CHAPTER 7

USING MARKET SIMULATIONS FOR ECONOMIC ASSESSMENT OF TRANSMISSION UPGRADES: APPLICATION OF THE CALIFORNIA ISO APPROACH

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7.1 INTRODUCTION

The need for new transmission planning processes that respond to the demands of a restructured power industry is widely acknowledged [1–10]:

> *"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" [11].*
>
> *"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" [12].*

Unlike the previous vertically integrated regime in which a single 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 use of transmission. A new approach to evaluate the economic benefits of transmission expansion is therefore needed. Specifically, the approach must anticipate how a transmission expansion would affect (a) transmission users' access to customers and generation, (b) bidding and operating behavior of existing generation, and (c) incentives for new generation investment. The approach must also account for

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uncertainty associated with key market factors such as hydro conditions, fuel prices, and demand growth. The California ISO's (CAISO's) response to this challenge has been to develop a planning approach called the Transmission Economic Assessment Methodology (TEAM) [13–15].

TEAM was developed because the CAISO is responsible for evaluating the need for transmission upgrades that California ratepayers may be asked to fund. These include construction of transmission projects needed either to promote economic efficiency or maintain reliability. The CAISO has clear standards for evaluating reliability-based projects. TEAM will help the CAISO fulfill its responsibility to identify economic projects that encourage efficient use of the grid.

The goal of TEAM is to streamline the evaluation process for economic projects, improve the accuracy of the evaluation, and add greater predictability to the evaluations of transmission need conducted by various agencies. In several previous cases, the CAISO has seen the same project receive multiple reviews of project need by various agencies, each carrying out its individual mandate. This has caused redundancies and inefficiencies [16, 17]. We believe that accepting the TEAM methodology as the standard for project evaluation will reduce redundant efforts and lead to faster and more widely supported decisions on transmission investment projects.

The TEAM methodology is based upon five principles for quantifying benefits. It 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 framework is a template defining the basic components that any transmission study in California should address, providing standards for the minimum functionality that modeling software should have. TEAM is intended to provide market participants, policy-makers, and permitting authorities with the information they need to make informed decisions.

This chapter summarizes the elements of the TEAM methodology for assessing the economic benefits of transmission expansions for wholesale market environments (Section 7.2). To illustrate its use, we summarize its application to a proposed transmission upgrade (Palo Verde-Devers 2, PVD2) (Section 7.3). We describe particular modeling procedures we used for the risk and market power analyses, which are new in transmission planning practice. We also summarize some issues that arise in applying TEAM to evaluating renewable-focused transmission (Section 7.4).

7.2 FIVE PRINCIPLES

The valuation methodology we propose here enhances traditional transmission evaluations in five ways, which we call "principles." With the exception of the market-based (market power) pricing principle, none of these individual principles is entirely novel, in that each has been considered previous transmission planning studies. However, no previous studies, to our knowledge, have considered all of the principles.

Although how the principles are applied will vary from study to study, the CAISO requires that the principles be considered in any economic evaluation of proposed upgrades presented to the CAISO for review. The TEAM report [13] suggests specific procedures that can be used to implement each principle. The study type and initial results will dictate the level of application. Our PVD2 study experience indicates that about 12 person-months of effort over three months is needed to fully apply TEAM, including analysis and public participation.

We note that the methodology was developed in collaboration with stakeholders in an open process. Further, its application to any particular project is subject to public review before submitting a project for approval to the CAISO Board of Governors. Finally, the TEAM results are reviewed in California Public Utilities Commission hearings. At any time during this process, stakeholders can propose alternatives for consideration by TEAM. This open process is intended to make the method's assumptions and procedures transparent to all interests involved.

7.2.1 First Principle: Benefit Framework

A benefit-cost analysis framework should enable users to clearly identify the beneficiaries and expected benefits of any kind of transmission project.

TEAM divides the total benefits due to a transmission expansion into three parts—changes in consumer surplus, producer surplus, and transmission owner (congestion revenue) benefits. For a vertically integrated utility, benefits arise from three sources—direct reductions in wholesale power costs, increases in net revenue for utility-owned generation, and increases in utility-derived congestion revenue.

The quantified benefits can be aggregated for individual subregions or groups of market participants (e.g., California ratepayers), as well as for the entire Western interconnection. A key policy question is which perspective should be used to evaluate projects. The answer depends on the viewpoint of the entity that the network is intended to benefit. If the network is operated to benefit ratepayers who have paid for the network, then the ratepayer perspective might be argued to be most appropriate. But in the long run, financially healthy utility generation and private supply may be needed to maximize ratepayer benefits. In this view, the network is operated to benefit all market participants and, thus, benefits to CAISO participants or the Western Electricity Coordinating Council (WECC) may be the relevant test. (The WECC includes 11 states, two Canadian provinces, and northwest Mexico.)

