.76]
PLU	0.65	[70.98]
Dummy for Peak hour	0.086	[23.77]
Dummy for Summer Months	0.15	[48.19]
R Squared		0.46
Number of Observations		31333

Source: California ISO market data.

4.3.1.4 Selecting Regression Specifications

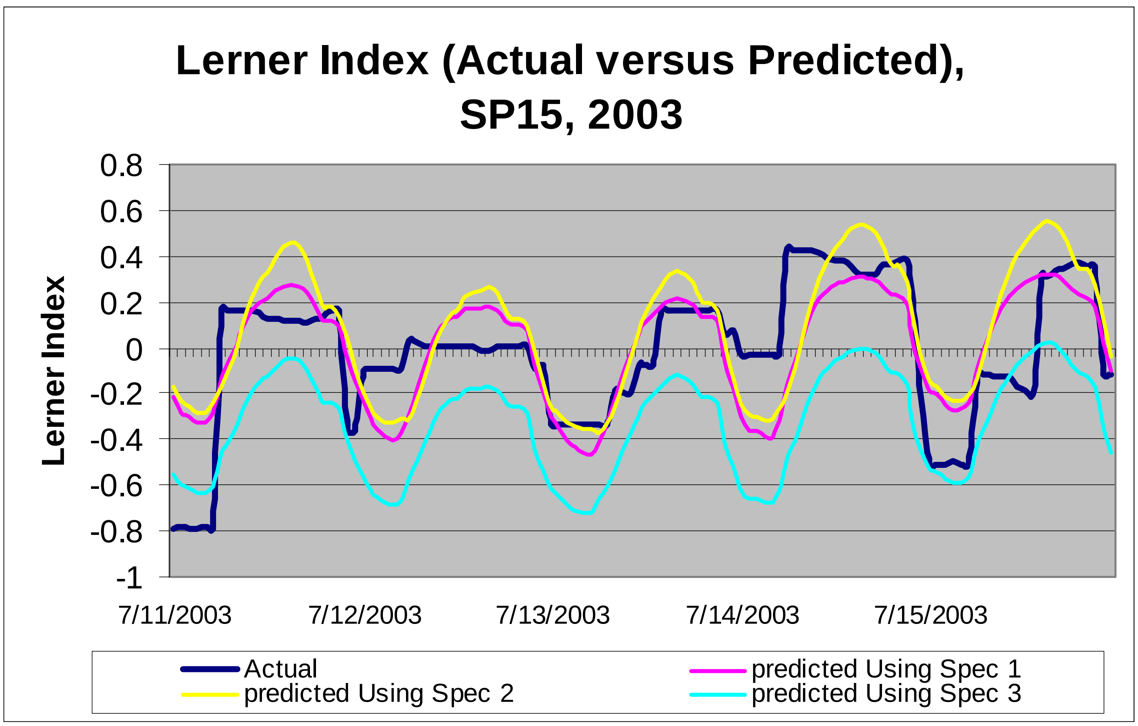
Because our regression specification will be used to derive future market prices for all the various scenarios considered, we believe it is important to develop as good a specification as possible. For this purpose, we developed several potential regression specifications and compared their predictive ability using an out-of-sample test. First, using the same data set (Nov99-Oct00, and 2003) we divided the entire sample into two parts: an in-sample data set and an out-of-sample data set. The out-of-sample data set consists of hourly data for a total of 60 days in 2003 (5-day for each month in 2003). The in-sample data set consists of hourly data from November 1999 to December 2000 and the remaining 2003 data (after excluding 60-day data used for in-sample data set). Using the in-sample data set, we generated regression estimates for each regression specification. Then, for each specification, we computed the projected Lerner Index for the out-of-sample data. Finally, we compared the projection results from every specification with the actual Lerner Index and chose the one specification that generated the best fit. Specifically, we tested the following three specifications:

Table 4.1 Different Specifications of Regression Model

Specifications	**Variables Included**
Specification 1 (Results presented in Figure 4.1)	RSI, PLU, Dummy for Peak hour, Dummy for Summer Months
Specification 2 (Polynomial specification)	RSI, RSI_squared, PLU, Dummy for Peak hour, Dummy for Summer Months
Specification 3 (Exponential specification)	1/RSI, PLU, Dummy for Peak hour, Dummy for Summer Months

Specification 1 produced a linear relationship between the Lerner Index and RSI.[6] Some might argue that relationship between RSI and the Lerner Index itself might be nonlinear, especially during tight system conditions. To test how a non-linear specification would improve our projection, we included a polynomial specification (Specification 2) and an exponential specification (Specification 3). Figure 4.1 compares the actual Lerner Index with the projected Lerner indexes using three specifications for the SP15 region for 5-days in July 2003 (which was the only five-day period where consistent positive price-cost markups were observed in the out-of-sample). For this summer period, we observed that Specification 3 (Blue line) generally under-predicted, while Specification 2 (yellow line) tended to over-estimate in peak hours. Among these three specifications, Specification 1 seemed to produce the best estimates. Therefore, we felt that it was reasonable to choose Specification 1 (detailed in Table 4.1) for the analysis.[7]

Figure 4.2 Comparison of Lerner Indexes, Prediction Versus Actual (Out-of-Sample Test)



[6] Even though there was a linear relationship between the Lerner index and RSI in Specification 1, the RSI has a non-linear relationship with actual market prices, due to the definition of Lerner index being ((Pi,j – Ci,j)/Pi,j).

[7] By no means are these specification tests exclusive. However, we think it was important to have a specification that was able to trace the actual movement of price-cost markups in the summer period where most markups were observed. We chose the 5-day in July for this test because this 5-day period was the only period we observed the consistent positive markups in the peak hours in the out-of-sample data set. Specification 1 seemed to produce a better result.

4.3.2 Step 2: Calculating System Variables for the Prospective Study Periods

This step involves calculating the necessary hourly variables for determining the price-cost markups to be used prospectively for 2008 and 2013 in three utility areas: PG&E, SCE, and SDG&E. The specific hourly data that were calculated for each simulation scenario are:

$RSI_{i,j}$ = Residual Supply Index in hour (i) for zone (j)

$Pct\_load\_unhedged_{i,j}$ = Percentage of load unhedged in hour (i) for zone (j)

The computation of these two variables and other variables are fully automated in PLEXOS.

The formula for the RSI calculation is:

$$RSI_{i,j} = \frac{TS_{i,j} - Max(TUC_{i,j})}{RND_{i,j}}$$

Where,

$TS_{i,j}$	=	Total Available Supply (the available capacity of the internal generation + import capacity)
$Max(TUC_{i,j})$	=	Total Uncommitted Capacity of Largest Single Supplier
$Load_{i,j}$	=	Actual zonal demand

The first component of the RSI calculation ($TS_{i,j}$) is equal to the aggregate of internal generation capacity and import capacity. The hourly internal generation's available capacity was computed as the difference between the generation's rating and planned and forced outages. In the projected assessment of system adequacy (PASA) run, PLEXOS generated the planned outage number by optimizing the maintenance schedule to balance supply and demand in the intermediate time horizon. In the same PASA run, it modeled the random outage. PLEXOS then computed the available capacity for each generation on an hourly basis.

For import capacity, we implemented a 30-day "look-back" algorithm. For each utility region, we identified the inter-regional lines that connect the region. The import capacity for region *j* and at day *d* was determined by:

$$import\_capacity_{d,j} = \underset{\xi d=t-1,\ldots,t-30\xi}{Max}(0, \sum_i Flow_{i,j,t})$$

where $i=1,\ldots,I$, denoting the inter-regional lines that connect to region *j*

$\sum_i Flow_{i,j,t}$ represents the actual aggregate net import schedules to region *j* in a hour in day *t*. The import capacity into region *j* at day *d* was determined as the maximum hourly net import schedule reported in the previous 30-days. This approach to determine the import capacity is slightly different from the one when we used to derive RSI values for the regression data (November 1999 to October 2000, and 2003), where we determined the import capacity at the branch group level with each branch group treated differently. Our current modification was necessary, partly due to our implementation of a DC network model, and partly due to the actual implementation and complexity of modeling in PLEXOS. [8]

4.3.3 Step 3: Estimating Bid-cost Markups for Market Price Run

In this step, we first estimated hourly Lerner Indexes based on the input data derived in Step 2. We then applied the estimated bid-cost markups in a region to all strategic suppliers. Specifically, for each generator, its corresponding bid-cost markups were added on its estimated marginal costs to derive its bids for the market price run. The marginal costs are estimated based on fuel costs, heat rates, and other O&M costs. Finally, we conducted market price runs in PLEXOS.[9]

We only treated the owners of merchant generation as strategic players, where the estimated bid-cost markups were added to the marginal cost in the market price run. In contrast, utility's owned generation, municipal generation, as well as generation under 2003 RMR Condition II contracts are treated as non-strategic suppliers and no bid-cost markups were added. More detailed discussion on this is provided in Chapter 8—Input Assumptions for the Path 26 Study. In the market price run, PLEXOS re-executes the optimal power flow model using the bids that have incorporated bid-cost markups (instead of the bids that only reflect the variable costs in the cost-based run).

Bid-cost Markup Scenarios

We stated before that the dependent variable in the regression equation is the Lerner Index, defined as:

Lerner Index = $((P_{i,j} - C_{i,j}) / P_{i,j})$

[8] Alternatively, we might use the line ratings to represent the import capacity. But we believe that line ratings would exaggerate the actual import capacity for a region. Or we may simply use the hourly actual net import volume, but this would likely under-estimate the import capacity. We believe that using the 30-day "look-back" algorithm strikes a balance between these two approaches, and more realistically represents the actual import capacity into the region. Finally, the resulting import capacity numbers are largely comparable with the historical numbers.

[9] It is worth noting the difference between the Lerner Index (or price-cost markups) and bid-cost markups. Strictly speaking, the predicted values from the regression equation are price-cost markups rather than bid-cost markups. In this analysis, we applied the derived price-cost markups as bid-cost markups for the following reasons. Theoretically, it is possible to use the weighted average zonal price in the cost-based run where every supplier is assumed to bid its marginal cost, and then apply the price-cost markups to directly derive the new regional prices that correspond to strategic bidding (without the market price run). However, due to the implementation of DC network model and the nature of econometric model itself, it is conceivable that the projected regional prices might not be consist with flows, the congestion patterns, and congestion revenues on the relevant inter-regional lines. In this analysis, we chose to treat the price-cost markups as bid-cost markups, and re-execute the full-network model, this would ensure that the resulting regional prices are consist with congestion patterns.

Alternatively, we could estimate the relationship between *bid-cost* markups (rather than the current *price-cost* markup) and system conditions, and apply this relationship prospectively. However, this is very difficult, if not impossible. First, we only had limited information on bidding behavior of suppliers. The energy transacted in the CAISO' real-time markets only account for a very small portion of the entire wholesale energy. For 2003, less than 5 percent of the energy was traded in the CAISO's real-time market. In other words, we did not have bidding information on the majority part of a supplier's generation portfolio. Second, the characteristics of suppliers, the generation locations, and the types of generation (base-load units or peaker units) are all likely to affect a supplier's bidding patterns. Because of the enormous complexity of this approach and the deadline we confronted, we decided to postpone this exploration for the future enhancements.

Finally, we did conduct some sanity checks, including comparison of the applied bid-cost markups and the price-cost markups after the market price run. We found that these two indexes usually move closely with each other such that in the hours where we had high markups, we also observed higher price-cost markups after the market price run.

where

$P_{i,j}$ = Actual price in hour (i) and zone (j)

$C_{i,j,}$ = Estimated competitive price in hour (i) and zone (j)

For the base markup scenario, the Lerner Index is the direct output of estimation equation. To derive actual market clearing prices, the estimated Lerner Indexes must first be converted to price-cost markups (PMU)[10]:

$$PMU_{i,j} = ((P_{i,j} - C_{i,j}) / C_{i,j})$$

For the high and low markup scenarios, the Lerner Index was adjusted upwards or downward to reflect the forecast errors. Mathematically, it is defined as

High Predicted Regional Lerner Index = max (0, ***Base*** Predicted Regional Lerner Index + $t_{\_value}$ * s);

Low Predicted Regional Lerner Index = max (0, ***Base*** Predicted Regional Lerner Index - $t_{\_value}$ * s);

We used a t_value of 1.645 to reflect the 90 percent confidence interval, and "s" is the standard deviation of the forecast error derived from the regression equation. A high-predicted regional Lerner Index represents an upper bound of the predicted Lerner Index, while a low predicted regional Lerner Index represents a lower bound.[11]

Proportional Bid-cost Markup

As mentioned earlier, we used the estimated price-cost markups as the bid-cost markups in the market price run. Given the market structure in California, only merchant power suppliers are treated as strategic suppliers that bid above their marginal costs. When computing the strategic capacity of each merchant supplier, its capacity under the contract was excluded.

Finally, instead of applying the same bid-cost markups to all the strategic suppliers in the same region, we used a "proportional markup" approach, assuming that the largest supplier had the highest bid-cost markup in the region. According to supply function equilibrium model proposed by Green and Newbery (1992), the price markup of a supplier is a proportional to the quantity it supplies and inversely proportional to the sum of residual supply elasticity and absolute value of demand elasticity.[12] This indicates that the largest supplier has more incentives than other supplier to bid higher and collect market power rent. The same implication can be also drawn from Cournot type models.

Specifically, the bid-cost markup of supplier *s* at region *j* at hour *i* was defined as:

$$BCM_{s,i,j} = PMU_{i,j} * SC_{s,i,j} \ / \ LSC_{s,i,j}$$

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[10] The relationship between price-cost markup (PMU) and Lerner Index is: **PMU=LI/(1-LI).**

[11] It is important to point out the differences between price-cost markups and bid-cost markups. If we directly use price-cost markups as the proxies for bid-cost markups, the resulting final price-cost markups from the market price simulations are likely to be lower than that predicted for importing regions (where market power is more relevant). Therefore, in the actual practice, some calibrations on bid-cost markups might be necessary.

[12] Green, R. and D. Newbery, "Competition in the British Electricity Spot Market," Journal of Political Economy, 100(5), 929-953, 1992. For a more recent paper see Linear Supply Function Equilibrium: Generalizations, Application, and Limitations, Baldick, Grant, and Kahnor, POWER Working Paper, 2000.

where:

$PMU_{i,j}$ = the price cost markup derived from the Lerner Index equation for the region

$SC_{s,i,j}$ = the strategic supply capacity of player s after netting out its contract commitment

$LSC_{s,i,j}$ = the largest supplier's capacity

After applying the bid-cost markups to each strategic supplier, we conducted the market price run.

All benefit computations were based on the results of market price run.

4.3.4 Calculating Economic Benefits for Market Price Runs

PLEXOS re-simulates using the marked-up bids and internally calculates monopoly rent, following which we apply the formulas in Chapter 2 – Quantifying Benefits – to derive measurements of benefits. A detailed discussion on computation of benefit components is provided in Chapter 2, and not discussed here.

4.4 Future Enhancement

4.4.1 Continue to Improve Existing RSI Approach

The further enhancements of market price methodology are both important and necessary. On the one hand, we will continuously improve the current methodology. We will experiment with new specifications to test and improve the model's prediction capability, especially when new data becomes available. We will also refine our methodology of estimating the cost-based market clearing prices. In the future, we would use PLEXOS to simulate competitive prices so that all transmission constraints and operation limitation can be appropriately accounted for. On the other hand, we will explore other approaches to derive the market prices. For instance, we will explore to derive the relationship between bid-cost markups and system conditions directly rather than the current approach -- relying on price-cost markups as the proxies for bid-cost markups. This approach will be more realistic after the CAISO starts to operate the day-ahead market where bids and other market information become more available.

4.4.2 Further Investigation of Game-Theoretical Approaches

On a parallel path, we will continue modeling the game-theoretical strategic bidding behavior in the DC network model. While it is very difficult to model the complex game-based strategic behavior in the DC network model, we will experiment with some simplified strategies such as pure Cournot strategy, or ConjectureMod developed by London Economics. The results from this modeling exercise can serve as a check for results from the econometric approach or provide an additional markup scenario in the market price run.

5. Sensitivity Case Selection

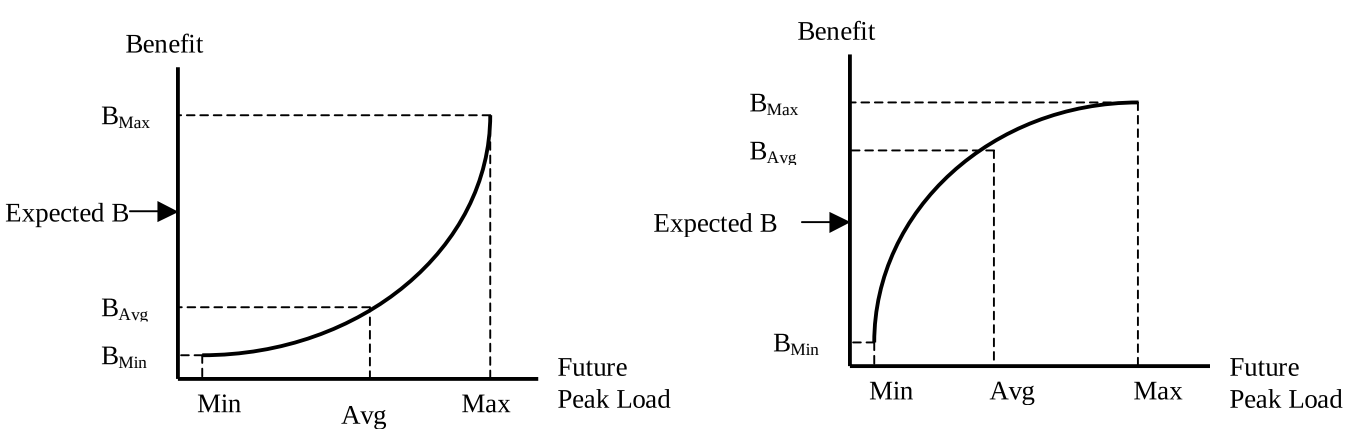
5.1 Overview

5.1.1 Importance of Risk and Uncertainty Analysis in Transmission Economic Evaluations

Decisions on whether to build new transmission are complicated by risks and uncertainties about the future. Future load growth, fuel costs, additions and retirements of generation capacities and the location of those generators, exercise of market power by some generators, and availability of hydro resources are among some of the many factors impacting decision makers. Some of these risks and uncertainties can be easily measured and quantified, and some cannot.

There are fundamentally three reasons why we must consider risk and uncertainty in transmission evaluation. First, changes in future system conditions can significantly affect benefits of a transmission expansion. The relationship between transmission benefits and underlying system conditions is in many cases nonlinear. Thus, evaluating a transmission project based only on assumptions of average future system conditions might greatly underestimate or overestimate the true benefit of the project and may lead to less than optimal decision making. The following figure depicts two examples of the possible relationship between the benefit of transmission expansion and future peak load. If the marginal benefit of a transmission project increases at an increasing rate with an increase in peak load (the left panel), then the evaluation based on average future peak load will underestimate the benefit. Conversely, if the benefit does not increase at the same or greater rate with an increase in peak load, then the evaluation based on average future peak load will overestimate the benefit (the right panel). Similar non-linear relationships may also exist between transmission benefits and other factors. To make sure we fully capture all impacts the project may have, we must examine the value of a transmission expansion under a wide range of possible system conditions.

Figure 5.1 Benefits and Expected Benefit



Second, transmission upgrades are particularly valuable during extreme conditions and major values of transmission upgrade are insurance against extreme events. For example, the California energy crisis might have been avoided has there been a significant transmission capacity between the Eastern interconnection and the Western interconnection. If all of the inexpensive Eastern power could have gotten to the West during that time period, prices would not have risen and the state of California would not have had to assign forward contracts at prices that reflected substantial market power. In addition, it would have perhaps avoided the recent blackout in the eastern U.S. that led to significant economic loss to that area of the country.

Third, transmission upgrades have significant option values and the only way to value these options is to consider probabilities of risk and uncertainty. Option analysis can tell whether projects are really needed, or can be deferred or should be advanced. Decision makers need to consider probabilities to calculate option values. Although our methodology does not focus on option analysis, nevertheless it is an important aspect of risk and uncertainty analysis.[1]

5.1.2 Approaches in Studying Risk and Uncertainty

As we discussed previously, the relationship between benefits of transmission expansion and factors that might impact those benefits can be highly nonlinear. Thus, it is important to consider a range of possible outcomes of those factors that can potentially affect the value of a transmission upgrade. There are several alternative approaches to assessing the impact of risk and uncertainty on the benefits of a transmission expansion. A deterministic approach or a stochastic approach, or a combination of the two is the approaches most often used. In the following sections, we will briefly review each approach and identify the approach that we selected for our methodology.

Deterministic Approach

Deterministic analysis is performed using point estimates, for example, a single set of assumptions about loads, natural gas prices, and the availability of generating plants to meet customer loads. While a deterministic analysis is useful for understanding a single set of input forecasts, it does not reflect the impact of risk and uncertainty. Deterministic analysis is best used for initial analysis of an expansion proposal. A complete transmission evaluation process should incorporate stochastic analysis or scenario analysis described below.

Stochastic Approach

Stochastic analysis models the uncertainty associated with different parameters affecting the benefits of an expansion project. Stochastic analysis often uses probabilistic representations of the future loads, gas prices, and generation unit availabilities. Usually, expected values of production costs and fuel consumptions are computed without the assumption of a perfectly known future.

Many types of stochastic approaches have been developed. One particular type is the “Monte Carlo” probabilistic simulation. Simulations that incorporate Monte Carlo analysis often use detailed, deterministic programs while allowing factors such as unit outages and variations of loads from base forecasts to be generated through the use of random sampling techniques. Random numbers are generated

[1] Including transmission upgrade’s option value could be an area for future enhancement to the CAISO methodology.

at regular time intervals and used to develop sample results from the appropriate probability distributions. For instance, Monte Carlo analysis may be used to draw random numbers that determine the status of a generating unit; whether it is operating at full capacity, experiencing a forced outage, or returning to service. The magnitude of the load deviation from the expected forecast may also be determined by a random number using a "forecast error" probability density.

Combined Approach – Scenario Analysis with Stochastic Component Incorporated

Monte Carlo is a useful tool for stochastic analysis. However, performing Monte Carlo simulation simultaneously for multiple variables can be very complicated and time consuming, especially for a large-scale DC network model. In our methodology, we use a combined approach with both deterministic and stochastic components. More specifically, we model the impact of exogenous variables on the power system in a deterministic fashion. Those variables included demand forecast, gas price forecast, hydro availability, new generation entry and cost markup. However, instead of focusing on one single set of deterministic assumptions for these exogenous variables, we developed a 2-stage sampling technique to select reasonably probable representations of future system conditions, i.e., scenarios. In addition, we developed two techniques to assign joint probabilities to various combinations of exogenous variables[2] to allow us to compute the expected value of a transmission upgrade, as well as the expected range of the values. Finally, as part of our methodology we recommend studying the insurance value that a transmission project may provide against extreme low-probability, high-risk system contingencies. For endogenous variables such as generation maintenance and forced outages, we incorporated the stochastic component in our simulation model so that these factors can be modeled correctly in a probabilistic manner. In other words, we used Monte Carlo probabilistic simulation for generation outages. This Monte Carlo technique can be further extended to include other endogenous variables such as transmission line outages and other system conditions affecting transmission values.

In the following section, we describe our scenario analysis. We first discuss the goal of using scenarios analysis. Then, we discuss how we choose scenarios and how we assign probabilities to scenarios.

5.2 Scenario Analysis

5.2.1 Goal of Scenario Analysis

The goal of our scenario analysis is to answer the following three questions:

- What is the expected benefit of a transmission upgrade
- What is the expected or most likely range of benefits
- What is the insurance value of a transmission upgrade against extreme conditions and contingencies

In the following sections, we discuss how we propose to answer these questions.

[2] By exogenous variables we mean variables that are outside the control of the power system operation and dispatch.

5.2.2 Selecting Variables and Their Values

Variables

The first step in preparing to answer the questions above is to decide what variables to include in benefit evaluation. The key principle is to select variables that have a significant impact on transmission expansion. In our Path 26 study, we decided to study the following five variables:

- Future demand level
- Future gas price level
- Future strategic bidding behavior (markup)
- Future hydro availability; and
- Future new economic generation entry

What variables to include in a transmission upgrade evaluation study should be determined on a case-by-case basis. Our methodology is general enough that, once variables are decided, it helps to define variable values and to assign probabilities to joint variable events.

Variable Values

The next step is to decide what value to consider for each variable. The approach here is to consider a wide range of possible future values for each variable. A reasonable approach is to compile a most likely base case (usually bounded by a 50 percent confidence interval surrounding the base case values), a range of possible values bounded by an intermediate confidence level (e.g., a 75 percent confidence interval in predicting the range), and a wider range bounded by a larger confidence level (e.g., a 90 percent confidence interval). In our Path 26 study, we chose to consider the following five levels for each variable:

- Very High (VH)
- High (H)
- Base (B)
- Low (L); and
- Very Low (VL)

VH and VL are the upper and lower bounds of the 90 percent confidence interval for a variable if an objective probability distribution could be derived. H and L are the upper and lower bounds of the 75 percent confidence interval, and B is the most likely base case.

Base Case Demand and Base Case Gas Price

A variable's base case value represents its most likely value in the future. In our Path 26 study, for California area, we adopted the California Energy Commission's (CEC's) demand base case forecast as our demand base case and CEC's gas price forecast as our gas price base case[3], while we directly predicted our base case

[3] More specifically, in our demand base case, we used the CEC's annual energy consumption forecast for moderate economic growth scenario as our base case energy consumption, and the CEC's peak load forecast for 1-in-2 temperature conditions as our peak load. For more details, see *California's 2003 Electricity Supply and Demand Balance and Five-Year Outlook*, California Energy Commission, available at www.energy.ca.gov.

markup from our regression analysis using future system conditions[4]. For other regions in WECC, we used WECC's 10-year forecast (2003-2012) of peak load and energy growth rate to derive the base case energy and peak load forecast from 2002 actuals.[5]

Others who might use our methodology can develop their own base case assumptions based on their judgment or historical experiences. We believe our base case reflects an appropriate approach for projects internal to California, but recognize that there may be circumstances that justify projects sponsors modifying the CEC forecasts in developing their base cases. Below, we explain how we developed the alternative values for each of the five variables considered in the Path 26 study.

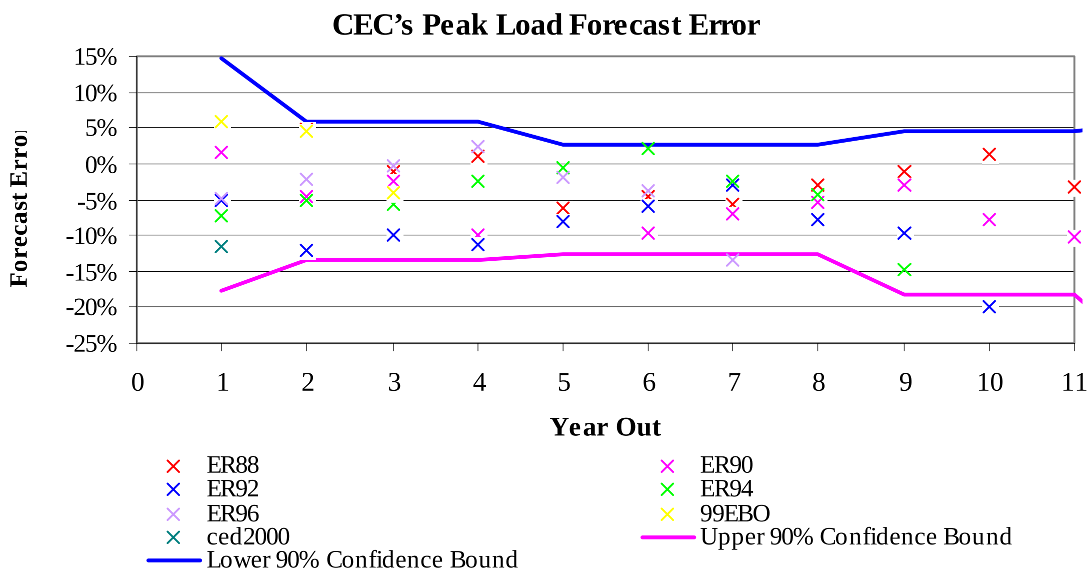
Demand

For other than base case values, people can either base on forecast errors or historical distributions to derive these values. We adopted the former approach because we have good historical tracking records of CEC's forecast errors. Assuming demand (both annual energy consumption and peak load) is normally distributed, we define demand forecast error (F.E.) as:

Demand F.E. = 1 – CEC Forecast Value/Actual Value.

Figure 5.2 shows CEC's forecast error of peak load by comparing CEC's various published peak load forecasts with actual peaks.

Figure 5.2 Forecast Errors



[4] See discussions in Chapter 4 for more details.

[5] For more detailed information, see *WECC 10-Year Coordinated Plan Summary (2003-2012)*, Committee of Planning and Operation for Electric System Reliability, December 2003. Available at http://www.wecc.biz/coord_plan_summary.html.

The alternative demand levels can be computed as:[6]

VH Demand = (1 + Upper 90% Confidence Bound of Demand F.E.)*Base

H Demand = (1 + Upper 75% Confidence Bound of Demand F.E.)*Base

L Demand = (1 + Lower 75% Confidence Bound of Demand F.E.)*Base

VL Demand = (1 + Lower 90% Confidence Bound of Demand F.E.)*Base

Gas Price

In deriving other gas price values, we assumed that the gas price is log-normally distributed. There are two reasons for assuming a lognormal distribution: (1) distributions of gas price values around their mean value tend to exhibit left skews and fat right tails; (2) log-normal distribution ensures that gas prices are always positive. Zero or negative gas prices cannot be produced by a lognormal distribution. We calculated the CEC's gas price forecast error as follows:

Gas Price F.E. = LN(CEC Forecast Value/Actual Value)

= LN(CEC Forecast Value) – LN(Actual Value).

The alternative gas price levels can be calculated as follows:[7]

VH Gas Price = Base * $e^{\text{Upper 90\% Confidence Bound}}$,

H Gas Price = Base * $e^{\text{Upper 75\% Confidence Bound}}$,

L Gas Price = Base * $e^{\text{Lower 75\% Confidence Bound}}$,

VL Gas price = Base* $e^{\text{Lower 90\% Confidence Bound}}$.

Bid Markups

We used the empirical approach described in Chapter 4 to derive bid markups for the base case. Since the explanatory variables in our markup regression can only explain about 50 percent of the historical price-cost markups, we felt it is important to consider a wider range of markups. Alternative values of bid markups were derived by using the confidence intervals for the base case markup prediction as follows:

VH Markup = Upper 90% Confidence Bound = Base + $t_{0.05}$*s;[8]

H Markup = Upper 75% Confidence Bound = Base + $t_{0.125}$*s;

H Markup = Lower 75% Confidence Bound = Base – $t_{0.125}$*s;

L Markup = Lower 90% Confidence Bound = Base – $t_{0.05}$*s.

Hydro Availability

The availability of hydroelectric generation is a complex but important factor in analyzing transmission expansion benefits, especially for California and the rest of the WECC system, which rely heavily on energy from hydroelectric facilities. Although we have a long series of historical hydro data throughout the WECC to analyze the frequencies of dry, normal, or wet annual hydro conditions, it is impossible to predict exactly what annual hydro production will be 5 or 10 years in

[6] We calculate forecast error separately for total annual energy consumption and peak load.

[7] We calculate gas price forecast error for each region separately and apply F.E. accordingly.

[8] More specifically, $t_{0.05}$ is t-value at 5% significance level, and s is the estimated standard deviation of the regression error term.

the future. Therefore, we believe it is important to consider multiple cases with different levels of hydro generation.

Note that for a multiple-year continuous study, different patterns of hydro availability could also have significant impact on transmission benefit. For a 10-year continuous study, a hydro pattern that starts with wet years then continues to normal years and ends with dry years will likely result different benefits than an alternative hydro pattern that starts with dry and ends with wet. In our Path 26 study, we produce results for only two discrete years: 2008 and 2013. For each, we evaluate three hydro production levels: wet (W), base (B), and dry (D), throughout the entire WECC area[9]. As a result, we can analyze many different hydro patterns and their impact on transmission benefits, for example, wet in 2008 and dry in 2013, or vice versa.

New Economic Generation Entry

The amount of new generation entry, the timing of new entry, and their location might greatly affect the value of transmission expansion. The specific impact of new generation entry on transmission upgrade will depend on whether new generation and transmission upgrade are substitutes or complements.

In the Path 26 study, the base case economic generation entry level was derived for the entire WECC region by comparing new generators' profitability with their revenue requirements for year 2013. We then derived an over- and under-entry scenario to study the impact of new generation on transmission expansion benefits and the possible substitution of transmission and new generation. Because there is, to our knowledge, no sound statistical basis for developing over and under entry scenarios, the approach we used in our Path 26 study is 50 percent above or below the base case as the over or under entry case.

Given multiple variables and multiple values possible for each variable, the total number of all possible variable combinations (scenarios) is very large. However, it is not necessary to simulate all possible scenarios. In the following sections, we discuss how we efficiently sampled necessary scenarios and assigned probabilities to assist us in answering the three questions identified above.

5.2.3 Answering Question #1: What is the Expected Benefit?

In order to answer question #1, we selected a combination event of demand, gas price, and markup using both an importance sampling technique and a second sampling approach, which is called a "Latin Hypercube" technique. For this stage, hydro and new generation entry are held constant at base case values. We then used a moment consistent linear programming (LP) approach to assign joint probabilities to the joint events of these three variables (coupled with base hydro and base new generation entry[10]).

There are two critical aspects to scenario analysis:

- Selecting important and representative scenarios

[9] Due to data inheritance, we adopted SSGWI's hydro cases for 2008 and 2013. More specifically, the wet hydro level is the year 1948 water condition, the base level is the year 1953 water condition, and the dry hydro level is the year 1930 water condition.

[10] The reason we keep hydro availability and new generation entry at base is that the moment consistent LP approach requires a point estimate and the distribution of each variable based on forecast errors, while, as we discussed previously, alternative hydro and new generation entry levels are selected rather subjectively without historical references.

- Determining how to weight the estimated benefits under each scenario in order to derive the expected benefit of the transmission expansion

Our methodology provides a practical and innovative approach that addresses both of these aspects. We discuss our scenario development below.

Sampling

A comprehensive scenario selection approach should include three kinds of scenarios:

- Scenarios that represent most likely conditions
- Scenarios that represent extreme “bookend” conditions
- Scenarios that represent in-between conditions

In the following discussion, we describe how we selected scenarios from each of these categories using importance sampling and the Latin Hypercube sampling technique.

Importance Sampling

Importance sampling is used to choose most likely scenarios (i.e., base case scenarios), bookend scenarios, and scenarios we believed useful for comparison purposes. This example shows how we would choose joint events of demand and gas price using importance sampling:

Table 5.1 Examples of Importance Sampling

Bookend

		Demand Scenario				
		VH	**H**	**B**	**L**	**VL**
Gas Price Scenario	**VH**	X		X		X
	H					
	B	X		X		X
	L					
	VL	X		X		X

Useful Analytic Comparison

Most likely

Latin Hypercube Sampling

The Latin Hypercube sampling technique is essentially random sampling without replacement. This technique ensures a representative sample of scenarios being selected. In this example, there are two variables, demand and gas price, The Latin Hypercube technique ensures there is a selection in every column and every row of the matrix. Table 5.2 shows two sets of Latin Hypercube samples (one denoted by “X” and the other denoted by “O”):

Table 5.2 Examples of Latin Hypercube Sampling

		Demand Scenario				
		VH	**H**	**B**	**L**	**VL**
Gas Price Scenario	**VH**		X	O		
	H	X			O	
	B		O			X
	L			X		O
	VL	O			X	

If a sample by the Latin Hypercube technique was already selected in the importance-sampling step, it can be discarded and replaced by another random sample. Latin Hypercube is an efficient method for picking scenarios for multiple variables and it yields a low error in approximating a "joint probability distribution".[11]

Moment Consistent LP to Assign Joint Probabilities for Calculating Expected Benefit

As we stated in our February 2003 CPUC filing, we had developed a Moment Consistent Linear Programming Approach for assigning joint probabilities for joint events. This method requires choosing joint probabilities for each joint event such that it matches probability distributions of gas price, demand, and markup. More specifically, we accomplished this by using a simple linear programming (LP) algorithm to select joint probabilities so that moments (e.g., mean, variance, covariance, and skew) of estimated probabilities of gas price, demand, and markup levels are preserved.

As previously noted, we directly adopted CEC's base case gas price forecast as our base case and derived the high and low gas price levels using upper or lower 90 percent confidence bounds of the CEC's gas price forecast error. This distribution of the gas price forecast error determined the distribution of our future gas price forecast levels. Given historical evidence of how close the CEC's gas price forecast predicted the actual gas price, we derived the probabilities for each gas price forecast level, adjunct with other variables, based on the confidence level of the CEC's forecast. This same approach can be applied to other variables, such as demand and markup, which have comprehensive historical data on predicted and actual values that allow for the calculation of probabilities.

Scenarios represent possible future states of the world, each having some probability of occurring. If we knew the marginal probabilities of each system variable, the correlations between system variables, and had a representative sample of each, determining the joint probabilities of each combination of system variables (scenarios) would be straightforward. Although we don't have perfect information on the marginal probabilities and correlations, we can try to estimate them based on past experience. Furthermore, we may have more confidence in our estimates of some variables than of others, depending on the quality of the data. Given the confidence levels that are derived from the estimated distribution of each variable (demand, gas price, and markup), we can take the following approach to assign a single set of probabilities to each joint event.

[11] In our Path 26 study, we did not use the Latin Hypercube sampling process due to the tight timeline for completing the results.

Suppose we are interested in *m* joint events of demand, gas price, and markup. Denote demand variable as D, gas price variable as G, and markup variable as M. Assume variable D has mean $\hat{\mu}_D$ and variance $\hat{\sigma}_D^2$, variable G has mean $\hat{\mu}_G$ and variance $\hat{\sigma}_G^2$, and variable M has mean $\hat{\mu}_M$ and variance $\hat{\sigma}_M^2$. Furthermore, assume covariance between variable D and G is $\hat{\sigma}_{DG}$, covariance between variable D and M is $\hat{\sigma}_{DM}$, and covariance between variable G and M is $\hat{\sigma}_{GM}$. We will assign a probability, p_i (i = 1, 2, ..., m), to each joint event, using the following LP algorithm:

We are interested in *m* joint events of demand, gas price, and markup. We name the demand variable as D, gas price variable as G, and markup variable as M. We assume variable D has mean $\hat{\mu}_D$ and variance $\hat{\sigma}_D^2$, variable G has mean $\hat{\mu}_G$ and variance $\hat{\sigma}_G^2$, and variable M has mean $\hat{\mu}_M$ and variance $\hat{\sigma}_M^2$. Furthermore, we assume the covariance between variable D and G is $\hat{\sigma}_{DG}$, the covariance between variable D and M is $\hat{\sigma}_{DM}$, and the covariance between variable G and M is $\hat{\sigma}_{GM}$. We then assign a probability, p_i (i = 1, 2, ..., m), to each joint event, using the following LP algorithm:

$$\underset{p_1, p_2, \ldots, p_m}{\textbf{Min}} \quad \sum_{i=1}^{m} p_i^2 + \left[\sum_{i=1}^{m} p_i (D_i - \hat{\mu}_D)^3\right]^2 + \left[\sum_{i=1}^{m} p_i (G_i - \hat{\mu}_G)^3\right]^2 + \left[\sum_{i=1}^{m} p_i (M_i - \hat{\mu}_M)^3\right]^2$$

$$\begin{aligned}
\textbf{s.t.} \quad & \sum_{i=1}^{m} p_i D_i = \hat{\mu}_D & \quad \ldots\ldots(1) \\
& \sum_{i=1}^{m} p_i G_i = \hat{\mu}_G & \quad \ldots\ldots(2) \\
& \sum_{i=1}^{m} p_i M_i = \hat{\mu}_M & \quad \ldots\ldots(3) \\
& \sum_{i=1}^{m} p_i (D_i - \hat{\mu}_D)^2 = \hat{\sigma}_D^2 & \quad \ldots\ldots(4) \\
& \sum_{i=1}^{m} p_i (G_i - \hat{\mu}_G)^2 = \hat{\sigma}_G^2 & \quad \ldots\ldots(5) \\
& \sum_{i=1}^{m} p_i (M_i - \hat{\mu}_M)^2 = \hat{\sigma}_M^2 & \quad \ldots\ldots(6) \\
& \sum_{i=1}^{m} p_i (D_i - \hat{\mu}_D)(G_i - \hat{\mu}_G) = \hat{\sigma}_{DG} & \quad \ldots\ldots(7) \\
& \sum_{i=1}^{m} p_i (D_i - \hat{\mu}_D)(M_i - \hat{\mu}_M) = \hat{\sigma}_{DM} & \quad \ldots\ldots(8) \\
& \sum_{i=1}^{m} p_i (G_i - \hat{\mu}_G)(M_i - \hat{\mu}_M) = \hat{\sigma}_{GM} & \quad \ldots\ldots(9) \\
& \sum_{i=1}^{m} p_i = 1 & \quad \ldots\ldots(10) \\
& p_i \geq 0 \qquad \textbf{for all} \quad i & \quad \ldots\ldots(11)
\end{aligned}$$

Constraint (1), (2), and (3) state that the sum of the joint probability weighted demand, gas price, and markup forecast errors have to match their respective estimated mean forecast errors, derived using historical data. Similarly, constraints (4), (5), and (6) specify that the joint probability-weighted variances have to match the estimated variances. Constraints (7), (8), and (9) state that the joint probability-weighted covariance between any two variables have to match the estimated covariance's as well. Constraint (10) is the sum of probabilities and has to equal 1. Constraint (11) is the non-negativity constraint.

After we obtained the joint probabilities for joint events of demand/gas price/markup coupled with the base case scenarios for hydro and new generation entry, calculating expected benefit of transmission expansion is straightforward if each single scenario is simulated and the benefit is calculated. Table 5.3 below shows the joint probabilities calculated through moment consistent LP for our Path 26 study:[12]

Table 5.3 Joint Probabilities Derived for Calculating Expected Benefit in the Path 26 Study

Scenario	1	2	3	4	5	6	7	8	9
Demand	VH	VH	VH	B	B	B	VL	VL	VL
Gas Price	VH	B	VL	VH	B	VL	VH	B	VL
Markup	H	H	H	H	H	H	H	H	H
Joint Prob.	0.000	0.023	0.000	0.023	0.094	0.023	0.000	0.023	0.000
Scenario	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**
Demand	VH	VH	VH	B	B	B	VL	VL	VL
Gas Price	VH	B	VL	VH	B	VL	VH	B	VL
Markup	B	B	B	B	H	B	B	B	B
Joint Prob.	0.023	0.094	0.023	0.094	0.165	0.094	0.023	0.094	0.023
Scenario	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**
Demand	VH	VH	VH	B	B	B	VL	VL	VL
Gas Price	VH	B	VL	VH	B	VL	VH	B	VL
Markup	L	L	L	L	L	L	L	L	L
Joint Prob.	0.000	0.023	0.000	0.023	0.094	0.023	0.000	0.023	0.000

Note that among the 27 joint events, 8 events have virtually zero joint probabilities. This indicates that we do not need to simulate these cases for expected benefit purposes. However, these cases may be studied for analytical comparison purposes.

5.2.4 Answering Question #2: What is the Expected or Most Likely Range of Benefits?

It is difficult to obtain good objective predictions for the future states of many important variables. However, we can always select some possible future states subjectively and assess the impact of varying these factors. Furthermore, given a wide range of variables, being subjectively or objectively selected, we can always assign joint probabilities to each scenario to see what maximum or minimum benefit results given differing scenarios. For example, we can't confidently provide means and standard deviations for new generation entry distribution. Instead, we can calculate two extreme cases that bookend the benefits of transmission expansion with respect to that variable.

This is the idea behind our Min/Max LP approach. In this approach, we selected additional variables and events and assigned joint probabilities to put bounds on

[12] We have assumed zero correlations among the three variables in deriving the joint probabilities in our Path 26 study. The estimates of means and variances used in the Moment Consistent LP are as follows: $\hat{\mu}_{\mathbf{D}} = \mathbf{0}$, $\hat{\mu}_{\mathbf{G}} = \mathbf{0}$, $\hat{\mu}_{\mathbf{M}} = \mathbf{0}$, $\hat{\sigma}^{\mathbf{2}}_{\mathbf{D}} = \mathbf{1.111}$, $\hat{\sigma}^{\mathbf{2}}_{\mathbf{G}} = \mathbf{1.119}$, $\hat{\sigma}^{\mathbf{2}}_{\mathbf{M}} = \mathbf{1.000}$.

the benefit estimates ("worst" and "best" benefits). In this process, we use some informed judgment to estimate the probabilities of each (demand, gas price, markup, new generation entry, hydro availability) combination that will give the minimum or maximum net benefit for the transmission project.

More specifically, we assign joint probabilities by solving the following LP problem:

$$\underset{f_1, f_2, \ldots, f_k}{Max} \sum_{j=1}^{k} f_j B_j \quad or \quad \underset{f_1, f_2, \ldots, f_k}{Min} \sum_{j=1}^{k} f_j B_j$$

$$s.t.\ Constraints \qquad s.t.\ Constraints$$

where f_i is the joint probability of realizing a particular scenario (i.e. unique combination of demand, gas price, markup, new generation entry, hydro availability). In this Max or Min LP problem, constraints could include conditions such that the joint probabilities of demand/gas/markup derived from the Moment Consistent LP process are observed in the Min/Max LP as well. Also usual non-negativity constraints and the sum of probabilities equal to 1 constraint should be included. Furthermore, we can make subjective assumptions about hydro availability and new generation entry and include them as constraints in the Min/Max LP approach. Both LP approaches (Moment Consistent and Min/Max) don't prohibit us from exercising our judgment about future system conditions and studying the implications of our assumptions on expected transmission benefit values or their expected range.

We believe this methodology provides a practical and innovative approach to addressing both the aspects of risk and uncertainty: Some risk and uncertainty can be specified with probability estimates and some cannot. Matching moments makes sense when probabilities can be specified; considering worst and best cases makes sense when there is insufficient basis for estimating probabilities.

5.2.5 Answering Question #3: What is the Insurance Value of Transmission Upgrade?

As we discussed previously, a transmission upgrade can provide important insurance value against extreme conditions and system contingencies. To capture this insurance value, transmission expansion evaluation needs to include low-probability, high-impact events. Exactly what contingency situations to select is subjective and will likely depend on the particular transmission upgrade project being studied. The objective is to choose those contingency events that may significantly affect transmission benefits.

In our Path 26 study we selected two contingencies to consider: (1) the San Onofre (SONGs) nuclear plant (2000 MW capacity) being out of service in 2008 and 2013; and (2) the Pacific DC Intertie (PDCI) transmission line (3100 MW) bi-directional between Northwest and Los Angles) on outage in 2008 and 2013. SONGs provides a significant amount of baseload internal generation to Southern California. A SONGs outage will likely result in a significant increase in north to south flows on Path 26, the major path from Northern California to Southern California, to import power from Northern California and Northwest. Thus, this event will likely significantly increase the value of a Path 26 expansion. The PDCI is a parallel path to Path 26, and can import power from the Northwest to the LA Basin. Similarly, if

PDCI has an outage, we would expect much more north to south congestion on Path 26 in which case upgrading Path 26 would likely be very valuable.

5.3 Future Enhancements

In performing our Path 26 study, we had to simplify many elements of our analysis due to data limitations. For example, in the Moment Consistent LP approach, we assumed the correlation between future demand and future gas price was zero. We can improve the joint probability estimates if we can derive correlations using historical data. Similar improvement can be made to the Max/Min LP approach if data availability permits.

Another area needing future enhancement is the Monte Carlo modeling of generation outages and transmission outages. Currently, our modeling software is capable of doing Monte Carlo simulation for generation outages but not for transmission outages. We are also exploring the possibilities of doing Monte Carlo simulation for other variables such as demand and gas price.

6. Considering Demand - Side/Generation Alternatives to Transmission Expansion

6.1 Components of Recommended Method

The evaluation process for a transmission upgrade must include an evaluation of one or more alternatives to the upgrade. As explained in greater detail below, this element of the methodology is not intended to replace or otherwise function as the primary vehicle for integrated resource planning. Evaluating the comparative economics of various resource types capable of separately or collectively meeting system needs is essential to efficient integrated resource planning and the TEAM approach provides a valuable tool in performing such an assessment. However, the primary purpose of including resource substitution in TEAM is more narrow. The TEAM methodology calculates the benefits of a proposed transmission upgrade by comparing the with and without upgrade scenarios. The without upgrade scenario may not necessarily equate with the status quo.[1] Simply put, in the absence of the transmission upgrade, the perceived system need may be satisfied by other non-transmission resources if profitable to do so. Accordingly, resource substitution assists in developing a more accurate no upgrade scenario against which to calculate the benefits of the proposed transmission project.

In many cases, resource substitution may involve considering implementation of load management programs (demand side programs) or construction of more local generation. This is often referred to as generation/transmission substitution. In the simplest case, it may be deciding between erecting a transmission line and building generation with similar capacity in the local load pocket. In most instances, the evaluation is not this straightforward. Construction of a transmission line often is accompanied by a need for additional local demand, response to voltage support requirements or other reliability reasons. There may also be additional outside generation needed in the exporting zone. Therefore, as noted above, to conduct a comprehensive evaluation of a transmission upgrade, we must first develop a transmission scenario that considers the new transmission capacity in conjunction with the least cost local and remote generation and demand response combination required to serve the load. To measure the benefits of new transmission, we then develop a scenario without the new transmission investment. The difference between the two scenarios is the benefit of the expansion that accounts for the generation/demand-side response to the transmission

[1] The "no project" alternative in the CEQA context provides a good analogy. CEQA requires that decision-makers compare a project to a no project alternative. However, the no project alternative is not the environmental baseline, but rather the status of the environment that will result if the project is not built. For example, if a proposed highway is not constructed, the traffic does not disappear, but instead must be accommodated by some other means such as increasing lanes on surface roads. The increased surface road scenario would be the no project alternative to the highway proposal.

upgrade. In this section we summarize how we optimize long-term resource additions for both with and without transmission upgrade cases.

Some of the key questions addressed by our evaluation method include:

- Why is it critical to optimize generation and demand side resources in each transmission scenario
- Should a transmission configuration be chosen first and then optimized with generation/demand side additions for that configuration (Why not decide on generation first)
- How do we optimize generation and demand side resources for a given transmission scenario

6.1.1 Optimizing generation and demand side resources for each transmission scenario

A critical step in the evaluation process is to optimize generation and demand side resources for each transmission scenario. The evaluation must consider alternatives to the upgrade and those alternatives should be optimal least cost options. This is the best way to measure any difference in benefits between the upgrade and non-upgrade cases. To do otherwise would result in benefit estimates that could be over or understated, since some information critical to benefit measurement is omitted. Optimizing generation and load response in both with and without cases allows us to measure and compare the costs and benefits of the best combination of resources for each scenario. It allows us to model a market response to each transmission configuration and better reflect the reality of the markplace. As such, our method provides a more valid comparison of the benefits between the two cases.

A common practice in some transmission evaluations is to start with the generation resources currently under construction. The transmission upgrade is then added to the system and costs/benefits are calculated for the upgrade. This traditional approach does not initially adjust the generation resources for either the scenario with an upgrade or the one without. Only after the transmission option has been chosen is a generation alternative considered. This process can result in under or over estimation of the benefits of upgrade. A simple example illustrates this point.

Consider building new transmission to the San Francisco area at a cost of $120 million. If we estimate that implementing new demand side management programs and building new peaking plants (without new transmission) would together cost $100 million, it would be cheaper than building the new transmission. If, however, the evaluation just modeled the current system, not considering the alternative of new peaking plants and, therefore, including no generation response, old, less efficient units may need to continue operating and more current expensive demand side programs might continue to be needed. This is assumed to result in total costs of $200 million. If we compare our transmission upgrade case costing $120 to the $200 million cost, it would overstate the benefits of the upgrade. By allowing us to use the optimal response in the no upgrade case, we see that the lowest cost alternative would have a cost of $100 million. The appropriate case to compare with the $120 million upgrade case is the optimized no transmission case. Our goal is to compare to the upgrade case to the least cost alternative. Additionally, we believe long-term procurement plans can guide this resource substitution process of choosing a transmission configuration and then optimizing the generation additions for that configuration

In the preferred method of optimizing generation with a transmission configuration, it may appear that a planner chooses the transmission configuration first and then optimizes other resources to suit that transmission case. This would be only a partial view of the process. First, in the process described above, the focus was on one particular transmission upgrade evaluation. In general, we are performing evaluations every year with multiple iterations in each year. We advocate considering all current resources in utility procurement plans, a variety of system conditions and over- build and under-build conditions in the transmission evaluation process. Furthermore, the existing transmission configuration has been developed as a result of many years of iterations, discussion and revision. It has benefited from multiple assessments of the most likely long-term generation resource development. Thus, when a specific transmission project is evaluated, it has benefited from information on resource additions. As a result, the transmission configuration used in any of our evaluations incorporates a market response for generation investment.

Second, given the long lead-time required for transmission construction, the decision process, in some cases, is ahead of the decision to initiate generation investment. Our evaluation process should not be viewed as fixing the transmission configuration, but rather as considering a set of what-if scenarios. It first assumes a no-upgrade case, and then optimizes other resource plans and scores this option. It then repeats the process for upgrade option 1, option 2 and so on. All along, it considers the way generation will respond to each transmission scenario. Through this iterative process, we select the best mix of generation for each transmission configuration.

6.1.2 Resource optimization process

Although we used the phrase “resource optimization”, it is by no means a central planning process. The optimization process is our best effort to characterize the market decisions made by private investors or end-users in siting new generation and implementing demand side management programs. The decision to enter into a market is based upon the investor’s expectation of the profitability of the investment. In the electric utility industry, this is usually defined by a target revenue requirement or rate of return. Our method uses a range of scenarios to define the profitability of new entry. For each transmission upgrade option, we utilize forecasts of demand growth, gas prices, and hydro conditions to develop a mix of new generation that would be profitable under those conditions. In the future, and to the extent it becomes feasible based on the continued development of the IOU long-term procurement plans, we intend to coordinate the assumptions and resource decisions reached in that CPUC process with the analysis of resource substitution in our transmission planning process. Our key assumptions at present are that, (i) new entry will be independent and non-strategic in the market; (ii) new entry will be just sufficient to maintain prices at levels that are competitive while providing an adequate rate of return.

We discuss the dynamics surrounding new entry to the market below by outlining the key assumptions we used to develop the generation mix for each case.

The first critical assumption for new entry into the market is that the expected profitability of new generation should be the reason that investors enter the market. As we discussed above, this expectation is the means by which we represent private investment decisions in the market place. In theory, prices help equilibrate demand with supply. When there is more demand than supply, the market price should increase and improve the profitability of new resources. When there is over-investment in resources, the market price would be depressed and profit would disappear. This will slow new investment. On a long-term basis, supply is expected to match the demand and market will be in balance. We recognize in actual operation, the market is constantly adjusting to changing conditions, and can experience some years of over-investment and some years of under-investment.

The second critical assumption in modeling the private investment decisions of firms in adding new generation or demand-side program is how we model future market prices. We recommend using a range of prices, including those resulting from competition, those influenced by market power, and averaging the prices resulting from these differing market conditions. Ideally, we would also extend the modeling to consider the differential costs of siting in the different market regions including emission costs, land costs, transmission interconnection costs, gas interconnection, and water costs.[2] However, considering the optimal timing and size, type and location of investment presents a very complex mathematical problem. Our methodology starts with a review of prices using expected demand and natural gas price for each specific transmission upgrade option. We then calculate a revenue target for the average of these scenarios.

For example, if we have three demand scenarios, expected, low and high, and the corresponding prices are $37, $34 and $45, then the average price we will use to evaluate the profitability of a new addition will be $38.70 (We use simple average for convenience here). If the average price were $39 for all scenarios, then an investor would likely build the generation. If we simply modeled investor behavior using the prices in the expected scenario, $37, we might underestimate revenues, and assume the investor would not build new generation. A key reason for this type of result is that there is non-linearity between market prices and profits with respect to market conditions such as demand. If lower demand reduces profit by 5%, higher demand may increase profit by 20%. So the average of the prices of three demand conditions does not equal the price of the expected demand condition. The one draw back to this recommended approach is that it can substantially increase the computing time. Due to severe time constraints, in our current application of the methodology we used a simplification of this process using reserve margin as a

[2]For simplicity of discussion, we use new generation entry to include new demand side programs that could be implemented, including real-time pricing programs.

proxy for market driven resource additions in order to meet the timeline for this filing.

Using these prices we can derive a target revenue requirement which is used to optimize new resource additions for both the with and without transmission expansion cases. With this method we can also consider a variety of technologies in this optimization. For the Path 26 application of TEAM, we assumed the most likely technologies for new generation will be either peaking gas-fired units (simple cycle gas turbines or SCGT) or a base load advanced combined cycle gas turbine (CCGT). We calculated the levelized annual revenue requirement to recover costs for a typical new entrant using each technology.

The annualized fixed revenue requirement to be recovered is approximately $137 /kW/yr for a CCGT in 2008, and about $91/kW/yr for the SCGT as shown in Table 6.1.

Table 6.1 Generation Cost Assumptions

Inflation		Mult.	Percent			
	2002-2008	1.17500	2.04%	(#11)		
	2008-2013	1.10186	1.96%	(#11)		

Combined Cycle		2002	2008	2013	Units	Source
	net capacity	500	500	500	MW	(#12)
	levelized capital	102	119	131	$/kw-yr	(#13, #19a)
	fixed O&M	15	18	19	$/kw-yr	(#13)
	base heat rate	7,100	7,100	7,100	btu/kwh	(#14)
	start-up costs	1,850	1,850	1,850	mmbtu/start	(#14)
	variable O&M	2.4	2.8	3.1	$/mWh	(#15)

Combustion Turbine		2002	2008	2013	Units	Source
	net capacity	100	100	100	MW	(#16)
	levelized capital	58	68	75	$/kw-yr	(#17)
	fixed O&M	20	23	26	$/kw-yr	(#17)
	base heat rate	9,300	9,300	9,300	btu/kwh	(#18)
	start-up costs	180	180	180	mmbtu/start	(#18)
	variable O&M	10.9	12.8	14.2	$/mWh	(#19)

Notes:

11 CEC's forecast of GDP Implicit Price Deflator, received from CEC in an e-mail from Todd Peterson, CEC Natural Gas Office, on 1/29/04.

12 "Comparitive Cost of California Central Station Electricity Generation Technologies", California Energy Commission, Report # 100-03-001F, June 5, 2003, Table C-2, "Plant Size, Line 5, p. C-1.

13 Ibid., Table C-10, "Cost Summary", Lines 1-3, p. C-3.

14 Ibid., Table C-5, "Fuel Use", lines 1 and 3, p. C-2.

15 Ibid., Table C-10, "Cost Summary", Line 6, p. C-3. Annual capacity is from Table C-6, Line 11, p. C-2.

16 Ibid., Table D-2, "Cost Summary", Lines 5, p. D-1.

17 Ibid., Table D-10, "Cost Summary", Lines 1-3, p. D-3.

18 Ibid., Table D-5, "Fuel Use", lines 1 and 3, p. D-2.

19 Ibid., Table D-10, "Cost Summary", Line 6, p. D-3. Annual capacity is from Table D-6, Line 11, p. D-2.

19a Capital costs for a combined cycle were changed to be 75 percent higher than those of a CT based on subgroup input and Table A-7, "Base case and performance assumptions for new generating resource options", Northwest Power Supply Adequacy / Reliability Study -- Phase 1 Report, p. A-10. Website is: http://www.nwcouncil.org/library/2000/2000-4a.pdf

6.1.3 Specific Modeling Procedure

The following are the specific steps we recommend be used to derive the amount of new demand-side management/generation for the with and without transmission upgrade cases. For each case:

1) Run Market Pricing PLEXOS (or similar analytical tool] without new generation for the 2008 and 2013 time horizons using the baseline average fuel cost and demand scenarios and the assumed hydro scenario

2) For the first year where the annual average MCP > revenue target price, add a combination of CCGT and SCGT capacity in each zone such that the initial internal reserve margin of the CAISO control area equaled 15percent

3) Re-run Market Pricing PLEXOS [or similar analytical tool] for that year in which the new generation was added and beyond, seeking the all-in average unit revenues earned by each typical new entrant. At this stage, we are continuously recalculating the net revenues based on the implied load factor from the projections, not based on the typical static dispatch assumption of 85 percent for CCGTs and 10 percent for peaking units. Thus, we are able to model the operating profile of a composite group of new CCGTs and identify their load factor. For example, assume that new CCGTs in SP15 are running only 75 percent of the time in 2008. We then use this implied load factor from our modeling to compute the revenues required for CCGTs in 2008 in SP15. This process results in a load factor-appropriate target price, which can then be compared to the new entrant's average unit revenues

4) If the amount of new generation added does not yield converging average unit revenues, we refine the reserve margin (by adjusting amounts and/or combination of CCGTs and SCGTs) until such convergence can be reached

5) Re-run Market Pricing PLEXOS [or similar analytical tool] for the entire time period and repeat step 2) – 5) for 2013

Due to the significant time it takes to model a totally comprehensive case for Path 26, we had to make significant simplifications in our current application to be able to have simulation results completed and to demonstrate other aspects of our methodology in time to publish this report on schedule. For expediency sake only, we calculated a regional reserve margin of 15 percent based upon a resource adequacy requirement for all load-serving entities. Based on this calculated reserve margin, we derived zonal new generation amounts as the difference between required zonal reserves and LSEs' existing capacity (including existing generation, contracts, and demand-side management). In this way, we derived an incremental new generation mix such that the resource adequacy requirements would be met. We used this only as a starting point. We recommend implementing the new entry revenue target approach in the next version of the PLEXOS model. For each case, new entry should be (eventually) remunerated such that its meets its levelized expectations for return. This would be the best way to optimize demand-side management/generation for each case and establish a consistent basis on which to compare the two cases.

6.2 Future Enhancements

6.2.1 Consideration of Capacity Value

We received stakeholder input regarding valuing capacity benefits of an upgrade as well as the energy benefits it can bring. We concur with this assessment and show how our methodology can accommodate this benefit when a formal capacity requirement is set up in the West. Currently, the California CPUC is working with IOUs and the CAISO to develop a resource adequacy requirement that will require an LSE to own or contract for resources to reach a reserve margin of 15-17 percent. Other regions in the WECC interconnection area are considering a similar requirement. If implemented, the resource requirement would create a capacity market that would influence investment in generation and demand side response. We have considered how to incorporate this element into the transmission evaluation. Our proposed solution is simple in concept. Our approach would be to simulate a capacity market by modeling capacity prices and adding the revenue stream from this market to the revenue of generation owners. Once accomplished, we would use our method for evaluating new generation investment as described above. It should be noted that no data is currently available to accurately simulate a capacity market in California.

An alternative procedure would be to assume a simple price curve for capacity resources. For example, if we assume the reserve requirement is 15 percent, the price curve will have a price equal to the long term fixed cost of a peaking unit (including capital and fixed O&M) at the point where the market reserve level is 15 percent. When the reserve is less than 15 percent, the price will be higher, and when reserves are greater than 15 percent, the capacity price falls. The installed capacity market in the eastern ISO's may provide us some data for estimating this price curve. We note the term price curve means that the curve is not simply the demand curve or the supply curve. It represents the equilibrium points of both demand and supply.

This revenue stream can be calculated offline and added at the step of considering the economics of new generation addition. At each assessment year for new generation, we can add fixed revenue for each new plant under consideration based upon the market-wide reserve level and capacity price.

7. Overview of Analytical Process

This section presents an overview of:

- The model (software) selection process
- The reasons for selecting the model used in the study, PLEXOS
- Enhancements and customizations made to the software for the CAISO
- Any off-line sensitivities and validation studies performed

7.1 The Model Selection Process

7.1.1 Introduction

The California Independent System Operator (CAISO) has developed a methodology for evaluating the economic benefits of transmission expansion – a process that began in September of 2001. As one of the first steps in the process, in 2002, the CAISO asked London Economics (LE) to work with the CAISO and develop a methodology and a supporting modeling framework. LE developed an analytical methodology and used its proprietary models, PoolMod (Production Cost) and ConjectMod (Supply Function Equilibrium), to perform a case study analysis. The CAISO published the results of this case study in September 2002 and filed the preliminary methodology with the CPUC in February of 2003.

This initial effort provided the CAISO with valuable insights into the complex economic interactions and the difficulties involved with accurately modeling them. It revealed some shortcomings in the LE methodology and modeling capabilities. In particular, the LE model:

- Represented the transmission network at only the zonal level (the so-called “bubble” model), which failed to capture loop flow effects in the AC network; and
- Relied on a supply-function equilibrium model[1], whose output failed to benchmark satisfactorily against observed market pricing behavior, and suffered from slow computation time

The CAISO made a decision to evaluate other vendors’ products. The key evaluation criterion was the product’s ability to meet five key principles the CAISO believed essential to accurate economic modeling of the transmission system. The CAISO required that the modeling software have the ability to:

[1] Supply Function Equilibrium (SFE) refers to a class of game theoretic models in which ‘players’ optimize their own position by manipulating the price *and* quantity components of their offers simultaneously. SFE is attractive in that, unlike Cournot competition, it can be shown to have equilibria in some cases when the demand function is vertical (perfectly inelastic), but there may exist multiple equilibria, and thus significant computational effort is required to search the solution space. In contrast, under certain assumptions, Cournot competition can be formulated as convex optimization problem with a unique equilibrium – see http://www.PLEXOS.info/kb/part_03/KB0307008.htm.

- Automatically compute the key financial outputs required to estimate the benefit of a proposed transmission expansion project
- Represent the transmission network at the nodal level
- Compute other-than-marginal-cost pricing ("market pricing") with the flexibility to implement alternative pricing formulae defined by the CAISO
- Represent uncertainty in a meaningful way *e.g.* via Monte Carlo simulation and/or scenario analysis; and
- Incorporate demand-side management and other resource alternatives in an integrated manner

7.1.2 Model Selection

The CAISO's evaluation resulted in a short-list of software products best meeting its criterion. From this list, it selected the PLEXOS software from Drayton Analytics[2]. This product included the following key features:

- A single, integrated optimization that solves the production cost (thermal generator) dispatch and transmission optimal power flow (OPF)
- The OPF included optimization of phase shifters and DC line flow
- It modeled transmission interface limits and custom monograms
- Pump storage dispatch was optimized with respect to transmission limits
- Hydro energy budgets were optimized in an integrated fashion
- Generator maintenance could be automatically scheduled
- Random generating unit outages were modeled and multiple outage patterns could be sampled in a single model run
- Generator bidding was dynamic and endogenous – the program included a number of competitive bidding models and allowed the CAISO to customize bidding to suit its needs in a straightforward manner
- Emissions and ancillary services were co-optimized with energy dispatch and pricing
- Demand forecasting tools were embedded into the software
- Data were input via a relational database with an object-oriented structure
- The software and data architectures were designed for rapid and seamless deployment of software updates and customizations, and the software vendor was willing to make software modifications required by CAISO as part of their standard software licensing fee arrangement (i.e. no additional charge); and

[2] http://www.draytonanalytics.com and http://www.PLEXOS.info. This website documents the basic logical processes which link model input data to model output information.

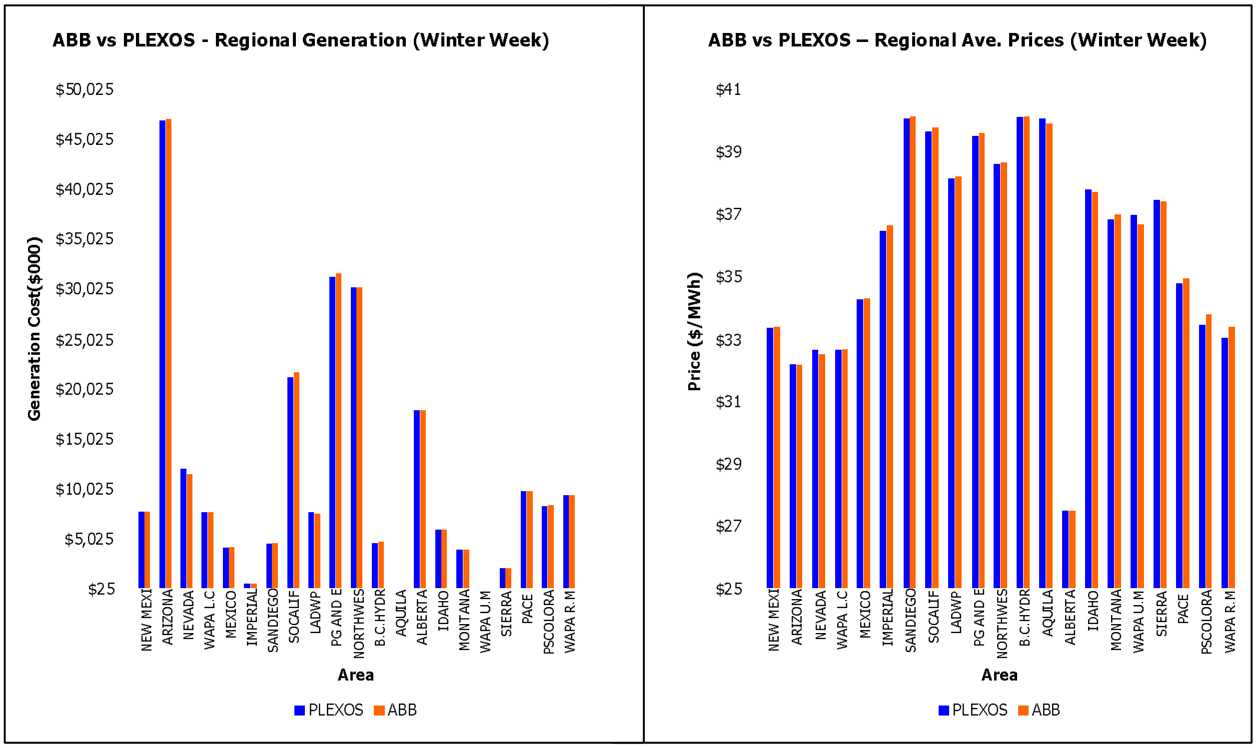
- The optimization models were entirely auditable (all solutions are derived from mathematical programming algorithms, which could be examined and validated)

7.2 PLEXOS Enhancements for the Methodology

7.2.1 Benchmarking

The first step in preparing PLEXOS for use in implementing the CAISO methodology was to benchmark PLEXOS outcomes to known solutions provided by the WECC. We compared solutions from the SSG-WI database for the year 2008 to those produced by PLEXOS. Figure 7.1: compares the database solutions of PLEXOS versus the SSG-WI results from ABB Simulator. Overall, PLEXOS produced near-identical results with equivalent program execution times compared to ABB Market Simulator.[3]

Figure 7.1 Comparison of Generation and Prices by Region SSGWI Cases Vs. PLEXOS



The CAISO received the SSG-WI 2008 'base case' in a format suitable for input to the ABB Market Simulator software. There were certain compromises and omissions in the dataset, including:

[3] PLEXOS solves the 2008 SSG-WI case in 60 minutes on a 2.5 GHz Pentium 4 PC.

- Pump storage hourly dispatch was fixed based on a simple peak-shave heuristic (rules-based) solution derived externally
- Generator maintenance and forced outage schedules were fixed and looked like scheduled maintenance (the origin of these 'schedules' was not clear)
- Hydro hourly dispatch was based upon a fixed historical pattern derived externally to the model
- Each plant had only a single fuel price for each year

Thus CAISO embellished the original SSG-WI dataset with:

- A model of pump storage sufficient for PLEXOS to optimize its dispatch as part of the simulation
- Generator maintenance rates, forced outage rates, and repair time functions
- Monthly variation of natural gas prices
- Added inflation for the other fuels

The CAISO also made other improvements to the dataset. It decided to retain the historical hydro "fixed profile". It performed an off-line sensitivity to confirm that re-optimization of the hydro energy would not significantly change the resulting benefits. (See the section Off-Line Sensitivities below.)

7.2.2 Enhancements to PLEXOS

Drayton Analytics enhanced two key areas of the PLEXOS program to suit the requirements of the CAISO:

1. They expanded the PLEXOS transmission model to include techniques for dealing efficiently with large-scale transmission networks such as the WECC. The program now includes a user-set option to change between 'standard' and 'large-scale' OPF models – the latter being employed in this study[4]. More details on the difference of these solution techniques are given below:

    The standard OPF

    - Employs a linearized DC approximation to the optimal power flow problem
    - Models transmission losses and the effect of marginal losses on locational marginal prices
    - Can model transmission augmentations and transmission outages dynamically *i.e.* the network topography does *not* need to be static

This model is sufficiently flexible that AC network sections can be combined easily with non-AC network sections. This feature is particularly useful for modeling AC transmission flows and constraints in a subset of the network, where detailed analysis is required, while treating the rest of the network as a more aggregated representation.

[4] This area of the program continues to be developed, with transmission loss modeling (which was previously only available in the 'standard' OPF), and is now being built into the large-scale OPF with expected delivery in June 2004.

PLEXOS optimizes the power flows using a linearized approximation to the AC power flow equations. This model is completely integrated into the mathematical programming framework. As a result, generator dispatch, line flows and nodal pricing are jointly optimized with the AC power flow.

The large-scale OPF

- Employs a linearized DC approximation to the optimal power flow
- Assumes losses do not affect power flows or locational pricing; and
- Assumes the network topography is static *i.e.* transmission lines must remain in-service throughout the horizon and no new elements can be added dynamically

Because the network topography is static and losses are assumed away, the network Power Transmission Distribution Factors (PTDF) or "shift factors" are constant. These shift factors are pre computed at the beginning of the simulation and stored. Then the generation and other simulation elements (*e.g.* hydro, pump storage, emissions, etc.) are optimized iteratively. Each iteration, the transmission flow implied by the optimal dispatch is compared to line and interface limits using the pre-computed shift factors. Where there are violations, "side constraints" are added to the simulation's linear program and the dispatch is re-optimized. This continues each step until an optimal and feasible dispatch is obtained.

The effect of congestion on transmission lines and interfaces is reflected in locational marginal prices using the dual solution to the linear program and the shift factors. Transmission losses are calculated ex-post but LMP will not reflect marginal losses.

2. The existing implementation of Dynamic Bid Cost Markup in PLEXOS based on computation of the Residual Supply Index (RSI) was expanded and made compatible with the latest formulation created by the CAISO

More details on the RSI computation are available in Chapter 4: Market Price Derivation.

These enhancements were made with the support of the CAISO Market Surveillance Committee (MSC) acting in an advisory role to Drayton Analytics[5].

7.3 Off-line Sensitivities

In addition to the core set of sensitivities, the CASIO performed a number of additional sensitivity analyses "off-line". The sensitivity analyses addressed assumptions and methodological issues that were constant across the core studies, and included testing the sensitivity of the measured benefits to:

1. The use of the PLEXOS Large Scale OPF in preference to the PLEXOS "standard" OPF
2. The pattern of generator forced and maintenance outages used

[5] Note that the MSC did not audit the implementation of the large-scale OPF or dynamic bid-cost markup. Rather, they provided academic references and suggestions for the development efforts at Drayton Analytics.

3. The method of using a fixed historical profile for hydro generation
4. The assumptions that line flows are without losses

7.3.1 Large Scale OPF Benchmark

The Large Scale OPF performs a significant amount of precomputation in the calculation of shift factors in order to reduce the size of the linear programming (LP) problems solved at each simulation step. To validate the algorithm, the results of the Large Scale OPF were compared to those of the Standard OPF. No significant differences existed in any simulation output.

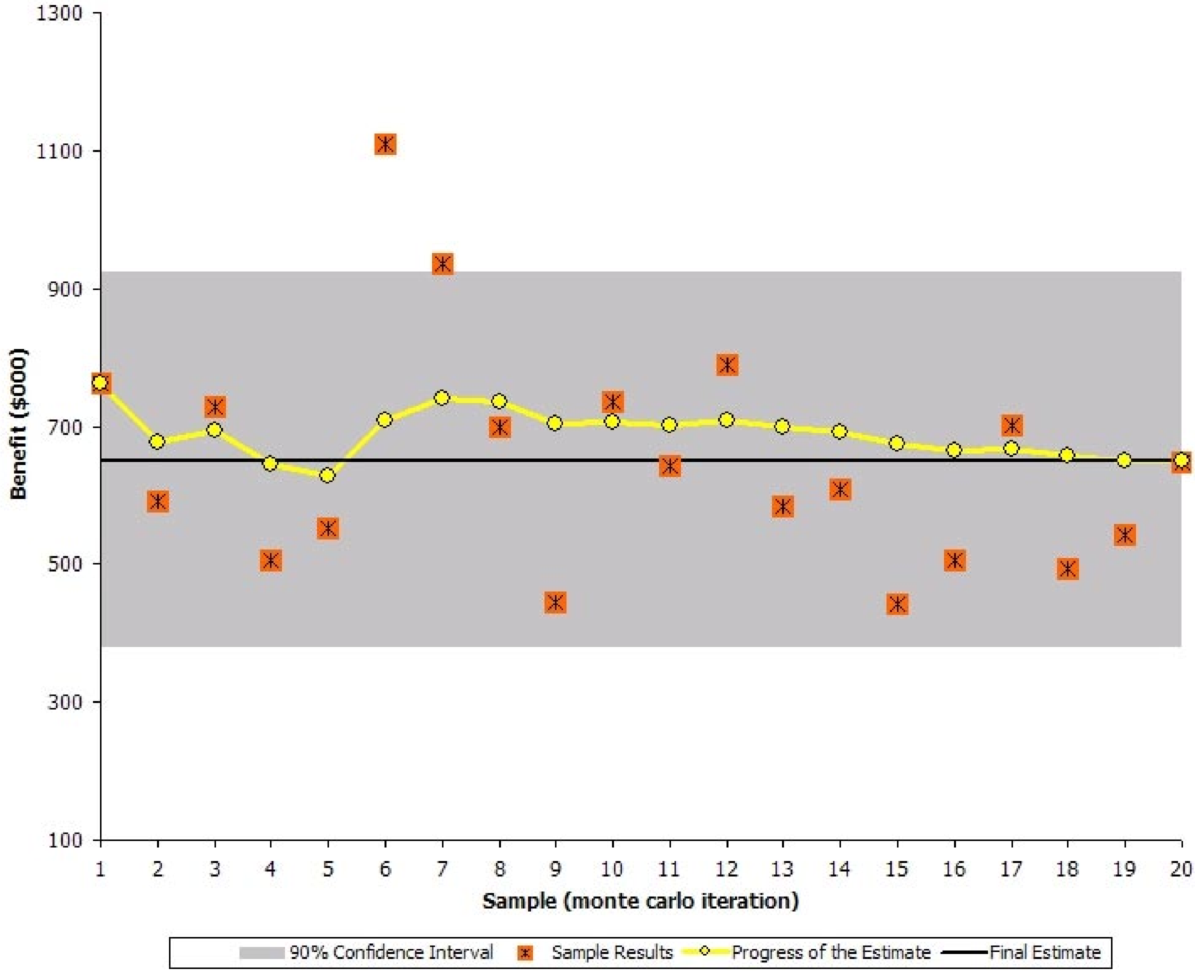
7.3.2 Generator Outages

PLEXOS can create and simulate the system with multiple samples or 'patterns' of random generator outages and endogenously optimized generator maintenances. Ideally, multiple samples would be used in every simulation and the benefit estimate would be the arithmetical average of those samples. This would yield an estimate of the variance in the results, and a likely shape of the distribution of benefits. But given the large size of the transmission problem and resulting execution times (of around 1 to 2 hours, depending on the case), it is not practical to solve multiple samples for every case.

Thus, if a single sample is to be used as 'the' estimate, it is important to gain some information about where the chosen sample's outcome lies in the distribution of outcomes. To achieve this, we ran the base case 2008 study with 20 Monte Carlo samples (distinct patterns of generator forced outage and timed maintenance). We used the same random number seed as in the 'core' studies. Thus the first sample equals the single sample used in those studies.

Figure 7.2 charts the individual sample results from one to 20. The black line is the average benefit from the 20 samples - $650,000. The yellow line shows how our estimate converges across the samples. The orange dots show each observation, and the grey area marks the boundaries of a 90 percent confidence interval based on the computed standard deviation of $166,000.

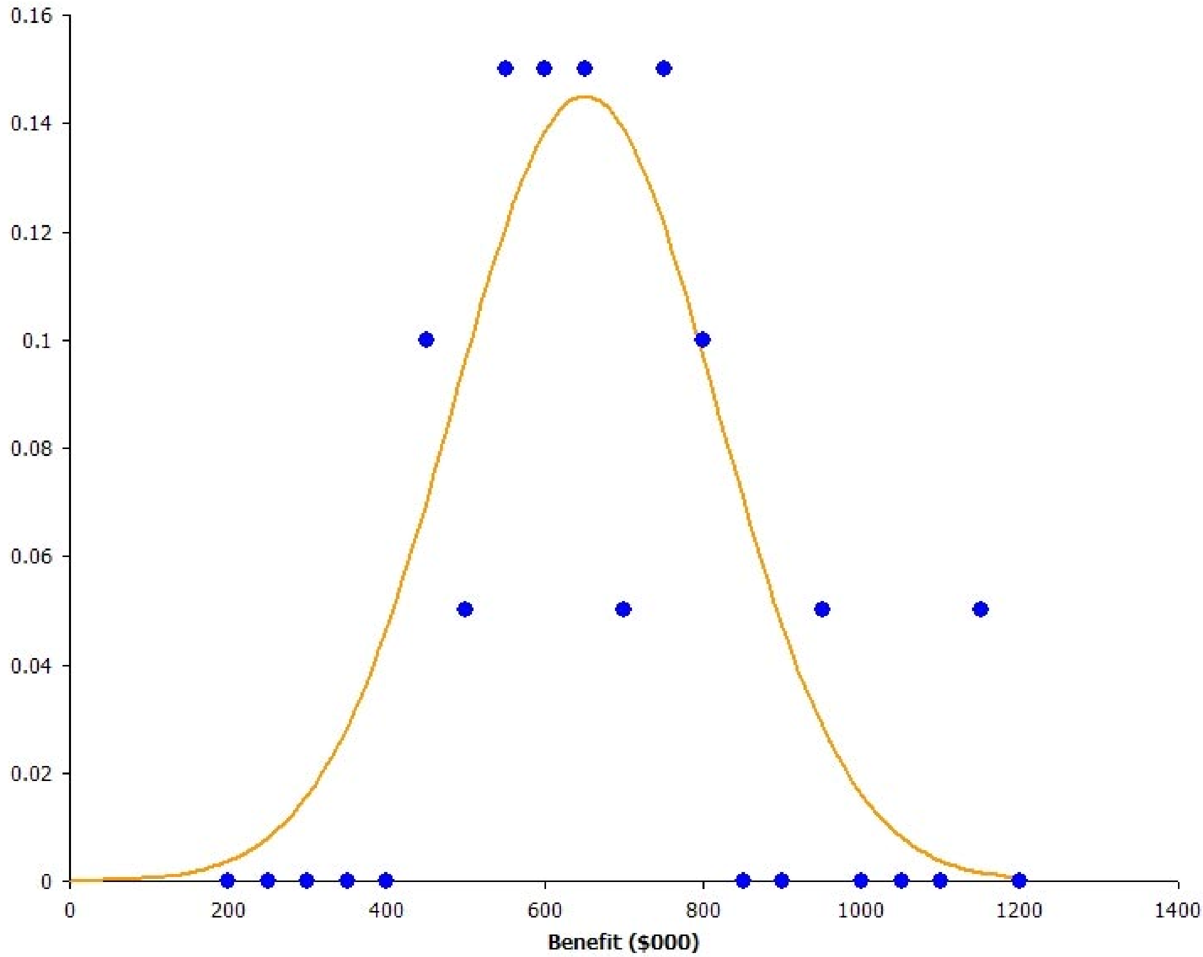
Figure 7.2 Convergence of the Societal Benefit Estimate Across 20 Monte Carlo Simulations



The results shown in Figure 7.2 are different than the final results described in the Executive Summary and elsewhere in the report, since this evaluation was performed before all the data inputs were finalized.

Figure 7.3 presents a histogram of the samples. Twenty samples are not sufficient to gauge whether or not the distribution of benefits is likely to be normal. Our intuition and experience suggests that it is likely to form a skewed distribution with a tail to the right-hand side – this would explain the two apparent outliers in the sample of 20. However, one must be cautious about drawing conclusions from a relatively small sample size.

Figure 7.3 Histogram of Societal Benefits



7.3.3 Hydro Re-optimization

Our core studies used a set of historical hydro generation patterns ('base', 'dry' and 'wet'). We took these profiles from years with different load patterns than those used to generate the load input files for 2008 and 2013. Thus, the potential for mismatches between the generation and load patterns exists. Clearly, some re-optimization of the hydro would help to avoid any distortion in the simulated generation (and computed generation cost). We could not estimate the extent to which this would affect the *benefits* (the difference between two cases with the same hydro assumptions) without actually performing the re-optimization.

To test this effect, we used the 2008 base case in an off-line sensitivity case with additional information:

- We deleted the hydro generator fixed schedule
- We entered the total daily energy for each hydro plant into PLEXOS as energy constraints (PLEXOS will then freely optimize the dispatch of those plants

inside each day to exactly meet that daily energy limit, which changes across time)

- We entered the minimum and maximum daily megawatt load of the generators as constraints on the generators (Min Load and Rating properties in PLEXOS). This captured any minimum flow constraints and head or other limitations that were present in the historical profile. (i.e. it would be unrealistic to assume that the entire daily energy budget can be optimized across the day without regard to minimum and maximum megawatts. Such constraints can arise from, e.g., minimum steady flow maintenance requirement.)

We solved the 2008 base for the ‘with’ and ‘without’ augmentation and compared the benefits to the core case. The benefits increased, which we expected when the optimization has more freedom. However, the increase in societal benefits of the transmission project was insignificant.

Given that, in reality, not all of the hydro would have the flexibility assumed in this test, the assumption of a fixed, historical hydro profile in this analysis seems reasonable. Based on this study’s outcome, it is not likely to cause any significant distortion in the benefits estimate.

Ideally, we prefer to optimize the hydro energy by month. However, since the large size of the network requires long computational times for the LP (Linear Program) to solve, it will be impossible to look ahead more than a day for any hydro optimization unless the network is significantly reduced.

7.3.4 Transmission Losses

The linearized DC optimal power flow (OPF) model assumes that line reactance is the key determinant of impedance (X), *i.e.*, the assumption is made that:

$$P = B\ (\theta_i - \theta_j)$$

where:
P is the real power flow on the transmission line (megawatts)
B is the susceptance, which, in this linearization, is equal to the inverse of X
θ_i, θ_j are the phase angles at the sending and receiving nodes respectively.

This does not preclude the modeling of thermal losses, which are equal to the square of P multiplied by R, provided those losses are small relative to the power flow and R is small relative to X. This is generally true in a high-voltage transmission network.

PLEXOS models transmission thermal losses by substituting P with a piecewise linear approximation, using non-negative directional flow variables. This is precisely the linear programming formulation used in a number of international markets that integrate linearized DC load flow with market dispatch and pricing[6].

A successive linearization approach is proposed with the help of MSC and will be a part of the future enhancements.

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[6] Examples include New Zealand and Singapore electricity markets. The Australian market uses a similar loss model, but does not model loop flow.

