CALIFORNIA ISO

Transmission Economic Assessment Methodology (TEAM)

California Independent System Operator

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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,

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[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.

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[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

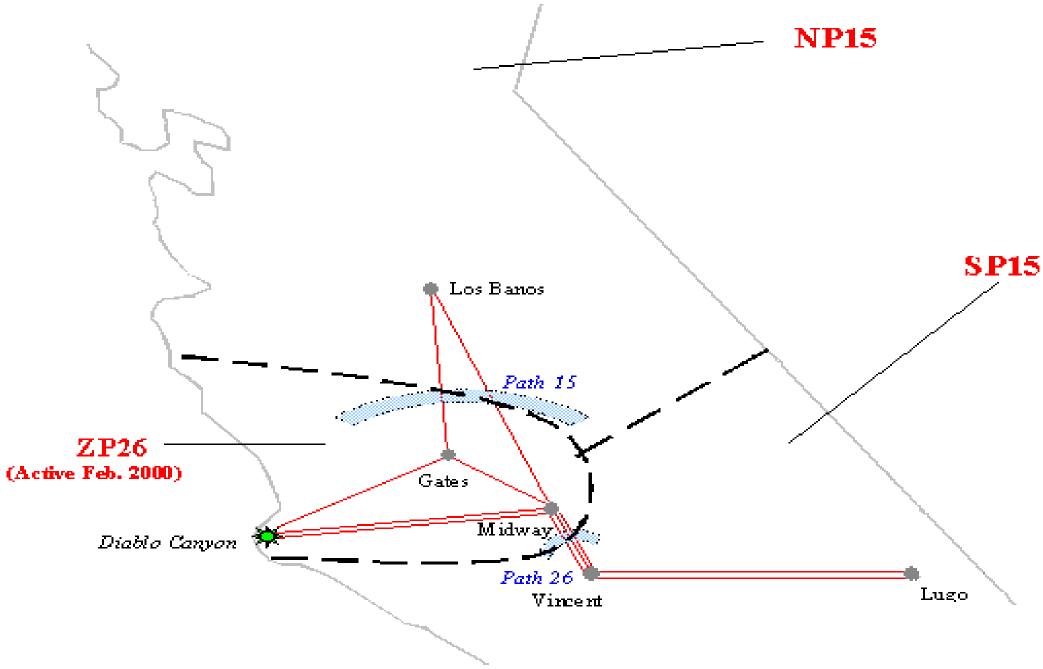
ES.11.1 Study Description

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.

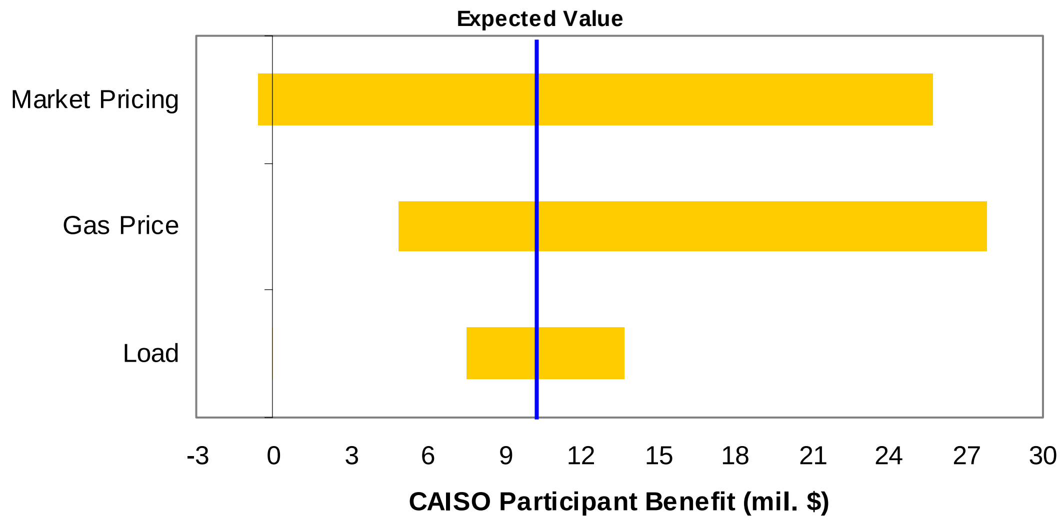
Figure ES.2 shows the impact of three input variables on the 2013 CAISO Participant benefits. The first variable, market pricing, is the level of uncompetitive bidding in the market and ranges from a perfectly competitive market to a highly uncompetitive one.

[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.

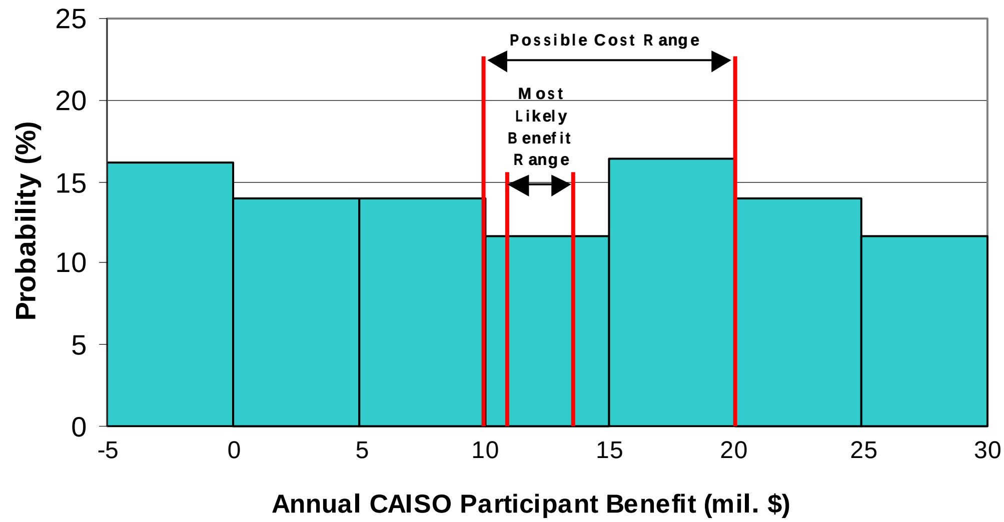
ES.11.4 Probable Benefit and Cost Range in 2013

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 benefits 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 costs 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 value of the Path 26 upgrade is substantial in this case, the expected value 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 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.

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.

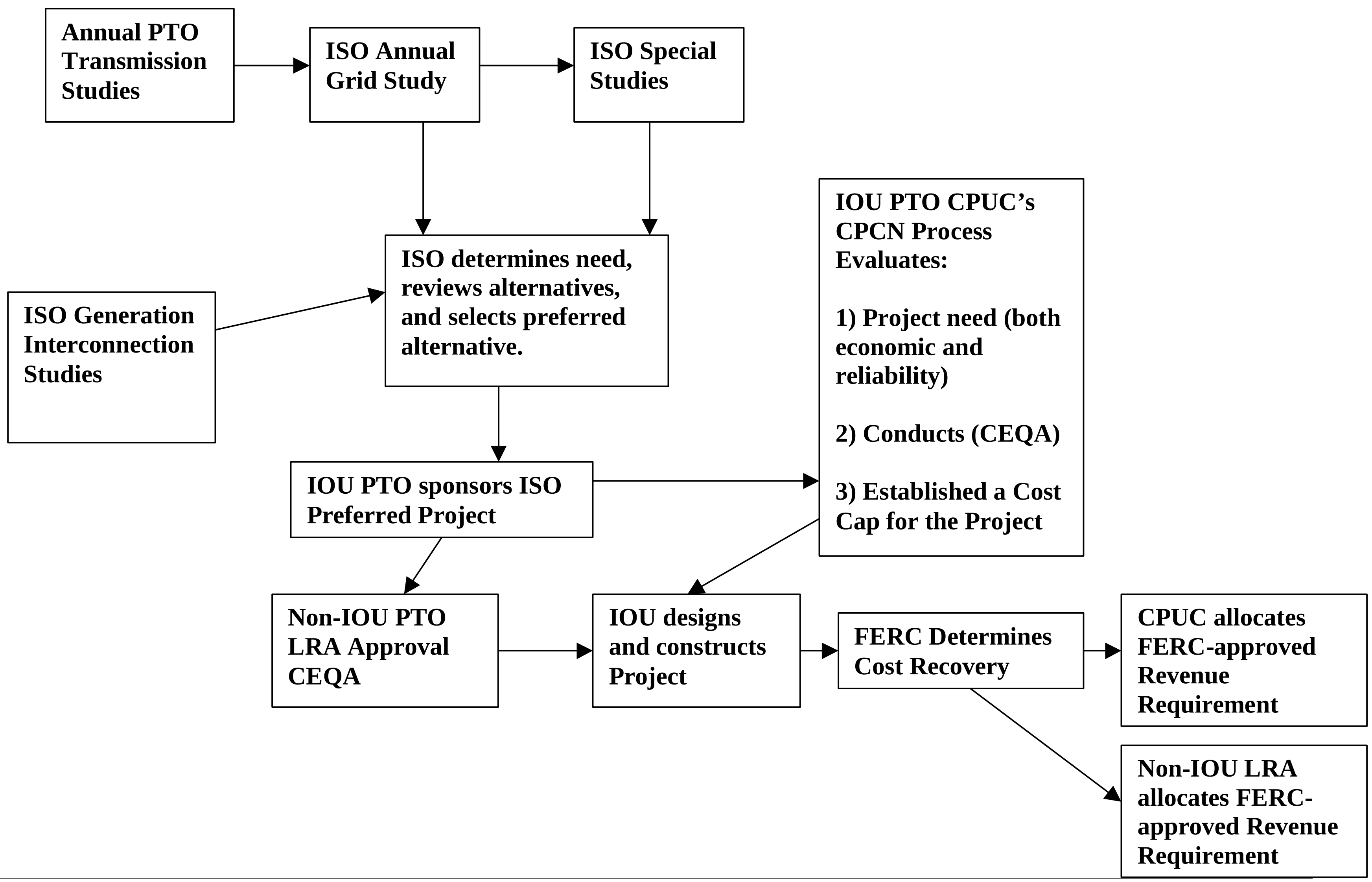
AB 1890 did not, however, revise state law governing transmission facility siting set forth in Public Utilities Code § 1001, et seq. As a result, IOUs continued to be required to obtain a CPCN as a prerequisite to constructing transmission facilities above 200 kV. Because publicly owned utilities were 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").

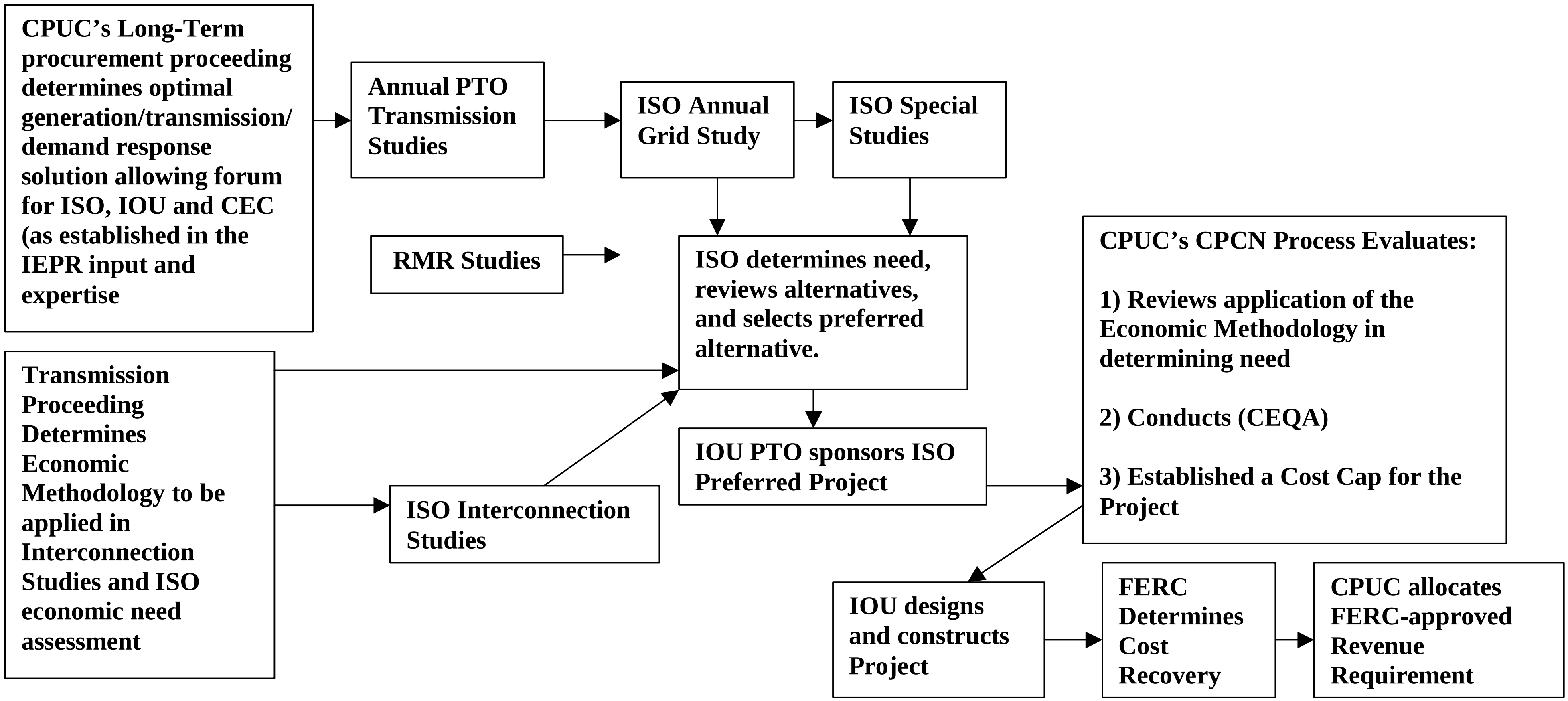
approved TEAM methodology, conducting CEQA review, and implementing more comprehensive resource planning through the IOU's long-term plans. Figure 1.2 outlines the proposed transmission planning and siting process.[6]

