ECONOMIC EVALUATION OF TRANSMISSION INTERCONNECTION IN A RESTRUCTURED MARKET

CONSULTANT REPORT

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EXECUTIVE SUMMARY

California's high voltage interconnections to neighboring states have played a vital role in meeting the state's electricity needs reliably and at great savings to the customers. However, in recent years the construction of new high voltage transmission capacity has not kept up with the load increases nor with the addition of generation capacity.

The California Independent System Operator (CA ISO) has carried out the development of a comprehensive methodology for economic evaluation of transmission projects in the restructured wholesale electricity market. This report provides a review of the CA ISO methodology and also provides recommendations for future enhancements.

The CA ISO established a stakeholder process to complete the development of the "Transmission Economic Assessment Methodology" (TEAM). The proposed CA ISO methodology addresses these major issues: modeling of market power; development of a robust set of scenarios; selection of appropriate simulation tools and programs; adequate representation of the transmission network; and selection of benefit tests.

The CA ISO has made the decision to use the price-cost mark up method based on historical data to take into consideration the market power of generators.

The CA ISO has adopted an elaborate process for the selection of scenarios and the determination of joint probabilities for those selected scenarios. These scenarios could be used in evaluating extreme cases for contingency planning or insurance against unlikely events. The development and selection of the scenarios should be an important element of the evaluation of projects.

The simulation tool selected by the CA ISO is a production simulation model called PLEXOS. It has the capability to integrate a direct current (DC) optimal power flow analysis of the transmission network system and a probabilistic production simulation model with unit commitment logic.

The network representation used by the CA ISO is a full network model of the Western system with data provided by the Western Electricity Coordinating Council (WECC). A linearized (so-called "DC") power flow model of the high voltage network is utilized.

Benefit tests examined by the CA ISO include: the participant/ratepayer test (benefits to those entities paying for the new transmission facility); the societal test (benefits to all consumers, producers and transmission owners, irregardless of who paid for the new transmission facility); and the modified societal test recognizing or excluding non-competitive revenues (monopoly rent) collected by some producers.

The CA ISO has selected two years, 2008 and 2013, for the benefit analysis. The reason for selecting only two years is that the model requires significant amounts of input data and the CA ISO staff had limited time for the collection of data and to carry out analysis. Furthermore, the CA ISO feels that due to data uncertainty, the analysis should not be carried out for the time frame beyond 10 years.

The CA ISO, then, compares the annual levelized cost of the transmission project (capital cost multiplied by an annual carrying charge) to the annual benefit in 2008 and 2013 to see if the project is cost effective.

The annual carrying charge is based on the regulated cost of capital of the transmission owner proposing the project and it also includes depreciation costs for the facility.

In the evaluation of the transmission project, there is a need to capture the dynamic relation between transmission expansion and the construction of new generation plants. Building of a new transmission project provides an incentive to construct new generation plants in the exporting region. The CA ISO model recommends an evaluation based on results for two years, 2008 and 2013. This limited analysis may not capture the interaction between transmission and generation expansion.

Based upon our review, we endorse the methodology developed by the CA ISO for adoption by the California Public Utilities Commission (CPUC). We further recommend that the following improvements should be examined and considered for future enhancement of the CA ISO methodology:

1. Analysis based on production simulation models be carried out for at least five years, say 2008 through 2013 for every year, to capture the dynamic relation between transmission and generation expansion;

2. There is need to capture the long-term benefits of transmission lines. Therefore, benefits beyond 2013 must be estimated by evaluating results from 2008-2013 or by estimating the construction and operation costs of power plants in exporting and importing regions;

3. The potential benefits from increased reserve sharing and firm capacity should be included in the benefits analysis;

4. The environmental benefits from new transmissions lines should be included in the economic evaluation; and

5. Since high voltage transmission lines are becoming “public goods” and the benefits from the construction of new lines are shared among customers,

generation owners, and transmission owners in both importing and exporting regions, the social discount rate should be used in calculation of the present worth of benefits from transmission lines. The regulated cost of capital for transmission owners should be used to calculate the transmission access charges and not to determine the present worth of benefits.

The detailed evaluation methodology proposed by the CA ISO and the modification recommended here, should be used for justification of a specific project during the permitting phase. In the strategic phase and the purchasing of rights-of-ways, it will be sufficient to assess the resource potential in each market hub. Estimates of the construction and operation costs in each market may then be used to establish the price differential for power between market hubs. Based on historical line loading and price differential between market hubs, a strategic decision should be made for purchasing rights-of-way for future transmission projects. Purchasing and banking of rights-of-way will insure the expansion of the transmission network in a timely manner.

INTRODUCTION

California's high voltage interconnections to neighboring states have played a vital role in meeting the state's electricity needs reliably and at great savings to the customers. However, due to changing industry structure and financial uncertainties, construction of transmission capacity has not kept up with the increase in load or with the addition of generation capacity. There is a need for the development of an evaluation methodology that will include strategic benefits from transmission lines.

This report addresses the need to capture the long-term benefits of transmission lines, including a perspective that transmission lines are a "public good" and therefore, should be evaluated using a social discount rate. This report provides recommendations to adapt and modify the CA ISO proposed evaluation methodology to capture the long-term benefits that transmission projects may provide.

Main Objectives for Transmission Expansion

Historically, high voltage transmission projects were planned and constructed to connect large remote power plants to load centers. In California these included 230kV lines, such as lines from Southern California Edison's Big Creek hydroelectric projects to Southern California. Later, 500kV and DC lines were constructed for connecting large nuclear and coal plants located in other states to serve the loads of different utilities within California. For example, a DC line was constructed to connect the Intermountain Coal Plant in Utah to Los Angeles, and the 500kV Palo Verde-Devers line for connecting Palo Verde Nuclear Plant in Arizona to the transmission system.

Several large transmission lines, mostly between the Pacific Northwest and California, were planned and constructed without connecting any specific power plants. These include the DC line from Oregon to Sylmar, Southern California, and the 500kV AC lines from Oregon to Northern California. These transmission lines were constructed to take advantage of load diversity between California (summer peaking) and the Pacific Northwest Region (winter peaking) and resource diversity -- hydroelectric systems in the Northwest and fossil fuel generation in California and Southwest states. Surplus economy energy and capacity exchanges were some of the benefits from these transmission lines.

As the load increased in urban centers, the construction of 230kV and 500kV lines became necessary for assuring the reliability of the transmission network. These projects were justified for their contribution to reliability, rather than for bringing additional power from remotely located generation plants. Examples of these reliability transmission projects are the third Midway-Vincent line, the upgrade of the Serrano Substation and transmission lines in surrounding areas in Southern California, and the Tesla-Newark line in Northern California.

Future transmission projects will also be constructed to serve similar objectives, (i.e., reliability needs, connecting load centers to market hubs that have surplus capacity and/or energy or connecting specific power plants to the existing grid). The proposed 230 kV Jefferson - Martin line on the San Francisco Peninsula will increase reliability, the second 500kV Palo Verde-Devers line will access the market hub in the Palo Verde area where many large gas fired combined cycle (CC) plants have been constructed recently, and the second DC line to Utah will be necessary when additional coal-fired units are constructed at the Intermountain site.

Nature of Transmission Projects

Transmission projects are capital intensive. Most of the cost occurs during the construction. There are also economies of scale. The operation and maintenance costs are normally a very small portion of the total overall costs.

The time from initial identification of a transmission project until the start of operation is very long. The lead time required for planning, permitting, finalizing design, and constructing a project may be 10 years or more. The permitting phase of these projects has taken longer in recent years as there is much more opposition to the siting of new transmission lines.

Transmission projects have a long physical and economic life, at a minimum from 30 to 50 years. If we assume 30 years of economic life, we may have a 40 year time horizon from the time of the economic analysis until the end of the project's economic life. Thus, the analysis will require up to 40 years of forecasts of power prices, the amount of power transmitted, and many other parameters affecting the market conditions. This is a difficult task and subject to a great deal of uncertainty.

Furthermore, transmission projects have strategic values, such as load and fuel diversity, environmental benefits, insurance against contingencies, and the replacement of aging power plants. These benefits have to be integrated into the economic evaluation of the project as well.

Types of Benefit-Cost Analysis

When a transmission project to a remote power plant is being evaluated, the analysis compares the cost of constructing a power plant close to load centers with interconnection to the local distribution network, versus the cost of constructing a remote power plant plus building and operating the high voltage transmission system from that plant to the local area network. The economic analysis is somewhat straightforward since the source of power is identified, the cost of constructing and operating the two alternative power plants can be forecast, and the amount of the power to be transmitted is commonly understood. The benefit-cost analysis attempts to quantify whether the cost of constructing a remote power plant plus transmission lines is less than the cost of building a power plant locally. Of course, there is still the need to forecast the operation and fuel costs of the two power plants over a long period of time.