8. Input Assumptions for the Path 26 Study

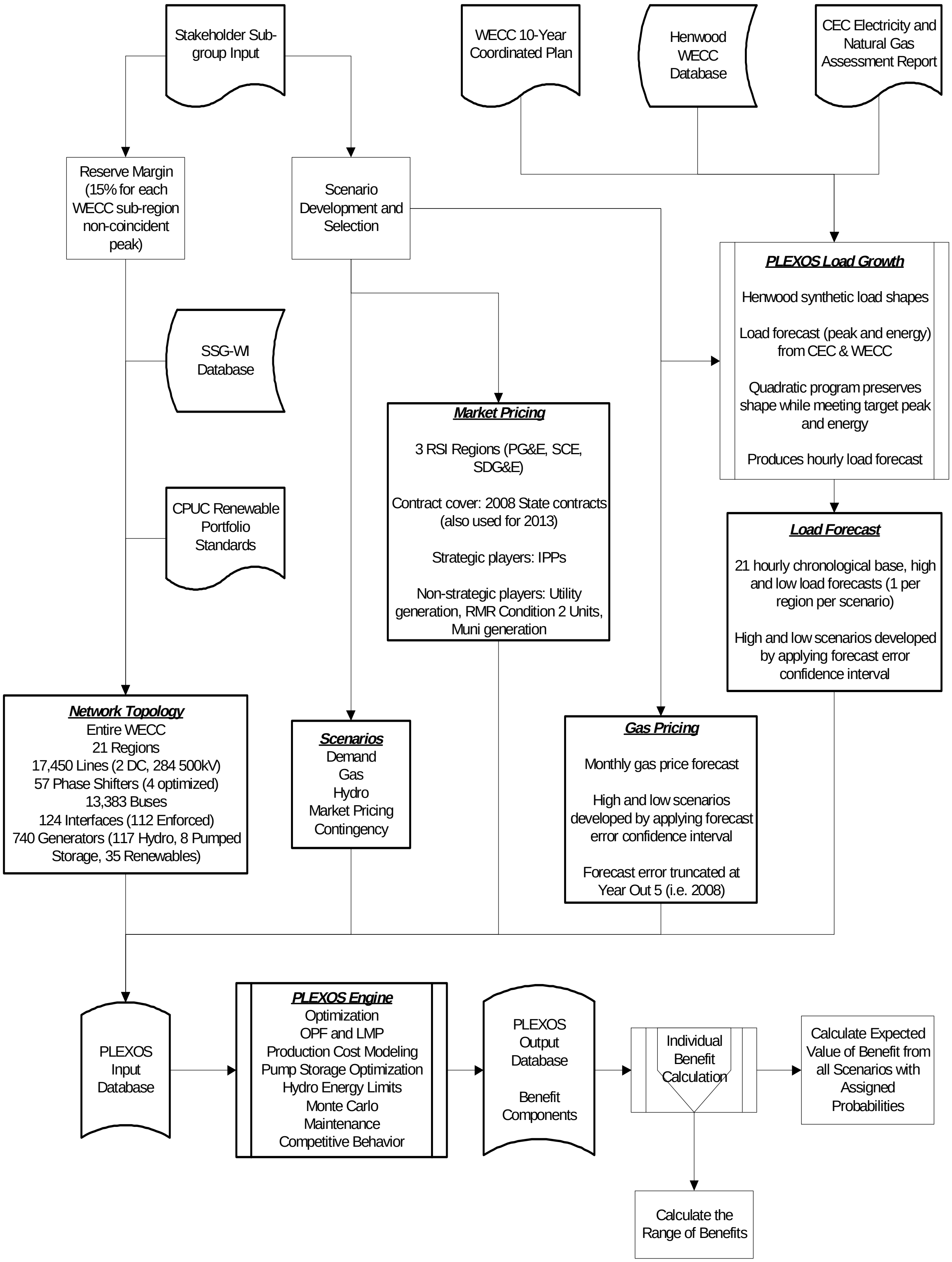
8.1 Overview

Any software model designed to forecast chronological market prices in a large-scale region will require a tremendous amount of input data, including demand forecast, gas price forecast, generation unit composition, and others. The data requirements are intensified if a transmission network model is used. Since it is a difficult and time-consuming activity to develop an appropriate full network database from scratch, the CAISO started with a full network database developed by the utilities participating in a regional transmission-planning forum. The CAISO then updated the original database with selected revised assumptions.

Figure 8.1 is a flow chart of the process by which the base case and sensitivities were developed. The flow chart also demonstrates how the base case and sensitivities were integrated into the overall process of the CAISO methodology. The major ingredients in the development of the input assumptions were reports from the CEC, the WECC and SSG-WI, input from CAISO stakeholders through sub-group committees, discussion with the CEC and data from the SSG-WI transmission study and Henwood Energy Services, Inc.

In the following sections we first describe how the initial database was developed, how we revise the database subsequently to incorporate more accurate or updated data. Then we discuss the assumptions for Path 26 upgrade, which is the focus of this study. We then also discuss the assumptions we used in deriving market prices. Finally we present our final set of sensitivities for the Path 26 study.

Figure 8.1 Development of CAISO Path 26 Study



8.2 SSG-WI Base Case Assumptions

We developed our 2008-base case database based on the 2008 SSG-WI database. The Seams Steering Group – Western Interconnection (SSG-WI) was organized for two purposes: (a) to facilitate the "creation of a Seamless Western Market"; and, (b) to propose "resolutions for issues associated with differences in RTO practices and procedures.[1] One of the SSG-WI work groups, the SSG-WI Planning Work Group (PWG), was tasked with performing various transmission studies to identify congested paths for the 2008 and 2013 time frames. From this effort, a comprehensive input dataset was developed.[2] Table 8.1 summarizes the network data developed by SSG-WI and adopted for the Path 26 study.

Table 8.1 Summary of Network Data in the Path 26 Study

Data Element	Number
Regions	21
Generators	740
Hydro	117
Pumped storage	8
Renewable	35
Transmission Lines (including transformers)	17,450
500 KV and higher	284
DC lines	2
Nodes	13,383
Interfaces	124

The CAISO started with the base case SSG-WI dataset. In the following we briefly discuss data for generation, transmission, non-gas fuels, and hydro as derived in the SSG-WI database.

8.2.1 Generation

The generation mixes in the SSG-WI database is shown in Figure 8.2 for 2008. The generation mix in 2000 is also shown as a reference point. The information shown is the "installed" or "nameplate" capacity for the resource categories. The installed capacity may differ considerably from the average energy available from these facilities or the project dependable capacity (PDC) that is used for reserve planning purposes.[3]

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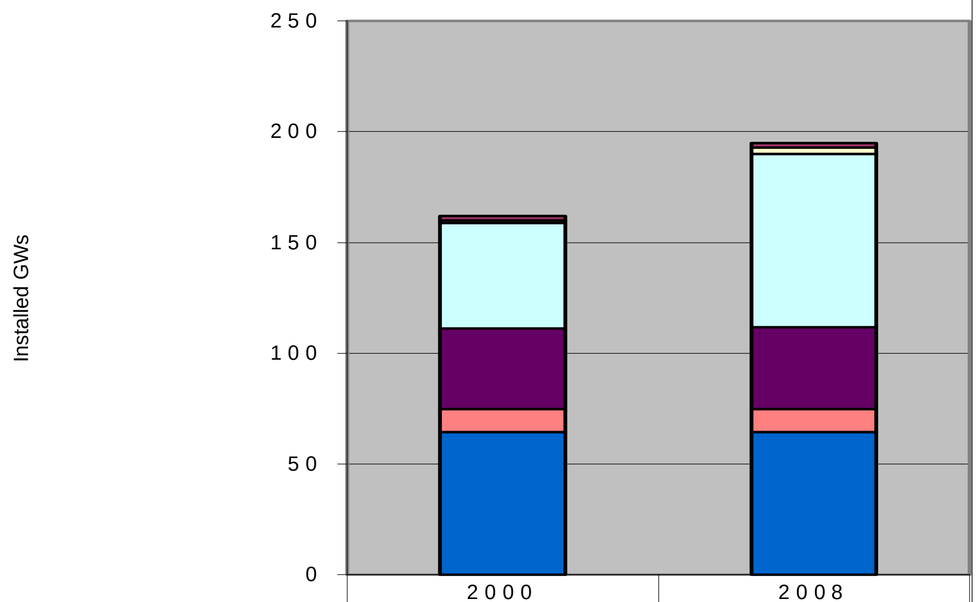
1 SSG-WI website: http://www.ssg-wi.com/.
2 SSG-WI website: http://www.ssg-wi.com/GeneralWorkGroupDetails.asp?wg_id=3&wg_name=Planning.
3 SSG-WI website: http://www.ssg-wi.com/documents/316-FERC_Filing___103103___FINAL_TransmissionReport.pdf, p. 26 of 54.

Figure 8.2 SSG-WI 2008 Generation Capacity by Fuel Type



	2000	2008
Solar	0	0
Geo & Biomass*	2.1	2.1
Wind*	1.2	2.8
Gas	47.4	78.3
Coal	36.6	36.9
Nuclear & Other	10.2	10.2
Hydro	64.6	64.6

Table 8.2 contains a summary of the regional[4] generation capacity by fuel type.[5]

[4] In this report, region refers to a PLEXOS region and not the entire WECC. There are 21 regions being modeled.

[5] SSG-WI website: http://www.ssg-wi.com/documents/317-FERC_Filing___103103___FINAL___Appx_D1_FINAL_103103.pdf, p. 7 of 122.

Table 8.2 Regional Generation by Fuel Type

	Coal	Geo & Bio	Wind	Solar	New CCT Gas Fire HtRt<7500	Older Gas	Nuclear	Other	Hydro & PS	Total Area
Model Areas										
ALBERTA	5,898	0	150	0	2,441	1,712	0	41	843	**11,085**
AQUILA	0	0	0	0	0	0	0	0	590	**590**
ARIZONA	7,351	0	0	0	6,558	3,208	3,733	0	462	**21,312**
B.C.HYDR	0	0	0	0	250	2,000	0	60	10,031	**12,341**
IDAHO	2,110	0	0	0	0	0	0	0	1,792	**3,902**
IMPERIAL	0	283	0	0	78	295	0	50	50	**756**
LADWP	1,710	0	0	0	574	2,801	0	0	1,260	**6,345**
MEXICO-C	0	675	0	0	1,100	953	0	0	0	**2,728**
MONTANA	2,311	0	0	0	0	0	0	39	573	**2,923**
NEVADA	595	0	0	0	3,022	1,128	0	0	0	**4,745**
NEW MEXI	1,885	0	200	0	0	1,125	0	0	82	**3,292**
NORTHWES	1,938	0	650	0	4,354	1,935	1,170	272	31,980	**42,299**
PACE	4,612	23	150	0	0	580	0	53	518	**5,936**
PG AND E	90	985	400	0	7,474	8,062	2,192	275	9,252	**28,730**
PSCOLORA	2,607	0	200	0	913	3,020	0	0	521	**7,261**
SANDIEGO	0	0	0	0	764	2,242	0	0	0	**3,006**
SIERRA	532	47	0	0	0	1,010	0	100	16	**1,705**
SOCALIF	1,677	56	1,050	0	2,678	10,237	2,167	0	2,040	**19,905**
WAPA L.C	0	0	0	0	2,227	0	0	0	3,379	**5,606**
WAPA R.M	3,546	0	0	0	480	1,037	0	0	1,225	**6,288**
WAPA U.M	0	0	0	0	0	0	0	0	0	**0**
Total By Type	**36,862**	**2,069**	**2,800**	**0**	**32,913**	**41,345**	**9,262**	**890**	**64,614**	**190,755**
2000 Base	36,571	2,069	1,200	0	3,045	41,345	9,262	890	64,614	**158,996**
Additions by Type	291	0	1,600	0	29,868	0	0	0	0	31,759

Appendix Tables AC.1 and AC.2 contain additional information regarding the SSG-WI 2008 generation resources.

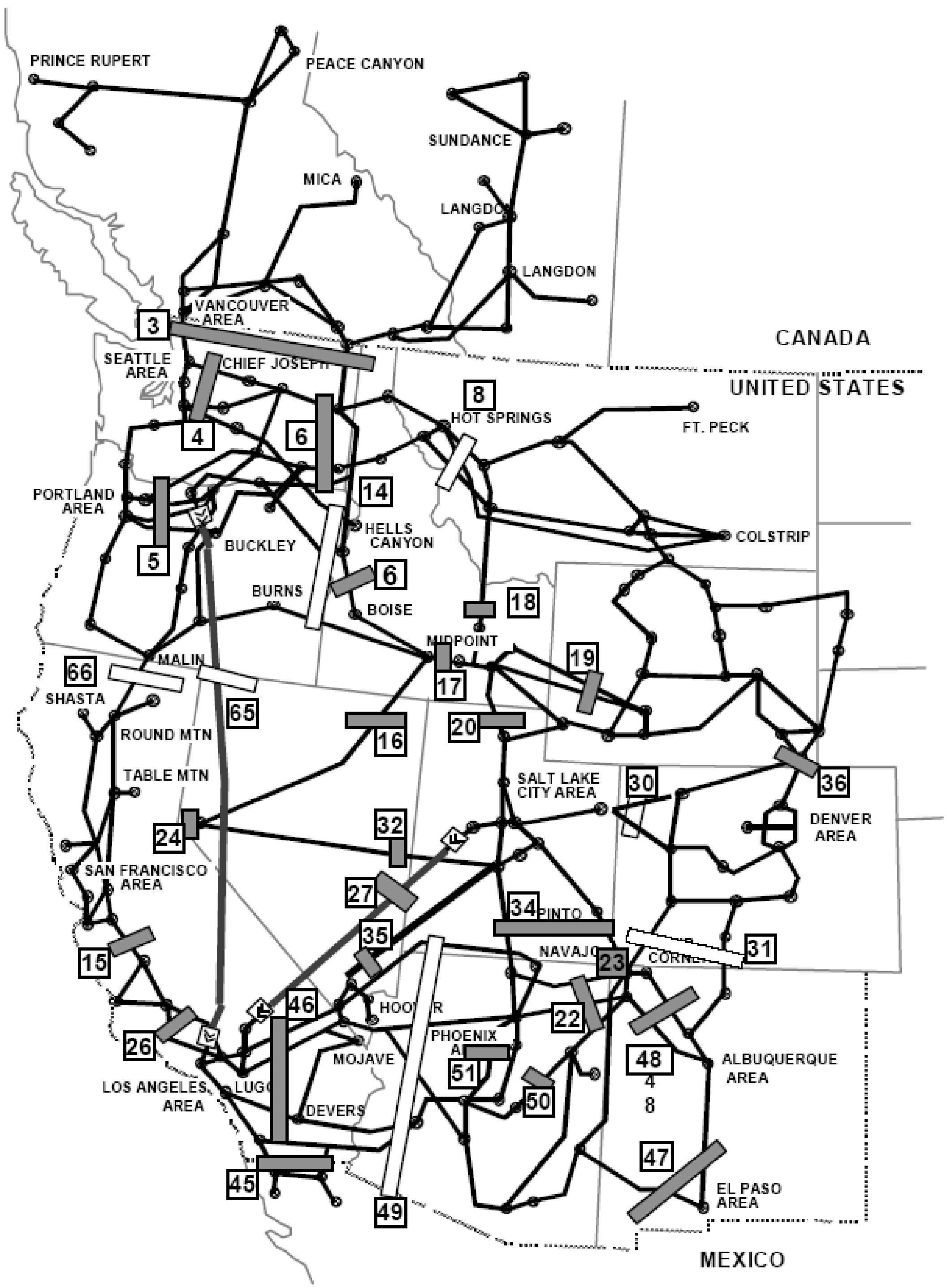
The 2008 SSG-WI generation database was further revised with the CAISO data described in Sections 8.3.3 and 8.3.4. This CAISO-modified 2008 generation database was then used as a base for 2008.

8.2.2 Transmission

The SSG-WI transmission data were derived from the "WECC 2008 LSP1_SA" approved base case. These data include approximately 17,500 transmission lines (including transformers) and 13,400 nodes. In addition, there are 33 transmission paths that are identified in the SSG-WI data shown in Figure 8.3.[6] Appendix Table AC.3 lists the individual path names.

[6] SSG-WI website: http://www.ssg-wi.com/documents/320-2002_Report final PDF , p. 8 of 70.

Figure 8.3 Summary of SSG-WI Transmission Path Data



The addition of many renewable and other resources to the WECC between 2008 and 2013 requires several new transmission projects to ensure deliverability. It is uncertain in 2004 which specific transmission projects will be built by 2013; however, transmission expansion is expected. Table 8.3 lists a set of transmission additions developed in conjunction with SSG-WI and stakeholder sub-groups that represent a likely transmission expansion plan.

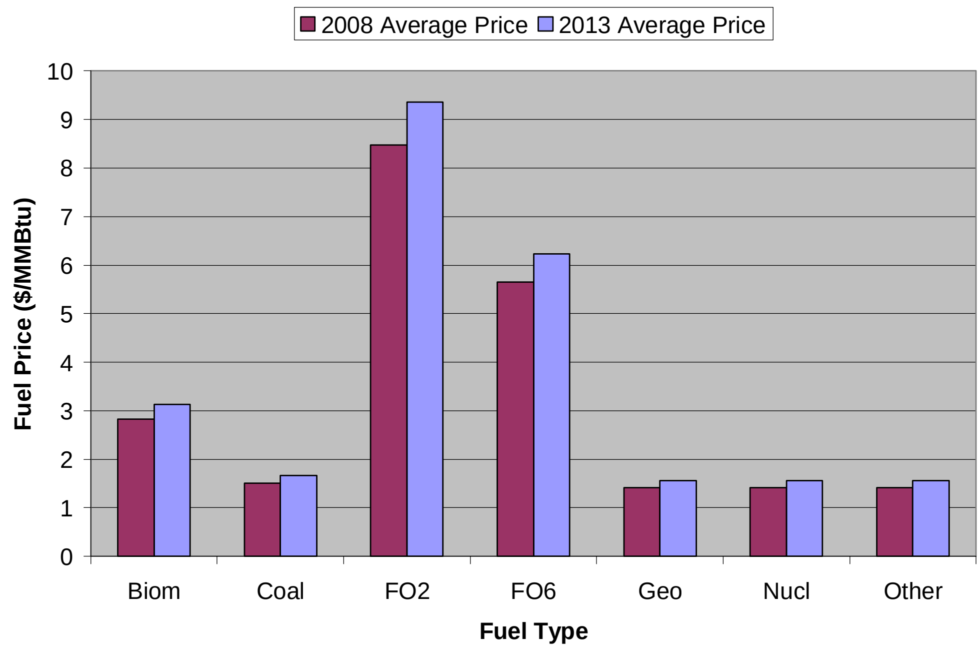
Table 8.3 Transmission Expansion Plan

Line Addition (500 kV AC unless noted)	Length	Path Number	Geographic Description	Gas Scenario		Renewable Scenario
Langdon-Cranbrook-Selkirk-Bell	420	1,3	Alberta to BC to Northwest	X		X
Harquala-Devers	225	46	Arizona to California	X		X
Hassyamp-North Gila-Imperial Valley-Miguel	260	49	Arizona to California	X		X
Sycamore-Ramona-Imperial Valley	120	42	Into San Diego	X		X
Chief Joe-Monroe	120	4	Into Puget Sound	X		X
Grand Junction-Emery 345 kV line	180	30	Colorado to Utah	X		X
Garrison-Hot Springs-Bell-Ashe	425	6	Western Montana to Washington			X
Midpoint-Melba-Grizzly	370	14	Idaho to Oregon			X
Melba-Caldwell-Locust-Boise Bench 230 kV line	100	14	Idaho to Oregon			X
Bridger-Ben Lomond-Midpoint	470	17, 19, 20	Wyoming to Utah to Idaho			X
Bridger-Midpoint	320	17, 19	Wyoming to Idaho			X
Green Valley-Stegall-Bridger	450	New	Through Wyoming			X
Colstrip-Broadview-Garrison	335	8	Through Montana			
Crystal-Mira Loma	260	46	Arizona to California			
Colstrip-Wyodak (3 lines)	390	38	Montana to Wyoming			
Wyodak-Bridger	290	37	Through Wyoming			
Wyodak-Laramie	135	New	Through Wyoming			
Emery-Mona-Crystal	340	31, 35, 78, 79	Utah to Nevada			
Wyodak-Los Angesel 500 kV DC	1375	Several	Wyoming to California			
Shiprock-Moenkopi-Market Place	542	22, 23, others	Arizona to Nevada			
Laramie River-Green Valley-Grand Junction- Craig	540	36, 39, 40	Wyoming to Colorado			
Ben Lomond-Mona	108	New	Through Utah			
Hassyamp-North Gila-Imperial Valley-Miguel	280	46, 49	Arizona to California			
Total Transmission Line Miles				**1325**		**3360**

8.2.3 Non-Gas Fuels

For thermal resources that burn fuels other than natural gas, fuel information was taken directly from SSG-WI transmission data when possible. This information includes the association between generating resources and fuel prices. Although natural gas prices vary monthly by region in the study, non-natural gas fuels vary only annually. However, non-natural gas fuel prices can vary by plant. This is especially true of coal prices. Figure 8.4 shows the average fuel prices by fuel type.

Figure 8.4 Average Fuel Prices for Non-natural Gas Fuels



Fuel prices are in nominal 2003 dollars. The CAISO study evaluates all financial elements in nominal dollars. For this reason, the prices of non-natural gas fuels are escalated by the inflation rate. Table 8.4 shows the escalation used for non-natural gas fuels. In 2008, the prices are 16 percent higher than in 2003. In 2013, the prices are 28 percent greater than in 2003.

Table 8.4 GDP Price Deflators provided by CEC and referenced to 2003 $

CED 2003			
GDP IMPLICIT PRICE DEFLATOR (2001 = 100)			
YEAR	Current INDEX	5/15/2002 ANNUAL GROWTH RATE	Ratio to 2003 $
2000	97.87	2.3%	0.95
2001	100.00	2.2%	0.97
2002	101.43	1.4%	0.99
2003	102.78	1.3%	1.00
2004	106.60	3.7%	1.04
2005	110.43	3.6%	1.07
2006	114.25	3.5%	1.11
2007	116.87	2.3%	1.14
2008	119.18	2.0%	1.16
2009	121.39	1.9%	1.18
2010	123.65	1.9%	1.20
2011	126.04	1.9%	1.23
2012	128.62	2.0%	1.25
2013	131.32	2.1%	1.28
2014	134.08	2.1%	1.30
2015	136.93	2.1%	1.33
2016	139.81	2.1%	1.36
2017	142.74	2.1%	1.39
2018	145.74	2.1%	1.42
2019	148.79	2.1%	1.45
2020	151.94	2.1%	1.48

Thermal resources added as part of the resource plan do not have data in the SSG-WI case. For the sake of consistency, these resources use existing fuels.

8.2.4 Hydro

Hydroelectric energy is a substantial component of total generation in the WECC. Accurately modeling hydroelectric production over the course of a year presents many challenges and requires extensive data about river systems, flood control measures, fisheries activity, rainfall patterns and demand for electric power. While it is possible to make approximations to relieve many of these data needs, it is clear that economic operation is only one aspect of modeling hydro. For this reason, the study does not attempt to economically optimize hydroelectric production. Instead the study relies heavily on hydroelectric generation profiles used in the SSG-WI study.

The generation profiles from SSG-WI were used to fix the hourly output of each hydro resource throughout each year. In a regional model, this would amount to netting the hydro generation out of the load. Since the study models a full network, distributing the generation across each region was necessary to simulate the locational aspect of hydro generation.

The SSG-WI medium hydro case is adopted as our base case for hydro. It is the year 1953 water condition through out WECC. Because *expected* hydro energy does not vary from one year to the next, the same profiles were used for both 2008 and 2013.

8.2.5 Nodal Loads

When modeling the entire WECC network, it is important to distribute load to the buses in the network at which the demand resides. In the study, this is done using Load Participation Factors. A Load Participation Factor assigns a constant portion (i.e. 4%) of the regional load to a particular bus for every hour of the year.

The underlying optimal power flow engine in the CAISO study, as well as the SSG-WI study from which much of the study is derived, solves the power flow problem once and computes "shift factors" for each hour of the simulation to determine how the network should respond to varying load. The Load Participation Factors are computed for each bus relative to the nodal load in the instant for which the power flow problem was solved.

The sum of the Load Participation Factors for each region is 1. This means that the full regional load is spread to the participating buses throughout each region.

8.3 Updates to SSG-WI Database

Much of the data for the study was derived from the SSG-WI transmission data. There are, however, several areas in which the study diverged from the SSG-WI study. In some cases, this divergence was a result of the CAISO study's focus on California and the need to model California in a way consistent with the needs of CAISO's stakeholders and with existing energy and transmission policy. In some cases, this divergence was part of an effort to expand upon the accomplishments of the SSG-WI transmission study. In both cases, the study attempted to develop a model that was fundamentally consistent with the previous SSG-WI study, while modeling a specific aspect of the network in enhanced detail, when useful and expedient.

8.3.1 Loads

One substantial difference between the CAISO study and the SSG-WI Transmission study is the development of a new hourly load forecast. This load forecast was the product of discussion with the CEC and stakeholder sub-groups. It incorporated baseline load forecasts produced by the CEC and the WECC.

Hourly load profiles for each of the 21 regions in the model are developed in three steps. First, a base hourly load profile is developed for each region. Second, the load forecast of peak and energy is developed for each region. Finally, the base hourly load profile is "grown" to the required peak and energy for each region. The result of these three steps was two hourly load profiles for each region which matched the required peak and energy for the region – one for based on the 2008 load forecast, the other based on the 2013 load forecast – in which the minimum load grows at a rate similar to the total energy. These new load profiles are said to preserve load shape.

8.3.1.1 Base Profile Development

In collaboration with the CEC, it was determined that synthetic load shapes would provide the most reasonable base profile. A synthetic load shape represents "normalized" load, with the effects of short-term weather fluctuation removed. More specifically, these load shapes were developed using five years (1998 – 2002) worth of "scrubbed" utility load data. These "average" load shapes preserve each utility's peak, total energy and minimum load values.

Appendix Table AC.8 shows how base profiles were aggregated for each of the 21 regions. The synthetic load shapes must represent the correct peak and minimum load values so that the aggregation of the load shapes correctly weights the contribution to the regional load shape from each constituent utility. The CAISO's Departments of Market Analysis and Grid Planning jointly developed the aggregation defined in Appendix Table AC.8.

EMSS, a Henwood Energy Services, Inc. product calculated the base profile aggregation. Henwood also provided synthetic load shapes for each utility in the WECC and several mappings of these utility load shapes to various regional assignments. Henwood's regional assignments did not match those adopted from SSG-WI; as a result, the Henwood mapping data was used solely as a reference when developing the aggregations.

8.3.1.2 Load Forecast

A load forecast is typically stated in terms of peak load and total demand (energy) for a load area for a specific period of time. This is a key input to most tools that forecast hourly load shapes. The base profile described in the previous section is another key input. The load forecast used in the CAISO study has two sources: the CEC and the WECC.

The CEC's 2003 Electricity and Natural Gas Assessment Report[7] provided peak and energy information for 2008 and 2013 for the five regions – PG&E, SCE, SDG&E, LADWP and IID – internal to California. The CEC report listed peak and energy for SMUD, California Department of Water Resources (DWR), Cities of Burbank, Glendale and Pasadena (BGP) and other areas of southern California. The SMUD load forecast was included in the PG&E region. The load forecast for DWR is split between PG AND E (48 percent) and SOCALIF (52 percent). The BGP load is included in SOCALIF. Other areas of southern California include IID. With assistance from the CEC, the load forecast for IID is separated from the other areas of southern California load forecast to form its own region. The remainder of the other load forecast is included in SOCALIF. Table 8.5 lists the resulting regional load forecasts for California regions.

Table 8.5 Load Forecast Data derived from the CEC 2003 - 2013

Region	2008 Peak Load (MW)	2008 Energy (GWh)	2013 Peak Load (MW)	2013 Energy (GWh)
PG AND E	25,508	128,929	27,162	137,230
SANDIEGO	4,223	21,595	4,530	23,349
SOCALIF	22,297	111,117	23,649	118,307
LADWP	5,588	26,345	5,731	27,370
IMPERIAL	875	3,716	976	4,148

The WECC's 2003 10-Year Coordinated Plan Summary[8] contained information for the remaining 16 regions. The WECC's Plan aggregated non-coincident monthly peaks and total energies for each utility in a sub-region to produce a single peak and energy for each sub-region. This practice can overestimate the peak for the sub-region since the utilities in a sub-region may not peak in the same hour.

[7] http://www.energy.ca.gov/reports/100-03-014F.PDF
[8] http://www.wecc.biz/documents/publications/tenyr03.pdf

Each WECC sub-region contains several of the regions used in the study. The regional peaks occur at different times of the year. For this reason, they sum to a non-coincident peak greater than the monthly coincident peak in the WECC report.

Table 8.6 Load Forecast Data from the WECC 2003 - 2013[9]

WECC Sub-Region	Region	2008 Peak Load (MW)	2008 Energy (GWh)	2013 Peak Load (MW)	2013 Energy (GWh)
Northwest Power Pool Area	ALBERTA	9398	72410	10155	79243
	B.C. HYDRO	9117	60613	9851	66332
	NORTHWEST	27461	172551	29671	188833
	AQUILA	902	5995	974	6560
	PACE	7512	43284	8116	47369
	WAPA U.M.	241	1371	260	1500
	SIERRA	2013	12872	2175	14087
	IDAHO	3797	20257	4103	22169
	MONTANA	1527	10636	1611	11639
California-Mexico Power Area	MEXICO-CFE	1850	10583	2029	11673
Rocky Mountain Power Area	COLORADO	6993	34138	7881	37839
	WAPA R.M.	4589	23732	5171	26305
Arizona-New Mexico -South Nevada Power Area	NEW MEXICO	4557	28400	5166	31975
	WAPA L.C.	1149	5369	1302	6045
	ARIZONA	16564	78968	18777	88908
	NEVADA	6577	28070	7456	31604

8.3.1.3 Load Growth

The base hourly load profile and the load forecast are requirements for most load growth tools. The PLEXOS load growth algorithm[10] used this data to develop hourly load profiles for each region for 2008 and 2013. The PLEXOS load growth algorithm uses a quadratic program, which aims to preserve the base profile shape while meeting energy and peak targets. Weekdays and holidays were mapped appropriately.

8.3.2 Natural Gas

The treatment of natural gas prices was another major difference between the SSG-WI study and the CAISO study. The CAISO study base case uses natural gas prices that vary monthly, instead of static, annual gas prices. Furthermore, the CAISO study used the base gas price forecast published in the CEC 2003 Electricity and Natural Gas Assessment Report[11] as a basis for regional gas prices. Table 8.7 below lists the regional prices as they were developed from the CEC published data.

[9] Growth rates for 2012 are extrapolated to 2013. The 10-Year Coordinated Plan covers 2003-2012.
[10] http://www.PLEXOS.info/kb/part_03/KB0301010.htm
[11] http://www.energy.ca.gov/reports/100-03-014F.PDF

Table 8.7 Regional Gas Prices in nominal $ for 2008 and 2013

Region Name	CEC Natural Gas Prices for Electricity Generation (Table A-19b)	Nominal 2008 ($/mmbtu)	Nominal 2013 ($/mmbtu)
NEW MEXICO	average of EL Paso North- and South-NM	4.51	5.54
ARIZONA	average of EL Paso North- and South-AZ	4.51	5.54
NEVADA	Nevada South	4.83	5.88
WAPA L.C.	Nevada South	4.83	5.88
MEXICO-CFE	Rosarito	4.75	5.82
IMPERIAL	SDG&E	4.71	5.76
SANDIEGO	SDG&E	4.71	5.76
SOCALIF	So. Calif Prod	4.62	5.69
LADWP	SoCal Gas	4.71	5.76
PG AND E	PG&E	4.65	5.62
NORTHWEST	ave. of PNW and PNW-Coastal	4.68	5.68
B.C.HYDRO	British Columbia	4.29	5.22
AQUILA	Alberta	3.88	4.70
ALBERTA	Alberta	3.88	4.70
IDAHO	PNW	5.00	6.02
MONTANA	Montana	4.36	5.20
WAPA U.M.	Montana	4.36	5.20
SIERRA	Nevada North	5.04	6.07
PACE	Utah	4.29	5.09
PSCOLORADO	Colorado	4.31	5.11
WAPA R.M.	Colorado	4.31	5.11
Average		**4.53**	**5.49**

The prices in the table are annual average prices. Monthly prices were computed by applying regional monthly multipliers, which average to 1 to each month for each region. These factors are independent of the gas price; as such, they can be applied to annual average prices for both 2008 and 2013. These multipliers were also published in the CEC 2003 Electricity and Natural Gas Assessment Report.

Table 8.8 Monthly Natural Gas Price Multipliers by Region

Table A-19a	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PG&E	1.06	1.06	0.99	0.97	0.99	0.96	0.96	0.96	0.96	0.96	1.05	1.09
So Cal Gas	1.10	1.07	1.03	0.97	0.95	0.94	0.92	0.94	0.98	1.00	1.08	1.17
SDG&E	1.09	1.04	0.96	0.94	1.00	0.97	0.92	0.97	0.98	0.98	1.09	1.22
So. Calif Prod.	1.10	1.07	1.03	0.97	0.95	0.94	0.92	0.94	0.98	1.00	1.08	1.17
Alberta	1.08	1.04	1.00	1.00	0.99	0.93	0.94	0.87	0.91	1.00	1.04	1.08
British Columbia	1.23	1.06	0.88	0.93	0.87	0.83	0.82	0.83	0.87	1.00	1.21	1.22
Colorado	1.08	0.90	0.84	0.86	0.94	1.03	1.02	0.99	0.93	1.04	1.08	1.13
El Paso North-AZ	0.98	0.98	0.90	1.02	1.02	1.02	0.92	0.94	1.06	1.00	1.13	1.03
El Paso North-NM	1.12	0.98	0.93	0.94	0.96	0.94	0.97	1.00	0.99	1.03	1.09	1.12
El Paso South-AZ	0.98	0.98	0.90	1.02	1.02	1.02	0.92	0.94	1.06	1.00	1.13	1.03
El Paso South-NM	1.12	0.98	0.93	0.94	0.96	0.94	0.97	1.00	0.99	1.03	1.09	1.12
Montana	1.08	0.90	0.84	0.86	0.94	1.03	1.02	0.99	0.93	1.04	1.08	1.13
Nevada-North	0.99	1.00	0.92	1.02	0.97	1.01	0.93	0.97	1.02	1.08	1.13	1.03
Nevada-South	0.99	1.00	0.92	1.02	0.97	1.01	0.93	0.97	1.02	1.08	1.13	1.03
PNW	0.68	0.83	1.00	1.27	1.35	0.76	1.01	1.00	1.11	0.90	0.96	1.09
PNW-Coastal	0.68	0.83	1.00	1.27	1.35	0.76	1.01	1.00	1.11	0.90	0.96	1.09
Utah	1.08	1.09	1.08	1.05	1.00	0.98	0.95	0.82	0.88	0.98	1.08	1.25
Rosarito	1.09	1.04	0.96	0.94	1.00	0.97	0.92	0.97	0.98	0.98	1.09	1.22
Average	**1.03**	**0.99**	**0.95**	**1.00**	**1.01**	**0.95**	**0.95**	**0.95**	**0.99**	**1.00**	**1.08**	**1.12**

The monthly natural gas prices are applied to every natural gas burning plant by region. The prices are burner tip prices and included transportation costs.

8.3.3 Renewable Resources

The California Energy Commission published the Renewable Resources Development Report[12] in November 2003. This report described a Renewable Portfolio Standard requiring a minimum production of energy from renewable resources. Quoting from the report,

> *"In 2002, the [California] Legislature passed the Renewable Portfolio Standard, which requires that certain retail sellers of electricity increase their sales of electricity from renewable energy sources by at least 1 percent per year, achieving 20 percent by 2017, at the latest. Since passage of the Renewable Portfolio Standard bill, the* ***Energy Action Plan*** *was adopted and establishes a more aggressive goal for renewable energy development with a target of 20 percent by 2010. The Renewable Energy Program will provide funds to generators to cover the above-market costs for electricity, and design a tracking and verification system to ensure that retail sellers are meeting their procurement targets."*[13]

In consultation with the CEC and in concert with current energy policy, the CAISO study incorporated renewable resources according to the more aggressive Accelerated Renewable Portfolio Standard, which requires the 20 percent target to be met by 2010 throughout California. The year 2003 is used as a baseline for computing renewable additions required before 2008. Unless there was a documented 2003 renewable

[12] http://www.energy.ca.gov/reports/2003-11-24_500-03-080F.PDF

[13] Policies Driving Renewable Development, p. 3

energy amount for a state (such as California), the 2003 starting point was derived from the 2002 position shown in the CEC report with an added the 0.6 percent per year standard assumed in the federal proxy[14].

Table 8.9 Renewable Energy Target Percentages, 2008 and 2013

State	RPS in Place?	2008	2013	Source	Notes
Arizona	Yes	1.1%	1.1%	ACC Rules R14-2-1618[15]	1.1% by 2007-2012 (60% from solar); assume constant after 2012
California	Yes	17.9%	20.0%	"Renewable Resources Development Report", CEC, Report # 500-03-080F	
Colorado	Considering	8.7%	13.7%	House Bill 1273 (passed House not Senate yet)[16]	Legislature considering state RPS
Idaho	No	10.0%	10.0%	see note #2	assume federal proxy
Montana	No	4.6%	10.0%	see note #2	assume federal proxy
Nevada	Yes	10.0%	15.0%	"Renewables Resources Development Report", CEC, 500-03-080F, November 2003; p. 15.	at least 5% from solar
New Mexico	Yes	7.0%	10.0%	"Renewables Resources Development Report", CEC, 500-03-080F, November 2003; p. 15.	assume federal proxy
Oregon	No	7.5%	10.0%	see note #2	assume federal proxy
Utah	Considering	10.0%	10.0%	House Bill 308, "Renewable Energy Amendments", 2002 General Session[17]	
Washington	No	7.7%	10.0%	see note #2	assume federal proxy
Wyoming	No	10.0%	10.0%	see note #2	assume federal proxy

Appendix Table AC.7 lists the resources that are included in the CAISO study to meet this requirement. These resources are in addition to the resources that were already part of the SSG-WI Transmission Study.

8.3.4 Reserve Margins

Utilities typically plan their capacity needs based on their expected peak load plus a planning reserve margin. In PUC ruling D.04-01-50, the PUC imposed on all LSEs a planning reserve margin of 15-17% to be phased-in no later than January 1, 2008. However, IOU's have to justify any reserve levels above 15%. Similarly, discussions are also ongoing at the WECC level regarding institution of a capacity reserve requirement.

Given the trend toward some capacity procurement process, the CAISO study assumed that utilities within each of the WECC's 21 regions would plan for a 15 percent reserve margin throughout the region. Resource capacity counting toward

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14 U.S. Senate version of RPS standard in federal Energy Bill for 2001-02 session as a proxy for a standard that might ultimately be implemented. Source: "Integrated Resource Plan 2003", PacifiCorp, http://www.pacificorp.com/File/File25682.pdf

15 http://www.ies.ncsu.edu/dsire/library/docs/incentives/AZ03R.htm

16 http://www.solaraccess.com/news/story?storyid=6065

17 http://www.le.state.ut.us/~2002/bills/hbillint/hb0308.htm

this reserve requirement include 100 percent of thermal and solar[18] capacity, 20 percent of wind and 100 percent of interruptible load and demand-side management capacity. The planning contribution from hydro resources, taken from the WECC 10-Year Coordinated Plan, was a WECC-wide total of 63,936 MW. Load regions also can count deliverable import capacity from other regions toward this planning reserve margin for the purposes of the CAISO study. Expected retirements increase the capacity requirement for the load region.

Table 8.10 describes the reserve margin prior to resource additions, the total capacity additions (renewable and gas-fired) and the final capacity surplus after additions. When a deficit exists, adding resources from a list of planned generation additions that are currently active proposals covers the deficit.

Table 8.10 Summary of WECC Sub-Region Level Reserve Margin Deficits and Additions for Planning Reserves

	2008			2013		
	Resource Margin w/o Additions (MW)	Additions/ Retirements (MW)	Surplus Capacity (MW)	Resource Margin w/o Additions (MW)	Additions/ Retirements (MW)	Surplus Capacity (MW)
WECC	6,606	5,251	11,857	(4,250)	10,785	6,535
• California	270	2,871	3,141	967	500	1,467
• Mexico	601	0	601	395	0	395
• Southwest	(624)	625	1	(5,572)	5,795	223
• Northwest	6,415	0	6,415	3,661	0	3,661
• Rocky Mountain	(1,623)	1,755	132	(3,469)	3,490	21
• Canada	1,566	0	1,566	(231)	1,000	769

The CAISO illustrative study recognizes that the process of constructing a power plant and connecting to the grid requires a substantial lead-time. For this reason, the study required all resource additions in 2008 to be specific approved projects or project proposals that are considered likely to develop. Projects that successfully bid and execute a contract with an IOU through the long-term procurement process to provide capacity beginning in a certain period are likely to constitute a specifically approved project for purposes of any study covering that same time frame. Prior to 2013, resources not yet in the planning stage may be developed. However, it is more reasonable to assume that a proposed project currently supported is more likely to develop than an arbitrary project not yet proposed. These projects are usually gas-fired power plants. Table 8.11 lists the projects added for the purpose of satisfying the 15 percent reserve margin.

[18] 100% contribution of solar capacity to planning reserves was determined in consultation with the CEC.

Table 8.11 Reserve Margin Resource Changes

Year	Region	Type	Adj. Name	General Location	Capacity (MW)	Type
2008	ARIZONA	Addition	MesquiteCC	Maricopa County, AZ	625	CC
	LADWP	Addition	Glenarm GT 3-4	Pasadena	94	CT
			Grayson 9	Glendale	49	CC
			Magnolia	SCPPA	315	CC
			Malburg	City of Vernon	135	CC
			Olive 2	Los Angeles	0	CT
		Retirement	Haynes 1	Los Angeles	1126	CC
	PG AND E	Addition	Cosumnes	Rancho Seco	458	CC
			Kings River	NP-15	85	CT
			Metcalf	South Bay	600	CC
			Pico	Santa Clara	147	CC
			Ripon	MID	90	CC
			SFPeaker	San Francisco	180	CT
		Retirement	HntrsPn1	NP-15	0	CT
			HntrsPn4	NP-15	0	CT
			Pttsbrg1	NP-15	321	CC
	PSCOLORA	Addition	RockyMtn EC1	Hudson, CO	585	CC
			RockyMtn EC2	Hudson, CO	1185	CC
			RockyMtn EC3	Hudson, CO	585	CC
	SANDIEGO	Addition	Otay Mesa	OTAYMESA 22609	510	CC
			Palomar	ESCONDIDO 22260	546	CC
	SOCALIF	Addition	Mountainview	SANBRDNO 24913	1132	CC
			Pastoria	Tejon Ranch	750	CC
		Retirement	AESlmts7	SP-15	0	CT
			EtwndGT5	SP-15	0	CT
			Mohave 1	Arizona	0	coal
2013	ALBERTA	Addition	GenesseeCC	Genesee, AB	500	CC
	ARIZONA	Addition	Santan	Gilbert, AZ	825	CC
			Arlington Valley 2	Buckeye, AZ	600	CC
			Bowie CC 1	Cochise County, AZ	500	CC
			Bowie CC 2	Cochise County, AZ	500	CC
			Sprngrv2	Apache County, AZ	400	CC
			Sprngrv3	Apache County, AZ	400	CC
			Harquahala CC 2	Harquahala, AZ	1000	CC
			Panda Gila River 5	Gila Bend, AZ	500	CC
	B.C.HYDR	Addition	Vancouver Island 1	Duke Point, BC	500	CC
	LADWP	Addition	HaynesCC	Los Angeles	575	CC
			ValleyCC2	LADWP	520	CC
		Retirement	Haynes 1	Los Angeles	1044	CC
			ValleyCC	LADWP	1094	CC
	MONTANA	Addition	Silver Bow	Butte, MT	500	CC
	NEVADA	Addition	Silver Hawk	Clark County, NV	570	CC
			CopperMtn	Clark County, NV	500	CC
	PG AND E	Addition	CntrCst6	East Bay	530	CC

Year	Region	Type	Adj. Name	General Location	Capacity (MW)	Type
			WalnutCC	TID	240	CC
			Comanch2	Pueblo, CO	750	coal
			BluSprc2	Aurora, CO	500	CC
	PSCOLORA	Addition	Front Range CC2	Fountain, CO	600	CC
	SIERRA	Addition	Wadsworth 1	Washoe City, NV	540	CC

8.3.5 Economic Entry

While currently active project proposals are reasonable to add to meet capacity requirements, independent power producers may find that capacity beyond that required for the reserve margin is profitable to build. The introduction of economic entry gas-fired generation measures the profitability of adding new generation in excess of the resource adequacy requirement.

This strategy is not appropriate for 2008 because of the long lead-time required to commission new generation. However, for 2013 it is reasonable to suspect that some projects not currently being proposed might be built. To test the profitability of so-called “economic new entry” generating resources, the CAISO study introduced example power projects to the model assuming technological efficiency improvement and fixed costs of operations and levelized capital costs in nominal dollars. By simulating the market with these test projects included, the profitability of the test projects can be measured for a given year and decisions can be made about which projects to keep and which to ignore. Table 8.12 below contains the parameters for economic new entry projects:

Table 8.12 Parameters for New Combined Cycle and Combustion Turbine Plants

Inflation		**Multiplier**	**Percent**		
	2002-2008	1.17500	2.04%		
	2008-2013	1.10186	1.96%		
Combined Cycle		**2002**	**2008**	**2013**	**Units**
	Net capacity	500	500	500	MW
	Levelized capital	102	119	131	$/kW-yr
	Fixed O&M	15	18	19	$/kW-yr
	Base heat rate	7,100	7,100	7,100	Btu/kWh
	Start-up costs	1,850	1,850	1,850	MMBtu/start
	Variable O&M	2.4	2.8	3.1	$/MWh
Combustion Turbine		**2002**	**2008**	**2013**	**Units**
	Net capacity	100	100	100	MW
	Levelized capital	58	68	75	$/kW-yr
	Fixed O&M	20	23	26	$/kW-yr
	Base heat rate	9,300	9,300	9,300	Btu/kWh
	Start-up costs	180	180	180	MMBtu/start
	Variable O&M	10.9	12.8	14.2	$/MWh

These parameters came from the CEC report "Comparative Cost of California Central Station Electricity Generation Technologies."[19] One exception is that the CEC's levelized capital cost of the CC was increased to 75 percent higher than that of a CT based on subgroup input and the Northwest Power Supply Adequacy / Reliability Study report "Base case and performance assumptions for new generating resource options."[20]

Each economic new entry project was sited to avoid increasing congestion while at the same time serving load in the affected region. Each region was allotted a new entry combined cycle plant (CC) and a new entry combustion turbine plant (CT). In an iterative process, units were added if a single unit was profitable and removed if the unit was obviously not profitable.

8.3.6 Economic Retirement

Older plants that are nearing obsolescence may be mothballed or decommissioned due to poor economics. The CAISO study tested nuclear generation plants for economic retirement. If a nuclear generation plant did not have net revenue before fixed costs per kW-yr greater than the fixed operations and maintenance and capital costs of a new combined cycle plant, it is considered to be a target for retirement. This metric was used because there is no reasonable way of estimating the fixed costs of nuclear generation plants.

Under these conditions, the fixed cost recovery target for nuclear generation was $130/kW-yr. In the base case, all nuclear generation plants exceeded this target. Thus, no economic retirement was included in the base case.

8.3.7 Scheduled Maintenance

Maintenance schedules have a significant impact on the generation cost in the WECC. The SSG-WI Transmission data contained an outage schedule developed for that study. However, this maintenance schedule was developed using a different set of hourly load profiles and a different set of generating resources. For these reasons, the CAISO study developed a new maintenance pattern optimized to the new load profiles.

This maintenance schedule was developed using the PLEXOS PASA[21] algorithm. For each generating resource, a maintenance rate was offered to the algorithm as well as regional load profiles and the major interregional interface constraints to allow for reserve sharing. Maintenance rates were taken from data provided by Henwood Energy Services, Inc.

8.3.8 Forced Outages

The SSG-WI Transmission data outage schedule included both planned and forced outages. Since the CAISO illustrative study developed a new maintenance schedule for planned outages based on maintenance rates, it was necessary to model forced outages separately. Forced outages were developed randomly using Monte Carlo techniques. Unfortunately, due to the time constraints of the study, it was not possible to run a full sample to allow the forced outage pattern to converge for every case, but the outcome of the sample was studied in an experiment of 20 samples. As

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[19] http://www.energy.ca.gov/reports/2003-06-06_100-03-001F.PDF
[20] Table A-7, http://www.nwcouncil.org/library/2000/2000-4a.pdf
[21] http://www.PLEXOS.info/kb/part_03/KB0311001.htm

described in Section 7.3.2, a single sample was used for every single case. This allowed each case to share an outage pattern that is almost identical. This technique does admit the possibility of a non-convergent result in a sensitivity case. However it is more reasonable than other alternatives, which are primarily: 1) reduce the number of sensitivity cases for the study, 2) ignore forced outages, 3) use an arbitrary forced outage pattern, not necessarily near the point of convergence for the base case. More detailed results are available in Chapter 7. Overview of Analytical Process, Section 3, Off Line Sensitivities.

8.3.9 Transmission Expansion

The 2008 SSG-WI transmission network was the base model for the network in the CAISO study. This base model was enhanced by the addition of anticipated resource additions for 2008 and 2013. The modifications in 2008 (which are also included in 2013) are related to the planned series capacitor upgrades in Southern California and the upgrade to Path 15. The modifications specific to 2013 are a subset of transmission upgrades submitted for consideration to the SSG-WI Planning working group. CAISO Grid Planning chose the subset of these upgrades included in the CAISO study. Table 8.13 below lists the upgrades being modeled in the CAISO study.

Table 8.13 Transmission Additions to SSG-WI 2008 Transmission Data

Year	Line	Path	New R (p.u.)	New X (p.u.)	New Rating (MVA)	Note
2008	IMPRLVLY - N. GILA #1				1,905	Existing line - series cap upgrade
2008	N. GILA - HASSYAMPA #1				1,905	Existing line - series cap upgrade
2008	PALO VERDE - DEVERS #1				2,338	Existing line - series cap upgrade
2008	DEVERS - DEVERS #2					New transformer - identical to DEVERS - DEVERS #1
2008	MOENKOPI - EL DORADO				1,992	Existing line - series cap upgrade
2008	NAVAJO - CRYSTAL #1				1,992	Existing line - series cap upgrade
2008		EOR			8,055	For flow into California - series capacitor upgrade
2008		SCIT			19,391	For flow into California - series capacitor upgrade
2008	LOS BANOS - GATES #3		7.67E-04	1.85E-02	3,752	New line - Path 15 upgrade
2008	ARCO - MIDWAY #1		1.09E-02	6.22E-02	300	Modified line - Path 15 upgrade
2008	GATES - ARCO #1		8.43E-03	4.80E-02	300	Modified line - Path 15 upgrade
2008	GATES - MIDWAY #1		1.58E-02	8.96E-02	300	New line - Path 15 upgrade
2008		Path 15			5,400	Path 15 South to North
2008		Path 15			3,265	Path 15 North to South
2013	SELKIRK - BELL #1		1.10E-03	1.13E-02	2,400	New Line - BPA
2013	LANGDON - CRANBROOK #2		2.00E-03	4.64E-02	4,560	New Line - BPA
2013	CRANBROOK - SELKIRK #2		1.10E-03	2.60E-02	4,560	New Line - BPA
2013	CHIEF JOE - MONROE #2		1.20E-03	2.83E-02	4,560	New Line - BPA
2013	GARRISON - HOT SPR #1		1.20E-03	4.17E-02	2,000	New Line - BPA
2013	HOT SPR - BELL #1		1.60E-03	1.90E-02	2,000	New Line - BPA
2013	BELL - ASHE #1		1.40E-03	1.60E-02	3,000	New Line - BPA
2013	GRIZZLY - MELBA #1		2.50E-03	1.78E-02	4,560	New Line - BPA
2013	MELBA - MIDPOINT #2		1.10E-03	8.00E-03	4,560	New Line - BPA
2013	SUMMER L - MELBA #1		2.03E-03	1.03E-02	2,340	New Line - BPA
2013	HARQUAHA - DEVERS #2		2.10E-03	2.90E-02	1,646	New Line - CAISO
2013	DEVERS - DEVERS I #2		0.00E+00	1.18E-01	1,120	New Transformer - CAISO
2013	DEVERS - DEVERS I #2		0.00E+00	4.00E-03	1,120	New Transformer - CAISO
2013	DEVERS T - DEVERS I #2		0.00E+00	2.71E-01	1,120	New Transformer - CAISO
2013	BRIDGER - BENLOMON #1		2.11E-03	1.20E-02	2,000	New Line - PacifiCorp
2013	BRIDGER - MIDPOINT #1		3.65E-03	2.07E-02	2,000	New Line - PacifiCorp
2013	BENLOMON - MIDPOINT #1		3.25E-03	1.84E-02	2,000	New Line - PacifiCorp
2013	BRIDGER - BRIDGER #1		7.00E-05	7.21E-03	1,650	New Line - PacifiCorp
2013	BENLOMON - BENLOMON #1		7.00E-05	7.21E-03	1,650	New Line - PacifiCorp
2013	STEGALL - GREENVAL #1		2.00E-03	1.13E-02	2,000	New Line - PacifiCorp
2013	STEGALL - BRIDGER #1		3.14E-03	1.78E-02	2,000	New Line - PacifiCorp
2013	GREENVAL - GREENVAL #1		2.00E-04	1.20E-02	1,100	New Line - PacifiCorp
2013	STEGALL - STEGALL #1		2.00E-04	1.20E-02	1,100	New Line - PacifiCorp
2013		EOR			9,250	Addition of HARQUAHA - DEVERS #2
2013		WOR			12,200	Addition of HARQUAHA - DEVERS #2
2013		SCIT			20,000	Addition of HARQUAHA - DEVERS #2

In the table, any values left blank are either not changed from the values in the SSG-WI data or they are not relevant to the upgrade.

8.4 Assumptions for the Path 26 Upgrade

The primary goal of the CAISO methodology was to measure the economic impact of transmission projects. This goal required two simulations to be performed for every case that was tested: one simulation modeled the network without the upgrade, and the other simulation modeled the network with the upgrade. The economic impact was measured by calculating the difference in several key results from each simulation.

Since the only difference between the two simulations was the transmission upgrade project, the treatment of the affected parts of the network was critical. In the case of the CAISO Path 26 study, the proposed upgrade being evaluated was an expansion of one of the three lines that connect the Midway and Vincent substations. However, since the major differences between the two simulations came as a result of congestion relief, it was important to accurately model Path 26 limits. For this reason, the CAISO study implemented a schedule of partial outages for Path 26 based on historical outage patterns.

8.4.1 Upgrade

Path 26 consists of three 500 kV lines between Midway and Vincent. On May 12, 2004, a path rating increase from a bi-directional 3000 MW to 3400 MW (N- S) and 3000 MW (S- N) was implemented. This new rating required implementation of SPS to trip generation north of Midway to mitigate for N-2 overload.

Based on a high-level screening analysis performed by CAISO's Grid Planning Department, the proposed new rating for Path 26 is 4400 MW (N- S) and 4000 MW (S-N). This new rating would require the following upgrades:

- Re-conductoring of Midway – Vincent #3 Line
- Replacing Midway – Vincent #3 series capacitors
- Replace wave traps, breakers and current transformers
- Re-conductoring Vincent – Antelope #1 230 kV Line

The model for these proposed improvements requires Midway-Vincent Line #3 to be modeled as identical to Midway-Vincent Lines #1 and #2. Furthermore, the interface must be modeled with the increased limits described above.

Table 8.14 Path 26 Upgrade Summary

Without Upgrade		With Upgrade	
North to South	South to North	North to South	South to North
3400 MW	3000 MW	4400 MW	4000 MW

8.4.2 Path 26 Operating Transfer Capability

Although Path 26 is currently rated for a bi-directional maximum flow of 3000 MW, the operating transfer capability (OTC) is regularly less than 3000 MW. There are a variety of reasons that the Path 26 North-to-South OTC might be derated. Outages at Diablo Canyon can affect the OTC of Path 26. Transmission outages in other interfaces (e.g. Path 15) can also affect the OTC of Path 26. Maintenance on the lines included in Path 26 can also affect the Path 26 OTC. Table 8.15 summarizes deratings of the OTC for Path 26 for 2001, 2002 and 2004 Q1[22] to produce forced outage rates and their corresponding derated levels that can be applied to Path 26 when forecasting a rating. Given that Path 26 is only capable of its maximum OTC 62 percent of the time, ignoring forced deratings on Path 26 would certainly underestimate the value of upgrading.

Table 8.15 Forced Outage Rates and Derated OTC Levels, Path 26 North-South

Outage Level	Forced Outage Rate (%)	Mean Time to Repair (hr)	Historically Likely Outage Ratings (MW)[23]	2008 & 2013 Outage Ratings Without Upgrade (MW)	2008 & 2013 Outage Ratings With Upgrade (MW)
0	61.95		3000	3400	4400
1	32.26	24	2500	2900	3900
2	3.5	24	2000	2400	3400
3	1.26	24	1500	1900	2900
4	1.03	12	500	900	1900

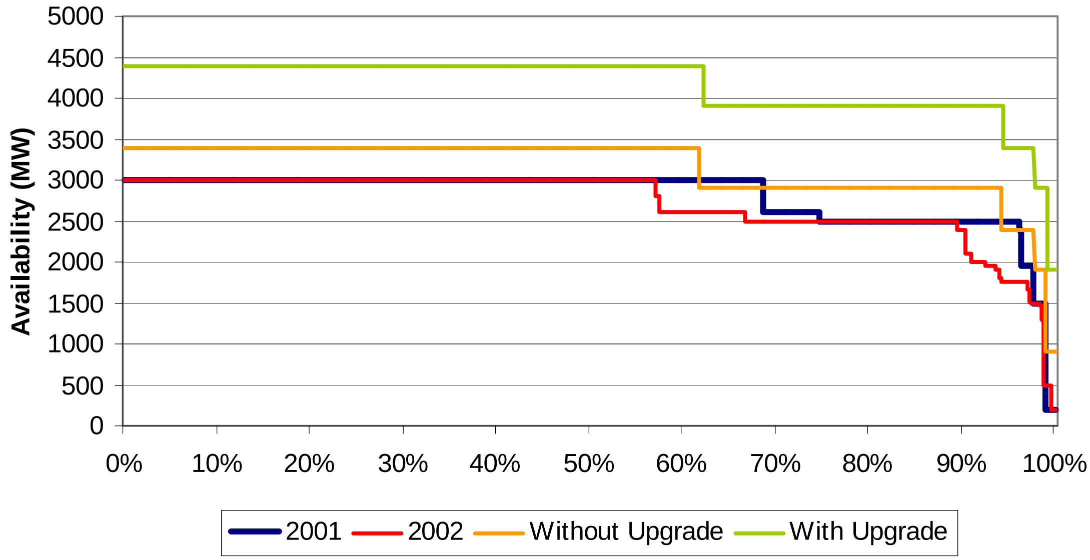
The outage ratings with and without the upgrade for 2008 and 2013 exhibit the same magnitude of decrease from the maximum OTC as the historically likely outage ratings. Neither the 400 MW upgrade to be implemented prior to the 2008 study year, nor the 1000 MW test upgrade are derated proportionately. This forms an economically conservative estimate of the capability of the interface and the value of an upgrade. At the same time, it values congestion relief for situations in which the congestion was a result of derating in the no upgrade case.

Figure 8.5 compares the OTC derated profiles used in the CAISO study to actual OTCs for 2001 and 2002.

[22] The OTC profile for 2003 was ignored because the Vincent sub-station fire impacted the rating of Path 26 for an unusual length of time. Since this event was a statistical "outlier," including the related OTC's would significantly overstate the likelihood of partial outage of Path 26 in the context of a three-year sample.

[23] A histogram counting the number of times that the hourly OTC was within 50 MW of an even 100 MW bin was developed. The five 100 MW increments that were most frequently active during the selected sample of hours were selected as Historically Likely Outage Ratings. The probability of outages in neighboring bins were rolled into the probabilities of each of these bins.

Figure 8.5 Historical Path 26 OTC Duration Curve and OTC Schedules for 2008, 2013 with and without Path 26 Upgrade



8.5 Assumptions for Market Price Derivation

Market Price Regions

In the Path 26 study, the strategic bidding methodology, described in Chapter 4, is implemented only in the three California utility regions, namely PG&E, SCE, and SDGE regions. Ideally, we would want to model strategic bidding for all regions in the WECC. However, the lack of sufficient information and market data for other WECC regions makes it difficult to accurately apply strategic bidding to these regions. Given this, we elected not to apply bid markups to resources in regions outside of the three California utility regions and instead assumed that suppliers in the non-California region would bid their marginal cost.

While we realize this limited application of the bid markup methodology is a deficiency in the current methodology, restricting strategic bidding to the California regions might not be such an unreasonable assumption. First, other regions in the WECC are predominately comprise of vertically integrated utilities. Under this regime, suppliers have fewer incentives to exercise market power.

Second, the assumption of marginal cost bidding in the other WECC regions does not preclude these regions from having significant price-cost markups. When the supply-demand margins become tight throughout the WECC, especially in California, price markups in California can be exported to other regions. In the market price run, if a significant level of markups are predicted in California, and there is no congestion on major inter-regional transmission lines, the high price-cost markups will propagate to other regions, even though we assume the suppliers in other regions bidding their marginal costs.

Third, the net import into California might not be significantly distorted whether or not we apply bid markups in the other regions. On average, the generation in the California's neighboring regions is more cost-efficient because a significant portion of their generation is either hydro-based (in the northwest region) or coal and nuclear-based (in the southwest region). Even if we apply the same markups in these regions as in California, generation in these regions would still have relative advantage in cost. If a higher market price is observed in California, suppliers would have same incentives to arbitrage and export to California. Therefore, our assumption of no bid markups in exporting regions might not significantly affect the volume of export to California. Therefore, the total benefits of transmission projects may not be affected significantly by this limitation.

Long Term Contracts

The extent to which buyers and sellers are hedged through long-term contracts will have important implications on the ability and incentives for exercising market power. If buyers are mostly hedged, the spot market will be relatively small, making it more difficult for any single supplier to exercise market power. Additionally, if most of capacity of a seller is pre-sold through long-term contracts, the incentives to exercise market power will be diminished because only a small portion of the supplier's portfolio can benefit from raising prices.

The contract levels used for the 2008 cases reflect our latest knowledge on existing contracts that will be effective in 2008. It is likely that additional short-term contracts such as one or two-year contracts will be signed prior to 2008. However, in this study, we do not estimate and include any possible additional new contracts. We decided to do this for two reasons. First, there are significant uncertainties regarding future contract positions that make it difficult to accurately estimate. Second, even if additional contracts are signed, these contracts will, to some extent, reflect expectations about market power and future prices in the spot markets in 2008. Because it typically takes at least 2-year to build new generation and 5-year to build new transmission lines, suppliers who choose to engage in these short-term contracts would inevitably incorporate their expectations of market prices in these contracts. Therefore, choosing not to include additional estimates of future forward contracts should not cause significant biases in the analysis.

Because the level of long-term contracting in 2013 is unknown, we assume the contract level in 2013 will be same as in 2008. We think this is a reasonable assumption. We recognize that under the CPUC resource adequacy requirement, utilities will be required to demonstrate, a year in advance, that they have sufficient contracted capacity to meet 90% of their expected annual peak load. However, a substantial share of that capacity is likely to include shorter-term (1-2 year) contracts at prices that are likely to reflect supplier's spot market expectations (i.e. contract prices that could potentially be impacted by the expected impacts a transmission upgrade could have on spot market prices).

Strategic Players and Non-Strategic Players

RMR Generators

Similar to today, we assume some measures of local market power mitigation would be implemented in 2008 and 2013. Based on this assumption, in deriving regional market prices, we focus on characteristics that affect market competitiveness at a regional level rather than market competitiveness in load and generation pockets within a region.

Specifically, we assume that generating units that are currently designated as RMR Condition 2 units will remain under a long-term contract (e.g. RMR or other bilateral arrangement), and therefore do not add any bid markups for these generators in the market price runs. RMR units that elect Condition 2 provisions are settled at pre-determined contact prices rather than market prices and under MD02, will be dispatched only for local reliability needs based on their contracted variable cost and thus, will not be able to exercise market power. Presumably, if other bilateral arrangements with these units are made, they will have similar provisions to mitigate market power.[24]

Utility, Municipal, and Merchant Generation

Given that fact that three large utilities are mostly net buyers the market, it is reasonable to assume that utilities' retained generation would have no incentive to exercise market power to increase the market price. Therefore, we assume in this analysis that a utility's retained generation is always bid at their marginal variable cost. Similarly, we also assume other municipal utilities in California bid their marginal costs. The derived bid-cost markups are only applied for the generation in California that is owned by merchant suppliers.

8.6 Assumptions for Sensitivities

In Chapter 5 we discussed in general how we select important variables, how we determine different levels for these variables, and how we assign joint probabilities to joint events. In this section we discuss the specific scenarios selected for our Path 26 study.

Demand Forecast Sensitivities

As we previously discussed, we derived demand sensitivities using CEC's demand forecast errors. In the Path 26 study, we had to center CEC's demand forecast errors around zero, smooth the forecast errors, and truncate the forecast errors at year out 8.[25] The following table shows the specific forecast errors used in deriving the base, VH, and VL demand cases.

Table 8.16 Demand Forecast Errors in Path 26 Study

	Forecast Error in Annual Energy Consumption Calculation			Forecast Error in Annual Peak Load Calculation		
	Base case	VH	VL	Base case	VH	VL
2008	0%	5.9%	-5.9%	0%	7.6%	-7.6%
2013	0%	5.9%	-5.9%	0%	7.6%	-7.6%

[24] Units that are currently operating under RMR Condition I contracts are only mitigated for local market power and are not precluded from participating in the market. Therefore, strategic bidding is applicable to these units, provided they are not utility owned (see next paragraph)..

[25] We centered CEC's demand forecast errors around zero because we believe that CEC improves it forecasting techniques over the time so the most recent demand forecast is unbiased. We had to smooth the forecast errors so that it increases monotonically with more years out. We had to truncate the forecast error at a certain year out to make sure annual energy consumption increases generally over the time.

Gas Price Sensitivity Cases

In Chapter 5 we already discussed how we should derive alternative gas price cases. In the Path 26 study, we had also to center CEC's gas price forecast errors around zero, smooth the forecast errors, and truncate the forecast errors at year out 8. Table 8.17 shows the specific forecast errors used in deriving the base, VH, and VL gas price cases.

Table 8.17 Gas Price Forecast Errors in Path 26 Study

	Forecast Error in Annual Average Gas Price Calculation – PG&E Service Area			**Forecast Error in Annual Average gas Price Calculation – SCE Service Area**		
	Base case	VH	VL	Base case	VH	VL
2008	0%	87.9%	-87.9%	0%	87.9%	-87.9%
2013	0%	87.9%	-87.9%	0%	87.9%	-87.9%

Hydro Sensitivities

SSG-WI high and low cases are adopted as our high and low hydro case. More specifically, the high hydro case is the year 1948 water condition, and the low hydro case is the year 1930 water condition.

Final Set of Sensitivities

In Chapter 5 we discussed the purpose of sensitivity analysis is to be able to answer three questions: (1) what is the expected value of a transmission upgrade; (2) what is the expected range of the upgrade; and (3) what is the insurance value of the upgrade. In this Path 26 study, we focus more on the sensitivities in 2013 than in 2008, because of the long planning time required for such an upgrade. The following table shows the final set of cases in 2013 for answering each question.

Table 8.18 Final Set of Scenarios for the Path 26 Study

Cases used for **Expected Value** Calculation	**Scenario**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
	Demand	VH	B	B	B	VL	VH	VH	VH	B	B
	Gas Price	B	VH	B	VL	B	VH	B	VL	VH	B
	Markup	H	H	H	H	H	B	B	B	B	H
	Hydro	B	B	B	B	B	B	B	B	B	B
	New Economic Entry	B	B	B	B	B	B	B	B	B	B
	Scenario	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	
	Demand	B	VL	VL	VL	VH	B	B	B	VL	
	Gas Price	VL	VH	B	VL	B	VH	B	VL	B	
	Markup	B	B	B	B	L	L	L	L	L	
	Hydro	B	B	B	B	B	B	B	B	B	
	New Economic Entry	B	B	B	B	B	B	B	B	B	
Additional cases used for **Expected Range** calculation	**Scenario**	**20**	**21**	**22**	**23**	**24**	**25**	**26**			
	Demand	B	VH	B	VH	B	VH	B			
	Gas Price	B	B	B	VH	B	H	B			
	Markup	B	B	B	B	B	B	B			
	Hydro	D	D	W	W	B	B	B			
	New Economic Entry	B	B	B	B	Under	Under	B&KW[26]			
Contingency cases used for **Insurance Value** calculation	**Scenario**	**27**	**28**	**29**	**30**						
	Demand	B	VH	B	VH						
	Gas Price	B	VH	B	VH						
	Markup	B	B	B	B						
	Hydro	B	B	B	B						
	Contingency	SONGs	SONGs	DC	DC						

[26] This case assumes that the connection of the Kern County new wind resources is with the PG&E transmission system.

9. Results of the Path 26 Study

Up to this point, we have presented the CAISO methodology and discussed the input assumptions for the Path 26 study. In this chapter, we will summarize the study results, including the various benefit calculations, power flows, and congestion patterns. As discussed in Chapter 5, we attempted to select a wide range of scenarios for this case study to show the benefit of a Path 26 upgrade under a range of future system conditions in 2008 and 2013, including some representative contingency conditions.

In this chapter, we first present in detail the results of our reference cases (both cost-based and market-based cases). Next, we discuss how changes in key system variables, such as gas price, demand, and hydro condition might affect the benefit of Path 26 upgrade. Then, we present our expected benefit of the upgrade and its expected range. Finally, we discuss how the upgrade benefit is affected by selected contingency situations. Throughout the chapter we present the total economic benefits from four different perspectives: 1) societal benefit; 2) modified societal benefits; 3) the CAISO participants' benefits; and 4) the CAISO' ratepayers' benefits.

These benefit amounts can be summed and viewed from a Western interconnection-wide societal or sub-regional perspective or California ratepayer perspective. A critical policy question is which perspective should be used to evaluate projects. The answer depends on the viewpoint of the entity the network is operated to benefit. If the network is operated to maximize benefit to ratepayers who have paid for the network, then some may consider the appropriate test to be the ratepayer perspective. Others say this may be a short-term view, which does not match the long-term nature of the transmission investment. In the long run, it may be both the health of utility-owned generation and private supply, which is needed to maximize benefits to ratepayers. Advocates of this view claim that the network is operated to benefit all California market participants (or for society in general), and therefore, the CAISO participant or Western Electricity Coordinating Council "WECC" perspective of benefits may be the relevant test.

Our view is each perspective provides the policy makers with some important information. If the benefit-cost ratio of an upgrade passes the CAISO participant test, but fails the WECC test of economic efficiency, then it may be an indicator that the expansion will cause a large transfer of benefits from one producer and consumer region to another.

On the other hand, if the proposed project passes the societal test but fails the CAISO participant test, this may be an indication that other project beneficiaries should help fund the project rather than solely CAISO ratepayers. Policy makers should review these differing perspectives to gain useful information when making decisions.

An additional consideration on viewing various perspectives of the benefits of a transmission expansion is how to treat the loss of monopoly rents by generation owners when the grid is expanded. Since monopoly rents result from the exercise of market power that reduces efficiency and harms consumers, the Market Surveillance Committee and the Electricity Oversight Board have argued that it is reasonable to exclude the loss of monopoly rents in the benefit calculations. This is the key difference between the WECC societal test and the WECC modified societal test (based on societal benefits minus monopoly rents). Monopoly rents for California producers was also excluded from the CAISO participant test since it considers only California competitive rents. Once benefits were calculated, the next step was to conduct a cost/benefit test for the upgrade.

Whether "quantified benefits exceeding the quantified project cost" is a criterion to accept or reject a project depends on whether the project is reliability-driven or market-driven. The reliability-driven projects include a set of alternative projects, all of which are identified as technically viable to address an existing or anticipated threat to reliable operation of the power system. At least one alternative must be selected based on its relative economic merits compared to the other candidate alternatives. Here, the objective of economic analysis of reliability-driven projects is to identify the most cost-effective alternative. This means that, even if the quantified economic benefits of none of the identified projects exceed the quantified costs, the most cost-effective alternative would be selected for reliability reasons and not be rejected solely because it is not economically viable from an economic cost–benefit perspective.

The market-driven or economic projects are candidate projects that might not be critical for reliable system operation but would be able to facilitate wholesale energy trade to reduce overall cost of generation. The decision as to whether or not to proceed with a given "economic" project will depend upon whether the project's identified economic benefits exceed its identified economic costs primarily for CAISO participants. In case several alternative market-driven projects are identified, the methodology will assist in determining those candidates that are economically viable, and in identifying the most cost-effective project among them from the perspective of the CAISO participants.

9.1 Benefits for Cost–based and Market–based Reference Cases

We use assumptions of base demand, base gas price, base hydro, and base economic new generation entry as our reference case. The reference case is used simply as a standard against which to analyze and understand deviations when other scenarios are run. To compute the economic benefits of the Path 26 upgrade, we conducted two simulations for each study year (2008 and 2013): with and without the Path 26 upgrade under both the cost-based assumption and the strategic bidding assumption. In the following sections, we first present the results from cost based simulations, and then the results from market price based simulations.

9.1.1 Reference Case: 2008 Cost-Based

Table 9.1 shows the composition of benefits as a result of a Path 26 upgrade in the cost-based simulation for year 2008.[1] For the CAISO participant benefit and CAISO ratepayer benefit, we separated competitive rent and all rents, where all rents included both competitive and monopoly rent.

[1] Note that all benefit values presented in chapter are in nominal dollars.

The total societal benefit for this cost-based case is $1 million for the entire WECC area. Total societal benefit can be decomposed into total consumer benefit, total producer benefits, and total transmission owner benefits.[2] In this case, consumers in WECC as a whole benefited from Path 26 upgrade by $3.52 million annually. Producers throughout WECC also benefited from Path 26 upgrade ($3.70 million annually). However, transmission owners (or CRR holders)[3] as a whole, lost $6.22 million annually. This was due to a reduction in congestion throughout WECC system because of the Path 26 upgrade.

The total societal benefit, the sum of total consumer benefit, total producer benefit, and total transmission owner benefit is always equal to production cost savings from upgrade as shown in Table 9.1 below. As noted in Chapter 2, we checked whether this held true at the WECC level for any economic-driven transmission evaluation case study to ensure consistency of the results.[4]

Since in the cost-based simulation we assumed all suppliers bid their marginal costs, the total modified societal benefit (which only accounts for competitive producer surplus) was the same as the total societal benefit. The CAISO participants as a whole benefited from the Path 26 upgrade. However, while the upgrade would significantly benefit producers in the CAISO region, the consumers and transmission owners would lose from this upgrade. The same situation happens using the CAISO ratepayer perspective. As stated above, cost-based analysis is not an appropriate basis to decide the relative merits of an upgrade project with respect to CAISO ratepayers or market participants, but is valuable as a reference point.

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[2] The decomposition of total societal benefit to consumer benefit, producer benefit, and transmission owner benefit is subject to the caveats discussed in Chapter 2. In essence, we assumed the entire WECC area is a centralized wholesale market for this Path 26 study. For discussion related to the pros and cons of this assumption, please refer to Chapter 2.

[3] Whether or not the reduction in congestion revenues is a loss to the transmission owners or other entities (such as load that is allocated CRRs in return for paying the cost of transmission through transmission access charge, TAC) depends on the regulatory mechanism as applicable to the specific transmission project. In order to avoid complications relate to the tracking of the flow of congestion revenues, in this methodology we assign the congestion revenue benefits (and losses) to the transmission owners.

[4] The total benefit of transmission upgrade equals the total production cost saving due to upgrade when demand is assumed to be inelastic. This means that the identity assumes resource adequacy so that load curtailment does not occur with or without the upgrade.

Table 9.1 2008 Reference Case – Cost Based – Annual Benefits

Perspective	Description	Consumer Benefit ($ M)	Producer Benefit ($ M)	Transmission Owner Benefit ($ M)	Total Benefit[5] ($ M)
Societal	WECC	3.52	3.70	(6.22)	1.00
Modified Societal	WECC	3.52	3.70	(6.22)	1.00
California Competitive Rent	CAISO Ratepayer Subtotal	(1.61)	3.05	(0.95)	0.50
	CAISO Participant Subtotal	(1.61)	4.66	(0.95)	2.10

9.1.2 Reference Case: 2008 Market-based

In the market-based reference case, we applied bid-cost markups that were dynamically determined based on the system condition for each hour, to simulate suppliers' strategic bidding behavior. We applied moderate bid-cost markups in the reference market-based case.[6] Table 9.2 below presents the market-based results for the reference case.

[5] The total benefit of transmission upgrade equals the total production cost saving due to upgrade assuming inelastic demand.

[6] As mentioned in Chapter 4, if we directly applied base-level price-cost markups as bid-cost markups in the market price runs, the final price-cost markups for importing regions such as SCE are likely to be lower than the predicted values derived from a regression equation. Therefore, in actual practice, we conducted calibration by increasing the bid-cost markups so that the final price-cost markups from the market price runs were more in line with the predicted levels of markups. The "moderate" levels of bid-cost markups we used for the reference case has incorporated this calibration. We found that final price-cost markups were generally consistent with the price-cost markups for the **base** markup scenario.

Table 9.2 2008 Reference Case – Market Based Benefits

Perspective	Description	Consumer Benefit ($ M)	Producer Benefit ($ M)	Transmission Owner Benefit ($ M)	Total Benefit[7] ($ M)
Societal	WECC	50.69	(31.68)	(14.73)	4.28
Modified Societal	WECC	50.69	(28.93)	(14.73)	7.04
California Competitive Rent	CAISO Ratepayer Subtotal	10.92	0.04	1.03	11.99
	CAISO Participant Subtotal	10.92	7.04	1.03	19.00

When we assumed that some suppliers bid strategically (i.e., bid at prices that exceeded their marginal costs), the total societal benefit, or total production cost savings for the entire WECC system, was $ 4.281 million for the year 2008. At the same time, the total modified society benefit was $7.04 million annually. In this case, when suppliers bid strategically above their marginal costs, the modified society benefit was no longer equal to the total societal benefit. The differences between the modified societal benefit and total societal benefit were exactly equal to the change in monopoly rent between the “no upgrade” case and “with upgrade” case. We found that in this reference case, the upgrade decreased the total monopoly rent by $2.66 million annually (i.e., $7.04-$4.28=$2.66 million), indicating that this transmission upgrade would reduce the overall market power. Finally, from the perspectives of CAISO ratepayers and CAISO participants, the total annual benefits (competitive rent) of this transmission upgrade were $11.99 million and $ 19 million, respectively.

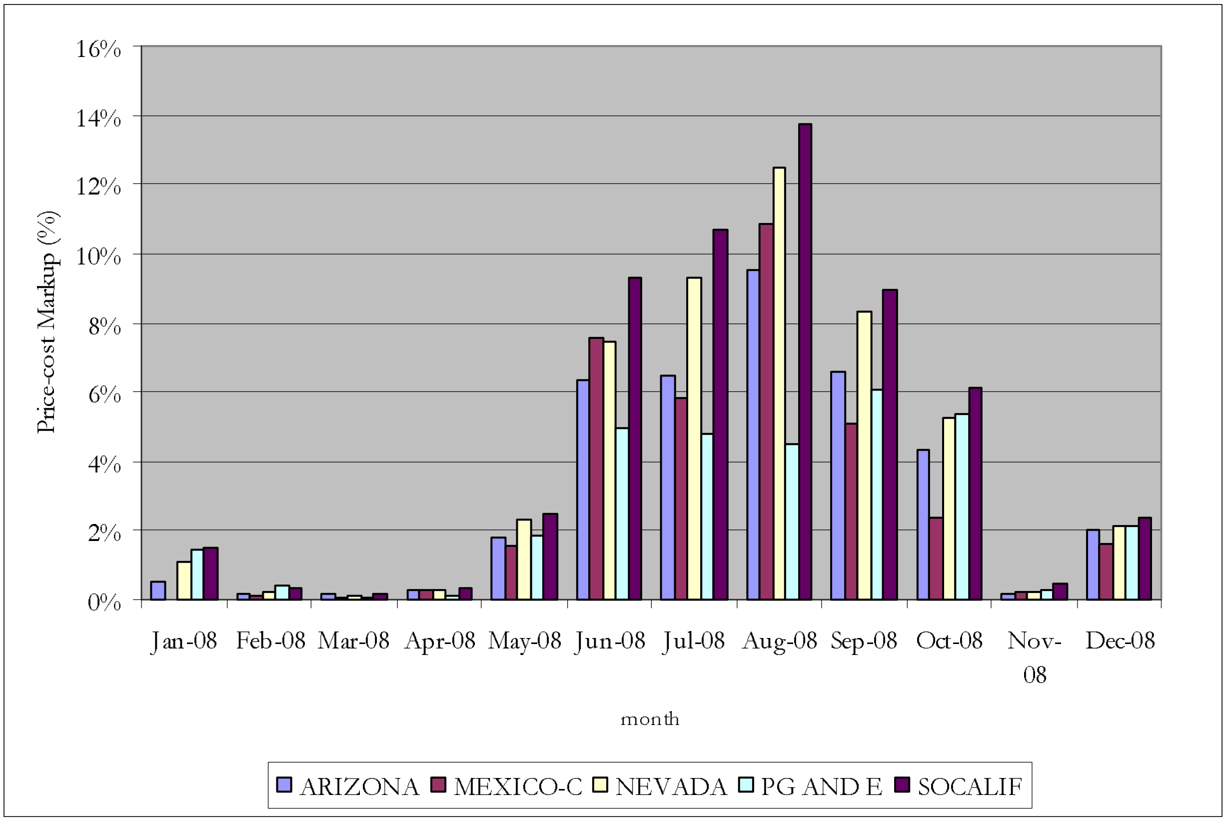
Note that we only modeled strategic bidding behavior in three utility regions in California. We elected not to apply bid markups to resources in regions outside of the three California utility regions because other regions in the WECC are predominately comprised of vertically integrated utilities. Under this regime, suppliers have fewer incentives to exercise market power. Moreover, the lack of market information made it difficult to accurately apply strategic bidding to these regions.

The assumption of marginal cost bidding in the other WECC regions did not preclude these regions from having significant price-cost markups. In fact, our results showed that price-cost markups increased significantly in other neighboring regions when significant markups were projected in California. Figure 9.1 below shows the average monthly price-cost markups in PG&E and SOCALIF (Southern California Edison),

[7] The total benefit of transmission upgrade equals the total production cost saving due to upgrade assuming inelastic demand.

MEXICO-C, Arizona, and Nevada regions under the scenario of base demand, base gas, base hydro, and the moderate markup. When we projected the high bid-cost markups in California, especially in the SCE region, the price-cost markups in all regions increased. The final price-cost markups in other regions followed closely with ones observed in California.

Figure 9.1 Regional Monthly Average Price-cost Markups , 2008, No Upgrade



9.1.3 Effects of Strategic Bidding on Path 26 Upgrade Benefits

Table 9.3 below further compares the economic benefits of the cost-based simulation and market-based simulation for both 2008 and 2013. The results from our reference cases indicated that the economic benefits of the upgrade were significantly larger when the strategic bidding behavior was explicitly considered. For instance, from the perspective of CAISO market participants, the economic benefits of this upgrade for year 2008 were $19 million in the market-based simulation, about 10 times as much as the cost-based simulation ($2.1 million). This difference was even more significant for 2013. In comparing benefits in 2008 to 2013, it appears that benefits decreased. This is largely due to the amount of renewable resources added by 2013 south of Path 26 in the Southern California service territory. This reduced the benefits of Path 26 upgrade in 2013 compared to 2008.

Table 9.3 Benefit Comparisons: Cost Based Versus Market-Based, Year 2008 & 2013

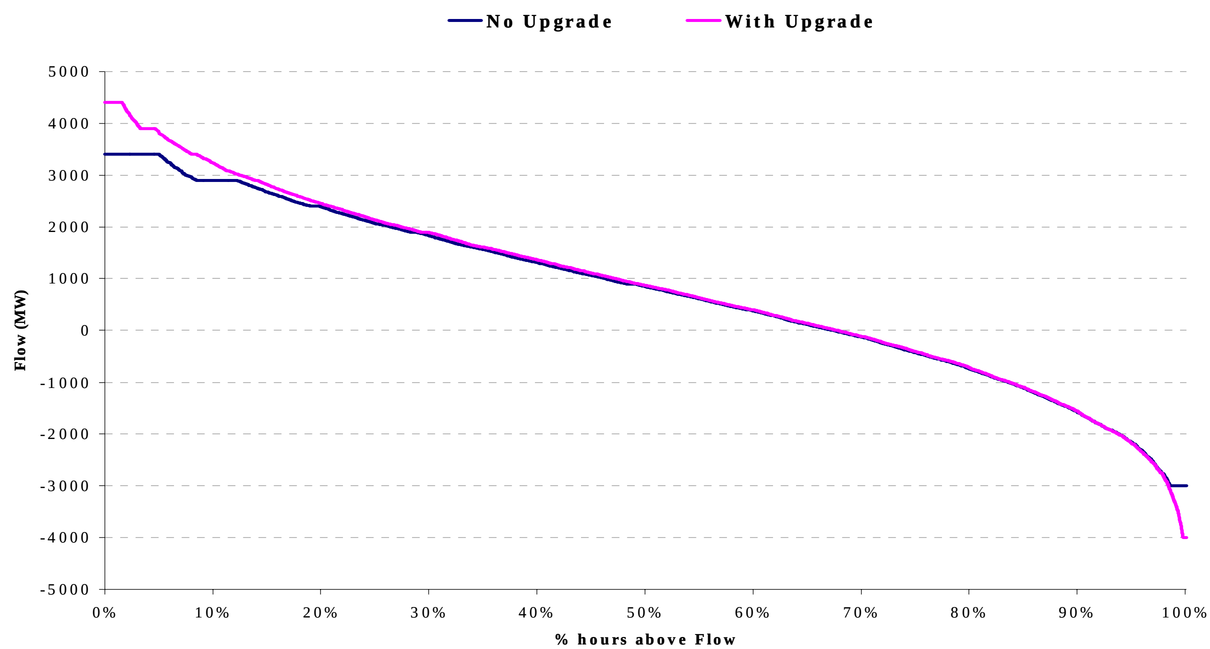
Year	Load	Gas Price	Hydro	Market Pricing	Other	Societal Benefits ($ M)	Modified Societal Benefits ($ M)	CAISO Participant Benefit ($ M)	CAISO Ratepayers Benefits ($ M)
2008	Base	Base	Base	None	None	$ 1.00	$ 1.00	$ 2.10	$ 0.50
2008	Base	Base	Base	Moderate	None	$ 4.28	$ 7.04	$ 19.00	$ 11.99
2013	Base	Base	Base	None	None	$ 0.55	$ 0.55	$ 0.67	$ (0.04)
2013	Base	Base	Base	Moderate	None	$ 2.21	$ 12.93	$ 18.04	$ 8.07

In the rest of this section, we focus more closely on two reference cases in 2008 (cost-based and market-based), and illustrate how the upgrade of Path 26 would change congestion patterns, generation across regions, bid-cost markups, as well as final price-cost markups.

9.1.4 Effects of Upgrade on Path26 Flows and Congestion Frequencies

Figure 9.2 shows flow duration curves for Path 26 in both the "with upgrade" and "no upgrade" cases in the cost-based scenario. We found that for most hours, the flow on Path26 was not affected by the upgrade. In about 70 percent of the hours, the flow on the path was in the north-south direction. However, the number of congested hours decreased from 1,076 hours (or 12.2 percent) in "no upgrade" to 397 hours (or 4.5 percent) in "with upgrade". In other words, this upgrade significantly decreased congestion occurrence on Path26.