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

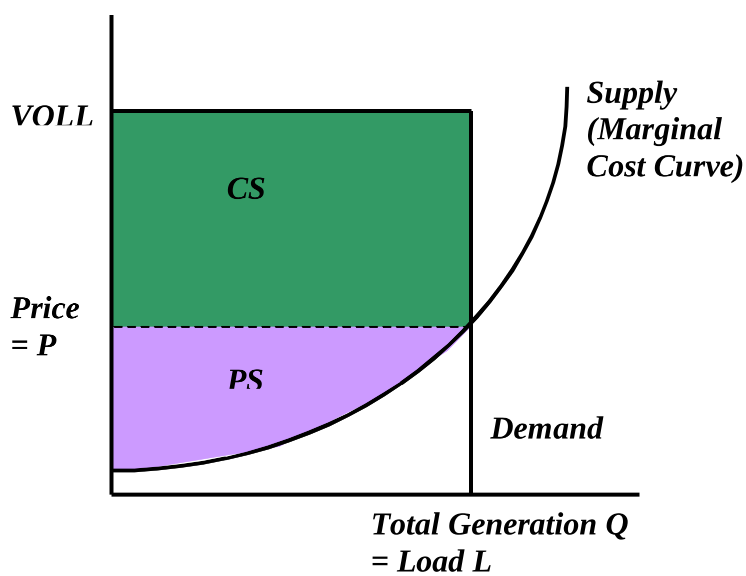


Figure 2.1 graphically depicts consumer and producer surplus under the simple case of an un-congested system where prices are the same across the whole network and all generators bid their marginal costs. The example also assumes that demand is perfectly inelastic and there are no transmission losses 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

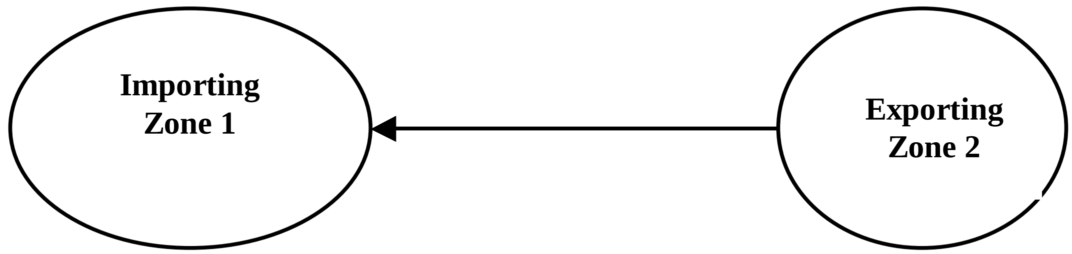
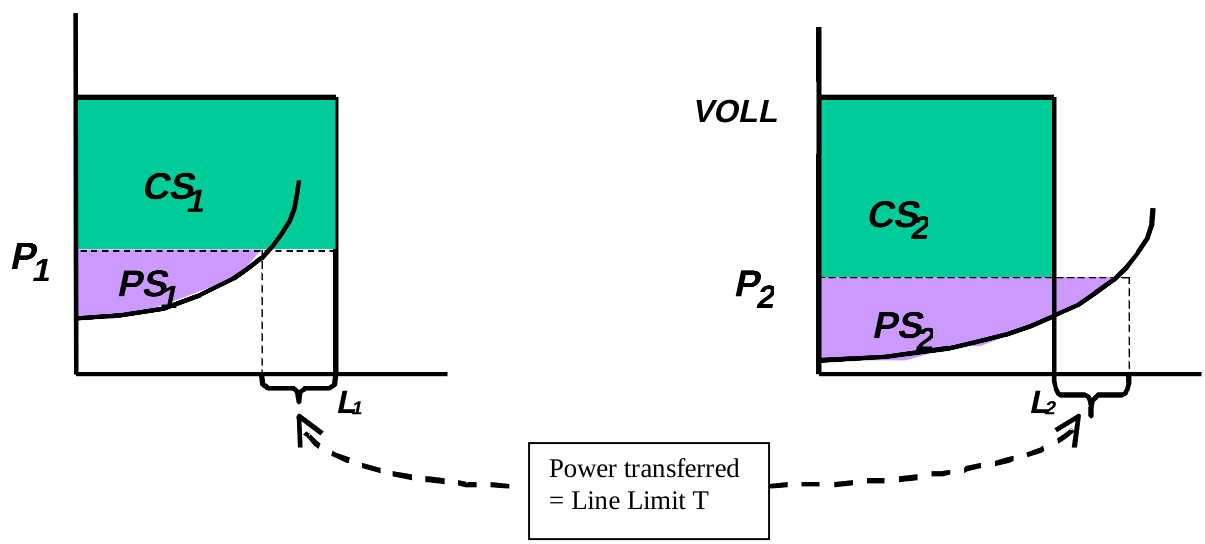


Figure 2.2 above depicts a two-zone example where Zone 1 and Zone 2 are interconnected by a transmission line with limited capacity. Zone 1 is an importing zone due to resource inadequacy or economic reasons (i.e. having more expensive local generation). Zone 2 is the exporting zone due to it having 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.

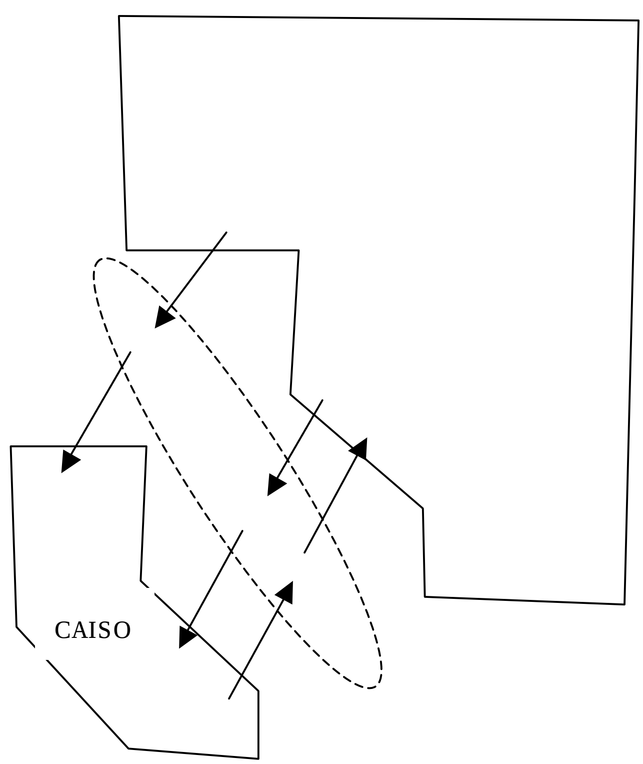
In this case, the congestion revenue is

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

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.

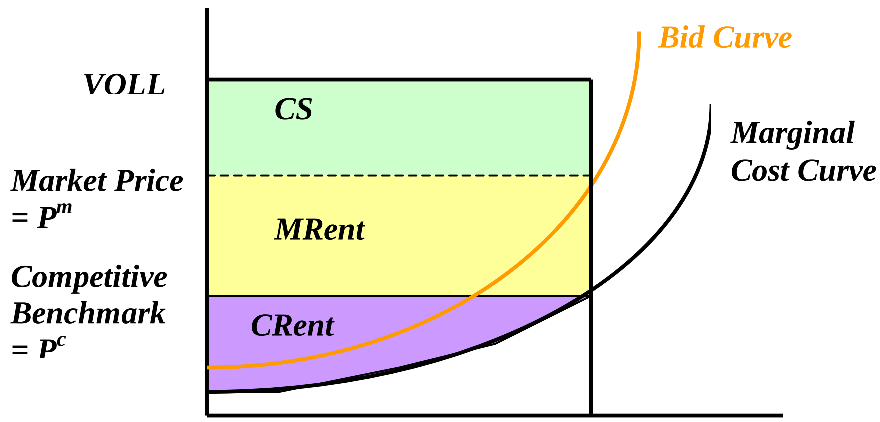
Impact on Consumers

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



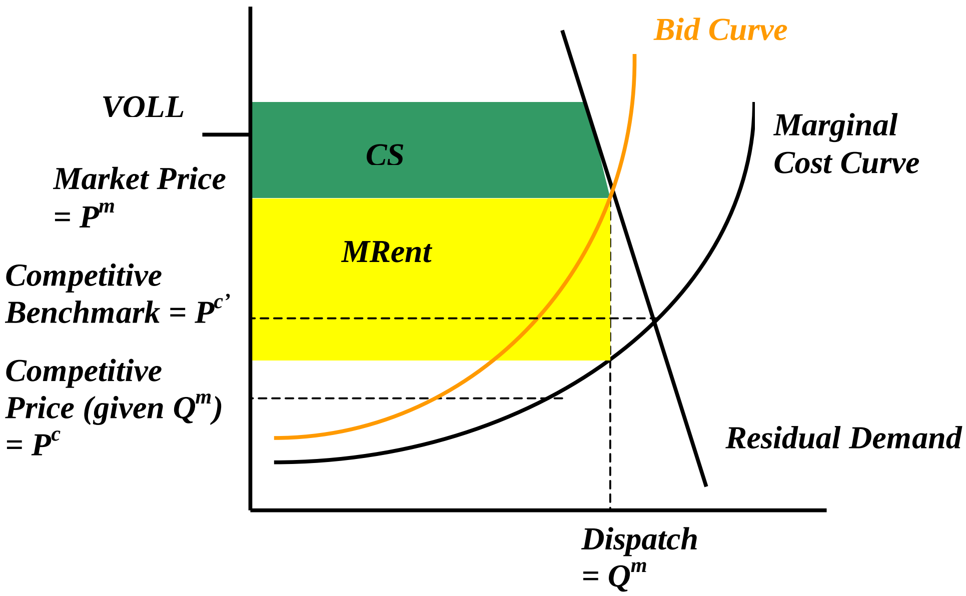
When there is congestion in the system, some consumers may be affected more by suppliers' strategic bidding than other consumers. Nevertheless, the impact of strategic bidding on consumers can still be measured by the reduction in total consumer surplus at the WECC level and at each regional level.

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:

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

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:

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

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:

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

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

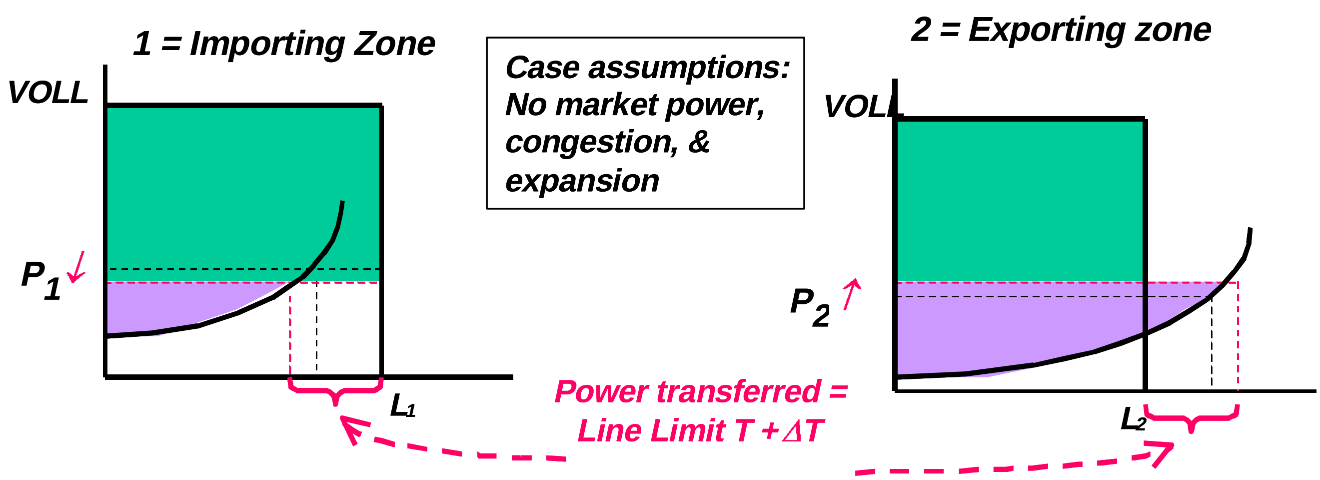
In the two-zone model we discussed before, Zone 1 and Zone 2 are connected by a transmission line with capacity T. Suppose we plan to expand the line limit to T + ΔT and would like to measure the benefit due to this expansion. The line may still be congested after expansion. With the transmission expansion, 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.