When a transmission project is being considered for accessing a surplus region instead of a specific power plant, the economic evaluation of the project becomes much more difficult. In recent years, multi-area production simulation models have been utilized to estimate the benefits of these types of transmission projects. These models calculate the prices in the exporting and importing regions and also estimate the amount of electricity flowing in the proposed transmission project.

FORECASTING BENEFITS OF A TRANSMISSION PROJECT

Evaluation in a Regulated Market

Before deregulation of the electricity industry, there was good information sharing about generation plants owned and operated by utilities and forecasts of power plant additions planed by these utilities to meet their future loads. It was possible to develop a comprehensive multi-regional model and data base. Through production simulation, one could find out how much surplus or deficit of power each region would have and what the regional marginal prices would be. When a new transmission line was studied, the simulation model would calculate the amount of energy this new transmission line would carry at different time periods. Assuming this surplus economy energy would be purchased at the marginal cost of the exporting region, the benefit for each Megawatt hour (MWh) of import based on the marginal cost differential between importing and exporting regions could then be quantified.

Of course, assumptions had to be made about many market parameters, such as fuel prices, load forecasts, construction costs, timing of new power plants, and production from hydro system. Assumptions of the economic life of projects and interest rates for discounting future benefits would also be made. Using sensitivity analysis, the uncertainties of fuel, load, and other factors could be investigated. Decision analysis was used to assign probability distribution for the benefits and costs of projects.

In the 1980s and 1990s, this type of analysis was employed by utilities in California to study the economic feasibility of the third AC line and the second Palo Verde-Devers line. The Investor Owned Utilities' (IOU) application to the CPUC for the construction of a third AC line was rejected on the grounds that this project was not economically feasible. However, this project was later constructed in the 1990s by municipal utilities in Northern California. About 10 years ago, SCE submitted to the CPUC and subsequently withdrew an application for the second Palo Verde-Devers line. Currently, SCE is considering a new application to the CPUC for the same line.

Evaluation in a Restructured Market

Under the restructured electricity market, the integration between generation and transmission planning has been considerably changed. In the past, a vertically integrated utility made planning decisions on both generation and transmission projects. The utility would set a reliability objective and then select a combination of generation and transmission projects to achieve the reliability objective with minimum revenue requirement. Integrated planning of generation and transmission was feasible. Transmission expansion improved reliability of the system and reduced the need for local generation.

Currently, planning and decision making for generation and transmission have become unbundled as a result of the industry restructuring. Different organizations are making decisions for generation and transmission expansion projects.

The location of new generation is creating congestion. As the cost of congestion goes up, the expansion of the transmission lines become economically justified. However, transmission expansion that eliminates the congestion also reduces the price differential between the two regions that are connected through the new line. In other words, the transmission revenue to be generated due to congestion is reduced. The price of power is also altered and the profit opportunities for generators are affected. This means that generation and transmission change each other's future revenues and profits. There are increasingly complex market interactions and the marginal prices calculated in a traditional multi-area production simulation should not be used to forecast the benefit of building a new transmission line. Actual market prices may be much higher or lower than the marginal prices produced by simulation models as prices include more than just variable costs.

The bidding strategies of power suppliers have a significant impact on prices and their volatility. The potential for earning capacity payments in addition to marginal operating and fuel costs can not be neglected. There are incentives to withdraw capacity from the energy market to increase capacity payment. There is a need for complex models that will take into account bidding strategies, the expansion and location of new merchant power plants, volatility and uncertainty factors, and an accurate representation of the network system.

CA ISO Proposed Evaluation Methodology

Background

On February 28, 2003, the California Independent System Operator (CA ISO) and London Economics International LLC (LE) submitted a report, "A Proposed Methodology for Evaluating the Economic Benefits of Transmission Expansion in a Restructured Wholesale Electricity Market" (Report)[1] to the California Public Utilities Commission (CPUC). This Report describes the methodology developed by CA ISO and LE with input from many California market participants. (See Appendix 1 for a detailed review of this Report.)

[1] *A Proposed Methodology for Evaluating the Economic Benefits in a Restructured Wholesale Electricity Market.* February 28, 2003. London Economics International LLC for the California Independent System Operator.

Three months later on May 30, 2003, LE completed an economic evaluation of the Path 15 and Path 26 transmission expansion projects using this proposed methodology[2]. The Report showed that the Path 15 transmission upgrade would deliver $330 million of net benefits. The Report also showed that an upgrade to Path 26 does not have net benefits.

CA ISO has continued its investigation of a comprehensive methodology to evaluate the economic benefits of transmission expansion in a restructured market environment by forming a stakeholder process to complete the development of the "Transmission Economic Assessment Methodology" ("TEAM") under the CA ISO Division of Market Analysis for ultimate filing with the CPUC in the Order Instituting Investigation (OII) 00-11-001. In the last three months, the CA ISO held three stakeholder meetings to share the proposed methodology, input assumptions, network representation, scenario selection and preliminary results. The TEAM group has been testing the proposed methodology on the upgrade of Path 26. They plan to submit their findings to the CPUC on June 2, 2004.

On February 3, 2004, the CA ISO held the first stakeholder meeting to report progress on the TEAM. The CA ISO stated that one of TEAM's requirements was that this model needed to have the ability to allow economic substitution of generation and demand side programs with transmission expansion projects, recognizing the interdependence of generation and transmission investments. With large regional network representation, the model should also be able to assess the economic value of large transmission expansion projects and analyze the benefits under a wide range of future system and market conditions. Another key requisite of the model is the ability to simulate market power or bidding strategies in the restructured market environment.

At the meeting, the CA ISO presented the basics of the proposed model; the benefit test considered; the assumptions for the base case; and the simulation tools examined.

On March 16, 2004, the TEAM group reported to stakeholders on the progress of the model development; the criteria used for resource additions and retirements; bidding strategies based on residual supply indexes; scenario selection logic; and the definition of the Path 26 upgrade project. Some initial base case results were also presented.

On April 28, 2004 further progress of the TEAM effort was reported. Development of market price algorithm and benefit tests were completed and integrated into the PLEXOS market simulation model, developed by Drayton Analytics. Demand forecasts for non-California regions were modified to reflect the latest data base of the Western Electricity Coordinating Council (WECC). The transfer capabilities of the

[2] London Economics International LLC, *Economic Evaluation of the Path 15 and Path 26 Transmission Expansion Projects in California.* May 30, 2003.

existing transmission network were de-rated based on historical operation transfer capability (OTC) and fixed costs for new generation options and fuel price escalations had been updated. Summaries of the results-to-date were shared and discussed.

Basics of the Proposed CA ISO Methodology

The proposed methodology presented by the CA ISO addressed these major issues: modeling of market power; development of a robust set of scenarios; selection of appropriate simulation tools or programs; representation of the transmission network and the assumptions of the future generation system; and selection of benefit tests.

Modeling Market Power

The most important issue acknowledged by the CA ISO was modeling market power and strategic bidding behavior. On one end of the spectrum, strategic bidding behavior could be pseudo represented with variable cost adders/modifiers. On the other end of the spectrum, the most complex modeling of market power impact could be done with Game Theory - Nash equilibrium simulation models. However, increasing the complexity of the simulation modeling may not necessarily yield increased accuracy for the assessment.

Recent research in operations research and economics has been focusing on solving game theory models for simulating the restructured electricity market. Researchers have solved oligopoly models with simplified strategy space and limited network configurations models of electricity market outcomes, according to Dr. Frank A. Wolak, Chairman, Market Surveillance Committee of CA ISO.[3]

The CA ISO has made the decision to use the price-cost mark up method, based on historical data, to take into consideration market power of generators.

Developing a Set of Scenarios

In general, there are two critical aspects in any scenario analysis: the selection of the most likely and the extreme scenarios to be analyzed; and the assignment of an appropriate weighting factor or probability for each of the scenarios. In any comprehensive economic evaluation of transmission expansions, the examination of important and representative scenarios of future conditions is absolutely crucial. And the challenge that analysts face is the determination of probabilities of each of the

[3] Wolak, Frank A. *Valuing Transmission Investment in a Wholesale Market Regime.* Presented at the California Independent System Operator Stakeholders' Meeting, February 3, 2004.

system variables, the correlations among them, and the joint probabilities of the combined system scenario.