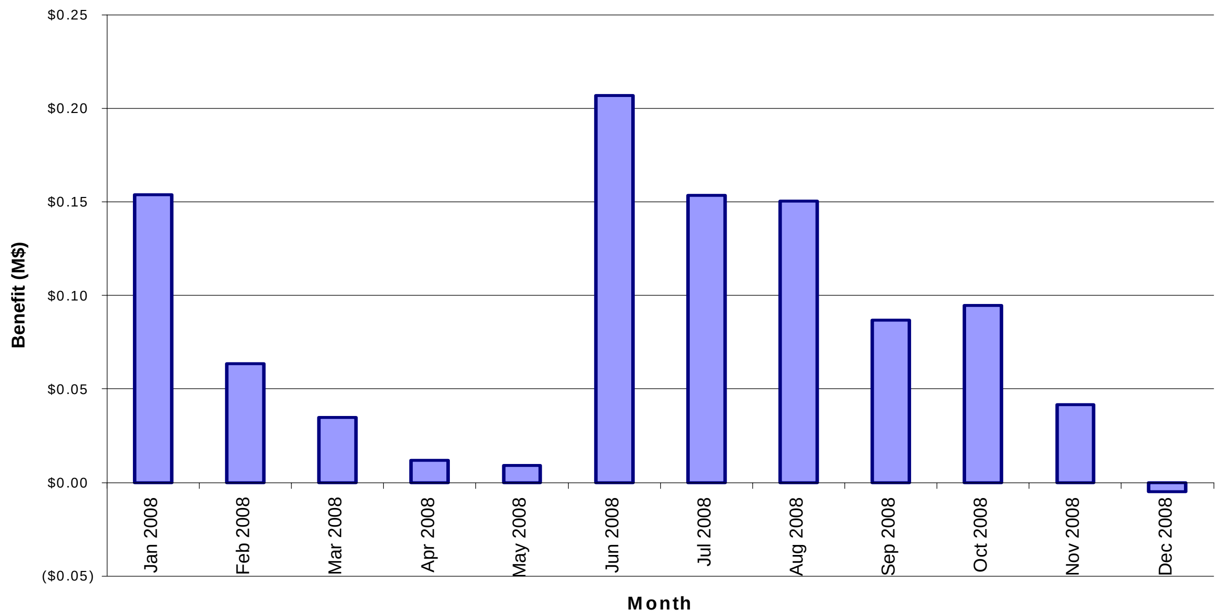
Figure 9.2 Path 26 Flows in Cost-based Reference Case



9.1.5 Effects of Path 26 Upgrade on Generation Cost Saving at the Monthly Basis

Figure 9.3 illustrates the production cost savings on a monthly basis in the cost-based reference case. We found that the highest benefit in terms of generation cost saving was reported in June 2008. The abundant hydropower from the Northeast and British Columbia peaks in June and the expansion of Path 26 improved Southern California's ability to access the cheaper hydropower, thereby generating significant benefits to reduce the overall generation cost.

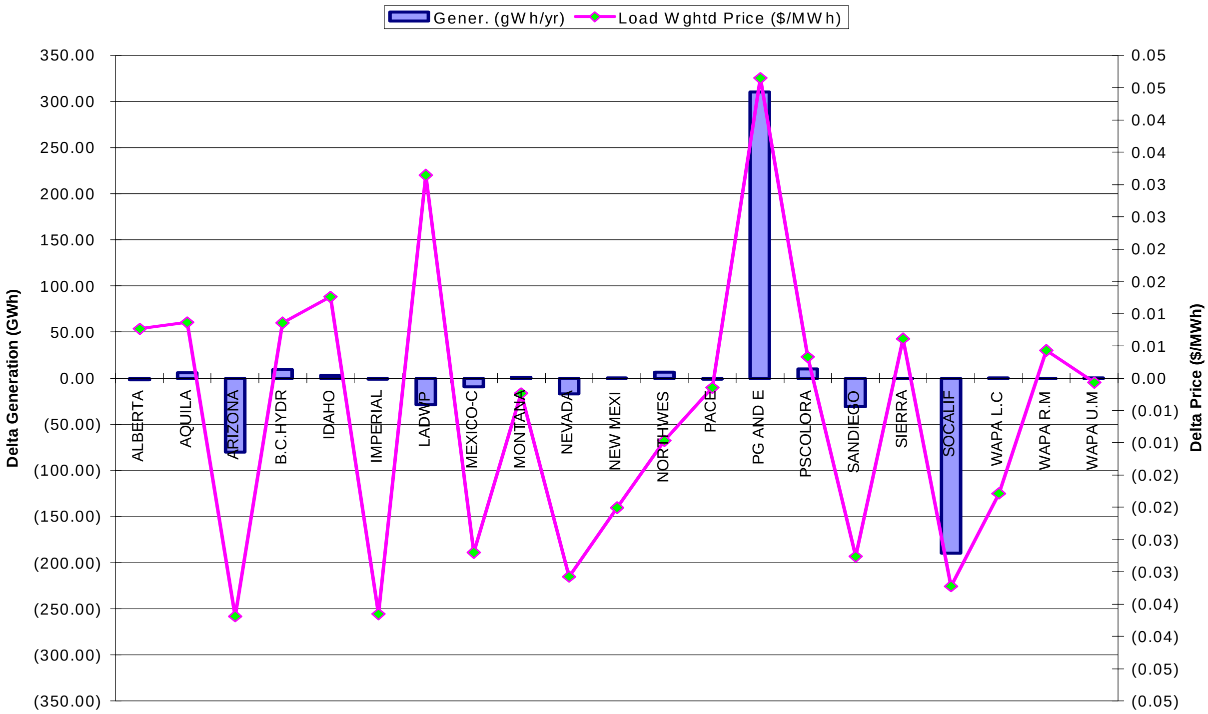
Figure 9.3 Total Societal Benefits – Monthly Variations in Cost-based Case



9.1.6 Effects of Path 26 Upgrade on Generation Re-dispatch and Regional Prices

Figure 9.4 below shows the differences in generation and load-weighted prices between the "no upgrade" and "with upgrade" cases. The upgrade caused significant re-dispatches across regions. The internal generation in SCE decreased by about 200 GWh, while generation in PG&E region increased by more than 300 GWh. At the same time, the prices in Southern California, including SCE and SDG&E decreased by about $0.03/MWh, and prices in PG&E increased by $0.05/MWh. The generators in the PG&E region were obviously the major beneficiaries of this upgrade.

Figure 9.4 Regional Generation Change and Price Change With Upgrade Vs. No Upgrade in Cost-based Case



9.1.7 Duration Curves for RSIs, Bid-cost Markups, and Price-cost Markups for 2008

Figures 9.5 through 9.8 show the duration curves for RSI, percentage of load unhedged, the predicted bid-cost markups, and price-cost markups in three utility regions in California for the market-based reference case. RSI indexes were higher in SCE than in PG&E (Figure 9.5). This is because in the SCE region, there was less utility-retained generation and less long-term contracts compared to the PG&E region (Figure 9.6).[8] Thus, the percentage of load unhedged in SCE region was higher, and was above 40 percent for the most of hours in 2008. As a result, the projected Lerner Indexes were higher in SCE than in the other two utility regions (Figure 9.7). Consequently, we observed positive bid-cost markups in about 50 percent of hours in 2008 in SoCalif, while positive bid-cost markups occurred in about 30 percent and 10 percent of hours in PG&E and SDGE regions. The highest bid-cost markups in SoCalif exceeded 160 percent, while the bid-cost markups in PGE and SDGE regions were mostly below 50 percent.

[8] In the PLEXOS database, the SCE region is named SoCalif. Therefore, we will use these two words interchangeably in the rest of document.

Figure 9.5 RSI Duration Curves, 2008, No Upgrade

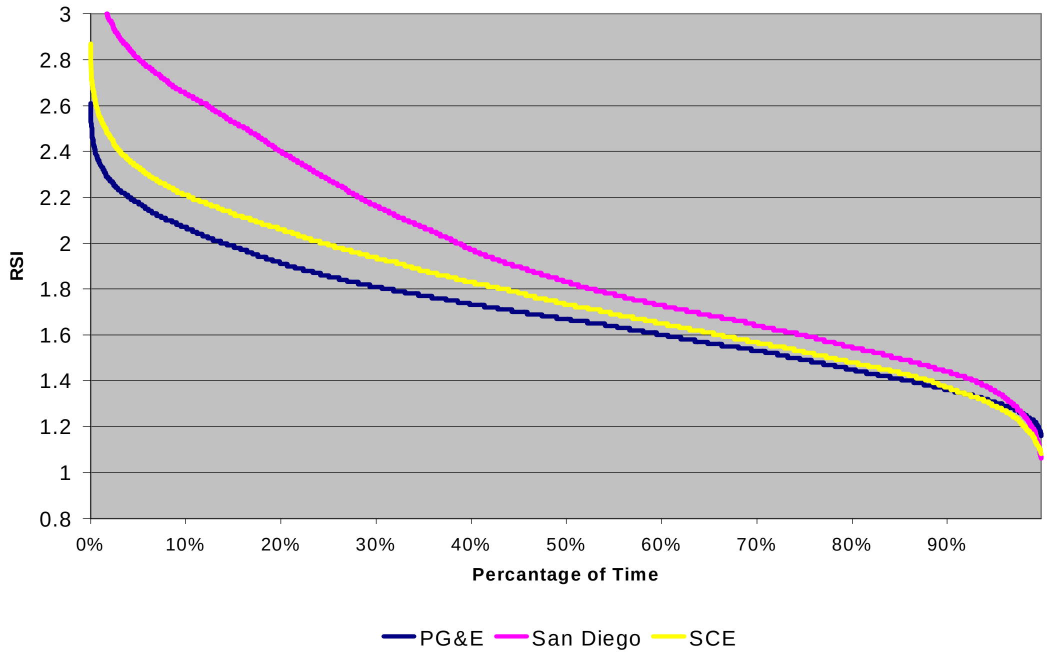
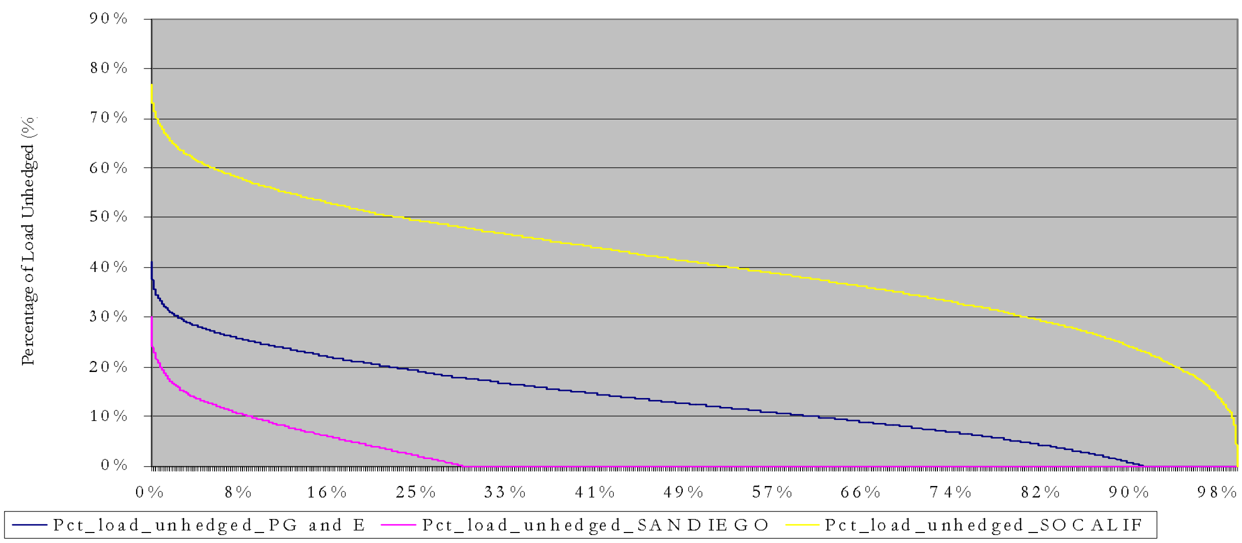


Figure 9.6 Percentage of Load Unhedged Duration Curves, 2008, BBB, No Upgrade



While the bid-cost markups might differ significantly across regions, the price-cost markups following the market price run (after implementing the bid-cost markups) converged [Figure 9.8]. For all three utility regions, the price-cost markups were positive in about 40 percent of the hours. The highest hourly price-cost markup was about 50 percent, with an average price cost mark-up of approximately 12 percent. This demonstrated that applying predicted price cost mark-ups as bid mark-ups to individual generators was an intermediate step that only approximated how individual suppliers bid. Some calibration of these bids would be required to get average predicted price cost mark-ups from these bids which approximate the Lerner Index derived from historical market data as discussed in Chapter 4.

Figure 9.7 Predicted Bid-cost Markups in 2008, No Upgrade

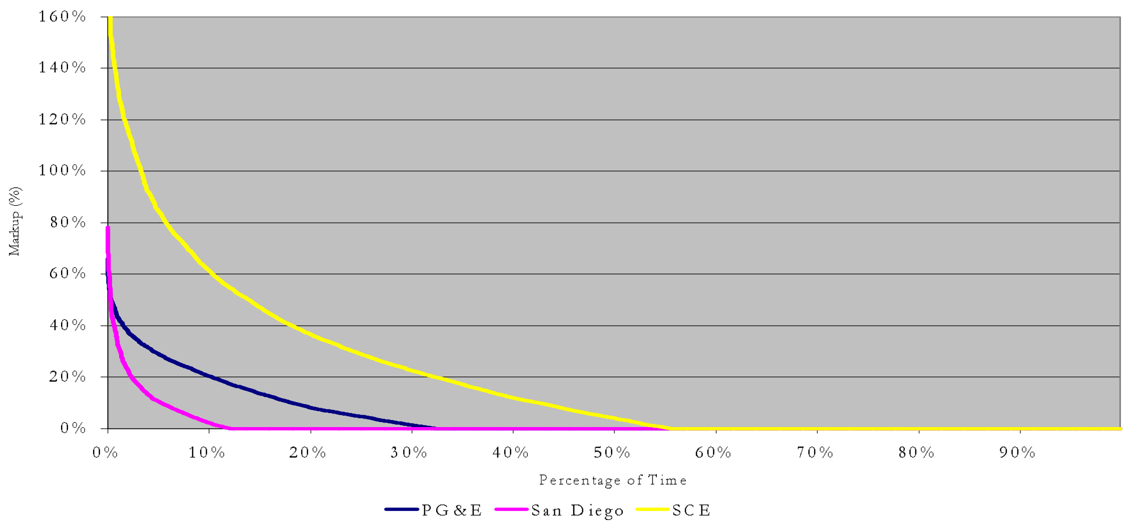
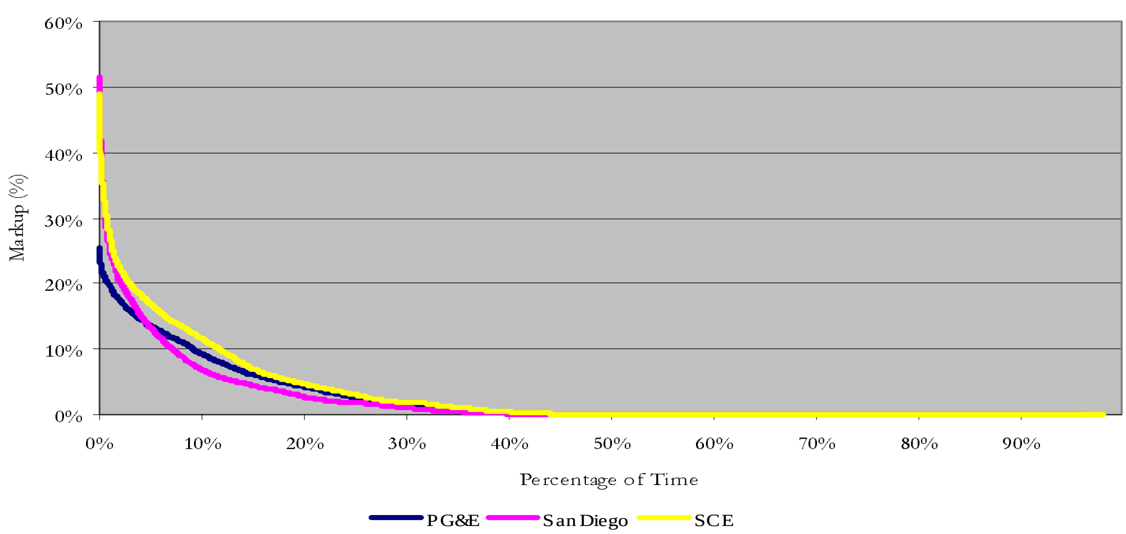


Figure 9.8 Predicted Price-cost Markups in 2008, No Upgrade



9.1.8 Sample Month Analysis for the Reference Cases

Figures 9.9 and 9.10 show the hourly data on bid-cost markups and price-cost markups for August 2008 in the "no upgrade" case in three utility regions. We found that the levels of bid-cost markups varied significantly both across days and within a single day. In most off-peak hours, the projected bid-cost markups were modest. In contrast, significant bid-cost markups were reported in the peak hours, and the highest bid-cost markup exceeded 160 percent in August in SCE.

After we implemented the "proportional markup approach" in the market price run -- assigning different bid-cost markups to different strategic suppliers based on their market shares, we observed positive price-cost markups in all three regions. In the SCE region, the final price-cost markups were lower than the initial bid-cost markups. When significant bid-cost markups existed in Southern California, the suppliers in the neighboring regions responded by exporting more power to the SCE region to arbitrage the price differences. The increasing import volume, in turn, dampened the final price-cost markups in the SCE region, and price-cost markups in all regions converged.

Figure 9.9 Predicted Bid-cost Markups, SCE, 2008, No Upgrade

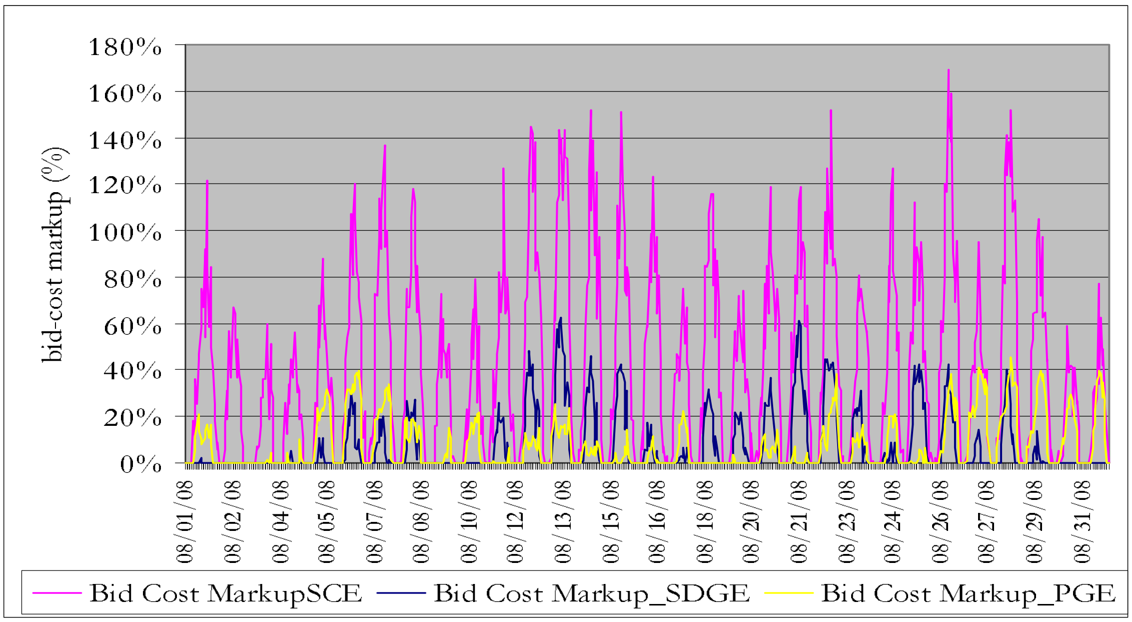
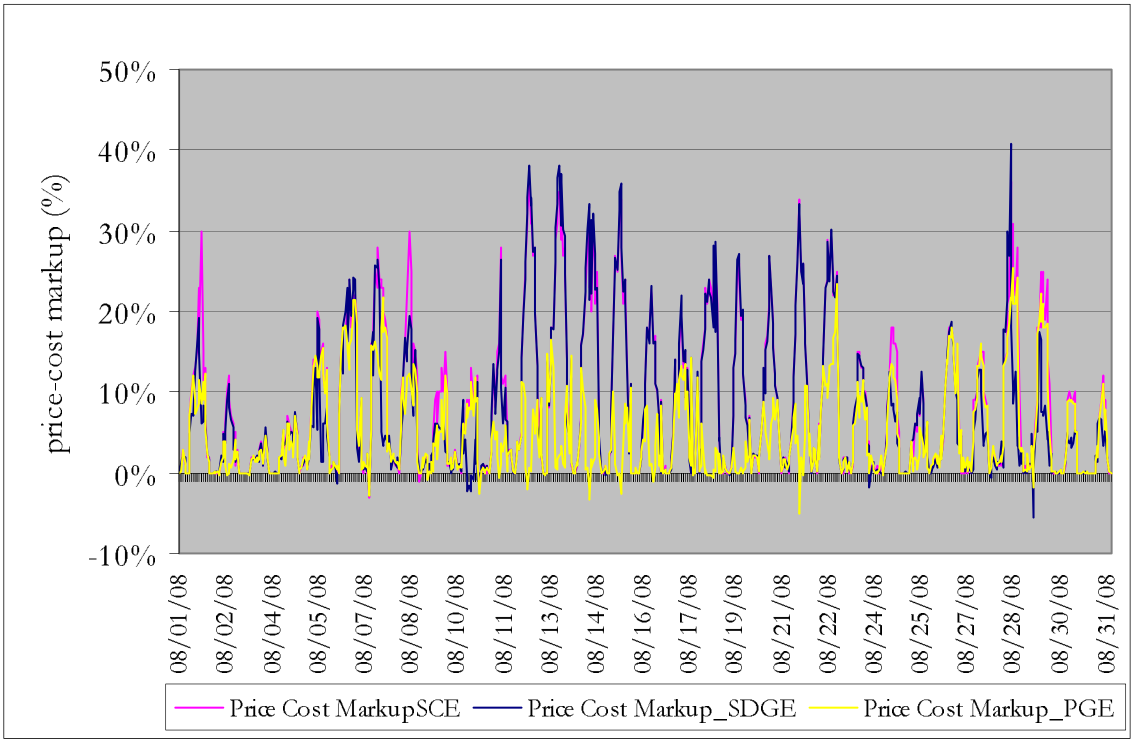


Figure 9.10 Price-cost Markups, SCE, 2008, No Upgrade



Finally, we further investigated the effects of the Path 26 expansion on bid-cost markups and price-cost markups. The Path 26 expansion could potentially affect the competitiveness in the SCE region in two ways. First, the expansion of Path 26 allows for more imports into SCE to compete with internal generation. The cheaper imports could potentially replace more expensive local generation to reduce the overall prices as well as price-cost markups in SCE (Effect I). Second, the suppliers in SCE, when confronting more competition from imports, might change their bidding behavior by bidding more in line with their marginal costs (Effect II). Figures 9.12 and 9.13 illustrate the changes in bid-cost markups and price-cost markups for SCE after the Path 26 expansion. We found that the increase in competition in terms of reductions in bid-cost markups (Effect II) was very modest. The largest decrease in the bid-cost markups in August was about 2 percent (Figure 9.11). In other words, the expansion of Path 26 did not significantly affect suppliers' bidding behavior in SCE.

However, Effect I was significant as shown in Figure 9.12. We found that the price-cost markups decreased by as much as 10 percent for a few hours in August. The expansion of Path 26 brought cheaper imports from neighboring regions (especially PG&E) into SCE, which in turn significantly reduced price-cost markups in SCE. In summary, the Path 26 expansion could have significant market power mitigation effects for the importing region such as SCE.

Figure 9.11 Changes in Bid-cost markups (With Exp-Without Exp), SCE, August 2008

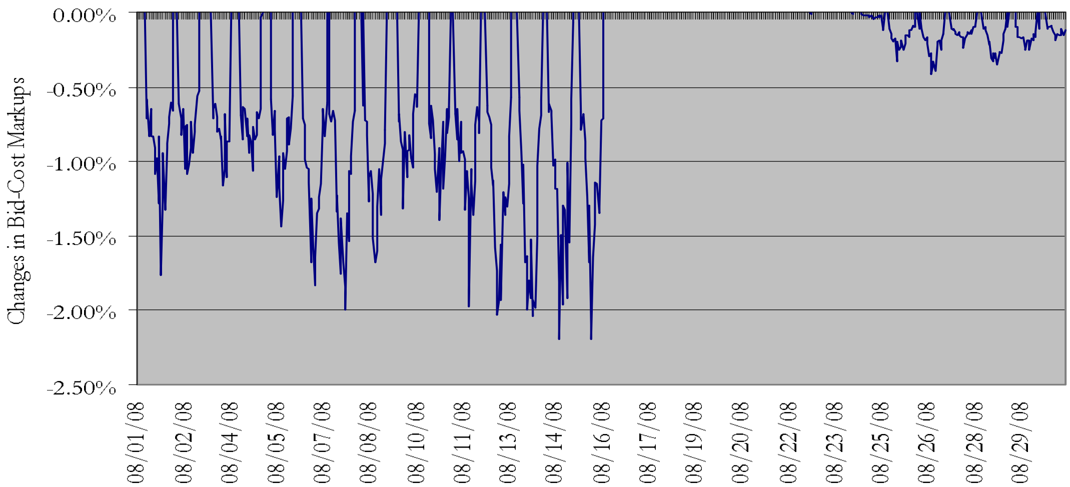
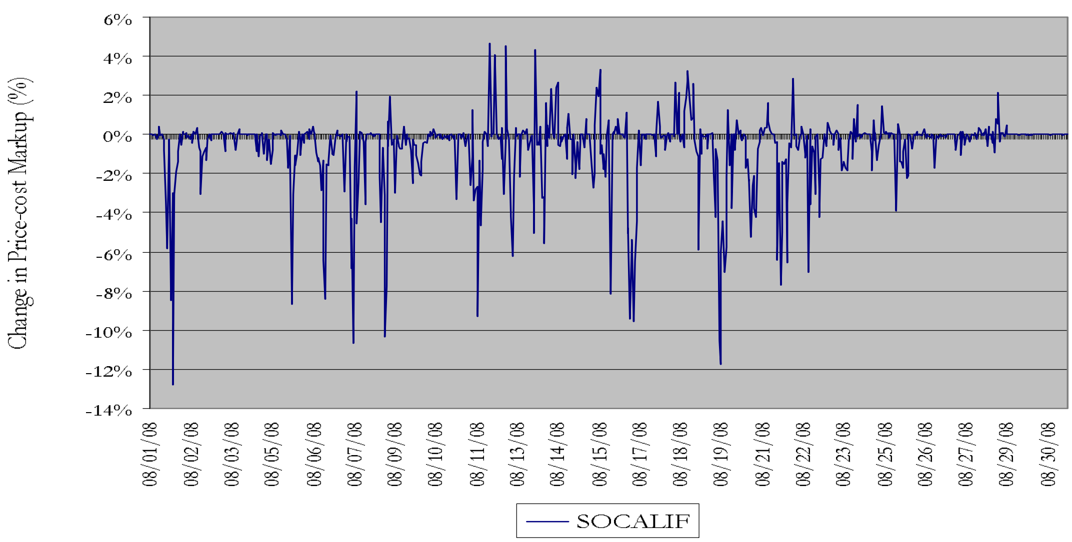


Figure 9.12 Changes in Price-cost Markups (With Exp – Without Exp), SoCalif, August 2008, BBB



9.2 Effects of Gas Prices, Demand, and Hydro on Benefits

In the following section, we discuss the impact of the important variables on total Path 26 upgrade benefit and its distribution. We use selective cases to illustrate how the input assumptions for each variable might affect the benefit results.

9.2.1 Impact of Gas Prices on Path 26 Upgrade Benefits

Figure 9.13 shows the ranges of gas prices for our three scenarios (very low, base, and very high) for 2008 and 2013 across regions. Table 9.4 summarizes the effects of gas prices on the economic benefits of upgrade under different system conditions for 2008 and 2013. We found that the increase in gas price had significant positive effects on the transmission benefit, especially the CAISO participant benefits. Under the base demand and base hydro conditions, the benefit to the CAISO participants increased by $4.44 million when we moved from the low gas price to the high gas price scenario. Also, the magnitude of effects from gas price was likely to be amplified if suppliers bid strategically above their marginal costs. For instance, when we assumed suppliers bid strategically based on the moderate bid-markup case and under the high gas price scenario, the total benefit to the CAISO participants was as high as $27.82 million, significantly higher than $ 4.89 million in the low gas price scenario.

Figure 9.13 Gas Price Sensitivity Data

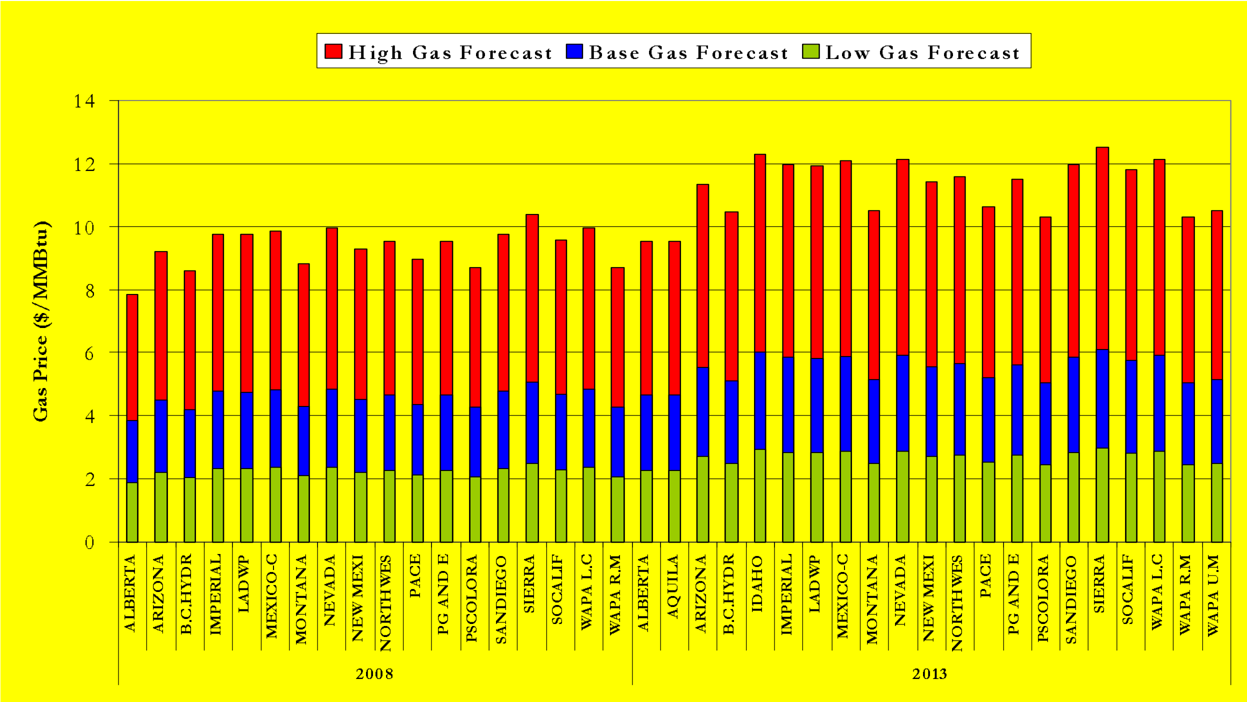


Table 9.4 Effects of Gas Prices on Benefits - Year 2008 & Year 2013

Year	Load	Gas Price	Hydro	Market Pricing	Other	Societal Benefits ($ M)	Modified Societal Benefits ($ M)	CAISO Participant Benefit ($ M)	CAISO Ratepayers Benefits ($ M)
2008	Base	VL	Base	Low	None	$ 0.35	$ (1.12)	$ (1.02)	$ (0.82)
2008	Base	Base	Base	Low	None	$ 0.89	$ 1.35	$ 1.85	$ 1.09
2008	Base	VH	Base	Low	None	$ 1.68	$ (0.06)	$ 3.93	$ 2.77
2008	Base	VL	Base	Moderate	None	$ 1.52	$ (1.50)	$ 6.15	$ 2.91
2008	Base	Base	Base	Moderate	None	$ 4.28	$ 7.04	$ 19.00	$ 11.99
2008	Base	VH	Base	Moderate	None	$ 7.49	$ 10.67	$ 25.68	$ 20.62
2013	VL	VL	Base	Low	None	$ 0.10	$ 0.13	$ 0.44	$ 0.02
2013	VL	Base	Base	Low	None	$ 0.76	$ 1.63	$ 3.21	$ 0.39
2013	VL	VH	Base	Low	None	$ 1.59	$ 3.81	$ 6.91	$ 1.21
2013	Base	VL	Base	Moderate	None	$ 0.82	$ 2.61	$ 4.89	$ 3.02
2013	Base	Base	Base	Moderate	None	$ 2.21	$ 12.93	$ 18.04	$ 8.07
2013	Base	VH	Base	Moderate	None	$ 3.14	$ 20.58	$ 27.82	$ 12.44

9.2.2 Impact of Demand on Path 26 Upgrade Benefits

Figure 9.14 shows the ranges of demand levels for our three load scenarios (low, base, and high) for 2008 and 2013 across regions. Table 9.5 summarizes the effects of demand on the economic benefits of the Path 26 upgrade. We found that the transmission upgrade would be more valuable when demand increased. For instance, under the scenarios of base gas price, base hydro condition, and moderate bid-cost markups in 2013, we observed that the total societal benefit increased from $1.27 million in the low demand case to $4.76 million in the high demand case. Similarly when generators bid high, total societal benefit will increase from $1.10 million in the low demand case to $5.64 million in the high demand case.

Figure 9.14 Demand Sensitivity Data

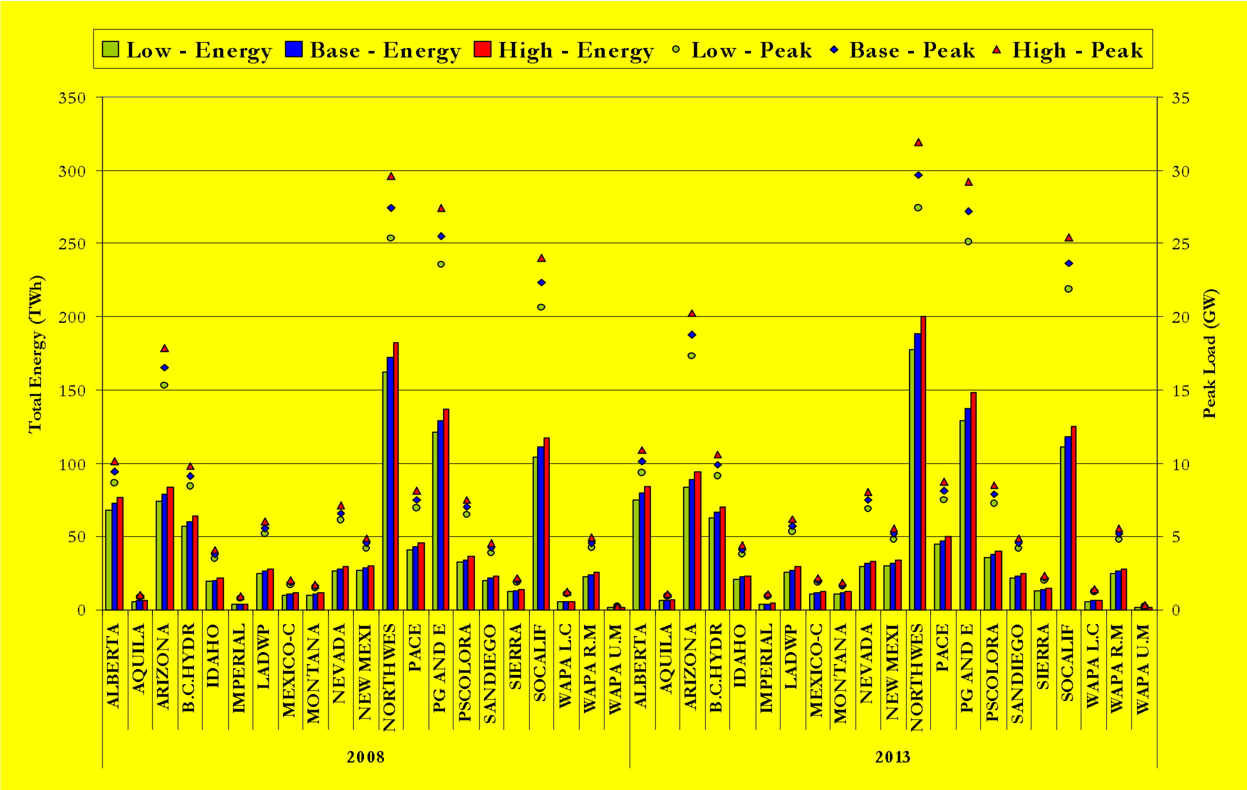


Table 9.5 Effects of Demand on Benefits - Year 2008 & Year 2013

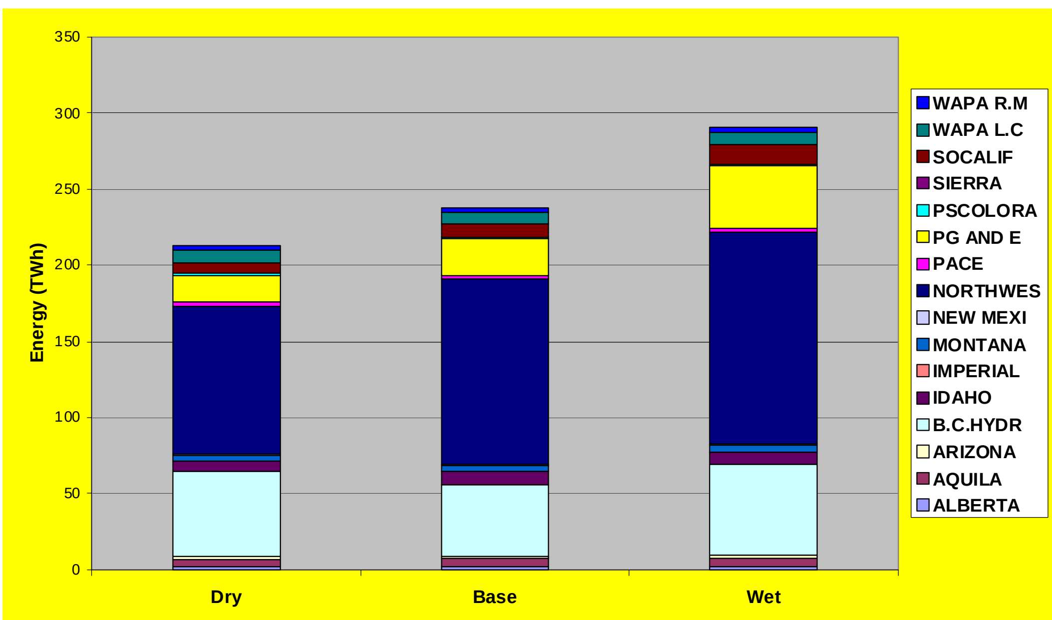
Year	Load	Gas Price	Hydro	Market Pricing	Other	Societal Benefits ($ M)	Modified Societal Benefits ($ M)	ISO Participant Benefit ($ M)	ISO Ratepayers Benefits ($ M)
2008	VL	Base	Base	Moderate	None	$ 2.05	$ 6.14	$ 9.48	$ 6.67
2008	Base	Base	Base	Moderate	None	$ 4.28	$ 7.04	$ 19.00	$ 11.99
2008	VH	Base	Base	Moderate	None	$ 6.20	$ 7.38	$ 17.50	$ 13.73
2013	VL	Base	Base	Moderate	None	$ 1.27	$ 4.32	$ 7.47	$ 2.24
2013	Base	Base	Base	Moderate	None	$ 2.21	$ 12.93	$ 18.04	$ 8.07
2013	VH	Base	Base	Moderate	None	$ 4.76	$ 9.68	$ 13.67	$ 12.53
2013	VL	Base	Base	High	None	$ 1.10	$ 6.11	$ 8.83	$ 2.62
2013	Base	Base	Base	High	None	$ 2.20	$ 15.93	$ 20.52	$ 8.42
2013	VH	Base	Base	High	None	$ 5.64	$ 17.10	$ 22.20	$ 16.87

9.2.3 Impact of Hydro Availability on Path 26 Upgrade Benefits

Figure 9.15 shows the hydro energy levels by region for our three hydro scenarios: dry, base, and wet hydro conditions.[9] Figure 9.16 further illustrates the availability of hydropower on a monthly basis for the base hydro scenario. The regions with most hydro energy in the WECC area are Northwest Region, BC Hydro region, and PG&E region. Hydro energy production typically peaks in June due to run-off conditions.

Table 9.6 provides a summary of the effects of hydro conditions on the economic benefits of the Path 26 upgrade. We found that the benefit of the upgrade was significantly larger in the wet hydro condition than base or dry hydro condition. For instance, under the scenarios of base demand, base gas price, and cost-based biddings in 2008, we observed that the benefit to the CAISO ratepayers increased from $–0.8 million in the dry hydro case, to $2.1 in base hydro case, and to $11.63 million in the wet hydro case. The significant benefit would only occur under the wet hydro condition. This result is intuitive in that when abundant hydro energy is available, the Path26 upgrade improves California's accessibility to cheaper energy from the northwest region and generates significant benefits to Californian consumers.

Figure 9.15 Hydro Energy Sensitivity Data



[9] We studied the effects of hydro conditions mainly for year 2013. Unlike the sensitivity data for other variables, for which we statistically developed in-house, this data did not lend itself to us making a straightforward estimate of the likelihood of each hydro sensitivity scenario occurring. As a result, we did not use these cases to determine the expected benefit value. However, we do provide a range of benefits under varying hydro conditions. As mentioned in Chapter 11: Analytical Approach, though it is ideal to optimize the hydro hourly operation, the profiles received from the SSG-WI data preparation entities assumed hydro operation to be fixed. The Market Surveillance Committee (MSC) supported the idea of fixing the hydro profiles from the SSGWI studies given the fact that the hydro operations within the WECC, and between BPA, BC Hydro and PG&E, vary and would be difficult to capture within one model.

Figure 9.16 Hydro Energy Monthly Variation - Base Case

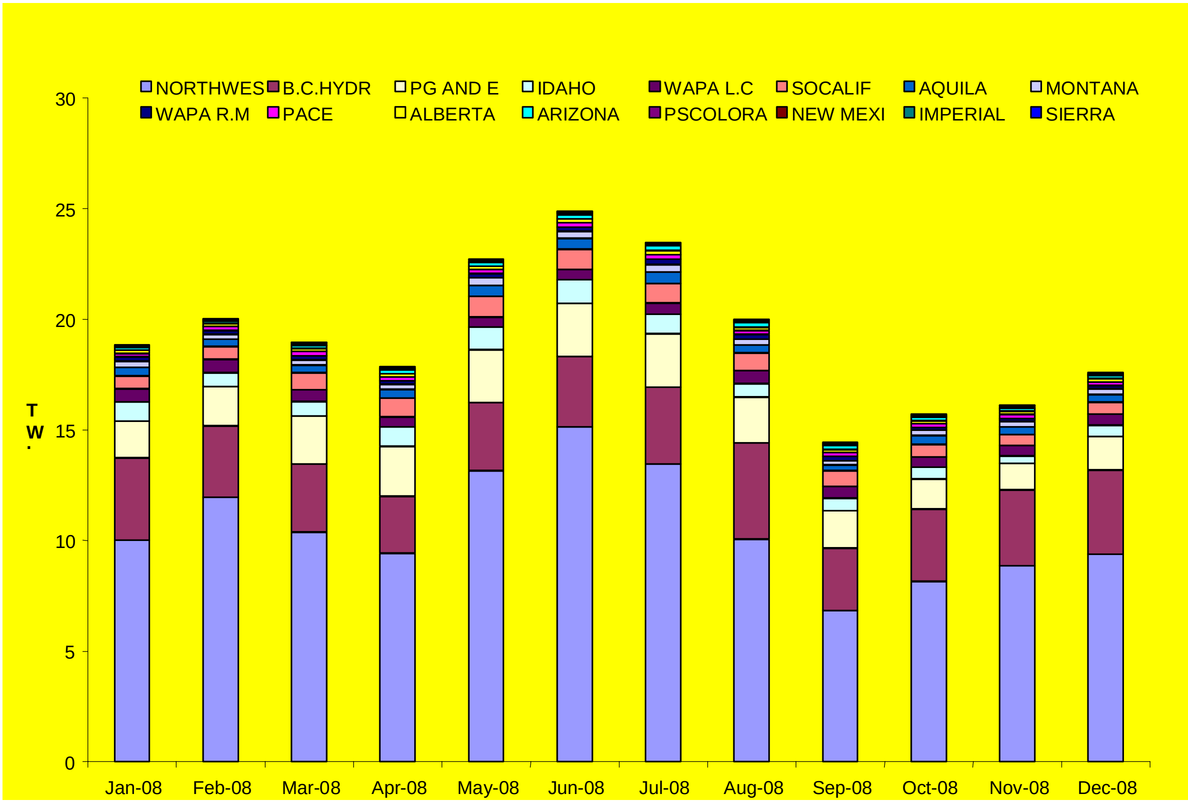


Table 9.6 Effects of Hydro Conditions on Benefits - Year 2008

Year	Load	Gas Price	Hydro	Market Pricing	Other	Societal Benefits ($ M)	Modified Societal Benefits ($ M)	ISO Participant Benefit ($ M)	ISO Ratepayers Benefits ($ M)
2008	Base	Base	Dry	None	None	$ 1.54	$ 1.54	$ (0.80)	$ 0.14
2008	Base	Base	Base	None	None	$ 1.00	$ 1.00	$ 2.10	$ 0.50
2008	Base	Base	Wet	None	None	$ 5.05	$ 5.05	$ 11.63	$ 5.90
2013	Base	Base	Dry	Low	None	$ 1.35	$ (0.39)	$ (3.17)	$ 2.15
2013	Base	Base	Base	Low	None	$ 0.49	$ (1.15)	$ (0.62)	$ (0.30)
2013	Base	Base	Wet	Low	None	$ 3.02	$ 4.24	$ 7.38	$ 0.58
2013	VH	VH	Dry	Low	None	$ 5.45	$ 4.45	$ (0.43)	$ 19.40
2013	VH	VH	Wet	Low	None	$ 5.53	$ 5.47	$ 11.58	$ 10.30

9.2.4 Impact of Wind Resource Location on Path 26 Upgrade Benefits

In Chapter 5 we discussed sensitivities other than demand, gas price, markup, and hydro. One of the sensitivities we are interested in is the connection of Kern County new wind resources. In all the cases we assumed that Kern County new wind resources would be connected with SCE's transmission system, i.e., to the south end of Path 26. An alternative is to connect Kern County wind with PG&E's transmission system, i.e., to the north end of Path 26. Table 9.7 below shows the comparison of these two alternatives, holding demand and gas price at base, and markup at low level. The results show very small impact of Kern County wind connection on Path 26 upgrade benefits.

Table 9.7 Effect of Kern County Wind Connection on Benefit (2013)

	Connected with SCE System	Connected with PG&E System
Total Societal Benefit	$0.49 M	$0.55 M
Total Modified Societal Benefit	$(1.15) M	$(1.05) M
CAISO Participant Benefit	$(0.62) M	$ (0.43) M
CAISO Ratepayer Benefit	$(0.30) M	$(0.04) M

9.3 Expected Benefit from Path 26 Upgrade

In the above sections, we discussed the Path 26 upgrade benefits under a wide range of future system conditions. We can see that benefit of Path 26 upgrade varied in different scenarios. In order to derive the expected benefit of Path 26 upgrade, we applied the joint probabilities derived in Chapter 5 to the benefits for joint events of demand, gas price, markup with base hydro and base new generation entry. Table 9.8 below shows the expected Path 26 upgrade benefit in 2008 and 2013 based on market-based simulation results.

Table 9.8 Expected Benefit of Path 26 Upgrade – Market Based[10] ($M)

	Total Societal Benefit	Total Modified Societal Benefit	Total CAISO Participants Benefit	Total CAISO Ratepayers Benefit
2008	$3.05 M	$4.46 M	$10.29 M	$8.65 M
2013	$2.11 M	$8.64 M	$12.17 M	$6.43 M

The expected benefits from market based simulation are significantly higher than the cost based simulation, which are shown in Table 9.9:

Table 9.9 Expected Benefit of Path 26 Upgrade – Cost Based[11] ($M)

	Total Societal Benefit	Total Modified Societal Benefit	Total CAISO Participants Benefit	Total CAISO Ratepayers Benefit
2008	$0.89 M	$0.89 M	$1.46 M	$0.24 M
2013	$0.67 M	$0.67 M	$0.63 M	$0.49 M

Comparison of Tables 9.9 and 9.10 illustrates what was mentioned earlier in this chapter regarding the necessity and sufficiency of the application of cost benefit analysis results. Cost-based benefits provide useful information but are inappropriate as a “GO/NoGO” criterion to determine economic viability of the project from the point of view of specific market participant categories. In contrast, market-based benefits do capture the relative impact of the project on different market participant classes; whether or not the market-based benefits are used as a “GO/NoGO” criterion depends on whether the project itself is reliability driven or market–driven (the cost benefit analysis results would be used for “ranking” if applied to the “reliability” project alternatives, and for “screening” of applied to “economic” projects).

9.4 Most Likely Range of Path 26 Upgrade Benefits

In Chapter 5 we discussed how to assign joint probabilities to all joint events of demand, gas price, markup, hydro, and new generation entry so that we can derive an

[10] The expected benefit values for 2008 presented in this table are subject to change as the CAISO was not able to complete and adequately review all of the high markup cases identified in Chapter 5 for year 2008. We expect that the expected benefit will move upward after all high markup cases are included in the expected value calculation.

[11] The probabilities applied for deriving the expected benefit for cost-based run were those reported in our February 2003 CPUC filing. These probabilities were derived for joint demand/gas price cases. The expected benefit values presented in this table are also subject to change as the CAISO was not able to complete all of the scenarios needed.

expected or most likely benefit range of a transmission upgrade. More specifically, we use the Max/Min linear programming approach discussed in Chapter 5 to assign joint probabilities for all joint events of demand, gas price, markup, hydro, and new generation entry such that total benefit is maximized or minimized.[12] Table 9.10 lists the most likely benefit range for each benefit perspective in 2013.

Table 9.10 Most Likely Benefit Range of Path 26 Upgrade in 2013

	Lower Bound	Upper Bound
Total Societal Benefit	$1.88 M	$2.78 M
Total Modified Societal Benefit	$7.47 M	$9.73 M
Total CAISO Participants Benefit	$10.70 M	$13.83 M
Total CAISO Ratepayers Benefit	$5.81 M	$6.38 M

The lower and upper bound give a much narrower benefit range for Path 26 upgrade than indicated by individual cases, thus can be used as a much more reliable benefit estimate. The lower bound indicates that expected total societal benefit couldn't be lower than $1.88 M in 2013, while the upper bound indicates that expected total societal benefit of Path 26 upgrade would not exceed $2.78 M.

9.5 Benefits Under Contingency Situations

In our Path 26 study, we selected two contingencies to consider: (1) the San Onofre (SONGs) nuclear plant (2000 MW capacity) being out of service in 2008 and 2013; and (2) the Pacific DC Intertie (PDCI) transmission line (3100 MW) bi-directional between Northwest and Los Angles) on outage in 2008 and 2013. SONGs provides a significant amount of baseload internal generation to Southern California. A SONGs outage would likely result in a significant increase in north to south flows on Path 26. This is the major path from Northern California to Southern California for importing power from Northern California and Northwest. Thus, this event might significantly impact the value of a Path 26 expansion. The PDCI is a parallel path to Path 26, and can import power from the Northwest to the LA Basin. Similarly, if PDCI has an outage, we would expect that it would also significantly affect the benefit of Path 26.

[12] For detailed discussion on how these joint probabilities are derived, please refer to Chapter 5.

Table 9.11 Effects of Contingency Events on Path 26 Upgrade Benefit

Year	Load	Gas Price	Hydro	Market Pricing	Outage	Societal Benefits ($ mil.)	Modified Societal Benefits ($ mil.)	ISO Participant Benefit * ($ mil.)	ISO Ratepayers Benefits * ($ mil.)
2008	Base	Base	Base	None	PDCI	$ 2.28	$ 2.28	$ 1.44	$ (0.09)
2008	Base	Base	Base	Moderate	PDCI	$ 7.60	$ 18.76	$ 13.26	$ 14.96
2008	Base	Base	Base	None	SONGs	$ 1.43	$ 1.43	$ 3.78	$ 1.82
2013	Base	Base	Base	Low	PDCI	$ 1.23	$ 3.54	$ 3.70	$ 1.93
2013	Base	Base	Base	Moderate	PDCI	$ 4.85	$ 21.21	$ 29.18	$ 12.65
2013	VH	VH	Base	Moderate	PDCI	$ 16.96	$ 67.62	$ 82.29	$ 40.87
2013	Base	Base	Base	Moderate	SONGs	$ 2.95	$ 16.43	$ 26.18	$ 12.74

Table 9.11 shows the impact of the two contingencies on Path 26 expansion benefits. When either outage occurred, the expansion of Path 26 provided more benefits than no-outage cases (or our reference cases). For instance, the total societal benefits of the upgrade was $2.28 million when SONGS was on outage, while under the cost-based reference case, the total societal benefit was $1 million. Also, we observed that the economic benefits increased significantly when suppliers bid strategically. Even if we assumed that suppliers bid with moderate bid-cost markups under the DC-outage case, we observed that the total societal benefit of the upgrade increased significantly to $7.60 million compared to $2.28 million in the low bid-cost markup case in 2008.

Upgrading Path 26 leads to very high benefits in 2013 under the DC-outage case, especially when generators bid strategically and when system condition is severe. Under the scenario of very high load, very high gas price, base hydro condition, and moderate bid-cost markup, the outage of pacific DC inter-tie could lead to significant economic benefits to the Path 26 upgrade. From the perspective of ISO participants, the annual benefit can exceeds $80 million. This result indicates that transmission upgrade can be extremely valuable in some extreme system conditions. In other words, transmission projects can provide some insurance to hedge against the worst system conditions.

9.6 Conclusions

The results presented above illustrate what was mentioned earlier regarding the application of the methodology either as a ranking method (for various reliability-driven project alternatives) or as an economic viability screen (for primarily economic transmission projects). It also illustrates the relevance of identifying the benefits at the region-wide level (WECC) and at the specific market participant level (CAISO market participants and CAISO rate payers). Specifically for the Path 26 upgrade project, the following observations are illuminating:

1. The expected cost-based benefits provides reference information on how traditional transmission planning studies may have seriously underestimated the value of an upgrade by considering cost-based bidding The expected cost-based annual benefits were below 1 million dollars at the WECC level ($0.89 million in 2008 and $0.67 million in 2013), far short of the expected annualized cost of the upgrade (more than $10 million per year). As stated earlier, it is inappropriate to use cost-based benefits as a criterion to identify the winners and losers or allocate costs and benefits of the upgrade to different participant classers. Thus the expected CAISO participant cost-based benefits ($1.46 million in 2008 and $0.63 million in 2013) and CAISO ratepayer benefits ($0.24 million in 2008 and $0.49 million in 2013) are useful only as reference information.
2. The expected market-based annual benefits, based on the scenarios conducted so far, point to the possible economic viability of the Path 26 upgrade project from the perspective of the CAISO market participants ($10.29 million in 2008 and $12.17 million in 2013), and potential economic viability from the perspective of the CAISO ratepayers ($8.65 million in 2008 and $6.43 million in 2013]. Due to time limitation, for 2008 we conducted only limited number of scenarios. Some scenarios with potentially higher benefits are underway that may increase the expected benefits identified above.

From these observations, we conclude that the Path 26 upgrade may be economically viable. However, to reach a definite conclusion in this regard, additional analytical refinements need to be performed. Specifically, these additional refinements would include the following:

- A more detailed estimate of capital costs -- preferably with a 20 percent or less margin of error
- An appropriate calculation of annual revenue requirements including capital recovery, relevant taxes, operating costs, and other associated costs
- A more comprehensive evaluation of other Path 26 upgrade alternatives including additional remedial action schemes (RAS)
- A net present value analysis of the benefits which would require additional years of benefits to be calculated beyond those for 2008 and 2013
- Consideration of the potential impact of other projects on the benefits of Path 26 upgrade (and those of other competing projects)

These additional tasks would enable the CAISO and the CPUC to make a more definitive recommendation regarding the economic viability of the proposed Path 26 upgrade.

ATTACHMENT 2
OF
PHASE 1 OPENING TESTIMONY ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR
October 21, 2005
A.05-04-015
I.05-06-041

Appendix A

AC	**Alternating Current**
ADR	**Alternative Dispute Resolution**
AGC	**Automatic Generation Control**
BCR	**Benefit-Cost Ratio**
CAISO	**California Independent System Operator**
CEC	**California Energy Commission**
CEQA	**California Environmental Quality Act**
CPCN	**Certificate of Public Convenience and Necessity**
CPUC	**California Public Utility Commission**
CRR	**Congestion Revenue Right**
CS	**Consumer Surplus**
CR	**Congestion Revenues**
CTL	**Cost-to-Load**
DC	**Direct Current**
EHV	**Extra High Voltage**
FACT	**Flexible AC Transmission**
FERC	**Federal Energy Regulatory Commission**

FTR	**Firm Transmission Rights**
IEPR	**Integrated Energy Policy Report**
IOU	**Investor-Owned Utility**
ISO	**Independent System Operator**
LE	**London Economics**
LP	**Linear Programming**
LRA	**Local Regulatory Authority**
LMP	**Locational Marginal Price**
MSC	**Market Surveillance Committee**
MW	**Megawatt**
NGO	**New Generation Owners (Divested Generation)**
NPV	**Net Present Value**
OPF	**Optimal Power Flow**
PC	**Producer Cost**
PDC	**Project Dependable Capacity**
PoolMod	**Production Cost Model**
PR	**Producer Revenue**
PS	**Producer Surplus**

PTDF	**Power Transmission Distribution Factors**
PTO	**Participation Transmission Owners**
PUC	**California Public Utilities Commission**
PWG	**Planning Work Group (SSG-WI)**
RMR	**Reliability Must Run**
RPS	**Renewable Portfolio Standard**
RSI	**Residual Supply Index**
RTO	**Regional Transmission Organization**
SC	**Scheduling Coordinators**
SFE	**Supply Function Equilibrium**
SFT	**Simultaneous Feasibility Test**
SSG-WI	**Seams Steering Group – Western Interconnection**
TB	**Total Benefit**
TCSC	**Thyristor Control Static Comp**
TEAM	**Transmission Economic Assessment Methodology**
TURN	**The Utility Reform Network**
UDC	**Utility Distribution Company**
UPFC	**United Power Flow Controller**

VoLL	**Value of Loss Load**
VOM	**Variable Operation and Maintenance (Costs)**
WECC	**Western Electricity Coordinating Council**

ATTACHMENT 3
OF
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I.05-06-041

Appendix B

AB.1 Demonstration of Transmission Benefit Calculation Using a 3-Node Prototype Model

AB.1.1 Introduction

This Appendix summarizes the applications of a three-node prototype model to calculate benefits resulting from a transmission expansion under the impact of long-term contract covering and strategic bidding. We use this 3-node prototype model to demonstrate how we simulate a power system, calculate and apply markup, calculate benefit, and how we conduct benefit tests.

Figure AB.1 shows the 3-node system. There are nine generation units connected to Node 1, three units to Node 2, and four units to Node 3. Table AB.1 summarizes the supply/demand balance of the system. Table AB.2 summarizes the characteristics of the generation units. Table AB.3 summarizes transmission line limits for both the without expansion and with expansion cases. We assume the transmission lines have equal impedance and, and for simplicity, the upgraded line had equal impedance with and without upgrade[1]. In the simulation, we modeled only the inter-nodal transmission lines (colored in blue). We construct this example with the three most important systems in the West in mind. Node 1 is the California area, Node 2 is the Northwest area, and Node 3 is the Southwest area. Generation capacity and load were proportionally scaled down by a factor of 1/10th.

[1] An increase in thermal capacity without a change in impedance could occur, for instance, if a transformer limitation is removed. In general, however, an increase in capacity due to re-conducting or addition of another circuit would lower impedance at the same time it increases capacity.

Figure AB.1 The 3-Node System

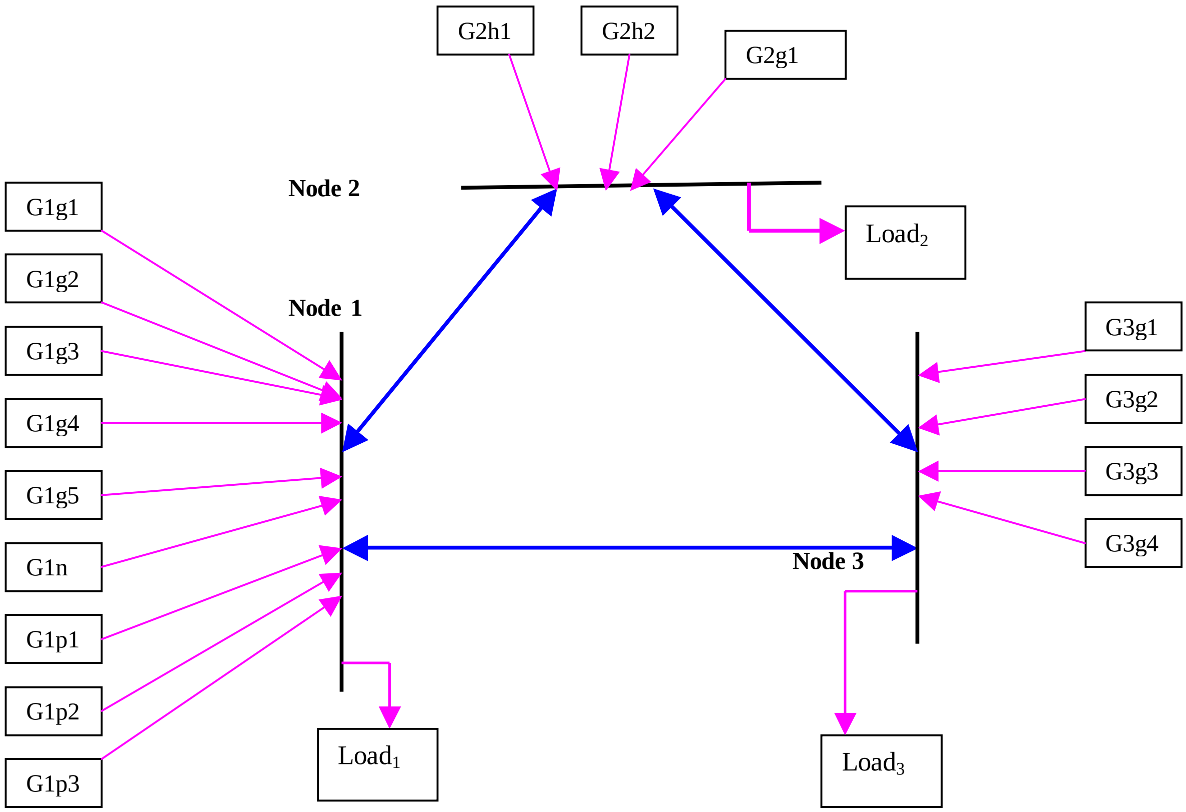

Table AB.1 Supply/Demand Balance in the 3-Node System

	Installed Capacity (MW)	Load (MW)
Node 1	5,000	6,000
Node 2	3,500	2,700
Node 3	2,000	1,500
System Total	**10,500**	**10,200**

Table AB.2 Generation Characteristics in the 3-Node Example

Node	Generator	Type	Installed Capacity (MW)	Marginal Cost ($/MWh)	Is it a UDC generator?	Is it a strategic generator?[2]
1	G1g1	Gas	500	20	No	Yes
	G1g2	Gas	500	22	No	Yes
	G1g3	Gas	400	30	No	Yes
	G1g4	Gas	400	40	No	Yes
	G1g5	Gas	400	50	No	Yes
	G1p1	Gas	100	60	No	Yes
	G1p2	Gas	100	70	No	Yes
	G1p3*	Gas	600	40	No	Yes
	G1n	Nuclear	2000	10	Yes	No
2	G2h1	Hydro	1500	10	Yes	No
	G2h2	Hydro	1500	10	Yes	No
	G2g1*	Gas	500	20 (0 – 250 MW) 30 (250 – 500 MW)	No	No
3	G3g1	Gas	500	22 (0 – 250 MW) 30 (250 – 500 MW)	Yes	No
	G3g2	Gas	400	18	Yes	No
	G3g3*	Gas	600	20	No	No
	G3g4	Gas	500	20	No	No

Note: Generators colored in red are the largest non-UDC generators at each node.

Table AB.3 Transmission Line Limits in the 3-Node Example

Line	From Node	To Node	Bi-Directional OTC (MW)	
			Without Expansion	With Expansion
L1-2	**Node 1**	**Node 2**	600	650
L1-3	**Node 1**	**Node 3**	1000	1000
L2-3	**Node 2**	**Node 3**	9999	9999

AB.2 Transmission Expansion Benefit: No Markup and No Contract

Figure AB.2 and AB.3 depict the marginal cost simulation results for the non-expansion and expansion cases with a marginal cost bidding assumption.

[2] A non-UDC generator could be a strategic generator (i.e., often bidding above marginal cost) or a non-strategic generator (i.e., always bid marginal cost). In this example, we assume all non-UDC generators at Bus 1 are strategic. Furthermore due to lack of information on strategic bidding, we treat all generators other than those in the CAISO region as non-strategic in both this example and in our Path 26 study.

Figure AB.2 No Expansion, No Markup

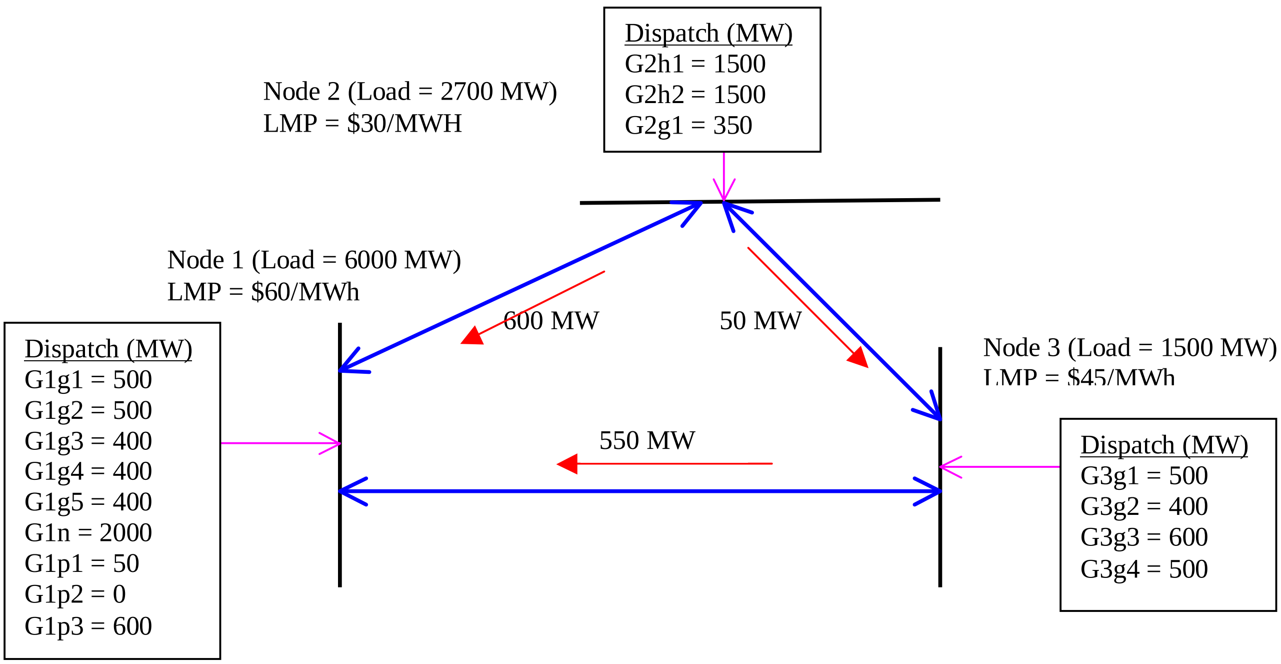

Figure AB.3 Expansion of L1-3, No Markup

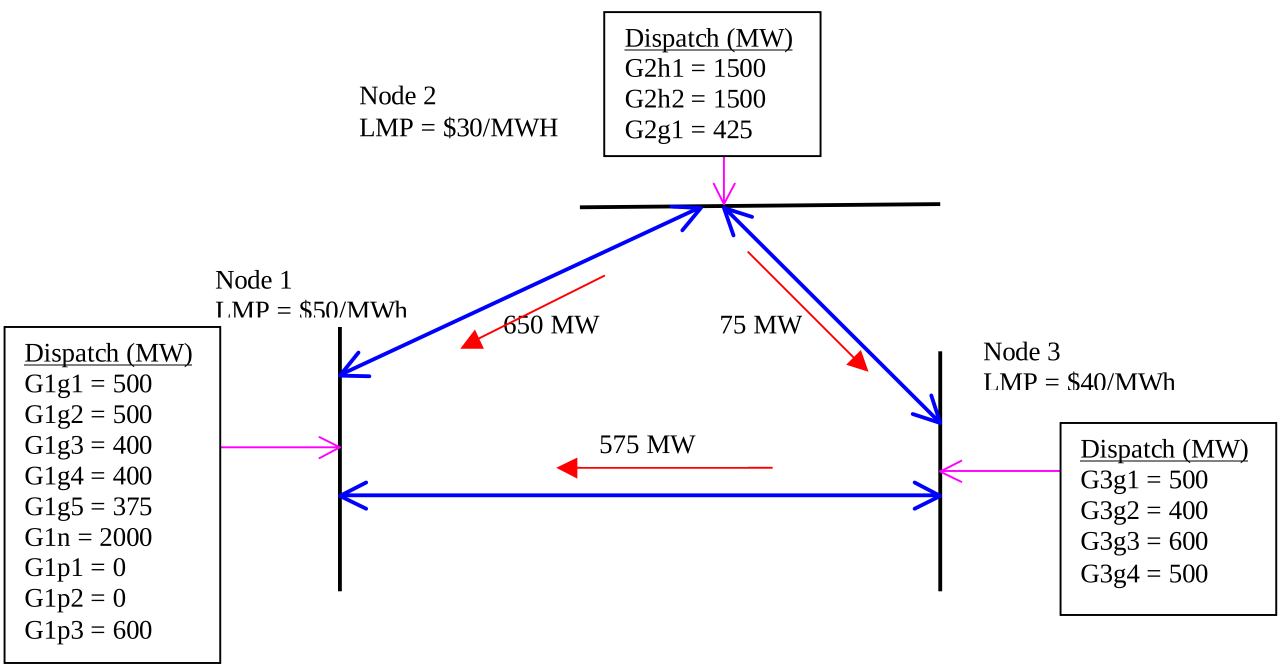

Table AB.4 compares the without and with case.

Table AB.4 Simulation Results: No Markup, No Contract Covering

			Without Expansion	With Expansion	Δ Change
LMP ($/MWh)		Node 1	$60	$50	-$10
		Node 2	$30	$30	$0
		Node 3	$45	$40	-$5
Line Flow (MW)		L1-2	600 MW (Node 2->1)	650 MW (Node 2->1)	+ 50 MW (Node 2->1)
		L1-3	550 MW (Node 3->1)	575 MW (Node 3->1)	+ 25 MW (Node 3->1)
		L2-3	50 MW (Node 2-> 3)	75 MW (Node 2->3)	+ 25 MW (Node 2->3)
Dispatch (MW)	Node 1	G1g1	500	500	0
		G1g2	500	500	0
		G1g3	400	400	0
		G1g4	400	400	0
		G1g5	400	375*	-25
		G1n	2,000	2,000	0
		G1p1	50*	0	-50
		G1p2	0	0	0
		G1p3	600	600	0
		Total	**4,850**	**4,775**	**-75**
	Node 2	G2h1	1500	1500	0
		G2h2	1500	1500	0
		G2g1	350*	425*	+75
		Total	**3,350**	**3,425**	**+75**
	Node 3	G3g1	500	500	0
		G3g2	400	400	0
		G3g3	600	600	0
		G3g4	500	500	0
		Total	**2,000**	**2,000**	**0**

Signifies the marginal generator that sets prices. In the absence of degeneracy, when one transmission constraint is binding, two generators will be marginal.

Table AB.5 and Table AB.6 show the benefits of upgrading the capacity of L1-3 from 600 MW to 650 MW.

Table AB.5 Surpluses without and with expansion: No Markup with No Contract Covering

			Without Expansion	With Expansion	Net Change
Cost-to-Load	Node 1		$60*6000 = $360,000	$50*6000 = $300,000	-$60,000
	Node 2		$30*2,700 = $81,000	$30*2,700 = $81,000	+$0
	Node 3		$45*1,500 = $67,500	$40*1,500 = $60,000	-$7,500
	Total		**$508,500**	**$441,000**	**-$67,500**
Producer Revenue	Node 1	Non-UDC Generators	$60*2850 = $171,000	$50*2775 = $138,750	-$32,250
		UDC Generator	$60*2,000 = $120,000	$50*2,000 = $100,000	-$20,000
		Total	$291,000	$238,750	-$52,250
	Node 2		$30*3,350 = $100,500	$30*3,425 = $102,750	+$2,250
	Node 3		$45*2,000 = $90,000	$40*2,000 = $80,000	-$10,000
	Total		**$481,500**	**$421,500**	**-$60,000**
Producer Cost	Node 1	Non-UDC generators	$96,000	$91,750	-$4,250
		UDC Generator	$20,000	$20,000	$0
		Total	$116,000	$111,750	-$4,250
	Node 2		$38,000	$40,250	+$2,250
	Node 3		$42,200	$42,200	$0
	Total		**+$196,200**	**+194,200**	**-$2,000**
Producer Surplus = PR - PC	Node 1	Non-UDC Generators	+$75,000	+$47,000	-$28,000
		UDC Generator	+ $100,000	+ $80,000	-$20,000
		Total	$175,000	$127,000	-$48,000
	Node 2		+ $62,500	$62,500	+$0
	Node 3		+$47,800	$37,800	-$10,000
	Total		**+285,300**	**+227,300**	**-$58,000**
Congestion Revenue	Total		$30*600 + $15*550 + $15*50 = $27,000	$20*650 + $10*575 + $10*75 = $19,500	-$7,500

Table AB.6 Expansion Benefit: No Markup and with No Contract Covering

Benefit		**Node 1**	**Node 2**	**Node 3**	**System Total**
ΔCS = -ΔCTL		+$60,000	+ $0	+$7,500	+$67,500
ΔPR	Non-UDC Generator	-$32,250			
	UDC Generator	-$20,000			
	Total	**-$52,250**	**+$2,250**	**-$10,000**	**-$60,000**
ΔPC	Non-UDC Generator	-$4,250			
	UDC Generator	$0			
	Total	**-$4,250**	**+$2,250**	**$0**	**-$2,000**
ΔPS = ΔPR – ΔPC	Non-UDC Generator	-$28,000			
	UDC Generator	-$20,000			
	Total	**-$48,000**	**+$0**	**-$10,000**	**-$58,000**
ΔCR					-$7,500
SB = ΔCS + ΔPS + ΔCR					**+$2,000**

In developing our CAISO Methodology, we stated that for any project, we would evaluate the project from different perspectives. We might evaluate the project using different criteria, depending on the extent of the project's impact on the system and what parties will be responsible for funding the project. We proposed four possible tests from various perspectives: Societal Test, Modified Societal Test, CAISO Ratepayers Test, and CAISO Participants Test. The Societal Test uses the perspective of the entire system (inter-connection). It evaluates a project based on how much total production cost saving it can bring to the entire system and compares the benefit with the project cost. If a project's cost (O&M cost and capital cost) is $500 for example and the total production cost saving to the entire system due to upgrade is $2,000, then the Societal Test would calculate a net benefit of $1,500 for the upgrade project ($2,000 - $500).

Some may argue that we should not include producers' monopoly rents in the producer surplus calculation, because we do not want to encourage generators to bid above their marginal costs. We proposed an alternative societal test – the Modified Societal Test, where monopoly rents are not included in the producer surplus calculation and any change in monopoly rents is not included in the producer benefit calculation. In a case where all generators bid their marginal costs (i.e., no markup), the Modified Societal Test will be the same as the Societal Test.

It is likely that a project approved by the CAISO will be paid by all ISO ratepayers through the PTO's revenue requirements. Because of this, we proposed a third evaluation criterion - the CAISO Ratepayers Test. In this test, we only include the benefit to the ISO ratepayers. This includes all LSEs and utility-retained generation. More specifically, this test includes the CAISO's consumer benefit, UDC generation's producer benefit, and PTOs' transmission owner benefit. In this particular example, Bus 1 is the ISO and the total consumer benefit at Bus 1 is $6,000, the total UDC-generation's producer benefit is -$2,000, and the ISO PTOs' transmission owner benefit (by owning L1-2 and L1-3) is -$7,500. The total CAISO ratepayers' benefit is $13,750.

AN argument can be made that when the CAISO approves a project it should consider all participants' benefit from the upgrade, not just the benefit to CAISO ratepayers. Therefore, we proposed a fourth test – the CAISO Participants Test. This test includes all CAISO participants' benefit (but not monopoly rent benefit), CAISO consumer's benefit, all generators' competitive rent benefit, and PTOs' transmission owner benefits. Table AB.7 shows the results for the four alternative tests:

Table AB.7 Four Proposed Tests: No Markup and With Contract

	Societal Test	Modified Societal Test	ISO Ratepayers Test	ISO Participants Test
Exp. Benefit	+$2,000	+$2,000	+$60,000 – $20,000 - $7,500 = +$32,500	+$60,000 - $48,000 - $7,500[3] = +$4,500
Cost	$500	$500	$500	$2,000
Net Benefit	+$1,500	+$1,500	+$32,000	+$2,500

The CAISO total participants' benefit is negative in this case because generators' more expensive resources at Bus 1 are replaced by cheaper imports when the line is upgraded. Thus both types of generators at Bus 1 are harmed by expansion in this example.

AB.3 Transmission Expansion: No Markup and With Contract Covering

Assume $Load_1$ is assigned long-term contracts with all non-UDC generators at Node 1 for 5 percent of their installed capacity at a fixed price **$59/MWh**. In other words, 1,500 MW of $Load_1$ is covered by long-term contract with non-UDC generators, and another 2,000 MW is covered by its own generation. Table AB.8 shows the contract amount for these generators. The last two columns of Table 8 show physical dispatch amounts for both the case without expansion and the one with expansion. If a generator dispatches less than its contract requirement, it has to purchase from the spot market to cover its position. In the case of expansion, G1p1 and G1p2 are not economic, thus their contract obligation of 50 MW each is purchased from the spot market. In addition we assume $Load_2$ and $Load_3$ didn't assign any long-term contract.

[3] Congestion revenue on L2-3 happens to be the same without and with upgrading of L1-2 in this example. Thus the CAISO's congestion revenue is the same as the total congestion revenue in this case. However this does not hold in general.

Table AB.8 Long-Term Contract Between Non-UDC Generators at Node 1 and $Load_1$

	Installed Capacity (MW)	Contract Amount with $Load_1$ (MW)	No Expansion Dispatch (MW)	With Expansion Dispatch (MW)
G1g1	500	250	500	500
G1g2	500	250	500	500
G1g3	400	200	400	400
G1g4	400	200	400	400
G1g5	400	200	400	300
G1p1	100	50	100	0
G1p2	100	50	100	0
G1p3	600	300	600	600
Non-UDC Total	3,000	1,500	3,000	2,700

We assumed that long-term contracting won't affect the dispatch of generation, nor the total transmission expansion benefit, but will affect the distribution of the benefit. Table AB.9 and Table AB.10 show the transmission expansion benefit with LTC.

Table AB.9 Surpluses without and with expansion: No Markup With Contract Covering

			Without Expansion	With Expansion	Net Change
Cost-to-Load	Node 1		CTL for un-covered load = \$60*4,500 = \$270,000 Fixed Contract Cost to Load = \$59*1,500 = \$88,500 Total CTL = \$358,500	CTL for un-covered load = \$50*4,500 = \$225,000 Fixed Contact Cost to Load = \$59*1,500 = \$88,500 Total CTL = \$313,500	-\$45,000
	Node 2		\$30*2,700 = \$81,000	\$30*2,700 = \$81,000	+\$0
	Node 3		\$45*1,500 = \$67,500	\$40*1,500 = \$60,000	-\$7,500
	Total		**\$507,000**	**\$454,500**	**-\$52,500**
Producer Revenue	Node 1	Non-UDC Generators	Gross Revenue from Spot Market = \$60*2,850 = \$171,000 Contract CFD = (\$59-\$60)*1,500 = -\$1,500 Total = \$169,500	Gross Revenue from Spot Market = \$50*2,775 = \$138,750 Contract CFD = (\$59-\$50)*1,500 = +\$13,500 Total = \$152,250	-\$17,250
		UDC Generator	\$60*2,000 = \$120,000	\$50*2,000 = \$100,000	-\$20,000
		Total	\$289,500	\$252,250	-\$37,250
	Node 2		\$30*3,350 = \$100,500	\$30*3,425 = \$102,750	+\$2,250
	Node 3		\$45*2,000 = \$90,000	\$40*2,000 = \$80,000	-\$10,000
	Total		**\$480,000**	**\$435,000**	**-\$45,000**
Producer Cost	Node 1	Non-UDC generators	\$96,000	\$91,750	-\$4,250
		UDC Generator	\$20,000	\$20,000	\$0
		Total	\$116,000	\$111,750	-\$4,250
	Node 2		\$38,000	\$40,250	+\$2,250
	Node 3		\$42,200	\$42,200	\$0
	Total		**+\$196,200**	**+194,200**	**-\$2,000**

Producer Surplus = PR - PC	Node 1	Non-UDC Generators	+ $73,500	$60,500	-$13,000
		UDC Generator	+ $100,000	$80,000	-$20,000
		Total	+$173,500	+$140,500	-$33,000
	Node 2		+$62,500	+$62,500	+$0
	Node 3		+$47,800	+$37,800	-$10,000
	Total		**+283,800**	**+240,800**	**-$43,000**
Congestion Revenue	Total		$30*600 + $15*550 + $15*50 = $27,000	$20*650 + $10*575 + $10*75 = $19,500	-$7,500

Table AB.10 Expansion Benefit: No Markup and With Contract Covering

Benefit		**Node 1**	**Node 2**	**Node 3**	**System Total**
$\Delta CS = -\Delta CTL$		+$45,000	+$0	+$7,500	+$52,500
ΔPR	Non-UDC Generator	-$17,250			
	UDC Generator	-$20,000			
	Total	**-$37,250**	**+$2,250**	**-$10,000**	**-$45,000**
ΔPC	Non-UDC Generator	-$4,250			
	UDC Generator	$0			
	Total	**-$4,250**	**+$2,250**	**$0**	**-$2,000**
$\Delta PS = \Delta PR - \Delta PC$	Non-UDC Generator	-$13,000			
	UDC Generator	-$20,000			
	Total	**-$33,000**	**+$0**	**-$10,000**	**-$43,000**
ΔCR					-$7,500
$SB = \Delta CS + \Delta PS + \Delta CR$					**+$2,000**

This example shows the following:

1. Total societal benefit from transmission expansion, if measured as the sum of all market participants' benefit, stays the same even if $Load_1$ signs long-term contact with NGO generators. ***In other words, long-term contracting does not affect the total societal benefit from transmission expansion, because the total production cost saving remains the same regardless of contract covering.***

2. Contract covering has a significant impact on transmission benefit distribution among various market participants.

3. Non-UDC producers at Node 1 lose from transmission expansion, but they lose less if they are partially hedged comparing to having no contract at all. We assumed that if a long-term contract were already in place, it would be in place regardless whether the line is upgraded or not. Signing long-term contract with load prior to transmission upgrade may provide insurance to non-UDC generators against potential price decreases due to transmission expansion.

Table AB.11 shows the results for the four tests:

Table AB.11 Four Proposed Tests: No Markup and With Contract

	Societal Test	Modified Societal Test	ISO Ratepayers Test	ISO Participants Test
Exp. Benefit	+$2,000	+$2,000	+$45,000 – $20,000 - $7,500 = + $17,500	+$45,000 - $33,000 - $7,500 = +$4,500
Cost	$500	$500	$500	$500
Net Benefit	+$1,500	+$1,500	+$17,000	+$4,000

Again the CAISO Ratepayers' Test is affected significantly by contract position of the load. The CAISO Participants Test is not affected by the contract because we assumed the contract is between the CAISO load and the non-UDC generation in the same region thus the net effect is canceled out.

AB.4 Transmission Expansion: With Markup and Without Contract Covering

Generators may bid above their marginal costs to exercise market power or to recover their fixed cost. Our RSI regression analysis establishes a statistical relationship between regional price-cost markups and system conditions based on historical data. Using hourly data from November 1999 – October 2000 and January 2003 – December 2003, we estimated the following regression:[4]

Lerner-Index = 0.14 – 0.53****RSI*** + 0.65****% of Load Un-hedged*** + 0.086****Peak Hour Dummy*** + 0.15****Summer Month Dummy.***

The definitions of the variables are:

(1) ***Lerner Index*** = $(P^m - P^c)/P^m$

Where P^m = Market Price,

P^c = Competitive Market Price if all generators bid their marginal costs.

(2) ***RSI*** = (A + B – C + D)/E

Where A = Total Regional Available Capacity

= Total Regional Capacity – Total Regional Capacity on Outages;

B = Maximum Importing Amount to the region in the Last 30 days;

C = The Largest Strategic Supplier's Available Capacity

= The Largest Strategic Supplier's Total Capacity – It's Capacity on Outages;

D = Long-Term-Contract Amount of the Largest Supplier;

E = Total Regional Load.

(3) ***Fraction of Load Un-Hedged*** = (E – F – G)/E

[4] Note that we have several alternative functional forms for regression analysis. Here I just listed one option.

Where F = Total UDC Available Generation Capacity;
G = Total State Long-Term-Contract in that region.

The relationship between Lerner Index and Price-Cost markup is

Price-Cost Markup = Lerner Index / (1 – Lerner Index),

where Price-Cost Markup = $(P^m - P^c)/P^c$. The purpose of applying the RSI regression prospectively is to predict price-cost markups for the importing region and use price-cost markups as generators' bid-cost markups where the internal supply cannot meet load and some of its internal generators are pivotal and have incentive to bid above marginal costs. Our historical experience suggests that a RSI value > 1.2 is usually a good indication of markup. Table AB.12 shows how we calculate regression variables required for predicting zonal price-cost markups.

Table AB.12 Calculation of Variables and Price-Cost Markups: the Case of No Contract

		Node 1	**Node 2**	**Node 3**
Largest Strategic Suppler and its capacity		G1p3 600 MW	G2g1 500 MW	G3g3 600 MW
Import Capability	**Without Expansion**	600 + 550 = 1,150 MW	500 + 9,999 = 10,499 MW	1,000 + 9,999 = 10,999 MW
	With Expansion	700 + 600 = 1,300 MW	700 + 9999 = 10,699 MW	1,000 + 9999 = 10,999 MW
Installed Capacity		5,000 MW	3,500 MW	2,000 MW
Load		6,000 MW	2,700 MW	1,500 MW
RSI Calculated	**Without Exp.**	=(5000 + 1150 – 600)/6000 = 0.925	>> 1.2	>> 1.2
	With Exp.	=(5000+1300 – 600)/6000 = 0.95	>> 1.2	>> 1.2
Fraction of Load Un-hedged		=(6000-2000)/6000 = 0.667	>> 100%	>> 100%
Predicted Lerner Index[5]	**Without Exp.**	0.3193		
	With Exp.	0.3061		
Predicted Price-cost Markup	**Without Exp.**	46.91%		
	With Exp.	44.10%		

We used the zonal RSI analysis-derived price-cost markup as the nodal bid-cost markup of strategic generators at Node 1. There are two approaches to apply the derived price-cost markup as bid-cost markup: apply to all strategic generators uniformly or apply to all strategic generators proportionally according to their capacity. We demonstrate here how the proportional approach works: each strategic generator's bid-cost markup is proportionally to its capacity according to its capacity share relative to the largest strategic supplier's capacity share. Table AB.13 shows how we derive bid-cost markups for each strategic generator at Node 1.