TEAM does not specify a single test as being the "right" test, nor any specific numerical threshold as being "do or die" for a project. Rather, each perspective provides important information to policy-makers [6]. If the benefit-cost ratio of an upgrade passes the CAISO participant test, but fails the WECC test of economic efficiency, then it may indicate that the expansion will mainly transfer benefits from one region to another. In contrast, if the project passes the societal test but fails the CAISO participant test, this implies that other project beneficiaries should help fund the project.

An additional consideration in weighing various perspectives is how to treat the loss of market power–derived rents by generation owners when the grid is expanded. Since market power reduces efficiency and harms consumers, it can be argued that it is reasonable to exclude the loss of those rents in benefit calculations. (These rents are distinguished from scarcity rents that arise in competitive markets.) This is the difference between the societal test and the modified societal test (based on societal benefits minus market power rents) used in the PVD2 study.

The basic calculations of cost-to-load and profits earned by market parties are given below; from these building blocks, the various benefit-cost metrics can be calculated. For simplicity, we here disregard the complications of long-run power purchase contracts, as well as ownership of and payments to transmission interfaces between different markets (e.g., California and Arizona). We also consider only the short-run, assuming capital stock is fixed; so we can ignore payments for fixed capital costs (e.g., customer wire charges paid to the transmission owner, or financing costs for generation), which are unaffected by operating decisions. Demand elasticity is zero (fixed load). Only one hour is considered. Of course, most or all these assumptions are relaxed in the actual calculations in any particular TEAM application.

Let L_i be the power consumed at bus i; g_{ui} the amount of utility-owned power produced at i; g_{mi} the amount of independent (merchant) power produced at i; and pi the price (LMP) at i. The function $C_{ui}(g_{\mathrm{ui}})$ is the production cost associated with utility-owned generation, while $C_{mi}(g_{\mathrm{mi}})$ is the production cost of merchant generation. The function $P_{imp}(imports_{\mathrm{r}}, p)$ is the cost of imports to the transmission owner which, in general, depends on the level of imports to r as well as the vector of prices in all locations. For exporting regions, $imports_r$ will be negative and, generally, will be their "cost" (i.e., revenue will be earned). $I(r)$ is the set of buses in region r.

Net cost-to-load in region $r = CTL_r = \Sigma_{i\in I(r)} p_i L_i - \Pi_{ur} - MS_r$
= payments for power minus utility and transmission profits (7.1)
(since utility-owned generation and transmission are assumed to be regulated on a cost-of-service basis)

Operating profit (gross margin) to utility-owned generation in r
$= \Pi_{ur} = \Sigma_{i\in I(r)}[p_i g_{ui} - C_{ui}(g_{ui})]$
= revenue minus cost (7.2)

Operating profit (gross margin) to merchant-owned generation in r
$= \Pi_{mr}$
$= \Sigma_{i\in I(r)}[p_i g_{mi} - C_{mi}(g_{mi})]$ (7.3)

Transmission owner merchandising surplus in r
$= MS_r$
$= \Sigma_{i\in I(r)} p_i[L_i - g_{ui} - g_{mi}] - P_{imp}(\Sigma_{i\in I(r)}[L_i - g_{ui} - g_{mi}], p)$
= revenue from load minus payments to generation and for imports. (7.4)

Assuming that $\Sigma_r P_{imp}(\Sigma_{i\in I(r)} [L_i - g_{ui} - g_{mi}], p) = 0$ (i.e., payments by one region for imports equal receipts to all other regions for exports to that region), then the total benefit to all parties = $\Sigma_r [\Pi_{ur} + \Pi_{mr} + MS_r - CTL_r]$ simplifies to $-\Sigma_r \Sigma_{i\in I(r)} [C_{ui}(g_{\mathrm{ui}}) + C_{mi}(g_{\mathrm{mi}})]$, the sum of all production costs. This is because all the p_i terms cancel. (One party's expenditure is another's revenue.)

7.2.2 Second Principle: Full Network Representation

It is important to accurately model physical transmission flows to correctly forecast the impact of an upgrade. Models based on contract paths may suffice for some types of resource studies, but that approach is generally deficient when analyzing a network modification that impacts regional transmission flows and locational marginal prices (LMPs).

We have recently seen how critical an accurate network representation is to making correct decisions. A utility proposed a transmission addition and justified its economic viability using a contract-path model. However, the CAISO found the line to be uneconomic due to adverse physical impacts on other parts of the transmission system that the contract-path model disregarded. The CAISO's full network model showed far more flow into California from a particular direction because the proposed line reduced the impedence of the system in that direction. Thus, the CAISO experienced an actual reduction in transfer capability, and additional upgrades were needed to get the benefits projected by the utility [18].