[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:

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[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

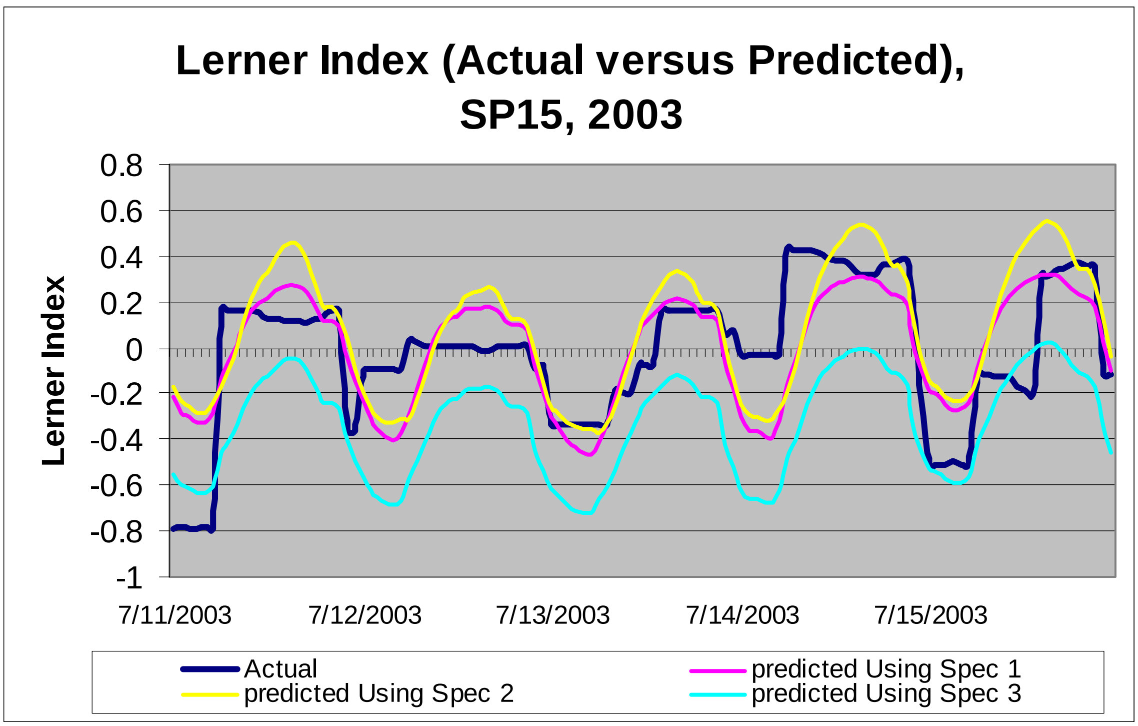
Because our regression specification will be used to derive future market prices for all the various scenarios considered, we believe it is important to develop as good a specification as possible. For this purpose, we developed several potential regression specifications and compared their predictive 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)



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[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:

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

[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

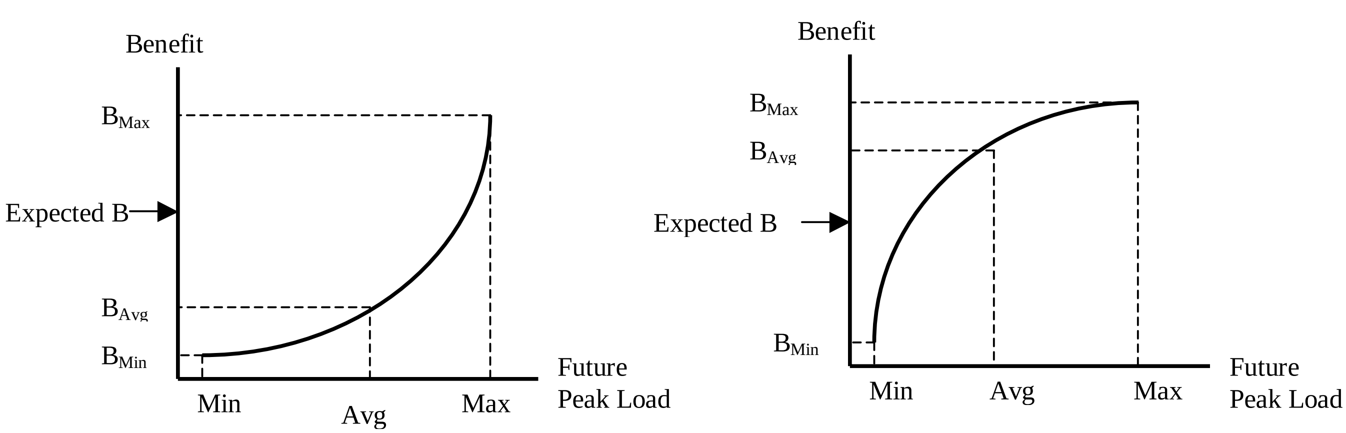
5.1 Overview

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.

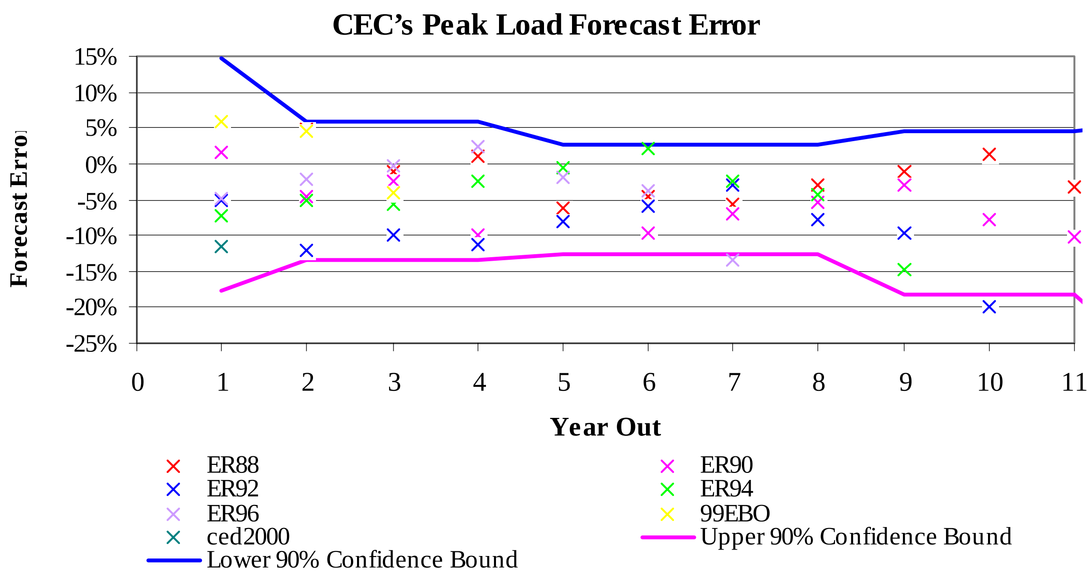
Demand

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.

<u>Importance Sampling</u>

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

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

Bookend

Useful Analytic Comparison

Most likely

<u>Latin Hypercube Sampling</u>

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:

$$\min_{\mathbf{p_1, p_2, \dots, p_m}} \sum_{i=1}^{m} \mathbf{p}_i^2 + \left[\sum_{i=1}^{m} \mathbf{p}_i (\mathbf{D}_i - \hat{\mu}_D)^3\right]^2 + \left[\sum_{i=1}^{m} \mathbf{p}_i (\mathbf{G}_i - \hat{\mu}_G)^3\right]^2 + \left[\sum_{i=1}^{m} \mathbf{p}_i (\mathbf{M}_i - \hat{\mu}_M)^3\right]^2$$

$$\text{s.t.}$$

$$\sum_{i=1}^{m} \mathbf{p}_i \mathbf{D}_i = \hat{\mu}_D \quad \text{......(1)}$$

$$\sum_{i=1}^{m} \mathbf{p}_i \mathbf{G}_i = \hat{\mu}_G \quad \text{......(2)}$$

$$\sum_{i=1}^{m} \mathbf{p}_i \mathbf{M}_i = \hat{\mu}_M \quad \text{......(3)}$$

$$\sum_{i=1}^{m} \mathbf{p}_i (\mathbf{D}_i - \hat{\mu}_D)^2 = \hat{\sigma}_D^2 \quad \text{......(4)}$$

$$\sum_{i=1}^{m} \mathbf{p}_i (\mathbf{G}_i - \hat{\mu}_G)^2 = \hat{\sigma}_G^2 \quad \text{......(5)}$$

$$\sum_{i=1}^{m} \mathbf{p}_i (\mathbf{M}_i - \hat{\mu}_M)^2 = \hat{\sigma}_M^2 \quad \text{......(6)}$$

$$\sum_{i=1}^{m} \mathbf{p}_i (\mathbf{D}_i - \hat{\mu}_D)(\mathbf{G}_i - \hat{\mu}_G) = \hat{\sigma}_{DG} \quad \text{......(7)}$$

$$\sum_{i=1}^{m} \mathbf{p}_i (\mathbf{D}_i - \hat{\mu}_D)(\mathbf{M}_i - \hat{\mu}_M) = \hat{\sigma}_{DM} \quad \text{......(8)}$$

$$\sum_{i=1}^{m} \mathbf{p}_i (\mathbf{G}_i - \hat{\mu}_G)(\mathbf{M}_i - \hat{\mu}_M) = \hat{\sigma}_{GM} \quad \text{......(9)}$$

$$\sum_{i=1}^{m} \mathbf{p}_i = 1 \quad \text{......(10)}$$

$$\mathbf{p}_i \geq 0 \quad \text{for all } i \quad \text{......(11)}$$

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.

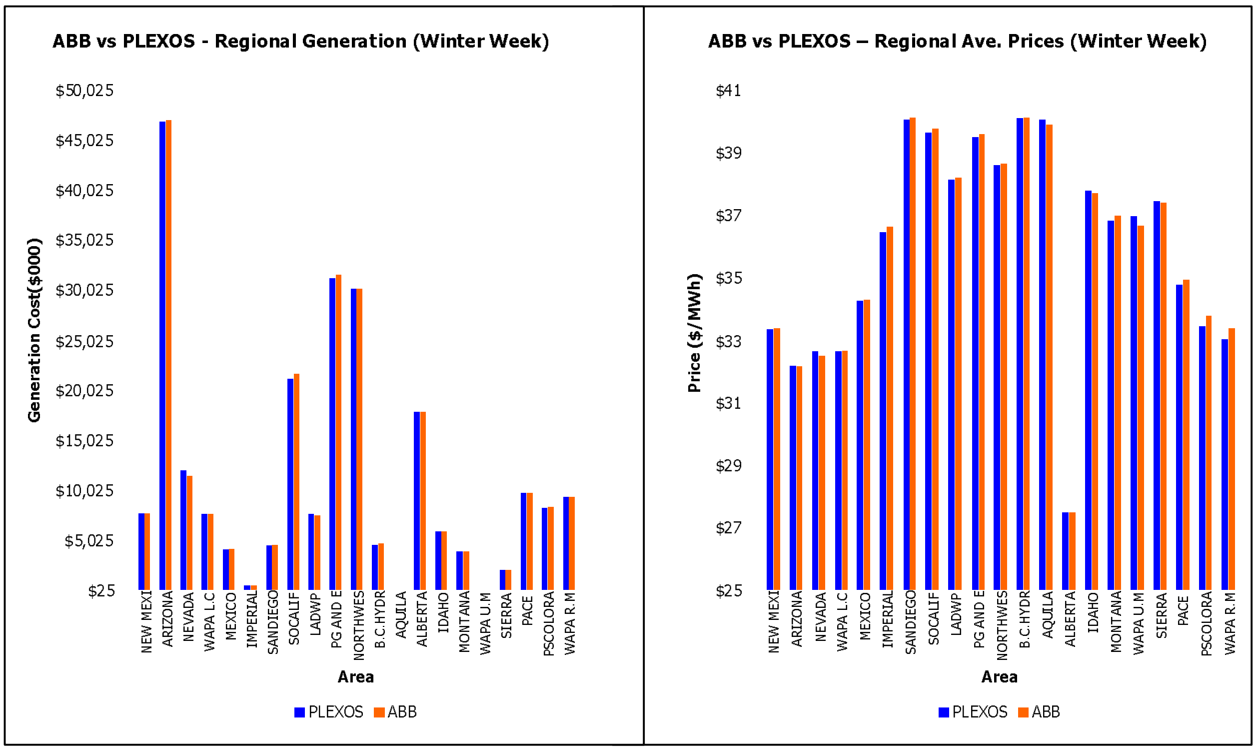
- The optimization models were entirely auditable (all solutions are derived from mathematical programming algorithms, which could be examined and validated)

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.