5 We assume in this example that the time is the peak hour in a summer month.

Table AB.13 Calculation of Bid Prices: the Case of No Contract

Generator at Node 1	Capacity (MW)	Marginal Cost ($/MWh)	Capacity Share	Without Expansion		With Expansion	
				Markup Applied	Bid Price Derived ($/MWh)	Markup Applied	Bid Price Derived ($/MWh)
G1g1	500	20	16.7%	=(16.7%/20%)*46.91% = 39.1%	= 1.391*20 = 27.8	=(16.7%/20%)*44.1% = 36.8%	27.4
G1g2	500	22	16.7%	39.1%	30.6	36.8%	30.1
G1g3	400	30	13.3%	31.3%	39.4	29.4%	38.8
G1g4	400	40	13.3%	31.3%	52.5	29.4%	51.8
G1g5	400	50	13.3%	31.3%	65.6	29.4%	64.7
G1p1	100	60	3.3%	7.8%	64.7	7.4%	64.4
G1p2	100	70	3.3%	7.8%	75.5	7.4%	75.1
G1p3	600	40	20.0%	=(20.0%/20%)*46.91% = 46.91%	58.8	=(20%/20%)*44.1%= 44.1%	57.6
Total Strategic Generators	3000						

Table AB.14 shows the simulation results using the derived bid prices above. The only difference between Table AB.14 and Table AB.4 (competitive simulation results) is the nodal LMPs.[6]

[6] It is, however, true in generally that the dispatch might be different with markup than without markup, and likewise with the flows. (This can happen if a large company marks its bids up so far that one of its infra-marginal units becomes marginal or doesn't run at all. However, the flows might not change if the import constraints are binding in the base case; higher markups in the importing region in that situation cannot increase imports.) This example is just a special case.

Table AB.14 Simulation Results: With Markup and No Contract Covering

			Without Expansion	With Expansion	Δ Change
LMP ($/MWh)		Node 1	$65.64	$64.70	-$0.94
		Node 2	$30	$30	$0
		Node 3	$47.82	$47.35	-$0.47
Line Flow (MW)		L1-2	600 MW (Node 2->1)	650 MW (Node 2->1)	+ 50 MW (Node 2->1)
		L1-3	550 MW (Node 3->1)	575 MW (Node 3->1)	+ 25 MW (Node 3->1)
		L2-3	50 MW (Node 2->3)	75 MW (Node 2->3)	+ 25 MW (Node 2->3)
Dispatch (MW)	Node 1	G1g1	500	500	0
		G1g2	500	500	0
		G1g3	400	400	0
		G1g4	400	400	0
		G1g5	350*	275*	-75
		G1n	2,000	2,000	0
		G1p1	100	100	0
		G1p2	0	0	0
		G1p3	600	600	0
		Total	**4,850**	**4,775**	**-75**
	Node 2	G2h1	1500	1500	0
		G2h2	1500	1500	0
		G2g1	350*	425*	+75
		Total	**3,350**	**3,425**	**+75**
	Node 3	G3g1	500	500	0
		G3g2	400	400	0
		G3g3	600	600	0
		G3g4	500	500	0
		Total	**2,000**	**2,000**	**0**

Table AB.15 and AB.16 summarize the expansion benefit with markup to various market participants assuming no-contract covering. Table AB.16 confirms that the total societal benefit from transmission expansion equals the total production cost saving even when market is not perfectly competitive; this is necessarily true when there is no demand elasticity.

Table AB.15 Expansion Benefit: With Markup and Without Contract Covering

			Without Expansion	**With Expansion**	**Net Change**
Cost-to-Load	Node 1		$65.64*6000 = $393,840	$64.7*6000 = $388,200	-$5,640
	Node 2		$30*2,700 = $81,000	$30*2,700 = $81,000	+$0
	Node 3		$47.82*1,500 = $71,730	$47.35*1,500 = $71,025	-$705
	Total		**$546,570**	**$540,225**	**-$6,345**
Producer Revenue	Node 1	Non-UDC Generators	$65.64*2850 = $187,074	$64.7*2775 = $179,543	-$7,532
		UDC Generator	$65.64*2,000 = $131,280	$64.7*2,000 = $129,400	-$1,880
		Total	$318,354	$308,943	-$9,412
	Node 2		$30*3,350 = $100,500	$30*3,425 = $102,750	+$2,250
	Node 3		$47.82*2,000 = $95,640	$47.35*2,000 = $94,700	-$940
	Total		**$514,494**	**$506,393**	**-$8,102**
Producer Cost	Node 1	Non-UDC generators	$96,500	$92,750	-$3,750
		UDC Generator	$20,000	$20,000	$0
		Total	$116,500	$112,750	-$3,750
	Node 2		$38,000	$40,250	+$2,250
	Node 3		$42,200	$42,200	$0
	Total		**+$196,700**	**+195,200**	**-$1,500**
Producer Surplus = PR - PC	Node 1	Non-UDC Generators	+$90,574	+$86,793	-$3,781
		UDC Generator	+ $111,280	+ $109,400	-$1,880
		Total	$201,854	$196,193	-$5,661
	Node 2		+ $62,500	$62,500	+$0
	Node 3		+$53,440	$52,500	-$940
	Total		**+317,794**	**+311,193**	**-$6,601**
Monopoly Rent (MR)[7]	Node 1 Strategic Generators		($65.64 - $60)*2,850 = $16,074	($64.7 - $50)*2,775 = $40,793	$24,719
Competitive Rent (ComR)[8]	Node 1 Strategic Generators		$90,574 - $16,074 = $74,500	$86,793 - $40,793 = $46,000	-$28,500
Congestion Revenue	Total		$34.64*600 + $16.82*550 + $17.82*50 = $32,076	$34.7*650 + $17.35*575 + $17.35*75 = $33,833	+$1,757

[7] Monopoly Rent is the excess profit strategic generators receive above what they would receive if they bid their marginal costs. We approximate monopoly rent with $MR \cong (p^m - p^c)*q^m$, where p^m is a (strategic) generator's locational marginal price if all strategic generators bid strategically (i.e., markup), and p^c is the generator's LMP if all generators bid marginal costs, and q^m is the generator's dispatch with markup. For non-strategic generators, we assume monopoly rent to be zero.

[8] Competitive Rent is the difference between producer surplus and monopoly rent for a strategic generator. For non-strategic generators, competitive rent is the same as producer surplus.

Table AB.16 Benefits from Upgrade: Markup and No Contract Covering

Benefit		**Node 1**	**Node 2**	**Node 3**	**System Total**
ΔCS = -ΔCTL		+$5,640	$0	+$705	+$6,345
ΔPR	Non-UDC Generator	-$7,532			
	UDC Generator	-$1,880			
	Total	**-$9,412**	**+$2,250**	**-$940**	**-$8,102**
ΔPC	Non-UDC Generator	-$3,750			
	UDC Generator	$0			
	Total	**-$3,750**	**+$2,250**	**$0**	**-$1,500**
ΔPS = ΔPR – ΔPC	Non-UDC Generator	-$3,781			
	UDC Generator	-$1,880			
	Total	**-$5,661**	**+0**	**-$940**	**-$6,601**
ΔMR		**+$23,898**	**$0**	**$0**	**+$23,616**
ΔComR		-$28,500-$1,880 = **-$30,380**	**+$0**	**-$940**	**-$31,320**
ΔCR					+$1,757
SB = ΔCS + ΔPS + ΔCR					**+$1,500**

Comparing Table AB.16 and Table AB.6 (benefit under competitive case), we can see generators' ability to bid above their marginal costs change the distribution of total benefit among consumers, producers, and transmission owners.[9] Table AB.17 below shows the differences in participants' benefit between the competitive case and the markup case.

Table AB.17 Comparing Benefits Between Competitive and Markup: the Case of No Contract

	Competitive Case	**Markup Case**	**Difference due to Markup**
Consumer Benefit (ΔCS)	+$67,500	+$6,345	-$61,155
Producer Benefit (ΔPS)	**-$58,000**	-$6,601	+$51,399
Transmission Owner Benefit (ΔCR)	-$7,500	+$1,757	+$9,257
Total Societal Benefit (ΔSB)	+$2,000	+$1,500	-$500

Consumers could benefit a lot more from transmission upgrade if generators bid their marginal costs. (This, however, is not necessarily always the result; under other circumstances, consumers might benefit more in the noncompetitive solution.) Conversely, producers lose a lot less from transmission upgrade if they were able to bid above marginal costs. Transmission owners (or CRR holders) in this particular example, receive a benefit from transmission upgrade due to the generators' markup. Table AB.18 shows the results of the four proposed benefit tests with markup and without contract.

[9] It is very likely that the total societal benefit under markup case might be different than that under the competitive case. In this particular example, since dispatches under the competitive case and under the markup case stay the same, the total societal benefits are the same in either case.

Table AB.18 Four Proposed Tests: With Markup and Without Contract

	Societal Test	Modified Societal Test	ISO Ratepayers Test	ISO Participants
Exp. Benefit	+$1,500	+$6,345 – $31,320 + $1,757 = -$23,218	+$5,640 – $1,880 + $2,496 = +$6,256	+$5,640 - $30,380 + $2,496 = -$22,244
Cost	$500	$500	$500	$500
Net Benefit	+$1,000	-$23,718	+$5,756	-$22,744

AB.5 Summary

The calculations performed above demonstrated that both markup and contract covering have significant impacts on the individual market participant’s benefit, as well as on benefit tests results. How contract covering and markups affect total benefit and its distribution should be studied on a case-to-case basis. We caution the readers to be very careful not to generalize the results from this particular example. It is critical to do a thorough calculation for any given market situation similar to what we demonstrated here.

ATTACHMENT 4
OF
PHASE 1 OPENING TESTIMONY ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR
October 21, 2005
A.05-04-015
I.05-06-041

Appendix C

Table AC.1 Summary of Thermal Resources by Technology

	Nuclear	Coal	Geothermal	New CCCT Gas Fire HtRt<7500	Older CCCT Gas (or Oil) Ca.9000	"Good" SCCT/ST 9500-10500	HHR SCCT/ST >10500	Other	Total Area
Model Areas									
ALBERTA	0	5,898	0	2,441	0	1,417	295	41	**10,092**
AQUILA	0	0	0	0	0	0	0	0	**0**
ARIZONA	3,733	5,311	0	7,568	776	877	1,555	0	**19,820**
B.C.HYDR	0	0	0	250	0	1,000	1,000	60	**2,310**
IDAHO	0	2,110	0	0	0	0	0	0	**2,110**
IMPERIAL	0	0	283	78	295	0	0	50	**706**
LADWP	0	1,710	0	574	0	2,370	431	0	**5,085**
MEXICO-C	0	0	675	1,100	428	465	60	0	**2,728**
MONTANA	0	2,311	0	0	0	0	0	39	**2,350**
NEVADA	0	595	0	3,022	298	603	227	0	**4,745**
NEW MEXI	0	1,885	0	0	0	713	412	0	**3,010**
NORTHWES	1,170	1,938	0	4,354	495	812	628	272	**9,669**
PACE	0	4,612	23	0	0	345	235	53	**5,268**
PG AND E	2,192	90	985	7,474	372	6,222	1,468	275	**19,078**
PSCOLORA	0	1,938	0	913	19	3,392	278	0	**6,540**
SANDIEGO	0	0	0	764	65	1,788	539	0	**3,156**
SIERRA	0	532	47	0	20	978	12	100	**1,689**
SOCALIF	2,167	97	56	2,303	1,176	6,294	2,767	0	**14,860**
WAPA L.C	0	0	0	1,710	0	0	0	0	**1,710**
WAPA R.M	0	3,546	0	480	116	778	143	0	**5,063**
WAPA U.M	0	0	0	0	0	0	0	0	**0**
Total By Type	**9,262**	**32,573**	**2,069**	**33,031**	**4,060**	**28,054**	**10,050**	**890**	**119,989**

Table AC.2 Resource Additions since 1/1/2000

Facility	Location	Technology	Fuel Type	# of Units	Output (MW)	Est Online Date
On or before 1/1/04					**35,458**	**1/1/2004**
Silver Hawk	Nevada	Combined	Gas	0	570	5/1/2004
Pastoria Phase 2	California	Combined	Gas	0	500	6/1/2004
Grande Prairie	Canada-Alberta		Wood Waste	0	25	6/1/2004
Metcalf Energy Center	California	Combined	Gas	2-2-1	600	12/1/2004
Otay Mesa	California	Combined	Gas	2-2-2	510	12/1/2004
Sundance Upgrade II	Canada-Alberta		Coal	0	100	12/1/2004
Contra Costa	California	Combined	Gas	2-2-1	530	6/1/2005
Genesee Phase 3	Canada-Alberta		Coal	1	400	7/1/2005
Total Conventional Thermal Additions					**38,693**	

Sum of Output (MW)	Fuel Type					
Technology	Coal	F02	Gas	Geothermal	Woodwaste	Grand Total
Biomass					10	10
Cogeneration		20	876			896
Combined			25,022			25,022
Combustion			132			132
Geothermal				112		112
Simple			3,958			3,958
(blank)	1,014		7,465	59	25	8,563
Grand Total	1,014	20	37,453	171	35	38,693

Table AC.3 Major Interfaces - Number and Description

Path Number	Description
1	ALBERTA - BRITISH COLUMBIA
2	ALBERTA - SASKATCHEWAN
3	NORTHWEST - CANADA
4	WEST OF CASCADES - NORTH
5	WEST OF CASCADES - SOUTH
6	WEST OF HATWAI
8	MONTANA - NORTHWEST
9	WEST OF BROADVIEW
10	WEST OF COLSTRIP
11	WEST OF CROSSOVER
14	IDAHO - NORTHWEST
15	MIDWAY - LOS BANOS
16	IDAHO - SIERRA
17	BORAH WEST
18	IDAHO - MONTANA
19	BRIDGER WEST
20	PATH C
21	ARIZONA - CALIFORNIA
22	SOUTHWEST OF FOUR CORNERS
23	FOUR CORNERS 345_500
24	PG&E - SPP
25	PACIFICORP_PG&E 115 KV INTERCON.
26	Z6- Path 26
27	IPP DC LINE
28	INTERMOUNTAIN - MONA 345 KV
29	INTERMOUNTAIN - GONDER 230 KV
30	TOT 1A
31	TOT 2A
32	PAVANT INTRMTN - GONDER 230 KV
33	BONANZA WEST
34	TOT 2B
35	TOT 2C
36	TOT 3
37	TOT 4A
38	TOT 4B
39	TOT 5
40	TOT 7
41	SYLMAR - SCE
42	IID - SCE
43	NORTH OF SAN ONOFRE
44	SOUTH OF SAN ONOFRE
45	Z7-Path 45

Path Number	Description
46	Z2-WOR
47	SOUTHERN NEW MEXICO (NM1)
48	NORTHERN NEW MEXICO (NM2)
49	Z2-EOR
50	CHOLLA - PINNACLE PEAK
51	Z5-South of Navajo
52	SILVER PEAK - CONTROL 55 KV
53	BILLINGS - YELLOWTAIL
54	CORONADO - SILVER KING - KYRENE
55	BROWNLEE EAST
58	ELDORADO - MEAD 230 KV LINES
59	EAGLE MTN 230_161 KV - BLYTHE 16
60	INYO - CONTROL 115 KV TIE
61	LUGO - VICTORVILLE 500 KV LINE
62	ELDORADO - MCCULLOUGH 500 KV
63	PERKINS - MEAD - MARKETPLACE 500
64	MARKETPLACE - ADELANTO
65	PACIFIC DC INTERTIE (PDCI)
66	Z6-COI
73	NORTH OF JOHN DAY
75	MIDPOINT - SUMMER LAKE
76	ALTURAS PROJECT
77	Z8-Crystal - H Allen230 kV PS
78	TOT 2B1
79	TOT 2B2
179	Albuquerque Sum with caps
180	Albuquerque Sum without caps
500	Z2-SCIT
501	Z1-PV to Devers
502	WOR - N.Gila
503	WOR - IID230
504	WOR -n- Mc-Vic
505	WOR -n- El Dor to Lugo
506	Path 15 Borah W Summer
507	Combined 4a; 4b
508	PACI vs PDCI
509	Tot 2a; 2b; 2c Nomogram
510	Z1- Hassayampa - N. Gila
511	Z1- N. Gila - Imperial Valley
512	Z1-Imperial Valley to Miguel
513	Z1-North of Miguel
514	Z1-Miguel Bank No. 1

Path Number	Description
515	Z1-Miguel Bank No. 2
516	Z77-Devers Bank No. 1 (Post Outage)
517	Z20-Imperial Valley - Miguel 2
518	Z1-Imperial Valley - Ramona
519	Z2: South of Lugo
520	Z3-Mohave - Lugo
521	Z3- Eldorado - Lugo
522	Z3-Mccullgh - Victorville
523	Z3-Market Place - Adelanto
524	Z4-Perkins - Big Sandy
525	Z4-Peacock - Mead
526	Z4-Navajo - Crystal
527	Z4- Moenkopi - El Dorado
528	Z5-Navajo - Moenkopi
529	Z5-Navajo - Table Mesa
530	Z6-East of PV
531	Z77-Devers - San Bernardino 1(Post Outage)
532	Z77-Devers - San Bernardino 2 (Post Outage)

Path Number	Description
533	Z77-Devers - Vista 2 (Post Outage)
534	Z77-Devers - Vista 1 (Post Outage)
535	Z2-AZ/CA
536	Z2-AZ/NV
537	Z2-NV/CA
538	Z9-HA-Red Butte PS
539	Z9-Sigurd - Glen Canyon PS
540	Z9-Shiprock - Lost Canyon PS
541	Z9-Pinto - 4 Corners PS
542	Z8-Crystal - H Allen 500 kV PS
543	Adj-HA Phase Shifters
544	Adj- Perkins Phase Shifters
545	Adj- Crystal 500 kV Phase Shifters
546	Adj-Crystal 230 kV Phase Shifters
547	Z7-Imperial Valley - La Rosita
548	Z7- Miguel - Tijuana
549	Z1- Devers Bank No. 1

Table AC.4 Inflation and Natural Gas Price Forecast

Inflation Forecast and re-index to 2003

CED 2003			
GDP IMPLICIT PRICE DEFLATOR (2001 = 100)			
YEAR	Current INDEX	5/15/2002 ANNUAL GROWTH RATE	Ratio to 2003 $
2000	97.87	2.3%	0.95
2001	100.00	2.2%	0.97
2002	101.43	1.4%	0.99
2003	102.78	1.3%	1.00
2004	106.60	3.7%	1.04
2005	110.43	3.6%	1.07
2006	114.25	3.5%	1.11
2007	116.87	2.3%	1.14
2008	119.18	2.0%	1.16
2009	121.39	1.9%	1.18
2010	123.65	1.9%	1.20
2011	126.04	1.9%	1.23
2012	128.62	2.0%	1.25
2013	131.32	2.1%	1.28
2014	134.08	2.1%	1.30
2015	136.93	2.1%	1.33
2016	139.81	2.1%	1.36
2017	142.74	2.1%	1.39
2018	145.74	2.1%	1.42
2019	148.79	2.1%	1.45
2020	151.94	2.1%	1.48

Table AC.5 Natural Gas Price Forecast, 2008

Region Name	CEC Natural Gas Region	Ave. Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NEW MEXICO	average of EL Paso North- and South-NM	4.51	5.05	4.41	4.19	4.23	4.32	4.23	4.37	4.51	4.46	4.64	4.91	5.05
ARIZONA	average of EL Paso North- and South-AZ	4.51	4.41	4.41	4.05	4.60	4.60	4.60	4.14	4.23	4.78	4.51	5.09	4.64
NEVADA	Nevada South	4.83	4.79	4.83	4.44	4.93	4.69	4.88	4.49	4.69	4.93	5.22	5.46	4.97
WAPA L.C.	Nevada South	4.83	4.79	4.83	4.44	4.93	4.69	4.88	4.49	4.69	4.93	5.22	5.46	4.97
MEXICO-CFE	Rosarito	4.75	5.18	4.94	4.56	4.47	4.75	4.61	4.37	4.61	4.66	4.66	5.18	5.80
IMPERIAL	SDG&E	4.71	5.13	4.90	4.52	4.43	4.71	4.57	4.33	4.57	4.62	4.62	5.13	5.75
SANDIEGO	SDG&E	4.71	5.13	4.90	4.52	4.43	4.71	4.57	4.33	4.57	4.62	4.62	5.13	5.75
SOCALIF	So. Calif Prod	4.62	5.08	4.94	4.76	4.48	4.39	4.34	4.25	4.34	4.53	4.62	4.99	5.41
LADWP	SoCal Gas	4.71	5.18	5.04	4.85	4.57	4.47	4.43	4.33	4.43	4.62	4.71	5.09	5.51
PG AND E	PG&E	4.65	4.93	4.93	4.60	4.51	4.60	4.46	4.46	4.46	4.46	4.46	4.88	5.07
NORTHWEST	ave. of PNW and PNW-Coastal	4.68	3.18	3.88	4.68	5.94	6.32	3.56	4.73	4.68	5.19	4.21	4.49	5.10
B.C.HYDRO	British Columbia	4.29	5.28	4.55	3.78	3.99	3.73	3.56	3.52	3.56	3.73	4.29	5.19	5.23
AQUILA	Alberta	3.88	4.19	4.04	3.88	3.88	3.84	3.61	3.65	3.38	3.53	3.88	4.04	4.19
ALBERTA	Alberta	3.88	4.19	4.04	3.88	3.88	3.84	3.61	3.65	3.38	3.53	3.88	4.04	4.19
IDAHO	PNW	5.00	3.40	4.15	5.00	6.35	6.75	3.80	5.05	5.00	5.55	4.50	4.80	5.45
MONTANA	Montana	4.36	4.71	3.92	3.66	3.75	4.10	4.49	4.45	4.32	4.05	4.53	4.71	4.93
WAPA U.M.	Montana	4.36	4.71	3.92	3.66	3.75	4.10	4.49	4.45	4.32	4.05	4.53	4.71	4.93
SIERRA	Nevada North	5.04	4.99	5.04	4.64	5.14	4.89	5.09	4.69	4.89	5.14	5.44	5.70	5.19
PACE	Utah	4.29	4.63	4.68	4.63	4.50	4.29	4.20	4.08	3.52	3.78	4.20	4.63	5.36
PSCOLORADO	Colorado	4.31	4.65	3.88	3.62	3.71	4.05	4.44	4.40	4.27	4.01	4.48	4.65	4.87
WAPA R.M.	Colorado	4.31	4.65	3.88	3.62	3.71	4.05	4.44	4.40	4.27	4.01	4.48	4.65	4.87
Average		**4.53**	**4.68**	**4.48**	**4.29**	**4.48**	**4.57**	**4.33**	**4.32**	**4.32**	**4.44**	**4.56**	**4.90**	**5.11**

Table AC.6 Natural Gas Price Forecast, 2013

Region Name	CEC Source (#1)	Ave. Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NEW MEXICO	ave. of EL Paso North- and South-NM	5.54	6.20	5.42	5.15	5.20	5.31	5.20	5.37	5.54	5.48	5.70	6.03	6.20
ARIZONA	ave. of EL Paso North- and South-AZ	5.54	5.42	5.42	4.98	5.65	5.65	5.65	5.09	5.20	5.87	5.54	6.25	5.70
NEVADA	Nevada South	5.88	5.83	5.88	5.41	6.00	5.70	5.94	5.47	5.70	6.00	6.35	6.64	6.06
WAPA L.C.	Nevada South	5.88	5.83	5.88	5.41	6.00	5.70	5.94	5.47	5.70	6.00	6.35	6.64	6.06
MEXICO-CFE	Rosarito	5.82	6.34	6.05	5.59	5.47	5.82	5.65	5.35	5.65	5.70	5.70	6.34	7.10
IMPERIAL	SDG&E	5.76	6.28	5.99	5.53	5.41	5.76	5.59	5.30	5.59	5.64	5.64	6.28	7.03
SANDIEGO	SDG&E	5.76	6.28	5.99	5.53	5.41	5.76	5.59	5.30	5.59	5.64	5.64	6.28	7.03
SOCALIF	So. Calif Prod	5.69	6.26	6.09	5.86	5.52	5.41	5.35	5.23	5.35	5.58	5.69	6.15	6.66
LADWP	SoCal Gas	5.76	6.34	6.16	5.93	5.59	5.47	5.41	5.30	5.41	5.64	5.76	6.22	6.74
PG AND E	PG&E	5.62	5.96	5.96	5.56	5.45	5.56	5.40	5.40	5.40	5.40	5.40	5.90	6.13
NORTHWEST	ave. of PNW and PNW-Coastal	5.68	3.86	4.71	5.68	7.21	7.66	4.31	5.73	5.68	6.30	5.11	5.45	6.19
B.C.HYDRO	British Columbia	5.22	6.42	5.53	4.59	4.85	4.54	4.33	4.28	4.33	4.54	5.22	6.32	6.37
AQUILA	Alberta	4.70	5.08	4.89	4.70	4.70	4.65	4.37	4.42	4.09	4.28	4.70	4.89	5.08
ALBERTA	Alberta	4.70	5.08	4.89	4.70	4.70	4.65	4.37	4.42	4.09	4.28	4.70	4.89	5.08
IDAHO	PNW	6.02	4.09	5.00	6.02	7.65	8.13	4.58	6.08	6.02	6.68	5.42	5.78	6.56
MONTANA	Montana	5.20	5.62	4.68	4.37	4.47	4.89	5.36	5.30	5.15	4.84	5.41	5.62	5.88
WAPA U.M.	Montana	5.20	5.62	4.68	4.37	4.47	4.89	5.36	5.30	5.15	4.84	5.41	5.62	5.88
SIERRA	Nevada North	6.07	6.01	6.07	5.58	6.19	5.89	6.13	5.65	5.89	6.19	6.56	6.86	6.25
PACE	Utah	5.09	5.50	5.55	5.50	5.34	5.09	4.99	4.84	4.17	4.48	4.99	5.50	6.36
PSCOLORADO	Colorado	5.11	5.52	4.60	4.29	4.39	4.80	5.26	5.21	5.06	4.75	5.31	5.52	5.77
WAPA R.M.	Colorado	5.11	5.52	4.60	4.29	4.39	4.80	5.26	5.21	5.06	4.75	5.31	5.52	5.77
Average		**5.49**	**5.67**	**5.43**	**5.19**	**5.43**	**5.53**	**5.24**	**5.22**	**5.23**	**5.38**	**5.52**	**5.94**	**6.18**

Table AC.7 2008 and 2013 Generation Expansion Plan

					2008			2013		
	Renew. Resource Name (region name / type)	General Location	Capacity Factor (%)	Bus Location	Nameplate Capacity (MW)	Depend. Capacity (MW)	Renew. Energy / Year (gWh)	Nameplate Capacity (MW)	Depend. Capacity (MW)	Renew. Energy / Year (gWh)
California	PG&E-Geothermal 1	Siskiyou	90%	Cottonwood	107.5	107.5	847.5	67.5	67.5	532.2
	PG&E-Wind 1	Solano	35%	Vaca-Dixon	400.0	80.0	1,226.4	-	-	-
	PG&E-Geothermal 2	Modoc	90%	Round Mt.	18.8	18.8	147.8	67.5	67.5	532.2
	PG&E-Wind 2	Alameda	35%	Tesla	186.3	37.3	571.0	18.8	3.8	57.5
	PG&E-Biomass 1	PG&E	80%	Los Banos	35.0	35.0	245.3	33.8	33.8	236.5
	PG&E-Digester Gas 1	PG&E	85%	Los Banos	40.0	40.0	297.8	-	-	-
	IID-Geothermal 1	Imperial	90%	Devers	240.0	240.0	1,892.2	120.0	120.0	946.1
	IID-Biomass 1	Imperial	80%	Devers	57.5	57.5	403.0	35.2	35.2	246.4
	SCE-Wind 1	Kern	35%	Vincent	2,661.3	532.3	8,159.4	1,316.3	263.3	4,035.6
	SCE-Geothermal 1	Mono	90%	Lugo	125.0	125.0	985.5	187.5	187.5	1,478.3
	SCE-Wind 2	Riverside	35%	Devers	530.0	106.0	1,625.0	-	-	-
	SCE-Wind 3	San Berardino	35%	Eldorado	110.0	22.0	337.3	217.5	43.5	666.9
	SCE-Solar 1	San Berardino	35%	Kramer	30.0	30.0	92.0	135.0	135.0	413.9
	SCE-Biomass 1	Los Angeles	80%	Rio Hondo	50.0	50.0	350.4	-	-	-
	SCE-Digester Gas 1	Los Angeles	85%	Rio Hondo	30.0	30.0	223.4	-	-	-
	SCE-Wind 4	Los Angeles	35%	Rio Hondo	135.0	27.0	413.9	210.0	42.0	643.9
	SCE-Wind 5	SCE	35%	Rio Hondo	30.0	6.0	92.0	-	-	-
	SCE-Digester Gas 2	Los Angeles	85%	Rio Hondo	35.0	35.0	260.6	-	-	-
	SDG&E-Wind 3	San Diego	35%	Los Coches	400.0	80.0	1,226.4	-	-	-
	SDG&E-Digester Gas 1	San Diego	85%	Los Coches	30.0	30.0	223.4	-	-	-
California Subtotal					5,251.3	1,689.3	19,620.2	2,408.9	998.9	9,789.3
Northwest	ID-Geothermal 1	Idaho	90%	Ponderosa 230	205.5	205.5	1,619.8	95.4	95.4	752.0
	ID-Geothermal 2	Idaho	90%	McCall 138	27.7	27.7	218.0	12.8	12.8	101.2
	WA-Wind 1	Washington	35%	Ellensbg	175.0	35.0	536.6	81.3	16.3	249.1
	WA-Wind 2	Washington	35%	Cusick	140.0	28.0	429.2	65.0	13.0	199.3

					2008			2013		
	Renew. Resource Name (region name / type)	General Location	Capacity Factor (%)	Bus Location	Nameplate Capacity (MW)	Depend. Capacity (MW)	Renew. Energy / Year (gWh)	Nameplate Capacity (MW)	Depend. Capacity (MW)	Renew. Energy / Year (gWh)
	ID-Wind 1	Idaho	35%	Adelaide	70.0	14.0	214.6	32.5	6.5	99.6
	ID-Wind 2	Idaho	35%	Mt Home	70.0	14.0	214.6	32.5	6.5	99.6
	ID-Wind 3	Idaho	35%	Don	35.0	7.0	107.3	16.3	3.3	49.8
Northwest Subtotal					723.1	331.1	3,340.1	335.7	153.7	1,550.8
Rocky Mountain	NV-Geothermal 1	Nevada	90%	Boardertown 345	184.6	184.6	1,455.4	184.6	184.6	1,455.4
	ID-Geothermal 1	Idaho	90%	Soda Springs	53.4	53.4	421.0	53.4	53.4	421.0
	CO-Geothermal 1	Colorado	90%	Blundll 1	40.0	40.0	315.4	40.0	40.0	315.4
	NV-Wind 1	Nevada	35%	Tonopah	120.0	24.0	367.9	120.0	24.0	367.9
	NV-Wind 2	Nevada	35%	Pahrump	120.0	24.0	367.9	120.0	24.0	367.9
	UT-Wind 3	Utah	35%	Pinto	20.0	4.0	61.3	20.0	4.0	61.3
	UT-Wind 4	Utah	35%	Washngtn	40.0	8.0	122.6	40.0	8.0	122.6
	UT-Wind 5	Utah	35%	Smithfld	140.0	28.0	429.2	140.0	28.0	429.2
	WY-Wind 6	Wyoming	35%	Miners	540.0	108.0	1,655.6	540.0	108.0	1,655.6
	WY-Wind 7	Wyoming	35%	Spence	600.0	120.0	1,839.6	600.0	120.0	1,839.6
	WY-Wind 8	Wyoming	35%	Naughton	240.0	48.0	735.8	240.0	48.0	735.8
	MT-Wind 1	Montana	35%	Conrad	280.0	56.0	858.5	280.0	56.0	858.5
	MT-Wind 2	Montana	35%	Clyde P	460.0	92.0	1,410.4	460.0	92.0	1,410.4
	CO-Wind 1	Colorado	35%	Laporte	80.0	16.0	245.3	80.0	16.0	245.3
	CO-Wind 2	Colorado	35%	Walsenbg	80.0	16.0	245.3	80.0	16.0	245.3
	UT-Solar 1	Utah	35%	Gonder	10.6	10.6	32.5	10.6	10.6	32.5
	CO-Solar 1	Colorado	35%	Vilas 115	11.6	11.6	35.6	11.6	11.6	35.6
Rocky Mountain Subtotal					3,020.2	844.2	10,599.3	3,020.2	844.2	10,599.3
Southwest	AZ-Geothermal 1	Arizona	90%	N. Gila 500	92.4	92.4	728.5	92.4	92.4	728.5
	NM-Geothermal 1	New Mexico	90%	Luna 345	40.8	40.8	321.7	40.8	40.8	321.7
	AZ-Wind 1	Arizona	35%	Apachst3	40.0	8.0	122.6	40.0	8.0	122.6
	AZ-Wind 2	Arizona	35%	Glenc7-8	20.0	4.0	61.3	20.0	4.0	61.3
	NM-Wind 1	New Mexico	35%	Blackwtr	220.0	44.0	674.5	220.0	44.0	674.5

					2008			2013		
	Renew. Resource Name (region name / type)	General Location	Capacity Factor (%)	Bus Location	Nameplate Capacity (MW)	Depend. Capacity (MW)	Renew. Energy / Year (gWh)	Nameplate Capacity (MW)	Depend. Capacity (MW)	Renew. Energy / Year (gWh)
	NM-Wind 2	New Mexico	35%	Curecant	40.0	8.0	122.6	40.0	8.0	122.6
	NM-Wind 3	New Mexico	35%	Shiprock	80.0	16.0	245.3	80.0	16.0	245.3
	AZ-Solar 1	Arizona	35%	Palo Verde 500	208.6	208.6	639.6	208.6	208.6	639.6
	NM-Solar 1	New Mexico	35%	Luna 345	55.6	55.6	170.5	55.6	55.6	170.5
Southwest Subtotal					797.4	477.4	3,086.6	797.4	477.4	3,086.6
Total					9,792.0	3,342.0	36,646.2	6,562.2	2,474.2	25,026.0

Table AC.8 Aggregation of regional synthetic load in Henwood Energy Services, Inc. data

	PLEXOS Region	Utility	State	Has Load?	Underlying Load Shape	Percent
Arizona-New Mexico-Southern Nevada	ARIZONA	Arizona Electric Power Cooperative Inc	AZ	Yes	Arizona Electric Power Cooperative Inc (AEPC)	38.3%
		Arizona Public Service Co	AZ	Yes	Arizona Public Service Co (APS)	92.6%
		Mesa, City of	AZ	Yes	Arizona Electric Power Cooperative Inc (AEPC)	14.3%
		Morenci Water & Electric	AZ	Yes	Arizona Electric Power Cooperative Inc (AEPC)	30.1%
		Navajo Tribal Utility Authority	AZ	Yes	Navajo Tribal Utility Authority (NTUA)	100.0%
		Salt River Project Agricultural Improvement & Power	AZ	Yes	Salt River Project (SRP)	94.2%
		Tucson Electric Power Co	AZ	Yes	Tucson Electric Power Co (TEPC)	100.0%
		WAPA - Lower Colorado	NV	Yes	Arizona Electric Power Cooperative Inc (AEPC)	3.0%
	NEVADA	Nevada Power Co	NV	Yes	Nevada Power Co (NEVP/NPC)	7.5%
	NEW MEXI	El Paso Electric	NM	Yes	El Paso Electric (EPE)	3.3%
		Farmington, City of	NM	Yes	City of Farmington (FARM)	100.0%
		Los Alamos County	NM	Yes	Los Alamos County (LAC)	100.0%
		Public Service Co of New Mexico	NM	Yes	Public Service Co of New Mexico (PSNM)	100.0%
		Texas-New Mexico Power WECC	NM	Yes	Texas New Mexico Power WSCC (TNP)	100.0%
		Tri-State G&T New Mexico/Plains Electric	NM	Yes	Tri-State G&T New Mexico (TSGTNM/PEGT)	100.0%
	WAPA L.C	Arizona Electric Power Cooperative Inc	AZ	Yes	Arizona Electric Power Cooperative Inc (AEPC)	100.0%
		Arizona Public Service Co	AZ	Yes	Arizona Public Service Co (APS)	100.0%

	PLEXOS Region	Utility	State	Has Load?	Underlying Load Shape	Percent
		Salt River Project Agricultural Improvement & Power	AZ	Yes	Salt River Project (SRP)	24.0%
		WAPA - Lower Colorado	NV	Yes	Arizona Electric Power Cooperative Inc (AEPC)	7.4%
California-Mexico Power Area	IMPERIAL	Imperial Irrigation District	CA	Yes	Imperial Irrigation District (IID)	5.8%
	LADWP	Los Angeles Department of Water and Power	CA	Yes	Los Angeles Department of Water and Power (LADWP)	8.4%
	MEXICO-C	CFE - North Baja California	MX	Yes	CFE - North Baja California (CFE)	100.0%
	PG AND E	Dept of Water Resources - North	CA	Yes	California Dept. of Water Resources (CDWR)	100.0%
		Modesto Irrigation District	CA	Yes	Modesto Irrigation District (MID)	100.0%
		Northern California Power Agency	CA	Yes	Northern California Power Agency (NCPA)	48.0%
		Pacific Gas & Electric - NP15	CA	Yes	Pacific Gas & Electric - NP15	100.0%
		Pacific Gas & Electric - San Francisco	CA	No	Pacific Gas & Electric - SF Peninsula (Inactive)	100.0%
		Pacific Gas & Electric - ZP26	CA	Yes	Pacific Gas & Electric - ZP26	100.0%
		Redding Electric Dept	CA	Yes	Redding Electric Dept (RDNG)	100.0%
		Sacramento Municipal Utilities District	CA	Yes	Sacramento Municipal Utilities District (SMUD)	100.0%
		Silicon Valley Power - Santa Clara Electric Dept	CA	Yes	Silicon Valley Power (SVP/SNCL)	100.0%
		Turlock Irrigation District	CA	Yes	Turlock Irrigation District (TID)	100.0%
		WAPA - Mid Pacific (CVP)	CA	Yes	WAPA - Mid Pacific (WAMP/CVP)	100.0%
	SANDIEGO	San Diego Gas & Electric	CA	Yes	San Diego Gas & Electric (SDGE)	100.0%
	SOCALIF	Anaheim Public Utilities Dept.	CA	Yes	Anaheim Public Utilities Dept. (ANHM)	100.0%
		Arizona Electric Power Cooperative Inc	AZ	Yes	Arizona Electric Power Cooperative Inc (AEPC)	100.0%
		Burbank Public Service Dept	CA	Yes	Burbank Public Service Dept (BUR)	100.0%
		Dept of Water Resources - South	CA	Yes	California Dept. of Water Resources (CDWR)	1.5%
		Glendale Water & Power	CA	Yes	Glendale Public Service Dept (GLEN)	100.0%
		Metropolitan Water District of Southern CA	CA	Yes	Metropolitan Water District of Southern CA (MWD)	52.0%
		Pasadena Water and Power Dept	CA	Yes	Pasadena Water and Power Dept (PASA)	100.0%
		Riverside Utilities Dept	CA	Yes	Riverside Utilities Dept (RVSD)	100.0%
		Southern California Edison	CA	Yes	Southern California Edison (SCE)	100.0%
		Vernon Municipal Light Dept	CA	Yes	Vernon Municipal Light Dept (VERN)	100.0%
Pow	ALBERTA	Alberta Load - Central	AB	Yes	ESBI Alberta Ltd. (EAL)	100.0%
		Alberta Load - Northeast (Ft. McMurray)	AB	Yes	ESBI Alberta Ltd. (EAL)	100.0%

	PLEXOS Region	Utility	State	Has Load?	Underlying Load Shape	Percent
		Alberta Load - Northwest	AB	Yes	ESBI Alberta Ltd. (EAL)	50.6%
		Alberta Load - South	AB	Yes	ESBI Alberta Ltd. (EAL)	1.5%
		Medicine Hat Alberta, City of	AB	Yes	ESBI Alberta Ltd. (EAL)	13.9%
	AQUILA	Aquila Networks Canada - West Kootenay Power	BC	Yes	West Kootenay (incl Cominco) (WKP)	32.5%
	B.C.HYDR	British Columbia Hydro and Power Authority	BC	Yes	British Columbia Hydro and Power Authority (BCHA)	1.5%
	IDAHO	Bonneville Power Administration	WA	Yes	Bonneville Power Administration Control Area (BPA)	100.0%
		Idaho Power Co	ID	Yes	Idaho Power Company (IPC)	100.0%
	NORTHWES	Avista	WA	Yes	Avista - Washington Water Power (AVIST/WWP)	3.3%
		Bonneville Power Administration	WA	Yes	Bonneville Power Administration Control Area (BPA)	20.0%
		Deseret Generation & Transmission Cooperative	UT	Yes	Deseret Generation & Transmission Coop (DGTC)	80.0%
		Eugene Water and Electric Board	OR	Yes	Eugene Water and Electric Board (EWEB)	97.5%
		PacifiCorp Northwest (OR/WA/CA)	OR	Yes	Bonneville Power Administration Control Area (BPA)	2.5%
		Portland General Electric	OR	Yes	Portland General Electric (PGE)	2.5%
		PUD No 1 of Chelan County	WA	Yes	PUD No 1 of Chelan County (CHEL)	16.5%
		PUD No 1 of Cowlitz County	WA	Yes	Bonneville Power Administration Control Area (BPA)	0.8%
		PUD No 1 of Douglas County	WA	Yes	PUD No 1 of Douglas County (DPUD)	9.1%
		PUD No 1 of Pend Oreille County	WA	Yes	Bonneville Power Administration Control Area (BPA)	9.1%
		PUD No 1 of Snohomish County	WA	Yes	Bonneville Power Administration Control Area (BPA)	8.2%
		PUD of Grant County	WA	Yes	PUD of Grant County (GPUD)	3.3%
		Puget Sound Energy	WA	Yes	Puget Sound Power & Light (PSPL/PSE)	4.9%
		Seattle City Light	WA	Yes	Seattle City Light (SCL)	23.0%
		Tacoma Public Utilities-Tacoma Power	WA	Yes	Tacoma Public Utilities-Light Div. (TCL/TPU)	86.3%
	PACE	Bonneville Power Administration	WA	Yes	Bonneville Power Administration Control Area (BPA)	100.0%
		PacifiCorp Idaho	ID	Yes	Idaho Power Company (IPC)	2.7%
		PacifiCorp Utah (UT/WWY)	UT	Yes	Utah Associated Municipal Power Systems (UAMP)	11.8%
		PacifiCorp Wyoming	WY	Yes	Black Hills Power & Light (BHPL)	0.9%
		Tri-State G&T Colorado/Wyoming	CO	Yes	Tri-State G&T CO/WY (TSGTCW)	12.7%
		Utah Associated Municipal Power Systems	UT	Yes	Utah Associated Municipal Power Systems (UAMP)	4.5%
		Utah Municipal Power Agency	UT	Yes	Utah Municipal Power Agency (UMPA)	12.7%

	PLEXOS Region	Utility	State	Has Load?	Underlying Load Shape	Percent
		WAPA - Colorado Missouri (Wyoming)	WY	Yes	WAPA - Lower Missouri (WALM)	100.0%
	SIERRA	Deseret Generation & Transmission Cooperative	UT	Yes	Deseret Generation & Transmission Coop (DGTC)	100.0%
		Sierra Pacific Power Co	NV	Yes	Sierra Pacific Power Co (SPP)	6.4%
		Utah Associated Municipal Power Systems	UT	Yes	Utah Associated Municipal Power Systems (UAMP)	100.0%
	WAPA U.M	WAPA - Colorado Missouri (Wyoming)	WY	Yes	WAPA - Lower Missouri (WALM)	1.4%
Rocky Mountain Power Area	MONTANA	Northwestern Energy - Montana	MT	Yes	Montana Power Co. (MPC)	9.9%
	PSCOLORA	Aquila Networks CO - WestPlains Energy Colorado	CO	Yes	WestPlains Energy Colorado (WPE/WEPL)	100.0%
		Xcel Energy - Public Service of Colorado	CO	Yes	Public Service of Colorado (PSC)	100.0%
	WAPA R.M	Basin Electric Power Coop WECC	WY	Yes	Basin Electric Coop (BEPCW)	100.0%
		Black Hills Power & Light	SD	Yes	Black Hills Power & Light (BHPL)	100.0%
		Colorado Springs Utilities	CO	Yes	Colorado Springs Utilities (CSU)	1.6%
		Platte River Power Authority	CO	Yes	Platte River Power Authority (PRPA)	12.4%
		Tri-State G&T Colorado/Wyoming	CO	Yes	Tri-State G&T CO/WY (TSGTCW)	774.8%
		WAPA - Colorado Missouri (Colorado)	CO	No	WAPA - Upper Colorado (WAUM)	95.8%
		WAPA - Colorado Missouri (Wyoming)	WY	Yes	WAPA - Lower Missouri (WALM)	98.8%
		Xcel Energy - Public Service of Colorado	CO	Yes	Public Service of Colorado (PSC)	114.3%

ATTACHMENT 5
OF
PHASE 1 OPENING TESTIMONY ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR
October 21, 2005
A.05-04-015
I.05-06-041

Appendix D

Transmission Economic Assessment Methodology (TEAM) Member Notification List

February 3, 2004 – Transmission Economic Assessment Methodology Stakeholder Meeting

- Agenda
- Market Notice (2)
- TEAM Stakeholder Meeting Sign In Sheet
- TEAM Stakeholder Meeting Conference Call Participant Report
- Notice to participate in TEAM Sub-committee's

NOTE: Presentations available at:
http://www1.caiso.com/docs/2003/03/18/2003031815303519270.html

March 16, 2004 – Transmission Economic Assessment Methodology Stakeholder Meeting

- Agenda
- Market Notice
- TEAM Stakeholder Meeting Sign In Sheet
- TEAM Stakeholder Meeting Conference Call Participant Report
- TEAM Stakeholder Meeting Conference Call Playback Information
- TEAM Stakeholder Meeting Conference Call Playback Information Participant Report

NOTE: Presentations available at:
http://www1.caiso.com/docs/2003/03/18/2003031815303519270.html

April 28, 2004 – Transmission Economic Assessment Methodology Stakeholder Meeting

- Agenda
- Market Notice
- TEAM Stakeholder Meeting Sign In Sheet
- TEAM Stakeholder Meeting Conference Call Participant Report
- TEAM Stakeholder Meeting Conference Call Playback Information
- TEAM Stakeholder Meeting Conference Call Playback Information Participant Report

NOTE: Presentations available at:
http://www1.caiso.com/docs/2003/03/18/2003031815303519270.html

May 17, 2004 – Market Surveillance Committee Meeting

- Agenda
- Public Notice
- Market Notice (2)
- Market Surveillance Committee Meeting Sign In Sheet
- Market Surveillance Committee Meeting Conference Call Participant Report

NOTE: Presentations available at:
http://www1.caiso.com/docs/2003/03/18/200303181530351927O.html

Transmission Economic Assessment Methodology Stakeholder Meeting Base Case Subgroup

- Base Case Subgroup Member Distribution List
- February 9, 2004
  - Agenda/Attachments
  - Attendance List
- February 13, 2004
  - Agenda/Attachments
  - Attendance List
- February 23, 2004
  - Agenda
- February 24,2004
  - Conference Call Discussion Topics and Issues
- March 10, 2004
  - Agenda
  - Attendance List
  - Summary of Conference Call

Transmission Economic Assessment Methodology Stakeholder Meeting Extreme Events Subgroup

- Extreme Events Subgroup Member Distribution List
- February 17, 2004
  - Agenda
  - Attendance List
- March 8, 2004
  - Agenda
  - Attendance List

Transmission Economic Assessment Methodology Stakeholder Meeting Market Power Subgroup

- Market Power Subgroup Member Distribution List
- February 24, 2004
  - Agenda
- March 9, 2004
  - Agenda

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Agenda
Stakeholder Meeting on Transmission Economic Assessment Methodology
February 3, 2004
CA ISO Board Room
101 Blue Ravine Road
Folsom, CA 95630

Dial-In Info (LISTEN ONLY):

Call-in Number:	800/341-6239
Company:	California ISO
Leader:	Jeff Miller
Meeting Name:	TEAM Stakeholder Meeting

10:00 A.M. Introduction, Background & Schedule – Anjali Sheffrin

10:20 A.M. Major Issues – Jeff Miller

10:30 A.M. What are the options for modeling market power? What are the relative advantages and disadvantages of each? How would appropriate bidding strategies be determined for simulating the future value of potential upgrades? Dr. Frank Wolak (MSC Chairperson)

Noon Working Lunch

12:20 P.M. What benefit tests should be considered when evaluating potential transmission upgrades? How are these tests calculated? -- Mingxia Zhang (CA ISO staff)

- Societal
- Modified Societal
- Participant (competitive and market power)
  - Producer
  - Consumer
  - Transmission / Congestion-Right Owner

1:20 P.M. What are the assumptions for the base case (nodal, cost-based simulation)? Mohamed Awad (CA ISO staff)

1:40 A.M. What tool(s) are being used to implement the CA ISO methodology? What is the current status of that work? Anna Geevarghese (CA ISO staff)

2:00 P.M. What is the purpose of sensitivity cases? How many should be modeled and under what conditions? How can these cases be appropriately weighted to derive an expected value? Dr. Ben Hobbs (MSC Member)

3:00 P.M. Scope of Next Meeting / Conclusion – Anjali Sheffrin

REMINDER: Please remember to RSVP for this important meeting.

Market Notice
Stakeholder Process and Meeting to Develop Transmission Economic Assessment Methodology (TEAM)

ISO Market Participants and entities/individuals on the official service list in CPUC Docket #I.00-11-001:

The ISO is initiating a new stakeholder forum to assist in the development of a comprehensive methodology to assess the economic benefits of potential transmission facility upgrades. Staff from the CPUC is expected to participate fully and, where feasible, to co-facilitate the forum. The new economic methodology is the subject of a pending proceeding before the CPUC and intends to serve as the basis to justify new transmission upgrades proposed primarily on economic, rather than reliability, benefits. If you would like to be a member of the stakeholder group, please e-mail Deborah Vanda at dvanda@caiso.com with your name, the entity you represent, your e-mail address, and your phone number.

The first meeting of this stakeholder group is scheduled for February 3rd from 10:00 to 3:00 at the California ISO's offices in Folsom. The draft agenda for the meeting is attached. If you would like to attend this meeting, please RSVP to Deborah Vanda at dvanda@caiso.com. Lunches will only be provided for those that RSVP.

If you have any questions regarding this meeting, please contact Eric Toolson at (916) 608-7156, Email: etoolson@caiso.com

REMINDER: Please remember to RSVP for this important meeting.

Market Notice
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The following number has been set up for those unable to attend that wish to listen in. Please note that those listening in will be unable to participate in the discussions.

Call-in Number:	800/341-6239
Company:	California ISO
Leader:	Jeff Miller
Meeting Name:	TEAM Stakeholder Meeting

If you have any questions regarding this meeting, please contact Eric Toolson at (916) 608-7156, Email: etoolson@caiso.com

TRANSMISSION ECONOMIC ASSESSMENT METHODOLOGY (TEAM) STAKEHOLDER MEETING

CALIFORNIA INDEPENDENT SYSTEM OPERATOR

3-Feb-04

Public Session: 10:00 a.m. - 3:00 p.m.

Offices of the California ISO, Lake Tahoe Conference Rooms

MEETING SIGN-IN

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TEAM Stakeholder Mtg #1

Feb. 3, 2004

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Conference Participant Report
Conf. Date: 02/03/2004
Conf. Time: 10:00 am PT

Company: California ISO
Leader: Jeff Miller
Conference ID: 5258843

Start Time	End Time	Name	Additional Information	Number	Co/Leader
12:54:41	18:31:15	MARYANNE CAUSLEY	RUMLA INC.		CALIF\MILLER
12:55:40	17:32:16	SHAWN BAILEY	SEMPRA ENERGY		CALIF\MILLER
12:57:30	15:46:51	TIM EUONG	CITY OF AZUSA		CALIF\MILLER
12:58:22	13:26:46	LINDA BROWN	SDG&E		CALIF\MILLER
12:58:42	16:34:39	MANUEL ALVAREZ	SOUTHERN CA EDISON		CALIF\MILLER
12:59:20	18:31:15	LARRY LUNA	NEVADA POWER		CALIF\MILLER
12:59:58	18:31:15	ROBERT DELGADO	CITY OF RIVERSIDE		CALIF\MILLER
13:00:16	17:26:11	MORTEZA SABET	WAPA		CALIF\MILLER
13:00:22	18:08:33	KEN SIMS	SILICON VALLEY POWER		CALIF\MILLER
13:00:54	17:19:30	JENNIFER JENSEN	NRG ENERGY		CALIF\MILLER
13:01:13	18:31:04	JOHN BURNETT	LADWP		CALIF\MILLER
13:01:15	15:20:39	BRUCE MCLAUGHLIN	BRAUN AND BLAISING		CALIF\MILLER
13:01:36	13:09:25	MR J MILLER LDR			LDR\MILLER
13:01:46	14:15:27	SHAUNA O'DONNELL	CA ENERGY MARKETS		CALIF\MILLER
13:01:48	17:31:42	WES WILLIAMS	SOUTHERN CA EDISON		CALIF\MILLER
13:01:49	15:16:00	BERNIE LESIEUTRE	LAWERENCE BERKLEY		CALIF\MILLER
13:02:38	15:50:40	KAREN GRIFFIN	CA ENERGY COMMISION		CALIF\MILLER
13:02:49	15:18:20	PAUL STECKELEY	TRANSENERGY		CALIF\MILLER
13:02:51	14:18:16	BARRY FLYNN	FLYNN RCI		CALIF\MILLER
13:02:57	13:31:35	MICKEY SIEGEL	EPG		CALIF\MILLER
13:03:18	18:02:50	ZORA LAZIC	BLG		CALIF\MILLER
13:03:22	14:30:30	ROBERT SPARKS	CALIFORNIA ISO		CALIF\MILLER
13:03:25	17:37:32	TOD O'CONNOR	SOLARGENICS ENERGY		CALIF\MILLER
13:03:26	13:26:46	DAVID CLARK	ECONOMIC PLANNING RES.		CALIF\MILLER
13:03:27	14:33:00	JOHN SEELKE	NEW ENERGY ASSOCIATES		CALIF\MILLER
13:03:35	15:09:36	HELEN VESSER	INPOWER CORP.		CALIF\MILLER
13:04:23	15:20:07	JESSICA BERTHOLD	DOW JONES		CALIF\MILLER
13:05:38	15:16:23	JIMAL JAFFARY	SOUTHERN CA EDISON		CALIF\MILLER
13:05:46	14:54:00	KATHLEEN WRIGHT	CDWR		CALIF\MILLER
13:06:23	18:30:59	ROBERT JENKINS	MIRANT		CALIF\MILLER
13:06:40	15:16:22	MATT LOWRY	WESTERN INTERSTATE		CALIF\MILLER
13:06:43	14:49:59	SCOTT LOGAN	ORA		CALIF\MILLER

Conference Participant Report
Conf. Date: 02/03/2004
Conf. Time: 10:00 am PT

Company: California ISO
Leader: Jeff Miller
Conference ID: 5258843

Start Time	End Time	Name	Additional Information	Number	Co/Leader
13:07:09	17:32:16	KEN KOHTZ	SILICON VALLEY POWER		CALIF\MILLER
13:08:07	13:27:24	KATIE KAPLAN	IEP		CALIF\MILLER
13:09:21	18:30:48	FARROKH RAHIMI	CALIFORNIA ISO		CALIF\MILLER
13:09:25	18:31:15	MR J MILLER LDR			CALIF\MILLER
13:10:55	13:26:46	RICHARD O'NEIL	FERC		CALIF\MILLER
13:18:23	15:55:41	YVONNE WALKUP	SOUTHERN CA EDISON		CALIF\MILLER
13:23:19	18:30:33	DENNIS PHILLIPS	BONNEVILLE POWER ADMIN		CALIF\MILLER
13:24:02	14:46:44	DARRELL ANTRICH	ENERGY CORP. TRADING		CALIF\MILLER
13:28:20	18:31:15	LINDA BROWN]R	SDG&E		CALIF\MILLER
13:29:16	15:23:19	RICHARD O'NEIL]R	FERC		CALIF\MILLER
13:33:47	15:15:20	LON PETERS	PUBLIC GENERATING		CALIF\MILLER
13:49:33	15:09:33	SAM KWONG	WILLIAMS		CALIF\MILLER
13:59:34	14:34:02	MIKE BROZO	TANC		CALIF\MILLER
14:09:17	16:28:57	CHAD WOZNIAK	SILICON VALLEY POWER		CALIF\MILLER
14:17:05	15:18:14	RICH LAUCKHART	HENWOOD		CALIF\MILLER
14:23:22	16:22:55	BARRY FLYNN]R	FLYNN RCI		CALIF\MILLER
14:36:54	14:44:27	JIM BRYNE	RMATS		CALIF\MILLER
14:39:14	18:31:15	MIKE EVANS	CORAL POWER		CALIF\MILLER
14:50:04	18:30:40	MICKEY SIEGEL]R	EPG		CALIF\MILLER
15:13:43	17:32:54	SAM KWONG	WILLIAMS		CALIF\MILLER
15:21:44	16:32:59	JIM HICKS	PACIFIC CORP		CALIF\MILLER
15:27:55	15:36:34	MATT LOWRY]R	WESTERN INTERSTATE		CALIF\MILLER
15:30:43	16:22:36	BRUCE MCLAUGHLIN]R	BRAUN AND BLAISING		CALIF\MILLER
15:30:56	16:05:42	BARRY FLYNN]R	FLYNN RCI		CALIF\MILLER
15:36:12	15:46:49	THOMAS FLINN	CA POWER AUTHORITY		CALIF\MILLER
15:37:19	17:24:34	RICHARD O'NEIL]R	FERC		CALIF\MILLER
15:37:45	16:17:24	MATT LOWRY]R	WESTERN INTERSTATE		CALIF\MILLER
15:46:57	15:58:42	BERNIE LESIEUTRE]R	LAWERENCE BERKLEY		CALIF\MILLER
15:47:14	15:58:13	THOMAS FLINN]R	CA POWER AUTHORITY		CALIF\MILLER
15:50:36	18:31:15	ROBERT SPARKS]R	CALIFORNIA ISO		CALIF\MILLER
15:51:57	18:31:13	RICH LAUCKHART]R	HENWOOD		CALIF\MILLER
16:09:06	18:31:14	CHARLES FAUST	FERC		CALIF\MILLER

Conference Participant Report
Conf. Date: 02/03/2004
Conf. Time: 10:00 am PT

Company: California ISO
Leader: Jeff Miller
Conference ID: 5258843

Start Time	End Time	Name	Additional Information	Number	Co/Leader
16:14:04	18:30:43	HELEN VESSER]R	INPOWER CORP.		CALIF\MILLER
16:14:47	16:36:15	DON GARBER	SEMPRA		CALIF\MILLER
16:25:28	17:39:45	BRUCE MCLAUGHLIN]R	BRAUN AND BLAISING		CALIF\MILLER
16:27:30	18:31:14	JAMAL JASARI	SOUTHERN CA EDISON		CALIF\MILLER
16:32:28	18:31:11	KATHLEEN WRIGHT]R	CDWR		CALIF\MILLER
16:36:08	18:02:25	MATT LOWRY]R	WESTERN INTERSTATE		CALIF\MILLER
16:37:27	18:07:24	BARRY FLYNN]R	FLYNN RCI		CALIF\MILLER
16:41:00	18:29:46	CHAD WOZNIAK]R	SILICON VALLEY POWER		CALIF\MILLER
17:10:27	18:31:14	MARY JOE HANNAN	BONNEVILLE POWER ADMIN		CALIF\MILLER
17:19:04	17:56:11	THOMAS FLINN]R	CA POWER AUTHORITY		CALIF\MILLER
17:52:19	18:06:14	SCOTT LOGAN]R	ORA		CALIF\MILLER
17:55:02	18:20:21	JESSICA BERTHOLD]R	DOW JONES		CALIF\MILLER
17:58:35	18:30:43	BRUCE MCLAUGHLIN]R	BRAUN AND BLAISING		CALIF\MILLER
18:19:26	18:31:15	MATT LOWRY]R	WESTERN INTERSTATE		CALIF\MILLER

If you are interested in participating in one of the sub-committee's listed below, please Email the Chairperson of that committee by the end of this week.

I. Base case assumptions for network and production costs
Chairperson: Eric Toolson Email: Etoolson@caiso.com

II. Choice of extreme events and choice of weights
Chairperson: Mingxia Zhang Email: Mzhang@caiso.com

III. Approach to quantifying market power benefits and appropriate benefits tests
Chairperson: Mingxia Zhang Email: Mzhang@caiso.com

Agenda
Stakeholder Meeting
Transmission Economic Assessment Methodology (TEAM)
March 16, 2004
10:00 a.m. – 3:00 p.m.
CA ISO Board Room
101 Blue Ravine Road, Folsom, CA 95630
Dial-In Number: (800) 341-6239
Conference ID #: 5980781

10:00 A.M. Overview of Agenda and Methodology – Anjali Sheffrin

- Introductions
- Purpose of methodology
- Review of methodology
- Progress since last meeting
- Phase I and II
- Purpose of today's meeting
- Questions

10:30 A.M. Base Case Assumptions Subgroup Report – Eric Toolson

- Loads and fuel prices
- Renewable portfolios standards
- Planning reserve margins
- Economic entry
- Resource additions / retirements
- Potential Phase II enhancements
- Questions

11:15 A.M. Market Price Subgroup Report – Keith Casey

- Review of RSI methodology
- Current implementation status
- Potential Phase II enhancements
- Questions

12:00 P.M. Working Lunch – Status Report from Regional Transmission Forums (SSG-WI, STEP) – Jeff Miller

12:45 P.M. Extreme Events Subgroup Report – Mingxia Zhang

- Sensitivity identification
- Sensitivity weighting
- Subjective contingencies
- Prioritization of sensitivities
- Potential Phase II enhancements
- Questions

1:30 P.M. Modeling of the Path 26 Upgrade Project – Mohamed Awad

- Definition of upgrade case
- Questions

1:45 P.M. Initial Base Case Results – Mohamed Awad and Anna Geevarghese

- Annual results
- Monthly results
- Source of benefits – description
- Selected flow duration curves
- Overall economics of initial studies
- Questions

2:15 P.M. Stakeholder Input – Eric Toolson, Moderator[1]

2:45 P.M. Project Schedule / Conclusion – Anjali Sheffrin

3:00 P.M. Adjourn

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[1] Please notify Linda Wright (lwright@caiso.com, 916-351-4470) in advance if you would like to make a presentation to the group so that all logistical details can be worked out in advance. To facilitate as many presentations as possible, presentations will be limited to 5 minutes. If you would like to distribute copies of your presentation, please prepare 40 copies in advance of the meeting and coordinate with Linda Wright so that the materials can be posted on the website (http://www1.caiso.com/docs/2003/03/18/2003031815303519270.html) and the participants listening in can have access to your material during the meeting.

Market Notice
Transmission Economic Assessment Methodology (TEAM)
Stakeholder Meeting - March 16, 2004

ISO Market Participants/TEAM Stakeholders:

The next meeting of this stakeholder group is scheduled for Tuesday, March 16th from 10:00 to 3:00 at the California ISO's offices in Folsom. The agenda for the meeting will follow later this week. If you would like to attend this meeting, please RSVP by noon on March 15th to Linda Wright at mailto:lwright@caiso.com. Lunches will only be provided for those that RSVP.

A number for those unable to attend that wish to listen in will be included on the agenda. Please note that those listening in will be unable to participate in the discussions.

If you have any questions regarding this meeting, please contact Eric Toolson at (916) 608-7156.

Client Relations Communications.0725
CRCommunications@caiso.com

TRANSMISSION ECONOMIC ASSESSMENT METHODOLOGY (TEAM) STAKEHOLDER MEETING
CALIFORNIA INDEPENDENT SYSTEM OPERATOR
March 16, 2004
Public Session: 10:00 a.m. - 3:00 p.m.
Offices of the California ISO, Lake Tahoe Conference Rooms
MEETING SIGN-IN

INITIAL	NAME	COMPANY	EMAIL ADDRESS	PHONE NUMBER
	Amirali, Ali	Calpine	aamirali@calpine.com	415-703-1487
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	El-Gasseir, Mohamed	CERS	mel@water.ca.gov	916-574-0294
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	Filippi, Jim	Pacific Gas & Electric	JLFa@pge.com	415-973-6530
	Flynn, Tom	California Power Authority	thomas.flynn@dgs.ca.gov	916-651-9756
	Gokbudak, Brent	So. Calif. Edison	Brent.Gokbudak@sce.com	626-302-8694
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RSH	Hunt, Randall	Navigant Consulting, Inc.	rhunt@navigantconsulting.com	616-631-3276
	Jenkins, Robert	Mirant Corporation	robert.jenkins@mirant.com	925-287-3124
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	Kritikson, Jim	KTA-Kritikson & Assoc.	jdritiksin@yahoo.com	510-480-7284/909-480-1028
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	McLaughlin, Bruce	Braun Legal (represent Ca.Municipal Utilities Assoc)	mclaughlin@braunlegal.com	916-326-5812
	Mi, Jingchao	CDWR		
	Pereira, Les	No. Calif. Power Agency	Les.Pereira@ncpa.com	916-781-4218
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CBR	Rochlin, Cliff	So. Calif. Gas Company	crochlin@semprautilities.com	213-244-8222/213-244-2451
	Romanowitz, Hal		hal@rwitz.net	
	Rupp, Steven	R.W. Beck	srupp@rwbeck.com	916-614-8246
	Schilberg, Gayatri	JBS Energy, Inc.	Gayatri@JbsEnergy.com	916-372-0534 X104
	Schneider, Susan	Phoenix Consulting	schneider@phoenix-co.com	916-797-3106
	Skowronski, Mark	Solargenix at Inland Energy Group	mjskowronski@inlandenergy.com	949-856-2200

AWJ	Tanghetti, Angela	CEC	Atanghet@energy.state.ca.us	916-654-4854
JJ	Turnbull, Jane	League of Women Voters	jaturnbu@ix.netcom.com	650-559-1766
MW	Werner, Michael	CDWR	mwerner@water.ca.gov	916-574-0617
	Winslow, Don	PPM Energy	don.winslow@ppmenergy.com	503-796-7088
JL	Xuguang, Leng	CPUC	xgl@cpuc.ca.gov	415-703-2801
	Arnold, Shaune	Alvarado Smith + Sanchez for LADWP	sarnold@asandc.com	213/629-7038
	Carl Silsbees	SCE		
	Kishore Patel	SDG&E	SDG&E	858-654-8231
	Wes Williams	SCE	weston.williams@sce.com	(626)3029615
	Olsson, Ray	EOB	rolsson@eob.ca.gov	(916) 322-8613
	Brian Hitson	PG&E	bjh9@pge.com	415 973-7720
	Steve Ghadiri	EOB	Sghadiri	(916) 322-8690
L	Tom Miller	PG&E	TEM3@PGE.Com	415-973-2070

Status	Last Name	First Name	Representing	Sponsor or Host	Date In	Time In
Active	Amirali	Ali	Calpine	Linda Wright	03/16/04	10:04
Active	Benjamin	Rich	CEC	Linda Wright	03/16/04	10:04
Active	Bracht	Kirk	CPUC	Linda Wright	03/16/04	10:05
Active	Falls	Chuck	SRP	Linda Wright	03/16/04	09:49
Active	Fillippi	Jim	PG & E	Linda Wright	03/16/04	10:51
Active	Flynn	Tom	CPA	Linda Wright	03/16/04	10:49
Active	Gokbudak	Brent	SO. California Edison	Linda Wright	03/16/04	10:05
Active	Henery	Nick	SMUD	Linda Wright	03/16/04	10:50
Active	Hunt	Randall	Navigant Consulting, In	Linda Wright	03/16/04	10:05
Active	Jenkins	Robert	Mirant Corporation	Linda Wright	03/16/04	10:10
Active	Kritikson	Jim	Kritikson & Associates	Linda Wright	03/16/04	09:48
Active	Lam	Tony	EOB	Linda Wright	03/16/04	10:58
Active	McCluskey	James	CEC	Linda Wright	03/16/04	10:05
Active	McLaughlin	Bruce	Braun Legal(CMUA)	Linda Wright	03/16/04	09:48
Active	Pereira	Les	NCPA	Linda Wright	03/16/04	10:10
Active	Rader	Nancy	CWEA	Linda Wright	03/16/04	11:50
Active	Roberts	Ted	SDG & E	Linda Wright	03/16/04	10:50
Active	Rochlin	Cliff	SoCal Gas Company	Linda Wright	03/16/04	09:48
Active	Romanowitz	Hal		Linda Wright	03/16/04	10:49
Active	Schilberg	Gayatri	JBS Energy, Inc.	Linda Wright	03/16/04	10:05
Active	Schenider	Susan	Phoenix Consulting	Linda Wright	03/16/04	10:05
Active	Skowronski	Mark	Solargenix at IEG	Linda Wright	03/16/04	09:48
Active	Tanghetti	Angela	CEC	Linda Wright	03/16/04	10:41
Active	Xuguang	Leng	CPUC	Linda Wright	03/16/04	10:07
Active	Mi	Jingchao	CDWR	Linda Wright	03/16/04	10:12
Active	Werner	Michael	CDWR	Linda Wright	03/16/04	10:06
Active	Williams	Weston	SCE	Linda Wright	03/16/04	09:44
Active	Arnold	Shaune	LADWP	Linda Wright	03/16/04	09:31
Active	SILSBEE	CARL	SoCal Edison	Linda Wright	03/16/04	09:41
Active	Patel	Kishore	SDG & E	Linda Wright	03/16/04	09:42
Active	Olsson	Ray	EOB	Linda Wright	03/16/04	09:47
Active	Sandhu	Paul	PG & E	Linda Wright	03/16/04	09:56
Active	Hitson	Brian	PG&E	Linda Wright	03/16/04	09:56
Active	Griffin	Karen	CEC	Linda Wright	03/16/04	09:57
Active	Richardson	Gary	Pegasus Consulting	Linda Wright	03/16/04	09:59
Active	Ghadiri	Steve	EOB	Linda Wright	03/16/04	09:59
Active	Turnbull	Jane	LOWV	Linda Wright	03/16/04	10:41

Transmission Economic Assessment Methodology (TEAM)
Stakeholder Meeting

March 16, 2004

Encore (Playback) Information

Encore Dial-In #: (800) 642-1687
Conference ID #: 5980781

Fast Forward options are:

Press "1" to fast forward 5 seconds
Press "2" to fast forward 30 seconds

Recording available through 9:00 p.m. PST on March 23, 2004

Contact Linda Wright at (916) 351-4470 with any questions.

Conference Participant Report
Conf. Date: 03/16/2004
Conf. Time: 10:00 am PT

Company: California ISO
Leader: Jeff Miller
Conference ID: 5980781

Start Time	End Time	Name	Additional Information	Number	Co/Leader
12:52:05	13:05:29	MR J MILLER LDR			LDR\MILLER
12:57:42	18:42:07	LARRY LUNA	NEVADA POWER COMPANY	7023675465	CALIF\MILLER
12:57:51	13:14:46	JOHN BURNETT	LADWP	2133671744	CALIF\MILLER
12:58:49	18:43:00	ENCORE RECORD\MILLER			CALIF\MILLER
12:58:50	17:18:29	RICHARD TORRES	CITY OF AZUSA	6268125214	CALIF\MILLER
12:58:58	15:58:55	ROBERT DELGADO	CITY OF RIVERSIDE	9093516312	CALIF\MILLER
13:00:59	13:07:49	HAL ROMANOWITZ	OAK CREEK ENERGY	6617470990	CALIF\MILLER
13:01:32	14:16:08	DARRELL HOLMES	SOUTHERN CA EDISON	6263026498	CALIF\MILLER
13:01:59	13:13:56	SCOTT LOGAN	CALIFORNIA PUC	4157031418	CALIF\MILLER
13:05:29	18:43:00	MR J MILLER LDR			CALIF\MILLER
13:07:46	15:47:47	RICH LAUCKHART	HENWOOD	9166097769	CALIF\MILLER
13:08:33	13:28:55	HAL ROMANOWITZ]R	OAK CREEK ENERGY	6617470990	CALIF\MILLER
13:11:43	15:42:47	KERRY HATTEVIK	CALIFORNIA PUC	5105261082	CALIF\MILLER
13:12:03	14:13:50	MARYANNE MIRZADEH	WAPA	9163534552	CALIF\MILLER
13:12:26	15:03:22	KRAIG CAMERON	SMUD	9167325363	CALIF\MILLER
13:15:54	15:29:10	DILIP MAHERANDA	SMUD	9167326180	CALIF\MILLER
13:19:02	13:19:57	JOHN BURNETT]R	LADWP	2133671744	CALIF\MILLER
13:23:00	14:00:02	TONY LAM	EOB	9168347196	CALIF\MILLER
13:28:14	16:28:48	CHARLES FAUST	FERC	9162940163	CALIF\MILLER
13:28:18	15:44:21	JOHN BURNETT]R	LADWP	2133671744	CALIF\MILLER
13:28:28	16:10:34	MIKE EVANS	CORAL POWER	8585262103	CALIF\MILLER
13:29:30	13:31:18	HAL ROMANOWITZ]R	OAK CREEK ENERGY	6617470990	CALIF\MILLER
13:32:35	13:50:09	HAL ROMANOWITZ]R	OAK CREEK ENERGY	6617470990	CALIF\MILLER
13:43:55	18:42:10	MARYANN CAUSLEY	RUMLA INC	9166573773	CALIF\MILLER
14:18:01	15:14:10	DON WINSLOW	PPM ENERGY	5037967088	CALIF\MILLER
15:00:22	17:21:52	OSCAR ALVAREZ	LADWP	2133670677	CALIF\MILLER
15:45:49	18:42:03	KERRY HATTEVIK]R	CALIFORNIA PUC	5105261082	CALIF\MILLER
16:17:27	16:34:08	RICH LAUCKHART]R	HENWOOD	9166097769	CALIF\MILLER
16:20:29	18:42:12	JOHN BURNETT	LADWP	2133671744	CALIF\MILLER
17:01:11	17:07:31	RICH LAUCKHART]R	HENWOOD	9166097769	CALIF\MILLER
17:05:53	18:42:12	MIKE EVANS]R	CORAL POWER	8585262103	CALIF\MILLER

Conf ID	Call Date	Call Time	Duration	Phone #	Name	Company Name
5980781	03/17/04	10:37:27	00:17:14	9093581227	ROBERT DELGADO	CITY OF RIVERSIDE
5980781	03/17/04	13:55:58	00:01:27	6263028694	NO MESSAGE	
5980781	03/18/04	18:33:01	00:12:22	6263028694	NO MESSAGE	

Agenda
Stakeholder Meeting
Transmission Economic Assessment Methodology (TEAM)
April 28, 2004
Stakeholder Meeting 9:00 A.M. – 3:00 P.M.
Technical Session 3:15 P.M. – 6:00 P.M.
CA ISO Board Room
101 Blue Ravine Road, Folsom, CA 95630
Dial-In Number: (800) 341-6239
Conference ID #: 6968028

9:00 A.M. Welcome and Overview – Jeff Miller
- Progress and schedule
- Example application of economic methodology
- The evolving grid planning process and CA regulatory process

10:00 A.M. Process for MSC Opinion – Jim Bushnell, MSC Member

10:15 A.M. Assumptions Update – Steven Broad

10:45 P.M. Summary of Results-to-Date – Anna Geevarghese & Jing Chen

11:45 P.M. Lunch Break

12:15 P.M. Summary of Results-to-Date (continued) – Anna Geevarghese & Jing Chen

1:15 P.M. Plexos Model -- Glenn Drayton[1]
- Overview
- Questions

2:45 P.M. Conclusion – Anjali Sheffrin

3:00 P.M. Adjourn Stakeholder Meeting

3:15 P.M. Technical Session – Plexos Discussion and Demonstration

6:00 P.M. Adjourn Technical Session

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[1] Dr. Glenn Drayton is the founder of Drayton Analytics Pty Ltd and the developer of the Plexos software model. Drayton Analytics is located in Adelaide, South Australia. Additional information on Drayton Analytics and Plexos can be found at: http://www.draytonanalytics.com

MARKET NOTICE
April 15, 2004

Transmission Economic Assessment Methodology (TEAM) Stakeholder Meeting - April 28th, 2004

ISO Market Participants/TEAM Stakeholders:

The next meeting of the Transmission Economic Assessment Methodology (TEAM) stakeholder group is scheduled for Wednesday, April 28th from 10:00 to 3:00 at the California ISO's offices in Folsom. The agenda for the meeting will follow early next week. If you would like to attend this meeting, please RSVP by noon on April 22nd to Linda Wright at mailto:lwright@caiso.com. Lunches will only be provided for those that RSVP.

A number for those unable to attend that wish to listen in will be included on the agenda. Please note that those listening in will be unable to participate in the discussions.

If you have any questions regarding this meeting, please contact Eric Toolson at (916) 608-7156.

Client Relations Communications.0724
CRCommunications@caiso.com <mailto:CRCommunications@caiso.com>

(Sign-In please,

Transmission Economic Assessment Methodology (TEAM) Stakeholder Meeting
April 28, 2004 9:00 a.m. - 3:00 p.m.
California ISO North and South Lake Tahoe Conference Rooms

NAME	COMPANY	EMAIL ADDRESS	PHONE NUMBER
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Altman, Art	EPRI	aaltman@epri.com	650 855 8740
Amirali, Ali	Calpine Corporation	aamirali@calpine.com	925-570-4256
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Arnold, Shaune	Alvarado Smith & Sanchez for LADWP	shaunearnoldesq@cs.com	213-229-2400 X2438
Bracht, Kirk	CPUC	kwb@cpuc.ca.gov	415-703-2868
Brown, Linda	San Diego Gas & Electric	lpbrown@semprautilities.com	858-654-6477
Causley, Marianne	CEC	Mcausley@energy.state.ca.us	916-657-3773
Chang, Ed	Flynn Resource Consultants, Inc.	edchang@flynnrci.com	925-634-7500
El-Gasseir, Mohamed	CERS	mel@water.ca.gov	916-574-0294
Elliott, Robert	CPUC	rae@cpuc.ca.gov	
Falls, Chuck	SRP	czfalls@srpnet.com	602-236-0965
Filippi, Jim	Pacific Gas & Electric	JLFa@pge.com	415-973-6530
Flynn, Tom	California Power Authority	thomas.flynn@dgs.ca.gov	916-651-9756
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Patel, Kishore	San Diego Gas & Electric	Kpatel@semprautilities.com	858-654-8231
Pereira, Les	No. Calif. Power Agency	Les.Pereira@ncpa.com	916-781-4218

Transmission Economic Assessment Methodology (TEAM) Stakeholder Meeting
April 28, 2004   9:00 a.m. - 3:00 p.m.
California ISO North and South Lake Tahoe Conference Rooms

NAME	COMPANY	EMAIL ADDRESS	PHONE NUMBER
Price, Jim	CAISO	jprice@caiso.com	916 608 5725
Rochlin, Cliff	So. California Gas Companuy	crochlin@semprautilities.com	213-244-2451
Romanowitz, Hal		hal@rwitz.net	
Schilberg, Gayatri	JBS Energy, Inc.	Gayatri@JbsEnergy.com	916-372-0534 X104
Schneider, Susan	Phoenix Consulting	schneider@phoenix-co.com	916-797-3106
Silsbee, Carl	Southern Calif. Edison	carl.silsbee@sce.com	626-302-1708
Woodruff, Kevin	Woodruff Expert Services	kdw@woodruff-expert-services.com	916-449-9941
Woods, Gregory	Roseville Electric	gwoods@roseville.ca.us	
TOM MILLER	PG&E	TCM3@PGE.COM	415-973-2070
Fred Mobasheri	EPG	~~275~~ / fmobasheri@aol.	310-877-8671
BERNARD LESIEUTRE	Lawrence Berkeley Lab	blesieutre@lbl.gov	510-486-6527

(191)

Visitor Log For Building 101

Date: 4-28-04

Name	Company	Reason For Visiting ISO	Driver License No.	Time In	Time Out
P Calvery	PG&E	training	W5362270	0716	
M Maffei	PG&E	TRAINING	R0363705	0748	
K. Mosier	SCE	TRAINING	R0158556	0750	
J. Godinez	"	"	N0584525	"	
G. Shearer	SCE	Training	N9448247	755	
J Regan	PGE	Training	A1008124	0750	
[illegible]	PG&E	class	[illegible]	0800	
[illegible]	PG&E	TRNG	K0681432	0800	
[illegible]	SDG&E	Tr[illegible]	[illegible]	[illegible]	
Rich Benjamin	CEC	TEAM		8:15	1:50
Don Fleder	TISCO	[illegible]		8:30	
Chuck Falls	Salt River Proj	TEAM			
Carolyn Kehrein	EMS	TEAM		8:45	2:50
B James Bushnell	MSC	TEAM		8:45	3:30
Sherman Chen	PG&E	TEAM		8:45	
Wilh Ahern	CPUC	TR	11:20	8:45	
Mike McDuffin	ISO		#102		
~~[illegible]~~					
JEFF ELLIS	USE	TEAM	A7126245	8:56	
BRENT GOKBUDAK	SCE	TEAM	C2023322	8:58	
Michael Werner	CDWR	TEAM	N0310156		
Kishore Patel	SDG&E	TEAM			
KAREN GRIFFIN	CEC	TEAM			
Russ McRae	Arava	Settlements		9:00	
~~Tony Lam~~ Kev					
Steve Ghadiri	EOB	TEAM	N5209757	9:20	
T. McAuliffe	CEC	"			
MARK SKOWRONSKI	SOLARGENIX	"	P0110[illegible]	10:15	
Chris King	SDG&E	TEAM	B4203763	11:00	
Jason Osiow	summit	serv	B6122945	1150	1:20
Justin Jaramillo	summit	serv/maint	B7523730	11:50	1:20

Visitor Log For Building 101

Date: ____________________

Name	Company	Reason For Visiting ISO	Driver License No.	Time In	Time Out
Stephen [illegible]	Accountants Plus	Interview	B5374289	12:45	
ED CHANG	FLYNN RCI	Mtg.	B7593058	3:15	

Conference Participant Report
Conf. Date: 04/28/2004
Conf. Time: 09:00 am PT

Company: California ISO
Leader: Jeff Miller
Conference ID: 6968028

Start Time	End Time	Name	Additional Information	Number	Co/Leader
11:52:51	12:11:28	MR J MILLER LDR			LDR\MILLER
11:58:58	16:54:03	ROBERT DELGADO	CITY OF RIVERSIDE	9093516312	CALIF\MILLER
11:59:15	18:28:26	ENCORE RECORD\MILLER			CALIF\MILLER
11:59:17	15:03:08	THOMAS FLYNN	CA POWER AUTHORITY	9166518756	CALIF\MILLER
11:59:20	15:07:06	RICH LAUCKHART	HENWOOD	9166097769	CALIF\MILLER
11:59:32	15:02:14	BRUCE MCLAUGHLIN	CA MUNICIPAL UTILITY	9167211959	CALIF\MILLER
11:59:54	13:26:17	SUSAN SCHNEIDER	PHOENIX CONSULTING	9167973106	CALIF\MILLER
12:00:02	15:07:36	JOHN BURNETT	LADWP	2133671744	CALIF\MILLER
12:01:16	12:59:00	ED CHANG	FLYNN RCI	9169417271	CALIF\MILLER
12:01:41	14:51:39	KATHLEEN WRIGHT	CDWR	9165740346	CALIF\MILLER
12:01:42	12:31:08	GARY ACKERMAN	WESTERN POWER	6504442706	CALIF\MILLER
12:02:25	13:54:04	GRACE ANDERSON	CA ENERGY COMMISSION	9166544999	CALIF\MILLER
12:05:49	16:32:02	HEDY BORN	ASPEN ENVIRONMENTAL	4159554775	CALIF\MILLER
12:11:28	20:32:41	MR J MILLER LDR			CALIF\MILLER
12:18:06	12:32:04	HAL ROMANOWITZ	OAK CREEK ENERGY	6617470990	CALIF\MILLER
12:24:59	20:30:06	MIKE EVANS	CORAL POWER	8585262103	CALIF\MILLER
12:31:00	13:17:32	KEITH CASEY	CALIFORNIA ISO	9166087125	CALIF\MILLER
12:32:02	13:26:37	JERRY ACKERMAN]R	WESTERN POWER	6504442706	CALIF\MILLER
12:32:25	13:08:46	HAL ROMANOWITZ]R	OAK CREEK ENERGY	6617470990	CALIF\MILLER
12:47:10	13:41:10	DILIP MAHENDRA	SMUD	9167429670	CALIF\MILLER
12:52:13	15:00:27	RICHARD TORRES	CITY OF AZUSA	6268125138	CALIF\MILLER
12:58:43	15:02:29	DARELL HOLMES	SOUTHERN CA EDISON	6263026498	CALIF\MILLER
13:05:27	14:48:59	MASOUD SHAFA	CALIFORNIA ISO	9163512216	CALIF\MILLER
13:08:48	15:03:26	ERIC WOYCHIK	STRATEGY INTEGRATION	5106352359	CALIF\MILLER
13:09:38	15:21:29	PUSHKAR WAGLE	LSG CONSULTING	6509629672	CALIF\MILLER
13:20:43	13:49:26	ARLIN TRAVIS	CORAL POWER	8583201520	CALIF\MILLER
13:24:04	13:56:11	KEITH CASEY]R	CALIFORNIA ISO	9166087125	CALIF\MILLER
13:24:50	13:48:41	SUSAN SCHNEIDER]R	PHOENIX CONSULTING	9167973106	CALIF\MILLER
15:20:28	18:11:18	RICH LAUCKHART]R	HENWOOD	9166097769	CALIF\MILLER
15:30:07	16:49:46	BRUCE MCLAUGHLIN]R	CA MUNICIPAL UTILITY	9167211959	CALIF\MILLER
15:33:06	16:17:27	RICHARD CLARK	LSG CONSULTING	4049481135	CALIF\MILLER
15:36:27	18:24:51	ERIC WOYCHIK]R	STRATEGY INTEGRATION	5106352359	CALIF\MILLER

Conference Participant Report
Conf. Date: 04/28/2004
Conf. Time: 09:00 am PT

Company: California ISO
Leader: Jeff Miller
Conference ID: 6968028

Start Time	End Time	Name	Additional Information	Number	Co/Leader
15:40:31	20:32:41	PUSHKAR WAGLE]R	LSG CONSULTING	6509629672	CALIF\MILLER
16:14:37	18:11:10	RICHARD TORRES]R	CITY OF AZUSA	6268125211	CALIF\MILLER
16:15:11	18:34:16	DARELL HOLMES]R	SOUTHERN CA EDISON	6263026498	CALIF\MILLER
16:29:15	18:23:31	KATHLEEN WRIGHT]R	CDWR	9165740346	CALIF\MILLER
16:49:15	19:10:00	JOHN BURNETT]R	LADWP	2136130063	CALIF\MILLER
17:49:37	18:07:15	CAROLYN KEHREIN	EMS	9165015891	CALIF\MILLER
18:21:50	20:24:11	BARRY FLYNN	FLYNN RCI	9169417038	CALIF\MILLER

Transmission Economic Assessment Methodology (TEAM)
Stakeholder Meeting

April 28, 2004

Encore (Playback) Information

Encore Dial-In #: (800) 642-1687
Conference ID #: 6968028

Fast Forward options are:

Press "1" to fast forward 5 seconds
Press "2" to fast forward 30 seconds

Recording available through 9:00 p.m. PST on May 5, 2004

Contact Linda Wright at (916) 351-4470 with any questions.