It is possible that, with careful tuning, aggregate path-based models that disregard parallel flows can be adequate in many circumstances. Indeed, this was the most controversial issue in the California regulatory review of the TEAM methodology [18]. But obtaining such approximations is challenging and invites criticism in regulatory proceedings; using a full network model avoids criticisms about equivalences. A useful research direction would be a systematic comparison of the results of path-based and full network (DC and AC) models at various levels of aggregation to more fully understand when they differ, and the implications of such differences. This could lead to a fuller understanding of what simplifications can be safely made without distorting the results of economic studies.[1]

There are many different techniques for modeling physical transmission networks. More accurate techniques may also increase computational and data burdens. Recognizing these tradeoffs, 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 the ability to model the following:

- Either a DC or AC optimal power flow (OPF) that correctly represents thermal and other constraints upon physical power flows for high-voltage transmission facilities and interfaces resulting from specific hourly load and generation patterns. Use of a full AC load flow model to represent hourly conditions in a large market over a planning horizon is not presently possible. Several production costing models are available (e.g., GE-MAPS [19] and PLEXOS [20]) that include a linearized DC load flow.
- Individual facility thermal or surge impedance loading-based constraints, linear nomograms resulting from stability and other limits, and path limits.
- Flow limits that depend on variables such as area load, facility loading, or generator availability.
- Phase shifters, DC lines, and other controllable devices.

[1]For an example of a study comparing the accuracy of load-flow simulation methods, see [37].

- LMPs.
- Hourly flows on individual facilities, paths, or nomograms.

It is also desirable to model transmission losses.

While the TEAM approach recommends use of a network model, a simplified analysis (contract path or transportation models) can also 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. Also, if the project proponent can convincingly demonstrate that a simpler model can estimate costs and market impacts as accurately as a full network model, it is permissible to use the simpler model; thus, TEAM is making a rebuttable presumption that a full network is necessary. Of course, in applying any transmission model, it is important to verify that results are not unduly affected by constraints that in the real world can be readily modified.

7.2.3 Third Principle: Market Prices

Historically, resource plans have relied on production cost simulations to quantify economic benefits of proposed upgrades. Such an approach made sense when utilities were vertically integrated and recovered costs through regulated rates. But naïvely assuming that profit-maximizing suppliers bid at marginal cost in a market environment may distort benefit estimates. Instead, suppliers are likely to optimize bidding strategies in response to system conditions or behavior of other market participants.

Modeling such bidding is important because transmission expansion can benefit consumers by improving market competitiveness. A project can enhance competitiveness of the wholesale market by increasing the number of independent generation owners that can supply energy at various locations. However, in theory, the presence of imperfect competition can either decrease or increase the benefits of transmission upgrades, depending on the situation [21].

Thus, strategic bidding can impact societal benefits of an upgrade, as well as transfers of benefits among participants. Because of this, forecasting market prices is critical.

There are two approaches to modeling strategic bidding in transmission valuation studies. The first involves use of game-theoretic models to simulate strategic bidding [e.g., 22]. Such a model typically represents several strategic suppliers, each seeking to maximize its profits by altering its bids or production in response to the strategies of other players. The second approach involves the use of estimated historical relationships between market structure and measures of market power such as bid-cost mark-ups or the difference between market prices and hypothetical competitive prices [23].[2]

[2]Several empirical studies have gauged the extent of unilateral market power exercised in a wholesale electricity market by computing the mark-up of the actual price over a counterfactual competitive benchmark price [24–26]. However, none of these studies have estimated predictive statistical models relating hour-by-hour mark-ups to shifting market conditions. The strength of the approach we use in the PVD2 case study is that it relies on California's experience with markets over the past seven years to estimate a stable predictive relationship between the mark-up of the actual market price over a counterfactual competitive price and key variables that measure system supply/demand conditions that influence mark-ups.

Each approach has advantages [13]. In our experience in California and elsewhere, we have found that game-theoretic models can be extraordinarily useful for providing general insights on how proposals for changes in market designs or industry structure might affect the ability to exercise market power. However, they have been less useful for predicting specific prices under particular supply and demand circumstances. In assessing these alternative approaches, we believe that an empirical approach to modeling strategic bidding is preferable to a game theoretic approach if relevant data are available and can be adapted to a detailed transmission network representation. On the other hand, game theoretic methods are advantageous in unprecedented situations or where data is lacking.