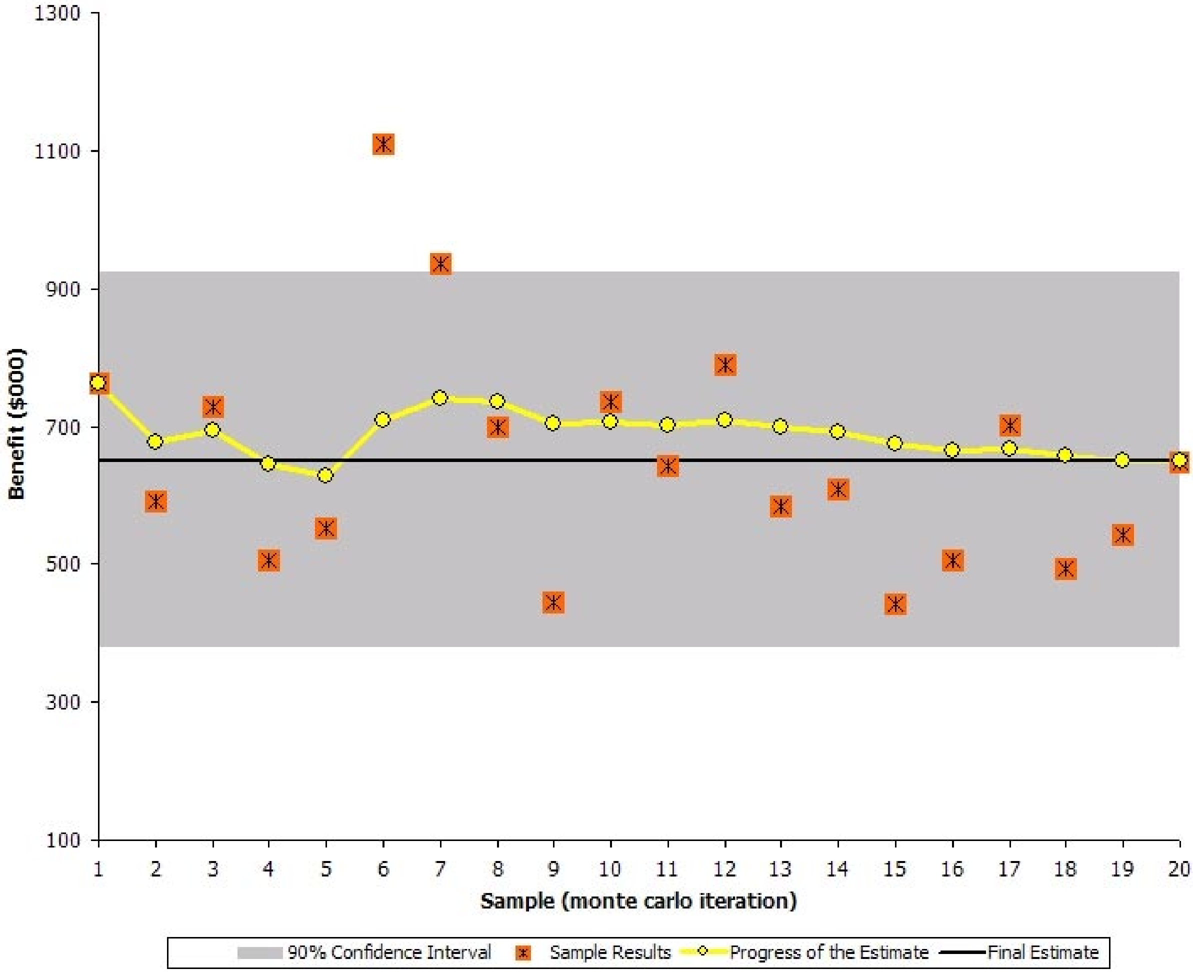
7.3.2 Generator Outages

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.

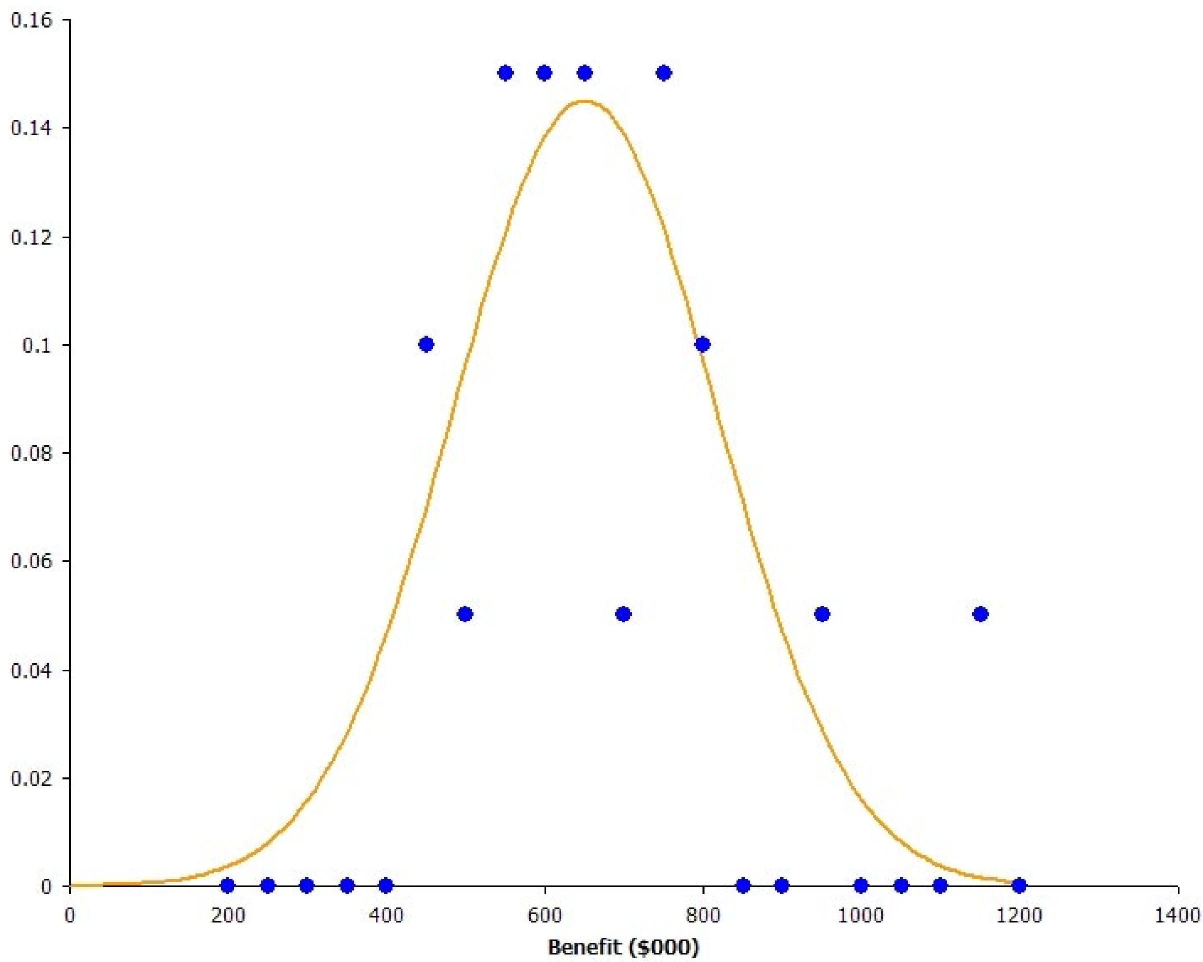
Figure 7.2 Convergence of the Societal Benefit Estimate Across 20 Monte Carlo Simulations



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.

[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

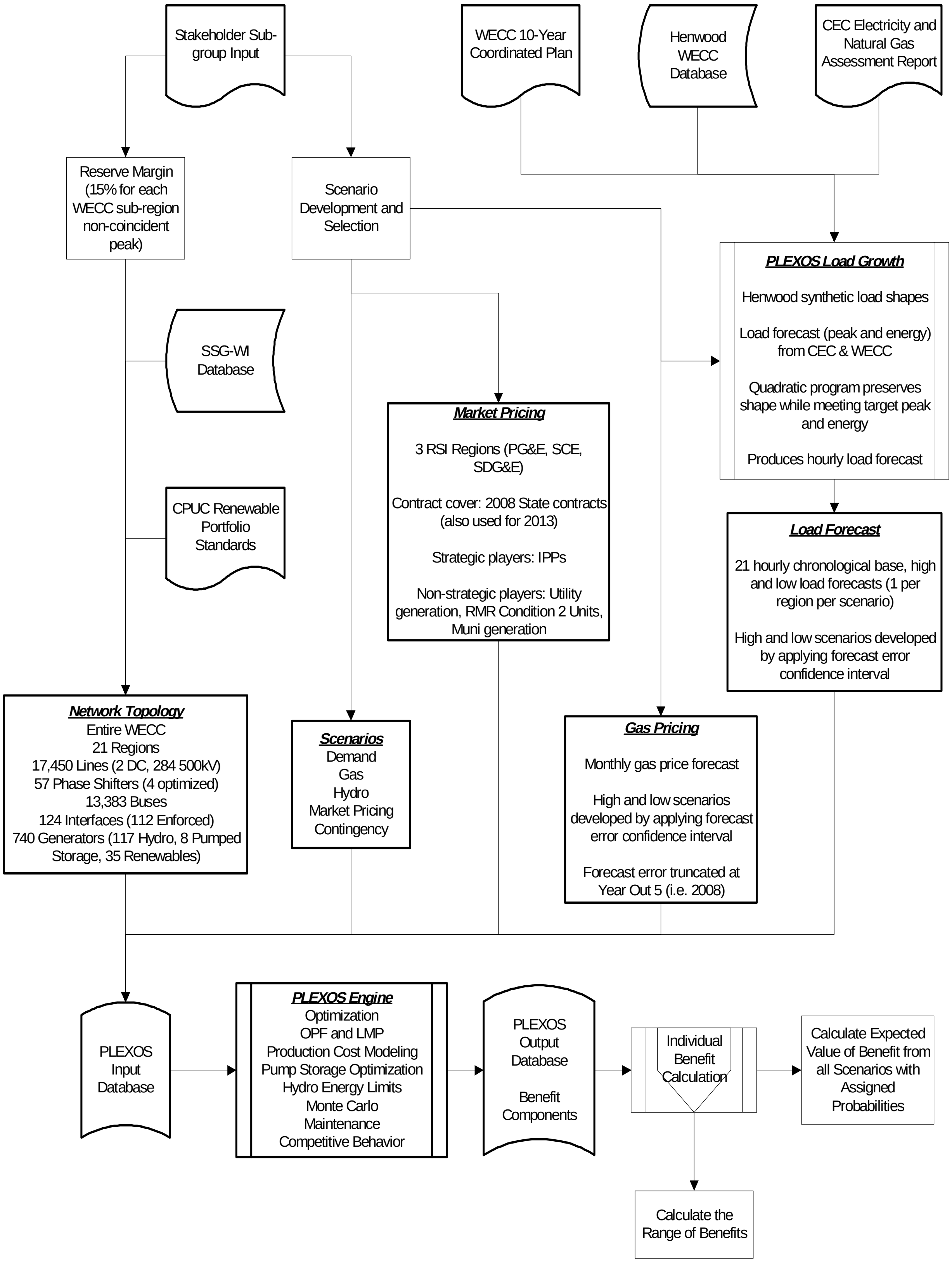
8.1 Overview

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

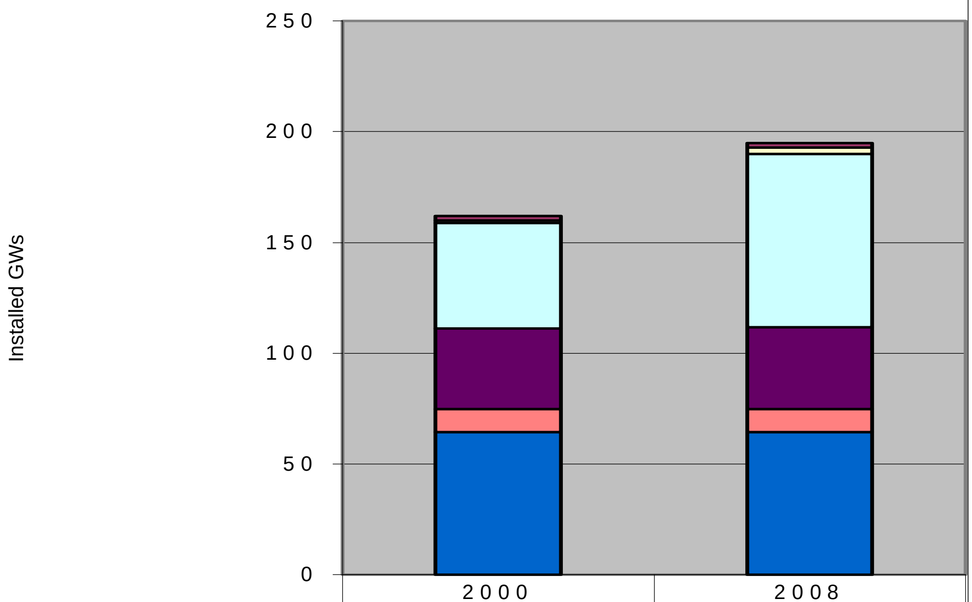
The CAISO started with the base case SSG-WI dataset. In the following we briefly discuss data for generation, transmission, non-gas fuels, and hydro as derived in the SSG-WI database.