Conf ID	Call Date	Call Time	Duration	Phone #	Name	Phone Number	Company
6968028	04/29/04	16:07:20	00:41:40	6263024725	MOHAN JUNTA	6263024725	
6968028	04/29/04	16:27:27	00:48:42	6263028694	BRENT GOKBUDAK	6263028494	HBC
6968028	04/29/04	18:20:17	00:10:28	6263023134	NO MESSAGE		
6968028	04/30/04	10:05:19	00:00:48	9164523211	NO MESSAGE		
6968028	04/30/04	12:29:37	00:00:07	7702707638	NO MESSAGE		
6968028	04/30/04	12:31:37	00:07:10	7702707638	NO MESSAGE		
6968028	05/03/04	13:17:41	02:56:28	4805059076	NO MESSAGE		
6968028	05/03/04	14:58:33	00:07:26	4157031418	SCOTT LOGAN	RAY PIER	
6968028	05/03/04	16:32:15	00:00:41	4805059068	NO MESSAGE		
6968028	05/03/04	16:34:06	02:54:52	4805059069	NO MESSAGE		
6968028	05/03/04	19:48:33	00:08:39	4805059070	NO MESSAGE		

CAISO MARKET SURVEILLANCE COMMITTEE MEETING AGENDA

General Session

May 17, 2004 9:30 AM – 4:00PM

California ISO

101 Blue Ravine Road, Folsom, CA

		For Internal Use		
		Time keeper: Brad Barber		
	Item	Presenters/Attendees	Action Requested	Time
		Board Room – Bldg 101		
I	**General Session**			**9:30 AM – 4:00 PM**
	Public Comments			9:30 AM – 10:00 AM
Tab 1	1. Market Update	Doug Bergman (DMA)	• Update on the market performance of March-April 2004.	10:00 AM – 10:30 AM
Tab 2	2. Overview of Transmission Evaluation Methodology	Frank Wolak Anjali Sheffrin (DMA)	• Update the MSC on the topic	10:30AM – 11:00 AM
Tab 3	3. Review of Input Assumptions	Frank Wolak Steven Broad (DMA)	• Update the MSC on the topic	11:00 AM – 11:30 AM
Tab 4	4. Cost based Pricing Results	Jim Bushnell Anna Geevarghese (DMA)	• Update the MSC on the issues related to the topic and solicit their input	11:30 AM – 12:30 PM
II	**Lunch**			**12:30 PM – 1:15 PM**
Tab 4	5. Market Pricing Results	Ben Hobbs/Brad Barber Jing Chen (DMA)	• Update the MSC on the topic and solicit their input	1:15 PM – 2:00 PM
Tab 5	6. MSC Opinion on Transmission Methodology	Frank Wolak Ben Hobbs	• Provide a draft outline of the opinion.	2:00 PM – 3:00 PM
Tab 6	7. Zonal Distribution of A/S Procurement – Splitting the Markets by Zone	Frank Wolak Jeff McDonald (DMA)	• Update the MSC on the issues related to the topic and solicit their input	3:00 PM – 4:00 PM
	Meeting Adjourned			*4:00 PM*

CALIFORNIA ISO

FINAL
Released: May 10, 2004

PUBLIC NOTICE:
MARKET SURVEILLANCE COMMITTEE MEETING

The Market Surveillance Committee of the California Independent System Operator will meet:

Date:	May 17, 2004
Time:	9:30 a.m. to 4:00 p.m. PDT
Location:	Offices of the California ISO, Lake Tahoe Conference Room (Previously named 101A-1A&1B)

During the above-noticed meeting, the Market Surveillance Committee, an Advisory Committee to the Board of Governors and ISO management, will discuss the following agenda items:

GENERAL SESSION **9:30 a.m. to 4:00 p.m.**
*** Call in Number (Listen Only) (877) 417-9307, Conference ID#: 7270604

1) Public Comments

2) Market Update

3) Overview of Transmission Evaluation Methodology
4) Review of Input Assumptions
5) Cost Based Pricing Results
6) Lunch (Please RSVP to canderson@caiso.com by 5/13/04 if you are planning to attend the meeting in person. This will enable us to provide you with adequate seating and lunch during the meeting.)
7) Market Pricing Results
8) MSC Opinion on Transmission Methodology

9) Zonal Distribution of A/S Procurement- Splitting the Markets by Zone

Note that this call-in number is available for convenience purposes only. The MSC encourages the public to attend the meeting in person to best promote a direct dialogue on key issues. Listeners should not rely on listening to meetings as a means to glean the final MSC opinion on any topic. MSC discussions are fast-paced and listening to only a portion of the meeting may leave the wrong impression on the position of any MSC member on a discussion topic. Only final MSC opinions which are published represent the position of the MSC.

The meeting documents are posted to the Web site. The California ISO Web site address is: http://www.caiso.com

Market Notice

May 3, 2004

Market Surveillance Committee Meeting – May 17, 2004

ISO Market Participants:

The CAISO will be hosting a Market Surveillance Committee meeting on May 17, 2004. The General Session will be held from 9:30am to 4:00pm. Lunch will be provided. The meeting will take place at the CAISO headquarters, 101 Blue Ravine Road, Folsom, CA, in the Lake Tahoe Conference Room (previously known as the 101 1A/1B Conference Room).

If you are planning to attend this meeting, please R.S.V.P. to Cheryl Anderson at 916-608-7080 or canderson@caiso.com by May 13, 2004. This will enable us to provide you with adequate seating and lunch during the meeting.

For your convenience a **listen only** conference call number has been arranged for the General Session. The dial-in number is (877) 417-9307.

The agenda is posted at http://www.caiso.com/meetings/. The relevant documents will be posted on the CA ISO meeting calendar at the following link http://www.caiso.com/pubinfo/BOG/documents/market/msc/ by noon on May 14, 2004.

Note that this call-in number is available for convenience purposes only. The MSC encourages the public to attend the meeting in person to best promote a direct dialogue on key issues. Listeners should not rely on listening to meetings as a means to glean the final MSC opinion on any topic. MSC discussions are fast- paced and listening to only a portion of the meeting may leave the wrong impression on the position of any MSC member on a discussion topic. Only final MSC opinions which are published represent the position of the MSC.

Market Notice

May 13, 2004

<u>Market Surveillance Committee Meeting – May 17, 2004</u>

****** THE MSC IS SOLICITING STAKEHOLDER INPUT ON THE ISO'S **** PROPOSED TRANSMISSION EXPANSION METHODOLOGY**

If you wish to make a public statement please email Anna Geevarghese at ageevarghese@caiso.com or Cheryl Anderson at canderson@caiso.com by close of business Friday, May 14, 2004.

ISO Market Participants:

The CAISO will be hosting a Market Surveillance Committee meeting on May 17, 2004. The General Session will be held from 9:30am to 4:00pm. Lunch will be provided. The meeting will take place at the CAISO headquarters, 101 Blue Ravine Road, Folsom, CA, in the Lake Tahoe Conference Room (previously known as the 101 1A/1B Conference Room).

If you are planning to attend this meeting, please R.S.V.P. to Cheryl Anderson at 916-608-7080 or canderson@caiso.com by May 13, 2004. This will enable us to provide you with adequate seating and lunch during the meeting.

For your convenience a **<u>listen only</u>** conference call number has been arranged for the General Session. The dial-in number is (877) 417-9307. The conference ID is **7270604.**

The agenda is posted at http://www.caiso.com/meetings/. The relevant documents will be posted on the CA ISO meeting calendar at the following link http://www.caiso.com/pubinfo/BOG/documents/market/msc/ by Noon on May 14, 2004.

Note that this call-in number is available for convenience purposes only. The MSC encourages the public to attend the meeting in person to best promote a direct dialogue on key issues. Listeners should not rely on listening to meetings as a means to glean the final MSC opinion on any topic. MSC discussions are fast- paced and listening to only a portion of the meeting may leave the wrong impression on the position of any MSC member on a discussion topic. Only final MSC opinions which are published represent the position of the MSC.

MARKET SURVEILLANCE COMMITTEE MEETING
CALIFORNIA INDEPENDENT SYSTEM OPERATOR
May 17, 2004

General Session: 9:30 AM – 4:00 PM
Offices of the California ISO, North & South Lake Tahoe Conference Rooms

MEETING SIGN-IN

Initials	NAME	COMPANY	EMAIL ADDRESS	PHONE NUMBER
	Frank Wolak	MSC Chair	[wolak@zia.stanford.edu]	(650) 723-3944
BMB	Brad Barber	MSC Member	[bmbarber@ucdavis.edu]	(530) 752-0512
JBB	Jim Bushnell	MSC Member	[bushnell@haas.berkeley.edu]	(510) 642-7316
	Ben Hobbs	MSC Member	[bhobbs@jhu.edu]	(410) 516-4681
	Anna Geevarghese	CAISO	[ageevarghese@caiso.com]	(916) 608-7072
	Farrokh Rahimi	CAISO	[frahimi@caiso.com]	(916) 608-7128
	Dan Shonkwiler	CAISO	[dshonkwiler@caiso.com]	(916) 608-7015
	Sidney Jubien	CAISO	[sjubien@caiso.com]	(916) 608-7144
	Keith Casey	CAISO	[kcasey@caiso.com]	(916) 608-7125
	Greg Cook	CAISO	[gcook@caiso.com]	(916) 608-7202
	Eric Hildebrandt	CAISO	[ehildebrandt@caiso.com]	(916) 608-7123
	Jeff McDonald	CAISO	(jmcdonald@casio.com)	(916) 608-7236

Anjali Sheffrin [illegible]

MARKET SURVEILLANCE COMMITTEE MEETING
CALIFORNIA INDEPENDENT SYSTEM OPERATOR

May 17, 2004

General Session: 9:30 AM – 4:00 PM
Offices of the California ISO, North & South Lake Tahoe Conference Rooms

MEETING SIGN-IN

Initials	NAME	COMPANY	EMAIL ADDRESS	PHONE NUMBER
	Doug Bergman	CAISO	(dbergman@caiso.com)	(916) 608-7276
	Lorenzo Kristov	CAISO	[lkristov@caiso.com]	(916) 608-7129
	Brian Theaker	CAISO	[btheaker@caiso.com]	(916) 608-7282
	Brett Franklin	CEOB	bfranklin@eob.ca.gov	916.233.9275
	Tony Law	CEOB	tlaw@eob.ca.gov	916-322-8632
	Charles Faust	FERC	charles.faust@ferc.gov	916-294-0163
	Jing Chen	CAISO	jchen@caiso.com	916-608-7009
	Mingxia Zhang	CAISO	mzhang@caiso.com	916-608-7054
	JINGCHAO MI	CDWR	jmi@water.ca.gov	916-574-0669
	KISHORE PATEL	SDG&E	KPATEL@SEMPRAUTILITIES.COM	858-654-8231
	CLIFF ROCHLIN	SOCALGAS	CROCHLIN@SEMPRAUTILITIES.COM	213-244-2451
	JIM FILIPPI	PG&E	JLF@@pge.com	(415) 973-6530

MARKET SURVEILLANCE COMMITTEE MEETING
CALIFORNIA INDEPENDENT SYSTEM OPERATOR
May 17, 2004

General Session: 9:30 AM – 4:00 PM
Offices of the California ISO, North & South Lake Tahoe Conference Rooms

MEETING SIGN-IN

Initials	NAME	COMPANY	EMAIL ADDRESS	PHONE NUMBER
	Bernard Lam	PG&E	BxLc@pge.com	(415) 973-4878
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	KIRK BRACHT	CPUC	KWB@CPUC.CA.GOV	(415) 703-2868
	Susan Schneider	Phoenix Consulting	schneider@phoenix-co.com	916-797-3106
	Steve Huhman	Mirant	steve.huhman@mirant.com	925-287-3120
	Dorell Holmes	SCE	holmesdf@SCE.COM	626.302.6498
	CARL SILSBEE	SCE	carl.silsbee@sce.com	626-302-1708
	Jane Turnbull	LWVC	jaturnbu@ix.netcom.com	650 559-1766
	Steven Broad	CAISO	sbroad@caiso.com	
	Jeff Miller	CAISO	jmiller@caiso.com	916-351-4464
	Farrokh Rahimi	CAISO (Consultant)	frahimi@caiso.com	916-608-7128
	Rich Lauckhart	HENWOOD	RLAUCKHART@HENWOODENERGY.COM	916-609-7769

MARKET SURVEILLANCE COMMITTEE MEETING
CALIFORNIA INDEPENDENT SYSTEM OPERATOR

May 17, 2004

General Session: 9:30 AM – 4:00 PM
Offices of the California ISO, North & South Lake Tahoe Conference Rooms

MEETING SIGN-IN

Initials	NAME	COMPANY	EMAIL ADDRESS	PHONE NUMBER
	Mariam Mirzadeh	WAPA	mirzadeh@wapa.gov	916-353-4552

CONFERENCE BILLING DETAIL

Billing Detail for Conference 7270604

For questions about the invoice information or other billing information, please call 1-800-374-2549.

Conference	Date	Time	Attendees	Minutes	Charged
7270604	05/17/04	11:54 AM	34	5538	$2,926.90

Attendee	Connect Time	Minutes	Charge
RAMONA GONZALEZ/EAST BAY MUD (LEG CHARGES)	6:10		0.00
RAMONA GONZALEZ/EAST BAY MUD (MINUTES CHARGES)	6:10	8	2.00
MOHAMED ELGASSIER/RUMLA INC (LEG CHARGES)	3:20		0.00
MOHAMED ELGASSIER/RUMLA INC (MINUTES CHARGES)	3:20	168	42.00
WES WILLIAMS/SOUTHERN CA EDISO (LEG CHARGES)	4:24		0.00
WES WILLIAMS/SOUTHERN CA EDISO (MINUTES CHARGES)	4:24	33	8.25
DILLIP MAHENDRA/SMUD (LEG CHARGES)	1:05		0.00
DILLIP MAHENDRA/SMUD (MINUTES CHARGES)	1:05	119	29.75
ALLEN COMBS/DINDBY (LEG CHARGES)	11:54		0.00
ALLEN COMBS/DINDBY (MINUTES CHARGES)	11:54	158	39.50
HEDY BORN/ASPEN ENVOROMENTAL G (LEG CHARGES)	12:36		0.00
HEDY BORN/ASPEN ENVOROMENTAL G (MINUTES CHARGES)	12:36	114	28.50
ROSE STEAR/PPL MONTANA (LEG CHARGES)	12:43		0.00
ROSE STEAR/PPL MONTANA (MINUTES CHARGES)	12:43	20	5.00
DIANA MAHMUD/METROPOLITAN WATE (LEG CHARGES)	1:39		0.00
DIANA MAHMUD/METROPOLITAN WATE (MINUTES CHARGES)	1:39	18	4.50
RAMONA GONZALEZ/EASTBAY MUD (LEG CHARGES)	12:45		0.00
RAMONA GONZALEZ/EASTBAY MUD (MINUTES CHARGES)	12:45	116	29.00
RAY OLSON/CA ELEC OVERSITE BOA (LEG CHARGES)	12:46		0.00
RAY OLSON/CA ELEC OVERSITE BOA (MINUTES CHARGES)	12:46	155	38.75
CHUCK FALLS/SALT RIVERS PROJEC (LEG CHARGES)	12:30		0.00
CHUCK FALLS/SALT RIVERS PROJEC (MINUTES CHARGES)	12:30	294	73.50
WES WILLIAMS/S.CALFORNIA EDISO (LEG CHARGES)	6:16		0.00
WES WILLIAMS/S.CALFORNIA EDISO (MINUTES CHARGES)	6:16	2	0.50
KATHLEEN WRIGHT/CDWR (LEG CHARGES)	12:46		0.00
KATHLEEN WRIGHT/CDWR (MINUTES CHARGES)	12:46	68	17.00

SHAUNE ARNOLD/ALVARADO SMITH&S (LEG CHARGES)	12:47		0.00
SHAUNE ARNOLD/ALVARADO SMITH&S (MINUTES CHARGES)	12:47	330	82.50
SHAWN BAILEY/SEMPRA ENERGY (LEG CHARGES)	1:31		0.00
SHAWN BAILEY/SEMPRA ENERGY (MINUTES CHARGES)	1:31	89	22.25
ENCORE RECORD\GEEVAR (LEG CHARGES)	12:06		0.00
ENCORE RECORD\GEEVAR (MINUTES CHARGES)	12:06	371	92.75
ALLAN COMNES/DYNEGY (LEG CHARGES)	2:32		0.00
ALLAN COMNES/DYNEGY (MINUTES CHARGES)	2:32	226	56.50
BOB TANG/CITY OF AZUSA (LEG CHARGES)	12:47		0.00
BOB TANG/CITY OF AZUSA (MINUTES CHARGES)	12:47	230	57.50
MOHAMED ELGASSEIR/RUMLA INC (LEG CHARGES)	12:48		0.00
MOHAMED ELGASSEIR/RUMLA INC (MINUTES CHARGES)	12:48	136	34.00
SUSAN SCHNEIDER/PHEONIX CON SA (LEG CHARGES)	12:37		0.00
SUSAN SCHNEIDER/PHEONIX CON SA (MINUTES CHARGES)	12:37	19	4.75
SHAWN BAILEY/SEMPRA ENERGY (LEG CHARGES)	12:34		0.00
SHAWN BAILEY/SEMPRA ENERGY (MINUTES CHARGES)	12:34	25	6.25
WESTON WILLIAMS/SOUTHERN CA ED (LEG CHARGES)	12:34		0.00
WESTON WILLIAMS/SOUTHERN CA ED (MINUTES CHARGES)	12:34	28	7.00
JEFFERY NELSON/SCE (LEG CHARGES)	5:04		0.00
JEFFERY NELSON/SCE (MINUTES CHARGES)	5:04	74	18.50
MIKE EVANS/CORAL POWER (LEG CHARGES)	12:31		0.00
MIKE EVANS/CORAL POWER (MINUTES CHARGES)	12:31	347	86.75
KATHER BODINE/CAL ISO (LEG CHARGES)	12:32		0.00
KATHER BODINE/CAL ISO (MINUTES CHARGES)	12:32	95	23.75
MS A GEEVARGHESE LDR (LEG CHARGES)	12:35		0.00
MS A GEEVARGHESE LDR (MINUTES CHARGES)	12:35	343	85.75
STEVE DIRI/EOB (LEG CHARGES)	12:49		0.00
STEVE DIRI/EOB (MINUTES CHARGES)	12:49	328	82.00
DAVID KATES (LEG CHARGES)	4:41		0.00
DAVID KATES (MINUTES CHARGES)	4:41	19	4.75
TAPE RECORD\GEEVARGH (LEG CHARGES)	12:13		0.00
TAPE RECORD\GEEVARGH (MINUTES CHARGES)	12:13	364	91.00
SARA TECTOU/OAK CREEK ENERGY (LEG CHARGES)	12:30		0.00
SARA TECTOU/OAK CREEK ENERGY (MINUTES CHARGES)	12:30	348	87.00
TIM HANNA/SAMPRA ENERGY TRADIN (LEG CHARGES)	1:01		0.00
TIM HANNA/SAMPRA ENERGY TRADIN (MINUTES CHARGES)	1:01	317	79.25
(MINUTES CHARGES)	2:04	163	24.45
(LEG CHARGES)	2:04		0.00
(LEG CHARGES)	8:16		0.00
(MINUTES CHARGES)	8:16	340	51.00
(LEG CHARGES)	12:52		0.00
(MINUTES CHARGES)	12:52	73	10.95

Vanda, Deborah

Distribution List Name: TEAM Base Case

Members:

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Xuguang Leng	xgl@cpuc.ca.gov
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TEAM Subgroup:

II. Base case Assumptions for Network & Production Cost

1. Eric Toolson
2. Mohamed Awad
3. LUIS PANDO
4. ANNA GEEVARGHESE

Draft Agenda
TEAM Subgroup – Base Case Assumptions
Monday, February 9, 2004
9:00 to 10:30 am
Call-in Number – xxx-xxx-xxxx

Discussion Topics:

1. Should new generation entry be:
    a. only economically based
    b. minimum reserve margin
    c. minimum portfolio standard
    d. all three above

2. If the new generation entry should include reserve margin and portfolio standards, what should those parameters be in 2008 and 2013? Should the margin and standard be applied at a regional, or sub-regional level?

3. Review renewable percentages and margins in SSG_WI gas and renewable scenarios (see Attachments #1, #2, and #3).

4. Review costs of new entry and application and potential generation expansion methodology (see Attachments #4 and #5).
    a. build out renewable portfolio to standard
    b. build out transmission expansion plan to accommodate renewable portfolio
    c. build out to achieve planning reserve margin with CT's and CC's
    d. evaluate economic entry of additional CT's or CC's (compare net revenue to annual fixed costs)
    e. evaluate new transmission additions to accommodate economic entry and iterate until no additional economic entry is feasible

5. Date, time, and potential issues for next meeting
    a. proposed date and time
    b. inflation rate
    c. natural gas forecast
    d. renewable expansion plan
    e. 2008 draft cost-based nodal case results
    f. other

Group Members:

- Mohamed Awad, CAISO – (916) 608-7156
- Linda Brown, SDG&E – (858) 654-6477
- Sherman Chen, PG&E – (415) 973-5268
- Anna Geevarghese, CAISO -- (916) 608-7072
- Mark Hesters, CEC – (916) 654-5049
- Darrell Holmes, SCE – (626) 302-6498
- Mohan Kondragunta, SCE – (626) 302-6498
- Xuguang Leng, CPUC – (415) 703-2801
- Tom Miller, PG&E – (415) 973-2070
- Luis Pando, So. Cal. Gas – (213) 244-3708
- Les Pereira, NCPA – (916) 781-4218
- Angela Tanghetti, CEC – (916) 654-4854
- Eric Toolson, CAISO consultant – (916) 608-7156

Other Recipients of Meeting Notices:

- Brent Gokbudak, SCE
- Jeff Miller, CAISO
- Anjali Sheffrin, CAISO

Attachments:

1. "Final SSG-WI Transmission Report – Appendix D1", table title "Western Interconnection % Energy by Fuel Source", p. 30, October, 2003. Website is: http://www.ssg-wi.com/documents/317-FERC_Filing 103103 FINAL Appx_D1_FINAL_103103.pdf

2. "Final SSG-WI Transmission Report", table title "Figure IV-3: Generation Mix in GWH/year-Western Interconnection", p. 23, October, 2003. Website is: http://www.ssg-wi.com/documents/316-FERC_Filing 103103 FINAL_TransmissionReport.pdf

3. See Attachment 1, "Renewable Portfolio Energy Percentages From SSG-WI Study".

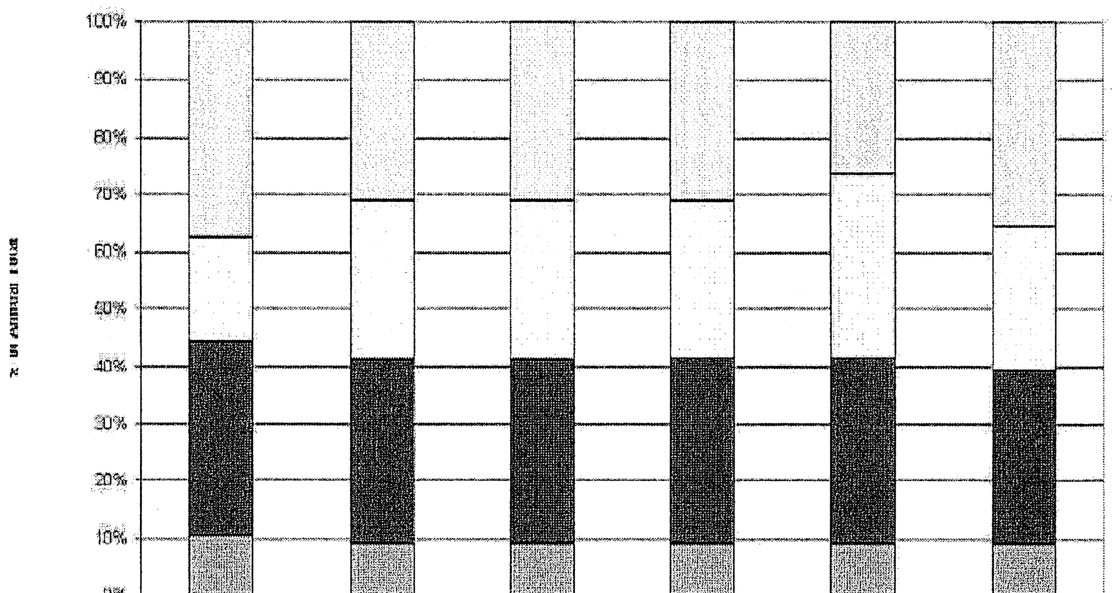
4. "Comparitive Costs of California Central Station Electricity Generation Technologies"; California Energy Commission; 100-03-001F; June 5, 2003 Table C 10 -- Cost Summary (Combined-Cycle Baseload without Duct Firing). Website is: http://www.energy.ca.gov/reports/2003-06-06_100-03-001F.PDF.

5. Ibid., Table D 10 – Cost Summary (Combustion Turbine).

6. Notes from telephone conversations:

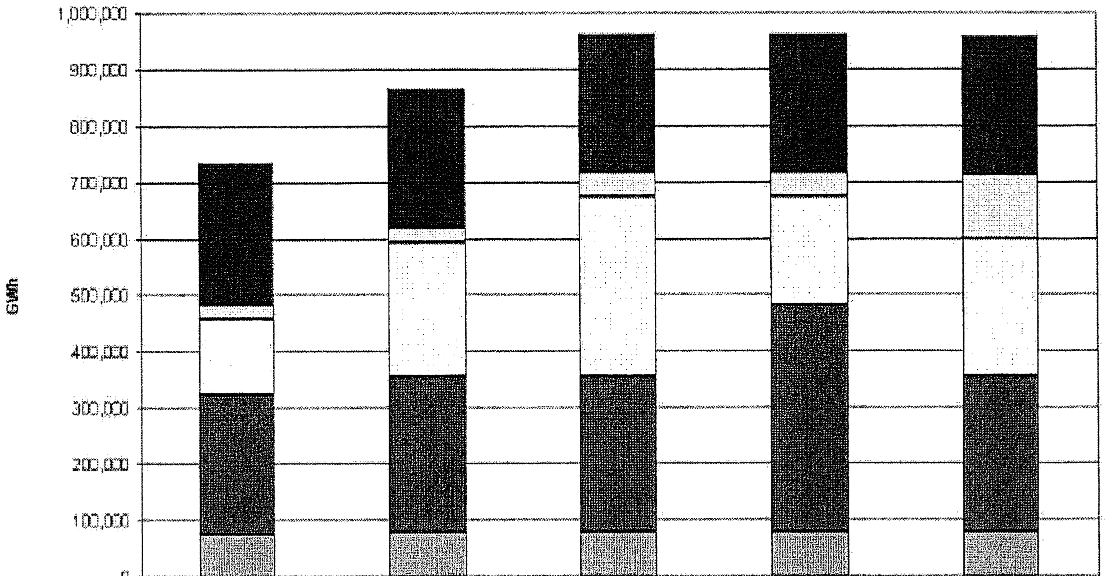
- Avista – Avista's planning reserve is10% of peak plus 90 MW which gives them a 15%-16% planning reserve margin (using project dependable capacity, and not nameplate, for hydro). No real renewable standard yet, and none required by the WUTC at this time.
- SRP – SRP uses 12 percent for planning reserve margin. SRP is in process of developing renewable portfolio standard and it will be defined by the Spring. They expect it to be comparable to ACC's requirement for APS and TEC, which is 1.1 percent renewable. Of that amount, 60 percent must be solar (strong solar lobby). The mandate goes through 2012 and includes only low-head hydro (none existing). He believes that the New Mexico's standard is much higher.

Attachment 1
WECC Renewable Percentages from SSG-WI Study



	1998 Expected MWh	2008 One Area - AW MG	2008 AW MG	2008 AW HG	2008 LW HG	2008 HW MG
Renewables	37.5%	31.2%	31.2%	31.2%	26.5%	35.5%
Gas	18.1%	27.5%	27.5%	27.3%	32.0%	25.1%
Coal	34.1%	32.3%	32.3%	32.3%	32.4%	30.5%
Other	10.3%	9.0%	9.0%	9.1%	9.1%	9.0%

Attachment 2
Breakdown of "Renewables" into "Hydro" and "Other Renewables"



	1998 Expected MWh	2008 AW MG	Gas 2013 NC	Coal 2013	Renewable 2013
Hydro	251,658	246,090	246,090	246,090	246,090
Renewables	23,889	24,244	42,395	42,396	112,884
Gas	132,593	237,926	317,224	191,767	243,676
Coal	249,972	279,813	279,839	405,367	277,929
Other	75,905	77,634	77,359	77,359	77,359

Attachment 3
Renewable Portfolio Energy Percentages From SSG-WI Study

	1998 (gWh)	1998 (%)	2008 (gWh)	2008 (%)	2013 Gas (gWh)	2013 Gas (%)	2013 Renew. (gWh)	2013 Renew. (%)
Hydro	251,658	34%	246,090	28%	246,090	26%	246,090	26%
Renewables	23,889	3%	24,244	3%	42,395	4%	112,984	12%
Gas	135,593	18%	237,925	27%	317,224	33%	243,675	25%
Coal	249,972	34%	279,813	32%	279,839	29%	277,929	29%
Other	75,905	10%	77,634	9%	77,359	8%	77,359	8%
Total	**737,017**	**100%**	**865,706**	**100%**	**962,907**	**100%**	**958,037**	**100%**

Attachment 4
CC Annual Fixed Costs

Table C-10
Cost Summary

Financing Costs ($/kW-Yr)	75
Fixed Operational Costs ($/kW-Yr)	15
Tax (w/Credits) ($/kW-Yr)	1
Fixed Costs	**90**
Fuel Costs ($/kW-Yr)	307
Variable O&M ($/kW-Yr)	19.09
Variable Costs	**326**
Total Levelized Costs ($/kW-Yr)	**416**
Capital ($/MWH)	11.25
Variable ($/MWH)	40.59
Total Levelized Costs ($/MWH)	**51.84**
Capital Costs	
Instant Cost ($/kW)	542
Installed Cost ($/MWH)	592
In-service Cost in 2004 ($/KW)	**616**

Attachment 5
CT Annual Fixed Costs

Table D-10
Cost Summary

Financing Costs ($/kW-Yr)	57
Fixed Operational Costs ($/kW-Yr)	20
Tax (w/Credits) ($/kW-Yr)	1
Fixed Costs	**78**
Fuel Costs ($/kW-Yr)	42
Variable O&M ($/kW-Yr)	9
Variable Costs	**51**
Total Levelized Costs ($/kW-Yr)	**129**
Capital ($/MWH)	94.99
Variable ($/MWH)	62.11
Total Levelized Costs ($/MWH)	**157.11**
Capital Costs	
Instant Cost ($/kW)	417
Installed Cost ($/MWH)	456
In-service Cost in 2004 ($/KW)	**475**

Attendance for Feb. 9, 2004

Linda Brown, SDG&E – (858) 654-6477
Sherman Chen, PG&E – (415) 973-5268
Mark Hesters, CEC – (916) 654-5049
Darrell Holmes, SCE – (626) 302-6498
Mohan Kondragunta, SCE – (626) 302-6498
Xuguang Leng, CPUC – (415) 703-2801
Tom Miller, PG&E – (415) 973-2070
Luis Pando, So. Cal. Gas – (213) 244-3708
Les Pereira, NCPA – (916) 781-4218
Angela Tanghetti, CEC – (916) 654-4854
Brent Gokbudak, SCE

Draft Agenda
TEAM Subgroup – Base Case Assumptions
Friday, February 13, 2004
9:00 to 10:30 am
Call-in Number – (888) 261-7938
Conference Code 1251037

Discussion Topics:

1. Review worksheet on renewable percentages and hopefully close on renewable target
   a. Study is not intended to be evaluation of renewables
   b. Renewable resources will be held constant for the "without" as well as "with" cases
   c. Largest question is RPS percentage in those areas where no state-approved RPS is in effect
   d. Will also discuss proposed new renewables, timing, type, and location for 2008

2. Review gas price worksheet and hopefully close on gas price forecast

3. Review Edison input / comments
   a. Appropriate capital costs for new CT's and CC's
   b. Expansion with either CC's w/o duct firing, or CC's w/ duct firing
   c. Seasonal heat rates for new CC's
   d. Start-up O&M estimates
   e. Interconnection cost estimates
   f. in 2008 and 2013? Should the margin and standard be applied at a regional, or sub-regional level?

4. Date, time, and potential issues for next meeting
   a. Next Thurs. from 1:30 to 3:00 pm ???
   b. Continue progress on generation expansion (renewables, reserve margins, and economic entry).

Approximation of Renewable Portfolio Standard for US Portion of WECC

No.	State	RPS in Place?	****************** Renewable Standards (%) *********** 2004	2008	2013	2018	Source	Notes
1	Arizona	yes	0.8%	1.1%	1.1%	1.1%	ACC Rules R14-2-1618; http://www.ies.ncsu.edu/dsire/library/docs/incentives/AZ03R.htm	1.1% by 2007-2012 (60% from solar); assume constant after 2012
2	California	yes	12.5%	16.1%	19.3%	19.7%	California Renewables Portfolio Standard (RPS), Senate Bill 1078, http://www.energy.ca.gov/reports/2003-07-01_100-03-009CR.PDF, p. 6.	includes hydro under 30 MW
3	Colorado	considering	4.6%	10.0%	15.7%	20.4%	House Bill 1273 (passed House not Senate yet), http://www.solaraccess.com/news/story?storyid=6065	legislature considering state RPS
4	Idaho	no	9.5%	10.0%	10.0%	10.0%	see note #1	assume federal proxy
5	Montana	no	6.1%	8.5%	10.0%	10.0%	see note #1	assume federal proxy
6	Nevada	yes	6.0%	10.0%	15.0%	15.0%	Draft "Renewables Resources Development Report", CEC, 500-03-080D, Sept. 30, 2003; p. 21.	at least 5% from solar
7	New Mexico	yes	1.0%	7.0%	10.0%	10.0%	Draft "Renewables Resources Development Report", CEC, 500-03-080D, Sept. 30, 2003; p. 21.	assume constant after 2011
8	Oregon	no	5.7%	8.1%	10.0%	10.0%	see note #1	assume federal proxy
9	Utah	considering	2.7%	5.1%	8.1%	10.0%	see note #1, assume federal proxy	legislature considering state RPS, PacifiCorp supports federl RPS
10	Washington	no	5.9%	8.3%	10.0%	10.0%	see note #1	assume federal proxy
11	Wyoming	no	9.9%	10.0%	10.0%	10.0%	see note #2	assume federal proxy
	WECC Weighted		**7.5%**	**10.5%**	**13.2%**	**13.8%**		

Notes:

1 U.S. Senate version of RPS standard in federal Energy Bill

for 2001-02 session as a proxy for a standard that might ultimately be implemented. Source: "Integrated Resource Plan 2003", PacifiCorp, http://www.pacificorp.com/File/File25682.pdf . Add 0.6 percent per year until 10 percent target is reached.

Year	2004	2008	2013	2017
<u>LOAD (gWh -- #10):</u>				
PG&E	72,496	78,530	83,569	89,398
SCE	68,146	74,365	79,289	85,154
SDG&E	14,947	16,348	17,541	18,913
Total DA	23,192	24,712	26,767	28,511
Total Rest of State	67,502	74,940	78,973	82,920
Total State	**246,283**	**268,895**	**286,139**	**304,896**
<u>RENEWABLES TARGET (gWh -- #11):</u>				
PG&E	8,665	12,527	16,714	17,880
SCE	11,601	14,873	15,858	17,031
SDG&E	410	1,103	2,060	2,978
Total DA	2,127	3,255	4,863	5,702
Total Rest of State	8,015	11,454	15,795	16,548
Total State	**30,818**	**43,212**	**55,290**	**60,139**
<u>RENEWABLES TARGET (%):</u>				
PG&E	12%	16%	20%	20%
SCE	17%	20%	20%	20%
SDG&E	3%	7%	12%	16%
Total DA	9%	13%	18%	20%
Total Rest of State	12%	15%	20%	20%
Total State	**12.5%**	**16.1%**	**19.3%**	**19.7%**

Notes:

10 "Preliminary Renewable Resource Assessment", California Energy Commission, 100-03-009 CR, July 1, 2003; Appendix A "Estimation of Energy Requirements. to meet California's RPS by 2017" (section 1 of table), p. 47.

11 Ibid., (section 4 of table).

Year	Renew. (MW)	PSCo Peak Load (MW)	West Plains Peak Load (MW)	Renew. %
2004	300	5,500	1000	5%
2005	400	5,599	1,018	6%
2006	**500**	**5,700**	**1,036**	**7%**
2007	600	5,802	1,055	9%
2008	700	5,907	1,074	10%
2009	800	6,013	1,093	11%
2010	**900**	**6,121**	**1,113**	**12%**
2011	1000	6,232	1,133	14%
2012	1100	6,344	1,153	15%
2013	1200	6,458	1,174	16%
2014	1300	6,574	1,195	17%
2015	1400	6,692	1,217	18%
2016	1500	6,813	1,239	19%
2017	1600	6,936	1,261	20%
2018	1700	7,060	1,284	20%
2019	1800	7,188	1,307	21%
2020	**1800**	**7,317**	**1,330**	**21%**

No.	State	Plexos Trans Areas Loads	2008 TransArea's Load (gWh)	2002 Load (gWh)	2002 Renew. (gWh)	2002 Existing Percent (%)	2004 (%)	2004 (gWh)	2008 (%)	2008 (gWh)
1	Arizona	Arizona	86,822	54,713	100	0.2%	0.8%	695	1.1%	955
2	California	PG&E, SCE, SDG&E, LADWP, Imperial	280,028				12.5%	35,041	16.1%	45,001
3	Colorado	Colorado, WAPA RM	62,777	39,560	200	0.5%	4.6%	2,897	10.0%	6,295
4	Idaho	Idaho	17,296	10,899	900	8.3%	9.5%	1,636	10.0%	1,730
5	Montana	Montana, WAPA UM	12,881	8,117	400	4.9%	6.1%	789	8.5%	1,098
6	Nevada	Nevada, Sierra, WAPA LC	40,673	25,631	200	0.8%	6.0%	2,440	10.0%	4,067
7	New Mexico	New Mexico	21,145	13,325	100	0.8%	1.0%	211	7.0%	1,480
8	Oregon	40% of Northwest	67,378	42,460	1,900	4.5%	5.7%	3,824	8.1%	5,441
9	Utah	80% of PACE	32,702	20,608	300	1.5%	2.7%	868	5.1%	1,653
10	Washington	60% of Northwest	101,067	63,689	3,000	4.7%	5.9%	5,973	8.3%	8,399
11	Wyoming	20% of PACE	7,267	4,580	400	8.7%	9.9%	722	10.0%	727
	Total		**730,037**					**55,097**		**76,846**
	Weighted						**7.5%**		**10.5%**	

Notes:
10

2013 (%)	2013 (gWh)	2018 (%)	2018 (gWh)
1.1%	955	1.1%	955
19.3%	54,109	19.7%	55,234
15.7%	9,870	20.4%	12,790
10.0%	1,730	10.0%	1,730
10.0%	1,288	10.0%	1,288
15.0%	6,101	15.0%	6,101
10.0%	2,115	10.0%	2,115
10.0%	6,738	10.0%	6,738
8.1%	2,634	10.0%	3,270
10.0%	10,107	10.0%	10,107
10.0%	727	10.0%	727
	96,374		**101,053**
13.2%		**13.8%**	

Renewable Resource Requirement:

Year	2008		
Starting Amount	55,097	gWh	
Ending Amount	76,846	gWh	
New Resources -- WECC	21,749	gWh	
o CA	9,961	gWh	includes CA, excludes CFE
o NW	4,137	gWh	includes WA, ID, OR
o RM	4,496	gWh	includes MT, WY, UT, CO
o SW	3,156	gWh	includes AZ, NM, NV

PDC Assumptions:

Geothermal	100%	percentage of nameplate	
Biomass	100%	"	"
Digester Gas	100%	"	"
Solar	80%	"	"
Wind	20%	"	"

Capacity Factor Assumptions:

Geothermal	90%	see source # 31 below	
Biomass	80%	"	"
Digester Gas	85%	"	"
Solar	35%	assumed to be about 1/3	
Wind	35%	"	"

No.	Renew. Resource Name (region name / type)	General Location	Name-plate Capacity (MW)	Depend. Capacity (MW)	Capacity Factor (%)	Renew. Energy / Year (gWh)	Bus Location	Source
Total for US Portion of WECC:			**2,600**	**876**		**10,032**		
California:								
1	PG&E-Biomass 1	PG&E	25	25	80%	175		# 30
2	PG&E-Wind 1	Solano	100	20	35%	307		# 30
3	PG&E-Geothermal 1	Siskiyou	100	100	90%	788		# 30

4	PG&E-Wind 2	Alameda	160	32	35%	491		# 30
5	PG&E-Digester 1	PG&E	40	40	85%	298		# 30
6	SCE-Wind 1	Kern	1,695	339	35%	5,197		# 30
7	SCE-Biomass 1	Los Angeles	50	50	80%	350		# 30
8	SCE-Geothermal 1	Mono	50	50	90%	394		# 30
9	SDG&E-Wind 1	SDG&E	200	40	35%	613		# 30
10	Imperial-Geothermal 1	Imperial	180	180	90%	1,419		# 30
	Subtotal CA		**2,600**	**876**		**10,032**		
Northwest:								
1	NW-Geothermal 1	Idaho	300	300	90%	2,365	Ponderosa 230	# 32
2	NW-Geothermal 2	Idaho	40	40	90%	315	McCall 138	# 32
3	NW-Wind 1	Washington	250	50	35%	767	Ellensbg	# 32
4	NW-Wind 2	Washington	200	40	35%	613	Cusick	# 32
5	NW-Wind 3	Idaho	40	8	35%	123	Mt. Home	# 32
	Subtotal CA		**830**	**438**		**4183**		
Rocky Mountain:								
1	PACE-Geothermal 1	PACE	267	267	90%	2,105	Soda Springs	# 32
2	PACE-Solar 1	Utah	40	32	35%	123	Gonder 230	# 32
3	Colorado-Solar 1	Colorado	40	32	35%	123	Vilas 115	# 32
4	Wyoming-Wind 1	Wyoming	700	140	35%	2,146	Cusick	# 32
	Subtotal CA		**1047**	**471**		**4497**		
Southwest:								
1	Nevada-Geothermal 1	SPP	250	250	90%	1,971	Bordertown 345	# 32
2	New Mexico-Geothermal 1	New Mexico	40	40	90%	315	Luna 345	# 32
3	Arizona-Solar 1	Colorado	150	120	35%	460	Palo Verde	# 32
4	New Mexico-Wind 1	New Mexico	150	30	35%	460	Blackwr1	# 32
						3206		3,156

Sources:

30 "Renewable Resource Development Report"; California Energy Commission; Report # 500-03-080D, Sept. 30, 2002; Table 12, p. 94.

31 Ibid., pp. 94-95.

32 "Final Transmission Report - Appendix D2, Seems Steering Group - Western Interconnect, p. 14.

Natural Gas Prices for Electricity Generation

Region #	Region Name	CEC Source (#1)	** Burner-Tip Prices ** Nominal 2008 ($/mmbtu) (#1)	** Burner-Tip Prices ** Nominal 2013 ($/mmbtu) (#1)	** Wellhead Prices ** Nominal 2008 ($/mmbtu) (#2)	** Wellhead Prices ** Nominal 2013 ($/mmbtu) (#2)	****** Trans. Cost ****** Nominal 2008 ($/mmbtu) (#3)	****** Trans. Cost ****** Nominal 2013 ($/mmbtu) (#3)
1	NEW MEXICO	ave. of EL Paso South-NM and El Paso North-NM	4.51	5.54	3.41	4.27	1.09	1.26
2	ARIZONA	ave. of EL Paso South-AZ and El Paso North-AZ	4.51	5.54	3.41	4.27	1.09	1.26
3	NEVADA	Nevada South	4.83	5.88	3.41	4.27	1.42	1.61
4	WAPA L.C.	Nevada South	4.83	5.88	3.41	4.27	1.42	1.61
5	MEXICO-CFE	Rosarito	4.75	5.82	3.41	4.27	1.34	1.55
6	IMPERIAL	SDG&E	4.71	5.76	3.41	4.27	1.30	1.49
7	SANDIEGO	SDG&E	4.71	5.76	3.41	4.27	1.30	1.49
8	SOCALIF	So. Calif Prod	4.62	5.69	3.41	4.27	1.21	1.42
9	LADWP	SoCal Gas	4.71	5.76	3.41	4.27	1.30	1.49
10	PG AND E	PG&E	4.65	5.62	3.41	4.27	1.24	1.35
11	NORTHWEST	ave. of PNW and PNW-Coastal	4.68	5.68	3.41	4.27	1.27	1.40
12	B.C.HYDRO	British Columbia	4.29	5.22	3.41	4.27	0.88	0.95
13	AQUILA	Alberta	3.88	4.70	3.41	4.27	0.47	0.43
14	ALBERTA	Alberta	3.88	4.70	3.41	4.27	0.47	0.43
15	IDAHO	PNW	5.00	6.02	3.41	4.27	1.59	1.75
16	MONTANA	Montana	4.36	5.20	3.41	4.27	0.95	0.93
17	WAPA U.M.	Montana	4.36	5.20	3.41	4.27	0.95	0.93
18	SIERRA	Nevada North	5.04	6.07	3.41	4.27	1.63	1.80
19	PACE	Utah	4.29	5.09	3.41	4.27	0.88	0.82
20	PSCOLORADO	Colorado	4.31	5.11	3.41	4.27	0.90	0.84
21	WAPA R.M.	Colorado	4.31	5.11	3.41	4.27	0.90	0.84
	Average		**4.53**	**5.49**	**3.41**	**4.27**	**1.12**	**1.22**

Sources:

1 "Electricity and Natural Gas Assessment Report", California Energy Commission, Commission Report, December, 2003, 100-03-014F, Table A-19b, "Natural Gas Prices For Electricity Generation", p. A-25.

2 For derivation of Wellhead Prices, see second worksheet.

3 The "transportation costs" is intended to include all charges from wellhead to burner-tip such as gathering / conditioning charges, transportaiton charges, and utility distribution charges.

Wellhead Prices

Assumptions:

	****** 2000 $ / mcf ******		*** 2000 $ / mmbtu *****		**Nominal $ / mmbtu**	
Producing Region (#10)	**2008 (#11)**	**2013 (#11)**	**2008 (#12)**	**2013 (#12)**	**2008 (#13)**	**2013 (#13)**
Rocky Mountain	2.96	3.20	2.93	3.16	3.57	4.24
San Juan	3.12	3.46	3.08	3.42	3.76	4.58
Alberta	2.41	3.02	2.38	2.99	2.91	4.00
Average	**2.83**	**3.23**	**2.80**	**3.19**	**3.41**	**4.27**

Sources:

10 According the CEC's 2003 Electricity and Natural Gas Report, 85 percent of the gas consumed in CA comes from the Rocky Mountain, San Juan, or Alberta basins. These three basins are averaged for purposes of an average WECC wellhead price, p. 110.

11 CEC 2003 Report, Table 4-3, "Project Wellhead Prices -- Annual Averages (2000$ per Mcf), p. 111.

12 Assumed conversion factor of 1 mcf = 1.01157 mmbtu. http://www.energyshop.com/energyshop/tools/Gj_to_m3.cfm

13 For derivation of inflation rates, see third worksheet.

CED 2003

GDP IMPLICIT PRICE DEFLATOR (2001 = 100)

YEAR	Current INDEX	05/15/02 ANNUAL GROWTH RATE	Ratio to 2000 $	
2000	97.87	2.3%	1.00	
2001	100.00	2.2%	1.02	
2002	101.43	1.4%	1.04	
2003	102.78	1.3%	1.05	
2004	106.60	3.7%	1.09	
2005	110.43	3.6%	1.13	
2006	114.25	3.5%	1.17	
2007	116.87	2.3%	1.19	
2008	119.18	2.0%	1.22	1.22
2009	121.39	1.9%	1.24	
2010	123.65	1.9%	1.26	
2011	126.04	1.9%	1.29	
2012	128.62	2.0%	1.31	
2013	131.32	2.1%	1.34	1.34
2014	134.08	2.1%	1.37	
2015	136.93	2.1%	1.40	
2016	139.81	2.1%	1.43	
2017	142.74	2.1%	1.46	
2018	145.74	2.1%	1.49	
2019	148.79	2.1%	1.52	
2020	151.94	2.1%	1.55	

Sources:

21 Received above information from Todd Peterson, CEC Natural Gas Office, January 29, 2004.

Attendance online for Feb. 13, 2004 – Base case Subgroup Meeting

Marianne Causley	CEC
Karen Griffin	CEC
Les Pereira	NCPA
Xuguang Leng	CPUC
Linda Brown	San Diego Gas & Electric
Tom Miller	PG & E
Pam Doughman	CEC
Jim Hoffsis	CEC
Darell Holmes	SCE

CAISO personnel in attendance:

Eric Toolson
Mohamed Awad
Anna Geevarghese
Jeff Miller
Mingxia Zhang
Keith Johnson

Draft Agenda
TEAM Subgroup – Base Case Assumptions
Tuesday, February 23, 2004
10:00 to 11:30 am
Call-in Number – (888) 261-7938
Conference Code 1251037

Discussion Topics:

1. Review renewable targets

2. Review reserve margin deficiencies

3. Review initial gas-fired resource additions

4. Develop understanding of states using BACT and those that are not (impacts capital and O&M costs of future CC's)

5. Review list of potential CA gas-fired resource additions prior to 2008 (if available)

Conference Call
February 24, 2004
10:30 – 11:30 AM

Discussion Topics and Issues yet to be resolved

Review of renewable targets:
There were no concerns noted on the percentages used on the Renewable Percentages Section One of Expansion Plan

On page 9: The review of 2008 Renewables reflected that the California
100 gwh higher then what the CEC has
PDC Assumptions: CEC agrees with the assumptions, the other members as well, however Edison questions New Solar

Page 11 line 9: Questions surrounding Vincent, initial assumption is to hook wind to Vincent

Page 13: All agree that since the information is derived from SSGWI that it is reasonably reliable. PG&E agrees that it is good to go with a proportional approach that has been started. Edison agrees that the approach seems reasonable

Page 16, 17 and 18: Margins looking at California: CEC stated that the numbers were off and they will get back to you with some information. PG&E: will also look at the numbers and get back to you. Edison: stated that they show a few thousand megawatts higher then what you show for 2008. CPUC: will provide region wide numbers
PG&E: will provide you with a list of resources

Discussion on wheeling rate:
CEC should be able to provide information on this

Question:
Is it possible to do a comparison of load used in this model and the CEC?

Draft Agenda
TEAM Subgroup – Base Case Assumptions
Wednesday, March 10, 2004
10:00 to 11:30 pm
Call-in Number – (888) 261-7938
Conference Code 1251037

Discussion Topics:

1. Review major changes / additions to 2008 case
    a. Hydro PDC
    b. Load forecast
    c. Interruptible and load management resources
    d. CA additions / retirements
    e. Transmission expansion plan

2. Review progress on 2013 case
    a. Renewables – requirements and additions
    b. Planning reserve requirements
    c. Resource additions
    d. Economic entry

Attendance for March 10, 2004 – Base Case Assumptions Subgroup Meeting

<u>IN ATTENDANCE</u>

Marianne Causley	CEC
Mark Hesters	CEC
Mohamed El-Gasseir	CERS

CAISO personnel in attendance:

Eric Toolson
Mohamed Awad
Anna Geevarghese
Jeff Miller
Mingxia Zhang
Keith Johnson
Anjali Sheffrin

Summary of Conference Call - Team Subgroup - Base Case Assumptions
March 10, 2004

Agenda Items Discussed

The Expansion Plan excel document was referenced and discussed throughout the discussion.
First to be discussed was page 31, there were no differences in opinions here, and information presented was supported by the subgroup.

Page 24
Do they base their assumptions on utility peak or CA peak?
CEC is to provide further information on this
As well as Edison and San Diego

Interruptible and load management resources for 2008
All were in agreement
The group was questioned whether Southwest imports to include Mexico?
Angela Tanghetti, CEC, stated that they don't include interruptible when calculating the planning reserve margin.
Edison and San Diego are expected to provide further expertise on this area

California additions / retirements
The group was questioned whether they were in agreement with the general source of information used or were there any suggestions on a better process.
In looking at Year 2008 Gas Fired Resources page 28, column 16, Mohamad Awad, CAISO, was concern with Mohave
It was then explained that we are only using California's share of Mohave

Transmission Expansion Plan:
Page 12
Mohamad Awad, CAISO, explained that path 15 is an ongoing project and the assumption made is valid.
Other members of the group were in agreement.
Columns 3/14/15/16 upgrades are expected by 2008 to be in placed
Column 3 is the only project that is finalized at this time.
All agreed that the assumptions are reasonable.

Economic Entry Assumptions page 9, 10
It was explained that nothing will be done for the economic entry for 2008
For 2013, comments were that the fixed O&M appeared high.

In review for progress on 2013 it began with a look at page 33 the 2013 Renewable Plan
It was suggested that the group look at page 34 for later discussion
Pam from California Energy Commission commented that the note on page 38 needs to be updated. She will provide the updated information by 3/11/04.

Planning Reserve Requirements, pages 39-42 were then looked at. The group is expected to review these pages for comment within the next two days.
The group was questioned whether the information be based in identified sites it or generics?
Angela Tanghetti, CEC, stated that they create it all generically.

Vanda, Deborah

Distribution List Name: TEAM Extreme Events

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TEAM Subgroup:

II. Choice of extreme events
& choice of weights

1. Ben Hobbs
2. ~~Mingxia Zhang~~ ~~Mingxia Zhang~~ * Mingxia Zhang
   Jing Chen
3. CLIFF ROCHLIN
4. Kishore Patel
5. BILL AHERN (CPUC)

Final Agenda
TEAM Subgroup – Choice of Extreme Events and Weights

Tuesday, February 17, 2004
10:00 to 11:30am
Call-in Number – 888-261-7938
Conference Code - 1251037

Discussion Topics:

1. Variables and Extreme Events Under Consideration:

(1) Demand Forecast: Very High (VH) and Very Low (VL). These extreme cases are derived based on 90% confidence interval of CEC's demand forecast error (see CAISO's Methodology for more detail).
(2) Gas Price Forecast: Very High (VH) and Very Low (VL). Again these cases are derived based on 90% confidence interval of CEC's gas price forecast (see CAISO's methodology for more detail).
(3) Hydro: Dry Year and Wet Year. We are considering using the same hydro scenarios as in SSG-WI's study for the entire WECC region.
(4) New Generation Entry: +/- 50% of basecase new generation entry developed by Eric.
(5) Markup: high markup and low markup scenarios derived based on 90% confidence interval of predicted price-cost markups using RSI regression that will be developed by Mingxia.
(6) Contract Covering: +/- 50% of basecase long-term contract covering. Note that contract covering will not affect the dispatch under competitive run, but will affect the dispatch under market power run since we believe contract covering will affect generators' bidding behaviors. Contract coving will affect benefit calculation and participant test regardless the competitiveness of the market.
(7) Sitting of New Renewable Resources: People in Eric's subgroup expressed concerns about the sitting of the new renewable resources in Kern County. It is believed that the sitting will greatly affect the economic benefit of Path 26. I'd like to add this as an additional sensitivity we want to perform.

(8) Generation/Transmission Contingencies: Les Pereira from NCPA suggested considering large contingencies – both generation and transmission – as extreme events. CEC folks also suggested considering availability of existing generation in NP26 versus in SP26 and to consider generation outages as extreme event. They also suggested considering Southwest import availability as one scenario and to consider transmission line outages as one extreme event. I'd like to raise this issue in the subgroup discussion

2. Scenarios: Combinations of Variables Under Consideration:

(1) ISO's Methodology on selecting combinations of demand forecast and gas price: at least 9 cases of combined demand and gas price required to derive the joint probabilities of demand and gas price (see CAISO's methodology for more details).

Figure 1. Combined Scenario of Demand and Gas Prices

Scenarios	1	2	3	4	5	6	7	8	9
Demand	VH	VH	VH	B	B	B	VL	VL	VL
Gas Price	VH	B	VL	VH	B	VL	VH	B	VL

(2) How we are going to select the combined scenarios of demand/gas price with other variables such as new generation entry, hydro, markup, and contract covering?

(3) CEC folks suggested to focus on reserve margin scenarios as the combined scenarios of demand/hydro/new generation, instead of consider many combinations of individual scenarios. I'd like to raise this issue in the discussion.

3. Total Number of Cases Under Consideration

Preferred: more is better. Consider 3 scenarios for hydro, 3 scenarios for new generation entry, 3 scenarios for markup, and 3 scenarios for contract covering, and 9 scenarios of combined demand and gas price forecast, we are talking about 729 cases.

Minimum: 20

Question to the Subgroup: We want to follow the CAISO Scenario Selection and Probability Assignment Methodology in principle, but we also want to get the project done on time. That means a very limited number of scenarios. How are we going to select limited number of scenarios but with wide range representation of the future states so that we can get an un-biased estimate of the expected benefit for Path 26?

4. Any Additional Variables We Should Consider?

5. Any Specific Extreme Events We Should Consider?

Attendance/online for Feb. 17, 2004 – Extreme Events and Weights Subgroup Meeting

ONLINE

Marianne Causley	CEC
Les Pereira	NCPA
Darell Holmes	SCE
Cliff Rochlin	Southern Calif. Gas Co.
Darell Holmes	SCE
Paul Nelson	SCE
Kishore Patel	San Diego Gas & Electric
Gayatri Schillberg	JBS Energy
Alice Harron	PG & E

IN ATTENDANCE

Karen Griffin	CEC
Mark Hesters	CEC
David Vidaver	CEC

CAISO personnel in attendance:

Eric Toolson
Mohamed Awad
Anna Geevarghese
Jeff Miller
Mingxia Zhang
Keith Johnson
Anjali Sheffrin

Draft Agenda
TEAM Subgroup – Choice of Extreme Events and Weights

Monday, March 8, 2004
10:30am to 12:00pm
Call-in Number – 888-261-7938
Conference Code - 1251037

<u>Discussion Topics:</u>

1. Status of CEC Double Checking DMA's Demand Forecasts

See attached spreadsheet for detailed comparison.

2. Finalizing Measurable Events for Path 26 Simulation

See attached document for more detailed discussion and ISO's proposal on minimum number of events.

3. Finalizing High-Risk, Low-Probability Contingency Events for Path 26 Study

We need to select 1 to 2 contingency events from the following list:

- SONGs going down;
- PDCI going down;
- Southwest importing lines to California going down or on outage for a substantial period;
- Path 15 going on outage for substantial period;
- Earthquake in LA or East Bay taking out important substations;
- Extended Western States drought;
- Huge flooding of the LA basin from a tropical storm that stalls at the San Gabriel Mountains for days;
- Another oil/LNG export embargo by producing countries for political reasons.

The chosen contingency events should have the following properties: (1) they should be plausible; (2) we should be able to model their impact in PLEXOS; and (3) they should be anticipated to have a significant impact on transmission benefits. After we select the contingency events, we will combine the contingencies with all base cases of the other five variables.

Attendance for March 8, 2004 – Extreme Events and Weights Subgroup Meeting

<u>IN ATTENDANCE</u>

Gayatri Schilberg	JBS Energy
David Vidaver	CEC
Mark Hesters	CEC
Karen Griffin	CEC

<u>CAISO personnel in attendance:</u>

Eric Toolson
Mohamed Awad
Anna Geevarghese
Jeff Miller
Mingxia Zhang
Keith Johnson
Anjali Sheffrin

Vanda, Deborah

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Zhang, Mingxia	MZhang@caiso.com

TEAM Subgroup:

III. Approach to Quantifying Market Power Benefits / Approrate Benefits Test

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2. Anjali Sheffrin ~~[illegible]~~
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13) Carl Silsbee carl.silsbee@SCE.com
14) Darell Holmes darell.holmes@SCE.com

Toolson
Seffmiller
Mohamad Awad
Keith Casey
Amnay
DoD.
Mingxa
Gayatri Schilberg

Final Agenda

TEAM Subgroup – Market Power Modeling and Benefit Calculation

Tuesday, February 24, 2004

12:30:00 to 2:00pm
Call-in Number – 888-261-7938
Conference Code - 1251037

Discussion Topic: Market Power Modeling

1. Comments and feedback from Stakeholders

Does anyone have comments on Frank's and Jeff's presentation at the last Stakeholders Meeting? Do we need further discussion on the importance and complexity of market power modeling?

2. Options on modeling market power

- Fix Adder Approach
- Game Theoretical Approach
- Quasi-Game Theoretical Approach
- Empirical Approach

3. ISO's proposal on market power modeling

ISO proposed to focus on the empirical approach for the June 2 deadline Path 26 study (Phase 1). In Phase 2 we will explore the game-theoretical approach and its variants and also enhance the empirical approach.

(1) Any comments on the variables we use? Any suggestions?
(2) Any concerns?

4. Specifics of the ISO's proposal

(1) Derive 3 price-cost markup scenarios based on RSI regression analysis
- Derive the average level of ***dynamic*** price-cost markup;
- Derive the high and low level of ***dynamic*** price-cost markup.

(2) Use price-cost markups as generators' bid-cost markups in network simulation
How to use?
- Use markup uniformly for all strategic suppliers;
- Use markup according to suppliers' size;
- Group suppliers to different categories and each category has a different markup.

Draft Agenda

TEAM Subgroup – Market Power Modeling and Benefit Calculation

Tuesday, March 9, 2004

2:00 pm to 3:30pm
Call-in Number – 888-261-7938
Conference Code - 1251037

Discussion Topic: Market Price Modeling, Benefit Calculation, and Tests

1. **Comments and feedback from Stakeholders on proposed market price modeling**

   Does anyone have comments on ISO proposed approach of market price modeling?

2. **Status update of RSI regression analysis**

   ISO staff will give a status update on the RSI analysis.

3. **ISO's proposal on benefit calculation and three tests**

   In the last stakeholders meeting, Mingxia presented ISO proposed methods and criteria for measuring benefits. Does anyone have comments and concerns?

4. **ISO's proposal to incorporate state long-term-contract in benefit calculation**

   Contract covering affects participants' benefits as well as the ISO participant test. See example in Mingxia's memo.

5. **ISO's proposal not to incorporate ETC in benefit calculation**

ATTACHMENT 6
OF
PHASE 1 OPENING TESTIMONY ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR
October 21, 2005
A.05-04-015
I.05-06-041

CALIFORNIA ISO

Board Report

Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)

Prepared by

California ISO

Department of Market Analysis & Grid Planning

February 24, 2005

Table of Contents

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I. SUMMARY

Southern California Edison (SCE) has requested that the CAISO Board approve the proposed Palo Verde-Devers No. 2 (PVD2) project. In order to provide a recommendation to the Board, CAISO staff performed a comprehensive analysis of the benefits of PVD2. We found that the PVD2 project will provide a significant amount of reliability and economic benefits to CAISO ratepayers. PVD2 would improve reliability by increasing voltage support in southern California, and enhance system operational flexibility by providing CAISO operators with more options in responding to transmission and generation outages.

The project's primary economic benefit results from an increased ability to import lower-cost energy from the southwest and displace higher-cost energy in California. PVD2 will also provide access to additional efficient generating capacity that can serve to meet the State's resource adequacy requirements. This will also lower total operating costs by reducing the amount of uneconomic generation dispatched for operational reliability purposes. The PVD2 line will significantly augment the transmission infrastructure that is critical to support competitive wholesale energy markets for California consumers.

We estimate that benefits from the line will exceed its costs under a wide range of future system conditions. Because we believe that no single point estimate can adequately capture its value, we calculated its costs and benefits under a number of likely system conditions. The expected benefit-cost ratio derived from these cases is shown in Table I.1, on the following page. The table summarizes the expected benefits and costs over the 50-year economic life of the PVD2 project for various perspectives.

Table I.1 Summary of PVD2 Lifecycle Benefits, Costs, and Benefit-Cost Ratios for the Four Primary Perspectives (millions of 2008 dollars)[1]

	WECC or Societal	Enhanced WECC Competition or Modified Societal	CAISO Ratepayer (LMP Only)	CAISO Ratepayer (LMP+ Contract Path)
Levelized Benefits				
- Energy	$56	$84	$57	$198
- Operational	$20	$20	$20	$20
- Capacity	$12	$12	$6	$6
- System Loss	$2	$2	$1	$1
- Emissions	$1	$1	$1	$1
- Total	$91	$119	$84	$225
Levelized Costs	$71	$71	$71	$71
Benefit-Cost Ratio	**1.3**	**1.7**	**1.2**	**3.2**

When evaluating a project, we believe it is important to consider alternatives such as other transmission or generation projects that may provide similar benefits. For this analysis, we reviewed several alternatives. The study assumed capacity from demand-side management (DSM) programs and renewables would be maximized first.

One alternative suggested in the public input process was the East-of-River (EOR 9000) transmission project, which upgrades lines between Nevada and Arizona. Our analysis showed that the EOR 9000 project to be complementary to the PVD2 project since it reduced congestion on other paths, but did not directly impact congestion on the Palo Verde path. EOR900 was included in the base case of our study.

Another alternative we examined was siting additional gas-fired, combined-cycle (CC) plants in California. In other words, we examined whether it is more efficient to build a combined cycle generation plant in California, or to build a CC in Arizona when one considers the cost of transmission to access the Arizona power. Comparing the California CC to the Arizona CC with the PVD2 transmission costs, the California CC is about 10 percent less expensive at a 50 percent capacity factor, and comparable in cost to the Arizona CC plus transmission, at a 90 percent capacity factor.[2]

Given the lower construction, operating, and gas costs in Arizona, the Arizona and California CC unit costs are a break-even if operated in a baseload mode, assuming no

1 As explained in the "VII. Results" section, the energy benefits were determined for two years – 2008 and 2013. These two years were selected since load, generation, and network data for these two years were available from a regional transmission planning group (SSG-WI). Although the proposed PVD2 does not come online until 2009, calculating the energy benefits of the line as if it were available in 2008, helps us better understand the benefits in the early years of the project.
2 We believe this to be a conservative projection of California CC costs since it does not include any significant transmission or natural gas connection fees (such as those incurred at Otay Mesa as an example).

extensive interconnection costs of plants in California. However, we believe there may be significant positive interconnection costs in California urban areas where generation is most valuable, so the saving differential favoring the Arizona CC will be positive. Moreover, since California will need to add 5,000+ of new capacity in the next five years due to load growth and unit retirement, there is a need to pursue the most attractive of both generation and transmission options. In conclusion, based on the transmission and generation options considered, based on the results of the STEP process and our comprehensive evaluation, we recommend that the CAISO Board approve the PVD2 project.

II. INTRODUCTION

The Palo Verde-Devers No. 2 500 kV Transmission Project ("PVD2") project is a major new transmission line that provides additional interconnection between southern California and Arizona and the desert southwest. The PVD2 project is part of the CAISO' s long-term grid plan to enhance transmission capability in southern California. PVD2 complements two other projects: (1) the short-term transmission upgrades that were approved by the CAISO Board in June of 2004, and (2) the proposed EOR 9000 project that upgrades several transmission lines between Arizona and Nevada. These projects are primarily upgrades of series capacitors that will increase the ability of the existing transmission system to import power from Arizona without having to add any new transmission lines. These upgrades can be accomplished in a much shorter time than a major transmission project. Even after these upgrades, our system simulations show there still will be congestion that is economic to relieve. When it comes online in 2009, the proposed PVD2 project will reduce congestion and add the ability to import an additional 1,200 MW of power from Arizona.[3]

The idea for the Palo Verde-Devers project originated in a regional transmission planning group process called the Southwest Transmission Expansion Plan (STEP). This group has approximately 300 members on its distribution list and about 50 members routinely attend the STEP meetings held every two months. In developing a transmission plan for the area, STEP analyzed 26 different combinations of facilities to increase the transmission capability between the southwest and southern California. It proposed a series of projects in four phases. The first project was the STEP Short-

3 There are EOR 9000 would upgrade the series capacitors on the Navajo-Crystal and Perkins- Mead 500 kV lines and therefore allow more flow on the northern EOR system. It does not have the same increase in import capability into Southern California (PV West. Interface). Increases in transfer capabilities on the two major interfaces into California are East of River and PV West:

Upgrades	Interface Increases	
	PV West	East of River
Short term upgrades	800 MW	505 MW
EOR 9000 + Moenkopi-Eldorado	0 MW	1500 MW
PVD2	1800 MW	1200 MW

Term Transmission Upgrades. The CAISO Board approved this in June 2004. We expect these facilities to be in service in 2006. The second part is the East of River 9000 Upgrades being developed between Arizona and Nevada. The third major project in the series is the PVD2 Project. The fourth part is a major 500 KV line into San Diego currently under study and for which we will make a recommendation to the Board in the near future.

In parallel with the STEP process, the Southern California Edison Company determined that PVD2 was a cost effective project and filed a report requesting that the CAISO approve the project addition. After we reviewed SCE's project justification, and had further discussions with SCE staff, we decided to undertake an independent economic feasibility study of PVD2 applying TEAM[4].

This report contains the results of our economic analysis using TEAM. It includes a description of the project, the associated public process, an overview of benefits and input assumptions used in the analysis, a discussion of the results and resource alternatives, and the CAISO management's recommendation to the Board. The CAISO's recommendation on PVD2 is based upon consideration of the economic, reliability, operational, and other strategic benefits of the line.

III. PROJECT DESCRIPTION

The proposed PVD2 project is a 500 kV transmission line from the Palo Verde area (near Phoenix, Arizona) to SCE's Devers substation near Palm Springs in southern California. If approved, we expect it to come online by year 2009, increasing California's import capability from the southwest by at least 1200 MW.

The PVD2 project includes the following facilities:

- A new 230 mile 500 kV line to be constructed between Harquahala Generating Company's Harquahala Switchyard (near Palo Verde) and SCE's Devers 500 kV Substation. The proposed route between Devers and Harquahala parallels SCE's existing Palo Verde-Devers No.1 (PVD1) transmission line. Most of the proposed line is to be constructed on single circuit steel lattice towers.
- The four 230 kV lines west of the Devers substation will be rebuilt and reconductored[5]: the Devers-San Bernardino 230 kV lines #1 and #2, and the Devers-Vista 230 kV lines #1 and #2.
- Voltage support facilities will be added in the Devers area in southern California

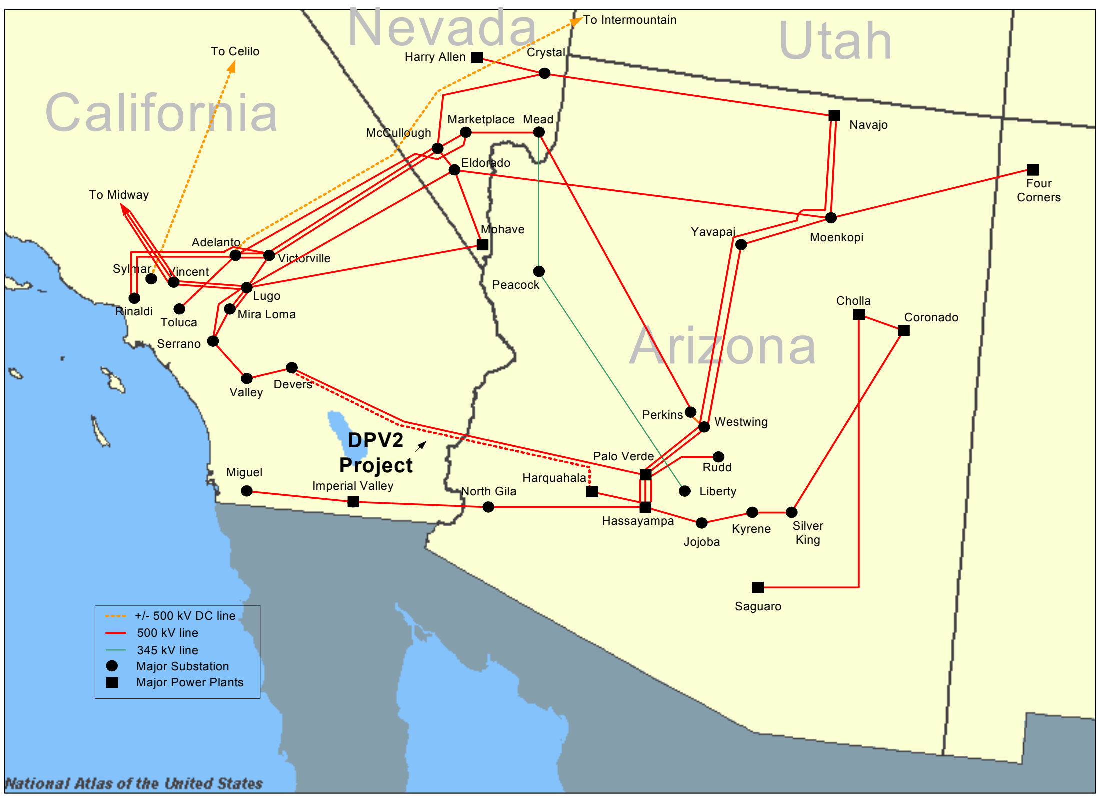
4 CAISO developed TEAM to significantly streamline the evaluation process of economic transmission projects, improve the accuracy of the evaluation, and add greater predictability to the evaluations of transmission need conducted by various agencies. The Transmission Economic Assessment Methodology (TEAM) was filed with the CPUC on June 2, 2004.
http://www1.caiso.com/docs/2004/06/03/2004060313241622985.pdf.
5 The reconductoring will be with 2B-1033 ACSR conductor.

Figure IV.1 below shows the location of the Proposed PVD2 Transmission Expansion Project.

IV. PUBLIC PROCESS

The public process for the Palo Verde-Devers #2 (PVD2) evaluation began during the STEP process. The economic evaluation utilized the Transmission Evaluation Assessment Methodology (TEAM) developed by the CAISO. The CAISO-developed methodology has been filed with the CPUC for approval as the standard by which all projects requiring regulatory approval will be evaluated. The goal of TEAM is to: (a) improve the overall accuracy of the evaluation; and, (b) add greater predictability to the assessment of economic transmission need. TEAM is the result of a four-month public stakeholder process that included three public workshops, a public Market Surveillance Committee meeting, and 12 technical subgroup meetings. The TEAM process resulted in a June 2004 report to the CPUC detailing the methodology and providing an example application.

Figure IV.1 Location of Proposed Palo Verde-Devers Project



The proposed PVD2 project is a 230 mile, 500 kV transmission line from the Haraquala substation near Palo Verde to SCE's Devers substation near Palm Springs, California. PVD2 will parallel the existing PVD1 line and will use the existing PVD1 right-of-way.

We have used TEAM to evaluate the proposed PVD2 project. We have reviewed the interim results in a number of public forums and have incorporated input from these meetings into our findings. These public forums included:

- October 1, 2004 – presented draft results to a STEP meeting in San Diego
- November 16, 2004 – presented draft results and discussed methodology in a Market Surveillance Committee meeting in Sacramento
- January 11, 2005 – presented draft results to a Western Arizona Transmission System (WATS) group in Las Vegas
- January 14, 2005 – presented draft results and discussed assumptions at a PVD2 stakeholder meeting in Sacramento (48 attendees from 33 different companies or agencies were present – see the Technical Appendix for detailed information).
- January 18, 2005 – presented draft results in a second public Market Surveillance Committee
- January 27, 2005 – briefed California ISO Board of Governors
- February 9, 2005 – presented results to a STEP meeting in San Diego, attendees indicated unanimous support for the project

During each of these meetings, we presented results from our analysis so that the stakeholders could understand the process and make informed comments to the CAISO Market Surveillance Committee and Board. In addition, we have provided answers to stakeholder questions and posted many of the significant work papers developed in our analyses of PVD2 on the CAISO's website at: HTTP://WWW1.CAISO.COM/DOCS/2005/01/19/2005011914572217739.HTML.

V. OVERVIEW OF BENEFITS

The CAISO uses a coordinated grid planning process that recognizes that transmission projects can fill a variety of needs, such as:

- **Maintaining reliability –** projects necessary to ensure that customer outages are minimal, minimizing the risk of widespread blackouts and the chance of damaging facilities through overloading or other technical conditions.
- **Interconnecting generation –** interconnection and transmission facilities necessary to reliably interconnect a new generator to the transmission system.
- **Enhancing operational flexibility –** projects that make it easier for the operators to operate the system that usually enhance system reliability. An example project would be the addition of a circuit breaker at a substation that would greatly simplify the actions necessary to take out a transmission line for maintenance.
- **Reducing overall costs to CAISO ratepayers –** addition of transmission lines may increase the cost of transmission to customers but any increase would be more than offset by a decrease in the power cost component on their bill. Therefore, a recommended project would be expected to result in a net saving.

Our recommendation to approve the PVD2 transmission upgrade is primarily based upon its economic benefits of reducing overall cost to CAISO ratepayers. Additionally, the line will also provide significant reliability and operational benefits. The line will allow load-serving entities in California to access a variety of power sources in the southwest including gas, coal, and new renewable resources. The line will improve the fuel diversity of the California electrical supply.

This project will improve current planning reliability levels by providing a back-up for the outage of Palo Verde-Devers #1 line, thus augmenting system reliability under N-1 and relevant N-2 planning criteria. We evaluated these reliability benefits in a qualitative manner. The line will also will provide substantial operational reliability benefits. The PVD2 project will provide the system operators with improved ability to respond to major transmission and generation outages. Although these operational benefits are difficult to quantify, we have been able to estimate their magnitude by using costs we currently incur to manage re-dispatches in real-time as a basis.

In addition to the economic benefit of lowering the price of power to consumers, we expect the Palo Verde-Devers #2 Project to reduce the overall consumption of natural gas. This will reduce air pollution because we will achieve lower air emissions by not having to dispatch old and inefficient generating units located in southern California.

In this report, we focus on identifying the economic benefits that can be quantified and attributed to the proposed PVD2 upgrade. Benefits such as fuel diversity, insurance value (e.g. risk premium), and long-term reliability advantages are not easily quantified and are, therefore, beyond the scope of our economic analysis.

For this economic evaluation, we quantified the following economic benefits attributable to the proposed PVD2 upgrade:

- Energy cost savings
- Operational benefits
- Capacity benefits
- System-loss reduction benefits
- Emission reduction benefits

The total benefit provided by the line depends upon the quantity and type of resources that will be constructed in California and outside of its borders in coming years. In the “Economic Benefits” section of the report, we present a summary of the salient input assumptions and the results from our analysis. More detailed information can be found in the Technical Appendix.

VI. INPUT ASSUMPTIONS

The benefits of the line must be considered in the context of the uncertainty associated with future events that will unfold over the life of the project. We have attempted to quantify the impact of this uncertainty in our modeling by varying the key input assumptions. Our analysis included developing cases with different levels of input assumptions for load, hydro conditions, gas prices and exercise of market power. We believe these cases spanned the reasonable range of possibilities for each combination of variables. Generally, the cases studied varied the respective input parameters between very low, average and very high conditions based on a 90 percent confidence interval of historically observed variation.

We conducted the analysis for two future years, 2008 and 2013 using an Optimized DC Power Flow (DCOPF) model called PLEXOS[6]. We chose the years 2008 and 2013 because we were able to obtain a representation of the network and associated data e for those years from the Seam Steering Group for the Western Interconnection (SSG-WI). Region-wide transmission planning representatives had contributed system information and reviewed the data. We assumed that the year 2008 would have the best network representation available to use as the first year that the PVD2 comes on-line.

We estimated the impact of uncertainty by developing numerous alternative cases. We then calculated an expected value for each of these cases taking into account the probability of each occurring. We also calculated a range of the expected value of benefit estimates based on the various contingencies that could occur over the life of the facilities. This expected value gave us the best understanding of the consequences of the line being utilized under a variety of future system conditions.

In this study, we focused on the four key variables described above (load, hydro, gas price, market power) that we thought would have significant impact on the economic benefit of the Palo Verde–Devers 2 line. In addition, we also evaluated potential combinations of transmission and/or generation that we considered as contingencies. We selected 66 cases for cost-based and market-based simulations to study their impacts. For the cases where we varied load, gas price, and market power, we examined three levels: very high (H), base (B), or very low (L). For the hydro cases, we also examined three levels: (W) wet, base (B), or dry (D) year. We determined these values by analyzing the historical accuracy of predictions of these variables. We calculated demand uncertainty using the predicted level of demand in the past 20 years of CEC load forecasts and natural gas prices and compared it to actual realized levels. We took hydro ranges from 80 years of historical hydro production records. We were limited in this analysis by the hydro production curves by plant provided to us by the SSG-WI database.

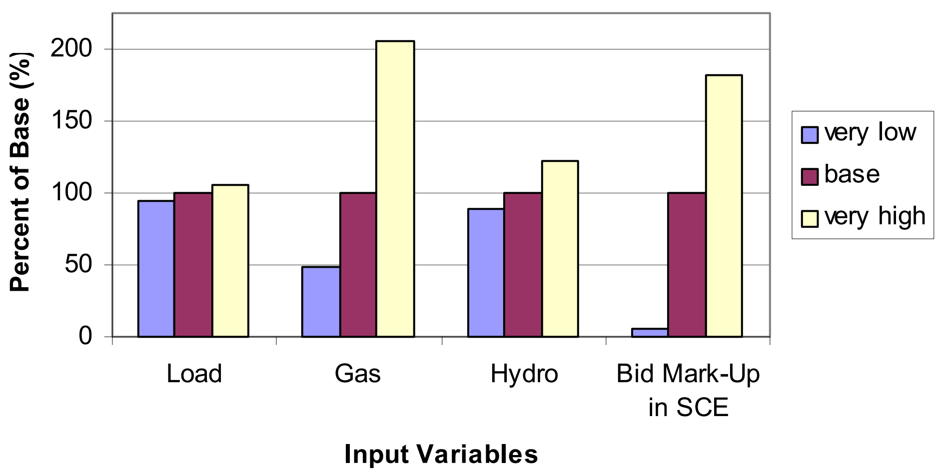
Figure VI.1 on the following page summarizes the relative values for the very high, base, and very low cases.

The combinations of values for each of these variables constitute a large set of possible future states of the WECC transmission/generation system. Given the large number of possible combinations, it was impossible for us to conduct simulation for every case. Therefore, we developed a scientific sampling method, applied it to the possible

6 WWW.PLEXOS.info

combinations, and selected a small but representative number of all possible cases. This sampling allowed us to develop a reasonably accurate estimate of the expected economic benefits that the line would provide under a wide range of system conditions. After we selected the cases, we assigned probabilities to the cases by using two mathematical approaches; one called “Maximum Log-Likelihood” to assign probabilities to the case used for the expected benefit calculation.

Figure VI.1 Comparison of Very-Low, Base, and Very-High Input Parameters in 2013



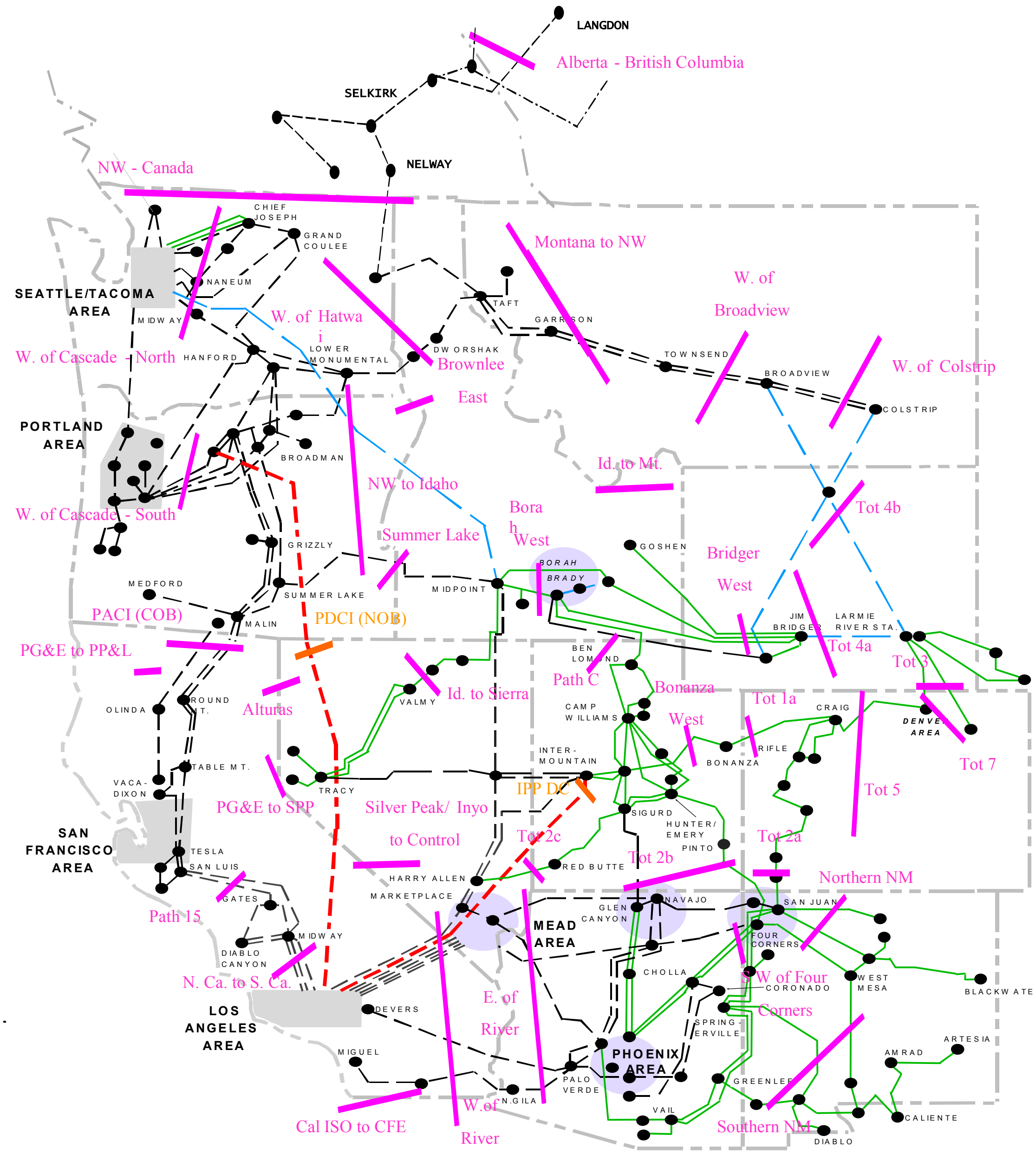
The upper and lower bounds used in the load and gas sensitivity cases are based on a 90 percent confidence interval of historical forecasts by the CEC. Given this confidence interval, the very-low and very-high values may change only slightly from the base case (i.e. load) or the change may be quite large (i.e. gas and mark-up)

A. Network

We studied the impact of the proposed PVD2 upgrade using a detailed transmission network model that represented the Western Electricity Coordinating Council (WECC) region.[7] The model computed physical transmission flows, associated transmission charges, and nodal prices for each hour of 2008 and 2013 for approximately 17,500 lines of different voltage levels and 13,400 nodes in the system.[8]

7 The WECC consists of eleven western states of United States, British Columbia, Alberta in Canada, and the northwest portion of Mexico.
8 The network representation includes approximately 17,500 transmission lines of different voltage levels, 13,400 nodes, 284 lines of 500-kV, 2 DC lines, and 120 interfaces. The model used for the analysis, PLEXOS, employs a linearized DC OPF solution.df

Figure VI.2 Western Interconnect Transmission Paths



We used a physical flow-based model to accurately represent the WECC network and to derive the benefits of the proposed PVD2 upgrade. We directly modeled 125 interfaces and 284 500KV or higher transmission lines.

B. Loads

We used the system load forecast from the 10-year forecast, published by the WECC in December 2003, for all regions except California. These system loads were disaggregated into hourly chronological load shapes for 21 regions and about 5,700 locations (nodes). For California loads, we used the California Energy Commission (CEC) March 2003 forecast. We took hourly load shapes from the Henwood Load Database, and adjusted to the year of modeling using PLEXOS load forecasting module.

From 2008 to 2013, overall energy growth in WECC is predicted to be about 1.7 percent for the base case, and 1.4 percent for the CAISO area. Due to current data limitations, we could only separate Los Angeles Department of Water and Power (LADWP) and Imperial Irrigation District (IID) loads from the CAISO load forecast in this analysis. Entities such as the Sacramento Municipal Utility District (SMUD), the Western Area Power Authority (WAPA), and the Northern California Power Authority (NCPA) are included as part of CAISO loads.