The CA ISO adopted an elaborated process for the selection of scenarios and the determination of joint probabilities for those selected scenarios. In their presentations of March 16, 2004 meeting, the CA ISO also introduced the concept of un-measurable variables, such as fires or terrorist attacks. These variables would be considered in evaluating extreme cases for contingency planning or insurance against unlikely events with significant impact on the value of transmission expansion projects.

Selecting production simulation model

The simulation tool preferred by the CA ISO is a production cost simulation model. PLEXOS has the capability to integrate a DC optimal power flow analysis of the transmission network system and a probabilistic production simulation model with unit commitment logic, as well as pumped storage and hydroelectric optimization capabilities. The PLEXOS model uses the Microsoft Access software to manage its database. Depending on the input available, the PLEXOS model can simulate the transmission network in a zonal or nodal format. This model also has some limited capability to account for transmission nomogram constraints, model market power behavior, and to incorporate new generation project evaluation.

Representing the transmission network and generation portfolio

For the evaluation of large transmission projects, a broad regional network representation was required. The CA ISO applied the proposed methodology to their economic evaluation of the Path 26 transmission upgrade project. Even though this project is an intrastate transmission network augmentation, the network representation used in this study is a full network model of the Western states' system with data provided by the WECC.

For the evaluation of the Path 26 upgrade project, a target reserve margin requirement for all regions in the WECC was set at 15 percent. A portfolio of long-term new generation plants as well as the retirements of older power plants was derived based on two basic criteria: 1) up to a 15 percent reserve margin, new and existing units must not lose more than the annual costs of a new combustion turbine (CT); and 2) for more than a 15 percent reserve margin, all new units must be able to fully cover annual fuel, operating, maintenance and capital costs.

Selecting the benefit test

Benefit tests examined by the CA ISO include:

- the participant/ratepayer test (benefits to those entities paying for the facility upgrades);
- the societal test (benefits to all consumers, producers, and transmission owners, irregardless of who paid for the upgrades); and
- the modified societal test recognizing or excluding non-competitive revenues (monopoly rent) collected by some producers.

The societal test is measured by the change in production costs across the entire interconnection. A transmission expansion project is deemed to pass the benefit test if its benefit to a participant, the entire society or the modified society exceeds the project cost.

Based on the CA ISO model applied to Path 26 for 2008, the price in the exporting region goes up, price in the importing region goes down, and revenue from congestion decreases due to upgrading this path by about 400 MW. Therefore, the revenue requirement of the consumers in the exporting region goes up and revenue requirement of the consumers in the importing region decreases. Profits for generator owners in the exporting region increase, whereas the profit for generation owners in the importing region goes down. Furthermore, the revenue from congestion to the transmission owners will decrease, which may impact both the consumers of the importing and the exporting regions if transmission revenue requirements are paid by all ratepayers.

Each of the above tests will provide the analyst some understanding of the economic impact of the transmission expansion project studied. Ideally, the findings from all of these tests should be scrutinized before making any investment decisions. Nevertheless, the CA ISO believes that the ratepayer test should be the primary one governing project approvals.[4]

On the other hand, the CA ISO was silent in its presentation on the recommended length of the study period for accruing these benefits. The transmission project cost for Path 26 was levelized, which includes the cost of capital and the depreciation rate, assuming an annual carrying charge rate of 17.5 percent. Based on this carrying charge rate assumption and the capital cost of the project, the annual project cost is calculated. (No discussion of annual operating and maintenance cost was provided.) The annual levelized cost of the transmission project is then compared with the annual benefit in 2008 to see if the project is cost effective. (A similar analysis will be done for 2013.)

Base Case Assumptions

[4] *Status of TEAM, Example Application, and the Evolving Grid Planning Process.* Jeff Miller, presentation to the California Independent System Operator TEAM Meeting, April 28, 2004. Page 23.

The CA ISO discussed the input assumptions in the following categories at the February 3, 2004 stakeholders' meeting:

- General study assumptions
- Generation units
- Load forecast
- Transmission network representation
- Operational constraints
- Fuel cost forecast

The CA ISO proposed to calculate the benefits for two years. The selected test years were 2008 and 2013. The bulk of the simulation data base was originally developed by the technical studies work group of the Seams Steering Group - Western Interconnection (SSG-WI) and modified in support of the Southwest Transmission Expansion Plan (STEP). Load forecasts, including peak, energy, load shapes, and growth rates were obtained from the WECC 2002 L&R Report.[5]

Power plants currently online or under construction as of January 1, 2004 were considered as existing resources. New generation additions considered are Otay Mesa, Palomar and Mountainview. . All announced unit retirements will be taken off line as scheduled, including the Mohave Generating Station. Generic average heat rates are assumed for classes of units, and typical maintenance outage rates are applied based on the technology type of the unit.

The WECC base case data is the foundation of the transmission network representation. Existing nomograms are modeled to reflect system constraints. Transmission line ratings are based on the most current path rating; and only 500kV line limits are enforced.

Fuel price forecast was another key assumption in the forecast of market prices. The CA ISO elected to base the analysis on the forecast reported in the Energy Commission Electricity and Natural Gas Assessment Report of December 2003[6] . The average burner tip price of natural gas for California utilities was forecast as $4.53/MMBtu for 2008 and $5.49 for 2013. Gas prices will be differentiated among regions in the WECC mostly by the differences in regional transportation costs/tariffs.

The reason provided by the CA ISO for selecting only two years for the benefits analysis is that the model requires significant amounts of input data and the available CA ISO staff time is limited for the collection of input data for every year from 2008 to 2013. Furthermore, the CA ISO feels that due to uncertainty in key assumptions, the analysis should not be carried out for the time frame beyond 2013.

[5] *Loads and Resources Report*, Western Electricity Coordinating Council, 2002.
[6] *Electricity and Natural Gas Report.* California Energy Commission. December 2003.

Evaluation of Transmission Projects in Other ISOs

As reported in the U.S. Department of Energy (DOE) "Transmission Bottleneck Project Report" (Bottleneck Report) (March 19, 2003)[7] , there are significant transmission bottlenecks in the nation's six established Independent System Operator/Regional Transmission Organization (ISO/RTO) control areas. To address the problems of transmission congestion, the Secretary of Energy chartered an Electricity Advisory Board which established the Transmission Grid Solution Subcommittee to identify transmission expansion or upgrade projects needed for the elimination of transmission bottlenecks.

Transmission bottlenecks may be present under normal operating conditions or they may exist as a result of equipment failures and/or system disturbance conditions. Regardless, they impair the physical security of the electricity system and reduce grid reliability. In addition, transmission bottlenecks also prevent efficient utilization of lower cost generating resources and hamper the ability to strive for an optimum utilization of available generation.

In most cases, ISOs/RTOs have the technical tools and abilities to identify and forecast transmission network deficiencies in their control areas based on system security and reliability criteria. Projects are justified base upon their need relative to North American Electric Reliability Council (NERC), regional or local applicable reliability standards.

ISOs can also identify current economically significant transmission bottlenecks in their systems. However, these economic bottlenecks tend to shift depending on market conditions, and the bidding behaviors of market participants which make it difficult to estimate the benefits from expansion of transmission to reduce these bottlenecks.

The Bottleneck Report concluded that:
"… The ISOs are challenged when asked to develop a business case justifying a market economics project and lack the necessary market models to adequately forecast and 'prove' their need…"[8]

In other words, there is a need to develop a methodology for the economic evaluation of transmission projects in a restructured electricity market. Currently, transmission projects for interconnecting new generating facilities dominate transmission planning and it is difficult to justify transmission expansions for relief of congestion or for increasing access to surplus energy from a neighboring region.

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[7] *The Transmission Bottleneck Project Report.* Electric Power Group, sponsored by the Consortium for Electric Reliability Technology Solutions. March 19, 2003.
[8] *The Transmission Bottleneck Project Report.* Electric Power Group, sponsored by the Consortium for Electric Reliability Technology Solutions. March 19, 2003, p. 14.

There are also a couple of additional roadblocks in front of “Inter-ISO transmission expansions.” The regulatory approval process, especially for multi-state projects, is long and very uncertain. Uncertainties about cost recovery and regulatory treatment are serious disincentives for investors of transmission projects.

The other roadblock for multi-region projects is the potential disconnect between who pays for the new transmission vs. who benefits. Customers of the local transmission owners could be straddled with the costs of fixing the bottleneck, while those benefiting might be located several states away.