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]

[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.

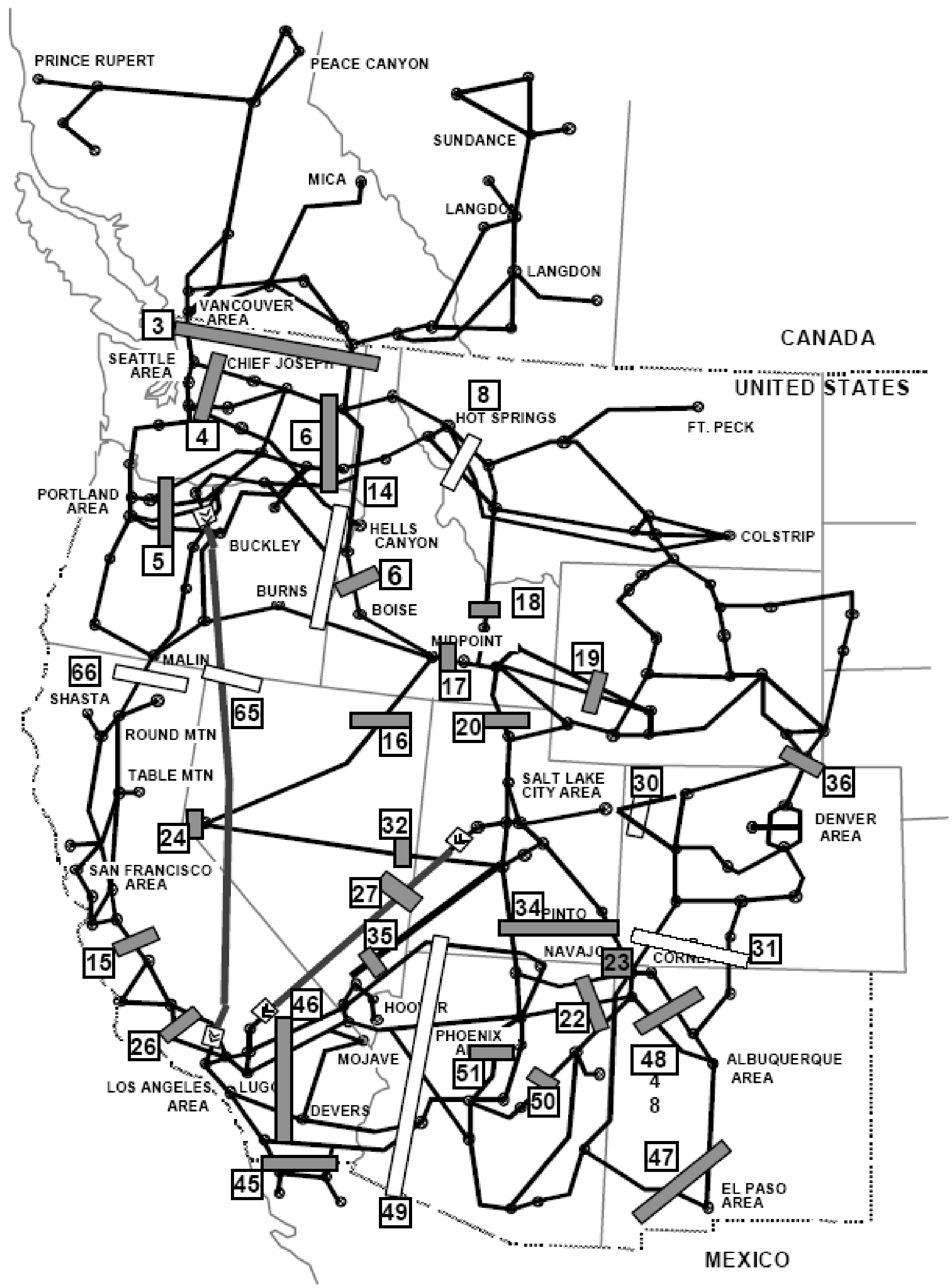
The 2008 SSG-WI generation database was further revised with the CAISO data described in Sections 8.3.3 and 8.3.4. This CAISO-modified 2008 generation database was then used as a base for 2008.

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.

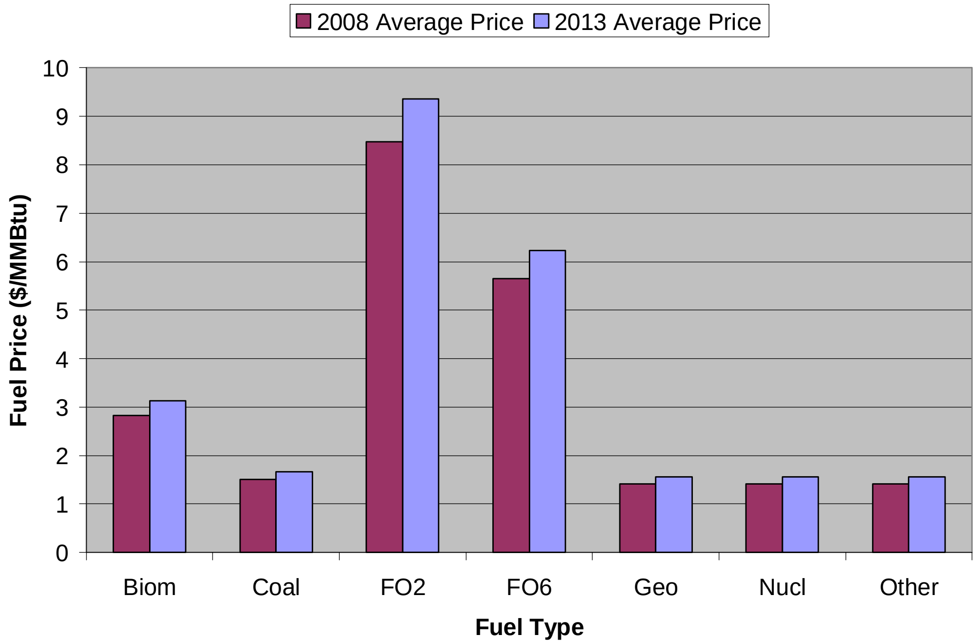
Table 8.3 Transmission Expansion Plan

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

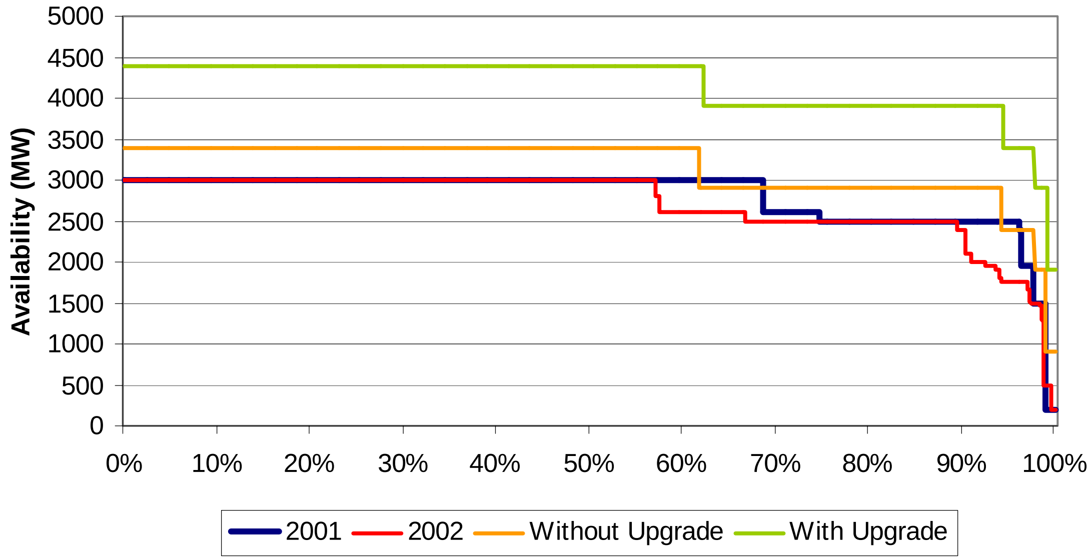
The outage ratings with and without the upgrade for 2008 and 2013 exhibit the same magnitude of decrease from the maximum OTC as the historically likely outage ratings. Neither the 400 MW upgrade to be implemented prior to the 2008 study year, nor the 1000 MW test upgrade are derated proportionately. 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.

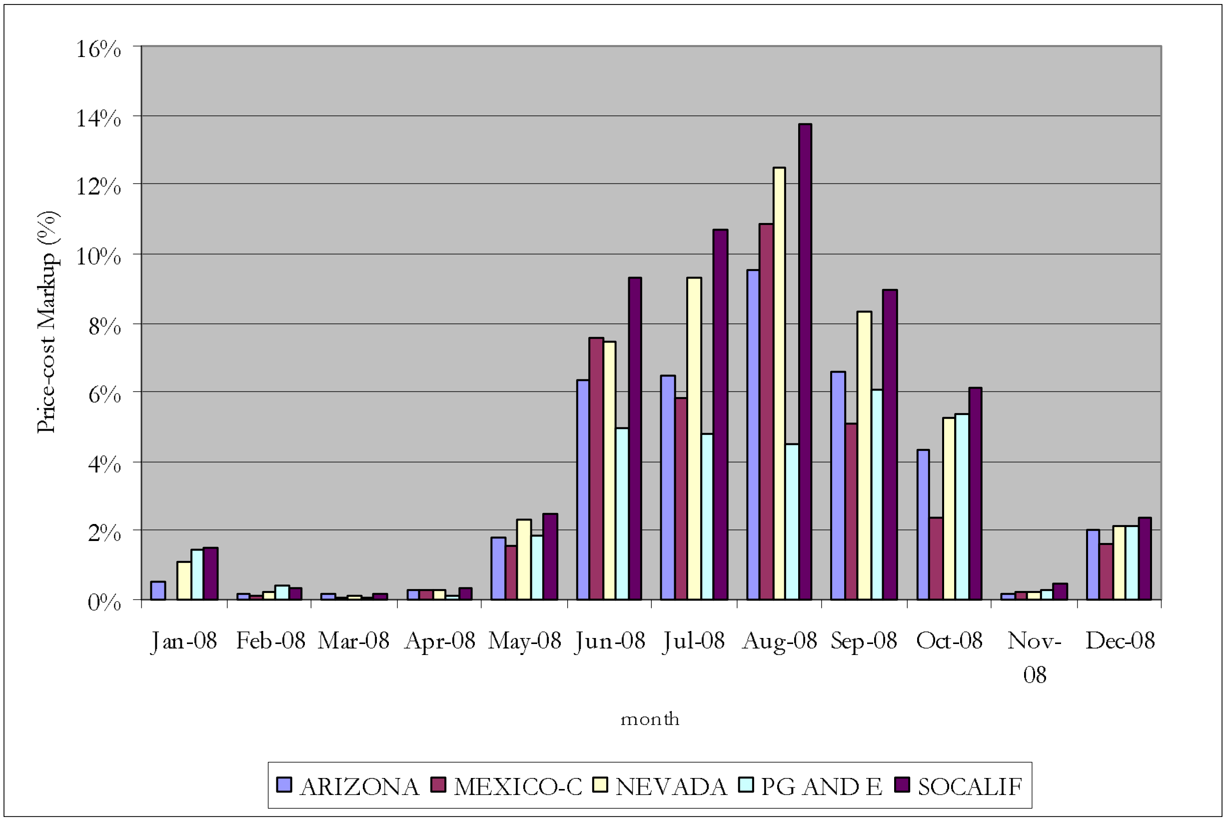
Note that we only modeled strategic bidding behavior in three utility regions in California. We elected not to apply bid markups to resources in regions outside of the three California utility regions because other regions in the WECC are predominately comprised of vertically integrated utilities. Under 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