For the analysis, we derived three different load cases, base, very high and very low. Table VI.1 on the following page summarizes each of these cases for WECC, CAISO and the other WECC regions.

In deriving the cases, we assumed that the demand and the forecast error were normally distributed. The very high and very low cases are at the 90 percent confidence interval of the demand forecast error published by CEC. The Technical Appendix summarizes the detailed regional non-coincident peak and annual energy loads used for each of the cases.

C. Resources

We obtained most of the system resource data from the database created by the WECC Regional Transmission Planning group, Seams Steering Group – Western Interconnection (SSG-WI) for their transmission planning studies. The system has about 800 thermal, hydro, pumped storage and renewable generators with a total capacity of approximately 196,000 MW in year 2008 and 213,000 MW in year 2013. We added resources to the SSG-WI database to reflect estimated renewable portfolio standards (RPS) in each of the states. We added new gas-fired generation, primarily combined cycle plants, in each of the WECC areas so that the area would have a 15 percent planning reserve margin. The California gas-fired resources that we added on top of the SSG-WI additions were those that appeared to have a high likelihood of completion based on the information compiled by the CEC.[9]

The total CAISO resource capacity is 59,204 MW in year 2008, and 64,447 MW in year 2013. The Technical Appendix summarizes the detail of the resource mix in other regions.

9 See "California Energy Commission Energy Facility Status" at http://www.energy.ca.gov/sitingcases/all_projects.html.

Table VI.1 Summary of Regional Loads for 2008 and 2013

Region	2008					
	Base		Very High		Very Low	
	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)
WECC	900,951	150,296	954,903	161,047	847,808	139,896
CAISO	261,641	51,271	277,067	55,185	246,216	47,356
California	291,702	57,682	308,900	62,085	274,504	53,279
CFE Mexico	10,583	1,850	11,207	1,991	9,959	1,709
Northwest/ Canada	389,353	56,759	412,307	60,961	366,373	52,561
Rocky Mountain	68,506	12,985	73,381	13,967	64,467	11,996
Southwest	140,807	28,110	149,108	30,225	132,505	25,997
Region	**2013**					
	Base		**Very High**		**Very Low**	
	Energy (GWh)	**Peak (MW)**	**Energy (GWh)**	**Peak (MW)**	**Energy (GWh)**	**Peak (MW)**
WECC	982,485	163,570	1,043,406	175,324	924,452	152,122
CAISO	278,886	54,532	298,326	58,695	262,443	50,368
California	310,404	61,181	331,703	65,852	292,103	56,511
CFE Mexico	11,673	2,029	12,361	2,183	10,985	1,874
Northwest/ Canada	426,093	61,351	451,213	65,903	400,863	56,910
Rocky Mountain	75,783	14,579	80,251	15,672	71,316	13,470
Southwest	158,532	31,855	167,878	34,259	149,185	29,448

Renewable resource additions included: wind, solar, biomass, geothermal, and digester gas. The Technical Appendix presents a breakdown of the renewables in California and detailed information of hydro energy by PLEXOS region (21) and by cases (Base, Dry, and Wet). The Technical Appendix also provides a detailed list of additions and retirements in the CAISO planning area.

The resulting WECC area planning reserve margins are summarized in Table VI.2 on the following page.

Table VI.2 Summary of Regional Reserve Margins for 2008 and 2013

Area Name	2008	2013
California / Mexico (CFE)	15%	15%
Southwest	21%	19%
Rocky Mountain	14%	16%
Northwest	21%	13%
Canada	24%	34%
WECC	**18%**	**18%**

D. Fuel Prices

The original TEAM demonstration case relied on gas prices from published CEC reports. These prices were revised to reflect the gas price differential that exists at different city gates and gas pricing hubs as of Aug 2004, and after discussions with SCE. For the analysis, we developed three different gas cases, base, very high and very low for each year. Table VI.3 provides the annual average of the monthly gas prices used for the analysis.

For the derivation of the cases, we assumed that the gas price is log normally distributed and the forecast error is normally distributed. The very high and very low cases are at the 90 percent confidence interval of the gas forecast error published by CEC. The monthly gas prices used for this study for each region and for years 2008 & 2013 are summarized in the Technical Appendix.

Table VI.3 Average Regional Gas Prices (2008 $/mmbtu)

	Base		Very Low		Very High	
Region	**2008**	**2013**	**2008**	**2013**	**2008**	**2013**
Canada	4.34	$4.84	$2.13	$2.37	$8.90	$9.92
Northwest	4.45	$4.94	$2.18	$2.42	$9.13	$10.13
N. Calif.	5.20	$5.61	$2.55	$2.75	$10.65	$11.51
S. Calif.	5.08	$5.50	$2.49	$2.70	$10.41	$11.28
Southwest	4.71	$5.17	$2.31	$2.53	$9.65	$10.60
Rocky Mtn.	4.41	$4.90	$2.16	$2.40	$9.05	$10.05
WECC Ave.	**4.70**	**$5.16**	**$2.30**	**$2.53**	**$9.63**	**$10.58**

The real escalation rate from 2008 to 2013 is about 1.9 percent. The Very High gas prices are about 200 percent of the Base and the Very Low gas prices are about 50 percent of the base prices.

E. Market Price Derivation

Historically, resource-planning studies have relied on production cost simulations (i.e. market simulations that assume marginal cost pricing) to evaluate the economic benefits of potential transmission investments. While such an approach may make sense in a vertically integrated regime, assuming marginal cost pricing in a restructured market environment where suppliers constantly seek to maximize their market revenues may result in an inaccurate benefit assessment. Therefore, a key objective in this study was to quantify the economic benefits of a transmission upgrade based on a market price simulation instead of a production cost simulation.

Furthermore, traditionally, transmission upgrades were used as means to enhance system reliability and reduce overall system production cost. In a restructured market regime, transmission upgrades also have a significant role in attracting more competitors to local markets and enhancing market competitiveness. Thus, another important task we identified was to accurately capture the significant benefits an upgrade has in enhancing overall market competitiveness in regions reliant on importing power to meet demand.

Although it is a great challenge to model strategic bidding of suppliers in a full network model, we were able to rely on the market operating experience of the past seven years. Using historical data, we were able to demonstrate a strong statistical relationship between price-cost markups and key variables that measure the system supply/demand conditions. The variables we used were the residual supply index (RSI) and the percentage of load that is un-hedged[10].

We estimated this relationship from observed data during two critical periods: from 1999 to 2000 when suppliers had few long term contracts with load, and the year 2002 when some suppliers had large amounts of supply contracted to load under long-term contracts. Based on these very divergent periods, we estimated a relationship of how prices are marked up above cost every hour in each of three California regions (south, central, north), based on the margin of supply over demand, accounting for potential import quantities. This relationship allowed us to build a dynamic bid adder mechanism in our market simulation model in which suppliers' bids are determined by their production costs and their abilities to bid above their costs. More importantly, the dynamic bid adder mechanism captured the impact of major transmission upgrades, such as the Palo Verde–Devers 2 line, on increasing the import capability into the CAISO control area thus reducing suppliers' ability to bid above cost. Finally we used the market prices forecasted by our simulation model in our assessment of the economic benefit of enhanced competitiveness due to the Palo Verde–Devers 2 line.

F. Project Costs

Southern California Edison (SCE) has estimated the capital cost of the proposed PVD2 upgrade to be $620 million at its online date at the beginning of 2009. SCE has also

10 The Residual Supply Index is total supply available to meet load without the largest supplier. For more detailed discussion on the relationship between price-cost markup and key market variables, please refer to Chapter 5 of the TEAM report at http://www1.caiso.com/docs/2004/06/03/2004060313241622985.pdf.

estimated an allowance for funds used during construction (AFUDC) of approximately $60 million, for a total capital cost of $680 million at the 2009 online date.

For purposes of our analysis, we have deflated the capital costs one year so that they can be expressed in 2008 dollars (to be consistent with the benefits which are also expressed in 2008 dollars). The capital costs deflated to 2008 are $667 million using a 2.0 percent inflation rate.

These capital costs can be converted to an equivalent stream of annual revenue requirements. Although these revenue requirements change from year-to-year, for purposes of economic evaluations, we expressed this series of annual revenue requirements as an equal or "levelized" annual payment over the project life.

We estimate the levelized revenue requirement for the capital costs of the proposed PVD2 project will be $70 million per year for 50 years.[11] If we assume that the operating costs of the line are approximately 0.25 percent of the capital cost per year, the total of capital and fixed operating costs will be $71 million per year. Thus, for this analysis, we compared our calculated levelized benefits to the $71 million levelized costs to determine the economic viability of the project.

G. Initial Review of Project Costs

As mentioned previously, SCE estimated the PVD2 project cost to be $680 million at its 2009 online date. The CAISO has not conducted an independent evaluation of the costs of the project. That function is typically performed by the CPUC in the Certificate of Public Convenience and Necessity (CPCN) hearings on the proposed project. We did perform a cursory review of the project costs. To determine if SCE's estimated cost for the proposed PVD2 Project was reasonable, we compared the project cost with the costs for other proposed 500 kV lines from Pacific Gas & Electric and San Diego Gas & Electric Companies: Path 15 Upgrades Project and the Valley – Rainbow 500 kV Line Project. [12] Table VI.4 summarizes these projects.

Table VI.4 Comparison of Proposed Project Costs

Project	Total Cost (2008 $)	Miles	Cost per Mile (2008 $)	New Right-of-Way Req?	Urban or Rural
Valley-Rainbow	370	30	12	yes	urban
Path 15	250	83	3.0	yes	rural
PVD2	680	230	3.0	no	rural

The Path 15 upgrades and the PVD2 project utilize rights-of-way owned by the transmission owners. The Valley – Rainbow 500kV Project, however, was proposed with new rights-of-way to be acquired by SDG&E. A cursory review of the project cost,

11 The revenue requirements include the impact of federal and state income taxes, administrative and generation costs, insurance expenses, and ad valorem tax. SCE provided the CAISO with its computed "Real Economic Carrying Charge Rate for Transmission" of 10.43 percent. This rate is comparable to a Nominal Economic Carrying Charge Rate of 15.6 percent.

12 The CPUC did not approve the proposed Valley – Rainbow 500kV Line Project and SDG&E decided not to re-file the project application.

based on 2009 dollars[13], indicated that the $2.7 million/mile unit cost for the PVD2 Project was the least expensive of all three 500 kV projects. This probably can be attributed to the fact that the PVD2 is constructed almost entirely in desert terrain with the rights-of-way already owned by SCE. The unit cost for the Valley – Rainbow 500 kV Project was the highest, partly attributed to the new rights-of-way that SDG&E proposed to acquire.

H. Approved Transmission Projects

The CAISO Board approves all projects that cost $20 million or more. Table VI.5 on the following page provides a list of the major transmission projects that the CAISO Board has approved from 2000 through 2004.

13 Project costs are adjusted to the same year (2009) for the purpose of cost comparison.

Table VI.5 CAISO Board Approved Transmission Projects

	Project Name	Transmission Owners	CAISO Board Approval	Scheduled Operating Date	Purpose (Economic / Reliability)	Cost ($ Million)
1	Northeast San Jose Transmission Reinforcement	PG&E	1/27/2000	5/2003	Reliability	$130 M
2	Tri-Valley Transmission Reinforcement Project	PG&E	1/27/2000	5/2003	Reliability	$39.2 M
3	San Luis Rey Substation Reinforcement	SDG&E	1/27/2000	December 2002	Reliability	Confidential Cost > $20 M
4	Installation of A Third Metcalf 500/230kV Transformer Bank	PG&E	2/21/2001	September 2002	Reliability	$33 M
5	Valley – Rainbow 500kV Transmission Project	SDG&E	3/30/2001	2008[14]	Reliability	$350 M
6	Midway 500/230kV Transformer #3 Project	PG&E	6/21/2001	October 2002	Economic	$32 M
7	Jefferson – Martin 230kV Transmission Project	PG&E	4/25/2002	1st or 2nd Quarter, 2006	Reliability	$200 - $ 250 M
8	Miguel – Mission Upgrade and Imperial Valley Transmission Upgrades	SDG&E	6/25/2002	May 2003 and June 2006[15]	Economic	$61 M
9	Path 15 Upgrade	PG&E, WAPA, Trans-Elect	6/25/2002	December 2004	Economic	$306 M
10	San Diego Transmission Upgrades	SDG&E	10/23/2003	December 2004	Economic	$22 M
11	Metcalf – Moss Landing Reinforcement Project	PG&E	4/22/2004	2006	Reliability	$29 M
12	STEP Short-Term Transmission Upgrades	SCE, SDG&E and APS	6/24/2004	June 2006	Economic	$148 M
13	Cross Valley Rector Loop Project	SCE	6/24/2004	2006	Reliability	$46 M
14	Lakeville – Sonoma 115kV Transmission Line Project	PG&E	6/24/2004	2006	Reliability	$30 M
15	Tehachapi Wind Generation Transmission Project (aka Antelope – Pardee 230kV Transmission Line Project)	SCE	7/29/2004	December 2006	Reliability / Renewable Generation	$94 M
16	Martin – Hunters Point 115kV Underground Cable Project	PG&E	11/10/2004	Summer 2007	Reliability	$35 M
17	Rancho Vista 500/230kV Substation Project	SCE	1/27/2005	Summer 2011 (SCE may advance the project as early as 2009)	Reliability	$130 M

14 This project was later rejected by the CPUC as part of its environmental permit review.)
15 June, 2006 for Miquel-Mission 230 kV Upgrade (temporary configuration may accelerate operational date to 2005. May 2003 for Imperial Valley Substation upgrade.

VII. RESULTS

In evaluating the project's potential economic benefits, we made estimates of five components: (a) energy savings; (b) operational benefits; (c) capacity savings; (d) system loss reduction; and, (e) emission reduction benefits. We derived the energy savings using the PLEXOS software model. We estimated operational benefits, capacity savings, system loss reduction, and emission benefits separately, outside of the market modeling process.

A. Energy Savings

i. Expected Value and Range

Energy savings is the difference between production costs to serve the load without the proposed PVD2 upgrade and the lower production costs with the upgrade in service. We estimated these benefits using sophisticated market simulation software that allowed us to capture the energy savings associated with the project. We evaluated the benefits for 66 different cases for the years 2008 and 2013.

Each case is composed of two simulations, "without" and "with" the proposed PVD2 upgrade. The 66 cases are divided into three categories. There are 16 cost-based cases where marginal costs, not market-based bids, are modeled. Cost-based cases are used to understand the impact of PVD2 in a variety of settings, without the added complication of modeling market-based bids. The second category includes the market-based cases with probability. The 34 market-based cases with probability are similar to the cost-based cases, except they include the impact of market prices and have a probability assigned to each of the cases. This second category of cases is used to determine the expected (probability-weighted average) benefits from various perspectives. The third category of cases includes the contingency cases. The 16 contingency cases represent extreme events for which it is difficult to assign a probability. These cases are used to understand the potential range of benefits.

We evaluated the benefits based on the following four important perspectives:

- ***Societal –*** Represents the production cost savings of adding the transmission upgrade to western states and provinces as represented by the Western Electric Coordinating Council (WECC). The total WECC benefit is also equal to the sum of the Consumer, Producer, and Transmission Owner benefits.
- ***Modified Societal –*** Represents the enhanced overall market competitiveness in WECC of adding the transmission upgrade. Producer Benefit includes the net generator revenue from competitive prices only. The Modified Societal perspective excludes the generator net revenue from uncompetitive market conditions.
- ***CAISO Ratepayer (LMP Only) –*** Demonstrates whether the benefits outweigh the costs for CAISO ratepayers. This perspective is used in deciding whether ISO ratepayers should fund the transmission expansion. This calculation is based on

locational marginal price (LMP) and the resulting congestion revenues applicable throughout the WECC.

- ***CAISO Ratepayer (LMP + Contract Path) –*** Same perspective as above but the flow-based or LMP market is modified by the utilization of selected contractual paths between CAISO and the Southwest region.

The CAISO Ratepayer (LMP Only) analysis is performed assuming congestion revenue is based on physical-flows throughout the Western Coordinating Council (WECC). An important assumption is that locational marginal pricing (LMP) will be uniformly implemented by all the entities in the Western Interconnection. However, this pricing mechanism may not be implemented in the immediate future. At present, most of the WECC operates based on contract path (rather than physical-flow network model) scheduling.

The CAISO Ratepayer (LMP Only) computes transmission congestion revenue for each line in the WECC. In some cases, this congestion revenue can be very high. However, today some congestion is managed in real-time resulting in uplift charges rather than congestion revenue. The net result is that the LMP methodology as applied to the CAISO Ratepayer perspective exaggerates the loss of congestion revenue in today's environment due to the upgrade.

For the CAISO Ratepayer (LMP + Contract Path) perspective, we make adjustments to the transmission congestion revenue both before and after the upgrade. The net impact was usually an increase in transmission upgrade benefits for the CAISO ratepayers, more closely reflecting the upgrade benefits to the ratepayers under the current WECC scheduling rules.

The energy benefits are summarized for the two years of study, 2008 and 2013, for these four perspectives in Table VII.1 below.

Table VII.1 Estimated Energy Benefits (2008 mil. $)

Perspective	2008		2013	
	Expected Value	Range[16]	Expected Value	Range[17]
Societal	$41	$4 - $200	$54	$20 - $200
Modified Societal	$61	$6 - $400	$81	$20 - $600
CAISO Ratepayer (LMP Only)	$39	($3) - $300	$56	($3) - $400
CAISO Ratepayer (LMP + Contract Path)	$110	$10 - $600	$200	$50 - $1,000

16 The range shown in this table is derived by taking the lowest and highest benefit for the various perspectives in 2008 and 2013, and then rounding the lower number down, and the higher number up to the next single significant digit.
17 Ibid.

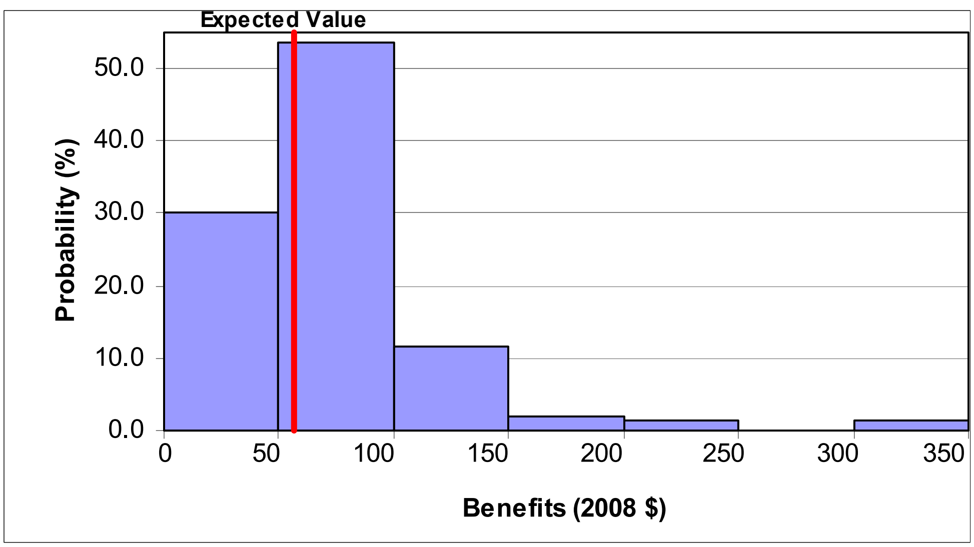
In Table VII.1 we summarize only the energy benefits of the proposed upgrade. These benefits cannot be directly compared to the annual costs since they do not include the other benefits described in the following sections, and these benefits have not be levelized over the 50-year life of the project.

ii. Probability Distribution of Energy Benefits

In Figure VII.1 we show a range of potential energy benefits for the CAISO Ratepayer (LMP Only) perspective. The range shown in Table VII.1 provides reasonable end-points for the estimated benefits for the four perspectives, but it does not provide any information regarding the likelihood or probability of the benefits occurring.

Since we have assigned probabilities to many of the cases, we can use this information to better understand the distribution of benefits.[18] In Figure VII.1, we illustrate the relative probabilities of various benefit ranges for the CAISO Ratepayer (LMP Only) perspective in 2013. The highest benefits resulted from those cases where several adverse events occurred simultaneously, such as high load, high gas price, dry hydro, and high market power (2013 HHDH).

Figure VII.1 Probability Distribution of Energy Benefits (2013, CAISO Ratepayer – LMP Only)



There is a 70 percent probability that the annual energy benefits in 2013 exceed $50 million. There is a 5 percent probability that the project would provide an annual ratepayer benefit between $150 and $350 million, thus providing a significant insurance value for extreme events.

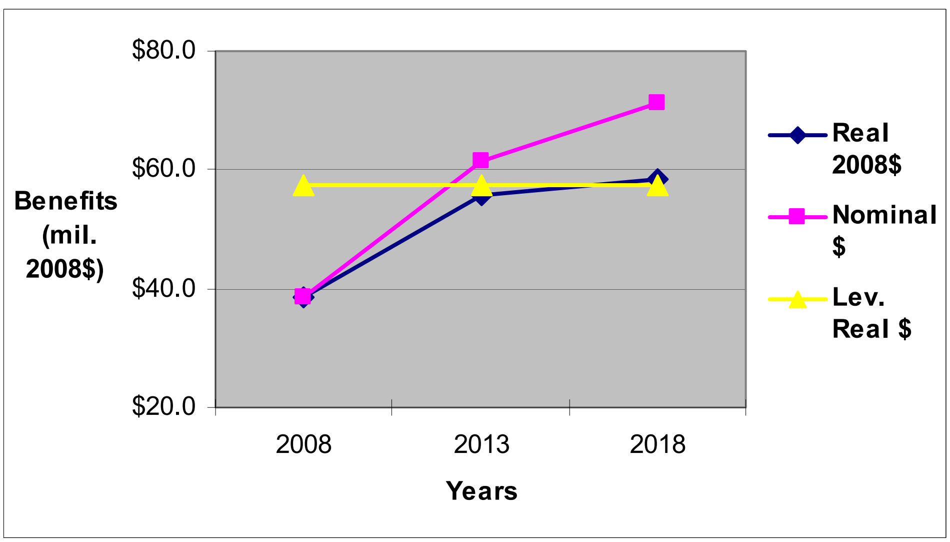
18 We assigned probabilities to all market-based cases where the joint probability was quantifiable. We did not assign cost-based case probabilities since these cases had no market representation. We did not include contingency cases where it was not possible to determine the joint probability.

iii. Levelized Energy Benefits

We represented the capital costs of the project as a constant or levelized stream of annual revenue requirements. Therefore, it is convenient to express the benefits in the same manner to facilitate comparison. In Figure VII.2 below, we show the relationship of the annual nominal benefits (including inflation) and the annual real benefits (excluding inflation) expressed in 2008 dollars. For purposes of illustration, we have assumed a 1 percent real escalation rate after 2013.

In Figure VII.2 we show the annual benefits in millions of real 2008 dollars with the blue line. Although the economic life of the project is 50 years, we show only the first 10 years so that the relationships between the various benefit streams can be better visualized. The nominal equivalent (with inflation beyond 2008) to the real benefits is depicted in the magenta line. And the levelized real benefits over the 50-year life of the project are shown as the yellow line.

Figure VII.2 Projection of Equivalent Annual Energy Benefits (Societal Perspective, mil. 2008 $)



The three annual benefits shown above are equivalent from a present value perspective. These energy benefits are expressed in: (a) 2008 dollars (real); (b) nominal dollars (includes inflation); (c) and in levelized dollars (real, 2008 $). The first 10 out of 50 years of benefits are shown in order to better understand the relationship between the three benefit streams.

Since we are levelizing the energy benefits over the assumed 50-year economic life of the project, we needed to estimate an escalation rate for the energy benefits after the last year of our study, 2013. As one might expect, one of the most significant assumption for this economic analysis is the 2013-2057 energy benefit escalation rate.

In Table VII.2 below, we show the sensitivity of the energy benefits to the real escalation rate assumption, for the period 2013 through 2057, for all perspective. The levelized energy benefits can vary up to 50 percent depending on the escalation rate assumed.

For the energy benefits, we assumed a 1 percent real escalation rate for the period of 2013 through 2057. We selected the 1 percent real escalation rate for two reasons. First, most of the commodity costs that are a factor in setting market-clearing prices will have some long-term real escalation rate (natural gas, labor, steel, concrete, land, emission offsets, etc.). Second, some fuel switching at the margin will occur from coal-fired to natural gas-fired generation. Natural gas variable costs are approximately twice as high as coal variable costs.

Table VII.2 Levelized Energy Benefits Based on Potential 2013-2057 Escalation Rates (mil. 2008 $)

Escalation Rate	Societal Benefit	Modified Societal	CAISO Ratepayer (LMP Only)	CAISO Ratepayer (LMP+cont. path)
-1	$47	$71	$48	$165
0	$51	$77	$52	$180
1	$56	$84	$57	$198
2	$62	$94	$64	$221
3	$70	$105	$72	$249

In Table VII.3, P. 24, we provide a summary of the 66 cases that were studied for 2008 and 2013. Each case consists of a "without PVD2" and a "with PVD2" simulation. The difference in WECC production costs equals the societal value.

B. Operational Benefit

The operational benefits of a transmission project are an important component of the benefits of the PVD2 project. Traditional production cost simulations may not capture all the operational costs that are incurred in managing the electric grid. This is especially true if generation unit commitment costs and ramp rate parameters are not explicitly modeled. Thus, there is an underestimation of the operational costs to meet an N-1 (and relevant N-2) planning contingency criteria (and hence an underestimation of transmission upgrade benefits related to reduction of the operational costs).

For contingencies that do not involve the outage of the Palo Verde line, the extra import capacity on the new Palo Verde line reduces the amount of internal on-line generation needed. Regarding Palo Verde line outages, the CAISO operators tell us they keep a number of units on minimum load to protect against an outage of the Palo

Verde line. In addition to committing units, and the corresponding payment of minimum load cost compensation (MLCC), re-dispatch of units is needed to address real-time congestion which is not resolved in Day –Ahead congestion management. To estimate theses operational benefits we performed a detail review of historical MLCC and real-time redispatch costs by location.

We estimated that the implementation of the so-called short-term upgrades that precede the PVD2 project would reduce some of these commitment (MLCC) and re-dispatch costs. When two Palo Verde-Devers lines are available, there will be further reduction of these costs, and thus operational savings not captured in the energy savings calculations from the line upgrade produced by the simulation model.

Table VII.3 Summary of Cases to Determine Energy Benefit for PVD2

		Year	Load	Gas Price	Hydro	Market Pricing	Other	Joint Probability	Societal Benefits (mil. nominal $)	Modified Societal Benefits (mil. nominal $)	CAISO Ratepayer Benefit (LMP Only) (mil. nominal $)	CAISO Ratepayer Benefit (LMP+ Contract Path) (mil. nominal $)
Cost Based	1	2008	B	B	B	N	N	n/a	$42.8	$42.9	$19.8	$70.8
	2	2008	B	B	D	N	N	n/a	$48.7	$48.8	$28.7	$82.4
	3	2008	B	B	W	N	N	n/a	$23.5	$23.6	$26.1	$69.0
	4	2008	B	H	B	N	N	n/a	$85.8	$85.9	$48.8	$141.5
	5	2008	B	L	B	N	N	n/a	$6.8	$6.8	-$2.4	$17.1
	6	2008	H	B	B	N	N	n/a	$38.1	$38.2	$0.8	$75.3
	7	2008	L	B	B	N	N	n/a	$29.5	$29.5	$34.8	$79.1
	8	2008	H	H	D	N	N	n/a	$110.4	$110.5	$21.6	$148.3
	9	2013	B	B	B	N	N	n/a	$55.5	$55.5	$40.0	$137.1
	10	2013	B	B	D	N	N	n/a	$60.6	$60.6	$38.3	$163.7
	11	2013	B	B	W	N	N	n/a	$37.5	$37.6	$44.2	$117.1
	12	2013	B	H	B	N	N	n/a	$102.4	$102.5	$91.7	$240.6
	13	2013	B	L	B	N	N	n/a	$20.7	$20.7	-$2.9	$50.8
	14	2013	H	B	B	N	N	n/a	$68.2	$68.3	$27.2	$151.1
	15	2013	L	B	B	N	N	n/a	$34.4	$34.4	$62.9	$130.0
	16	2013	H	H	D	N	N	n/a	$163.3	$163.3	$194.1	$308.3
Market Based	17	2008	B	B	B	M	N	11.0%	$45.3	$58.9	$37.9	$98.7
	18	2008	B	B	B	H	N	5.0%	$47.0	$71.1	$54.8	$124.5
	19	2008	B	B	D	M	N	9.9%	$50.5	$66.6	$34.5	$115.7
	20	2008	B	B	W	M	N	13.1%	$24.3	$26.2	$29.1	$72.8
	21	2008	B	H	B	M	N	2.3%	$90.0	$113.1	$76.7	$185.9
	22	2008	B	H	B	H	N	1.8%	$92.5	$133.9	$104.8	$229.1
	23	2008	H	B	B	H	N	3.3%	$45.3	$120.8	$70.9	$199.8
	24	2008	H	H	D	M	N	1.8%	$118.9	$237.0	$85.2	$317.5
	25	2008	B	H	D	H	N	1.8%	$106.0	$151.6	$80.7	$257.3
	26	2008	B	B	B	L	N	15.0%	$42.5	$41.5	$17.0	$68.5
	27	2008	L	B	B	M	N	12.7%	$29.9	$31.6	$35.6	$83.3
	28	2008	B	L	B	M	N	10.1%	$8.8	$18.5	$8.0	$36.6
	29	2008	H	H	B	H	N	1.5%	$93.8	$235.2	$143.2	$371.1
	30	2008	H	L	B	M	N	4.9%	$4.4	$23.7	$2.2	$41.0
	31	2008	L	H	B	M	N	2.3%	$56.9	$59.5	$74.1	$155.4
	32	2008	H	H	D	H	N	1.5%	$135.8	$387.7	$234.9	$568.5
	33	2008	H	H	W	M	N	1.9%	$19.1	$21.5	$5.6	$119.7
Market Based	34	2013	B	B	B	M	N	11.0%	$58.5	$77.4	$54.9	$193.5
	35	2013	B	B	B	H	N	5.0%	$59.5	$93.9	$65.2	$237.2
	36	2013	B	B	D	M	N	9.9%	$65.3	$94.7	$57.5	$247.1
	37	2013	B	B	W	M	N	13.1%	$38.8	$44.4	$50.7	$138.8
	38	2013	B	H	B	M	N	2.3%	$106.1	$137.5	$112.5	$322.4
	39	2013	B	H	B	H	N	1.8%	$108.8	$163.4	$127.7	$387.1
	40	2013	H	B	B	H	N	3.3%	$83.8	$222.7	$138.0	$478.6
	41	2013	H	H	D	M	N	1.8%	$184.9	$359.2	$152.5	$629.2
	42	2013	B	H	D	H	N	1.8%	$123.1	$191.5	$114.3	$484.7
	43	2013	B	B	B	L	N	15.0%	$55.4	$55.9	$38.2	$137.8
	44	2013	L	B	B	M	N	12.7%	$34.5	$34.2	$54.2	$132.1
	45	2013	B	L	B	M	N	10.1%	$24.1	$38.0	$6.7	$94.1
	46	2013	H	H	B	H	N	1.5%	$155.8	$364.1	$222.3	$746.9
	47	2013	H	L	B	M	N	4.9%	$30.9	$68.5	-$0.5	$136.2
	48	2013	L	H	B	M	N	2.3%	$61.2	$60.0	$106.7	$227.1
	49	2013	H	H	D	H	N	1.5%	$189.8	$517.3	$303.5	$993.5
	50	2013	H	H	W	M	N	1.9%	$109.1	$148.5	$94.2	$352.8
Contingency	51	2008	B	B	B	M	PV1	n/a	$59.5	$75.9	$65.6	$136.4
	52	2008	B	B	B	M	PV2	n/a	$68.7	$90.7	$105.7	$170.9
	53	2008	B	B	B	M	MV	n/a	$49.6	$72.2	$60.2	$140.6
	54	2008	B	B	B	M	MH	n/a	$55.5	$71.1	$67.1	$124.4
	55	2008	B	B	B	M	SO	n/a	$58.2	$82.0	$74.6	$161.8
	56	2008	B	B	B	M	PDCI	n/a	$30.1	$40.4	$28.2	$111.9
	57	2008	B	B	B	M	COI_EOR	n/a	$45.7	$57.1	$55.3	$73.2
	58	2008	B	B	B	M	SCE RE	n/a	$41.0	$54.4	$49.9	$109.0
	59	2013	B	B	B	M	PV1	n/a	$85.0	$114.5	$127.6	$291.9
	60	2013	B	B	B	M	PV2	n/a	$91.4	$122.5	$184.0	$338.5
	61	2013	B	B	B	M	MV	n/a	$58.9	$93.0	$78.0	$267.3
	62	2013	B	B	B	M	MH	n/a	$73.7	$96.2	$104.2	$243.0
	63	2013	B	B	B	M	SO	n/a	$85.8	$134.1	$145.7	$380.7
	64	2013	B	B	B	M	PDCI	n/a	$63.8	$84.7	$51.9	$214.8
	65	2013	B	B	B	M	COI_EOR	n/a	$61.5	$80.7	$99.6	$124.0
	66	2013	B	B	B	M	SCE RE	n/a	$56.5	$74.1	$43.7	$191.4

Note: B=Base; L=Low; H=High; M=Moderate; N=None; W=Wet Hydro; D=Dry Hydro; PV= 1200 MW CC in PV; PV2 = 2400 MW CC in PV; MV= Mountian View unit O/S; MH= Mohave Unit I/S; SO=San Onofre Outage; DC=PDCI Line Outage; COI_EOR= 10% less in Transfer Capability; SCE RE = Retirement of 3 Units in SCE Control Area.

We estimated the CAISO payments in southern California to keep generating units on line (including MLCC and re-dispatch costs) to protect against N-1 (and relevant N-2) contingencies after accounting for the short-term upgrades.

We estimate that short-term upgrades could reduce the MLCC by 75% for contingencies related to imports from Arizona and by 10% for MLCC related to system shortages and Nuclear unit maintenance outages. We also estimate that the associated re-dispatch costs would be lower by 75%. We then estimate that the PVD2 upgrade would result in further reductions as follows: 25% of (the remaining 25%) SCIT MLCC, 25% of (the remaining 90%) system MLCC, 80% of (the remaining 90%) Nuclear MLCC, and 50% (of the remaining 25%) re-dispatch cost, resulting in a total annual savings of $18 million in 2004 dollars, or $20 million in 2008 dollars.

Table VII.4 Annual Average Payments

	MLCC (AZ & CA Imports)	*MLCC (CAISO System wide Shortages)*	*MLCC (Nuclear Maintenance)*	*Re dispatch (AZ & CA Imports)*
Real Time Annual Average	$51,208,305.99	$ 28,614,216.90	$11,551,880.94	$ 2,110,578.65
	Total Annual Real Time Operational Costs			**$ 93,484,982.48**
After Short Term Upgrade	25%	90%	90%	25%
	$12,802,076.50	$ 25,752,795.21	$10,396,692.84	$ 527,644.66
	Total Annual Average Operational Benefit			**$ 49,479,209.21**
PVD2 Benefits	25%	25%	80%	50%
	$ 3,200,519.12	$ 6,438,198.80	$ 8,317,354.27	$ 263,822.33
	Total Annual Average Operational Benefit			**$ 18,219,894.53**

Note: The Real time data used are from March of 2003 to September 2004

C. Capacity Benefit

We derived capacity benefits using the assumption that California will continue to have a resource adequacy requirement and that Arizona can be the source of contracted capacity to serve California load. A key assumption for these savings is that the future cost of capacity in Arizona will be less than the cost in California. We believe this to be so for two reasons:

- We believe that the capital and fixed operating costs for a peaking unit are significantly less in Arizona. We expect that situation to continue indefinitely. The reduced capital and operating costs in Arizona would also translate into a lower capacity price.
- We also project a greater resource surplus in Arizona than in California for the early years of the project. We expect the demand for capacity, and the resulting price, to be less in Arizona.

Lower fixed costs for a combustion turbine in Arizona would be directly reflected in lower capacity costs. We estimate that differential to be $14/kw-year in 2004 $, or

$15/kw-year in 2008 dollars. If we further assume that firm summer capacity is available for the entire 1,200 MW upgrade, the capacity benefit would be $18 million per year in 2008 $. The $18 million per year represents the maximum savings benefit when the capacity price is capped at the cost of new peaking units. In order to provide a more conservative estimate, we have decreased this amount by one-third to $12 million. In addition, we assume that this benefit will be split equally between the buyers and sellers of capacity. Thus, we estimate the societal benefit will be $12 million and assume the CAISO benefit will be half that amount or $6 million.

D. Loss Savings

We used a linearized DC power flow model for this analysis. This model does not model transmission losses internally. In practice, we expect PVD2 to lead to more efficient generation dispatch. We expect transmission losses to be lower as a result of the transmission upgrade. We attempted to quantify the transmission loss reduction benefits of the upgrade in this analysis. The Technical Appendix details the decreases in transmission losses we expect as a result of the upgrade. In our analysis we used the computed power flows before and after the upgrade, and calculated the loss savings. We estimate these to be $2 million annually, an estimate that implicitly includes the interplay between increased losses due to heavier power transfers, and loss reduction due to redistribution of these power flows on the existing and new transmission paths.

E. Emissions

We did not model airborne emissions directly in the market simulation model due to a lack of emission rate availability. We used the results of the model, however, to estimate the reduction in NOx emissions as a result of the upgrade. The PVD2 upgrade allows more efficient Arizona gas-fired generation to displace less-efficient California gas-fired generation. This generation displacement results in a reduction of natural gas usage and a corresponding reduction in NOx emissions. In a post-processing application, we compared the difference in generation by plant before, and after, the PVD2 upgrade. We estimated a NOx emission reduction of 390 tons per year. The NOx emission cost reduction we derived was $2.2 million total, or half that amount to be considered a CAISO benefit. Detailed information regarding this derivation can be found in the Technical Appendix.

F. Summary of Results

In the previous sections, we have presented the levelized annual benefits as well as the levelized annual costs for the proposed PVD2 upgrade. In Table VII.5 on the following page, we summarize our findings and determine an overall benefit-cost ratio for the societal, modified societal, and CAISO ratepayer perspective.

Table VII.5 Derivation of PVD2 Benefit-Cost Ratio (mil. 2008 $)

	WECC or Societal	Enhanced WECC Competition or Modified Societal	CAISO Ratepayer (LMP Only)	CAISO Ratepayer (LMP+ Contract Path)
Levelized Benefits				
- Energy	$56	$84	$57	$198
- Operational	$20	$20	$20	$20
- Capacity	$12	$12	$6	$6
- System Loss	$2	$2	$1	$1
- Emissions	$1	$1	$1	$1
- Total	$91	$119	$84	$225
Levelized Costs	$71	$71	$71	$71
Benefit-Cost Ratio	**1.3**	**1.7**	**1.2**	**3.2**

We calculated the total benefits of the PVD2 line using energy, operational, capacity, system loss, and emission benefits.

We compared the total benefits over the lifecycle of the project (converted to an equivalent annual number) to the annual costs of the line. The expected value of the benefits is based on 34 cases.

i. Social Discount Rate

We derived the benefit-cost ratio (BCR) summarized in Table VII.5 using a real discount rate of 7.16 percent. This figure represents SCE's weighted cost of capital (i.e. debt, preferred stock, and common equity). Some individuals and groups, such as the CEC, have argued that a lower discount rate is appropriate for capital-intensive public works.

If we use a "social" discount rate of 3 percent instead of the 7.16 percent, the energy benefits increase by a factor or two. We recognize the concern that using a social discount rate can create a discrepancy between the revenue requirements funded at the borrowing entity's cost of capital, and the benefits, which are valued at a different discount rate.

VIII. RESOURCE ALTERNATIVES

Before a decision is made to construct and operate the proposed PVD2 upgrade, we need to consider alternative resources. These resources may include:

- Demand-side resources
- Renewable resources

- Thermal generation resources
- Transmission resources

From our perspective, we do not consider the first two categories of resources as alternatives. To the extent demand-side management (DSM) or renewable resources are technically and economically feasible, these resources should be fully developed and utilized. Only when the resource contributions from the DSM and renewable resources are maximized, should traditional resources be considered. Therefore, this section will focus on thermal generation and transmission alternatives.

i. Generation Alternatives

Prior to committing to build or upgrade a transmission line, we need to consider alternative generation resources. In today's market, the most likely generation alternative is a new combined-cycle (CC) generating plant. The question for this analysis is whether the CAISO should promote the PVD2 upgrade, or recommend building new CC's in the CAISO area, or both.

In Table VIII.1, we compare the expected total costs of a new 500 MW combined-cycle station located in California with one located in Arizona. We expect the total CC costs (capital, O&M, and fuel), excluding any transmission interconnection costs, to be about 10 percent less in Arizona. When the levelized pro-rated cost of 500 MW of PVD2 upgrade is added to the cost of the Arizona CC, the Arizona CC becomes more expensive. At a 50 percent capacity factor, the Arizona facility is 10 percent more expensive. At a 90 percent capacity factor, the Arizona facility is 4 percent more expensive. This is summarized in Table VIII.1.

Table VIII.1 Comparison of Combined Cycle Costs In California and Arizona (2008 $)

Parameter	Units	California	Arizona	Percent Dif.
Installed Capital Cost	$/kw	$1,184	$1,080	10%
Real Econ. Carrying Charge	%	10%	10%	0%
Annual Capital Cost	$/kw-yr	$118	$108	10%
Fixed O&M Costs	$/kw-yr	$15	$10	50%
Annual Fixed Costs	$/kw-yr	$133	$118	13%
PVD2 Transmission Costs	$/kw-yr	$0	$59	-100%
Total Fixed Costs	$/kw-yr	$133	$177	-25%
Average Heat Rate	btu/kwh	7,100	7,100	0%
Fuel Costs	$/mmbtu	$5.08	$4.71	8%
Fuel Costs	$/MWh	$36	$33	8%
Variable O&M Costs	$/MWh	$3	$2	50%
Total Variable Costs	$/MWh	$39	$35	10%
Assumed Capacity Factor	%	90%	90%	0%
Total Costs	$/MWh	$56	$58	-4%

By itself, the information presented in Table VIII.1 does not present a complete picture. Other important factors need to be considered for the following reasons:

- No interconnection costs – In the above example, we have not included any transmission or gas interconnection costs due to lack of applicable data. In California these costs can be substantial, such as Otay Mesa. In Arizona, the majority of the new CC's are being constructed in the Palo Verde region where they can directly connect with the existing 500 kV network and the natural gas pipeline with minimal interconnection costs.
- Limited ability to site resources in CA urban areas -- Many PVD2 stakeholders have suggested that a new CC located in the load centers of southern California would be more valuable than a similar unit located in Arizona. We agree that new or refurbished generating units are needed in the load centers for reliability and operational purposes. However, we believe that these opportunities will be very limited in the future. In many cases, even using the sites of existing units in urban areas is strongly opposed by the local communities. An example of this opposition is San Francisco, where local generation would be very valuable, but the residents surrounding the Hunters Point and Potrero sites strongly oppose any new developments on those sites and advocate shutdowns of the existing units.

Therefore, we believe that both local generating options in addition to transmission solutions need to be aggressively pursued. Constructing and operating PVD2 does not preclude the construction of local facilities. California needs to add 5000 MW or more in the next 5 years due to load growth and generation retirement.

ii. Transmission Alternatives

STEP was created as a sub-regional planning group to address transmission concerns in the Arizona, southern Nevada, southern California, and northern Mexico areas. The new generation that has been developed at certain locations in the southwest region had made it clear to the STEP participants that the existing transmission system is inadequate. By enhancing the capability of the system, this new, relatively clean, and efficient generation would be better able to serve future load growth and displace older and less efficient generation. STEP held its first meeting on November 1, 2002 in San Diego and has met on a monthly or bi-monthly basis since that meeting. Participants include representatives from utilities, independent power producers (IPPs), state agencies/regulators and other stakeholders with an interest in the transmission system in southern Nevada, Arizona and southern California.

STEP evaluated a large number of potential transmission upgrade plans during the year of 2003. In fact, STEP analyzed 26 different upgrade cases with different combinations of transmission lines in the southwest region. See http://www1.caiso.com/docs/2004/03/08/2004030814004810105.doc for further information.

The group selected six transmission alternatives based on the initial screening studies for further technical and economic analysis. The Palo Verde–Devers No. 2 500 kV line was part of two ("AC1" and "AC2") out of the six. Analysis deemed three of the alternatives ("AC4", "DC1" and "DC2") not viable options due to reasons such as lack of project sponsorship, inadequate technical performance or insufficient economics. The last alternative, “AC3”, included a variant of the Palo Verde–Devers No. 2 500 kV line with termination points at Blythe and Parker Substations. Desert Southwest Power LLC and SCE have been discussing the connection point at Blythe (“Midpoint Substation”). Likewise, SCE and APS are discussing the use of the proposed terminal point for the Palo Verde–Devers project at Harquahala Substation as a joint substation for both the PVD2 project and APS’s TS5 Project. We expect neither of these variances to significantly change the scope of the proposed Palo Verde-Devers No. 2 project.

Based on the technical and economic studies, and a consensus building process, the group narrowed the number of alternatives to one general expansion plan. STEP has now begun several of the initial steps in the expansion plan that can be implemented quickly and economically. These initial steps primarily involve upgrades to the 500 kV series capacitors of the existing Palo Verde–Devers and the Southwest Power Link (SWPL). The planned in-service date for these upgrades is June 2006. They will increase the rating on EOR from 7,550 MW to 8,055 MW. LADWP and several utilities in Arizona have also suggested upgrading the series capacitors on the Perkins–Mead and Navajo–Crystal 500 kV lines between Arizona and Nevada. This project is called the “EOR9000+” project. Its goal is to increase the EOR path rating from 8,055 MW to 9,300 MW, an increment of 1,245 MW. If the EOR 9000 project goes forward, then the CAISO will likely sponsor the upgrade of the third major line between Arizona and Nevada, the Moenkopi-Eldorado 500 kV line.

We received stakeholder feedback in Nov 2004 that questioned whether the EOR 9000 upgrades could substitute for the Palo Verde-Devers No. 2 line. We ran sensitivities with and without EOR 9000. We found that the two projects are predominately complements rather than substitutes for one another. Solely undertaking the EOR 9000 project, does not deliver the benefits expected from the PVD2 line. This is because those upgrades increase transmission capability between Arizona and Nevada, but do not relieve congestion on the transmission facilities that run directly from Arizona to southern California. Thus having just the EOR9000 project does not significantly enhance the import capability into California. The PVD2 expansion would complement the EOR 9000 Project by relieving a major bottleneck into southern California.

IX. RECOMMENDATION

We recommend that the Board approve the PVD2 project for the following reasons:

- It represents a cost effective investment for California ratepayers with an expected benefit-to-cost ratio ranging from 1.2 to 3.2 over the 50-year life of the project.
- Benefits of the PVD2 upgrade include: (a) reduction in production costs (energy savings); (b) operational savings (reduced use of uneconomic generation for reliability purposes); (c) capacity savings (increased access to lower capacity cost generation in the southwest); (d) emission reductions (displacement of inefficient California generation with more efficient southwest generation); and (e) loss

reduction (WECC total system losses will be reduced due to increased transmission capacity).

- Under extreme conditions, such as high load growth and fuel prices, dry hydro, and uncompetitive markets, the benefits of PVD2 can be very high with an annual benefit-to-cost ratio that can range from 2 to 10. Given these large savings or, alternatively, the large cost exposure under adverse conditions, this line can provide a significant insurance value that will help to mitigate the impact of adverse conditions on CAISO ratepayers.
- The project provides CAISO grid operators with significant additional flexibility for scheduling and responding to transmission outages.
- PVD2 increases the economic investment in the California infrastructure necessary to ensure competitive energy markets and high reliability.

As required by CAISO policy, we will update the economic analysis as necessary as part of the annual development of the 10-Year Grid Plan. We expect the initial investment required to proceed with the permitting phase of the project will cost less than $10 million or 1.3 percent of the total project costs. SCE is required to present the project to the CPUC for environmental review and need assessment. The regulatory process for reviewing transmission projects has steps sufficient to ensure that large amounts of capital will not be expended without oversight and review. Approval of PVD2 by the CAISO Board allows this option to be aggressively pursued in a timely manner. It does not commit the entire capital cost of the project until the completion of the CPUC process. If SCE obtains all other regulatory approvals, no further action by the CAISO Board is required.

X. NEXT STEPS

February 2005 – Board consideration of management's recommendation.

March 2005 – If the Board approves this project, CAISO will support SCE's Certificate of Public Convenience and Necessity ("CPCN") process at the California Public Utility Commission ("CPUC"). SCE has been working on the application and should be able to file it by the spring of 2005. Once the CPCN request is filed, the CPUC would complete an environmental impact report (EIR) for the project, hold hearings on the project including a detailed review of the project costs, and ultimately decide whether the project should be granted a CPCN. The CPUC process is expected to take between 18 and 24 months. Once a CPCN has been granted, SCE would complete the design of the project and complete the acquisition of any additional land the project requires. The design and land acquisition phase of a major project like PVD2 typically requires about a year. At this point, construction can begin. Constructing the line can be expected to take another 18 to 24 months. Given these timelines, the project could be in-service as early as 2009. In parallel with this process, SCE as the sponsor of the PVD2 project will complete the WECC path rating process to receive an accepted rating for the project.

ATTACHMENT 7
OF
PHASE 1 OPENING TESTIMONY ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR
October 21, 2005
A.05-04-015
I.05-06-041

CALIFORNIA ISO

Technical And Other Appendices

(To be accompanied by the Board Report)

Economic Evaluation of the Palo Verde Devers Line No. 2 (PVD2)

Prepared by

California ISO
Department of Market Analysis & Grid Planning

February 16, 2005

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Appendix A. SCENARIO SELECTION

In this study we considered five key variables that might have significant impact on the economic benefit of Palo Verde – Devers #2 line and selected 25 scenarios for production cost simulation and market based simulation. These five key variables include future demand levels, future gas price levels, future hydro production levels, future markup levels of suppliers, and potential transmission or generation outage contingency events. More specifically, we considered three demand levels: Very high (H), base (B), Very low (L); three gas price levels: Very high (H), base (B), Very low (L); three hydro production levels: wet year (W), base (B), dry year (D); three markup levels: Very high (H), moderate (M), and Very low (L)[1].

The combinations of these variables and their values consist a large set of possible future states of the WECC transmission/generation system. Given the large number of all combinations, it is impossible for us to conduct a simulation for every single case. Therefore we developed a scientific way and selected a small but representative sample of all possible cases such that we can still reasonably accurately estimate the expected economic benefit of the line as well as the expected range of the benefit under a wide range of system conditions. After we selected scenarios, we assigned probabilities to each scenario by using two mathematical approaches; one called "Maximum Log-Likelihood" to assign probabilities to scenarios used in the expected benefit calculation, another called "Max/Min Linear Programming" to assign probabilities to scenarios that are used for the expected benefit range calculation.

Table A.1 summarizes the scenarios and the probabilities that we used to calculate expected benefit of Palo Verde – Devers #2 line. All these scenarios are combined with normal transmission/generation situations in simulation. In other words, no transmission/generation outage contingencies are considered in the expected benefit calculation.

1 For more detailed discussion on how each variable value is determined, please refer to Chapter 5 of the TEAM report at http://www1.caiso.com/docs/2004/06/03/2004060313241622985.pdf.

Table A.1 Scenarios Selected for Expected Benefit Calculation

Scenario	Demand	Gas Price	Hydro	Markup	Probability
1	B	B	B	M	0.110
2	B	B	B	H	0.050
3	B	B	D	M	0.099
4	B	B	W	M	0.131
5	B	H	B	M	0.023
6	B	H	B	H	0.018
7	H	B	B	H	0.033
8	H	H	D	M	0.018
9	B	H	D	H	0.018
10	B	B	B	L	0.150
11	L	B	B	M	0.127
12	B	L	B	M	0.101
13	H	H	B	H	0.015
14	H	L	B	M	0.049
15	L	H	B	M	0.023
16	H	H	D	H	0.015
17	H	H	W	H	0.019

Table A.2 summaries the additional scenarios selected for expected benefit range calculation. These are the scenarios with either transmission or generation outage contingencies.

Table A.2 Additional Scenarios Selected for Expected Benefit Range Calculation

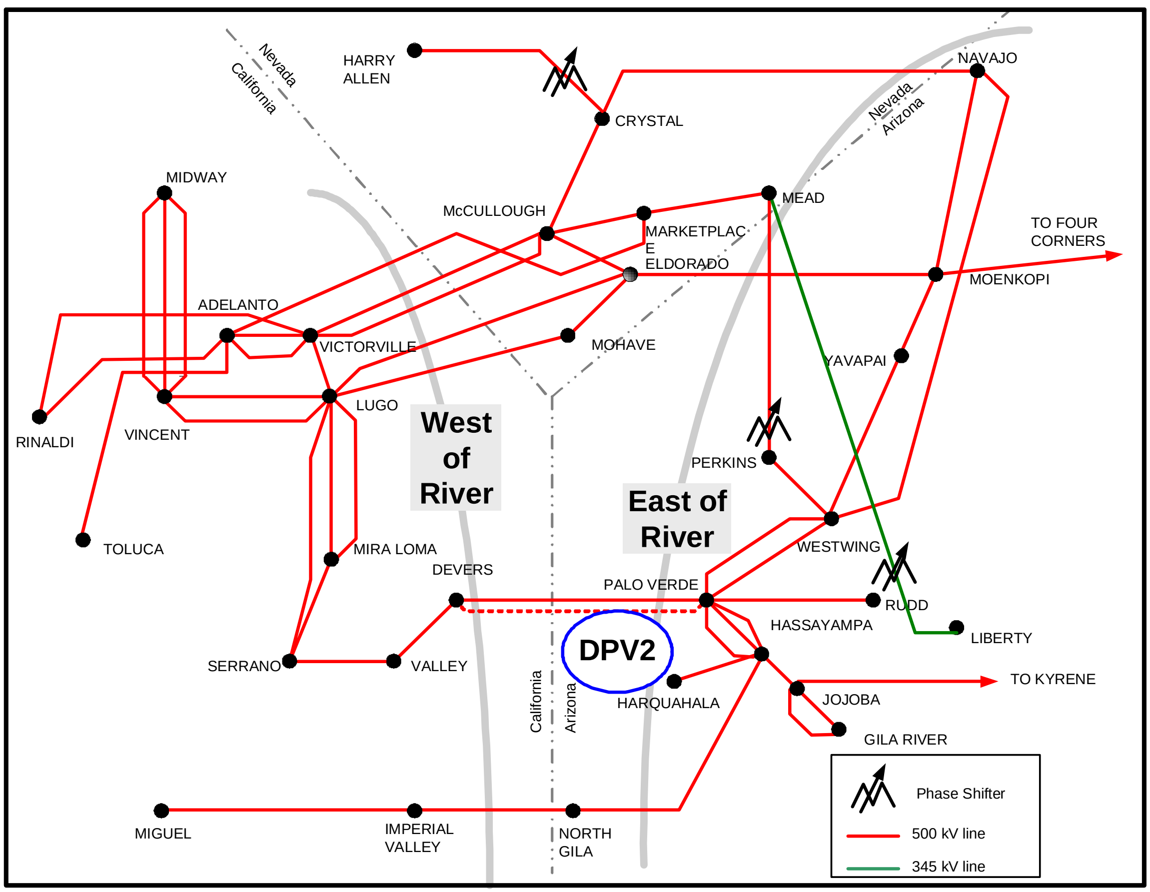
Scenario	Demand	Gas Price	Hydro	Markup	Contingency
18	B	B	B	M	PV1
19	B	B	B	M	PV2
20	B	B	B	M	MV
21	B	B	B	M	MH
22	B	B	B	M	SO
23	B	B	B	M	PDCI
24	B	B	B	M	COI/EOR
25	B	B	B	M	SCE/RE

Appendix B. NETWORK

A. Description

The transmission grid in the Southwest (Arizona, Southern Nevada and Southern California) consists of a number of 345 and 500 kV AC transmission lines. This EHV system brings power to the large metropolitan areas like Phoenix, Las Vegas and Los Angeles from generation plants located geographically far away. The two main interfaces in the region, West-of-Colorado River (WOR, WECC Path 46) and East-of-Colorado River (EOR, WECC Path 49), dictate the amount of flow that can reliably be transferred across the region. A diagram of the EHV system in the Southwest can be found in Figure B.1 below.

Figure B.1 Map of EHV System in the Southwest



The cases used in the analysis assumed the projects proposed as part of the Southwest Transmission Expansion Plan (STEP) with operational date before 2008 to be in service. This includes the already ISO Board approved "Short-Term Upgrade" which consists of increasing the capacity of the series capacitors on the existing Palo Verde – Devers and Hassyampa – North Gila – Imperial Valley 500 kV lines, dynamic voltage support, and a second 500/230 kV transformer bank at Devers Substation in addition to a 230/230 kV phase shifter at El Centro Substation. Also, the proposed "EOR9000+" project was included in the cases used in the analysis for the PVD2 project. This project includes an upgrade of the existing series capacitors on the Perkins – Mead and Navajo – Crystal 500 kV lines and to bypass the two 500 kV phase shifters at Perkins. In addition to the EOR9000+ project, the series capacitors on Moenkopi – Eldorado 500 kV line were assumed to be upgraded before the PVD2 project comes online since the economic analysis indicated a significant amount of congestion on the line without this upgrade in place.

Table B.1 below lists the flow limits on several interfaces and lines in the Southwest region used in the analysis.

Table B.1 Limits on Key Interfaces/Lines in the Southwest Region

Limits used in PVD2 analysis on key interfaces/lines (MW)			
	Today	Case without PVD2	Case with PVD2
East of River	7,550	9,300	10,500
West of River	10,118	10,623	11,823
Palo Verde West	2,857	3,600	5,400
Palo Verde - Devers 1 (&2) 500 kV	1,645	2,338	4,676
Hassayampa - North Gila 500 kV	1,212	1,905	1,905
Navajo - Crystal 500 kV	1,411	1,808	1,808
Moenkopi-Eldorado 500 kV	1,645	2,000	2,000
Perkins - Mead 500 kV	1,238	1,905	1,905
Mohave-Lugo 500 kV	1,385	1,385	1,385
Eldorado-Lugo 500 kV	1,385	1,385	1,385
Marketplace-Adelanto 500 kV	1,638	1,638	1,638
McCullough-Victorville 1&2 500	2,770	2,770	2,770
SCIT (Southern California	15,200	19,391	19,391
Path 26 (S->N/N->S)	3,000/3,400	3,000/3,400	3,000/3,400
Path 15	5,400	5,400	5,400
PDCI	3,100	3,100	3,100
COI	4,800	4,800	4,800

B. New Lines Modeled

New lines in the WECC region anticipated to be in service by 2008 and 2013 were modeled in the respective cases. The following table B2 shows a list of these additions.

Table B.2 Future Lines Added

Future lines added	
2008	**2013**
Otay Mesa - Sycamore Canyon 230 kV	Otay Mesa - Sycamore Canyon 230 kV
Otay Mesa - Old Town 230 kV	Otay Mesa - Old Town 230 kV
Palo Verde - Trilby Wash - Westwing 500 kV	Palo Verde - Trilby Wash - Westwing 500 kV
Hassayampa - Jojoba 500 kV No. 2	Hassayampa - Jojoba 500 kV No. 2
Jojoba- SES 500 kV	Jojoba- SES 500 kV
SES - Browning 500 kV	SES - Browning 500 kV
SES - Silverking 500 kV	SES - Silverking 500 kV
	Bell BPA - Ashe 500 kV
	Cranbrook - Selkirk 500 kV No.2
	Chief Joseph - Monroe 500 kV No.2
	Garrison - Hot Springs 500 kV
	Grizzly - IDAHO 500 kV
	Hot Springs - Bell BPA 500 kV
	IDAHO - Bridger 345 kV
	IDAHO-Midpoint 500 kV
	IDAHO - PACE 500 kV
	Langdon - Cranebrook 500 kV
	PACE - Ben Lomond 345 kV
	PACE - Midpoint 500 kV
	PSCOLORA - Green Valley 230 kV
	Selkirk - Bell BPA 500 kV
	Summer Lake - IDAHO 500 kV
	WAPA R.M - IDAHO 500 kV
	WAPA R.M - PSCOLORA 500 kV
	WAPA R.M - Stegall 230 kV

Appendix C. LOADS

The system load forecast from the 10-year forecast published by the WECC in December 2003 was used for all regions except California. These system loads were disaggregated into hourly chronological load shapes for 21 regions and about 5,700 locations (nodes). For California loads, the California Energy Commission (CEC) March 2003 forecast was used. The load duration curves were taken from Henwood synthetic load data, and adjusted to the year of modeling with the forecast using PLEXOS Load forecasting module.

The peak loads for California include the impact of demand-side resources. From 2008 to 2013, overall energy growth in WECC is predicted to be about 1.7 percent for the base case, and 1.4 percent for the CAISO area. Due to current data limitations, we could only separate Los Angeles Department of Water and Power (LADWP) and Imperial Irrigation District (IID) loads from the CAISO load forecast in this analysis. Entities such as Sacramento Municipal Utility District (SMUD), Western Area Power Authority

(WAPA), and Northern California Power Authority (NCPA) are included as part of CAISO loads.

For the analysis, we derived 3 different load scenarios, base, very high and very low. The summary of these scenarios for WECC, California ISO and the other WECC regions are available in the following Table C1.

Table C.1 Annual Peak and Energy for the Scenarios, Base, Very High & Very Low

Region	2008					
	Base		Very High		Very Low	
	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)
WECC	900,951	150,296	954,903	161,047	847,808	139,896
CAISO	261,641	51,271	277,067	55,185	246,216	47,356
California	291,702	57,682	308,900	62,085	274,504	53,279
Mexico CFE	10,583	1,850	11,207	1,991	9,959	1,709
Northwest & Canada	389,353	56,759	412,307	60,961	366,373	52,561
Rocky Mountain	68,506	12,985	73,381	13,967	64,467	11,996
Southwest	140,807	28,110	149,108	30,225	132,505	25,997
Region	**2013**					
	Base		**Very High**		**Very Low**	
	Energy (GWh)	**Peak (MW)**	**Energy (GWh)**	**Peak (MW)**	**Energy (GWh)**	**Peak (MW)**
WECC	982,485	163,570	1,043,406	175,324	924,452	152,122
CAISO	278,886	54,532	298,326	58,695	262,443	50,368
California	310,404	61,181	331,703	65,852	292,103	56,511
Mexico CFE	11,673	2,029	12,361	2,183	10,985	1,874
Northwest & Canada	426,093	61,351	451,213	65,903	400,863	56,910
Rocky Mountain	75,783	14,579	80,251	15,672	71,316	13,470
Southwest	158,532	31,855	167,878	34,259	149,185	29,448

For the derivation of the scenarios, it is assumed that the demand and the forecast error are normally distributed. The very high and very low cases are at the 90% confidence interval of the demand forecast error published by CEC. Though we have derived high and low cases representing a 75% confidence interval, they were not used for this study. The detailed regional non-coincident peaks and annual energy loads used for each of the scenarios are summarized in following figures and tables.

Figure C.1 Load Scenarios, Peak and Energy Years 2008 & 2013

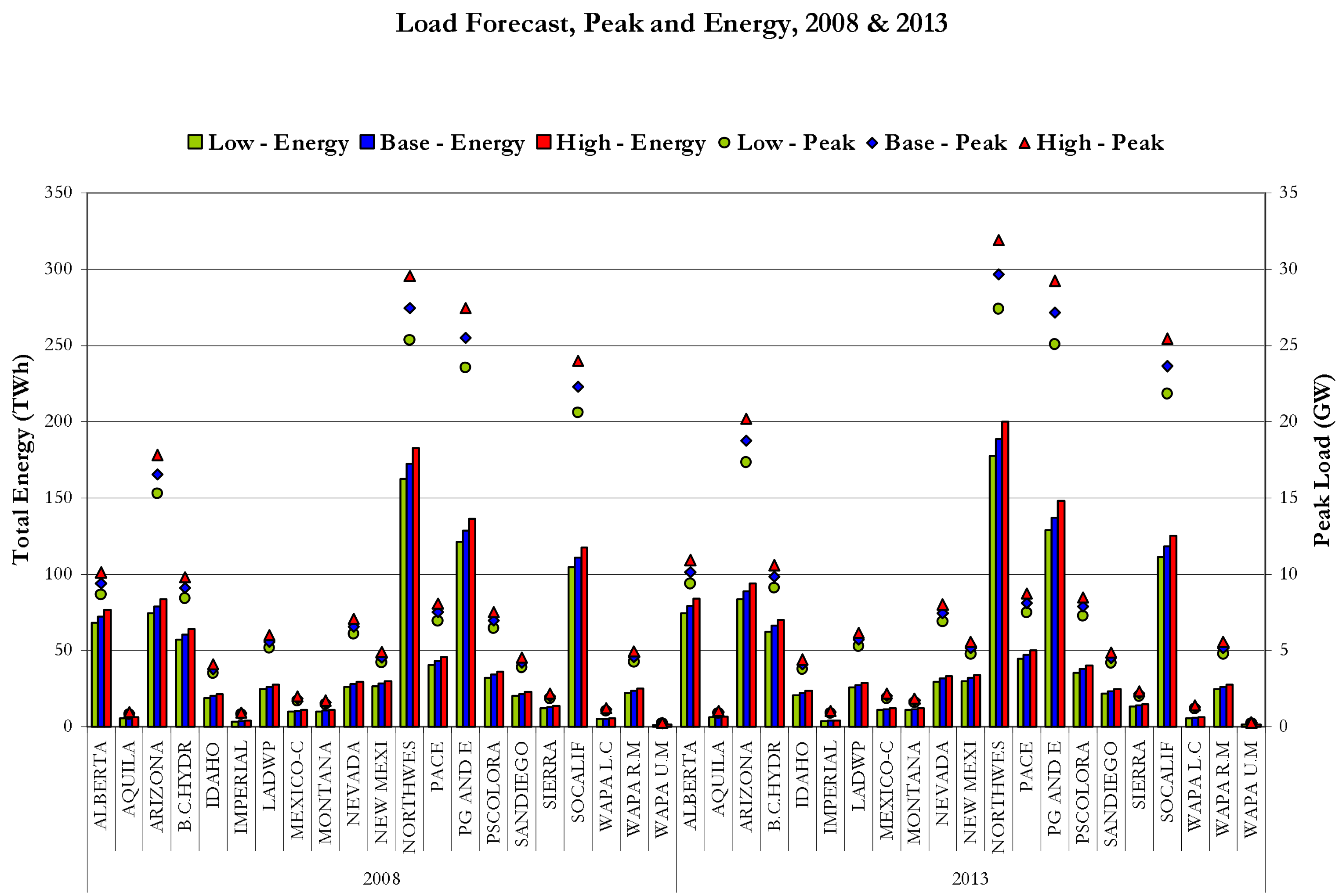


Table C.2 Peak and Energy by Region Year 2008

Peaks and Energy by Region						
Sceanrios Base, Very Low & Very High						
Year 2008						
	Base		Very Low		Very High	
Region	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)
ALBERTA	72,410	9,398	68,141	8,681	76,679	10,116
AQUILA (CANADA)	5,995	902	5,641	833	6,348	971
ARIZONA	78,968	16,564	74,312	15,299	83,623	17,829
B.C.HYDRO	60,613	9,117	57,039	8,421	64,186	9,813
IDAHO	20,257	3,797	19,063	3,507	21,452	4,087
IMPERIAL (IID)	3,716	875	3,497	808	3,935	942
LADWP	26,345	5,588	24,791	5,161	27,898	6,014
MEXICO	10,583	1,850	9,959	1,709	11,207	1,991
MONTANA	10,636	1,600	10,009	1,478	11,263	1,722
NEVADA	28,070	6,577	26,415	6,075	29,725	7,079
NEW MEXICO	28,400	4,557	26,725	4,209	30,074	4,905
NORTHWEST	172,551	27,461	162,378	25,364	182,724	29,558
PACE (PACIFICORP)	43,284	7,512	40,732	6,938	45,836	8,085
PG AND E	128,929	25,508	121,328	23,560	136,530	27,456
PSCOLORADO	34,138	6,993	32,125	6,459	36,151	7,527
SANDIEGO	21,595	4,223	20,322	3,901	22,869	4,546
SIERRA	12,872	2,013	12,113	1,859	13,631	2,167
SOCALIF (SCE)	111,117	22,297	104,566	20,594	117,668	24,000
WAPA L.C (LOWER COLORADO)	5,369	1,149	5,053	1,061	5,686	1,237
WAPA R.M (ROCKY MOUNTAIN)	23,732	4,589	22,333	4,238	25,132	4,939
WAPA U.M (UPPER MISSOURI)	1,371	241	1,290	223	1,451	259
WECC	**900,951**	**150,296**	**954,903**	**161,047**	**847,808**	**139,896**
CAISO	**261,641**	**51,271**	**277,067**	**55,185**	**246,216**	**47,356**
California	**291,702**	**57,682**	**308,900**	**62,085**	**274,504**	**53,279**
Mexico	**10,583**	**1,850**	**11,207**	**1,991**	**9,959**	**1,709**
Northwest	**389,353**	**56,759**	**412,307**	**60,961**	**366,373**	**52,561**
RockyMountain	**68,506**	**12,985**	**73,381**	**13,967**	**64,467**	**11,996**
Southwest	**140,807**	**28,110**	**149,108**	**30,225**	**132,505**	**25,997**

Note: Mexico is only the CFE region, and Northwest includes Canadian regions of WECC as well.

Table C.3 Peak and Energy by Region Year 2013

Peaks and Energy by Region Sceanrios Base, Very Low & Very High Year 2013						
Region	Base		Very Low		Very High	
	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)
ALBERTA	79,243	10,155	74,571	9,379	83,915	10,930
AQUILA (CANADA)	6,560	974	6,174	900	6,947	1,049
ARIZONA	88,908	18,777	83,666	17,343	94,150	20,211
B.C.HYDRO	66,332	9,851	62,422	9,098	70,243	10,603
IDAHO	22,169	4,103	20,862	3,789	23,476	4,416
IMPERIAL (IID)	4,148	976	3,903	901	4,393	1,051
LADWP	27,370	5,731	25,757	5,294	28,984	6,169
MEXICO	11,673	2,029	10,985	1,874	12,361	2,183
MONTANA	11,639	1,729	10,953	1,597	12,325	1,861
NEVADA	31,604	7,456	29,741	6,886	33,467	8,025
NEW MEXICO	31,975	5,166	30,089	4,771	33,860	5,561
NORTHWEST	188,833	29,671	177,701	27,405	199,966	31,937
PACE (PACIFICORP)	47,369	8,116	44,576	7,496	50,161	8,736
PG AND E	137,230	27,162	129,139	25,087	148,320	29,236
PSCOLORADO	37,839	7,881	35,608	7,279	40,070	8,483
SANDIEGO	23,349	4,530	21,972	4,184	24,725	4,876
SIERRA	14,087	2,175	13,256	2,009	14,917	2,341
SOCALIF (SCE)	118,307	23,649	111,332	21,843	125,281	25,455
WAPA L.C (LOWER COLORADO)	6,045	1,302	5,689	1,203	6,401	1,402
WAPA R.M (ROCKY MOUNTAIN)	26,305	5,171	24,755	4,776	27,856	5,566
WAPA U.M (UPPER MISSOURI)	1,500	260	1,411	241	1,588	280
WECC	**982,485**	**163,570**	**1,043,406**	**175,324**	**924,452**	**152,122**
CAISO	**278,886**	**54,532**	**298,326**	**58,695**	**262,443**	**50,368**
California	**310,404**	**61,181**	**331,703**	**65,852**	**292,103**	**56,511**
Mexico	**11,673**	**2,029**	**12,361**	**2,183**	**10,985**	**1,874**
Northwest	**426,093**	**61,351**	**451,213**	**65,903**	**400,863**	**56,910**
RockyMountain	**75,783**	**14,579**	**80,251**	**15,672**	**71,316**	**13,470**
Southwest	**158,532**	**31,855**	**167,878**	**34,259**	**149,185**	**29,448**

Note: Mexico is only the CFE region, and Northwest includes Canadian regions of WECC as well.

Appendix D. RESOURCES

Most of the system resource data was taken from the database created by the WECC Regional Transmission Planning group, Seams Steering Group – Western Interconnection (SSG-WI) for their transmission planning studies and was further modified to fit the needs of CAISO TEAM analysis.

The modifications included:

1. The addition of new renewable resources to achieve the statewide renewable portfolio standards throughout the WECC. The renewable percentage for California (including municipals) is about 28% percent in 2008, and 26% in 2013, inclusive of Hydro and Pumped Storage.
2. The addition of thermal units required for capacity adequacy (assuming a 15 percent planning reserve margin).
3. The addition of few new thermal units that were economically attractive after renewable and capacity adequacy standards were met.
4. The retirement of units that are expected to be mothballed before year 2008 for economic or other reasons.

The following two figures, D1 and D2 show the resource mix in California for years 2008 and 2013 after these modifications.

Figure D.1 Resource Mix in California – Year 2008

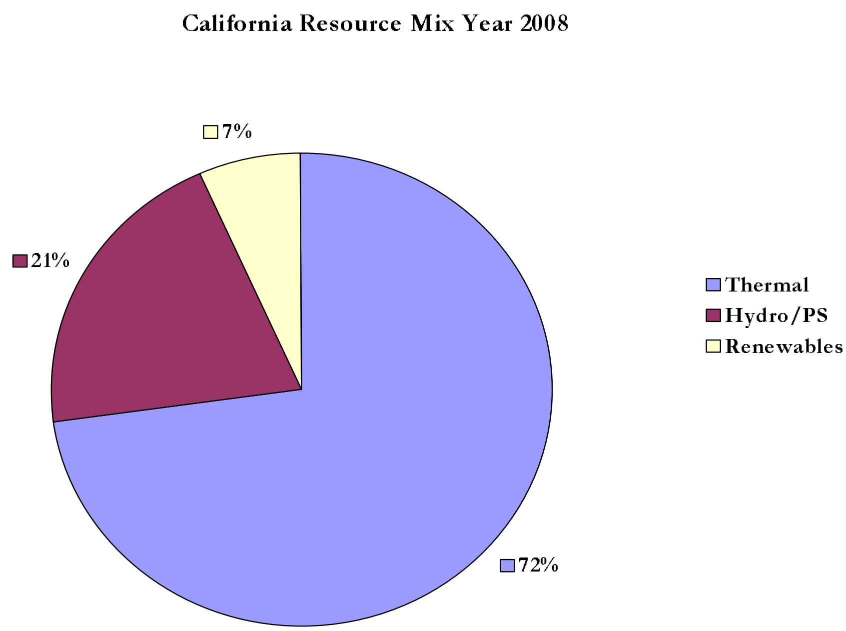
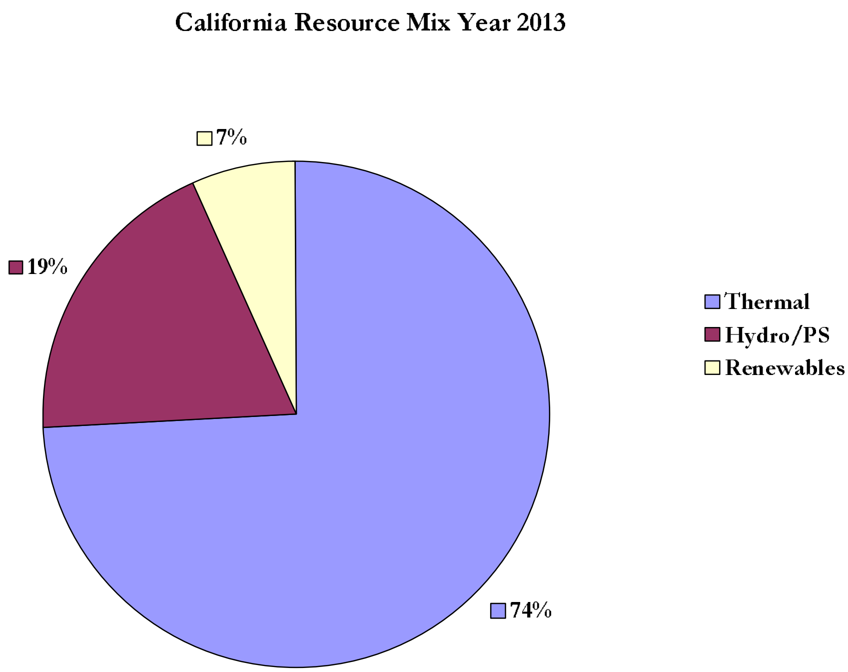


Figure D.2 Resource Mix in California – Year 2013



The system has about 800 thermal, hydro, pumped storage and renewable generating plants? Units? with a total capacity of approximately 196,000 MW in year 2008 and 213,000 MW in year 2013. The total CAISO resource capacity is 59,204 MW in year 2008, and 64,447 MW in year 2013.

The renewables, include Wind, solar, biomass, geothermal, and digester gas. A break-down on the renewables in California is available in Figure D.3.

The following table shows the Hydro energy assumptions for the Base case for years 2008 & 2013. Detailed information on this hydro energy in PLEXOS regions (21) and by scenarios (Base, Dry, and Wet) is available in Figure D.5.

Table D.1 Available Hydro Energy – Years 2008 & 2013

Region	Hydro Energy (GWh)
WECC	237,995
California ISO	32,336
California	32,600
Northwest & Canada	186,921
Rocky Mountain	7,421
Southwest	11,051

In all of the tables, the California ISO also includes SMUD, WAPA, and other NCPA municipals due to lack of independent data on loads. The regions that are included in California include the LADWP and IID regions in addition to the CAISO control area. Northwest includes Canada.

The following Table D.2 shows the capacity additions by region for years 2008 & 2013. A total of 13,693 MW was added to the system in 2008 and an additional 13,823 MW was added in year 2013. A unit-by-unit list of additions is available in Tables D.5 and D.6.

Table D.2 Capacity Additions by Region

Additions by Region		
	Capacity (MW)	
Region	Year 2008	Year 2013
ALBERTA		500
ARIZONA	5,525	5,025
B.C.HYDRO	1,000	500
LADWP	663	1,025
MONTANA		500
NEVADA	2,000	1,070
PG AND E	562	1,058
PSCOLORA	1,755	3,605
SANDIEGO	1,056	
SOCALIF	1,132	
SIERRA		540
Total	**13,693**	**13,823**

The following Table D.3 shows the capacity retirements by region. Most of the units retired were from California. A total of 1,793 MW was retired from WECC.

Table D.3 Capacity Retirements by Region

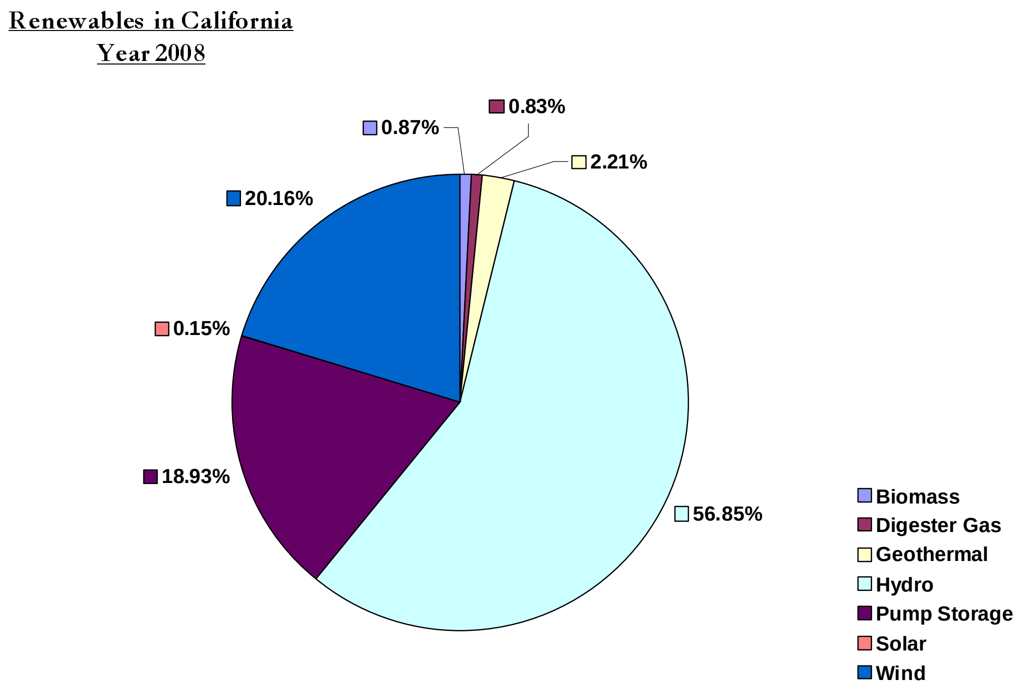
Generator Retirements			
Generator	**Year 2008**		**Year 2013**
	Rating (MW)	**Region**	
Haynes 1	444	LADWP	There were no additional retire-ments for Year 2013
Olive 2	55	LADWP	
Pittsburgh 1	304	PG AND E	
HntrsPn4	163	PG AND E	
HntrsPn1	52	PG AND E	
Pastoria	500	SOCALIF	
EtwndGT5	141	SOCALIF	
AESlmts7	134	SOCALIF	
Total	**1,793**	**WECC**	

Additional information on the resource mix is available in the following tables and figures.