To the best of our knowledge, no one has successfully developed and implemented a market simulation model based on strategic supply bids that dynamically respond to supply conditions while incorporating a detailed physical transmission modeling capability. However, we acknowledge that much research and development remains to be done in this area, and that approaches other than the empirical bid mark-up method we use below may be more useful in other circumstances. TEAM does not specify the process to be used for forecasting market power. Rather, at this point, the CAISO asks only that a credible and comprehensive approach for forecasting market prices be utilized in the evaluation. We consider the empirical bidding model we use in the PVD2 analysis below to be one of several useful methods for deriving market prices.

7.2.4 Fourth Principle: Explicit Uncertainty Analysis

Decisions on whether to build new transmission are complicated by uncertainty. Future load growth, fuel costs, additions and retirements of generation capacity, exercise of market power, and availability of hydropower are among the many uncertainties that impact decision making. Some of these risks and uncertainties are readily quantified, but others are not.

There are two reasons why we must consider uncertainty. First, changes in system conditions can significantly affect transmission benefits and the relationship between benefits and underlying system conditions is nonlinear. (This is true in the case study; see Table 7.1 below.) Thus, evaluating an upgrade based just on average future system conditions might greatly under- or overestimate the expected project benefits and lead to a suboptimal decision. To capture all project impacts, we must examine a wide range of possible system conditions.

Second, historical evidence suggests that transmission upgrades have been particularly valuable during extreme conditions. A hypothetical interconnection between WECC and the eastern US that would have been able to convey many gigawatts of power during the 2000–2001 period would have been worth tens of billions of dollars, based on differences between the regions' prices. Had such a significant inter-connection been in place, western prices would not have risen to levels that they did during that period. (Such an interconnection could be analyzed by the TEAM approach, but has not since it would not be under CAISO jurisdiction.)

There are several approaches for assessing the impact of uncertainty on transmission expansion [e.g., 3, 4]. A complete evaluation process should incorporate

TABLE 7.1 Seventeen market cases considered in 2008 expected benefits analysis (all benefits are in millions of $2008, and are the difference between "with PVD2" and "without PVD2" simulations)

Case i	LD	GP	HY	MU	Pr_i	Societal	Modified societal	CAISO ratepayer (LMP only)	CAISO R.P. (LMP + contract path)
1	B	B	B	B	0.11	45.3	58.9	37.9	98.7
2	B	B	B	H	0.05	47	71.1	54.8	124.5
3	B	B	D	B	0.099	50.5	66.6	34.5	115.7
4	B	B	W	B	0.131	24.3	26.2	29.1	72.8
5	B	H	B	B	0.023	90	113.1	76.7	185.9
6	B	H	B	H	0.018	92.5	133.9	104.8	229.1
7	H	B	B	H	0.033	45.3	120.8	70.9	199.8
8	H	H	D	B	0.018	119.9	237	85.2	317.5
9	B	H	D	H	0.018	106	151.6	80.7	257.3
10	B	B	B	L	0.15	42.5	41.5	17	68.5
11	L	B	B	B	0.127	29.9	31.6	35.6	83.3
12	B	L	B	B	0.101	8.8	18.5	8	36.6
13	H	H	B	H	0.015	93.8	235.2	143.2	371.1
14	H	L	B	B	0.049	4.4	23.7	2.2	41
15	L	H	B	B	0.023	56.9	59.5	74.1	155.4
16	H	H	D	H	0.015	135.8	387.7	234.9	568.5
17	H	H	W	B	0.019	19.1	21.5	5.6	119.7
	Expected Value					41	61	39	110

Key: LD = load level; GP = gas price level; HY = hydro level; MU = mark-up

probabilistic analysis or scenario analysis. The probabilistic approach models uncertainties associated with parameters that affect project benefits, and assigns probabilities to, for example, scenarios of future loads, gas prices, and generating unit availabilities.

Unless the proposed project economics are overwhelmingly favorable when using "expected" input assumptions, we need to perform sensitivity studies using a range of input assumptions. We do this to compute the following risk measures:

- Expected value
- Range
- Values under specified rare but potentially important contingencies, such as loss of a major transmission link

Much of the economic value of an upgrade is realized when unusual or unexpected situations occur. Such situations may include high load growth, high gas prices, or extreme 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. These are not combined mechanistically into a single index of project desirability or risk. Rather, the various measures provide a fuller picture of the advantages and disadvantages of a proposal.

A transmission upgrade can also be viewed as a type of insurance 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. The events considered could include physical contingencies such as extended transmission outages, as in the PVD2 analysis below. They could also include drastic changes in regulation (e.g., CO_2 caps).

An extension of risk analysis would assess the value of waiting for more information before committing to construction [27]. This so-called "option value" could be quantified by constructing decision trees representing the defer option and later construction possibilities, along with changes in scenario probabilities that could result from the information ("posterior probabilities").