In the spring of 2003, the Pennsylvania-New Jersey-Maryland ISO (PJM) filed revisions to its tariff to comply with the December 2002 FERC Order requiring upgrades of transmission, both to ensure reliability and to support competition. Under the proposal, PJM would determine areas where “unhedgeable” congestion exists. Then PJM provides an opportunity for market solutions. . Absent such a solution, then PJM would independently determine which transmission owners should construct an upgrade, what parties would be beneficiaries and how the regulated rates will be allocated to those beneficiaries. PJM is then to work with parties and states to construct the upgrades. If the parties could not agree, then PJM will file this information with the Federal Energy Regulatory Commission (FERC). FERC may then decide if it should take action under Federal Power Act.

The Midwest Independent Transmission System Owner (MISO) supports the role of regional transmission owners (RTOs) in performing a benefits test for cost allocation of a potential transmission investment. It will then assess each zone a demand charge applicable to the benefit ratio. MISO, as of end of 2003, wanted to create a “Regional Expansion Criteria and Benefits Task Force.”

It should be noted that the ISOs mentioned above are not operating under conditions that are necessarily representative of conditions in the West. In the West, there is strong population and economic growth, and therefore the approaches used to solve problems in other parts of the country are not necessarily appropriated for use in the CA ISO.

It is clear that developing a methodology for the economic evaluation of transmission expansion projects in a restructured market is a “hot topic” and additional work effort will be required in various ISOs to come up with a workable evaluation methodology.

STRATEGIC VALUES OF TRANSMISSION

As stated in Section I of this report, the main objectives for a transmission expansion project are reliability, connecting a remote power plant to load centers, or providing access to surplus energy region.

For the third category of projects, factors such as load diversity, fuel diversity, and potential for firm power purchases, economy energy purchases and power exchanges are taken into consideration in the economic evaluation of transmission projects.

Furthermore, transmission projects can provide strategic benefits such as:

- Price stability and more efficient energy market operations due to increased competition and decreased “Market Power” for existing generators in the importing region;

- The potential for increased reserve sharing and firm capacity purchases, and therefore for decreasing the number of power plants that have to be constructed in the importing region to meet reserve adequacy requirements;

- Insurance against contingencies during abnormal system conditions such as fuel supply disruption, loss for an extended time period of large base load power plants, and extreme weather conditions leading to an extended drought period and greatly reducing production from a hydroelectric system;

- Environmental benefits due to reduction of air emissions and offset requirements in the importing region;

- Reduction in the construction of additional infrastructure such as gas pipelines and pumping stations, and water and waste treatment systems; and

- State policy objectives to commercialize renewable resource development consistent with state law.

Transmission planners recognize these strategic benefits. However, due to difficulties in measuring and monetizing them, some of these benefits have not usually been counted in the calculation of primary benefits of transmission expansion projects.

Market Power

Modeling market power is a very important aspect of the CA ISO proposed evaluation methodology. Different options have been investigated, and the relative advantages and disadvantages of each option have been discussed and evaluated. These include, as was discussed previously, game theory models with a simplified network and the empirical method using the historical relationship (regression) between price-cost markups and certain system conditions in determining suppliers' bidding behavior.

Mitigation of local market power in the restructured market is a critical issue. A new transmission project has a positive effect on this mitigation. This strategic benefit should be included in the economic evaluation of a new transmission project which increases competition. In other words, increasing transmission capacity may be a solution to a local market power problem since the number of suppliers expands and local suppliers have less incentive or ability to exercise local market power.

Professor Frank A. Wolak discussed major challenges to valuing transmission upgrades in the restructured market in a CA ISO meeting.[9] One of these challenges is "how do strategic suppliers bid both before and after the transmission upgrade?" He believes that the "historical relationship between bids and system conditions may not be representative of future bids with and without the upgrade."

A game theory model could be used to estimate a suppliers' bid. However this is an extremely difficult problem to solve. As stated by Professor Wolak, "Much current research in operations research and economics focus on solving these theoretic models."

As it was stated, the price-cost markup method, based on historical data, may also be used to calculate the bidding markup. The CA ISO reported in the March 16 and April 28, 2004 stakeholders' meetings the development of those historical relationships (regression) between price-cost markups and certain system conditions[10]. The regression results were applied prospectively to predict hourly price-cost markups for 2008 and 2013. Markups are estimated separately for each hour and each demand region (i.e., PG&E, SCE, and SDG&E). Three levels of the markups -- base, high, and low, were examined to evaluate the magnitude and the range of the impact of bidding behaviors.

Because of simplifications used in this method, one may not be able to calculate the precise reduction of market power as a result of the construction of a proposed transmission project. However, as Professor Wolak concluded in his remarks on February 3, "Including these analyses in the evaluation would most likely underestimate rather than overestimate market power benefits of transmission upgrade."

[9] *Valuing Transmission Investment in A Wholesale Market Regime*. Frank A. Wolak. Presented to the California Independent System Operation TEAM Meeting, February 3, 2004.
[10] *TEAM Preliminary Result-to-Date Year 2008.* Anna S. Geevarghese and Dr. Jing Chen. Presented to the California Independent System Operator TEAM Meeting. April 28, 2004. P. 14-15.

Resource Sharing

Another benefit of expanding the transmission network is the potential for increased reserve sharing and firm capacity purchases. Fewer power plants would need to be constructed in the importing region to meet reserve adequacy requirements when access to surplus energy and capacity of the neighboring regions are made possible due to transmission/interconnection system upgrades.

In addition to the benefit of increasing the accessibility to the energy supply from other regions, the expansion of the interconnected transmission network will improve the overall system reliability, i.e., reduce the loss-of-load probability of the entire region which might in term lessen the regional reserve margin requirement in order to satisfy a given reliability criterion.

The CA ISO proposed methodology has the capability to estimate the potential for accessing supply resources in neighboring regions in its production simulation analyses. However, it may not be possible to quantify potential benefits derived from the lessening of reserve margin requirements through production simulation models.

Insurance Against Contingencies

Uncertainties due to variables where values can be easily measured, such as demand level, gas price level, etc., are generally incorporated in production simulation models, even though this exercise may be extremely data intensive. Other variables, such as the risk from fire and terrorist attack, are not easily defined or routinely estimated. They are sometimes referred to as the unmeasurable variables which might introduce some intangible benefits. Nonetheless, they could impact significantly the evaluation and decision making about generation and/or transmission projects.

Scenario and sensitivity analyses are normally used to capture the uncertainties due to measurable variables, i.e., load variations, fuel price volatilities, and hydroelectric productions. Contingencies for very low probability but high-risk events are sometimes analyzed in economic evaluations of new power plants or transmission projects through an in-depth examination of a few specific examples of contingency events. For example, the CA ISO selected three contingency situations for analysis: a) the San Onofre Nuclear Generating Station (SONGS) going off-line to terrorist attack; b) the Pacific High Voltage Direct Current Intertie (PDCI) going off-line due to fire; and c) the Devers - Palo Verde (DPV) #1 line going down for an extended time due to a forced outage.

The result of these evaluations will provide some indication of their impact on the value of a transmission expansion project. Furthermore, the high voltage transmission expansion project in question, through the interconnection to regions with diverse characteristics, could provide some mitigation during these significant events to prevent blackouts or brownouts.

Environmental Benefits

The existing transmission lines have provided environmental benefits for both California and Pacific Northwest. Due to environmental energy exchange in 1990s both regions received significant environmental benefits. California received energy during peak hours in the summer season, therefore reducing energy production from older California fossil fuel plants. While energy used in the Pacific Northwest was produced during off-peak and winter months from newer units with better efficiency and lower NO_x emissions, as well as during the time periods when the ambient NO_x level was lower in California. These environmental energy exchanges also helped the Pacific Northwest in meeting increased in-stream flow releases (from the region's reservoirs) required to mitigate impacts to fish.

There was also significant reduction in NO_x production in California due to a large amount of firm and economy energy purchasers from the Pacific Northwest and Desert Southwest.

Emission credits may command higher market prices in load centers classified as non-containment areas, such as the South Coast Air Management District in Southern California, when compared with less populated areas, such as the Desert Southwest region. Therefore, including environmental benefits will increase the benefit of building new power plants outside of load centers, thus favoring the construction of associated transmission expansion projects.

Production simulation models may be used to estimate the environmental benefits of a transmission project. There are two ways to accomplish this task.

The first approach is to calculate the total emissions produced in each region based on energy production and emission rates of the generation resources. Knowing the emissions produced and the costs of air emissions, one can easily evaluate the benefit or cost of alternative generation or transmission projects.

The second approach is to internalize the cost of emissions in the dispatch algorithm. Resources with lowest total dispatch cost, which includes fuel, variable operations and maintenance (O&M) and emission costs, will be dispatched first. From simulation analysis using models with this capability, the regional marginal prices for energy will reflect the cost of emissions. Therefore, using these marginal prices for cost-benefit analysis, the environmental benefits will be internalized.