Table D.4 California Resource Mix by Region - Years 2008 & 2013

Resource Mix in California by Region (MW)							
Year 2008							
Resources	**IID**	**LADWP**	**PG&E**	**San Diego**	**SCE**	**California**	**CAISO**
Biomass			35		106	141	141
Digester Gas			40	30	65	135	135
Geothermal			124		234	358	358
Solar					24	24	24
Wind			468		2,794	3,262	3,262
Thermal	706	4,155	18,881	4,062	15,217	43,021	38,160
Hydro	40		7,750		1,410	9,200	9,160
Pump Storage		1,260	1,603		200	3,063	1,803
Year 2013							
Resources	**IID**	**LADWP**	**PG&E**	**San Diego**	**SCE**	**California**	**CAISO**
Biomass			62		106	168	168
Digester Gas			40	30	65	135	135
Geothermal			216		254	470	470
Solar					110	110	110
Wind			482		2,944	3,426	3,426
Thermal	706	6,577	20,179	4,062	16,352	47,876	40,593
Hydro	40		7,750		1,410	9,200	9,160
Pump Storage		1,260	1,603		200	3,063	1,803

Figure D.3 California Renewables - Years 2008 & 2013



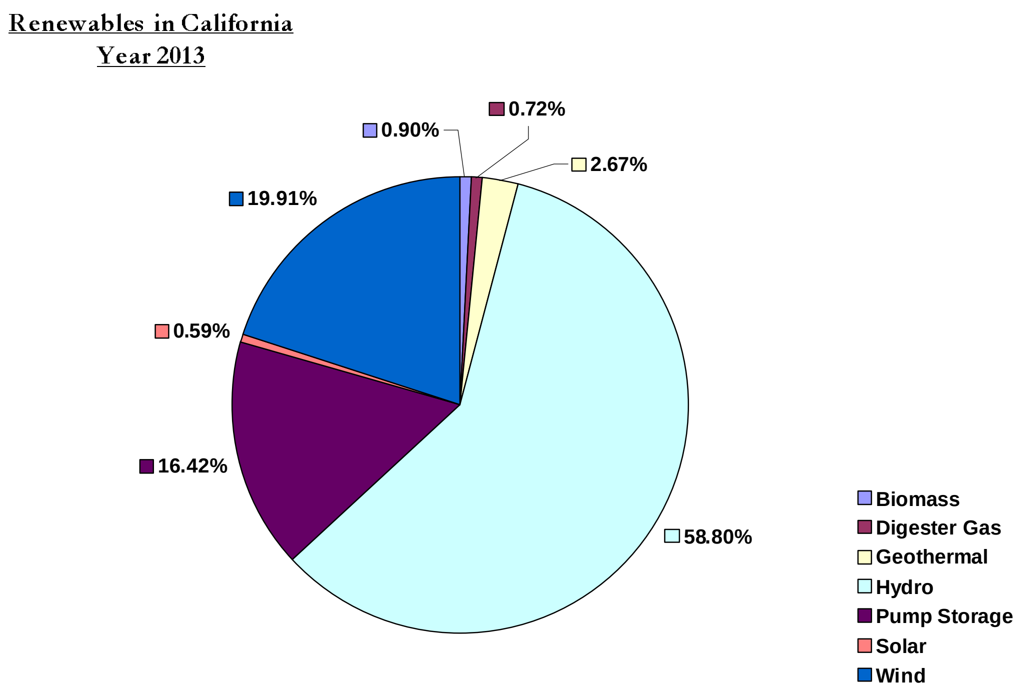
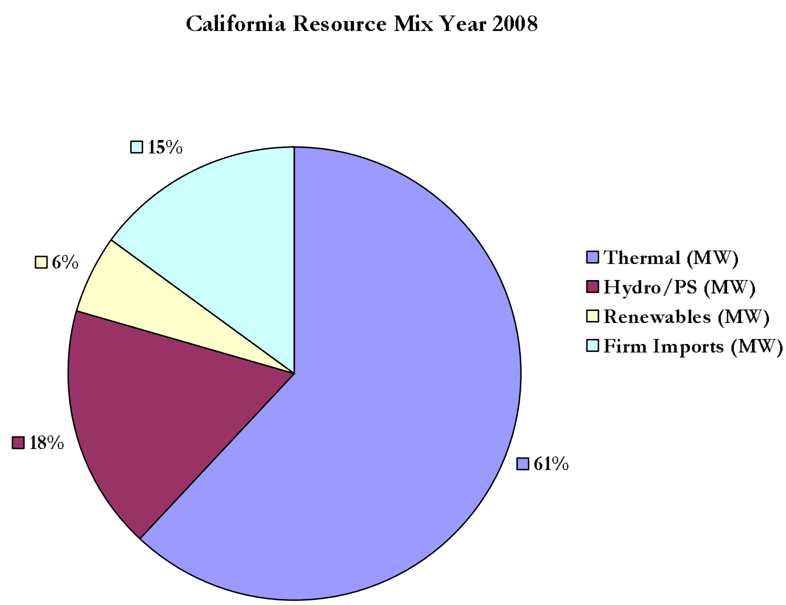


Figure D.4 California Resource Mix by Region - Years 2008 & 2013



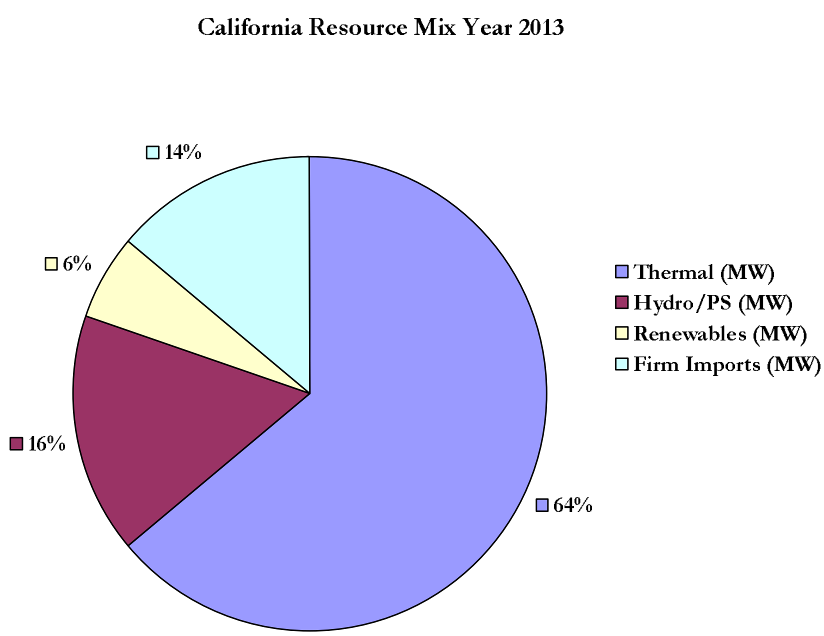
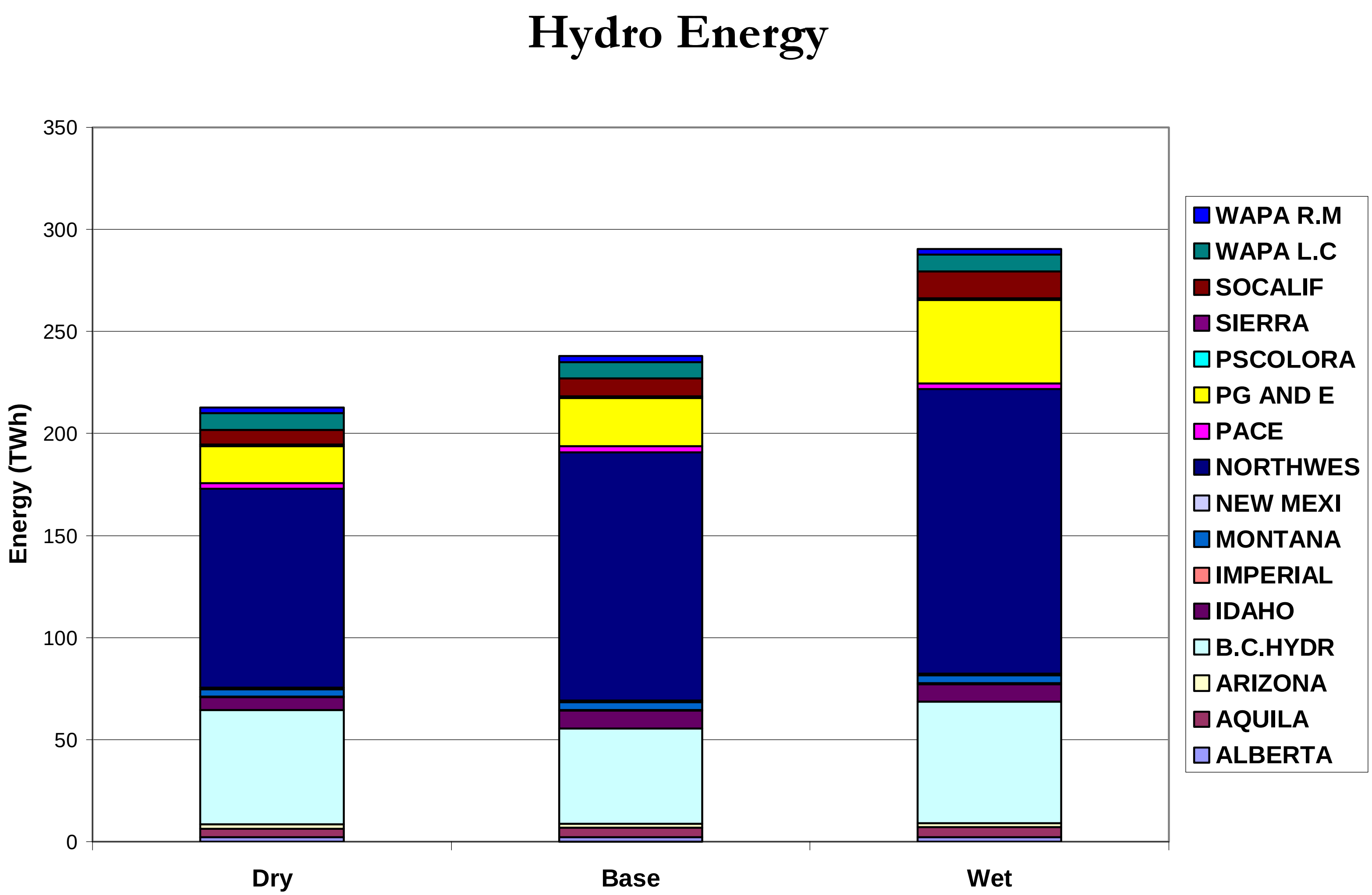


Table D.5 Capacity Additions by Region and by Unit - Years 2008 & 2013

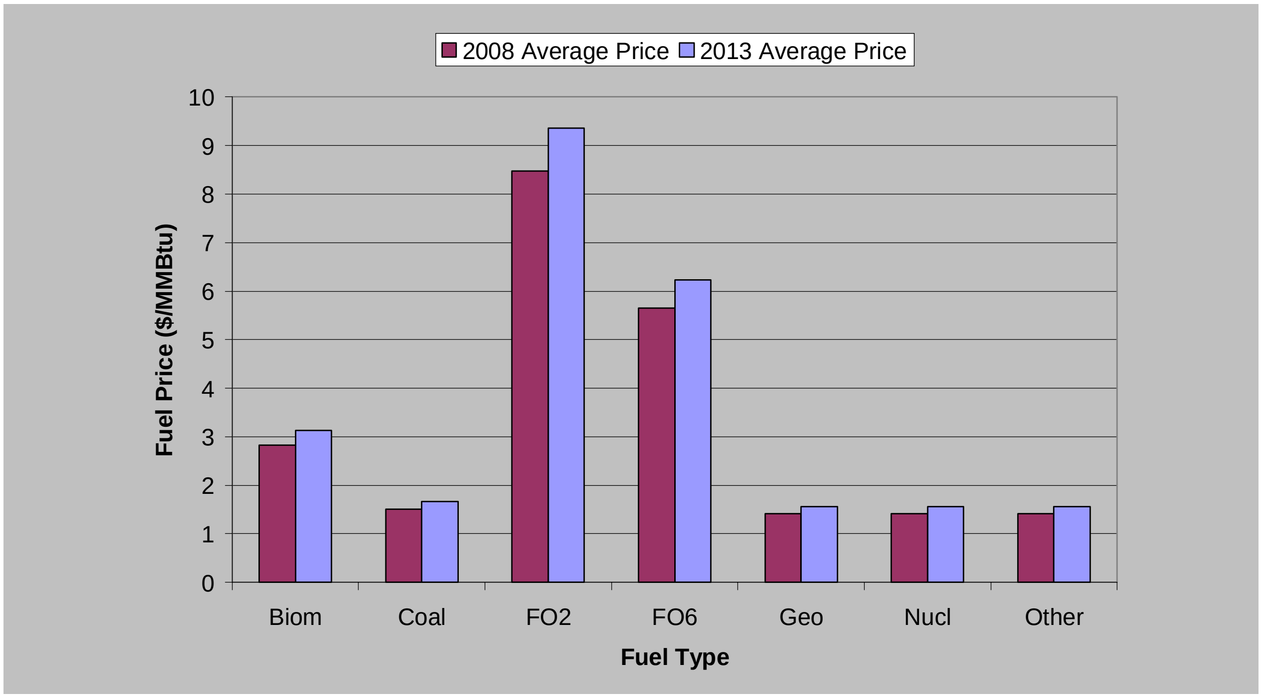
Capacity Additions by Region					
Year 2008			Year 2013		
Generator	Rating (MW)	Region	Generator	Rating (MW)	Region
MesquiteCC 3	625	ARIZONA	GenesseeCC	500	ALBERTA
MesquiteCC 4	625	ARIZONA	Arlington Valley 2	600	ARIZONA
Panda Gila River 5	600	ARIZONA	Bowie CC 1	500	ARIZONA
Panda Gila River 6	600	ARIZONA	Bowie CC 2	500	ARIZONA
Blythe CC 1	600	ARIZONA	Harquahala CC 2	1,000	ARIZONA
Redhawk CC 1	500	ARIZONA	Palo Verde CC	1,200	ARIZONA
Saguaro CC 1	500	ARIZONA	Santan	825	ARIZONA
Santan CC 1	850	ARIZONA	Fourcorners Coal	400	ARIZONA
MesquiteCC	625	ARIZONA	Vancouver Island 1	500	B.C.HYDR
BC HYDRO CC 1	250	B.C.HYDRO	HaynesCC	575	LADWP
BC HYDRO CC 2	250	B.C.HYDRO	Magnolia	315	LADWP
BC HYDRO CC 3	250	B.C.HYDRO	Malburg	135	LADWP
BC HYDRO CC 4	250	B.C.HYDRO	Silver Bow	500	MONTANA
Grayson 9	49	LADWP	CopperMtn	500	NEVADA
ValleyCC2	520	LADWP	Silver Hawk	570	NEVADA
Glenarm GT 3-4	94	LADWP	Cosumnes	458	PG AND E
Clark CC 2	500	NEVADA	Metcalf	600	PG AND E
Clark CC 3	500	NEVADA	BluSprc2	500	PSCOLORA
H Allen CC 1	500	NEVADA	Front Range CC2	600	PSCOLORA
H Allen CC 2	500	NEVADA	RockyMtn EC1	585	PSCOLORA
Pico	147	PG AND E	RockyMtn EC2	585	PSCOLORA
Ripon	90	PG AND E	RockyMtn EC3	585	PSCOLORA
WalnutCC	240	PG AND E	Comanch2	750	PSCOLORA
Kings River	85	PG AND E	Wadsworth 1	540	SIERRA
RockyMtn EC1	585	PSCOLORA			
RockyMtn EC2	585	PSCOLORA			
RockyMtn EC3	585	PSCOLORA			
Otay Mesa	510	SANDIEGO			
Palomar	546	SANDIEGO			
Moutainview	1,132	SOCALIF			
Total	**13,693**	**WECC**	**Total**	**13,823**	**WECC**

Figure D.5 Hydro Scenarios - Years 2008 & 2013



Appendix E. FUEL PRICES

Figure E.1 Average Fuel Prices for Non-Natural Gas Fuels



All of the fuel prices are in nominal dollars. The CAISO study evaluates all financial elements in real dollars. For this reason, the prices of non-natural gas fuels are escalated by the inflation rate. In 2008, the prices are 16 percent higher than in 2003. In 2013, the prices are 28 percent greater than in 2003.

The gas prices used for this study originated from the published CEC natural gas prices and used for the TEAM methodology filed with the CPUC in June 2004. The prices were adjusted by the gas differential that existed in different city gates and gas pricing hubs as of Aug 2004 and with discussions with SCE. For the analysis, we derived 3 different gas scenarios, base, very high and very low for each year. The Annual average of the monthly gas prices used for the anlayis is provided in the following Table E.1 and in Figure E.2.

Table E.1 Annual Average Gas Prices

Annual Average Gas Prices ($/MMbtu)						
Region	Base		Very Low		Very High	
	2008	2013	2008	2013	2008	2013
ALBERTA	$ 4.34	$ 5.34	$ 2.12	$ 2.61	$ 8.89	$ 10.94
ARIZONA	$ 4.71	$ 5.71	$ 2.30	$ 2.79	$ 9.64	$ 11.69
B.C.HYDRO	$ 4.34	$ 5.34	$ 2.12	$ 2.61	$ 8.89	$ 10.94
IMPERIAL (IID)	$ 5.08	$ 6.08	$ 2.48	$ 2.97	$ 10.40	$ 12.45
LADWP	$ 5.08	$ 6.08	$ 2.48	$ 2.97	$ 10.40	$ 12.45
MEXICO	$ 5.08	$ 6.08	$ 2.48	$ 2.97	$ 10.40	$ 12.45
MONTANA	$ 4.41	$ 5.42	$ 2.16	$ 2.64	$ 9.04	$ 11.09
NEVADA	$ 4.71	$ 5.71	$ 2.30	$ 2.79	$ 9.64	$ 11.69
NEW MEXICO	$ 4.71	$ 5.71	$ 2.30	$ 2.79	$ 9.64	$ 11.69
NORTHWEST	$ 4.45	$ 5.45	$ 2.17	$ 2.66	$ 9.13	$ 11.17
PACE (PACIFICORP)	$ 4.41	$ 5.41	$ 2.15	$ 2.64	$ 9.04	$ 11.09
PG AND E	$ 5.19	$ 6.20	$ 2.54	$ 3.02	$ 10.64	$ 12.70
PSCOLORADO	$ 4.41	$ 5.42	$ 2.16	$ 2.64	$ 9.04	$ 11.09
SANDIEGO	$ 5.08	$ 6.08	$ 2.48	$ 2.97	$ 10.40	$ 12.45
SIERRA	$ 4.42	$ 5.41	$ 2.15	$ 2.64	$ 9.04	$ 11.09
SOCALIF (SCE)	$ 5.08	$ 6.08	$ 2.48	$ 2.97	$ 10.40	$ 12.45
WAPA L.C (LOWER COLORADO)	$ 4.71	$ 5.71	$ 2.30	$ 2.79	$ 9.64	$ 11.69
WAPA R.M (ROCKY MOUNTAIN)	$ 4.41	$ 5.42	$ 2.16	$ 2.64	$ 9.04	$ 11.09

For the derivation of the scenarios, it is assumed that the gas price is log normally distributed and the forecast error is normally distributed. The very high and very low cases are at the 90% confidence interval of the gas forecast error published by CEC. Though we have derived high and low cases at the 75% confidence interval, it was not used for this study. The monthly gas prices used for this study for each region and for years 2008 & 2013 is summarized in tables, E2 through E7. The very high and very low prices are approximately 5% higher and lower than the base gas price.

Figure E.2 Gas Price Scenarios Years 2008 & 2013

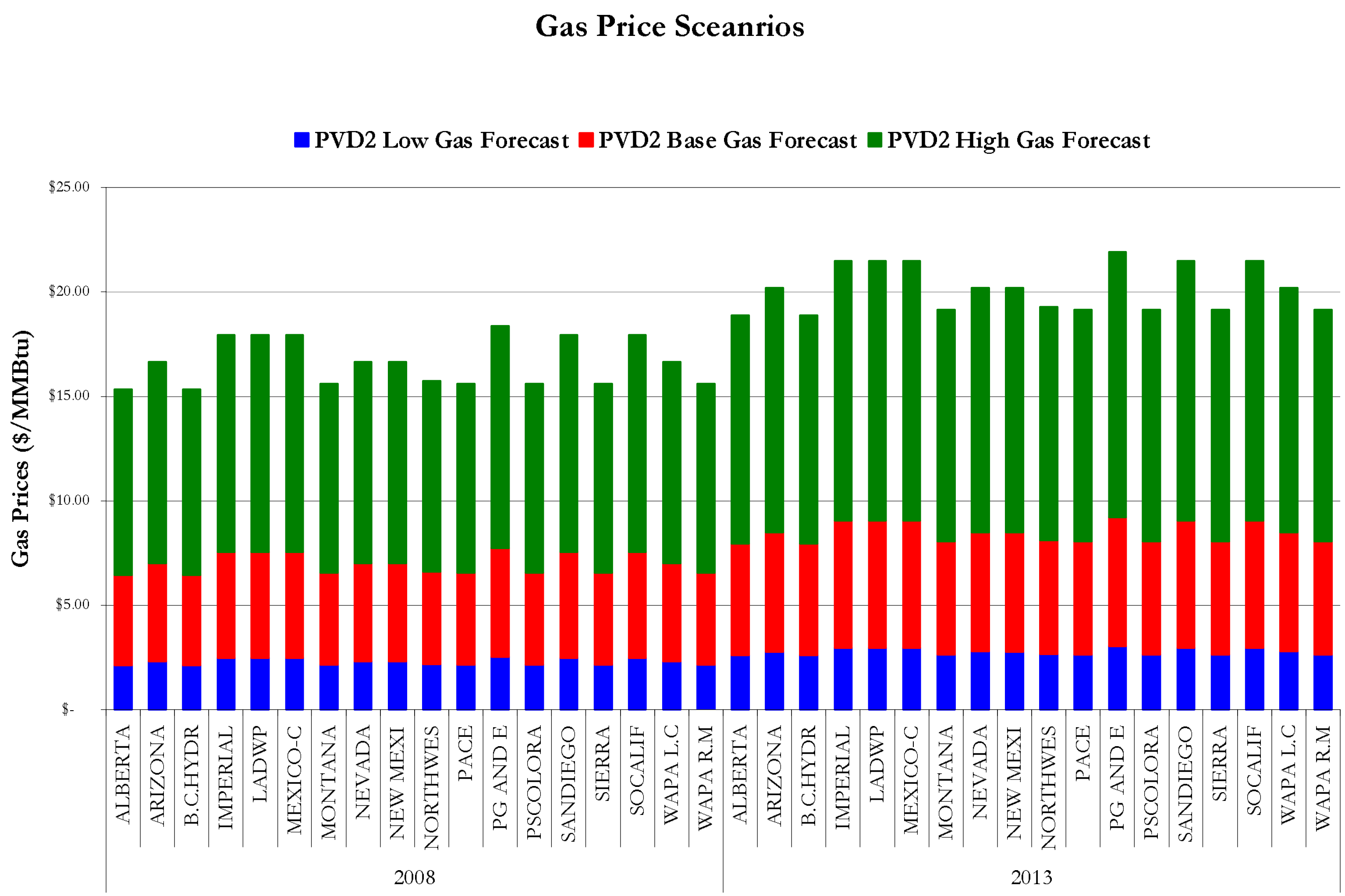


Table E.2 Base Gas Price Scenario Year 2008

Base Gas Forecast ($/mmbtu)													
Year 2008													
Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
ALBERTA	$ 4.74	$ 4.56	$ 4.38	$ 4.38	$ 4.34	$ 4.08	$ 4.12	$ 3.81	$ 3.99	$ 4.38	$ 4.56	$ 4.74	$ 4.34
ARIZONA	$ 4.61	$ 4.61	$ 4.24	$ 4.80	$ 4.80	$ 4.80	$ 4.33	$ 4.43	$ 4.99	$ 4.71	$ 5.32	$ 4.85	$ 4.71
B.C. HYDRO	$ 5.45	$ 4.70	$ 3.90	$ 4.12	$ 3.86	$ 3.68	$ 3.64	$ 3.68	$ 3.86	$ 4.43	$ 5.36	$ 5.41	$ 4.34
IMPERIAL (IID)	$ 5.46	$ 5.21	$ 4.81	$ 4.71	$ 5.01	$ 4.86	$ 4.61	$ 4.86	$ 4.91	$ 4.91	$ 5.46	$ 6.11	$ 5.08
LADWP	$ 5.52	$ 5.37	$ 5.17	$ 4.86	$ 4.76	$ 4.71	$ 4.61	$ 4.71	$ 4.91	$ 5.01	$ 5.42	$ 5.87	$ 5.08
MEXICO	$ 5.46	$ 5.21	$ 4.81	$ 4.71	$ 5.01	$ 4.86	$ 4.61	$ 4.86	$ 4.91	$ 4.91	$ 5.46	$ 6.11	$ 5.08
MONTANA	$ 4.83	$ 4.03	$ 3.76	$ 3.85	$ 4.20	$ 4.61	$ 4.56	$ 4.43	$ 4.16	$ 4.65	$ 4.83	$ 5.05	$ 4.41
NEVADA	$ 4.64	$ 4.68	$ 4.31	$ 4.77	$ 4.54	$ 4.73	$ 4.35	$ 4.54	$ 4.77	$ 5.05	$ 5.29	$ 4.82	$ 4.71
NEW MEXICO	$ 5.24	$ 4.59	$ 4.35	$ 4.40	$ 4.49	$ 4.40	$ 4.54	$ 4.68	$ 4.63	$ 4.82	$ 5.10	$ 5.24	$ 4.71
NORTHWEST	$ 3.04	$ 3.71	$ 4.47	$ 5.68	$ 6.03	$ 3.40	$ 4.51	$ 4.47	$ 4.96	$ 4.02	$ 4.29	$ 4.87	$ 4.45
PACE (PACIFICORP)	$ 4.67	$ 4.72	$ 4.67	$ 4.54	$ 4.33	$ 4.24	$ 4.11	$ 3.55	$ 3.81	$ 4.24	$ 4.67	$ 5.41	$ 4.41
PG AND E	$ 5.50	$ 5.50	$ 5.14	$ 5.04	$ 5.14	$ 4.98	$ 4.98	$ 4.98	$ 4.98	$ 4.98	$ 5.45	$ 5.66	$ 5.19
PS COLORADO	$ 4.83	$ 4.03	$ 3.76	$ 3.85	$ 4.20	$ 4.61	$ 4.56	$ 4.43	$ 4.16	$ 4.65	$ 4.83	$ 5.05	$ 4.41
SAN DIEGO	$ 5.46	$ 5.21	$ 4.81	$ 4.71	$ 5.01	$ 4.86	$ 4.61	$ 4.86	$ 4.91	$ 4.91	$ 5.46	$ 6.11	$ 5.08
SIERRA	$ 4.34	$ 4.39	$ 4.04	$ 4.48	$ 4.26	$ 4.43	$ 4.08	$ 4.26	$ 4.48	$ 4.74	$ 4.96	$ 4.52	$ 4.42
SOCALIF (SCE)	$ 5.52	$ 5.37	$ 5.17	$ 4.86	$ 4.76	$ 4.71	$ 4.61	$ 4.71	$ 4.91	$ 5.01	$ 5.42	$ 5.87	$ 5.08
WAPA L.C. (LOWER COLORADO)	$ 4.64	$ 4.68	$ 4.31	$ 4.77	$ 4.54	$ 4.73	$ 4.35	$ 4.54	$ 4.77	$ 5.05	$ 5.29	$ 4.82	$ 4.71
WAPA R.M. (ROCKY MOUNTAIN)	$ 4.83	$ 4.03	$ 3.76	$ 3.85	$ 4.20	$ 4.61	$ 4.56	$ 4.43	$ 4.16	$ 4.65	$ 4.83	$ 5.05	$ 4.41

Table E.3 Base Gas Price Scenario Year 2013

Base Gas Forecast ($/mmbtu)													
Year 2013													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
ALBERTA	$ 5.83	$ 5.61	$ 5.39	$ 5.39	$ 5.34	$ 5.02	$ 5.07	$ 4.69	$ 4.91	$ 5.39	$ 5.61	$ 5.83	$ 5.34
ARIZONA	$ 5.59	$ 5.59	$ 5.14	$ 5.82	$ 5.82	$ 5.82	$ 5.25	$ 5.37	$ 6.05	$ 5.71	$ 6.45	$ 5.88	$ 5.71
B.C.HYDRO	$ 6.71	$ 5.78	$ 4.80	$ 5.07	$ 4.75	$ 4.53	$ 4.47	$ 4.53	$ 4.75	$ 5.45	$ 6.60	$ 6.65	$ 5.34
IMPERIAL (IID)	$ 6.54	$ 6.24	$ 5.76	$ 5.64	$ 6.00	$ 5.82	$ 5.52	$ 5.82	$ 5.88	$ 5.88	$ 6.54	$ 7.32	$ 6.08
LADWP	$ 6.60	$ 6.42	$ 6.18	$ 5.82	$ 5.70	$ 5.64	$ 5.52	$ 5.64	$ 5.88	$ 6.00	$ 6.48	$ 7.02	$ 6.08
MEXICO	$ 6.54	$ 6.24	$ 5.76	$ 5.64	$ 6.00	$ 5.82	$ 5.52	$ 5.82	$ 5.88	$ 5.88	$ 6.54	$ 7.32	$ 6.08
MONTANA	$ 5.93	$ 4.94	$ 4.61	$ 4.72	$ 5.16	$ 5.65	$ 5.60	$ 5.43	$ 5.10	$ 5.71	$ 5.93	$ 6.20	$ 5.42
NEVADA	$ 5.62	$ 5.67	$ 5.22	$ 5.79	$ 5.50	$ 5.73	$ 5.28	$ 5.50	$ 5.79	$ 6.13	$ 6.41	$ 5.84	$ 5.71
NEW MEXICO	$ 6.36	$ 5.56	$ 5.28	$ 5.33	$ 5.45	$ 5.33	$ 5.50	$ 5.67	$ 5.62	$ 5.84	$ 6.19	$ 6.36	$ 5.71
NORTHWEST	$ 3.72	$ 4.54	$ 5.47	$ 6.95	$ 7.39	$ 4.16	$ 5.53	$ 5.47	$ 6.07	$ 4.93	$ 5.25	$ 5.97	$ 5.45
PACE (PACIFICORP)	$ 5.73	$ 5.78	$ 5.73	$ 5.57	$ 5.31	$ 5.20	$ 5.04	$ 4.35	$ 4.67	$ 5.20	$ 5.73	$ 6.63	$ 5.41
PG AND E	$ 6.56	$ 6.56	$ 6.13	$ 6.01	$ 6.13	$ 5.94	$ 5.94	$ 5.94	$ 5.94	$ 5.94	$ 6.50	$ 6.75	$ 6.20
PS COLORADO	$ 5.93	$ 4.94	$ 4.61	$ 4.72	$ 5.16	$ 5.65	$ 5.60	$ 5.43	$ 5.10	$ 5.71	$ 5.93	$ 6.20	$ 5.42
SAN DIEGO	$ 6.54	$ 6.24	$ 5.76	$ 5.64	$ 6.00	$ 5.82	$ 5.52	$ 5.82	$ 5.88	$ 5.88	$ 6.54	$ 7.32	$ 6.08
SIERRA	$ 5.33	$ 5.38	$ 4.95	$ 5.49	$ 5.22	$ 5.44	$ 5.00	$ 5.22	$ 5.49	$ 5.81	$ 6.08	$ 5.54	$ 5.41
SOCALIF (SCE)	$ 6.60	$ 6.42	$ 6.18	$ 5.82	$ 5.70	$ 5.64	$ 5.52	$ 5.64	$ 5.88	$ 6.00	$ 6.48	$ 7.02	$ 6.08
WAPA L.C (LOWER COLORADO)	$ 5.62	$ 5.67	$ 5.22	$ 5.79	$ 5.50	$ 5.73	$ 5.28	$ 5.50	$ 5.79	$ 6.13	$ 6.41	$ 5.84	$ 5.71
WAPA R.M (ROCKY MOUNTAIN)	$ 5.93	$ 4.94	$ 4.61	$ 4.72	$ 5.16	$ 5.65	$ 5.60	$ 5.43	$ 5.10	$ 5.71	$ 5.93	$ 6.20	$ 5.42

Table E.4 Low Gas Price Scenario Year 2008

Low Gas Forecast ($/mmbtu)													
Year 2008													
Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
ALBERTA	$ 2.31	$ 2.23	$ 2.14	$ 2.14	$ 2.12	$ 1.99	$ 2.01	$ 1.86	$ 1.95	$ 2.14	$ 2.23	$ 2.31	$ 2.12
ARIZONA	$ 2.25	$ 2.25	$ 2.07	$ 2.34	$ 2.34	$ 2.34	$ 2.11	$ 2.16	$ 2.44	$ 2.30	$ 2.60	$ 2.37	$ 2.30
BC HYDRO	$ 2.66	$ 2.29	$ 1.90	$ 2.01	$ 1.88	$ 1.80	$ 1.77	$ 1.80	$ 1.88	$ 2.16	$ 2.62	$ 2.64	$ 2.12
IMPERIAL (IID)	$ 2.67	$ 2.54	$ 2.35	$ 2.30	$ 2.45	$ 2.37	$ 2.25	$ 2.37	$ 2.40	$ 2.40	$ 2.67	$ 2.98	$ 2.48
LADWP	$ 2.69	$ 2.62	$ 2.52	$ 2.37	$ 2.33	$ 2.30	$ 2.25	$ 2.30	$ 2.40	$ 2.45	$ 2.64	$ 2.86	$ 2.48
MEXICO	$ 2.67	$ 2.54	$ 2.35	$ 2.30	$ 2.45	$ 2.37	$ 2.25	$ 2.37	$ 2.40	$ 2.40	$ 2.67	$ 2.98	$ 2.48
MONTANA	$ 2.36	$ 1.97	$ 1.83	$ 1.88	$ 2.05	$ 2.25	$ 2.23	$ 2.16	$ 2.03	$ 2.27	$ 2.36	$ 2.47	$ 2.16
NEVADA	$ 2.26	$ 2.28	$ 2.10	$ 2.33	$ 2.22	$ 2.31	$ 2.12	$ 2.22	$ 2.33	$ 2.47	$ 2.58	$ 2.35	$ 2.30
NEW MEXICO	$ 2.56	$ 2.24	$ 2.13	$ 2.15	$ 2.19	$ 2.15	$ 2.22	$ 2.28	$ 2.26	$ 2.35	$ 2.49	$ 2.56	$ 2.30
NORTHWEST	$ 1.48	$ 1.81	$ 2.18	$ 2.77	$ 2.95	$ 1.66	$ 2.20	$ 2.18	$ 2.42	$ 1.96	$ 2.09	$ 2.38	$ 2.17
PACE (PACIFICORP)	$ 2.28	$ 2.30	$ 2.28	$ 2.22	$ 2.11	$ 2.07	$ 2.01	$ 1.73	$ 1.86	$ 2.07	$ 2.28	$ 2.64	$ 2.15
PG AND E	$ 2.69	$ 2.69	$ 2.51	$ 2.46	$ 2.51	$ 2.43	$ 2.43	$ 2.43	$ 2.43	$ 2.43	$ 2.66	$ 2.76	$ 2.54
PS COLORADO	$ 2.36	$ 1.97	$ 1.83	$ 1.88	$ 2.05	$ 2.25	$ 2.23	$ 2.16	$ 2.03	$ 2.27	$ 2.36	$ 2.47	$ 2.16
SAN DIEGO	$ 2.67	$ 2.54	$ 2.35	$ 2.30	$ 2.45	$ 2.37	$ 2.25	$ 2.37	$ 2.40	$ 2.40	$ 2.67	$ 2.98	$ 2.48
SIERRA	$ 2.12	$ 2.14	$ 1.97	$ 2.18	$ 2.08	$ 2.16	$ 1.99	$ 2.08	$ 2.18	$ 2.31	$ 2.42	$ 2.21	$ 2.15
SOCALIF (SCE)	$ 2.69	$ 2.62	$ 2.52	$ 2.37	$ 2.33	$ 2.30	$ 2.25	$ 2.30	$ 2.40	$ 2.45	$ 2.64	$ 2.86	$ 2.48
WAPA LC (LOWER COLORADO)	$ 2.26	$ 2.28	$ 2.10	$ 2.33	$ 2.22	$ 2.31	$ 2.12	$ 2.22	$ 2.33	$ 2.47	$ 2.58	$ 2.35	$ 2.30
WAPA RM (ROCKY MOUNTAIN)	$ 2.36	$ 1.97	$ 1.83	$ 1.88	$ 2.05	$ 2.25	$ 2.23	$ 2.16	$ 2.03	$ 2.27	$ 2.36	$ 2.47	$ 2.16

Table E.5 Low Gas Price Scenario Year 2013

Low Gas Forecast ($/mmbtu)													
Year 2013													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
ALBERTA	$ 2.84	$ 2.74	$ 2.63	$ 2.63	$ 2.61	$ 2.45	$ 2.48	$ 2.29	$ 2.40	$ 2.63	$ 2.74	$ 2.84	$ 2.61
ARIZONA	$ 2.73	$ 2.73	$ 2.51	$ 2.84	$ 2.84	$ 2.84	$ 2.56	$ 2.62	$ 2.95	$ 2.79	$ 3.15	$ 2.87	$ 2.79
BC HYDRO	$ 3.28	$ 2.82	$ 2.34	$ 2.48	$ 2.32	$ 2.21	$ 2.18	$ 2.21	$ 2.32	$ 2.66	$ 3.22	$ 3.25	$ 2.61
IMPERIAL (IID)	$ 3.19	$ 3.05	$ 2.81	$ 2.75	$ 2.93	$ 2.84	$ 2.69	$ 2.84	$ 2.87	$ 2.87	$ 3.19	$ 3.57	$ 2.97
LADWP	$ 3.22	$ 3.14	$ 3.02	$ 2.84	$ 2.78	$ 2.75	$ 2.70	$ 2.75	$ 2.87	$ 2.93	$ 3.16	$ 3.43	$ 2.97
MEXICO	$ 3.19	$ 3.05	$ 2.81	$ 2.75	$ 2.93	$ 2.84	$ 2.69	$ 2.84	$ 2.87	$ 2.87	$ 3.19	$ 3.57	$ 2.97
MONTANA	$ 2.89	$ 2.41	$ 2.25	$ 2.30	$ 2.52	$ 2.76	$ 2.73	$ 2.65	$ 2.49	$ 2.79	$ 2.89	$ 3.03	$ 2.64
NEVADA	$ 2.75	$ 2.77	$ 2.55	$ 2.83	$ 2.69	$ 2.80	$ 2.58	$ 2.69	$ 2.83	$ 2.99	$ 3.13	$ 2.85	$ 2.79
NEW MEXICO	$ 3.10	$ 2.71	$ 2.58	$ 2.60	$ 2.66	$ 2.60	$ 2.69	$ 2.77	$ 2.74	$ 2.85	$ 3.02	$ 3.10	$ 2.79
NORTHWEST	$ 1.82	$ 2.22	$ 2.67	$ 3.39	$ 3.61	$ 2.03	$ 2.70	$ 2.67	$ 2.97	$ 2.40	$ 2.57	$ 2.91	$ 2.66
PACE (PACIFICORP)	$ 2.80	$ 2.82	$ 2.80	$ 2.72	$ 2.59	$ 2.54	$ 2.46	$ 2.12	$ 2.28	$ 2.54	$ 2.80	$ 3.24	$ 2.64
PG AND E	$ 3.20	$ 3.20	$ 2.99	$ 2.93	$ 2.99	$ 2.90	$ 2.90	$ 2.90	$ 2.90	$ 2.90	$ 3.17	$ 3.30	$ 3.02
PS COLORADO	$ 2.89	$ 2.41	$ 2.25	$ 2.30	$ 2.52	$ 2.76	$ 2.73	$ 2.65	$ 2.49	$ 2.79	$ 2.89	$ 3.03	$ 2.64
SAN DIEGO	$ 3.19	$ 3.05	$ 2.81	$ 2.75	$ 2.93	$ 2.84	$ 2.69	$ 2.84	$ 2.87	$ 2.87	$ 3.19	$ 3.57	$ 2.97
SIERRA	$ 2.60	$ 2.63	$ 2.42	$ 2.68	$ 2.55	$ 2.65	$ 2.44	$ 2.55	$ 2.68	$ 2.84	$ 2.97	$ 2.71	$ 2.64
SOCALIF (SCE)	$ 3.22	$ 3.14	$ 3.02	$ 2.84	$ 2.78	$ 2.75	$ 2.70	$ 2.75	$ 2.87	$ 2.93	$ 3.16	$ 3.43	$ 2.97
WAPA L.C (LOWER COLORADO)	$ 2.75	$ 2.77	$ 2.55	$ 2.83	$ 2.69	$ 2.80	$ 2.58	$ 2.69	$ 2.83	$ 2.99	$ 3.13	$ 2.85	$ 2.79
WAPA R.M (ROCKY MOUNTAIN)	$ 2.89	$ 2.41	$ 2.25	$ 2.30	$ 2.52	$ 2.76	$ 2.73	$ 2.65	$ 2.49	$ 2.79	$ 2.89	$ 3.03	$ 2.64

Table E.6 High Gas Price Scenario Year 2008

High Gas Forecast ($/mmbtu)													
Year 2008													
Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
ALBERTA	$ 9.70	$ 9.34	$ 8.98	$ 8.98	$ 8.89	$ 8.35	$ 8.44	$ 7.81	$ 8.17	$ 8.98	$ 9.34	$ 9.70	$ 8.89
ARIZONA	$ 9.45	$ 9.45	$ 8.68	$ 9.84	$ 9.84	$ 9.84	$ 8.87	$ 9.06	$10.22	$ 9.64	$10.90	$ 9.93	$ 9.64
BC HYDRO	$11.17	$ 9.63	$ 7.99	$ 8.44	$ 7.90	$ 7.54	$ 7.45	$ 7.54	$ 7.90	$ 9.08	$10.99	$11.08	$ 8.89
IMPERIAL (IID)	$11.19	$10.67	$ 9.85	$ 9.65	$10.26	$ 9.96	$ 9.44	$ 9.96	$10.06	$10.06	$11.19	$12.52	$ 10.40
LADWP	$11.30	$10.99	$10.58	$ 9.96	$ 9.76	$ 9.66	$ 9.45	$ 9.66	$10.07	$10.27	$11.09	$12.02	$ 10.40
MEXICO	$11.19	$10.67	$ 9.85	$ 9.65	$10.26	$ 9.96	$ 9.44	$ 9.96	$10.06	$10.06	$11.19	$12.52	$ 10.40
MONTANA	$ 9.89	$ 8.25	$ 7.70	$ 7.88	$ 8.61	$ 9.44	$ 9.34	$ 9.07	$ 8.52	$ 9.53	$ 9.89	$10.35	$ 9.04
NEVADA	$ 9.50	$ 9.59	$ 8.82	$ 9.78	$ 9.30	$ 9.68	$ 8.91	$ 9.30	$ 9.78	$10.35	$10.83	$ 9.87	$ 9.64
NEW MEXICO	$10.74	$ 9.39	$ 8.92	$ 9.01	$ 9.20	$ 9.01	$ 9.30	$ 9.59	$ 9.49	$ 9.87	$10.45	$10.74	$ 9.64
NORTHWEST	$ 6.23	$ 7.60	$ 9.15	$11.63	$12.36	$ 6.96	$ 9.25	$ 9.15	$10.16	$ 8.24	$ 8.79	$ 9.98	$ 9.13
PACE (PACIFICORP)	$ 9.57	$ 9.66	$ 9.57	$ 9.31	$ 8.86	$ 8.68	$ 8.42	$ 7.27	$ 7.80	$ 8.68	$ 9.57	$11.08	$ 9.04
PG AND E	$11.27	$11.27	$10.53	$10.32	$10.53	$10.21	$10.21	$10.21	$10.21	$10.21	$11.17	$11.59	$ 10.64
PS COLORADO	$ 9.89	$ 8.25	$ 7.70	$ 7.88	$ 8.61	$ 9.44	$ 9.34	$ 9.07	$ 8.52	$ 9.53	$ 9.89	$10.35	$ 9.04
SAN DIEGO	$11.19	$10.67	$ 9.85	$ 9.65	$10.26	$ 9.96	$ 9.44	$ 9.96	$10.06	$10.06	$11.19	$12.52	$ 10.40
SIERRA	$ 8.90	$ 8.99	$ 8.27	$ 9.17	$ 8.72	$ 9.08	$ 8.36	$ 8.72	$ 9.17	$ 9.71	$10.16	$ 9.26	$ 9.04
SOCALIF (SCE)	$11.30	$10.99	$10.58	$ 9.96	$ 9.76	$ 9.66	$ 9.45	$ 9.66	$10.07	$10.27	$11.09	$12.02	$ 10.40
WAPA LC (LOWER COLORADO)	$ 9.50	$ 9.59	$ 8.82	$ 9.78	$ 9.30	$ 9.68	$ 8.91	$ 9.30	$ 9.78	$10.35	$10.83	$ 9.87	$ 9.64
WAPA RM (ROCKY MOUNTAIN)	$ 9.89	$ 8.25	$ 7.70	$ 7.88	$ 8.61	$ 9.44	$ 9.34	$ 9.07	$ 8.52	$ 9.53	$ 9.89	$10.35	$ 9.04

Table E.7 High Gas Price Scenario Year 2013

High Gas Forecast ($/mmbtu)													
Year 2013													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
ALBERTA	$11.93	$11.49	$11.05	$11.05	$10.94	$10.28	$10.39	$ 9.61	$10.06	$11.05	$11.49	$11.93	$ 10.94
ARIZONA	$11.46	$11.46	$10.52	$11.92	$11.92	$11.92	$10.76	$10.99	$12.39	$11.69	$13.21	$12.04	$ 11.69
B.C.HYDRO	$13.74	$11.84	$ 9.83	$10.39	$ 9.72	$ 9.27	$ 9.16	$ 9.27	$ 9.72	$11.17	$13.52	$13.63	$ 10.94
IMPERIAL (IID)	$13.39	$12.78	$11.79	$11.55	$12.28	$11.92	$11.30	$11.92	$12.04	$12.04	$13.39	$14.99	$ 12.45
LADWP	$13.52	$13.16	$12.66	$11.93	$11.68	$11.56	$11.31	$11.56	$12.05	$12.29	$13.28	$14.38	$ 12.45
MEXICO	$13.39	$12.78	$11.79	$11.55	$12.28	$11.92	$11.30	$11.92	$12.04	$12.04	$13.39	$14.99	$ 12.45
MONTANA	$12.14	$10.11	$ 9.44	$ 9.66	$10.56	$11.57	$11.46	$11.12	$10.45	$11.69	$12.14	$12.70	$ 11.09
NEVADA	$11.52	$11.62	$10.69	$11.85	$11.27	$11.74	$10.81	$11.27	$11.85	$12.55	$13.13	$11.97	$ 11.69
NEW MEXICO	$13.02	$11.39	$10.81	$10.93	$11.16	$10.93	$11.27	$11.62	$11.51	$11.97	$12.67	$13.02	$ 11.69
NORTHWEST	$ 7.62	$ 9.30	$11.21	$14.24	$15.13	$ 8.52	$11.32	$11.21	$12.44	$10.09	$10.76	$12.22	$ 11.17
PACE (PACIFICORP)	$11.74	$11.85	$11.74	$11.41	$10.87	$10.65	$10.33	$ 8.91	$ 9.57	$10.65	$11.74	$13.59	$ 11.09
PG AND E	$13.44	$13.44	$12.56	$12.30	$12.56	$12.18	$12.18	$12.18	$12.18	$12.18	$13.32	$13.82	$ 12.70
PS COLORADO	$12.14	$10.11	$ 9.44	$ 9.66	$10.56	$11.57	$11.46	$11.12	$10.45	$11.69	$12.14	$12.70	$ 11.09
SAN DIEGO	$13.39	$12.78	$11.79	$11.55	$12.28	$11.92	$11.30	$11.92	$12.04	$12.04	$13.39	$14.99	$ 12.45
SIERRA	$10.91	$11.02	$10.14	$11.24	$10.69	$11.13	$10.25	$10.69	$11.24	$11.91	$12.46	$11.35	$ 11.09
SOCALIF (SCE)	$13.52	$13.16	$12.66	$11.93	$11.68	$11.56	$11.31	$11.56	$12.05	$12.29	$13.28	$14.38	$ 12.45
WAPA LC (LOWER COLORADO)	$11.52	$11.62	$10.69	$11.85	$11.27	$11.74	$10.81	$11.27	$11.85	$12.55	$13.13	$11.97	$ 11.69
WAPA RM (ROCKY MOUNTAIN)	$12.14	$10.11	$ 9.44	$ 9.66	$10.56	$11.57	$11.46	$11.12	$10.45	$11.69	$12.14	$12.70	$ 11.09

Appendix F. MARKET PRICE DERIVATION

Historically, resource-planning studies have typically relied on production cost simulations (i.e. marginal cost pricing) to evaluate the economic benefits of potential transmission investments. While such an approach may make sense in a vertically integrated regime, assuming marginal cost pricing in a restructured market environment where suppliers constantly seek to maximize their market revenues may result in inaccurate benefit assessment. Therefore a major task to us in this study is to quantify economic benefit of transmission upgrade based on market price simulation instead of production cost simulation.

Furthermore, traditionally, transmission upgrades were used as means to enhance system reliability and reduce overall system production cost. In a restructured market regime, transmission upgrades also have significant functions to bring in more competitors to local markets and enhance market competitiveness. Thus another important task to us is to accurately capture the significant impact of transmission upgrades on enhancing market competitiveness.

Although it is a great challenge to fulfill both tasks, our 7-year experiences of operating the CAISO grid and market gave us a very good start. Our historical data shows a strong statistical relationship between price-cost markups and key variables that measure the system supply/demand conditions such as RSI and percentage of load un-hedged[2]. Based on this historical relationship, we were able to build a dynamic bid adder mechanism in our market simulation model where suppliers' bids are determined by their production costs AND their abilities to bid above their costs. More importantly, the dynamic bid adder mechanism captured the impact of major transmission upgrades, such as Palo Verde – Devers #2 line, on increasing the import capability into the CAISO Control Area thus reducing suppliers' ability to bid above cost. Finally market prices forecasted by our simulation model were used in this economic benefit assessment of Palo Verde – Devers #2 line.

Appendix G. PROJECT COST

Southern California Edison (SCE) has estimated the capital cost of the proposed PVD2 upgrade to be $620 million at its online date at the beginning of 2009. SCE has also estimated an allowance for funds used during construction (AFUDC) of approximately $60 million, for a total capital cost of $680 million at the 2009 online date.

For purposes of our analysis, we have deflated the capital costs one year so that they can be expressed in 2008 dollars (to be consistent with the benefits which are also expressed in 2008 dollars). The capital costs deflated to 2008 are $667 million using a 2.0 percent inflation rate.

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2 For more detailed discussion on the relationship between price-cost markup and key market variables, please refer to Chapter 5 of the TEAM report at http://www1.caiso.com/docs/2004/06/03/2004060313241622985.pdf.

These capital costs can be converted to an equivalent stream of annual revenue requirements. Although these revenue requirements change from year-to-year, for purposes of economic evaluations, we expressed this series of annual revenue requirements as an equal or "levelized" annual payment over the project life.

We estimate the levelized revenue requirement for the capital costs of the proposed PVD2 project will be $70 million per year for 50 years.3 If we assume that the operating costs of the line are approximately 0.25 percent of the capital cost per year, the total of capital and fixed operating costs will be $71 million per year. Thus, for this analysis, we compared the calculated levelized benefits to the $71 million levelized costs to determine the economic viability of the project.

A. Initial Review of Project Costs

As mentioned previously, SCE estimated the PVD2 project cost to be $680 million at its 2009 online date. The CAISO has not conducted an independent evaluation of the costs of the project. That function is typically performed by the CPUC in the Certificate of Public Convenience and Necessity (CPCN) hearings on the proposed project. We did perform a cursory review of the project costs. To determine if SCE's estimated cost for the proposed PVD2 Project was reasonable, we compared the project cost with the costs for other proposed 500 kV lines from Pacific Gas & Electric and San Diego Gas & Electric Companies: Path 15 Upgrades Project and the Valley – Rainbow 500 kV Line Project. [4] Table G.1 summarizes these projects.

Table G.1 Comparison of Proposed Project Costs

Project	Total Cost (2008 $)	Miles	Cost per Mile (2008 $)	New Right-of-Way Req?	Urban or Rural
Valley-Rainbow	370	30	12	yes	urban
Path 15	250	83	3.0	no	rural
PVD2	680	230	3.0	no	rural

The Path 15 upgrades and the PVD2 project utilize rights-of-way owned by the transmission owners. The Valley – Rainbow 500kV Project, however, was proposed with new rights-of-way to be acquired by SDG&E. A cursory review of the project cost, based on 2009 dollars[5], indicated that the $2.7 million/mile unit cost for the PVD2 Project was the least expensive of all three 500 kV projects. This probably can be attributed to the fact that the PVD2 is constructed almost entirely in desert terrain with the rights-of-way already owned by SCE. The unit cost for the Valley – Rainbow 500 kV Project was the highest, partly attributed to the new rights-of-way that SDG&E proposed to acquire.

3 The revenue requirements include the impact of federal and state income taxes, administrative and generation costs, insurance expenses, and ad valorem tax. SCE provided the CAISO with its computed "Real Economic Carrying Charge Rate for Transmission" of 10.43 percent. This rate is comparable to a Nominal Economic Carrying Charge Rate of 15.6 percent.
4 The CPUC did not approve the proposed Valley – Rainbow 500kV Line Project and SDG&E decided not to re-file the project application.
5 Project costs are adjusted to the same year (2009) for the purpose of cost comparison.

Appendix H. APPROVED TRANSMISSION PROJECTS

The CAISO Board approves all projects that cost $20 million or more. Table H.5 below provides a list of the major transmission projects that the CAISO Board has approved from 2000 through 2004.

Table H.1 CAISO Board Approved Transmission Projects

	Project Name	Transmission Owners	CAISO Board Approval	Scheduled Operating Date	Purpose (Economic / Reliability)	Cost ($ Million)
1	Northeast San Jose Transmission Reinforcement	PG&E	1/27/2000	5/2003	Reliability	$130 M
2	Tri-Valley Transmission Reinforcement Project	PG&E	1/27/2000	5/2003	Reliability	$39.2 M
3	San Luis Rey Substation Reinforcement	SDG&E	1/27/2000	12/ 2002	Reliability	Confidential Cost > $20 M
4	Installation of A Third Metcalf 500/230kV Transformer Bank	PG&E	2/21/2001	09/2002	Reliability	$33 M
5	Valley – Rainbow 500kV Transmission Project	SDG&E	3/30/2001	2008[6]	Reliability	$350 M
6	Midway 500/230kV Transformer #3 Project	PG&E	6/21/2001	10/2002	Economic	$32 M
7	Jefferson – Martin 230kV Transmission Project	PG&E	4/25/2002	1st or 2nd Quarter, 2006	Reliability	$200 - $ 250 M
8	Miguel – Mission Upgrade and Imperial Valley Transmission Upgrades	SDG&E	6/25/2002	May 2003 and June 2006[7]	Economic	$61 M
9	Path 15 Upgrade	PG&E, WAPA, Trans-Elect	6/25/2002	12/2004	Economic	$306 M
10	San Diego Transmission Upgrades	SDG&E	10/23/2003	12/2004	Economic	$22 M

6 This project was later rejected by the CPUC as part of its environmental permit review.)
7 June, 2006 for Miquel-Mission 230 kV Upgrade (temporary configuration may accelerate operational date to 2005. May, 2003 for Imperial Valley Substation upgrade.

	Project Name	Transmission Owners	CAISO Board Approval	Scheduled Operating Date	Purpose (Economic / Reliability)	Cost ($ Million)
11	Metcalf – Moss Landing Reinforcement Project	PG&E	4/22/2004	2006	Reliability	$29 M
12	STEP Short-Term Transmission Upgrades	SCE, SDG&E and APS	6/24/2004	06/2006	Economic	$148 M
13	Cross Valley Rector Loop Project	SCE	6/24/2004	2006	Reliability	$46 M
14	Lakeville – Sonoma 115kV Transmission Line Project	PG&E	6/24/2004	2006	Reliability	$30 M
15	Tehachapi Wind Generation Transmission Project (aka Antelope – Pardee 230kV Transmission Line Project)	SCE	7/29/2004	12/2006	Reliability / Renewable Generation	$94 M
16	Martin – Hunters Point 115kV Underground Cable Project	PG&E	11/10/2004	Summer 2007	Reliability	$35 M
17	Rancho Vista 500/230kV Substation Project	SCE	1/27/2005	Summer 2011 (SCE may advance the project as early as 2009)	Reliability	$130 M

Appendix I. CASE SUMMARY

Table I.1 Case Summary

		Year	Load	Gas Price	Hydro	Market Pricing	Other	Joint Probability	Societal Benefits (mil. nominal $)	Modified Societal Benefits (mil. nominal $)	CAISO Ratepayer Benefit (LMP Only) (mil. nominal $)	CAISO Ratepayer Benefit (LMP + Contract Path) (mil. nominal $)
Cost Based	1	2008	B	B	B	N	N	n/a	$ 42.83	$ 42.89	$ 19.81	$ 70.83
	2	2008	B	B	D	N	N	n/a	$ 48.73	$ 48.80	$ 28.68	$ 82.43
	3	2008	B	B	W	N	N	n/a	$ 23.51	$ 23.56	$ 26.13	$ 69.00
	4	2008	B	H	B	N	N	n/a	$ 85.81	$ 85.88	$ 48.79	$ 141.49
	5	2008	B	L	B	N	N	n/a	$ 6.76	$ 6.81	$ (2.41)	$ 17.07
	6	2008	H	B	B	N	N	n/a	$ 38.10	$ 38.17	$ 0.82	$ 75.30
	7	2008	L	B	B	N	N	n/a	$ 29.47	$ 29.52	$ 34.83	$ 79.14
	8	2008	H	H	D	N	N	n/a	$ 110.41	$ 110.45	$ 21.59	$ 148.33
	9	2013	B	B	B	N	N	n/a	$ 55.50	$ 55.54	$ 40.05	$ 137.07
	10	2013	B	B	D	N	N	n/a	$ 60.60	$ 60.64	$ 38.34	$ 163.74
	11	2013	B	B	W	N	N	n/a	$ 37.53	$ 37.57	$ 44.16	$ 117.13
	12	2013	B	H	B	N	N	n/a	$ 102.45	$ 102.49	$ 91.68	$ 240.63
	13	2013	B	L	B	N	N	n/a	$ 20.68	$ 20.73	$ (2.89)	$ 50.81
	14	2013	H	B	B	N	N	n/a	$ 68.22	$ 68.27	$ 27.16	$ 151.08
	15	2013	L	B	B	N	N	n/a	$ 34.36	$ 34.40	$ 62.90	$ 129.99
	16	2013	H	H	D	N	N	n/a	$ 163.31	$ 163.33	$ 194.13	$ 308.33
Market Based	17	2008	B	B	B	M	N	11.0%	$ 45.29	$ 58.85	$ 37.87	$ 98.74
	18	2008	B	B	B	H	N	5.0%	$ 46.96	$ 71.12	$ 54.82	$ 124.50
	19	2008	B	B	D	M	N	9.9%	$ 50.48	$ 66.65	$ 34.55	$ 115.74
	20	2008	B	B	W	M	N	13.1%	$ 24.33	$ 26.17	$ 29.06	$ 72.77
	21	2008	B	H	B	M	N	2.3%	$ 89.96	$ 113.13	$ 76.68	$ 185.88
	22	2008	B	H	B	H	N	1.8%	$ 92.48	$ 133.95	$ 104.81	$ 229.12
	23	2008	H	B	B	H	N	3.3%	$ 45.30	$ 120.82	$ 70.88	$ 199.75
	24	2008	H	H	D	M	N	1.8%	$ 118.94	$ 236.98	$ 85.15	$ 317.47
	25	2008	B	H	D	H	N	1.8%	$ 106.00	$ 151.62	$ 80.71	$ 257.26
	26	2008	B	B	B	L	N	15.0%	$ 42.51	$ 41.51	$ 17.04	$ 68.45
	27	2008	L	B	B	M	N	12.7%	$ 29.85	$ 31.62	$ 35.55	$ 83.27
	28	2008	B	L	B	M	N	10.1%	$ 8.83	$ 18.46	$ 8.00	$ 36.56
	29	2008	H	H	B	H	N	1.5%	$ 93.81	$ 235.19	$ 143.23	$ 371.07
	30	2008	H	L	B	M	N	4.9%	$ 4.43	$ 23.72	$ 2.17	$ 40.99
	31	2008	L	H	B	M	N	2.3%	$ 56.94	$ 59.55	$ 74.09	$ 155.45
	32	2008	H	H	D	H	N	1.5%	$ 135.84	$ 387.68	$ 234.95	$ 568.52
	33	2008	H	H	W	M	N	1.9%	$ 19.10	$ 21.49	$ 5.63	$ 119.70

		Year	Load	Gas Price	Hydro	Market Pricing	Other	Joint Probability	Societal Benefits (mil. nominal $)	Modified Societal Benefits (mil. nominal $)	CAISO Ratepayer Benefit (LMP Only) (mil. nominal $)	CAISO Ratepayer Benefit (LMP + Contract Path) (mil. nominal $)
Market Based	34	2013	B	B	B	M	N	11.0%	$ 58.53	$ 77.43	$ 54.88	$ 193.50
	35	2013	B	B	B	H	N	5.0%	$ 59.46	$ 93.86	$ 65.22	$ 237.23
	36	2013	B	B	D	M	N	9.9%	$ 65.30	$ 94.71	$ 57.48	$ 247.07
	37	2013	B	B	W	M	N	13.1%	$ 38.75	$ 44.43	$ 50.66	$ 138.84
	38	2013	B	H	B	M	N	2.3%	$ 106.08	$ 137.49	$ 112.49	$ 322.36
	39	2013	B	H	B	H	N	1.8%	$ 108.80	$ 163.42	$ 127.73	$ 387.10
	40	2013	H	B	B	H	N	3.3%	$ 83.79	$ 222.70	$ 137.97	$ 478.56
	41	2013	H	H	D	M	N	1.8%	$ 184.94	$ 359.22	$ 152.53	$ 629.18
	42	2013	B	H	D	H	N	1.8%	$ 123.14	$ 191.45	$ 114.35	$ 484.75
	43	2013	B	B	B	L	N	15.0%	$ 55.36	$ 55.89	$ 38.16	$ 137.76
	44	2013	L	B	B	M	N	12.7%	$ 34.46	$ 34.21	$ 54.24	$ 132.11
	45	2013	B	L	B	M	N	10.1%	$ 24.10	$ 38.01	$ 6.68	$ 94.10
	46	2013	H	H	B	H	N	1.5%	$ 155.79	$ 364.06	$ 222.28	$ 746.87
	47	2013	H	L	B	M	N	4.9%	$ 30.85	$ 68.47	$ (0.46)	$ 136.21
	48	2013	L	H	B	M	N	2.3%	$ 61.23	$ 59.98	$ 106.72	$ 227.13
	49	2013	H	H	D	H	N	1.5%	$ 189.78	$ 517.32	$ 303.47	$ 993.46
	50	2013	H	H	W	M	N	1.9%	$ 109.09	$ 148.54	$ 94.16	$ 352.79
Contingency	51	2008	B	B	B	M	PV1	n/a	$ 59.54	$ 75.89	$ 65.56	$ 136.39
	52	2008	B	B	B	M	PV2	n/a	$ 68.69	$ 90.65	$ 105.69	$ 170.85
	53	2008	B	B	B	M	MV	n/a	$ 49.63	$ 72.22	$ 60.17	$ 140.57
	54	2008	B	B	B	M	MH	n/a	$ 55.48	$ 71.14	$ 67.09	$ 124.43
	55	2008	B	B	B	M	SO	n/a	$ 58.16	$ 82.00	$ 74.64	$ 161.83
	56	2008	B	B	B	M	PDCI	n/a	$ 30.06	$ 40.41	$ 28.19	$ 111.89
	57	2008	B	B	B	M	COI_EOR	n/a	$ 45.66	$ 57.13	$ 55.25	$ 73.21
	58	2008	B	B	B	M	SCE RE	n/a	$ 40.96	$ 54.43	$ 49.87	$ 109.05
	59	2013	B	B	B	M	PV1	n/a	$ 85.01	$ 114.52	$ 127.58	$ 291.87
	60	2013	B	B	B	M	PV2	n/a	$ 91.39	$ 122.45	$ 184.03	$ 338.52
	61	2013	B	B	B	M	MV	n/a	$ 58.85	$ 92.95	$ 77.95	$ 267.30
	62	2013	B	B	B	M	MH	n/a	$ 73.68	$ 96.21	$ 104.22	$ 242.96
	63	2013	B	B	B	M	SO	n/a	$ 85.82	$ 134.10	$ 145.74	$ 380.68
	64	2013	B	B	B	M	PDCI	n/a	$ 63.80	$ 84.73	$ 51.92	$ 214.81
	65	2013	B	B	B	M	COI_EOR	n/a	$ 61.53	$ 80.65	$ 99.59	$ 123.99
	66	2013	B	B	B	M	SCE RE	n/a	$ 56.51	$ 74.11	$ 43.75	$ 191.39

Note: **B=Base; L=Low; H=High; M=Moderate; N=None; W=Wet Hydro; D=Dry Hydro; PV= 1200 MW CC in PV; PV2 = 2400 MW CC in PV; MV= Mountian View unit O/S; MH= Mohave Unit I/S; SO=San Onofre Outage; DC=PDCI Line Outage; COI_EOR= 10%**

Appendix J. ESTIMATION OF VALUE OF TRANSMISSION LOSS REDUCTION

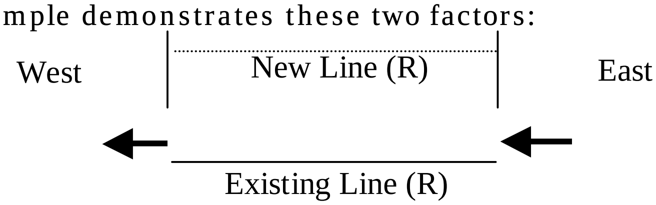
Summary – The current PVD2 analysis uses a DC power flow model and thus does not model transmission losses internally. In practice, the PVD2 upgrade is expected to lead to more efficient generation dispatch. The transmission losses are generally expected to be lower as a result of the transmission upgrade. This analysis attempts to quantify the transmission loss reduction benefits of the upgrade.

Benefit Overview – From the PLEXOS simulations:

1. We have hourly flows (P_i) in MWh on each of the major transmission lines (line i) of interest
2. We can approximate the hourly line losses (Li) in MWh knowing the per unit resistance of each line (R_i) using the formula $Li = R_i*(P_i)^2/100$ (the formula assumes adequate reactive support to maintain nominal voltage and the100 number in the denominator represents the MVA base used for per unit computations).
3. We add up the transmission losses for all lines of interest
4. Using a weighted average energy price, we compute the energy cost associated with these transmission losses.
5. We perform steps (1) through (4) before, and after the upgrade. The difference ($cost of losses before the upgrade - $cost of losses after the upgrade) is the cost savings attributed to transmission loss reduction.

Caution – The following comments are in order here:

1. Whether or not the transmission upgrade results in reduction of transmission losses (MWh) depends on the interplay between two factors: (a) the upgrade increases power transfers thus potentially increasing transmission losses; (b) the upgrade re-routes power flow on paths of less resistance, and reduces the power flow on the existing paths, thus reducing transmission losses. The following simple example demonstrates these two factors:



Here the existing and the new line both have a per unit resistance of R. The rating of the path before the upgrade is T1 and after the upgrade (both lines together) it is T2 (with T2>T1). Assume the path is at full capacity both before and after upgrade to bring less-expensive energy from East to West (the balance of the load in the West is served locally from more expensive energy with no transmission losses.

Before the upgrade the losses are: $L(NU) = R*(T1)^2/100$, and after the upgrade, $L(U) = 2*R*(T2/2)^2/100 = 0.5* R*(T2)^2/100$. The ratio $r = L(U)/L(NU)$ determines whether transmission losses increase or decrease as a result of the upgrade. Here: r = $0.5*(T2/T1)^2$. Thus if the increase in rating is 40% or less, i.e., $T2/T1 \leq 1.4$, the transmission losses decrease as a result of the upgrade. In our analysis we use the computed power flows before and after the upgrade, which implicitly include the inter-play between these factors.

1. The price ($/MWh) attributed to the losses may be different before and after the upgrade. Whether this price is higher or lower after the upgrades depends on where the energy is assumed to be generated to compensate for losses. If one takes the point of view that the MWh lost in transmission must be provided close to the point of consumption, average price at the load is the relevant number to use (which is generally lower after the upgrade resulting in higher computed savings for transmission loss reduction). However, if one takes the point of view that more energy must be generated at the remote supply location to compensate for transmission losses, then the average piece at the remote supply location would be the relevant number to use (which is generally higher after the upgrade resulting in lower computed savings for transmission loss reduction). In our analysis we use the same $/MWh price for losses before and after the upgrade to avoid potential bias resulting from such assumption.

Benefit Estimation - In table J.1, we develop an estimate of the transmission loss savings as result of the upgrade. For purposes of this estimate, the price of energy to compensate for transmission losses is $45/MWh, which is an average of the nodal prices in CAISO and Arizona in the base case scenario with moderate market power.

Table J.1 Estimated Transmission Loss Energy Savings for PVD2

Transmission Lines	Line Resistance (p.u)	Pre-PDV2 Annual Power Loss (MWh)	Post-PDV2 Annual Power Loss (MWh)	Annual Saving in Losses (MWh)	Energy Savings (Based on $45/MWh)
Palo Verde- Devers #1 500 kV	0.0022	738,273	415,379	322,894	$14,530,230
Palo Verde-Devers #2 500 kV	0.0022	-	415,379	(415,379)	($18,692,055)
Hassyampa- N. Gila 500 kV	0.0012	148,845	134,584	14,261	$641,745
N. Gila-Imperial Valley 500 kV	0.0008	92,915	85,945	6,970	$313,650
Imperial Valley-Miguel 500 kV	0.0008	189,233	175,719	13,514	$608,130
Mohave –Lugo 500 kV	0.0017	208,709	191,176	17,533	$788,985
El Dorado-Lugo 500 kV	0.0017	200,493	183,351	17,142	$771,390
McCullough-Victorville #1 500 kV	0.0016	172,669	170,990	1,679	$75,555
McCullough-Victorville # 2 500 kV	0.0016	172,669	170,990	1,679	$75,555
Market Place-Adelanto 500 kV	0.0012	161,011	162,015	(1,004)	($45,180)
El Dorado-Mohave 500 kV	0.0006	76,410	69,931	6,479	$291,555
Lugo-Mira Loma #2 500 kV	0.0003	22,665	14,710	7,955	$357,975
Lugo-Mira Loma #3 500 kV	0.0003	21,675	14,068	7,607	$342,315
Lugo – Serrano 500 kV	0.0005	18,521	11,431	7,090	$319,050
Lugo-Victorville 500 kV	0.0001	16,315	10,425	5,890	$265,050
Palo Verde-Westwing #1 500 kV	0.0004	42,336	34,302	8,034	$361,530
Palo Verde-Westwing #2 500 kV	0.0004	42,336	34,302	8,034	$361,530
Jojoba- Kyrene 500 kV	0.0004	40,932	36,486	4,446	$200,070
Palo Verde-Rudd 500 kV	0.0003	19,521	16,218	3,303	$148,635
Devers- Valley 500 kV	0.0004	72,236	118,680	(46,444)	($2,089,980)
Perkins- Mead 500 kV	0.0010	195,238	168,481	26,757	$1,204,065
Navajo-Crystal 500 kV	0.0021	367,116	350,045	17,071	$768,195
Moenkopi-El Dorado 500 kV	0.0020	409,994	390,107	19,887	$894,915
Total		**3,430,112**	**3,374,714**	**55,398**	**$2,492,910**

Appendix K. OPERATIONAL BENEFITS ESTIMATED FOR THE PVD2 ECONOMIC ASSESSMENT

The operational benefits of a transmission project are an essential component of the benefits of the PVD2 project. Traditional production cost studies may not capture all the operational costs that are incurred in managing the system. When two Palo Verde Devers lines are available, some operational benefits accrue which are not captured in the energy savings calculations from the line upgrade produced by the model. One means of quantifying these benefits is to review the current ISO payments in southern California to keep generating units on line to protect against N-1 (and relevant N-2) operational contingencies. CAISO operators estimate that a portion of these costs can be saved as a result of the short-term upgrades, and additional portions can be saved with the addition of the second Palo Verde Devers 500 kV line and the associated 230 kV upgrades, West of Devers. The PVD2 line increases the import capacity into southern California from Arizona by 1200MW through the interface East of the River (EOR) and subsequently in Southern California Import Transmission Nomogram (SCIT). The CAISO currently commits many units in southern California for N-1 and N-2 transmission contingency and pays Minimum Load Cost Compensation (MLCC). Moreover, re-dispatch of other units is needed to accommodate the minimum load of such units, thus resulting in re-dispatch costs. The SCIT nomogram requires a certain level of inertia within southern California to maintain reliability of the system. With the short term upgrades, the SCIT nomogram constraint as we know it today will not be binding; however, the need to commit internal units beyond what is strictly needed to serve the bid-in or scheduled load and provide ancillary services to guard against N-1 (and relevant N-2) contingencies will persist, albeit at a lower level. To keep adequate capacity within southern California the operators commit units and must re-dispatch the already scheduled units within southern California. An increase in imports is estimated to minimize these commitment (MLCC) and re-dispatch costs and the need to keep the plants running at minimum level.

As an estimate to these costs, we collected some of the real time information that is monitored by the ISO. The MLCC payments by the CAISO were broken down into several components based on “cause”. These include MLCC payments for system shortages, contingencies related to various transmission paths including, SCIT, Miguel, Lugo, Sylmar, Transmission Substation maintenance, Nuclear, etc.. It was estimated that the PVD2 project would reduce the MLCC costs (and the corresponding re-dispatch cost) for a portion of the system, SCIT, and Nuclear MLCC. The short-term upgrades would have already reduced some of these costs, some substantially, and the PVD2 upgrade would reduce them further. Thus, it was estimated that the short-term upgrades could reduce the MLCC by 75% for contingencies related to imports from Arizona (referred to as SCIT for ease of reference here, although as explained earlier this is really not the SCIT nomogram as we know it) and by 10% for MLCC related to system shortages and nuclear unit maintenance outages. We also estimate that the associated re-dispatch costs would be lower by 75%. We then estimate that the PVD2 upgrade would result in further reductions as follows: 25% of (the remaining 25%) SCIT MLCC, 25% of (the remaining 90%) system MLCC, 80% of (the remaining 90%) Nuclear MLCC, and 50% (of the remaining 25%) re-dispatch cost[8]. The following Table summarizes these computations.

8 The rationale for these percentages is as follows: The largest N-2 contingency may involve a loss of up to 5,000 MW. The 1,200 MW new PVD2 capacity represents 25% of this amount (thus the 25% MLCC benefit for SCIT and system). The nuclear unit outage is almost comparable in capacity to the additional PVD2 capacity (thus the 80% MLCC benefit for nuclear outage). The re-dispatch cost savings related to commitment of these resources is somewhere between 25% and 80% (thus the 50% reduction).

Table K.1 Annual Average MLCC and Re Dispatch Payments

	MLCC (AZ & CA Imports)	*MLCC (CAISO System wide Shortages)*	*MLCC (Nuclear Maintenance)*	*Re dispatch (AZ & CA Imports)*
Real Time Annual Average	$51,208,305.99	$ 28,614,216.90	$11,551,880.94	$ 2,110,578.65
	Total Annual Real Time Operational Costs			**$ 93,484,982.48**
After Short Term Upgrade	25%	90%	90%	25%
	$12,802,076.50	$ 25,752,795.21	$10,396,692.84	$ 527,644.66
	Total Annual Average Operational Benefit			**$ 49,479,209.21**
PVD2 Benefits	25%	25%	80%	50%
	$ 3,200,519.12	$ 6,438,198.80	$ 8,317,354.27	$ 263,822.33
	Total Annual Average Operational Benefit			**$ 18,219,894.53**

Note: The Real time data used are from March of 2003 to September 2004

Appendix L. TRANSMISSION ALTERNATIVES

STEP was created as a sub-regional planning group to address transmission concerns in the Arizona, southern Nevada, southern California, and northern Mexico areas. The new generation that has been developed at certain locations in the southwest region had made it clear to the STEP participants that the existing transmission system was inadequate. By enhancing the capability of the system, this new, relatively clean, and efficient generation would be better able to serve future load growth and displace older and less efficient generation. STEP held its first meeting on November 1, 2002 in San Diego and has met on a monthly or bi-monthly basis since that meeting. Participants include representatives from utilities, independent power producers (IPPs), state agencies/regulators and other stakeholders with an interest in the transmission system in southern Nevada, Arizona and southern California.

STEP evaluated a large number of potential transmission upgrade plans during the year of 2003. In fact, STEP analyzed 26 different upgrade scenarios with different combinations of transmission lines in the southwest region. See http://www1.caiso.com/docs/2004/03/08/2004030814004810105.doc for further information.

The group selected six transmission alternatives based on the initial screening studies for further technical and economic analysis. The Palo Verde–Devers No. 2 500 kV line was part of two ("AC1" and "AC2") out of the six. Analysis deemed three of the alternatives ("AC4", "DC1" and "DC2") not viable options due to reasons like lack of project sponsorship, inadequate technical performance or insufficient economics. The last alternative, "AC3", included a variant of the Palo Verde–Devers No. 2 500 kV line with termination points at Blythe and Parker Substations. Desert Southwest Power LLC and SCE have been discussing the connection point at Blythe ("Midpoint Substation"). Likewise, SCE and APS are discussing the use of the proposed terminal point for the Palo Verde–Devers project at Harquahala Substation as a joint substation for both the PVD2 project and APS's TS5 Project. We expect neither of these variances to significantly change the scope of the proposed Palo Verde-Devers No. 2 project.

Based on the technical and economic studies, and a consensus building process, the group narrowed the number of alternatives to one general expansion plan. STEP has now begun several of the initial steps that can be implemented quickly and economically. These initial steps primarily involve upgrades to the 500 kV series capacitors of the existing Palo Verde–Devers and the Southwest Power Link (SWPL). The planned in-service date for these upgrades is June 2006 and will increase the rating on EOR from 7,550 MW to 8,055 MW. LADWP and several utilities in Arizona have also suggested upgrading the series capacitors on the Perkins–Mead and Navajo–Crystal 500 kV lines between Arizona and Nevada. This project is called the “EOR9000+” project. Its goal is to increase the EOR path rating from 8,055 MW to 9,300 MW, an increment of 1,245 MW. If the EOR 9000 project goes forward, then the ISO will likely sponsor the upgrade of the third major line between Arizona and Nevada, which is the Moenkopi-Eldorado 500 kV line.

We received stakeholder feedback in Nov 2004 that questioned whether the EOR 9000 upgrades could substitute for the Palo Verde-Devers No. 2 line. We ran sensitivities with and without EOR 9000. We found that the two projects are predominately complementary rather than substitutes for one another. Solely undertaking the EOR 9000 project, does not deliver the benefits expected from the PVD2 line. This is because those upgrades increase transmission capability between Arizona and Nevada, but do not relieve congestion on the transmission facilities that run directly from Arizona to southern California. Thus having just the EOR9000 project does not significantly enhance the import capability into California. The PVD2 expansion would complement the EOR 9000 Project by relieving a major bottleneck into southern California.

Appendix M. Resource Alternatives

Prior to committing to build or upgrade a transmission line, alternative generation resources need to be considered. In today’s market, the most likely generation alternative is a new combined-cycle (CC) station. The question is whether the CAISO should promote the PVD2 upgrade, or recommend building new CC’s in the CAISO area, or both.

In Table M.1, we compared the expected total costs of a new combined-cycle station located in California, versus one located in Arizona. The total CC costs (capital, O&M, and fuel), excluding any transmission interconnection costs, are expected to be about 10 percent less in Arizona. When the levelized cost of 500 MW of PVD2 upgrade is added to the cost of the Arizona CC, the Arizona CC becomes more expensive. At a 50 percent capacity factor, the Arizona facility is 10 percent more expensive. At a 90 percent capacity factor, the Arizona facility is 4 percent more expensive as is summarized in Table M.1.

Table M.1 Comparison of Combined Cycle Costs In California and Arizona (2008 $)

Parameter	Units	California	Arizona	Percent Dif.
Installed Capital Cost	$/kw	$1,184	$1,080	10%
Real Econ. Carrying Charge	%	10%	10%	0%
Annual Capital Cost	$/kw-yr	$118	$108	10%
Fixed O&M Costs	$/kw-yr	$15	$10	50%
Annual Fixed Costs	$/kw-yr	$133	$118	13%
PVD2 Transmission Costs	$/kw-yr	$0	$59	-100%
Total Fixed Costs	$/kw-yr	$133	$177	-25%
Average Heat Rate	btu/kwh	7,100	7,100	0%
Fuel Costs	$/mmbtu	$5.08	$4.71	8%
Fuel Costs	$/MWh	$36	$33	8%
Variable O&M Costs	$/MWh	$3	$2	50%
Total Variable Costs	$/MWh	$39	$35	10%
Assumed Capacity Factor	%	90%	90%	0%
Total Costs	$/MWh	$56	$58	-4%

By itself, the information presented in Table M.1 is not a complete picture. Other important factors need to be considered for the following reasons:

- No interconnection costs – In the above example, we have not included any transmission or gas interconnection costs due to lack of applicable data. In California these costs can be substantial, such as Otay Mesa. In Arizona, the majority of the new CC's are being constructed in the Palo Verde region where they can directly connect with the existing 500 kV network and the natural gas pipeline with minimal interconnection costs.
- Limited ability to site resources in CA urban areas -- Many PVD2 stakeholders have suggested that a new CC located in the load centers of Southern California would be more valuable than a similar unit located in Arizona. We agree that new or refurbished generating units are needed in the load centers for reliability and operational purposes. However, we believe that these opportunities will be very limited in the future. In many cases, even using the sites of existing units in urban areas is strongly opposed by the local communities. An example of this opposition is San Francisco, where local generation would be very valuable, but the residents surrounding the Hunters Point and Potrero sites are adamantly against any new developments on those sites and advocate shutdowns of the existing units.

Therefore, we believe that both local generating options and transmission solutions need to be aggressively pursued. Constructing and operating PVD2 does not preclude the construction of local facilities, as California needs to add significant capacity between 2004 and 2009.

Appendix N. ALTERNATIVE MARKET PARADIGMS

The analysis is performed using a physical network model. It is also based on a paradigm assuming locational marginal pricing (LMP) throughout WECC. This combination, although most efficient and potentially conceivable for the future, will take years or even decades to implement and may likely not be implemented during the life cycle of the transmission projects considered here. At present, the California market is based on a zonal market paradigm (with no forward energy market), and most of the WECC operates based on contract path (rather than physical network model) scheduling. In near future California will move to an LMP paradigm (including a forward energy market). However, under both the current zonal market design and the LMP market paradigm (MRTU as currently envisioned for an indefinite period) scheduling at the ties with the neighboring control areas is checked for transmission feasibility using a scissors cut radial external network. This does not account for physical flows on individual lines comprising these interfaces. In this case, if the physical flows on one or more of these lines exceed the corresponding line ratings due to the looped external network (loop flows), these are managed in real time. This is how most of the congestion between Arizona and California is managed today and will continue to be managed under the initial LMP implementation.

In contrast, the PLEXOS model uses a full (meshed) external model respecting both the interface flow limits and the individual tie line limits, thus managing both the interface and tie line flows in the scheduling time frame. As a result, the model may generate congestion rents based on marginal pricing, whereas in practice congestion on these tie lines is managed in real-time using an as-bid paradigm and leading to uplift charges rather than congestion rents. The net result is that the network model with looped external (as in PLEXOS) may overestimate the loss of congestion rental associated with the upgrade (and thus underestimate the benefits of the upgrade) for California compared to what may occur in practice under the scheduling paradigm prevailing at present and in the near future.

Although it is possible to use a network model replicating contract path flows, it is unrealistic to attempt to model the behavior of various participants across WECC under an otherwise “inefficient” scheduling paradigm. Rather than attempting such a questionable modeling effort, we adopted a method to adjust the model results to capture higher short term and medium term benefits that the transmission upgrade would have for the California ratepayers under the current WECC paradigm. To this end we identified three interfaces, namely the East of River (EOR), West of River (WOR) and Palo Verde West (PV West), and 20 major lines that generate the majority of the transmission rents associated with transfers between Arizona and Nevada to California. All of the congestion revenue resulting from these 20 lines that was associated with congestion that would be mitigated in real-time was removed as a cash flow to the ISO. A share of the congestion rental associated with relevant day-ahead interface scheduling limit(s) was directed to the ISO. For today’s system, and for the foreseeable future, the only congestion that could result in a cash flow to the ISO in this group of facilities is the congestion on the East of River (EOR) Scheduling interface. Congestion on the individual lines and on the other two interfaces is in practice managed in real-time and will continue to be managed in real-time under the initial California LMP paradigm. We thus adopted the following adjustments in computing the transmission rental for the California region before and after the upgrade:

1. Divide the 20 lines of interest into 4 categories as follows:
   - CA: Both terminals of the line are in CAISO. Regardless of rental allocation ratio, the optimized scheduling program (PLEXOS) allocates 100% of congestion rents to CAISO.
   - N: Neither of the two line terminals is in CAISO. Regardless of rental allocation ratio, the optimized scheduling program (PLEXOS) allocates 0% of congestion rents to CAISO.
   - R: The "TO" terminal of the line is in CAISO, but the "FROM" terminal is not. PLEXOS allocates the congestion rents to CAISO based on the rental allocation factor R.
   - 1-R: The "FROM" terminal of the line is in CAISO, but the "TO" terminal is not. PLEXOS allocates the congestion rents to CAISO based on (1 - R).
2. Retrieve the congestion rents for each of the 20 lines as produced by PLEXOS. These include congestion rents due to interfaces containing the line as well as the line itself.
3. Using the line category (CA, N, R, or 1-R) for each of the 20 lines, back compute the congestion rents that PLEXOS allocated to CAISO from these 20 lines.
4. Retrieve the CAISO congestion rent from all lines from PLEXOS.
5. Compute the CAISO congestion rents due to lines other than the 20 lines of interest by subtracting (3) from (4)
6. Obtain the congestion rent due to the EOR constraint from PLEXOS (EOR is assumed to be the principal scheduling bottleneck under the current and near future scheduling paradigm between California and the Southwest.)
7. Compute the CAISO share of EOR congestion rents: 55% before PVD2 upgrade; 60% after PVD2 upgrade based on the ISO's share of the scheduling rights.
8. The adjusted CAISO rental is computed by adding (5) and (7).

The above adjustments are carried out both before and after the upgrade. The net impact is generally an increase in transmission upgrade benefits for the CAISO ratepayers, more closely reflecting the upgrade benefits to the ratepayers under the WECC scheduling rules in the foreseeable future.

This approach is believed to more accurately estimate the economic benefits of the PVD2 Project to the CAISO ratepayers than the assumption that LMP pricing will be adopted uniformly across the entire interconnection. However, this approach has the following shortcomings:

1. The adjustment for the difference between physical flow and contract path scheduling is applied only in so far as it impacts California ratepayers. To ensure consistency between overall WECC and the regional benefits, one of the fol-

lowing approaches may be adopted: (a) Keep track of the adjustment in a separate "benefit bucket" without attempting to allocate it to any specific region; (b) Allocate the adjustment to selected regions based on their interconnection with CAISO through the 20 lines of interest. In either case since the underlying network model still assumes physical scheduling in the rest of WECC such allocation may be unrealistic. Thus we have made no attempt to perform overall regional adjustments that would replicate the benefit allocation under the current WECC contract path scheduling practices for regions other than the CAISO.

2. In the ISO's planned MRTU, load would pay prices based on the results of the day-ahead scheduling process. In calculating these prices, the MRTU computer model would use a contract path approach for inter-tie schedules, which could mask much of the congestion that would show up in real-time. This is expected to result in a lower price difference to consumers and generators before and after the addition of the project than the PLEXOS computer model would produce. As a result, the PLEXOS results may be overstating the benefit to consumers and the impact to generators in California compared to what may occur under MRTU, and therefore may overstate the ISO Ratepayer benefits of the PVD2 project. This means that the adjustment performed here somewhat exaggerate the benefits of the upgrade to the CAISO ratepayers.

3. This approach does not capture the costs to the ISO ratepayers of having to clear congestion in real-time through the INC'ing and DEC'ing of generators. This cost can be substantial. The congestion that the ISO has had to mitigate recently at Miguel resulted in a cost to the ISO ratepayers of $50 million in a one-year period. Although this cost is not necessarily eliminated after the upgrade under the contract path paradigm, it is expected to be lower. This cost differential (benefit of the upgrade) is not captured by the model, nor by the adjustment procedure mentioned above; so the model may be underestimating the benefits of the PVD2 Project despite the adjustment.

4. This approach assumes that all schedules on the EOR path would be set in the day-ahead market. In reality, the ISO only controls slightly over half of this capability. As a result, if schedules are not accepted in the ISO's day-ahead process, generators and customers can access the other half of the transmission scheduling rights to deliver the same generation to California. These transactions could be arranged anytime between when the day-ahead market closes and real-time. The end result would be that the ISO would end up clearing the congestion twice, once in day-ahead and once in real-time. While clearing congestion in the day-ahead market would generate revenue for ISO ratepayers (through either the CRR revenues allocated to load, or the reduction of the Transmission Access Charge), clearing congestion in real-time would generate a cost. As a result the approach used to evaluate the PVD2 project may understate the benefit of the PVD2 Project.

Without extensive additional analysis it would be difficult to determine if, or to what extent, this adjustment captures or exaggerates the true benefits of the upgrade for the CAISO ratepayers. The true answer lies somewhere between the CAISO benefits computed with and without this adjustment.

Appendix O. CHANGES FROM ORIGINAL TRANSMISSION EXPANSION ASSESSMENT METHODOLOGY (TEAM)

This current evaluation utilized the standard methodology the CAISO developed and filed at the CPUC under the title TEAM report with the following enhancements: (1) Calculation of transmission congestion revenues referred to as transmission rental (2) Treatment of contract settlement

We provide a description of each enhancement as well as the reason for the change.

1. *Change in transmission rental calculation*

Transmission rentals also known as congestion revenues are associated with transmission constraints, namely path limitation, interface constraints and nomogram limitations. If none of the transmission constraints are binding, the least expensive supply anywhere in the system can be used to serve the load, there is no congestion in the system and as a result there is no associated congestion revenue.

If a transmission constraint is binding, however, it is inevitable to forego some cheaper generation and use some more expensive generation to serve the load, which results in congestion and revenues thereof. There are two ways to compute the transmission rental: using the LMP at each node connecting the transmission line whether or not it is congested (Point to Point or P2P Method), or using the shadow price of the line which is congested (Flow Gate or FG Method). The LMP is the cost of serving one more MW of load at each node (without violating transmission constraints). The shadow price is the congestion price associated with the usage of each constrained transmission line (referred to as the "flowgate shadow price"). This shadow price is the reduction in total system generation cost with 1 MW of increase in the transmission capacity of the congested line.

In a radial network the congestion price ($/MWh) associated with the usage of a line is the same as the difference of the LMPs at the two ends of the line, where as it is different when it is a looped network such as the one used in the study, WECC. Although in a radial network the two methods (P2P and FG) give exactly the same congestion rental on every line, in a looped network these two methods give different congestion rentals on individual lines and even for the congestion rentals associated with individual regions. However, the total congestion rental system-wide is the same regardless of whether the P2P or the FG method is used.

The results presented in TEAM were based on the P2P rental computation. In a looped network, there may exist differences in LMP between any two nodes, even when the line connecting them is not congested. Also, the LMP difference across a congested line can be less that the shadow price on that line. Thus the P2P method tends to assign the congestion cost (rental) to any region, even to the ones where the transmission bottleneck did not exist, and underestimates the rental to the regions with transmission bottleneck. The FG methodology has since been adopted because in a looped network it assigns the congestion cost (rental) only to the regions where the transmission bottlenecks occur.

2. *Treatment of Contract Settlement*

Bilateral contracts between buyers and sellers are considered in TEAM and this analysis. The primary impact of the contracts is to reduce the seller incentives to exercise market power, and is captured in the market power analysis employed in the model. A secondary issue is how to assign the settlement of the contracts as they may impact the benefits of different parties at different locations; either to the seller, buyer or both, at the receiving end or at the generating end. In TEAM, the settlement of bilateral contracts was carried out both ways (delivery at the supply location and delivery at the load location). However, since the contract resources and loads were simplistically modeled on the same side of the transmission upgrade, both methods underestimated the consumer's portion of the benefit.

In this analysis, the contracts are still considered to account for the impact on the exercise of market power. However, it was realized that although the total system-wide societal benefits associated with the transmission upgrade is independent of the assumptions regarding the contract settlement, these assumptions have substantial impacts on the assignment of benefits to different categories of stakeholders in the market and different regions, depending on the load, generation, and the cost associated with the contracts. Since each of the existing contracts has its unique characteristics, and since there is no simple way to estimate the quantity and associated parameters of future bilateral contracts that may become part of the system, it was decided to eliminate the consideration of the contracts in benefit allocation at this time to alleviate the ambiguity that can be associated with the benefits to any particular category of stakeholders. This also portrays the true economic impact on the stakeholders in the system, independent of the bilateral contacts.

Appendix P. Public Process

The public process for the Palo Verde Devers #2 (PVD2) evaluation started during the STEP process. The economic evaluation utilized the Transmission Evaluation Assessment Methodology (TEAM) developed by the CAISO and filed with the CPUC. The goal of TEAM is to: (a) improve the overall accuracy of the evaluation; and, (b) add greater predictability to the assessment of economic transmission need. TEAM is the result of a four-month public stakeholder process that included three public workshops, a public Market Surveillance Committee meeting, and 12 technical subgroup meetings. The TEAM process resulted in a June 2004 report to the CPUC detailing the methodology and providing an example application.