7.2.5 Fifth Principle: Interactions with Other Resources

The economic value of a proposed upgrade directly depends on the cost of resources that could be added or implemented in lieu of the upgrade. We consider the following resource options singly and in combination:

- Central station, renewable, and distributed generation
- Demand-side management
- Modified operating procedures
- Additional remedial action schemes
- Alternative transmission upgrades

Examining such alternatives must recognize that an alternative can either complement the upgrade or substitute for it.

In addition to considering resource alternatives, another important issue to consider is the decision where to site new resources. One perspective is that the transmission should be sited after the siting of new generation. Another point of view is that the transmission should be planned anticipating how generation investment would react. (Sauma and Oren [21] carefully analyze these different perspectives.)

We believe the latter perspective will yield the greatest long-run societal benefits. Transmission additions have planning horizons that require decisions a decade in advance of the line being placed in service. A new combined cycle natural gas-fired generation unit can easily be built in half this time. Consequently, we believe it is best to plan the grid anticipating the entry decisions of new generation as a result of the upgrade [21]. In this way, the transmission planner influences generation decision making, rather than accounting for it after the fact.

The ideal means to account for private investment decisions is to model the profitability of generation investment [21]. We suggest a "what if" framework. As an example, if a new line was to be built, what would be the most likely resulting outcomes in the profitability of private generation decisions? Profitability should consider energy and ancillary service revenues, as well as markets for capacity or long-term energy contracts created in response to resource adequacy requirements. Comparing this to a case where we did not build the line, how much would the profitability of generation investments differ? The methodology can then optimize generation additions for both the with- and without upgrade cases, adding generation when its revenues can cover its fixed and variable costs. (As a less preferable alternative, fixed entry scenarios could be considered.) The difference in costs between the scenarios, including both the fixed and variable costs of the new resources, will be the value of the upgrade.

7.3 PALO VERDE-DEVERS NO. 2 STUDY

No other ISO, to our knowledge, has included all five of the above principles in their planning studies [28]. PJM, for example, includes multiple scenarios in their regional transmission expansion process [29], but not market-based pricing. The Italian ISO proposes a market simulation method based on the statistical methods we used [30], but does not consider the interaction of transmission and generation investment.

The purpose of our case study is to illustrate the application of the above principles to a market-driven upgrade. Below we summarize the project, assumptions of the analysis, results for each category of benefits, and resource alternatives to the project. We focus on identifying quantifiable economic benefits that can be attributed to PVD2. These include:

- Energy cost savings
- Operational benefits
- Capacity benefits
- System-loss reduction
- Emission reductions

Energy cost savings are estimated using the market simulation model PLEXOS [20], an optimal power flow model based on a linearized DC-load flow [31].[3] In theory, such a market simulator could also calculate the other categories of benefits, but as explained below, either data or software limitations preclude such calculations at this time; we recommend that such capabilities be developed for future analyses.

7.3.1 Market Model: PLEXOS

PLEXOS simulates hour-by-hour bid-based dispatch by minimizing as-bid costs, and yields dispatch quantities, flows, costs, and LMPs. The general formulation can be summarized as follows:

[3]PLEXOS simulates hour-by-hour bid-based dispatch by minimizing as-bid costs, and yields dispatch quantities, flows, costs, and LMPs. The model has the capability to include individual facility limits, path limits, and linearized nomograms capturing stability constraints on operations. Although PLEXOS has the capability of optimally shaping non-pumped hydropower output over time, we took hydro schedules over the day and year as varying over time but not changeable, reflecting historical operating patterns. The amount and timing of pumped storage is optimized by simulating 24 hours simultaneously.

MIN Sum of hourly generation and ancillary services costs (as bid) over 24 hours

subject to:

- Generation limits, including multi-fuel constraints, ramp rate limits, and random plant outages (using multiple Monte Carlo runs)
- Pump storage constraints, including environmental restrictions
- Spin and non-spin ancillary services
- Transmission limits, including thermal and SIL limits, interface (multiline) limits, phase shifters, and linearized nomograms capturing stability constraints on operations
- PDTF representations of line flows, based on line reactances[4]

Demand is assumed to be perfectly inelastic (fixed).

Thus, PLEXOS simulates a market in which ancillary services and energy are in equilibrium (or, equivalently, are co-optimized by an ISO). Oligopolistic behavior is simulated using exogenous bid adders, as described below, that are calculated as a function of system supply-demand conditions. Theoretically, an alternative is to calculate market power endogenously using PLEXOS' Cournot modeling capabilities [20], but that is not practically possible for a system with tens of thousands of buses, as in the western US. If bid adders are zero (cost-based bidding), then PLEXOS is equivalent to a perfectly competitive market equilibrium model in which generators are price takers. This is, in essence, an implementation of the famous Samuelson principle [39]: a perfectly competitive market (with no market failures) can be simulated by maximizing the sum of consumer and producer surpluses or equivalently, in the case of zero price elasticity of demand, minimizing the sum of production costs.