The CA ISO proposed methodology has the capability to keep track of the emissions produced; however, it does not internalize the emission costs in its dispatch decisions. Currently, the CA ISO analysis ignores the environmental benefits of a new transmission project. Input data on emission rates of power plants and the regional cost of emissions are required for the CA ISO proposed methodology to estimate the impact of a transmission expansion project. Presently, these data are not input into the PLEXOS model.

Furthermore, building power plants in less populated area introduces some additional tangible benefits that most of the economic evaluation studies do not capture. These benefits might include, for example:

- Higher level of economic growth and employment in California, since building power plants outside of load centers will reserve those relatively scarce “emission off-set credits” in load centers for the development of other industries which are also in need of off-sets credits in the region. The secondary benefit due to higher economic growth in the region is hard to quantify and mostly ignored in the economic evaluation of transmission expansion projects.

- Lower water consumption and waste disposal levels as electric production in California is decreased and the need for power is satisfied with more imports. Of course there will be additional demand for water and waste disposal systems in the exporting regions. Therefore, the net environmental benefit should be calculated.

Of course, the anti-haze legislation which makes it difficult to locate generation plants near national parks will impact California’s ability to locate generation plants outside of native load centers.

Infrastructure Benefits

Due to the construction of a transmission line, the level of power production in the importing region will somewhat decrease. This may mean reduction in development of new generation in the importing region. In California this means reduction in the development of gas-fired generation. Therefore, there is a chance that the need for additional gas pipelines and pumping stations will diminish. These secondary benefits may not be significant when only one single generation plant is under review. However, when planning is carried out for the state and construction of several transmission lines are being planned, then these benefits will become large and should not be neglected.

Other infrastructure that will be influenced by decrease in power production in California include water and waste treatment systems. Again, these benefits from construction of new transmission lines should be evaluated from a statewide point of view.

It may be difficult to estimate and capture the infrastructure benefits for a single project. These benefits should be evaluated at the state level planning. The California Energy Commission (Energy Commission) should be able to incorporate these benefits when carrying out generation, transmission and natural gas planning analyses and examine impact of different levels of transmission development upon the need for the expansion of gas pipelines, water, and waste-water systems.

ECONOMIC LIFE AND SOCIAL RATE OF DISCOUNT

Through many investigations in the past few decades, the benefit-cost-analysis methodology has been developed to evaluate investment decisions for new generation and transmission projects. Steps usually included in the benefit-cost-analysis of a project are:

1. Identification of different parts of the project and measurement of their costs;

2. Identification and measurement of the significant consequences of the project, i.e., benefits;

3. Timing of the costs during construction and the time pattern of the benefit occurrences;

4. Translation and aggregation of benefits and costs to a common point of time, for example, the present.

5. Establishment of a criterion and its application to establish justification for the investment.

The first step is estimation of the project cost for a transmission project. It is carried out during initial design and later on during final engineering design of the project. The costs of operation and maintenance should also be forecast. On the benefit side of a transmission project, there are primary benefits such as reliability and increased energy and capacity import and also many strategic benefits. These benefits were described and discussed in Section II and III of this report.

Establishing criteria was also discussed in Section II, which included ratepayers and societal tests.

In this section, two remaining factors, i.e., time horizon and aggregation to a common point of time through a discount rate, will be discussed.

Economic Life

As was discussed previously, transmission projects remain in operation for a long time. Definitely, 30 years is a minimum economic life for a new transmission project. When we add another 10 years of lead time for planning, permitting, and construction, it is necessary to have a 40 year forecasts of inputs, such as load, generation system, transmission network, fuel prices and other operating costs to be able to perform the necessary analysis.

However, the availability of data may limit the application of the complex multi-area production simulation models to ten years. Even when one assumes, at a minimum, that there are only six years lead time for planning, permitting, and construction, the multi-area simulation will capture only the first four years of project operation and the benefits accrued for a very short time period. It is very difficult to justify a transmission expansion project on benefits accrued during the first four years of operation. To overcome this problem, the CA ISO recommends calculating the benefit for two years and then using the levelized annual cost of the project to compare the benefit from these two years to levelized annual cost. This assumes that the benefits calculated from the one or two test years are a good representation of the benefits over the entire life of the project.

Furthermore, one or two years of analysis will not capture the dynamic aspect of a transmission expansion impact on the location of new generation. In other words, just by looking at 2008 results from a production simulation model, the impact of the transfer capability increase on creating opportunities for expansion of generation resources in the exporting region is neglected. Taking two years out of a 30-to-50 year time frame is not a correct approach to make an economic choice.

In the CA ISO methodology, when only one year is analyzed, the revenue requirement of the ratepayers in the exporting region is always increased due to higher prices in the region after transmission capacity expansion. In a one-year static analysis, there is no consideration that due to higher prices in the exporting region and the creation of new opportunities for additional exporting, there will be incentives to invest in the construction of new generation in the exporting region.

In the past, construction of new transmission created benefits for both importing and exporting regions. Now to state that the ratepayers of the exporting region will always be losers and that their rates will increase, is not correct and is neglecting the interaction between transmission expansion and generation construction.

It is strongly recommended that in the CA ISO proposed methodology at least every year between 2008 and 2013 be analyzed so that the production simulation model may incorporate the interaction between transmission and generation. PLEXOS has some capability to carry out new generation project evaluation. When prices during 2008 - 2013 start going up in the exporting region, then the model will carry out analysis for evaluation of new generation plants in the exporting region. Construction of new generation will moderate the price increase in this region. Including this feedback in the analysis will decrease the negative price impact in exporting regions and therefore increase the net benefit from a new transmission line. By evaluating only two years, 2008 and 2013, there is a good chance that the interaction between new transmission and the addition of new generation plants in the exporting region will not be captured.

There are two choices to expand the benefit estimation over a longer period beyond 2013: first, expand the time period of the multi-area production simulation modeling; second, use the output from the production simulation modeling of the system for the initial period, say five years, and then for the remaining economic life, say another 25 years, make a forecast of annual benefits based extrapolation of the results from the production simulation or from the output of simple spreadsheet models. The problem with the first choice is that the accuracy of the input assumptions used in the complex production simulation models diminishes significantly when one goes beyond ten years. There is no point in carrying out a complex analysis for the years beyond 2013 when there is no confidence in many of the input assumptions. The second choice, i.e., extrapolation of the result from the first five years or a simple spreadsheet analysis may provide a reasonable estimate of the longer term benefits.

To illustrate the impact of economic life on the present worth of benefits, a simple example has been developed. In this example, we have assumed that the annual discount rate is 10 percent. The transmission project has 1500 MW of transfer capacity and carries 5.9 billion KWh during on-peak hours each year (at 80 percent loading) and 2.3 billion KWh during off-peak hours (at 40 percent loading). Average annual loading is around 62 percent. The price differential between the importing and exporting regions are $8/MWh during on-peak and $4/MWh during off-peak hours. The annual benefit from this project will be about $56.4 million. It is also assumed that this benefit level remains the same during the project life. Furthermore, we are ignoring all strategic values of the project. Figure 1 shows the input assumptions and the value of the present worth of the benefits. The present values of the annual benefits for this project will be $214 million, $346 million, and $532 million, for 5, 10, and 30 years, respectively. It is clear that even at a high 10 percent rate of discount, there is significant increase in the size of present worth of the annual benefits; the increase in going from 10 years to 30 years is 56 percent. This sizable increase should not be ignored. It may be difficult to economically justify the construction of large high voltage transmission lines when we only assume 5 to 10 years of economic life for the project.