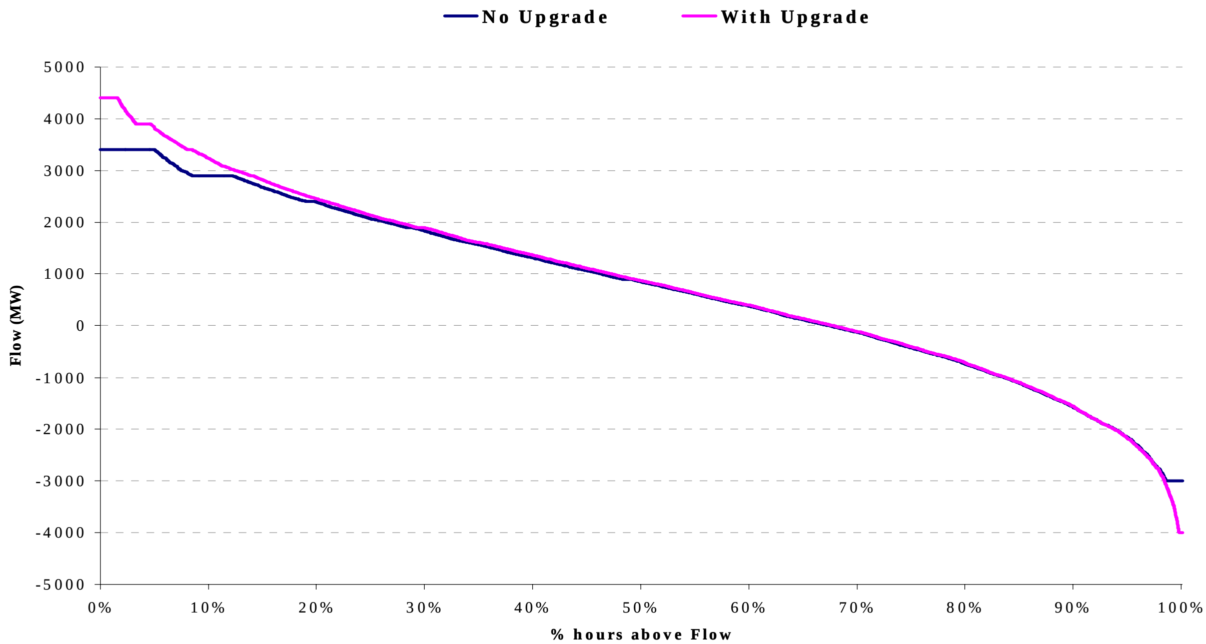
Year	Load	Gas Price	Hydro	Market Pricing	Other	Societal Benefits ($ M)	Modified Societal Benefits ($ M)	CAISO Participant Benefit ($ M)	CAISO Ratepayers Benefits ($ M)
2008	Base	Base	Base	None	None	$ 1.00	$ 1.00	$ 2.10	$ 0.50
2008	Base	Base	Base	Moderate	None	$ 4.28	$ 7.04	$ 19.00	$ 11.99
2013	Base	Base	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.

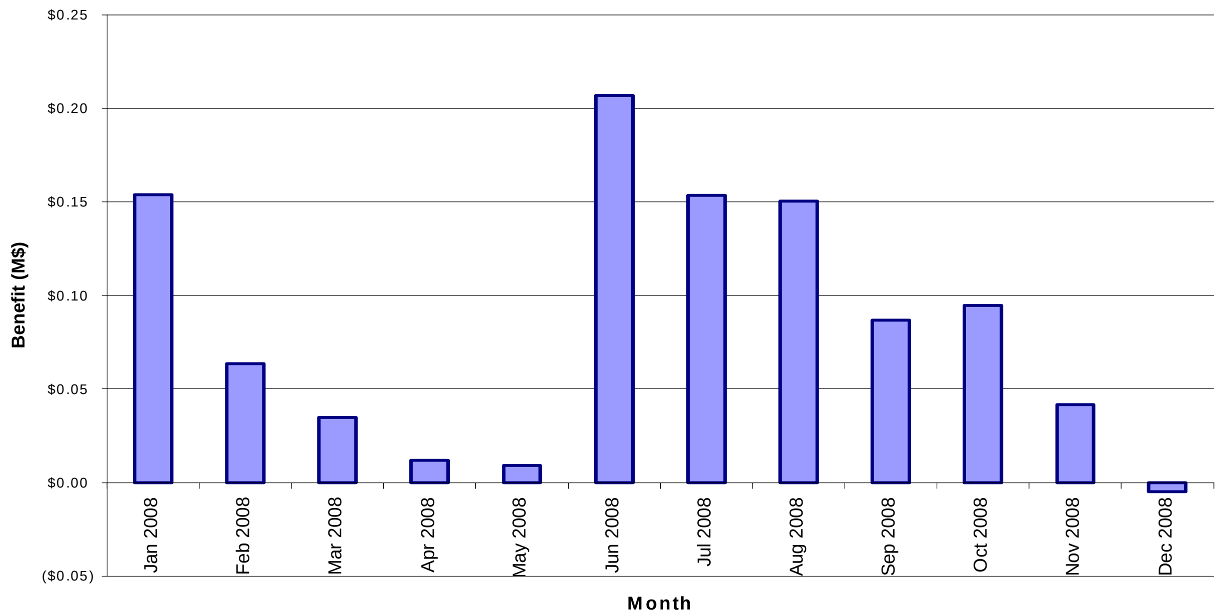
Figure 9.2 Path 26 Flows in Cost-based Reference Case



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.

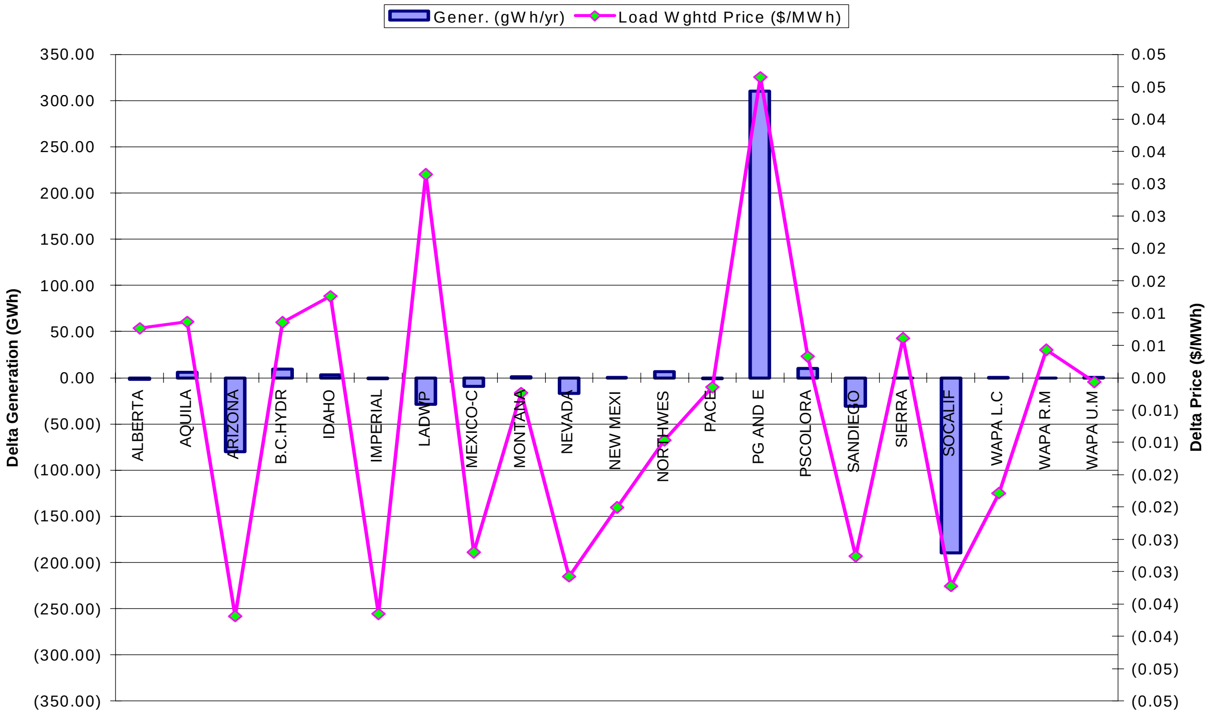
Figure 9.3 Total Societal Benefits – Monthly Variations in Cost-based Case



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

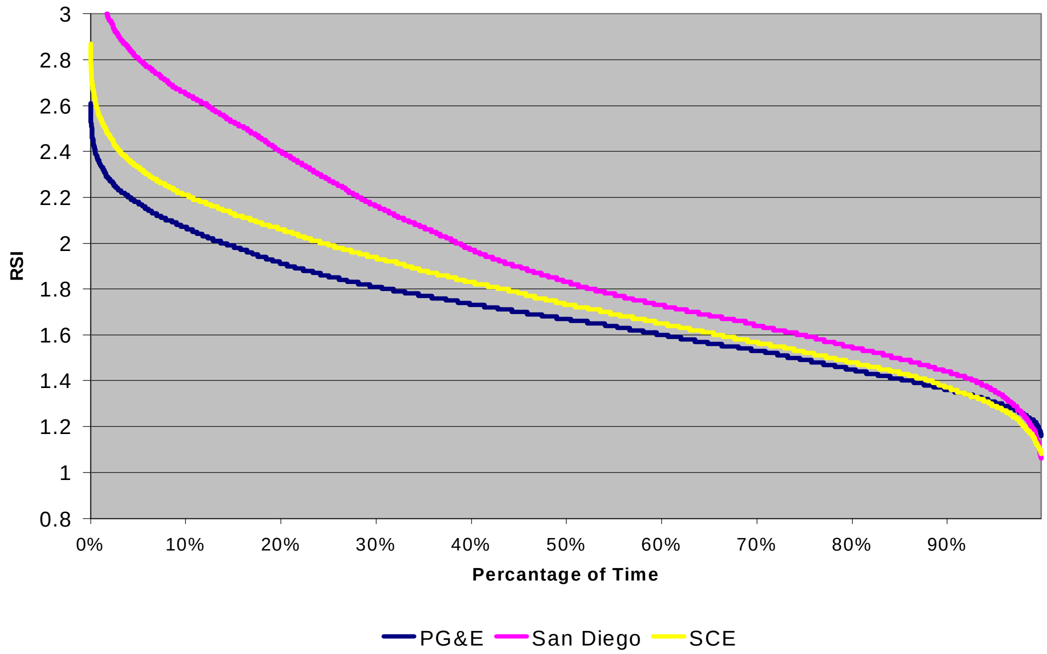
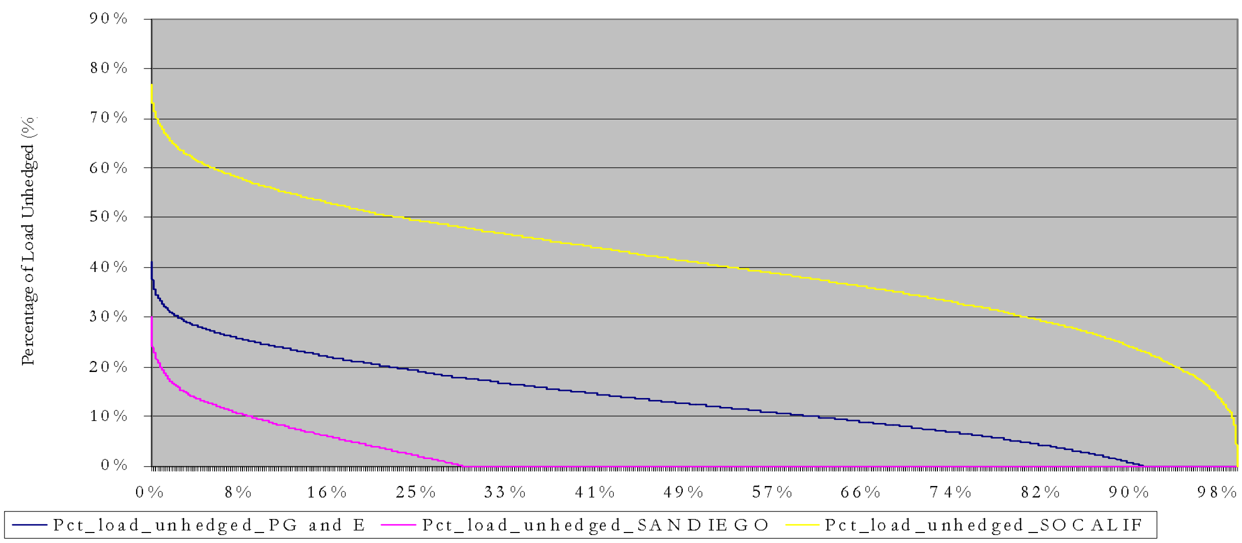