The WECC implementation of PLEXOS included:

- Calculation of flows on 17,450 lines
- Constraints upon flows on 3 DC lines, 284 high voltage (500 kV) AC lines, and 129 interfaces
- Calculation of prices at 13,383 buses
- Representation of 57 phase shifters (7 optimized, 50 fixed)
- Hourly dispatch of 760 generators over a 24-hour day
- Bids of California plants based on empirical *RSI*-based mark-ups, with other plants bid competitively
- Optimal operation of 8 pumped storage plants, and predetermined output schedules from 117 hydro plants

With so many power plants and line flows to simulate over 24 hours, PLEXOS constitutes a very large linear program which, however, can be solved using standard linear programming solvers.

[4]PLEXOS has the capability of simulating quadratic resistance losses [38], but this capability was not used in this analysis.

7.3.2 Project Description

The PVD2 project is a proposed 500 kV line that would provide additional interconnection between southern California and Arizona. If approved, the project could come online by 2009, increasing California's import capability from the southwest by at least 1200 MW. This is important because California depends on imports for more than 20% of its power needs. The CAISO recently used the TEAM methodology to identify and quantify the economic benefits of this line [32].

The idea for the PVD2 project originated in a regional planning process called the Southwest Transmission Expansion Plan (STEP) [33]. PVD2 is the third of fourth major project recommended by that process. In parallel with the STEP process, the Southern California Edison Company (SCE) determined that PVD2 was cost effective and filed a report requesting that the CAISO approve the project addition. The CAISO then undertook an independent economic study of PVD2 applying TEAM.

The location of the PVD2 project is shown in Figure 7.1. It includes the following facilities:

- A new 230 mile 500 kV overhead line between Harquahala Generating Company's Harquahala Switchyard (near Palo Verde) and SCE's Devers 500 kV Substation
- Rebuilding and reconductoring of four 230 kV lines west of the Devers substation
- Voltage support facilities in southern California

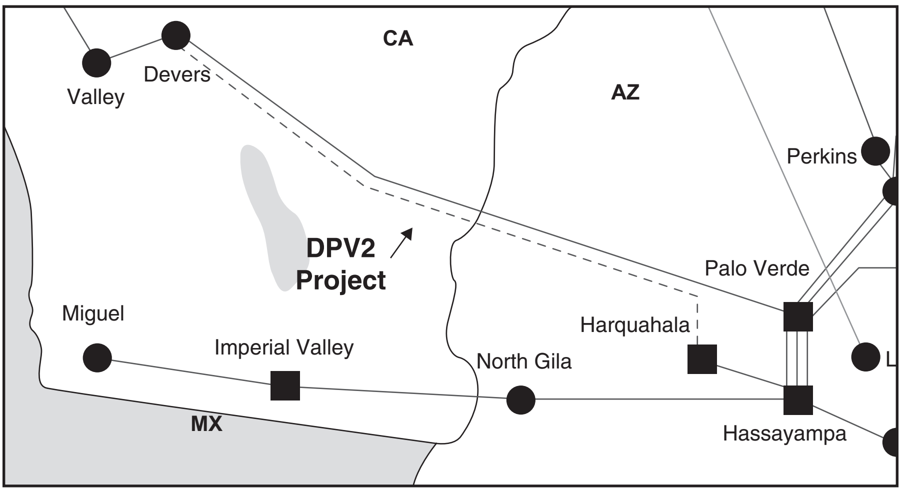

Figure 7.1 Location of proposed Palo Verde-Devers project

7.3.3 Input Assumptions

We conducted the energy benefits analysis for two future years, 2008 and 2013, using PLEXOS. Each hour of the year is simulated in PLEXOS, although a smaller number of runs could have been made while still spanning the range of possible system conditions. (The number of runs required to obtain an accurate estimation of production costs is an empirical question, and should be determined by experimentation for each particular system as a part of the study design.) We chose the years 2008 and 2013 because those were the only years for which vetted network and resource data were available from the Seams Steering Group (SSG) for WECC. It is common in long-range planning and market modeling studies to estimate benefits in five-year time steps because the planning cycle is often on the order of a half decade, and using a multiyear time step makes computation times more reasonable. Additional years could have been simulated if a simpler, unvetted network had been used; we decided that such an analysis would have raised other issues without significantly improving our understanding of the time distribution of benefits. All benefits are expressed in year 2008 dollars.