Figure 1
Impact of Economic Life on the Present Worth of Benefits for a 1500 MW Transmission Expansion Project

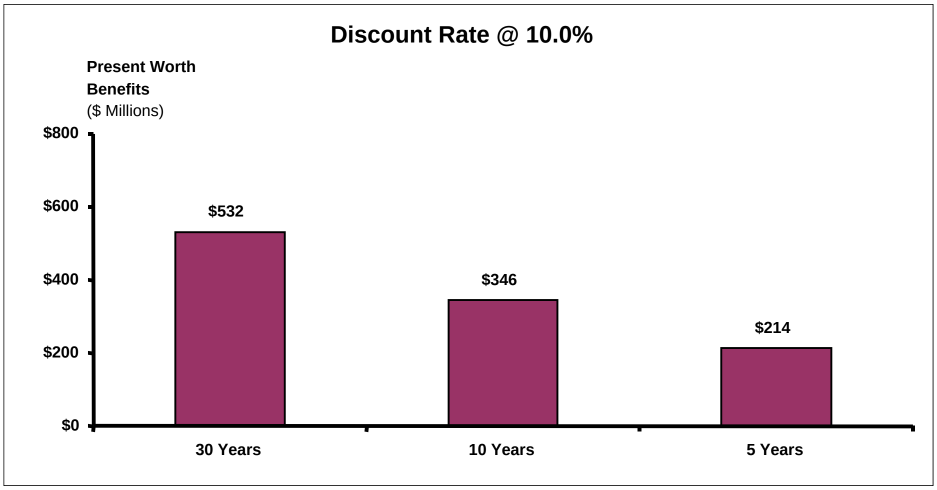


Table 1
Assumptions Used for Figures 1 and 2

Time Period	Line Loading	Annual Energy Transmitted (MWh)	Avg. $/MWh Price Differential (between import and export region)	Annual Benefit ($000s)
On-Peak	80%	5,894,400	$8.00	$47,155
Off-Peak	40%	2,308,800	$4.00	$9,235
Annual Total	62%	8,203,200	-	$56,390

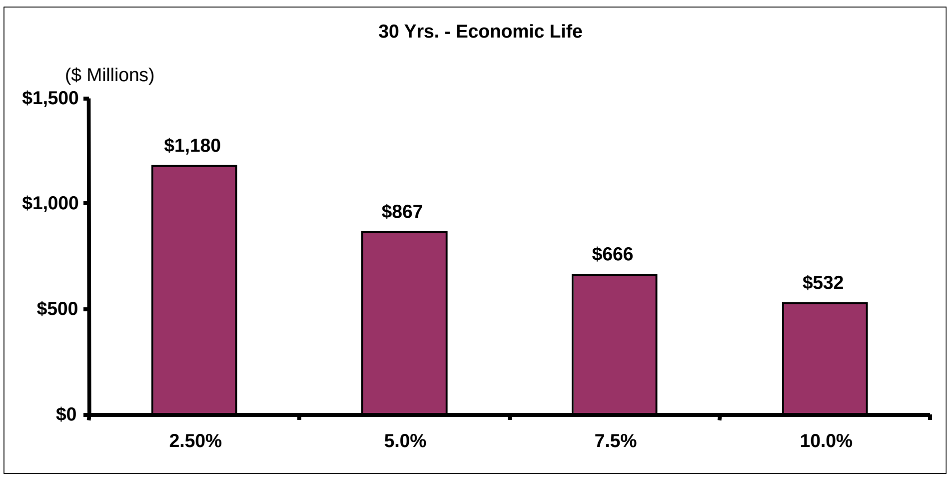
Social Discount Rate

As was stated, the monetary value attached to benefits and costs have to be aggregated to a common point in time for the economic evaluation of a project. The common method is to calculate the present value of benefits and costs using a discount rate.

In a regulated environment, based on the cost of capital and the capital structure of the utility (percent of long-term bond, shareholder equity and preferred stock), a rate of return is established by the CPUC. It has been a common practice to use this regulated rate of return both to calculate opportunity cost of capital and discount rate to calculate the present value of benefits.

The higher the discount rate, the smaller will be the present worth of benefits and the lower chance that a transmission project will be economical. Figure 2 illustrates the impact of the discount rate on the present worth of a benefit. This example assumes that the economic life of the project is 30 years. The project is 1500 MW of increased transmission with the same loading and regional price differential used in Figure 1.

Figure 2
Impact of Discount Rate on Present Worth Benefits for a 1500 MW Transmission Expansion Project



As shown in Figure 2, the present worth of benefits is increased from $532 million at a 10 percent discount rate to $1,180 million at 2.5 percent discount rate, more than doubling of the size of the benefit.

The important question is, “Should we continue to use the rate of return specified by the CPUC for a Transmission Owner as the discount rate in the restructured wholesale market?” This question is very relevant when we are applying the “societal test” for evaluating the construction of a new transmission project which impacts ratepayers, and generation and transmission owners in both the importing and exporting regions. Should we not apply the “social rate of discount” when we are using the “societal test” to make a decision on economic value of a project?

The structure of the transmission industry has greatly changed in the last few years. In the past, when a utility was constructing a new transmission project, the utility will carry out the investment and after the regulatory approval will put the capital cost in its rate base, and it will receive revenue from its ratepayers to the cover capital cost and rate of return on the investment. The ratepayers of this utility will receive the benefits such as importing economy energy and for firm capacity and energy. The transmission revenue from other utilities using this line would also go to the ratepayers who were paying for the project. The utility that owned the project was involved in planning, permitting, construction, and finally operation of the project.

Now in the restructured market in California, the planning activity is shared between the utility, the CA ISO and is subject to stakeholders' input. The utility does not control the operation of the high voltage transmission lines. The utility's customers do not get all the benefit of a transmission line constructed by the utility. Furthermore, the capital cost of the new high voltage transmission project is paid through the Transmission Access Charge by all retail customers in the CA ISO grid, as they all get benefit from this project.

It seems that high voltage transmission in a restructured market has become a "public good." The benefit from a project cannot be denied to any retail customer nor generation owners. The cost is shared by every customer.

For calculating the present worth of a "public good" project, one should use the "social rate of discount" instead of the "opportunity cost of capital."

The question of the "social rate of discount" has been discussed among economists for many decades. In an essay published in 1950, Maurice Dobb stated that "clearly, for planning purposes we are interested in tomorrow's satisfaction as such, not in today's assessment of tomorrow's satisfaction. To discount later enjoyment in comparison with earlier ones is a practice which is ethically indefensible and arises merely from the weakness in imagination."[11] Professor Sen presents the same idea by writing, "While it is true that the decision has to be taken now, there is no necessary reason why today's discount of tomorrow should be used and not tomorrow's discount of today."[12]

Dobb recommends that the rate of the increase of labor productivity should be used as the basis for fixing the social rate of discount.[13] However, in a complex economic system there are other factors beside the rate of increase of labor productivity which influence the rate of economic growth and the social welfare profile over time. And it is the rate of economic growth that determines the social rate of discount. "In fact, if there was no economic growth and stagnation was prevailing, then there are good reasons to set the social rate of discount to zero."[14]

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[11] *An Essay on Economic Growth and Planning.* Maurice Dobb. Monthly Review Press. Month?? 1960, p. 18.
[12] *On Optimizing the Rate of Saving.* A.K. Sen. Economic Journal. Vol. LXXI. September 1961, p. 487
[13] *An Essay on Economic Growth and Planning.* Maurice Dobb. Monthly Review Press. 1960, p. 26.
[14] *Economic Evaluation of a Water Resources Development Project in a Developing Economy.* Fereidoun Mobasheri. U.C. Berkeley Water Resources Center. Contribution No. 126, July 1968, p. 41.

Based on the formulation by David Evans and Hank Sezer[15], the social discount rate is a function of per capita consumption growth rate, the elasticity of the marginal utility of consumption and the probability of survival of the "average consumer" from one period to the next:

SDR	=	$(1 + g)^{\lvert e \rvert}(1/\Pi) - 1$
whereas SDR	=	social discount rate
g	=	growth rate of per capital real consumption
e	=	elasticity of the marginal utility of consumption
Π	=	weighted probability of survival of the average consumer from one period to the next, which is a measure to capture the pure time discount rate

Evans and Sezer, using empirical data for U.K. for the period 1967-1997, inclusive, came up with: SDR = $(1 + 0.0230)^{(1.6)}(1/0.98918) - 1 = 0.0484 = 4.87\%$

Erham Kula has used similar formulation to derive the social discount rate for the United States and Canada.[16] He used the data for the period 1954-1976 for estimating the growth rate and elasticity of the marginal utility of consumption, and for the annual average survival probability he used data from 1946-1970 from the U.S. and data from 1946-1975 from Canada. Kula obtained the following results:

For U.S.: SDR = $(1 + 0.023)^{1.89}\ (1/0.991) - 1 = 0.053 = 5.3\%$
For Canada: SDR = $(1 + 0.028)^{1.56}\ (1/0.992) - 1 = 0.052 = 5.2\%$

Many economists have recommended the use of social discount rates for economic appraisal of public projects in sectors such as transport, agriculture, water resource development, and land-use.[17, 18, 19] The use of a social rate of discount in evaluating energy efficiency projects has also been recommended in the development of building and appliance standards in the Energy Commission's 2003 Integrated Policy Report. We should accept the fact that high voltage transmission system has also become a "public good" in the restructured market. As with other public goods, the social discount rate should be used to calculate the present worth of benefits from a new transmission upgrade or expansion.