Figure 9.6 Percentage of Load Unhedged Duration Curves, 2008, BBB, No Upgrade



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

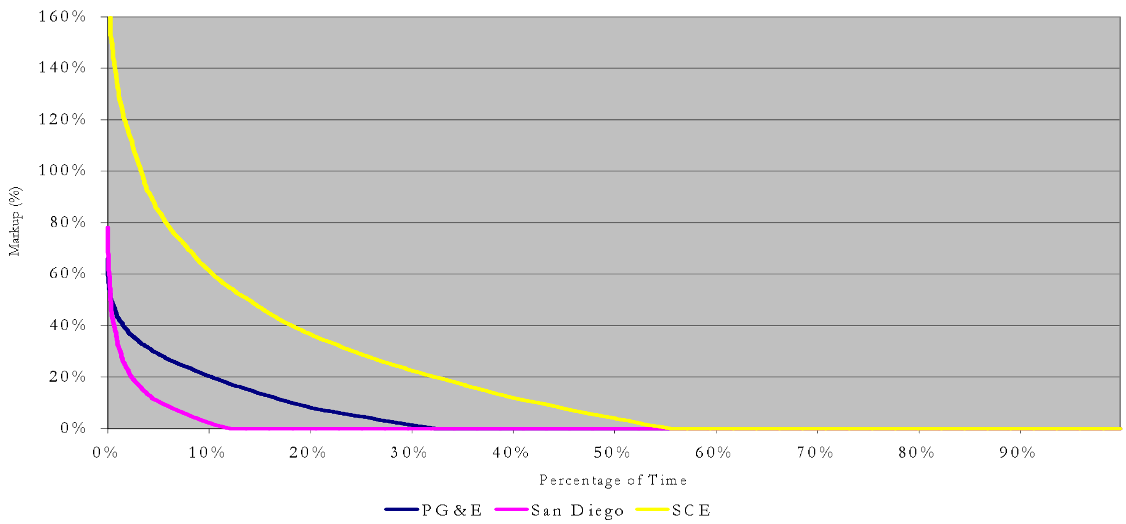
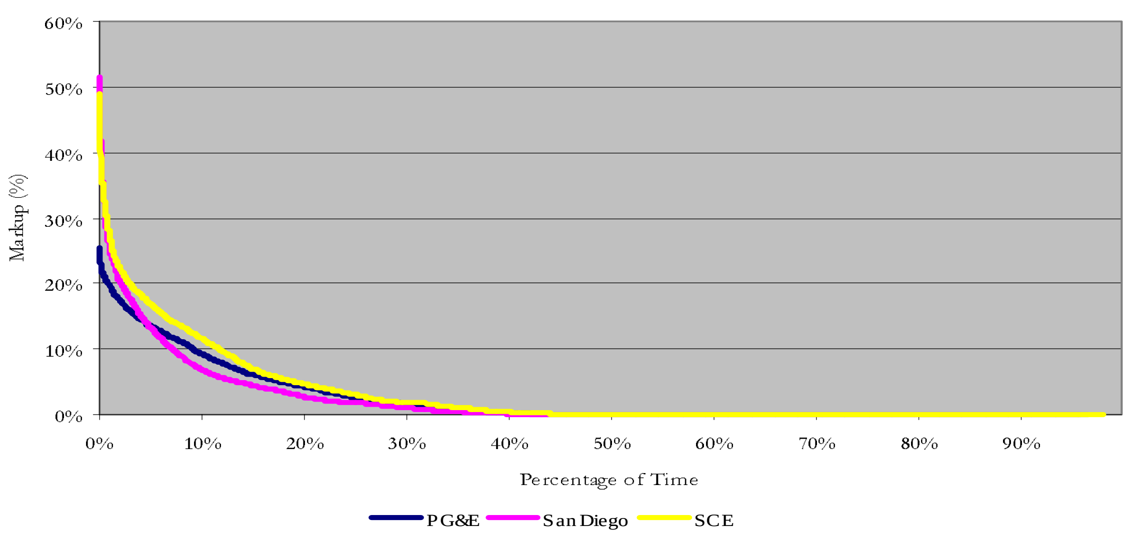


Figure 9.8 Predicted Price-cost Markups in 2008, No Upgrade



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

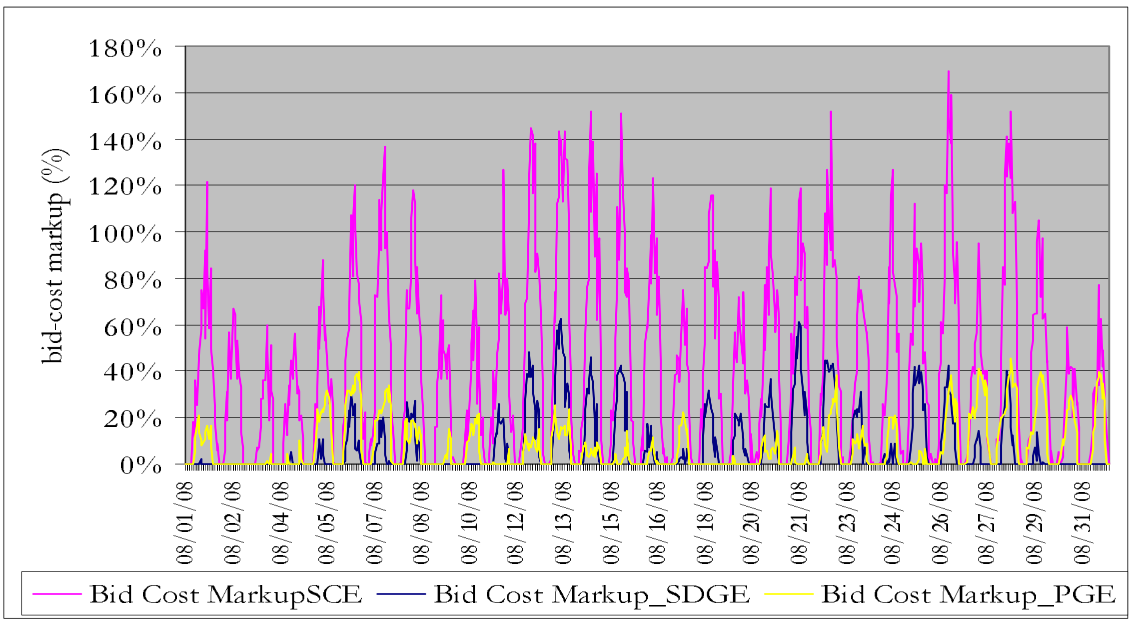
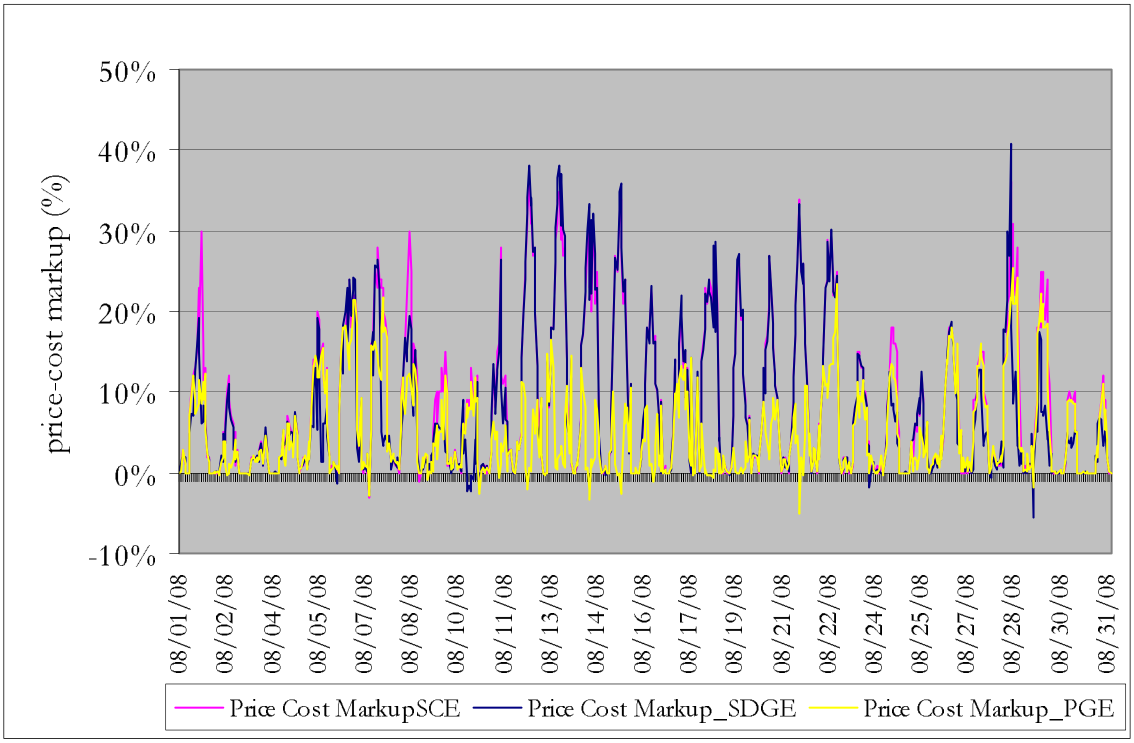


Figure 9.10 Price-cost Markups, SCE, 2008, No Upgrade



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

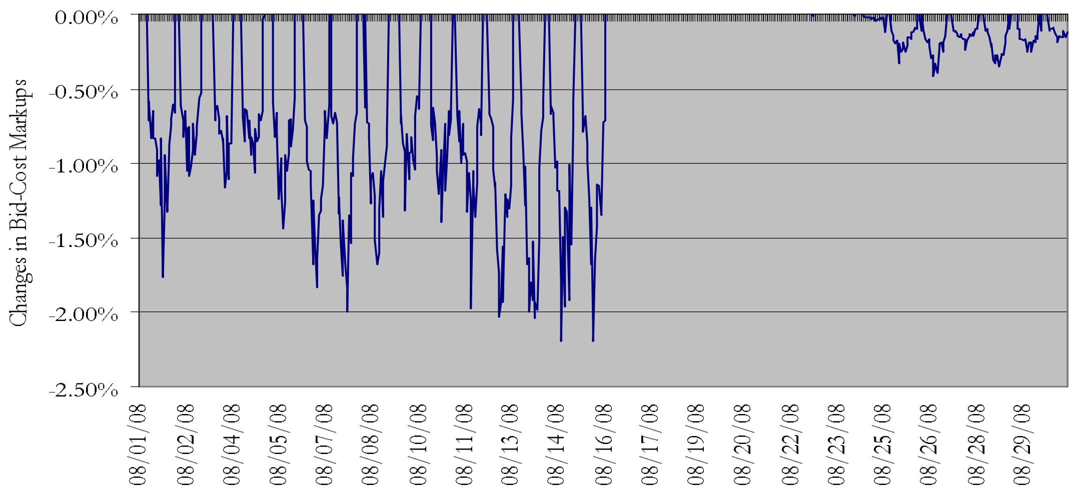
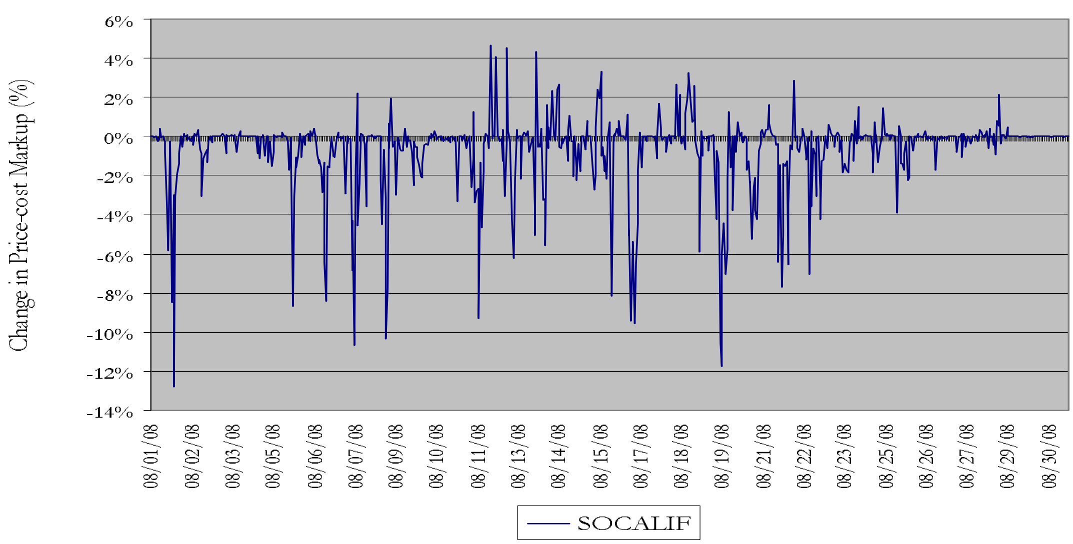