7.3.3.1 Transmission Consistent with the second TEAM principle ("full network modeling"), we studied the impact of the proposed PVD2 upgrade using a detailed transmission network model of the WECC (Figure 7.2). The model computed physical transmission flows, associated transmission charges, and nodal prices for each hour of 2008 and 2013 for the high-voltage WECC network. Constraints on flows were imposed for 284 500 kV lines, two DC lines, and 124 interfaces (involving 468 lines), while flows were calculated for lower voltage lines. Flows were calculated for 17,500 lines of different voltage levels, allowing LMPs to be calculated for 13,400 buses in the system.

Consistent with the market design implemented in California in 2008, prices to California loads are based on zonal averages, while prices received by generators are bus-based.

7.3.3.2 Loads For loads outside California, WECC forecasts were used, and were disaggregated into hourly chronological load shapes for 21 regions and about 5700 locations (nodes). For California loads, we used the California Energy Commission (CEC) March 2003 forecast. From 2008 to 2013, overall energy growth in WECC is predicted to be about 1.7%/yr for the base case, and 1.4%/yr for the CAISO area. In 2013, the CAISO peak is 33% of the WECC peak.

7.3.3.3 Generation We obtained most of the system resource data from the SSG database. Their WECC database has about 800 thermal, hydro, pumped storage, and renewable generators with a total capacity of about 196,000 MW in 2008 and 213,000 MW in 2013. We added resources to the SSG database to reflect renewable portfolio standards in each of the states. Renewable resource additions included wind, solar, biomass, geothermal, and digester gas. We also added new gas-fired generation, primarily combined cycle plants, in each WECC area to attain a 15% planning reserve margin. The California gas-fired resources that we added on top of

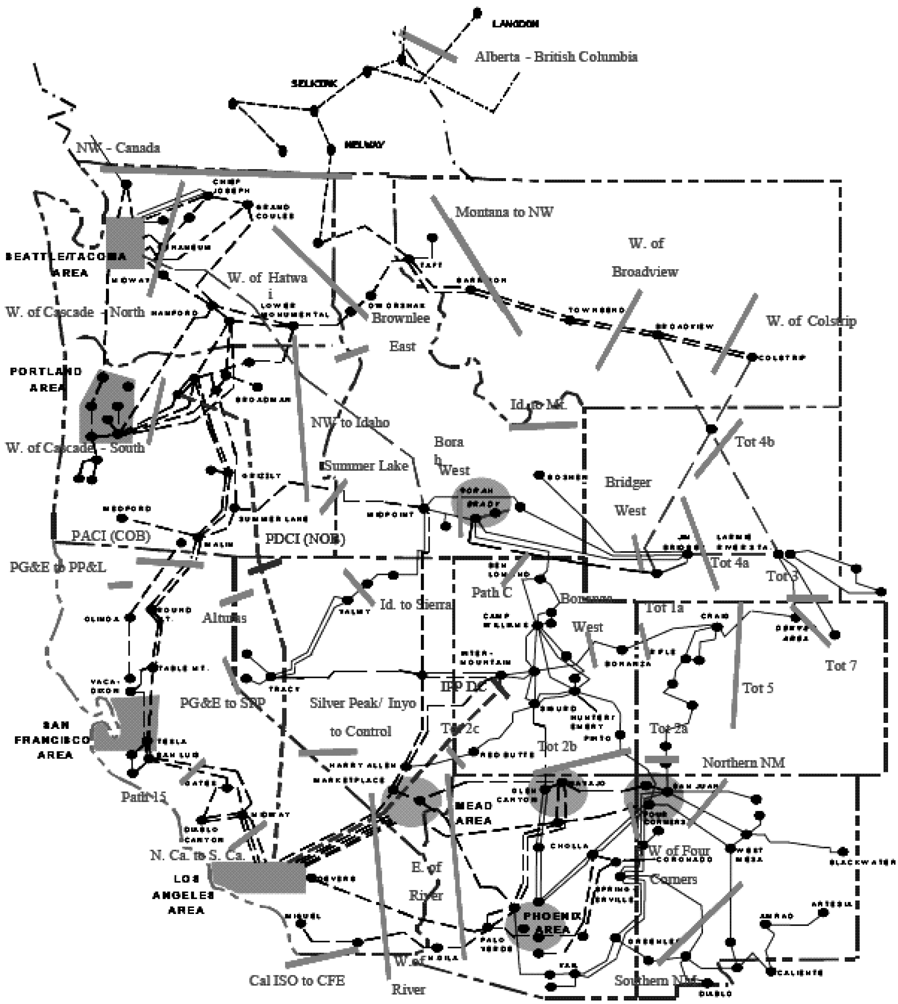

Figure 7.2 WECC network and path interfaces used in PLEXOS analysis of PVD2 line

the SSG additions were those that appeared to have a high likelihood of completion based on information compiled by the CEC.