We have used TEAM to evaluate the proposed PVD2 project. We have reviewed the interim results in a number of public forums and have incorporated input from these meetings into our findings. These public forums included:

- October 1, 2004 – presented draft results to a STEP meeting in San Diego

- November 16, 2004 – presented draft results and discussed methodology in a Market Surveillance Committee meeting in Sacramento
- January 11, 2005 – presented draft results to a Western Arizona Transmission System (WATS) group in Las Vegas
- January 14, 2005 – presented draft results and discussed assumptions at a PVD2 stakeholder meeting in Sacramento (48 attendees from 33 different companies or agencies were present – see the Technical Appendix for detailed information).
- January 18, 2005 – presented draft results to a second public Market Surveillance Committee
- January 27, 2005 – briefed California ISO Board of Governors
- Feb 4, 2005 – MSC conducted a public stakeholder conference call to solicit comments on the draft report posted on Feb 2, 2005.
- Feb 9, 2005 - review the PVD2 economic results at STEP meeting in San Diego

During each of these meetings, we presented results from our analysis so that the stakeholders could understand the process and make informed comments to the CAISO Market Surveillance Committee (MSC) and Board.

- Feb 11, 2005 – published responses to the comments received by the MSC on the Feb 4th Conference call.[9]
- Feb 11, 2005 – published responses to set of comments received by ISO on the draft report [10]

Attached below are the attendee lists from the some of the meetings. As can be seen from the attendee list, the participation has varied from the stakeholders in and out of California.

Table P.1 Southwestern Transmission Expansion Planning Group (STEP) Meeting

October 1, 2004
ATTENDEES

Last	First	Representing	Telephone	E-Mail Address
Abed	Abbas	SDG&E	858 654 1677	amabed@semprautilities.com
Ante	Jesse	CPUC	415 703 2820	ja1@cpuc.ca.gov
Bagley	Ken	R. W. Beck	480 367 4282	kbagley@rwbeck.com
Bailey	Shawn	Sempra Energy Resources	619 696 2962	sbailey@sempra-res.com
Barajas	David	Imperial Irrigation District	760 339 9093	dlbarajas@iid.com
Bhaumik	Ashish	CAISO	636 537 2791	abhaumik@caiso.com
Brown	Linda	SDG&E	858 654 6477	lpbrown@semprautilities.com
Bryce	Donald	Reclamation	702 293 8102	dbryce@lc.usbr.gov
Charters	Jim	Ordinary Citizen	623 572 7972	j_charters@msn.com
Chopra	Rajiv	Areva T&D	484 766 8174	rajiv.chopra@areva-td.com

9 Available at http://www1.caiso.com/docs/2005/01/19/2005011914572217739.html
10 Available at http://www1.caiso.com/docs/2005/01/19/2005011914572217739.html

October 1, 2004
ATTENDEES

Last	First	Representing	Telephone	E-Mail Address
Cole	Perry	Trans-Elect, Inc.	406 782 1907 or 703 563 4300	pcole@trans-elect.com cole@in-tch.com
Congalton	Bruce	Mitsubishi Electric Power Products, Inc.	686 442 2340	bruce.congalton@meppi.mea.com
Connelly (1)	Ron	US Bureau of Reclamation	702 293 8111	rconnelly@lc.usbr.gov
Delgado	Robert	City of Riverside	909 351 6312	rdelgado@pac.state.ca.us
Downey	Carrie	IID	619 435 5690	cadowney@san.rr.com
Erickson	Dan	Black & Veatch	303 671 4305	ericksond@bv.com
Etherton	Mark	KR Saline & Assoc for Imperial Irrigation Dist	480 610 8741	mle@krsaline.com
Evans	Mike	Coral Power LLC	858 526 2103	mevans02@coral-energy.com
Geevarghese	Anna	CAISO	916 608 7072	ageevarghese@caiso.com
Ghadiri	Steve	EOB	916 322 8690	sghadiri@eob.ca.gov
Green	Irina	CAISO	916 608 1296	igreen@caiso.com
Hsu	James	Salt River Project	602 236 0969	jchsu@srpnet.com
Jackson	Robert	SDG&E	858 654 8293	rwjackson@semprautilities.com
John	Eric	ABB		eric.john@us.abb.com
Joyce	John	Siemens	503 296 6840	jcjoyce2@comcast.net
Keel	Brian	SRP	602 236 0970	bkkeel@srpnet.com
Kondzoilka	Robert	SRP	602 236 0971	rekondzi@srpnet.com
Kritikson	James	Kritikson & Associates	909 480 1028	jkritikson@yahoo.com
L'Esperance	Lynne	Malcolm Pirnie, Inc.	602 797 4624	llesperance@pirnie.com
Linssen	Bob	Arizona Power Authority		bob@powerauthority.org
Mackin	Peter	Navigant Consulting	916 631 3212	pmackin@navigantconsulting.com
Mavis	Steve	SCE	626 302 8175	steven.mavis@sce.com
McCluskey	Jim	CEC	916 654 3911	jmcclusk@energy.state.ca.us
Mendoza	Steve	Western Wind Energy		steve@verderesources.com
Miller	Jeff	CAISO	916 351 4464	jmiller@caiso.com
Moulton	Ron	Western - DSW	602 352 2668	moulton@wapa.gov
Murphy	Tom	Aspen Environmental Group	818 597 3407	tmurphy@aspeneg.com
Olsen	Dave	Center for Energy Efficiency and Renewable Technologies (CEERT)	805 653 6881	olsen@avenuecable.com
Padilla	Leslie	Sempra Energy Resources	619 696 4425	lpadilla@sempra-res.com
Patel	Kishore	SDG&E	858 654 8231	kpatel@semprautilities.com
Patterson	Gregg	AZCPA		greg@azcpa.org
Percival	Milt	Western Area Power Administration	602 352 2794	percival@wapa.gov
Perez	Armie	CAISO	916 351 4444	aperez@caiso.com
Proctor	Doug	DSWP	916 967 8861	douglas@proctor.net
Santamaria Jaimes	Jose Refugio	CFE	011 52 6865 58 1541	jose.santamaria@cfe.gob.mx
Smith	Robert	APS	602 250 1144	robert.smith@aps.com
Stanton	Rose	ABB	760 720 3141	rose.stanton@us.abb.com
Thompson	Justin	Pinnacle West Energy	602 250 2060	justin.thompson@pwenergy.com

October 1, 2004
ATTENDEES

Last	First	Representing	Telephone	E-Mail Address
Todus	Harold	SDG&E	858 654 1673	htodus@semprautilities.com
Tran	Chau	SDG&E	858 654 1746	cbtran@semprautilities.com
Uhler	Leeanne	Riverside	951 351 6356	luhler@riverside.ca.gov
Wait	Rexford	LEAPS Project	760 599 0086	rwait@controltechnology.org
Wang	David	SDG&E	858 654 1622	dwang@semprautilities.com
Weinstein	Lauren	EPG, Inc.	602 956 4370	lweinst@epgaz.com
Winn	Carolyn	SDG&E	858 654 1648	cwinn@semprautilities.com
Woldemariam	Jonathan	SDG&E	858 650 4084	jwolde-mariam@semprautilities.com
Wood	Tim	American Superconductor	602 448 8005	twood@amsuper.com
Wu	Tim	LADWP	213 367 0650	chuan-hsier.wu@ladwp.com

Table P.2 Market Surveillance Committee Meeting

	Tuesday, November 16, 2004 12:00 p.m. – 5:00 p.m. California ISO North and South Lake Tahoe Conference Rooms ATTENDEES			
X=Present P=Phoned	NAME	COMPANY	PHONE NUMBER	EMAIL ADDRESS
P	Alvarez, Oscar	LADWP	216 367 0677	oscar.alvarez@ladwp.com
X	Barber, Brad	MSC Member	530 752-0512	bmbarber@ucdavis.edu
X	Bergman, Doug	CAISO	916 608 7276	dbergman@caiso.com
P	Berry, Robert	Robert Berry		
P	Burnett, John	LADWP	213 367 1747	john.burnett@ladwp.com
X	Bushnell, Jim	MSC Member	510 642-7316	bushnell@haas.berkeley.edu
X	Casey, Keith	CAISO	916 608 7125	kcasey@caiso.com
P	Cazalet, Edward	CAISO	916 351 2366	
P	Chatterjee, Bishu	CPUC		
P	Clemenhagen, Barbara	Sempra Energy		
X	Cook, Greg	CAISO	916 608 7202	gcook@caiso.com
P	Cordner, Christine	Platts		
P	Delgado, Robert	Riverside		
P	Evans, Mike	Coral Power	858 526 2103	mevans02@coral-energy.com
X	Faust, Charles	FERC	916 294 0163	charles.faust@ferc.gov
X	Filippi, Jim	PG&E	415 973 6530	jlfa@pge.com
P	Flynn, Barry	FLYNN RCI		brflynn@flynnrci.com
X	Franklin, Brett	EOB	916 322 8587	bfranklin@eob.ca.gov
X	Geevarghese, Anna	CAISO	916 608 7072	ageevarghese@caiso.com
P	Ghadiri, Steve	EOB	916 322 8690	sghadiri@eob.ca.gov
P	Greenleaf, Steve	CAISO	916 608 7136	sgreenleaf@caiso.com
X	Hahn, Ernest	MWD	213 217 7185	ehahn@mwdh2o.com
X	Haines, Tim	CAISO	916 608-1285	thaines@caiso.com
X	Harvey, James	The Structure Group	720 635 1100	james.harvey@scgo.com
P	Hathaway, Katherine	APS Energy Services		
X	Hobbs, Ben	MSC Member	410 516 4681	bhobbs@jhu.edu
P	Hester, Mark	CEC		
X	Jubien, Sidney	CAISO	916 608 7144	sjubien@caiso.com
X	Kristov, Lorenzo	CAISO	916 608 7129	lkristov@caiso.com
X	Lam, Tony	EOB	916 322 8632	tlam@eob.ca.gov
X	Martin, Glenn	Mirant	925 287 3106	glenn.martin@mirant.com
X	McDonald, Jeff	CAISO	916 608 7236	jmcdonald@caiso.com
X	McLean, Chris	CAISO	916 608 7025	cmclean@caiso.com

	Tuesday, November 16, 2004 12:00 p.m. – 5:00 p.m. California ISO North and South Lake Tahoe Conference Rooms ATTENDEES			
X=Present P=Phoned	NAME	COMPANY	PHONE NUMBER	EMAIL ADDRESS
P	Moosen, Irene	City of San Francisco		
X	Nelson, Jeffrey	SCE	626 302 4834	jeff.nelson@sce.com
X	O'Connor, John	EOB	916 445 5905	joconnor@eob.ca.gov
P	Purewal, Balwant	CDWR		
X	Robinson, Charles	CAISO	916 351 2334	crobinson@caiso.com
P	Rochlin, Cliff	SoCal Gas Company	213 244 2451	crochlin@semprautilities.com
X	Sandhu, Paul	PG&E	415 473 3114	
P	Sandino, David	CAISO		
X	Schneider, Susan	Phoenix Consulting	916 797 3106	schneider@phoenix-co.com
X	Sheffrin, Anjali	CAISO	916 608 7122	asheffrin@caiso.com
X	Toolson, Eric	CAISO	916 608 7156	etoolson@caiso.com
P	Whieldon, Esther	Platts		
X	Wolak, Frank	MSC Chair	650 723 3944	wolak@zia.stanford.edu
P	Wright, Kathleen	CDWR		
X	Wynne, Michele	Grid Services	310 643 4416	mwynne@gridservices.com

Table P.3 WATS Meeting

Monday, January 11, 2005 Las Vegas, NV ATTENDEES			
NAME	**COMPANY**	**PHONE NUMBER**	**EMAIL ADDRESS**
Bagley, Ken	CAP	480 367 4282	kbagley@rwbeck.com
Black, Lorin	EPE	915 543 4060	lblack1@epelectric.com
Bryce, Donald	Bureau of Reclamation	702 293 8102	dbryce@lc.usbr.gov
Etherton, Mark	IID	480 610 8741	mle@krsaline.com
Falls, Chuck	SRP	602 236 0965	czfalls@srpnet.com
Finley, Ann	MWD	213 217 7136	afinley@mwdh2o.com
Galleberg, Johan	CAISO	916 351 2313	jgalleberg@caiso.com
James Hsu	SRP	602 236 0969	jchsu@srpnet.com
Keel, Brian	SRP	602 236 0970	bkkeel@srpnet.com
Krzykos, Peter	APS	602 250 1649	peter.krzykos@aps.com
Mackin, Peter	TANC	916 631 3212	pmackin@navigantconsulting.com
Mavis, Steven	SCE	626 302 8175	steven.mavis@sce.com
Miller, Jeff	CAISO	916 351 4464	jmiller@caiso.com
Patel, Kishore	SDG&E	858 654 8231	kpatel@semprautilities.com
Percival, Milt	Western - DSW	602 352 2794	percival@wapa.gov
Sheffrin, Anjali	CAISO	916 608 7122	asheffrin@caiso.com
Smith, Richard	MID	209 526 7463	richards@mid.org
Wu, Tim	LADWP	213 367 0650	chuan-hsier.wu@ladwp.com

Table P.4 Palo Verde-Devers #2 Economic Studies Stakeholder Meeting

Friday, January 14, 2005 9:00 a.m. – 12:00 p.m.
California ISO North and South Lake Tahoe Conference Rooms
ATTENDEES

X=Present P=Phoned	NAME	COMPANY	PHONE NUMBER	EMAIL ADDRESS
P	Alvarez, Oscar	LADWP	216 367 0677	oscar.alvarez@ladwp.com
P	Bailey, Shawn	Sempra Energy		sbailey@sempragenereration.com
X	Blanchard, Billie	CPUC		bcb@cpuc.ca.gov
X	Brown, Gary	CAISO	916 608 5715	glbrown@caiso.com
P	Burnett, John	LADWP	213 367 1747	john.burnett@ladwp.com
X	Cole, Perry	Trans-Elect	406 782 1907	pcole@trans-elect.com
X	Cronin, Holly	CDWR	916 574 0708	hcronin@water.ca.gov
P	Denton, Maria	SRP		mxdenton@srpnet.com
P	Evans, Mike	Coral Power	858 526 2103	mevans02@coral-energy.com
X	Faust, Charles	FERC	916 294 0163	charles.faust@ferc.gov
X	Filippi, Jim	PG&E	415 973 6530	jlfa@pge.com
P	Flynn, Barry	Flynn RCI		brflynn@flynnrci.com
P	Flynn, Tom	CPUC	916 324 8689	trf@cpuc.ca.gov
X	Galleberg, Johan	CAISO	916 351 2313	jgalleberg@caiso.com
X	Geevarghese, Anna	CAISO	916 608 7072	ageevarghese@caiso.com
X	Ghadiri, Steve	EOB	916 322 8690	sghadiri@eob.ca.gov
P	Gokbudak, Brent	SCE	626 302 8694	brent.gokbudak@sce.com
X	Griffin, Karen	CEC	916 654 4833	kgriffin@energy.state.ca.us
X	Hesters, Mark	CEC		mhesters@energy.state.ca.us
X	Holmes, Darell	SCE	626 302 6498	holmesdf@sce.com
X	Hsu, Jim	SRP	602 236 0969	jchsu@srpnet.com
P	Jackson, Robert	SDG&E		rwjackson@semprautilities.com
X	Jafari, Jamal	SCE	626 302 9602	jamal.jafari@sce.com
P	Kaplan, Katie	IEP	916 448 9499	kaplan@iepa.com
X	Keel, Brian	SRP	602 236 0970	bkkeel@srpnet.com
X	Kritikson, Jim	Kritikson & Associates	909 480 1028	jkritikson@adelphia.net
X	Krzykos, Peter	APS	602 250 1649	peter.krzykos@aps.com
P	Kwong, Sam	Williams	949 481 7329	samuel.kwong@williams.com
X	Kyei, John	CAISO	916 608 5721	jkyei@caiso.com
P	Lauckhart, Rich	Henwood	916 569 0985	rlauckhart@henwood.com
P	Le, David	CAISO	916 608 7302	dle@caiso.com
X	Lee, Susan	Aspen Environmental	415 955 4775 x203	slee@aspeneg.com

Friday, January 14, 2005 9:00 a.m. – 12:00 p.m.
California ISO North and South Lake Tahoe Conference Rooms
ATTENDEES

X=Present P=Phoned	NAME	COMPANY	PHONE NUMBER	EMAIL ADDRESS
		Group		
X	Martin, Glenn	Mirant	925 287 3106	glenn.martin@mirant.com
X	Mavis, Steven	SCE	626 302 8175	steven.mavis@sce.com
X	McCluskey, Jim	CEC	916 654 3911	jmcclusk@energy.state.ca.us
X	Miller, Jeff	CAISO	916 351 4464	jmiller@caiso.com
P	Mooney, Bob	Desert SW Transmission		bob@pmaloc.net
P	Muller, Phillip	SCD Energy	415 479 1710	philm@scdenergy.com
P	O'Neil, Murray	PPM Energy	503 796 7174	murray.oneil@ppmenergy.com
P	Padilla, Leslie	Sempra Generation	619 696 4425	lpadilla@sempragenerationn.com
X	Percival, Milt	Western - DSW	602 352 2794	perciaval@wapa.gov
X	Perez, Armando	CAISO	916 351 4444	aperez@caiso.com
X	Rahimi, Farrokh	CAISO	916 608 7128	frahimi@caiso.com
P	Rochlin, Cliff	SoCal Gas Company	213 244 2451	crochlin@semprautilities.com
X	Scheuerman, Paul	Scheuerman Consulting	916 630 7073	pgs@ieee.org
X	Schneider, Susan	Phoenix Consulting	916 797 3106	schneider@phoenix-co.com
P	Sheffrin, Anjali	CAISO	916 608 7122	asheffrin@caiso.com
P	Simpson, John	Reliant Energy		jlsimpson@reliant.com
P	Smith, Mark	FPL	925 831 0545	mark_j_smith@fpl.com
X	Terry, Lee	CDWR	916 574 0664	lterry@water.ca.gov
X	Toolson, Eric	CAISO	916 608 7156	etoolson@caiso.com
X	Vidaver, David	CEC		dvidaver@energy.state.ca.us
P	Wagle, Pushkar	Flynn RCI		pushkarwagle@flynnrci.com
P	Williams, Wes	SCE	626 302 9615	weston.williams@sce.com
X	Witham, Ted	AREVA T&D, Inc.	916 201 3071	Ted.witham@areva-td.com
X	Woodruff, Kevin	Woodruff Expert Services	916 442 4877	kdw@woodruff-expert-services.com
X	Wu, Tim	LADWP	213 367 0650	chuan-hsier.wu@ladwp.com

Table P.5 Market Surveillance Committee Meeting

Tuesday, January 18, 2005 12:00 p.m. – 5:00 p.m.
California ISO North and South Lake Tahoe Conference Rooms
ATTENDEES

X=Present P=Phoned in	NAME	COMPANY	PHONE NUMBER	EMAIL ADDRESS
X	Barber, Brad	MSC Member	530 752 0512	bmbarber@ucdavis.edu
P	Barnett, John	LADWP	213 367 1744	
X	Bushnell, Jim	MSC Member	510 642 7316	bushnell@haas.berkeley.edu
P	Carpenter, Todd	PACIFIC CORP	503 813 5769	
X	Cheng, Margaret	EPG/CDWR	626 284 1586	cheng@electricpowergroup.com
X	Comnes, Alan	DYNEGY	503 239 6913	alan.comnes@dynegy.com
X	Cook, Greg	CAISO	916 608 7202	gcook@caiso.com
P	Evans, Mike	CORAL POWER	858 526 2103	
X	Faust, Charles	FERC	916 294 0163	charles.faust@ferc.gov
P	Franklin, Brett	EOB	916 322 8587	
X	Geevarghese, Anna	CAISO	916 608 7072	ageevarghese@caiso.com
P	Ghadiri, Steve	EOB	916 322 8690	
P	Gokbudok, Brent	SOUTHERN CA EDISON	626 302 8694	
P	Goldbeck, Glenn	PG&E	415 973 3235	
P	Griffin, Karen	CA ENERGY COMMISSION	916 654 4833	
X	Haines, Tim	CAISO	916 608 1285	thaines@caiso.com
P	Hathaway, Cath-erine	APS ENERGY SERVICES	623 975 6370	
P	Haubenstock, Auther	PG&E	415 973 4868	
X	Hildebrandt, Eric	CAISO	916 608 7123	ehildebrandt@caiso.com
X	Hobbs, Ben	MSC Member		
P	Holmes, Darrell	SOUTHERN CA EDISON	626 302 6498	
X	Jubien, Sidney	CAISO	916 608 7144	sjubien@caiso.com
P	Kehrein, Carolyn	EMS	706 678 9506	
P	Kristov, Lorenzo	CAISO		
X	Lam, Tony	EOB	916 322 8632	tlam@eob.ca.gov
P	Lindh, Karen	LINDH & ASSO-CIATIES	916 729 1562	
P	Mahmud, Diana	METROPOLITAN WATER DISTRICT	213 217 6985	

X=Present P=Phoned in	NAME	COMPANY	PHONE NUMBER	EMAIL ADDRESS
	Tuesday, January 18, 2005 12:00 p.m. – 5:00 p.m. California ISO North and South Lake Tahoe Conference Rooms ATTENDEES			
P	McDonald, Jeff	CAISO		
P	McNamara, Grace	SEMPRA ENERGY TRADING	203 355 5122	
X	Miller, Jeff	CAISO	916 351 4464	jmiller@caiso.com
X	O'Connor, John	EOB	916 445 5905	joconnor@eob.ca.gov
X	Rahimi, Farrokh	CAISO		
P	Rochlin, Cliff	SoCal Gas Company	310 836 9814	
X	Schneider, Susan	PHOENIIX CON-SULTING	916 797 3106	schneider@phoenix.com
P	Shea, Karen	PUC	415 703 5404	
X	Sheffrin, Anjali	CAISO	916 608 7122	asheffrin@caiso.com
P	Smith, David	PPL	610 774 2305	
P	Tang, Bob	CITY OF AUZUSA	626 812 5214	
P	Tirmazi, Ma-zooma	SOUTHERN CA EDISON	626 302 1769	
P	Torres, Richard	CITY OF AUZUSA	626 812 5214	
P	Warner, Michael	CDWR	916 574 0617	
P	Wieser, Eric	PLATTS	202 383 2092	
P	Withrow, David	CAISO		
X	Wolak, Frank	MSC Chair	650 723 3944	wolak@zia.stanford.edu
P	Wright, Kathleen	CDWR	916 574 0346	
X	Yan, Joseph	SOUTHERN CA EDISON	626 302 4804	joseph.yan@sce.com

Table P.6 Southwestern Transmission Expansion Planning Group (STEP)

	Last	First	Representing	Telephone	E-Mail Address
Attendees					
As of February 9, 2005					
	Last	**First**	**Representing**	**Telephone**	**E-Mail Address**
X	Adame	Raul	CFE	011 52 55 52 29 4732	raul.adame@cfe.gob.mx
X	Adler	Tom	City of Chula Vista	619 409 5483	tadler@ci.chula-vista.ca.us
X	Avila	Miguel	CFE	011 52 55 229 47 32	miguel.avila@cfe.gob.mx
X	Bagley	Ken	R. W. Beck	480 367 4282	kbagley@rwbeck.com
X	Baughman	Kenneth	Wellton-Mohawk Irrigation & Drainage District	928 785 3351	kbaughman@wellton-mohawk.org
X	Brown	Linda	SDG&E	858 654 6477	lpbrown@semprautilities.com
X	Bryce	Donald	Reclamation	702 293 8102	dbryce@lc.usbr.gov
X	Charters	Jim	Ordinary Citizen	623 572 7972	j_charters@msn.com
X	Chowdry	Azar	ABB	760 720 6197	azar.chowdry@us.abb.com
X	Delgado	Robert	City of Riverside	909 351 6312	rdelgado@pac.state.ca.us
X	Denton	Maria	SRP		mxdenton@srpnet.com
X	Downey	Carrie	IID	619 435 5690	cadowney@san.rr.com
X	Erickson	Dan	Black & Veatch	303 671 4305	ericksond@bv.com
X	Etherton	Mark	KR Saline & Assoc for Imperial Irrigation Dist	480 610 8741	mle@krsaline.com
X	Evans	Mike	Coral Power LLC	858 526 2103	mevans02@coral-energy.com
X	Filippi	Jim	PG&E	415 973 6530	jlfa@pge.com
X	Firooz	Sharon	SDG&E	858 650 6158	sfirooz@semprautilities.com
X	Flynn	Tom	CPUC	916 324 8689	trf@cpuc.ca.gov
X	Gonzalez	Alberto	CFE-Mexico	011 52 68-65-58-15-17	alberto.gonzalez@cfe.gob.mx
X	Hochheimer	Jack	FPL Energy	561 694 4908	jack_g_hochheimer@fpl.com
X	Hsu	James	Salt River Project	602 236 0969	jchsu@srpnet.com
X	Jackson	Robert	SDG&E	858 654 8293	rwjackson@semprautilities.com
X	John	Eric	ABB		eric.john@us.abb.com
X	Keel	Brian	SRP	602 236 0970	bkkeel@srpnet.com
X	Kirby	Neil	Areva T&D	484 766 8163	neil.kirby@areva-td.com
X	Kondzoilka	Robert	SRP	602 236 0971	rekondzi@srpnet.com
X	Krzykos	Peter	APS	602 250 1649	peter.krzykos@aps.com
X	Kwong	Sam	Williams	949 481 7329	samuel.kwong@williams.com
X	Lee	Susan	Aspen Environmental Group	415 955 4775 x203	slee@aspeneg.com
X	Linssen	Bob	Arizona Power Authority		bob@powerauthority.org
X	Mackin	Peter	Navigant Consulting	916 631 3212	pmackin@navigantconsulting.com
X	Mavis	Steve	SCE	626 302 8175	steven.mavis@sce.com

Attendees					
As of February 9, 2005					
	Last	**First**	**Representing**	**Telephone**	**E-Mail Address**
X	McCluskey	Jim	CEC	916 654 3911	jmcclusk@energy.state.ca.us
X	Miller	Jeff	CAISO	916 351 4464	jmiller@caiso.com
X	Mooney	Bob	Desert SW Transmission Project	208 890 0369	bob@pmallc.net
X	Nilsson	Bo	ABB		bo.a.nilsson@se.abb.com
X	Olsen	Dave	Center for Energy Efficiency and Renewable Technologies (CEERT)	805 653 6881	olsen@avenuecable.com
X	Patel	Kishore	SDG&E	858 654 8231	kpatel@semprautilities.com
X	Patterson	Gregg	AZCPA		greg@azcpa.org
X	Percival	Milt	Western Area Power Administration	602 352 2794	percival@wapa.gov
X	Perez	Armie	CAISO	916 351 4444	aperez@caiso.com
X	Stanton	Rose	ABB	760 720 3141	rose.stanton@us.abb.com
X	Strack	Jan	SDG&E	858 650 6179	jstrack@semprautilities.com
X	Weinstein	Lauren	EPG, Inc.	602 956 4370	lweinst@epgaz.com
X	Winn	Carolyn	SDG&E	858 654 1648	cwinn@semprautilities.com
X	Wood	Tim	American Superconductor	602 448 8005	twood@amsuper.com
X	Wu	Tim	LADWP	213 367 0650	chuan-hsier.wu@ladwp.com

Appendix Q. Estimation of Capacity Value

Summary – The current economic evaluation of the DPV2 upgrade is based on energy savings only. Since the DPV2 upgrade would provide an additional 1,200 MW of firm import capability into the CAISO, this increased capacity would provide a benefit that should be considered in the economic feasibility study.

Benefit Overview -- The $620 million cost of the DPV2 upgrade is included in the economic analysis. If the future price of capacity is forecast to be less in Arizona than in California, then those savings should be considered.

We believe that the future cost of capacity in Arizona will be less than the cost in California for the following two reasons:

We understand that the capital and fixed operating costs for a peaking unit are significantly less in Arizona. We expect that situation to continue indefinitely. The reduced capital and operating costs in Arizona would also translate into a lower capacity price.

We also project a greater resource surplus in Arizona than in California for the early years of the project. Thus, the demand for capacity, and the resulting price, would be expected to be less in Arizona.

Benefit Estimation – In Table Q.1 below, we develop an estimation of the capital and fixed O&M costs for a simple-cycle combustion turbine.

Table Q.1 Estimation of Combustion Turbine Costs in CA and AZ

Category	Component	CA	AZ	Notes
Plant Characteristics	net capacity (mw)	100	100	
	economic life (years)	30	30	
Capital Costs	component cost (mil. $)	$32	$32	turbine / generator, assume same for CA and AZ
	land costs (mil. $)	$5	$3	assume $100k / acre in CA and $50k / acre in AZ, both sites require 50 acres
	air emission permits (mil. $)	$0	$0	offset costs in CA and AZ est. to be less than $0.1 mil. For peaking facility
	air emission technology, SCR (mil. $)	$5	$0	assume emission technology is half (SCR may not be required in AZ)
	water control technology (mil. $)	$5	$3	assume AZ costs are 50% of CA
	total capital -- instant costs (mil. $)	$47	$37	
	total capital -- installed costs (mil. $)	$52	$41	assume 10 % inc. in costs due to interest during construction (IDC)
	total annual capital costs	$52	$41	assume 10 % real economic carrying charge
Total Fixed Costs	fixed O&M costs	$10	$7	assume AZ labor costs are 1/3 less than CA
	total fixed costs	$62	$47	CA costs are about 30 % higher

Notes:

1. All costs in Table Q.1 are in 2004 dollars.

2. CA costs are from the CEC's "Comparitive Cost of California Central Station Electricity Generation Technology", Appendix D, "Combustion Turbine, June 5, 2003.

3. AZ costs are based on CA's costs, with reductions applied as appropriate and explained in the "Notes" column.

If we assume that the lower fixed costs for a CT in Arizona would be directly reflected in lower capacity costs, the differential would be $14/kw-year in 2004 $, or $15/kw-year in 2008 (results differ slightly from above table due to rounding). If we further assume that firm summer capacity is available for the entire 1,200 MW upgrade, the capacity benefit would be estimated at $18 million per year in 2008 $. The $18 million per year represents the maximum savings benefit when the capacity price is capped at the cost of new peaking units. In order to provide a more conservative estimate, we have decreased this amount by one-third to $12 million. In addition, we assume that this benefit will be split equally between the buyers and sellers of capacity. <u>Thus the societal benefit is $12 million, and the CAISO benefit is estimated to be half that amount of $6 million.</u>

We have projected the planning reserve margins for the California / Mexico, and the Southwest, sub-regions for WECC. These results are summarized in Table P.2 below:

Table Q.2 Projected Planning Reserve Margin for Selected WECC Sub-Regions

	Year	
WECC Sub-region	2008	2013
CA / MX	16%	16%
SW	27%	27%

We have not tried to quantify the additional reduction in Arizona capacity costs due to the surplus expectation that we have assumed for the first 5 years or so of the project economic life. We do not have sufficient data comparing capacity market prices and planning reserve margins to make such an estimate. We do expect that reserve margins influence capacity prices. From this perspective, the capacity benefits estimated on the previous page may be conservative.

Appendix R. Estimation of Value of Emission Reduction

***Summary* –** The current DPV2 analysis does not model emissions since that data were not part of the initial database received from SSG-WI. The DPV2 upgrade is expected to allow more efficient gas-fired generation in Arizona to dispatch less-efficient or less-economic generation in California. The increase in generating efficiency has direct environmental benefits such as the reduction of airborne emissions and fuel burn. This analysis attempts to quantify the emission benefits for NOx. Other emissions are not quantified at this time since the emission rate data are not available.

***Benefit Overview* –** From the PLEXOS simulations, we are able to: (1) compute the generation produced annually for about 700 stations; and, (2) compare the generation for the "without" and "with" upgrade cases. In the 2008 cost-based, expected condition case (2008 BBBN), approximately 6,100 gWh/yr of generation was produced from more economic plants due to the upgrade.

In this 2008 case, approximately 200 generation stations increased their generation, and about 250 plants decreased their generation. Instead of trying to analyze the impact of the upgrade on the emissions of 450 plants, we decided to identify those plants accounting for 80 percent of the incremental and decremental generation, and extrapolate for the other 20 percent.

Roughly 80 percent of the incremental generation is produced by only 11 plants. Nine of these 11 stations are relatively new, combined-cycle units in the Palo Verde area, such as Mesquite, Redhawk, and Harquahla.

On the other side, the decremental generation is spread over more plants. Approximately 80 percent of the decremental generation is reduced from 39 plants. These stations decreasing generation were primarily in California and included:

Less-efficient, older generating plants, such as Ormond Beach, Haynes, and South Bay

Newer, high-efficient generating plants such as Mountainview, HighDesert, and Palomar.

The percentage of generation displaced at many of the older units ranges from 10 to 30 percent. The percentage of generation displaced at many of the newer units ranges from 3 to 7 percent. The relative economics of gas-fired generation in Arizona compared to California is dependent on two factors:

Gas price differential between Arizona and California – currently estimated to be 37 cents per mmbtu cheaper in AZ in 2008.

Thermal plant efficiency – New plants have heat rates in the 7,000 to 7,300 btu/kwh range, older plant have heat rates generally in the 9,000 to 15,000 btu/kwh range.

The greatest savings are achieved when newer generation in Arizona is able to displace older, inefficient generation in California. Less significant savings occurs when Arizona efficient generation is able to displace California efficient generation since the gas prices are lower in Arizona. These relative savings are reflected in the percent of power displaced. Since it is more economic to displace the older CA generation, the amount of power displaced can be as high as 30 percent (Huntington 3). Since it is less economic to displace newer CA generation, the displacement rate is 7 percent or lower.

Benefit Estimation -- In Attachment 1, we develop an estimate of the fuel savings and NOx emission reductions as result of the upgrade. For purposes of this estimate, the value of NOx offsets in CA was assumed to be $40,000[11]. The value of NOx offsets in the Palo Verde region of AZ was assumed to be half that of CA.[12] The one-time cost of NOx was then inflated from 2003 to 2008, and amortized over the approximately 50-year economic life of the transmission line.

The reduction in NOX emissions and costs, as well as natural gas savings are summarized in Table R.1 below.

11 The $40,000 value is derived from California Air Resources Board (CARB); "Emission Reduction Offsets Transaction Cost Summary Report for 2003"; prepared in March, 2004; Table 1 "2003 Prices Paid in Dollars Per Ton for Offsets", page 1. NOx values ranged from a low of $6,000 to a high of $140,000 per ton in the San Diego area. We used a state-wide average of $39,842 rounded to the nearest thousand.

12 We were unable to research the value of offsets in Palo Verde region of Arizona. We do know that offsets are required for plants in AZ and that the newer plants use best available control technology. Since Palo Verde is 50 miles west of Phoenix and according to one source not considered part of the Phoenix air non-attainment area, a two-thirds reduction in CA offset costs was assumed.

Table R.1 Summary of Emission and Fuel Benefits Resulting from the PVD2 Upgrade

Parameter	Units	Impact From Incremental Generation	Impact From Decremental Generation	Benefit From Upgrade
NOx	tons / yr	200	-590	390
	mil. $ / yr	$0.4	-$2.6	$2.2
Natural Gas	tbtu / yr	45	-51	6

From this analysis, we estimate that 2,600 tons of NOx emissions are eliminated in the WECC each year as a result of the PVD2 upgrade. California emissions went down 590 tons, and Arizona emissions went up 200 tons.

We estimate that the NOx emission costs as a result of the upgrade decrease $2.2 million. Given the uncertainty in the offset costs, actual emission rates, and the rate of retrofitting the older thermal generation in California we would consider half of the $2.2 million to be a more reasonable estimate. Thus, we <u>estimate the societal benefit at $1 million per year, and the CAISO share to be half that amount, or $0.5 million.</u>

We also estimate that access to more efficient thermal generation in Arizona would provide a more efficient fuel burn throughout WECC resulting in a net savings of approximately 6 million mmbtu, or enough energy to create about 600 gWh of energy in conventional thermal generation stations.

Table R.2 Forecast of Emission and Fuel Benefits By Plant

	Plexos Plant Name	Change in Gen. (gWh/yr)	Plexos Ave. Heat Rate (btu/kwh)	Change in Fuel Use (mmbtu/yr)	NOx Emission Rate (ppm)	NOx Emission Rate (lbs/ mmbtu)	NOx Emissions (tons)	NOx Cost ($/ton-year)	Change in NOx Cost (mil. $)	NOx Cost ($/MWh)
	Incremental Generation:									
	MesquiteCC	743	7,100	5,277,154	2.5	0.009	24	$2,208	0.052	$0.07
1	Redhawk CC 1	712	7,100	5,057,562	2.5	0.009	23	$2,208	0.050	$0.07
2	Harquahl	710	7,250	5,151,008	2.5	0.009	23	$2,208	0.051	$0.07
3	Redhawk1	699	7,250	5,066,656	2.5	0.009	23	$2,208	0.050	$0.07
4	Mesquit1	654	7,250	4,738,610	2.5	0.009	21	$2,208	0.047	$0.07
5	ArlngtnV	613	7,250	4,445,569	2.5	0.009	20	$2,208	0.044	$0.07
6	Blythe CC 1	285	7,100	2,026,082	2.5	0.009	9	$2,208	0.020	$0.07
7	Santan CC 1	275	7,100	1,955,517	2.5	0.009	9	$2,208	0.019	$0.07
8	WPhnx4	162	7,250	1,172,904	2.5	0.009	5	$2,208	0.012	$0.07
9	Saguaro CC 1	129	7,100	914,709	2.5	0.009	4	$2,208	0.009	$0.07
10	FrntRng(	83	7,250	604,293	2.5	0.009	3	$2,208	0.006	$0.07
	Subtotal -- 82%	5,066		36,410,063			162		0.359	
	Total -- 100%	6,194		44,510,603			199		0.438	
	Percent of Total	82%								
	Decremental Generation:									
1	ElSgndC1	-32	7,250	-231,329	2.5	0.009	-1	$4,416	-0.005	$0.14
2	Beaver 1	-32	9,300	-300,519	10.0	0.036	-5	$4,416	-0.024	$0.73
3	PdtJrz-5	-43	9,500	-405,399	10.0	0.036	-7	$4,416	-0.032	$0.75
4	LRst(CCP	-43	7,000	-299,401	2.5	0.009	-1	$4,416	-0.006	$0.14
5	JmBrdgr1	-43	10,500	-449,989	10.0	0.036	-8	$4,416	-0.035	$0.83
6	ASRdndB7	-45	9,500	-426,233	10.0	0.036	-8	$4,416	-0.034	$0.75
7	H Allen CC 1	-47	7,100	-336,974	2.5	0.009	-2	$4,416	-0.007	$0.14
8	Pastoria	-56	7,250	-404,272	2.5	0.009	-2	$4,416	-0.008	$0.14
9	KrnRvrC1	-58	7,250	-416,953	2.5	0.009	-2	$4,416	-0.008	$0.14
10	SouthPnt	-60	7,250	-436,796	2.5	0.009	-2	$4,416	-0.009	$0.14
11	ElSgndP3	-62	9,500	-586,689	10.0	0.036	-10	$4,416	-0.046	$0.75
12	ClovrBr1	-66	9,500	-625,847	10.0	0.036	-11	$4,416	-0.049	$0.75
13	H Allen CC 2	-71	7,100	-502,495	2.5	0.009	-2	$4,416	-0.010	$0.14
14	LaRosit1	-73	7,000	-510,979	2.5	0.009	-2	$4,416	-0.010	$0.14
15	SycmrCG1	-77	7,250	-558,560	2.5	0.009	-2	$4,416	-0.011	$0.14
16	TR-Cntr1	-79	9,500	-748,168	10.0	0.036	-13	$4,416	-0.059	$0.75
17	WtsnCgn1	-79	7,250	-574,827	2.5	0.009	-3	$4,416	-0.011	$0.14
18	Etiwand3	-84	9,500	-793,963	10.0	0.036	-14	$4,416	-0.063	$0.75
19	Sutter	-88	7,250	-640,244	2.5	0.009	-3	$4,416	-0.013	$0.14
20	MorroBy3	-92	9,500	-873,284	10.0	0.036	-16	$4,416	-0.069	$0.75
21	LosMdns1	-98	7,250	-708,431	2.5	0.009	-3	$4,416	-0.014	$0.14
22	Encina 4	-100	9,500	-951,351	10.0	0.036	-17	$4,416	-0.075	$0.75
23	Scttrgd3	-107	9,500	-1,018,757	10.0	0.036	-18	$4,416	-0.080	$0.75
24	DltnrgyC	-116	7,250	-842,861	2.5	0.009	-4	$4,416	-0.017	$0.14
25	BrrrdTh2	-122	9,500	-1,162,789	10.0	0.036	-21	$4,416	-0.092	$0.75
26	Thrmlct1	-127	7,000	-891,148	2.5	0.009	-4	$4,416	-0.018	$0.14
27	Hntngtn3	-142	9,500	-1,351,079	10.0	0.036	-24	$4,416	-0.106	$0.75
28	ElkHlls1	-146	7,250	-1,055,951	2.5	0.009	-5	$4,416	-0.021	$0.14
29	Palomar	-153	7,100	-1,084,607	2.5	0.009	-5	$4,416	-0.021	$0.14
30	MssLndn6	-158	9,500	-1,498,351	10.0	0.036	-27	$4,416	-0.118	$0.75
31	SnrsPwr1	-165	7,250	-1,194,878	2.5	0.009	-5	$4,416	-0.024	$0.14
32	MssLndn1	-187	7,250	-1,354,044	2.5	0.009	-6	$4,416	-0.027	$0.14
33	LaPalom1	-211	7,250	-1,527,033	2.5	0.009	-7	$4,416	-0.030	$0.14
34	SouthBy1	-241	9,500	-2,286,049	10.0	0.036	-41	$4,416	-0.180	$0.75
35	Haynes 1	-284	9,500	-2,700,452	10.0	0.036	-48	$4,416	-0.213	$0.75
36	OrmndBc1	-292	9,500	-2,778,748	10.0	0.036	-50	$4,416	-0.219	$0.75
37	AESlmts3	-305	9,500	-2,900,322	10.0	0.036	-52	$4,416	-0.229	$0.75
38	HighDsrt	-329	7,250	-2,382,065	2.5	0.009	-11	$4,416	-0.047	$0.14
39	Moutainview	-468	7,100	-3,325,691	2.5	0.009	-15	$4,416	-0.066	$0.14
	Subtotal -- 81%	-4,980		-41,137,528			-476		-2.102	
	Total -- 100%	-6,161		-50,896,482			-589		-2.601	
	Percent of Total	81%	**Net Impact**	**-6,385,879**			**-390**		**-2.162**	

ATTACHMENT 8
OF
PHASE 1 OPENING TESTIMONY ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR
October 21, 2005
A.05-04-015
I.05-06-041

California Independent
System Operator

Memorandum

To: CAISO Board of Governors

From: Armando J. Perez, Director of Grid Planning
Anjali Sheffrin, Director of Market Analysis

cc: CAISO Officers; Board Assistants

Date: February 14, 2005

Re: ***Palo Verde-Devers No. 2 500 kV Transmission Project***

This memorandum requires Board action.

SUMMARY

During the last few years, a large number of new and efficient combined cycle generation power plants have been constructed in western Arizona near the Palo Verde area. This new generation is more efficient than the older steam boiler generation that exists in the Los Angeles, San Francisco, and San Diego load centers. In addition, the new gas-fired generation in Arizona and elsewhere in the Southwest is expected to be significantly less expensive than similar generation located in California due to permitting, land, emission credit, labor, and gas costs. However, the current transmission system is not adequate to import this new generation to southern California. As a result, it continues to be necessary to operate old and inefficient generation in southern California.

In June of 2004, the ISO Board approved the "STEP Short-Term Transmission Upgrades." These upgrades increase the ability of the existing transmission system to import power from Arizona without adding any new transmission lines. These short-term upgrades are planned to be in place in June 2006. Additional upgrades are planned for the existing transmission lines between Arizona and Nevada. However, even after these additions have been completed, our analysis indicates that there will still be substantial congestion on the grid between Arizona and California. The Palo Verde-Devers No. 2 (PVD2) project, as described later in this memo, would further reduce this congestion and provide economic benefits to California ISO ratepayers as well as the interconnection as a whole. Our analysis indicates that expected benefit-cost ratio for ISO Ratepayers ranges from 1.2 to 3.2 depending on input assumptions and allocation of transmission congestion rental.

The ISO analysis of the PVD2 project further indicates that the project scope and cost appear to be appropriate.

Based on the economic and reliability benefits of the PVD2 Project (as discussed later in this memo and in the attached report), ISO Management recommends that the ISO Board approve the project.

PROJECT DESCRIPTION

The PVD2 project includes the following facilities:

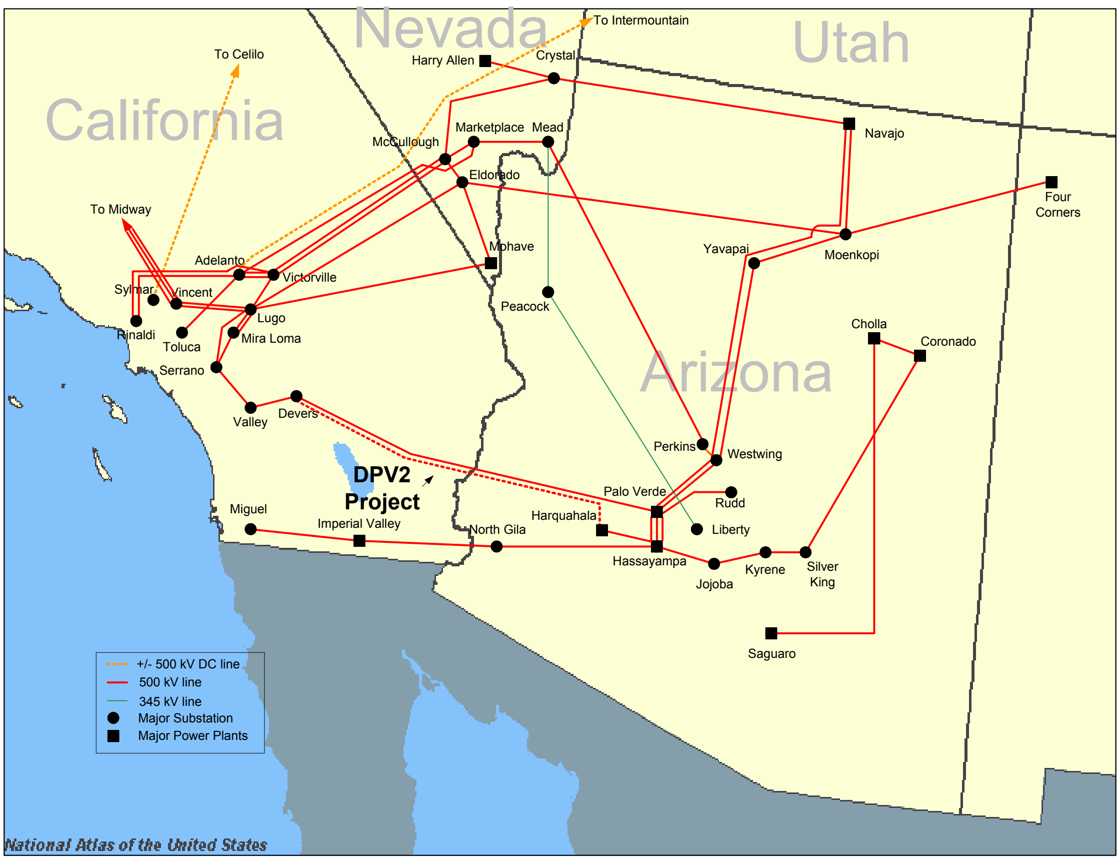
- A new 230 mile 500 kV line to be constructed between the Harquahala Switchyard (near Palo Verde) and SCE's Devers 500 kV Substation. The route proposed from Devers to Harquahala parallels SCE's existing Palo Verde-Devers No.1 (PVD1) transmission line. Most of the proposed line is to be constructed on single circuit steel lattice towers.

- The four 230 kV lines west of the Devers substation will be rebuilt: the Devers-San Bernardino 230 kV lines #1 and #2, and the Devers-Vista 230 kV lines #1 and #2.

- Voltage support facilities will be added in the Devers area in southern California.

The proposed PVD2 project is expected to increase California's ability to import power from Arizona by at least 1,200 MW. The project could be operational as early as 2009 and is expected to cost $680 million in year 2009 dollars. Figure 1 shows the location of the project.

Figure 1
Location of Proposed PVD2 Transmission Expansion Project



The proposed PVD2 project is a 230 mile, 500 kV transmission line from the Haraquala substation Haraquala switchyard near Palo Verde to SCE's Dever substation near Palm Springs, California. PVD2 will parallel the existing PVD1 line and use an existing transmission line corridor and will use the existing PVD1 right-of-way.

PUBLIC PROCESS IN DEVELOPING RECOMMENDATION

The development of the Palo Verde- Devers project originated in a transmission group process called the Southwest Transmission Expansion Plan (STEP). This group has approximately 300 members on its distribution list and about 50 members routinely attend STEP meetings that are held every two months. The goals of STEP include:

- To provide a forum to further the development of a robust transmission system between the Arizona, Nevada, Mexico, and southern California areas that meets WECC and NERC Reliability Criteria and is capable of supporting a competitive, efficient, and seamless west-wide wholesale electricity market;

- To encourage all interested parties to participate in the development of transmission plans that benefits the customers in the Southwest; and

- To provide a broad basis of support that will aid the implementation of future transmission projects.

In developing a transmission plan for the area, STEP analyzed 26 different combinations of facilities to increase the transmission capability between the Southwest and Southern California and proposed a series of projects. The first project was the STEP Short-Term Transmission Upgrades. The CAISO Board approved the California portion of this project in June 2004 and these facilities are expected to be in service in 2006. Similar upgrades are being planned on the transmission lines between Arizona and Nevada. The next major project in the series is the PVD2 Project. STEP determined the PVD2 Project would provide more benefits from both a technical and economic perspective than the other transmission projects that were considered.

In parallel with STEP, SCE determined that PVD2 was a cost effective project and requested that the CAISO approve the project. The CASIO staff has performed an independent evaluation of the economic and reliability benefits of the PVD2 project using the newly developed Transmission Economic Assessment Methodology (TEAM).

The TEAM methodology was the subject of a four-month public stakeholder process in 2004. The ISO conducted three public workshops and conducted a CAISO Market Surveillance Committee meeting in public. In addition, three technical subgroups were formed. They worked on base case assumptions, the scenario selection, and methods of modeling market prices. In all, there were twelve separate technical sessions. The CAISO filed a report with the California Public Utility Commission (CPUC) in June 2004, documenting this methodology and providing a detailed example study.

In its analysis of the PDV2 project, the CAISO staff has reviewed the interim results in a number of public forums. We have incorporated input from these meetings into our findings. We presented our preliminary results in a public Market Surveillance Committee meeting in November 2004. At this meeting, the Los Angeles Department Water and Power (LADWP), a significant operator in the project area, asked whether we had reviewed the impact of proposed East-of-River (EOR) 9000 upgrades in Nevada/Arizona. LADWP suggested that this upgrade could be an alternative to the Palo Verde Devers project. We spent the following two months reviewing the implication of the EOR 9000 upgrades on the PVD2 project. Our results indicated that the EOR

9000 Project was a complementary project to the PVD2 Project and not an alternative. The STEP Plan includes the upgrades that are currently part of the EOR 9000 project.

The following stakeholder opportunities were provided to review the latest economic studies for the PVD2 project. These meetings are in addition to the two years of STEP meetings that were spent in determining the overall transmission expansion plan for the region.

1. On January 11th, we presented our findings-to-date to the Western Arizona Transmission Studies (WATS) group
2. On January 14th, we conducted a CASIO stakeholder meeting to review preliminary results with a broader group of interested parties. 48 attendees from 33 different companies or agencies were present at the stakeholder meeting.
3. On January 18th, we solicited further review and input from the CAISO Market Surveillance Committee.
4. On January 25th, we posted a variety of our study work papers on our website and on February 2nd, we posted the Draft PVD2 report.
5. On February 4th, we discussed the PVD2 study results at a MSC Open Meeting.
6. On February 9th, we reviewed the PVD2 study results at a STEP meeting and received concurrence on proceeding with the approval of the project.

Throughout this process, we have solicited input from a wide variety of stakeholders. We will summarize the input we have received and our responses at the Board meeting. Written responses to the comments we receive are posted on our web site.

ECONOMIC AND RELIABILITY BENEFIT ASSESSMENT

CAISO management's recommendation on PVD2 are based on consideration of the project economic and reliability benefits. As mentioned previously, CAISO staff completed a comprehensive analysis of the benefits of PVD2 Project using TEAM and concluded that the project will provide significant reliability and economic benefits to CAISO ratepayers. PVD2 would improve reliability by increasing voltage support in southern California and enhance system operational flexibility by providing CAISO operators with more options in responding to transmission and generation outages. The project's primary economic benefit is the increased ability to import low-cost generation from the southwest and displace higher-cost generation in California. It will also provide access to additional capacity that can serve to meet the State's resource adequacy requirements and lower transmission system power losses. The PVD2 Project will significantly augment the transmission infrastructure critical to support competitive wholesale energy markets for California consumers.

As part of the evaluation of the project, alternatives to the project were considered such as other transmission and generation. Demand-side and renewable resources were not considered alternatives since CAISO staff believes these resources should be maximized first, before other traditional resources are considered. For this analysis, we reviewed several alternatives. One alternative we examined was the East-of-River (EOR) 9000 transmission project, which upgrades lines between Nevada and Arizona. Our analysis showed the EOR 9000 project to be complementary to the PVD2 project and was therefore included in the base case. Another alternative we examined was siting additional in-state generation. The resource mix we used in the study assumed additions of gas-fired plants known to be under consideration. The mix also met California's renewable standards. Because the southwest has less expensive permitting, land, emission-offset, and labor expenses, we estimate the fixed costs of a new combined-cycle (CC) plant to be about 13 percent less than in California. We expect California generation interconnection costs to make the generation deliverable to load to increase this cost differential. In addition, we expect units in the southwest to have lower operating costs due to lower natural gas costs forecast for that region. Thus, from strictly a unit cost perspective, the CAISO ratepayer would benefit more from having access to lower costs units in the southwest. Constructing new in-state gas-fired generation would also not increase access to the more diverse fuel supply available in the southwest.

The quantified benefits of the PVD2 upgrade in this evaluation include: (a) reduction in production costs (energy savings); (b) operational savings (reduced uneconomic generation dispatch for reliability purposes); (c) capacity savings (lower capacity costs from the Southwest); (d) NOx emission reduction (displacement of inefficient California generation with more efficient Southwest generation); and, (e) loss reduction (WECC total system losses are reduced due to increased transmission capacity). The energy benefits were determined in accordance with the Transmission Evaluation Assessment Methodology (TEAM) that was developed and filed with an example study to the CPUC in June 2004. The remaining benefits were estimated outside of the market simulation model used to determine the energy benefits and are documented in the Board Report and Technical Appendices.

We estimate that benefits from the line will exceed its costs under a wide range of future system conditions. Because we believe that no single point estimate can adequately capture its value, we calculated its costs and benefits under a number of likely system conditions. We believe this range presents the best assessment of the impact of the line on the CAISO system. The expected benefit-cost ratio ranges from 1.2 to 3.2 depending on input assumptions and allocation of transmission congestion rental. The attached report describes this analysis in detail.

RECOMMENDATION

As a result of the extensive analysis that has been completed for the PVD2 Project, ISO Management recommends the approval of the Palo Verde-Devers #2 Project and suggests the following motion:

MOVED, that the Board of Governors:

1. Grants its approval of the Palo Verde-Devers #2 Project as documented in the ISO Board Memorandum dated February XX, 2005, and finds that the proposed project is a necessary and cost effective addition to the ISO Controlled Grid.

2. Directs Southern California Edison to complete the Palo Verde-Devers #2 Project, preferably by the summer of 2009.

ATTACHMENT 9
OF
PHASE 1 OPENING TESTIMONY ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR
October 21, 2005
A.05-04-015
I.05-06-041

CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: ISO Board of Governors

From: Armando Perez, Director of Grid Planning
Anjali Sheffrin, Director of Market Analysis

cc: ISO Officers; Board Assistants

Date: November 5, 2004

Re: ***Update on Palo Verde-Devers No. 2 500 kV Transmission Project***

This memorandum does not require Board action.

EXECUTIVE SUMMARY

Southern California Edison Company ("SCE") submitted its Technical and Cost Effectiveness reports for the proposed Palo Verde-Devers No. 2 ("PVD2") project to the CAISO for review and approval. SCE found the PVD2 project to be economic and concluded that "PVD2 is a necessary and cost-effective addition to the ISO Controlled Grid".[1] The purpose of this memo is to brief the Board on the status of the CAISO's evaluation of the PVD2 upgrade. In addition, the memo provides a proposed schedule for bringing this decision to the Board.

BACKGROUND

During the last few years, a large number of new and efficient combined cycle generation power plants have been constructed in western Arizona near the Palo Verde area. This new generation is far more efficient than the older steam boiler generation that exists in the Los Angeles, San Francisco, and San Diego load centers. In addition, the new gas-fired generation in Arizona and elsewhere in the Southwest is expected to be significantly less expensive than similar generation located in California due to permitting, land, emission credit, labor, and gas costs. However, the current transmission system is not adequate to import this new generation to southern California. As a result, it continues to be necessary to operate old and inefficient generation in southern California.

In June of 2004, the ISO Board approved the "STEP Short-Term Transmission Upgrades." These upgrades increase the ability of the existing transmission system to import power from Arizona without adding any new transmission lines. These short-term upgrades are planned to be in place in June 2006. The Palo Verde-Devers No. 2 (PVD2) project complements these upgrades and is expected to increase California's ability to import power from Arizona by 1,200 MW. The PVD2 project includes the following facilities:

- Constructing a new 230 mile 500 kV line between Harquahala Generating Company's Harquahala Switchyard (near Palo Verde), to SCE's Devers 500 kV Substation. The proposed route between Devers and Harquahala parallels SCE's existing Palo Verde-Devers No.1 (PVD1) transmission line. Most of the proposed line is to be constructed on single circuit steel lattice towers.

[1] "Palo Verde-Devers No. 2, Technical and Cost-Effectiveness Report", Southern California Edison, April 7, 2004, page 3.

- Rebuilding the four 230 kV lines west of the Devers substation: The Devers-San Bernardino 230 kV lines #1 and #2, and the Devers-Vista 230 kV lines #1 and #2.

- The addition of voltage support facilities in the Devers area in southern California.

The project could be operational as early as 2009. The CAISO's final recommendations on PVD2 will include considerations of economic benefits, reliability benefits and other strategic benefits of the lines.

Economic Benefits
Earlier this year, the CAISO formed a Transmission Economic Assessment Methodology (TEAM) stakeholder group to finalize the development of a standard methodology to evaluate the economic benefits of transmission upgrades. The CAISO has reviewed the economics of the PVD2 project using the TEAM methodology. Forty cases are being completed using assumptions about a variety of future system conditions regarding load growth, gas prices, hydro conditions, levels of market competitiveness, and possible system contingences. CAISO staff is also reviewing the cost of this project with Edison.

Reliability Benefits
Historically, most new transmission projects were justified based on satisfying criteria that are established by regional reliability councils. Based on current projections of online dates of new generation, the Palo Verde-Devers #2 Project is not needed to meet minimum planning reliability requirements. However, in the future, if the current and projected plans for generation in California do not materialize, the PVD2 project may be needed to meet these basic reliability standards.

Although the Project is not presently needed to meet minimum planning reliability standards, it will provide substantial operational reliability benefits. By having this line in place, the State, from a loads and resources perspective, will be less susceptible to power outages due to transmission or generation outages. In addition, the Project will provide the system operators with greater operational flexibility in the scheduling of outages of major transmission lines and will provide them with improved ability to respond to major transmission outages. These benefits are clearly qualitative in nature, as they are difficult to quantify.

Additional Benefits
In addition to the economic benefit of lowering the price of power to consumers, the Palo Verde-Devers #2 Project will reduce the consumption of natural gas, and reduce air pollution due to lower air emissions by not having to dispatch old and inefficient generating units located in Southern California. These benefits are also difficult to quantify but need to be considered when evaluating a project of this nature.

Because it takes so much longer to install new transmission lines than new generation projects, it has been historically difficult for transmission projects to compete with generation projects that can be built and ready to serve load in a few years. The California Energy Commission has suggested one way to minimize this difference in project timing would be to complete the permitting process for strategic transmission projects such as PVD2. By completing the permitting process for the Palo Verde-Devers #2 Project, the timeline for completing the project would be comparable to that for a major new generation facility. Permitting the project would preserve an important option for California to meet its future power needs.

DISCUSSION

Next Steps

The next steps in the evaluation and licensing process for the proposed PVD2 upgrade are:

CAISO

- November 16th – Market Surveillance Committee Meeting. Discussion of the CAISO analysis including the assumptions and results in order to solicit feedback from the members of the Committee and public.
- November 16th through December 3rd – CAISO staff will incorporate feedback from the MSC meeting into the analysis as appropriate, and will conduct a final review of assumptions and results and make any adjustments that may be necessary. CAISO staff will also discuss with SCE the final results and recommendations through conference calls.
- Dec 3rd – ISO Board Meeting. CAISO staff will present final evaluation results and a final recommendation to the Board.
- January 2005 – If the CAISO Board approves this project, CAISO will support SCE's Certificate of Public Convenience and Necessity ("CPCN") process at the California Public Utility Commission ("CPUC").

SCE

If the CAISO Board approves the PVD2 project at the December 3rd Board meeting, it is the CAISO's understanding that Edison (after reviewing the CAISO Board approval with Edison Management) will finalize its application for a CPCN, and submit the application to the CPUC as early as January, 2005.

As the project sponsor of the PVD2 project, SCE has initiated the Western Electricity Coordinating Council ("WECC") path rating process to achieve a WECC accepted rating for the project. The path rating process will proceed in parallel with the CPCN process described above. SCE will continue to work with interested parties to resolve issues related to the PVD2 project.

CAISO Management will finalize its recommendation to the Board for consideration at the December 3rd Board meeting.

ATTACHMENT 10
OF
PHASE 1 OPENING TESTIMONY ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR
October 21, 2005
A.05-04-015
I.05-06-041

Assessment of An Economic Analysis of the Palo Verde-Devers Line Number 2 (PVD2) Transmission Network Upgrade

by
Frank A. Wolak, Chairman; Brad Barber, Member;
James Bushnell, Member; Benjamin F. Hobbs, Member
Market Surveillance Committee of the California ISO

February 22, 2005

1. Introduction

We have been asked by the ISO management and Board of Governors to assess the results of the report "Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)," prepared by the ISO's Departments of Market Analysis and Grid Planning. The report describes the results of an application of the ISO's Transmission Economic Assessment Methodology (TEAM) to the PVD2 upgrade. We have previously commented on the TEAM approach.[1] We discussed aspects of its application to the PVD2 project at several MSC meetings and have met several times with ISO staff to review simulation results. We have also received written comments on the PDV2 analysis from Southern California Gas, Los Angeles Department of Water and Power, and Southern California Edison. On February 4, 2005, we held a public conference call where we received additional comments on this report[2] from stakeholders. We are grateful for this very helpful input.

We have also been asked to provide an opinion on whether the ISO Board should approve this transmission upgrade. Our overall conclusion from reviewing ISO's report on the PVD2 upgrade and stakeholder comments on this report is that the Departments of Market Analysis and Grid Planning have, for the most part, undertaken a conservative economic analysis of the expected benefits of this proposed upgrade. Their modeling results imply a wide range of plausible scenarios for future system conditions that yield significant net benefits to California ISO ratepayers from the upgrade. Appendix D of the Technical Appendices notes that substantial amount of new generation is currently planned or under construction in Arizona. The PVD2 line will provide California consumers with access to a significant share of the energy that will be produced by these very efficient natural gas-fired generation units that are less expensive to build and operate in Arizona as opposed to near Southern California load centers.

The remainder of this opinion summarizes why we believe that this application of the TEAM methodology provides credible, yet conservative, estimates of the expected benefits of the PVD2 upgrade to California ISO ratepayers and why we recommend that the ISO Board approve this transmission expansion. Based on the ISO analysis, the PVD2 upgrade represents a sound investment offering a sound rate of return and an insurance policy against future adverse, potentially catastrophic, market conditions. Because TEAM is an evolving methodology and subject to continual improvement, we also suggest enhancements that we believe are worth considering for future applications.

[1] CAISO Market Surveillance Committee, "Comments on the California ISO's Transmission Expansion Assessment Methodology (TEAM)" June 1, 2004, http://www.caiso.com/docs/2004/06/01/200406011457422435.pdf.
[2] ISO Draft PVD2 Report posted on the ISO website on Feb 2, 2005.

2. Sources of Energy Cost Savings from Upgrade

A transmission expansion typically allows cheaper distant energy to substitute for higher-priced locally produced energy. How large this benefit is depends on a number of factors that are unknown at the time the upgrade is considered. The TEAM methodology solves this problem by using its best estimate of the configuration of the transmission network and stock of generation capacity available in the Western Electricity Coordinating Council (WECC) at the time the proposed transmission expansion would be operational and computes the ex-post benefits of the expansion for a number of possible realizations of future system conditions. These system conditions differ in terms of the expected growth in electricity demand, the level of input fuel prices, hydrological conditions in the Pacific Northwest and remainder of the WECC, the amount of new investment in generation capacity, the availability of key transmission and generation facilities, and the extent of unilateral market power that suppliers are able to exercise. The ISO has forecasts for these future system conditions from a number of sources.

Load Growth: 10-year load forecasts published by the WECC are used for all regions besides California. The load forecasts used for California were computed by the California Energy Commission (CEC). These figures are used to construct three possible future load scenarios--baseline, low and high. The low and high load scenarios are designed to provide a 90 percent confidence interval on the level of future load throughout the WECC. Although future demand levels above the high load scenario and future demand level below the low load scenario are possible and are likely to lead to a wider range of benefit estimates for the upgrade, the ISO's procedure provides credible range of future demand conditions in the WECC.

Input Fuel Prices: Natural gas prices are a major source of uncertainty in assessing the benefits of this upgrade because so many existing generation units in California burn natural gas at heat rates significantly above that of a state-of-the-art combined cycle natural gas turbine (CCGT) facility, the typical unit currently being constructed in Arizona. Although oil prices tend to fluctuate with natural gas prices, very little energy is produced from oil-fired units in the WECC. Although coal produces a significant amount of the electricity produced in the WECC, its price is unlikely to change significantly, and coal is rarely on the margin. Three scenarios for gas prices are selected based on the CEC natural gas price forecasts and the estimated forecast errors. The baseline price scenarios are for 2008 and 2013 are broadly consistent with recent futures prices for Henry Hub natural gas for 2008 to 2010 from the New York Mercantile Exchange. The average of the high scenario natural gas prices is approximately double the level of average prices for the baseline scenario, although these high scenario prices are well below the levels of natural gas prices reported in California during the period December 2000 to May 2001 and are approximately equal to the historical highs for Henry Hub natural gas prices. The average price for the low price scenario is roughly half the average for the baseline scenario. These prices seem overly optimistic in terms of a future low price scenario. Anticipating too low of a price scenario would tend to underestimate the benefits of the transmission upgrade because the benefits of substituting high heat rate units in California for low heat rates units in Arizona is much less with lower natural gas prices. The reasonableness of the baseline and high price scenario and the overly optimistic low price scenario all imply that the methodology yields conservative estimates of the future benefits of the transmission upgrade.

Hydrological Conditions and Future Generation Resources: A major driver of the benefits of transmission upgrades is the mix of available generation resources in California and the rest of the WECC. In particular, the amount of hydroelectric energy available in British Columbia, the

Pacific Northwest and California is a major driver of the benefits of the transmission expansion. The methodology assumes that California meets its renewable portfolio standards. In addition, California is also assumed to have enough new thermal generation capacity to meet a 15 percent planning reserve margin. Known generation retirements in California were built into these planning reserve scenarios. The reserve margin assumption limits the magnitude of potential benefits from the upgrade because it eliminates insurance value that the upgrade provides against years in the future when there is less than a 16 percent planning reserve. The methodology accounts for uncertainty in future hydrological conditions by specifying energy availability under baseline, wet and dry hydro conditions using data compiled by the Seams Steering Group--Western Interconnection (SSG-WI) Planning group. The total amount of hydroelectric energy assumed available in the Pacific Northwest under the low hydro scenario is significantly above the levels observed in 2000 and 2001. Because lower hydro conditions yield higher benefits from the upgrade, this implies that the ex-post benefits associated with low hydro scenarios are likely to be a lower bound on the ex-post benefits of the upgrade under actual low hydro conditions, which can be considerably more severe than those assumed in the methodology. Again, these modeling assumptions imply conservative estimates of the benefits of the upgrade.

Impact of Market Pricing: Transmission upgrades typically increase the number of independent suppliers able to compete to sell energy at a specific location in the transmission network. For the PVD2 upgrade, suppliers located near the Southern California load centers will face greater competition from suppliers located in Arizona. The ISO's methodology accounts for the greater competition suppliers face as a result of the upgrade by using historical data on California price-cost margins to model the impact of this increased competition on the level of price-cost margins reflected in market prices. The level of mark-ups anticipated by the methodology are relatively low, as a result of the comparatively high levels of forward contracting assumed in the ISO's analysis. Nevertheless, the results show that CAISO participants and consumers benefit significantly from the modeled decreases in those mark-ups. We note that it is possible that the assumption of no mark-ups outside of California might result in some error in the estimates of the value of the PVD2 upgrade, but it is not clear a priori if this would bias the benefit estimates upward or downward. As we have stated in our previous opinions on transmission evaluation, estimating mark-ups is an uncertain and ambiguous task, and basing mark-up projections on past behavior and allowing alternative scenarios as has been done in the TEAM methodology is an appropriate approach. We encourage the ISO to continue to explore alternative approaches to modeling the impact of transmission upgrades on market prices. We look forward to working with ISO staff on modeling this very important component of the value of transmission upgrades in a wholesale market regime.

3. Other Sources of Benefits from Transmission Upgrades

The ISO's methodology incorporates other sources of benefits from a transmission upgrade besides those due to energy cost savings. These include system operation benefits, transmission loss savings, capacity cost benefits, emissions savings benefits, and additional benefits from alternative congestion management paradigms outside of California. Although these benefit sources clearly exist, they are significantly more difficult to quantify in a rigorous manner. Therefore, in the PVD analysis, they were quantified outside of the PLEXOS runs used to quantify energy cost savings. Potentially, improvements in PLEXOS or other market simulation models would allow these other benefits to be quantified simultaneously and consistently with energy savings. We encourage the ISO to consider the development or use of such improved methods and stand willing to assist the ISO staff in this effort.

System Operation Benefits: The ISO operators estimate that as a result of the PVD2 line there will be less need to keep generation units local to the Southern California load centers operating in real-time in order to manage the constraints implied by N-1 and relevant N-2 operating criteria that are not captured in the TEAM. Appendix K of the ISO's Technical Appendices discusses the current costs of managing congestion and re-dispatch costs because of these operating criterion. The annual cost of managing this constraint is just above $93 million and will decrease to just below $50 million with the short-term upgrades coming in June of 2006. The ISO operations staff estimates that it is likely that the PVD2 upgrade will further reduce these costs by 25 to 50 percent. This estimated operational cost savings yields $18 million benefits per year in 2004 dollars.

While we concur that these are the best estimates available at the present time of operational cost savings as a result of the PVD2 upgrade, we would have preferred a more detailed analysis incorporating unit commitment costs into the PLEXOS model to arrive at these cost saving estimates. However, this would assume efficient day-ahead management of congestion, rather than the real-time management given day-ahead schedules that takes place in a multi-settlement locational marginal pricing (LMP) market.

Transmission Loss Savings: The ISO's energy price benefits analysis does not account for transmission line losses in setting locational marginal prices. To the extent that the upgrade reduces the level of line losses, this is a tangible source of economic benefits. Appendix J of the ISO Technical Appendices presents a methodology for measuring benefits from line loss reductions and finds tangible, but not excessive benefits from reducing line losses. Ideally, the market simulation software would calculate losses endogenously. Although the capability to do this at the level of detail represented in PLEXOS is not now available, it is technically feasible to develop such a capability, and it should be considered in future analyses.

Capacity Savings Benefits: Appendix M of the ISO Technical Appendices provides a comparison of the estimated costs of constructing and operating a combined cycle natural gas turbine (CCGT) generation unit in California versus Arizona. Both construction costs and operating maintenance costs are assumed to be lower for units built in Arizona versus those built in California. These capacity savings are estimated to amount to roughly $12 million on an annual basis. The large amount of new generation planned and under construction in Arizona--roughly 5,000 MW of new capacity by 2008 and an additional 5,000 MW of capacity between 2008 and 2013 according to Appendix D of the ISO Technical Appendices--implies clear cost savings as a result of constructing generation capacity in Arizona versus California. However, further details on the sources of these cost differences would provide greater credibility to the capacity cost savings figures in the report. We note that these construction and operating costs have been studied extensively in the eastern ISOs as they have designed their resource adequacy mechanisms, and that despite this effort the estimates remain both controversial and uncertain.

Emissions Savings Benefits: The ISO report notes that generating more electricity from new units in Arizona will reduce the amount of natural gas consumed in the WECC because higher heat rate units located near the Southern California load centers will be displaced by the new lower heat rate units located in Arizona. Valuing the benefits of these emissions reductions is complicated by the fact that there is no transparent price for NO_X emissions permits in Southern California or Arizona. Fortunately, the ISO's estimate of the emission savings benefits is extremely modest, approximately $1 million annually, which should not impact the decision to construct the transmission line. If those benefits were considerably larger, we would recommend that the explicit modeling of emissions caps in the market modeling software be considered.

Alternative Congestion Management Schemes Outside of California: A complaint of a number of stakeholders with the ISO's methodology for determining the energy savings associated with a transmission upgrade is the fact that an locational marginal pricing (LMP) market is assumed to exist outside of California, as well as within California. There are two issues here. One is whether the dispatch and costs resulting from the LMP assumption are a reasonable approximation of operations under the actual transmission pricing systems in place in the West. The ISO's extensive calibration and validation of the PLEXOS simulations gives us confidence that the answer to that question is yes. The second issue is whether the distribution of transmission rents resulting from LMP adequately represents the actual split among market participants, given the mix of transmission pricing mechanisms. It is clear that there is at least one circumstance where there is a significant divergence that affects the welfare of California market participants.

The ISO report addresses this second issue in Appendix N by specifying a mechanism for refunding congestion charges to various market participants located outside California and in California in a manner that attempts to replicate the existing mechanism used to manage congestion into Southern California and allocate its costs to consumers in and outside of California. The alternative congestion management mechanism implies even greater benefits associated with the transmission upgrade. Table VII.4 of the ISO report shows that the expected benefits of the upgrade to Californians under this alternative mechanism for congestion management are almost triple the expected benefits assuming that LMP is used throughout the WECC. This results from transferring selected transmission rents from ISO participants to non-ISO participants, so that decreases in those rents no longer appear as a cost to ISO participants.

Although we cannot verify the exact numbers, we do indeed expect that this alternative mechanism would result in a significant increase in benefits to CAISO participants. This is because the rents on lines into Southern California that the LMP method assumes are earned by CAISO participants instead partially accrue to Southwestern market participants. Thus, when the PVD2 line is installed and the transmission rents in that area decrease, this is not actually experienced as a loss by CAISO participants, although under LMP there would be such a loss.

4. Alternatives to PVD2

Though the projected benefits of the PVD2 upgrade appear to justify the estimated upgrade 2009 online cost of $680 million, it is reasonable to ask whether these benefits could be realized with a lower cost alternative to the PVD2 upgrade. To answer this question, the ISO considered two viable alternatives--building additional generation inside California and alternative transmission projects.

The benefits of PVD2 are estimated under the assumption that there is generation expansion in Southern California (see Table D.2, Technical Appendix D). The key issue is whether even more generation inside California could replace the transmission upgrade. The ISO report argues that additional generation inside California is infeasible and is unlikely to accrue the same benefits as the transmission upgrade, because it is cheaper to build generation in Arizona than California. This seems like a reasonable conclusion based on existing evidence. However, just as importantly, a transmission upgrade provides greater flexibility than new generation, because the PVD2 upgrade leaves a wider range of generation--both inside and outside of California--competing to provide energy to load inside California. This healthy mix of suppliers provides an important backstop against extreme market conditions, such as those observed in the 2000-2001.

As a result of stakeholder input, the CAISO analysis of PVD2 considers several transmission alternatives to the PVD2 upgrade. Most importantly, the analysis considers whether the PVD2 upgrade could be replaced by the proposed East-of-River project ("EOR 9000"), which would increase the EOR path rating from 8,055 MW to 9,300 MW, an increment of 1,245 MW. At the January 18, 2005, MSC meeting, the CAISO staff presented the results of sensitivity analyses where the benefits of the PVD2 line were estimated with and without the EOR 9000 upgrade. The analysis suggests these projects are complements and should both be pursued.

5. Conclusion

There is a wide range of realized benefits of the project, primarily because of the uncertainty in future market conditions in the Western Electricity Coordinating Council (WECC). There are a range of future system conditions--demand growth, natural gas prices, hydroelectric energy availability, and the extent of unilateral market power exercised by suppliers--where the project would have limited realized benefits, in part because of the conservative modeling assumptions made by the ISO. However, there are also ranges of future system conditions, where the project would have realized benefits substantially in excess of the cost of the project. The ISO estimates that the probability is greater than 70 percent that future system conditions will occur such that the project realizes benefits in any given year that exceed the annualized cost of the project. The strength of the TEAM approach is that it is able to estimate this probability or the entire distribution of realized values of the project over all possible future system conditions in an internally consistent manner. Although it would be desirable to have run additional scenarios, we believe that the method used to define scenarios and assign probabilities to them is reasonable.

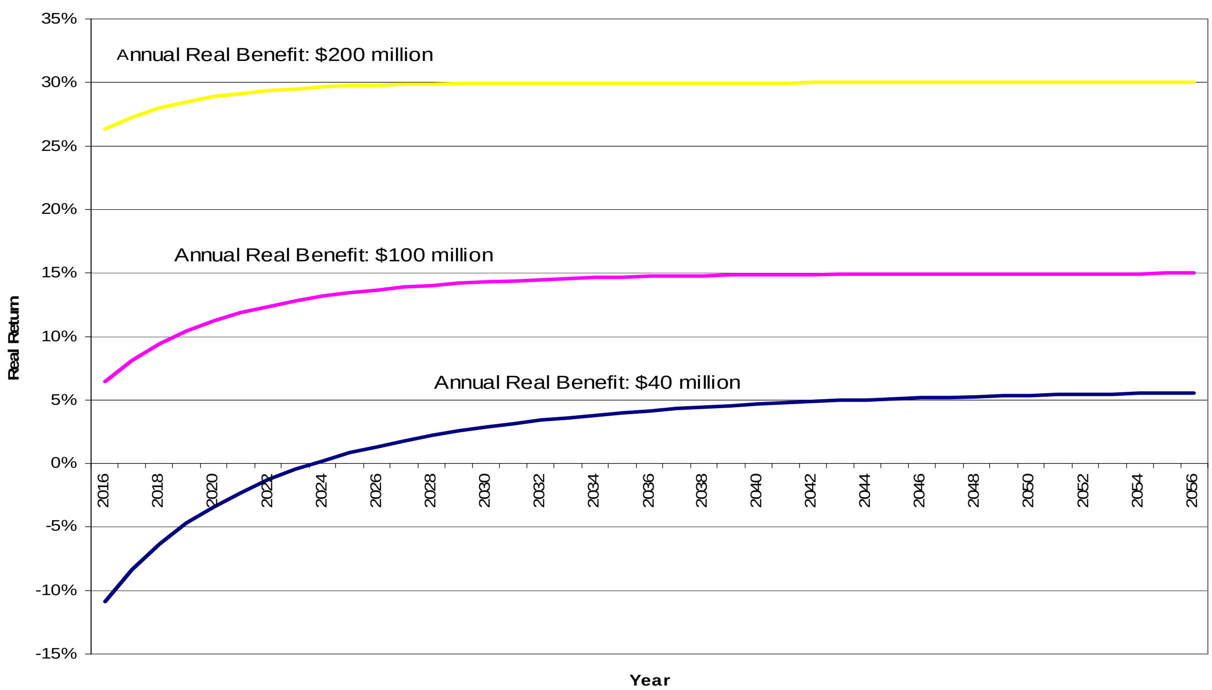
As we emphasized in our earlier discussion of the TEAM approach, transmission projects need to be viewed not just in terms of their expected benefits but in terms of the insurance they provide against adverse, and potentially catastrophic, outcomes. Extreme market conditions (e.g., high energy prices or blackouts) disrupt business and society in a way that exacts a toll beyond the high-energy prices incurred during these periods. This standard is consistent with other aspects of the State energy action plan, such as a focus on the diversification of fuel sources through extensive support of renewable energy. Thus even if the expected benefits were negative, a project can have significant value under some future scenarios. A negative expected value of a project could be viewed as the insurance premium against these catastrophic outcomes. The significant probability of realized values in excess of the annualized cost of the project suggests that this project is an insurance policy that is very likely to yield substantial ex post benefits.

Though the PDV2 upgrade provides an important insurance policy, it does so while also providing a sound rate of return and a relatively quick payback for the expected price tag of $667 million (in 2008 dollars). The ISO provides benefit savings for only two years – 2008 and 2013. A simple way to view these benefit estimates is to consider two questions (1) in how many years would the transmission project recoup its cost and (2) if the annual benefits accrue over a long horizon, what is the return on the $667 million investment. Even at the very low range of estimated annual benefits from *only* energy savings ($40 million, table VII.1), the PVD2 upgrade breaks even in 2024 and offers a real rate of return over 5% (see figure 1). At more realistic annual levels of

$100 or $200 million, the PVD2 upgrade breaks even in 2014 and 2011 (respectively) and offers an attractive long-run real rate of return of between 15 and 30 percent.

The evaluation of transmission expansion is an extremely complex task. The Departments of Market Analysis and Grid Planning have done provided a comprehensive analysis of the benefits of this upgrade using state-of-the-art methods. As noted above, a number of factors argue in favor the ISO's estimate of the expected benefits of the PVD2 upgrade being conservative. The substantially higher expected benefits of the upgrade under a congestion management mechanism for the rest of the WECC that is more representative of the current scheme argues in favor these benefit estimates being conservative. Finally, the more than 10,000 MW of new generation that are reported to be planned for Arizona by 2013 provides further evidence that there would be substantial benefits to the PVD2 line. For these reasons, we recommend that the ISO Board move forward with this transmission upgrade.

Figure 1: Real Rate of Return on PVD2 Upgrade (assuming annual real benefits of $40, $100, or $200 million and a project cost of $667 million).



Note: Assumes initial real project cost of $667 million is incurred year-end 2007, while benefits begin accruing year-end 2008.

ATTACHMENT 11
OF
PHASE 1 OPENING TESTIMONY ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR
October 21, 2005
A.05-04-015
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ATTACHMENT 11

Qualifications of Anjali Sheffrin, Ph.D.

Q. Please state you name, title and business address.

A. My name is Anjali Sheffrin. I am employed by the California Independent System Operator Corporation (CAISO) as Director of Market and Product Development and Acting Vice-President of Market Development and Program Management. My business address is 151 Blue Ravine Road, Folsom, California 95630.

Q. What are your responsibilities with the CAISO?

A. In my position with the CAISO, I am responsible for product and service development for the CAISO's wholesale electricity markets toward ensuring an open and efficient market for energy, ancillary services, and transmission services. My duties include developing or revising market rules and protocols to address design flaws, gaming and market power opportunities, implementing the corrective actions allowed under the CAISO tariff, and assisting the CAISO's Regional Transmission Department in evaluating the economic impact of major transmission lines proposed in the CAISO service area.

Q. Please describe your professional background.

A. I received a Ph.D. in Economics from the University of California, Davis in 1981. I have 24 years of managerial and technical experience in the electric utility industry working on utility deregulation, market design, competitive business strategies, generation, demand-side and transmission planning, load and market research, marginal cost of service studies, and rate design. Prior to joining the CAISO, I was Manager of the Power Systems Planning and Evaluation Department at the Sacramento Municipal Utility District (SMUD). I directed a staff of 40 engineers, economists, and financial analysts in strategic planning and analysis which included assessment of generation options, initiating relicensing of SMUD's hydro project (Upper American River Project), transmission planning, load forecasting, and advanced and renewable technology development. I was the chief economist at SMUD through the closure of the Rancho Seco nuclear power plant and the evaluation of bids for replacement power. I started my professional career as Senior Economist in the Load Forecasting Department of the Potomac Electric Power Company in Washington D.C.

ATTACHMENT 12
OF
PHASE 1 OPENING TESTIMONY ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR
October 21, 2005
A.05-04-015
I.05-06-041

ATTACHMENT 12

Qualifications of Mingxia Zhang, Ph.D.

Q: Please state your name, title and business address.

A: My name is Mingxia Zhang. I am employed by the California Independent System Operator Corporation (CAISO) as Lead Market Monitoring Specialist. My business address is 151 Blue Ravine Road, Folsom, California 95630.

Q: What are your responsibilities at the CAISO?

A: As Lead Market Monitoring Specialist, I was, and am, responsible for developing portions of the CAISO Transmission Evaluation Assessment Methodology (TEAM). This methodology sets the evaluation framework and criteria for the CAISO sponsored economic-driven transmission upgrade projects. I am also responsible for assisting the CAISO Regional Transmission Department on reviewing and evaluating economic transmission projects submitted by PTOs.

Q: Please describe your professional background.

A: I received a Ph.D. in Agricultural and Resource Economics from the University of California, Davis in 1997. I have over 10 years of research and working experience in market competition and market power analysis, cost/benefit analysis and benefit distribution analysis, and game theoretical analysis in the electric industry and the agricultural industry. I joined the CAISO as Principal Economist/Market Monitoring Specialist in 2001. I had conducted various analyses on market performance, market competitiveness, and generators' strategic bidding in the California electricity wholesale market. Prior to joining the ISO, I was Research Economist at the University of California, Davis (UCD). During my tenure at UCD, I published over 10 journal articles in internationally leading economic journals, including *Journal of Industrial Economics*, *Southern Economic Journal*, *American Journal of Agricultural Economics*, *International Journal of Agricultural Economics*, *Agricultural and Resource Economics*, *International Journal of Agribusiness*, and *European Review of Agricultural Economics*. Most of my research and analyses focused on empirical and game theoretical modeling of imperfect competition and market power and the impact of market power on social benefit and its distribution. I started my professional career as Post-Doctorate Researcher at UCD.

ATTACHMENT 13
OF
PHASE 1 OPENING TESTIMONY ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR
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ATTACHMENT 13

QUALIFICATIONS OF JOHN KYEI

(TO BE FORWARDED)

ATTACHMENT 14
OF
PHASE 1 OPENING TESTIMONY ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR
October 21, 2005
A.05-04-015
I.05-06-041

ATTACHMENT 14

Qualifications of Christopher McLean

Q: Please state your name, title and business address.

A: My name is Christopher McLean. I hold the title of Market Monitoring Specialist at the California Independent System Operator Corporation. The business address for my place of work is 151 Blue Ravine Road, Folsom, California.

Q: In what capacity are you employed?

A: My primary responsibilities involve the day to day monitoring of the price action and participant bidding behavior in all of the CAISO markets for Ancillary Services, as well as the price action in the bi-lateral and exchange traded natural gas markets. In addition to the application of statistical and fundamental analysis in the aforementioned areas, my experience in performing production cost and network modeling is leveraged on special projects similar to and including the Palo Verde-Devers II application of CAISO's Transmission Economic Assessment Methodology.

Q: Please describe your professional background.

A: My role as a Market Monitoring Specialist with the CAISO Department of Market Monitoring at the California ISO began in August of 2004. Prior to joining the ISO, I held an Energy Analyst position with the State of California's Electricity Oversight Board. I began working in the energy industry in 1999 as a Staff Consultant for Henwood Energy in Sacramento, CA. My experiences range from market monitoring and statistical analysis to multi-area production cost modeling, price forecasting and market analytics in support of both generation and transmission project finance deals. My educational background includes a B.S. in Mathematics from Oregon State University.

CERTIFICATE OF SERVICE

I hereby certify that I have served, by electronic and United States mail, a copy of the foregoing Phase 1 Opening Testimony on Behalf of the California Independent System Operator Corporation to each party in Docket Nos. A.05-04-015 and I.05-06-041.

Executed on October 21, 2005 at Folsom, California.

C. N. Wilson

Charity N. Wilson
An Employee of the California
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