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[15] *A Time Preference Measure of the Social Discount Rate for the UK.* David Evans and Haluk Sezer. Applied Economics, 2002, 1026, p. 34.
[16] *Derivation of Social Time Preference Rates for the United States and Canada.* Erham Kula. Quarterly Journal of Economics, 1984, Vol. 99, pp. 873-82.
[17] *Time Discounting and Future Generations.* Erham Kula. Quarum Books. Chapters 7 and 9.
[18] *Economic Evaluation of a Water Resources Development Project in a Developing Economy.* Mobasheri, Fereidoun. UC Berkeley Water Resources Center. Contribution No. 126, July 1968, pp. 78-121.
[19] *The Social Discount Rate for Land-Use Projects in India.* R.A. Sharma, M.J. McGregor, and J.F. Blyth. Journal of Agricultural Economics, Vol. 42, pp. 86-92.

The techniques utilized by Evans and Sezer, and Kula should be used to come up with the social discount rate to be used in appraisal of high voltage transmission projects.

Per capita growth rate of consumption, the elasticity of the marginal utility of consumption and the probability of survival from one period to the next have to be calculated from more recent data than the data used by Kula for the U.S.

STREAMLINING AND COORDINATING PLANNING AND PERMITTING

As in the previous report, "California's Electricity Generation and Transmission Interconnection Needs Under Alternative Scenarios," the interconnection planning process needs to be segmented into a strategic phase and a permitting phase.[20] In the strategic phase, the focus would be on a longer planning horizon, to build consensus on the need for interconnections, and to identify potential projects. There will be the need to work with neighboring states to build consensus on projects and corridors. It has become very difficult to get siting approval for new transmission paths. Therefore, it is important that regulatory steps be taken to make sure that utilities are able to acquire needed rights-of-way and bank them so that the objectives of long-term plans can be achieved and projects envisioned in these plans be constructed when they are needed.

A mechanism should be set up for recovering costs associated with right-of-way acquisitions and corridor planning. Utilities have to provide economic justification for these costs. Since these projects will be constructed many years from now, one should not expect the use of a complex methodology for such economic evaluation.

On the other hand, during the permitting phase the focus is on a specific project needed in the next 5-to-10 year window. For economic justification a more detailed valuation methodology will be needed to address both economic and strategic value of transmission. The CA ISO evaluation methodology and modifications recommended in this report will be the type of tools needed for justification of a specific project during the permitting phase. But this methodology will not be useful in strategic phase. There should not be a need for such a detail analysis to justify the cost of rights-of-way and corridor planning.

In the strategic phase, it will be sufficient to assess resource potential and market hubs. Estimates of construction and operation costs in each market hub may then be used to establish the price differential for power between different market hubs. Based on historical experiences an estimate on line loading could also be made.

Table 2 illustrates the benefit from 1 MW of transmission over a 30 year period when the average benefits (price differential plus strategic value) are $4.00, $6.00, or $8.00 per MWh and the annual loading is 50 percent, 60 percent, or 70 percent, respectively. Four interest rates are used: 2.5 percent, 5.0 percent, 7.5 percent, and 10.0 percent. The maximum present value benefit of 1 MW is over $1 million when using a discount rate of 2.5 percent, the average benefit is assumed to be $8.00/MWh and the line-loading is estimated at 70 percent.

[20] *California's Electricity Generation and Transmission Interconnection Needs Under Alternative Scenarios.* Electric Power Group. Prepared for the California Energy Commission. March 2004.

Table 2
Present Worth of 1 MW Increase in Transmission Capacity

	Average Benefit ($/MWh)								
	$4.00			$6.00			$8.00		
	Average Annual Line Loading (%)								
	50%	60%	70%	50%	60%	70%	50%	60%	70%
Discount Rate	Present Worth of Benefits – 30 Year Period ($000s)								
2.50%	$370	$440	$510	$550	$660	$770	$730	$880	$1,030
5.00%	$270	$320	$380	$400	$480	$570	$540	$650	$750
7.50%	$210	$250	$290	$310	$370	$430	$410	$500	$580
10.00%	$170	$200	$230	$250	$300	$350	$330	$400	$460

A refinement of this simple approach would be to use probabilities for each level of benefits and loadings to come up with a probability distribution and expected benefits. A simple decision analysis based on regional prices and the loadings of new lines will provide sufficient information for justification of right-of-way purchases.

RECOMMENDATIONS

California's high voltage interconnections to neighboring states have played a vital role in meeting the state's electricity needs reliably and at great savings to the customers. . However, due to changing industry structure and financial uncertainties, construction of transmission capacity has not kept up with increase in load nor with the addition of generation capacity.

There is a need for the development of an evaluation methodology that will include the strategic benefits from transmission lines.

The CA ISO has been engaged in the development of an evaluation methodology that takes into consideration:

- Market power and bidding strategy;
- Scenarios and impact from low probability high impact events, i.e., insurance against contingencies;
- Regional network representation for all of WECC; and,
- Benefits to consumers, producers, and transmission owners.

The CA ISO methodology could also evaluate the environmental impacts (air emissions). However, currently the input data required (emission rate of individual generation units and cost of air emission) are not included in data set.

The CA ISO model should be able to consider the interdependence of generation and transmission investments and allow substitution of generation and demand-side for transmission expansion. However, due to time limitations, the CA ISO is planning to include only two years of data, 2008 and 2013, and to analyze only these two years. It is doubtful that the interdependence of generation and transmission investments can be analyzed if the analysis is limited to only two years.

It is recommended that the following additions or modifications of the CA ISO model be carried out:

1. Gather data for every year from 2008 through 2013, and analysis be carried out for each year to make sure that the dynamic relation between transmission and generation expansion is taken into account;

2. Air emission rates and emission cost information should be gathered and input to the model. Without this information, the production simulation may not carry out the correct dispatch of the units. Furthermore, environmental benefits from a new transmission line would be neglected;

3. There is the need to capture the long-term benefits of transmission lines. Calculating the benefit from one or two years and then comparing such annual benefits with the levelized annual cost of a transmission project may not be the

right method to capture the long-term benefits of the project. There is the need to extrapolate the benefits beyond 2013. This can be done by evaluating the annual results from 2008 to 2013 or by estimating the cost of constructing and operating power plants at exporting and importing regions and making reasonable assumptions on loading of the new line.

4. Since high voltage transmission lines are becoming “public goods,” benefits are shared among customers, generation, and transmission owners in both importing and exporting areas. The social discount rate should be used in determining the present worth of these benefits. The social discount rate is a function of per capita real consumption growth and the elasticity of the marginal utility of consumption. The social discount rate is around 5 percent for the U.S., which is much less than authorized rate of return for utilities.

The CA ISO proposed evaluation methodology, with the above modifications, will be a reasonable method to estimate the benefits from projects that are at the permitting phase. In the planning phase when focus is on a longer horizon, this proposed methodology would not be appropriate. For the longer term planning horizon the use of available tools and acceptable data needs to be examined. Economic analysis to justify the cost of purchasing right-of-way should be based on simpler models. A decision analysis type of model based on regional power values and annual average line loadings may be sufficient at the planning stage to estimate the benefit from construction of a new high voltage line for justification of purchasing rights-of-ways to be banked for future projects.

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APPENDIX

A Review of *A Proposed Methodology for Evaluation of the Economic Benefits of Transmission Expansions in a Restructured Wholesale Electricity Market*

Introduction

The first CA ISO proposed evaluation methodology was developed to capture the benefits of transmission expansion projects in the restructured environment. Traditionally, utility planning for transmission expansion would only need to address the investment trade-offs between transmission and generation projects. In the deregulated electricity market environment, valuation methodology for transmission expansion projects would need to explore the economic value of the expansion project under various future market conditions, consider the risks and mitigations of potential market power, and capture the interdependencies between transmission and generation investments.

In the following sections, basic elements of the first CA ISO proposed methodology will be reviewed.

Key Modeling Components

Transmission network representations

To properly evaluate the benefits of a transmission expansion project, the most fundamental component relies on the appropriate modeling of the existing transmission network. Depending on the characteristics of the expansion project in question, the network representation requirement could change significantly. In the case of the Path 15 expansion illustrated by LE, detailed network representation of the transmission network within California was necessary, while the rest of the regions in the WECC were represented as two import zones.

However, in California's long term transmission planning, where out of state power is a viable option, a broad regional network representation is likely required. With the broader regional network, trade-offs between generation investments in other states and investments in interstate interconnection expansion projects can be analyzed and the benefits quantified. In the current CA ISO proposed methodology this is somewhat accomplished by using a DC optimum power flow analysis. This is an important improvement of the current proposal compared to the method proposed in February 2003.