Figure 9.12 Changes in Price-cost Markups (With Exp – Without Exp), SoCalif, August 2008, BBB



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

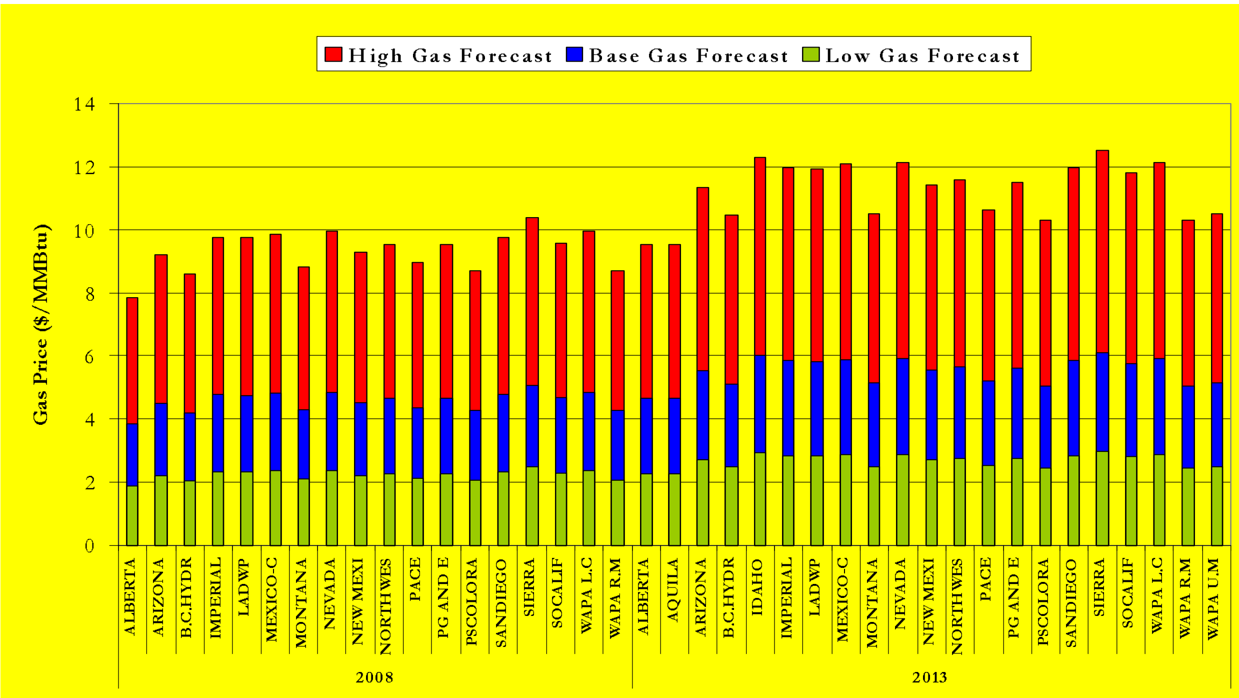


Table 9.4 Effects of Gas Prices on Benefits - Year 2008 & Year 2013

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

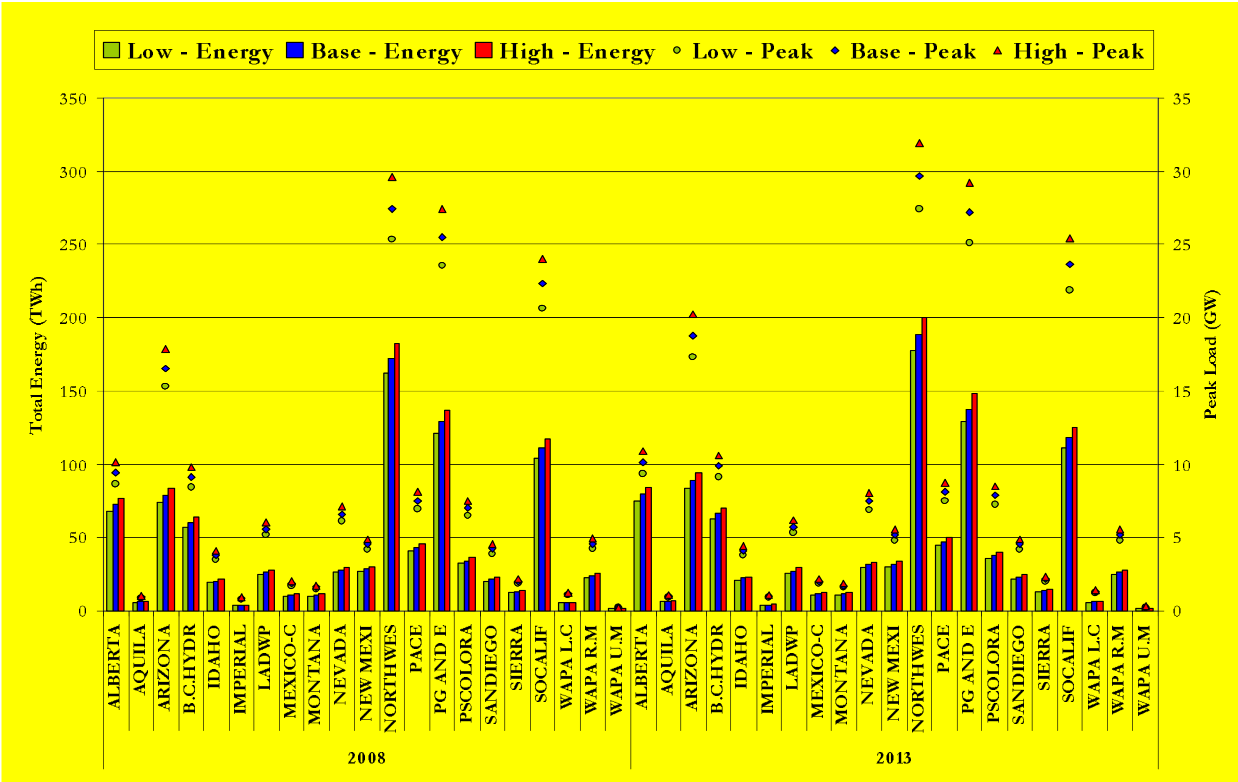


Table 9.5 Effects of Demand on Benefits - Year 2008 & Year 2013

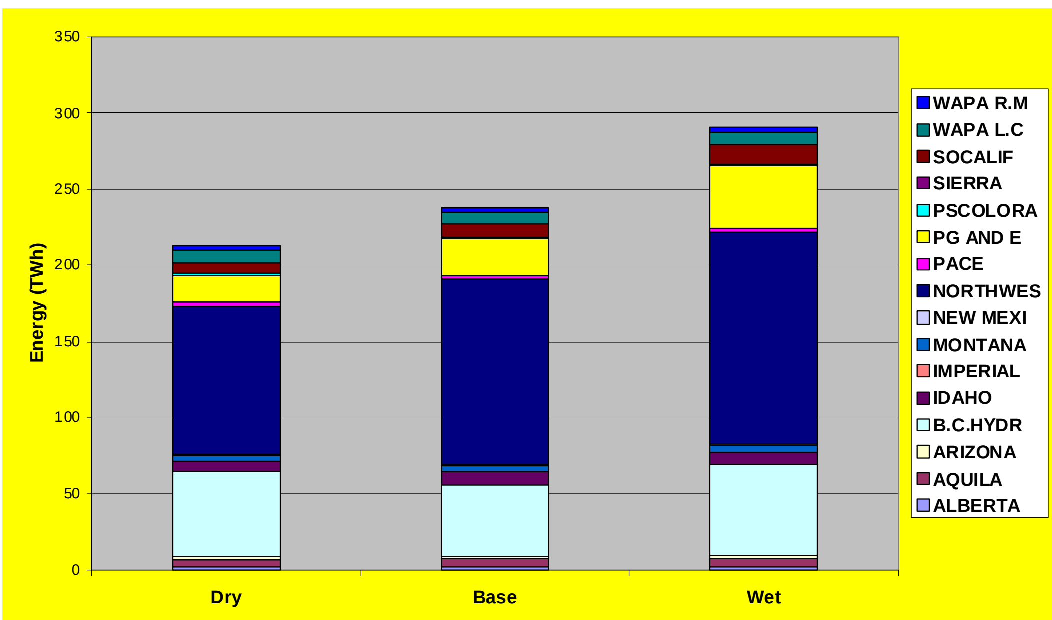
Year	Load	Gas Price	Hydro	Market Pricing	Other	Societal Benefits ($ M)	Modified Societal Benefits ($ M)	ISO Participant Benefit ($ M)	ISO Ratepayers Benefits ($ M)
2008	VL	Base	Base	Moderate	None	$ 2.05	$ 6.14	$ 9.48	$ 6.67
2008	Base	Base	Base	Moderate	None	$ 4.28	$ 7.04	$ 19.00	$ 11.99
2008	VH	Base	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

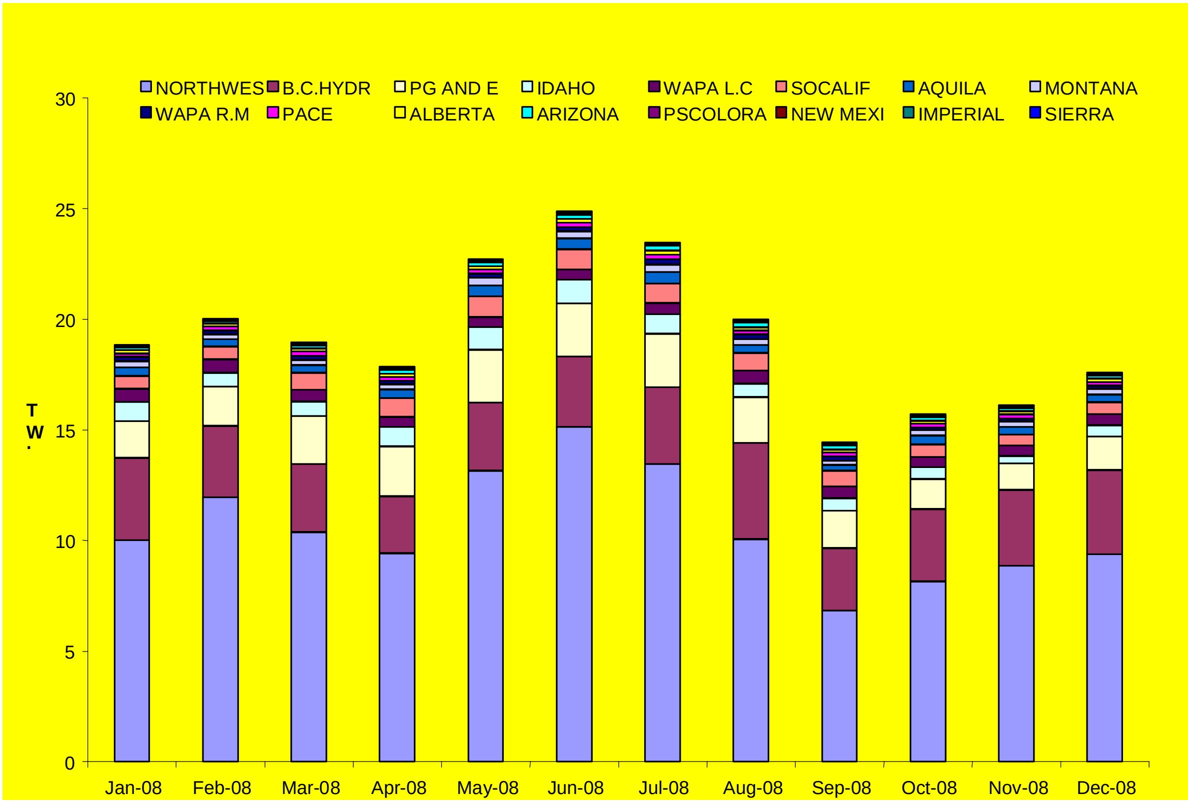


Table 9.6 Effects of Hydro Conditions on Benefits - Year 2008

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.