Critical Market Drivers

Assumptions of the future market conditions are equally important for the evaluation of any incremental resources, either transmission or generation projects. The basic market forces that analysts always take into account are the following:

- Demand forecasts for all affected regions;
- Natural gas prices and availabilities;
- Hydrology condition forecasts for the study period;
- New generation and transmission projects scheduled to be in service prior to the new transmission project to be evaluated;
- Transmission capacity limitations, e.g., nomograms;
- Cost, location, and characteristics of new generation options; and
- System wide reserve margin requirements

The CA ISO February 2003 Report describes how some of these critical inputs were developed and others were examined in different scenarios. Demand forecast, gas prices and new entrants of generation projects are treated as the basic market drivers for the determination of plausible scenarios. Hydrology conditions were examined as sensitivity cases. An opportunity cost approach to dispatching limited hydroelectric energy was to optimize the value of hydroelectric generation. The one parameter that this CA ISO Report did not explicitly discuss is the reserve margin requirements.

The production simulation model used in February 2003 report was a proprietary LE model, where as the new CA ISO proposal uses PLEXOS, a commercially available model which uses Microsoft Access software to manage the input data base. This is an improvement over the 2003 methodology.

Representation of market bidding behavior

For modeling of strategic bidding behavior, commitment and dispatch prices were adjusted to take account of bid markups. These markups only applied to incremental output above a threshold output level.

Two approaches were presented in the CA ISO Report to assess the price markup induced by market power. The first approach involves developing a game theory model of strategic bidding. The second approach involves capturing strategic bidding through estimated historical relationships between price-cost markups and bid-cost markups. Each modeling approach has its advantages and disadvantages.

The advantage of the game theory approach is that because it is derived independent of observed historical behavior, it can simulate market power under a variety of future market conditions without the potential bias of having been based on observed historical behavior. However, the game theory model's independence from observed historical relationships between market power and specific market conditions raises a significant risk in that if the model is not able to calibrate against historical bidding practices, there is no guarantee that it will predict strategic bidding in the future. Another risk in simulation-based game theory models is that the converged solution may not be truly converged or represent a true equilibrium.

The advantage of modeling market power through an empirical approach relying on historical relationships between market power and market variables is that the approach has a strong historical basis. A potential disadvantage of this approach is that because it is based on estimated historical relationships, its predictive capability may be limited if applied under very different market conditions.

With all that said, the 2003 CA ISO Report recommended that strategic bidding markups should be used only in the determination of new generation entry economics. And the current CA ISO methodology uses the historical relationships between market prices and market variables to estimate price markups.

Development of plausible scenarios and determining appropriate probabilities

To accurately assess the benefits of a transmission expansion project, many plausible combinations of system parameters must be examined. The 2003 CA ISO Report utilized a two-step process for selecting scenarios to ensure extreme conditions are included and a representative sample of more moderate scenarios are also analyzed. For the selection of scenarios, assumptions about demand forecast, natural gas prices and new generation entry were used as the major market drivers.

The next step after defining the various scenarios is to determine the weighting factors for the scenarios needed for the quantification of the "expected benefit" of the expansion project. The 2003 CA ISO Report adopted a two-stage approach for this task, too. In the first stage, joint probabilities were derived for various combinations of gas prices and demand forecasts. These probabilities are then used in the second stage to determine the joint probabilities of the pairs of gas price and demand levels and the new generation entry scenarios. The fact that better probability distribution data are more readily available for gas prices and demand levels means that the joint probabilities of them can be calculated fairly straightforward. On the other hand, there are not much data on the probability distribution for the level of new generation entry. The CA ISO Report considered the sensitivities of the resultant benefits under a range of plausible distributions and adopted a Min-Max optimization approach to incorporate the uncertainty of the level of new generation entry.

Input assumptions

Overall hydrology conditions and hydroelectric dispatch based on opportunity costs

A methodology for modeling hydroelectric generation must recognize that these resources are typically energy-limited and the optimal dispatch must reflect opportunity costs of the energy produced today which should reflect the foregone opportunity of selling that energy in some future period. The California hydrology data in this CA ISO Report came from Energy Commission historical hydroelectric monthly output data (1984-2000). Hydrology systems in the other WECC regions were not modeled explicitly. They were predetermined and incorporated in the modeling of imports to California. The peak capacity of the hydroelectric systems in California was further adjusted based on historical patterns observed of the monthly energy availability.

Commitment and dispatch logic for Thermal units

LE used proprietary market simulation software, PoolMOD, to perform unit commitments and dispatches. Daily commitments of units are based on the total short run operating costs, including specified start-up and no-load heat costs, if provided. Hydroelectric resources are scheduled according to the optimal duration of operation in the scheduled day.

Resources are dispatched to operate above their minimum loading points based on their incremental heat rates. Transmission system constraints are observed during commitments and dispatching. Units are committed to meet demand plus reserve and dispatched to serve hourly loads.

Price response demand programs in California were modeled as supply options or curtailable demands.

Investment decision for new entrant generation projects

Recognizing the interdependencies or the trade-offs between generation and transmission investments, evaluation of each transmission upgrade option is done assuming a pattern of long term new generation entries has been completed. This pattern was derived under the assumption that new entries are independent of each other and they will be added just sufficient to maintain prices at the appropriate remunerative levels. It is assumed that over the long run that the remunerative level will be defined by the levelized annual revenue requirement for the generation project, in order to recover its capital cost, operating cost, debt financing cost, and appropriate rate of return on investment.

For each transmission option, the new entry decision is made based on a probability-weighted average of prices under high low and medium demand scenarios. Because the new entry is added to the system incrementally in an iterative process, it is not practical to consider more scenarios.

In the 2003 CA ISO report, imports from outside of California were modeled with aggregated regional loads and composite generation resources. There were no new generation entries in the Pacific Northwest or Desert southwest assumed or evaluated.

Measuring Benefits

The 2003 CA ISO proposed methodology utilizes cost-benefit analysis based on a predefined "optimal investments rules" to determine whether a proposed project is desirable from a societal welfare standpoint.

The optimal investment rules insure that:

- The social benefit of the evaluated transmission project out-weighs its social cost ; and
- The transmission project investment delivers the highest net social surplus.

Alternatives analyzed to address the second rule include timing of the project, alternative transmission options, new entry generation project, and demand side management measures.

Modeling time horizon and project life assumptions

The 2003 CA ISO Report recognized the importance of the appropriate modeling time horizon for the valuation of transmission expansion projects. Because the accuracy of the base-line input assumptions used in the model diminish significantly for long-term projections, it is critical that the benefits of the transmission expansion be evaluated under a number of different input assumptions. In addition, since most transmission projects typically take several years to complete, a study period in the range of 12-15 years would provide 6-9 years of annual benefit estimates. The 2003 CA ISO Report believes a shorter time horizon can be appropriate if a transmission project can be shown to be economically viable within a shorter time frame. This short time horizon is not a reasonable assumption. Most transmission projects are capital intensive and create benefits over a long period.

In the cost-benefit analysis used to determine if a project is desirable from the societal welfare standpoint, project lives are assumed to be 20 years for combined cycle units and 10 years for simple cycle gas turbine units. However, the project life for transmission expansion project was not discussed explicitly.

Social discount rates

In cost-benefit analysis, project alternatives are evaluated and compared based on the net present value of all relevant costs and benefits. An important component of the net present value (NPV) calculation is the determination of an appropriate set of social discount rates. The 2003 CA ISO proposed methodology recommends that the regulated rate of return approved for previous transmission assets should be used as the appropriate social discount rate for evaluating transmission expansion investments. This is not the correct definition of social rate of discount. The current CA ISO methodology attempts to bypass the issue of economic life of a transmission project by comparing benefits from a one or two test year analysis with levelized capital cost of the project.

Allocation of benefits

The 2003 CA ISO proposed methodology introduced another parameter for evaluating project benefits, namely the distributional effects of the benefits. It proposes that there should be some distinction between producer and consumer surpluses or regional shifts in surpluses within these groups.

When a rigorous cost and benefit analysis indicated that a particular project is welfare enhancing in the aggregate, it may not be considered desirable, if its benefits are disproportionately skewed towards particular groups. Thus the measurement of benefit can be further refined to include additional benefit objective functions.

The CA ISO Report suggests that investments should be evaluated based on:

- Changes in social welfare in the aggregate – this criteria gives equal weights to consumer and producer benefits;
- Changes in consumer benefit – this approach only credits the benefit to consumers; and
- Changes in consumer benefit plus changes in competitive producer surplus – this approaches ignores the producer benefit associated with strategic bidding in a not-so-perfect competitive market.

The current CA ISO methodology includes benefits/costs for importing and exporting regions and, in each region, ratepayers and power producers. This model also takes into account the impact on transmission revenue due to congestions.