The total CAISO resource capacity is 59,204 MW in 2008, and 64,447 MW in 2013. The WECC area planning reserve margin is 18% in both 2008 and 2013, although some regions are more resource rich than others; California in particular is projected to have lower reserves than most other regions.

The base gas price case was based on CEC forecasts [17], revised to reflect the gas price differential that existed at various city gates and gas pricing hubs as of August 2004.

7.3.3.4 Uncertainty Cases Consistent with fourth TEAM principle ("explicit uncertainty analysis"), the benefits of the line must be considered in the context of uncertainties that will unfold over the life of the project. We quantified the impact of this uncertainty by developing cases with different levels of input assumptions for load, gas prices, hydro conditions, and the exercise of market power. We believe that these cases cover a reasonable range of possibilities. We then calculated expected benefits across these cases taking into account their probabilities. In addition, we consider the line's "insurance benefit" by calculating benefits under various possible contingencies. Sixteen combinations of transmission and/or generation outages were considered as contingencies.

In the expected benefit calculation, we focused on the four key variables just mentioned, defining 17 combinations for each year. For the cases where we varied load, gas price, and market power, we examined three levels: very high (H), base (B), or very low (L). For the hydro cases, we also examined three levels: wet (W), base (B), or dry (D) year.

We determined the values of the demand and gas price cases by analyzing the historical accuracy of predictions of those variables, comparing CEC forecasts of loads and prices over the past 20 years [17] to their actually realized levels. Load distributions are characterized using normal distributions fitted to the historical forecast errors, while gas prices follow a log-normal distribution. The L and H levels used in the load and gas sensitivity cases are based on 90% confidence intervals from their distributions. For loads, those levels vary only slightly from the base case, while for gas and mark-up, the differences are large (Figure 7.3).

We took hydro ranges from 80 years of historical hydro production records. Derivation of the bid mark-up uncertainty cases is discussed in the subsection on market pricing, below.

The $3 \times 3 \times 3 \times 3 = 81$ possible combinations of values for the four uncertain variables are too many to simulate. Therefore, we considered a small but representative subset of the cases in the expected benefits calculations:

1. Base values for all four variables (one case).
2. Base values for three of the four variables, and the low value for the fourth variable (four cases).

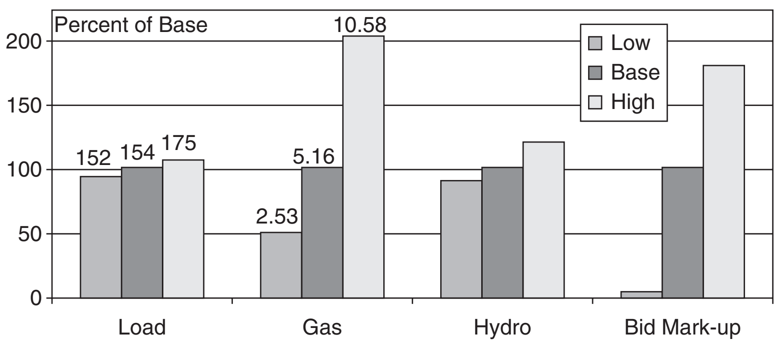

Figure 7.3 Comparison of very low, base, and very high assumptions, 2013 (WECC Peak Load in GW; Gas price, WECC Annual Average in $/MMBTU)

3. Base values for three of the four variables, and the high value for the fourth variable (three cases; the high load case with base values for other variables is not considered).
4. Additional cases representing plausible combinations of extreme scenarios such as a high stress condition (high load, high gas price, dry hydro, high market mark-up), economic boom (high load and gas prices), or recession induced by high fuel prices (low load, high gas price). Another consideration in selecting these cases was to make it possible for probabilities to be chosen so that the means and standard deviations of each of the individual variables matched the assumptions, and for correlations to be reasonable (for instance, we expect a positive correlation between dry conditions and high demand due to warm temperatures) (nine cases). Latin-hypercube sampling, which has been used in another TEAM application [13], could also have been used in the PVD2 study to select additional scenarios, but the 17 selected scenarios were considered to be sufficient.

Table 7.1 shows the selected 17 cases for 2008.

After choosing the cases, it is necessary to determine the probability that each will occur in the future. Each case is a realization of the various dimensions of uncertainty in future system conditions. However, the input data described above only provides an estimate of the marginal distribution of each of these dimensions. For example, we have information on the marginal distributions of future hydro conditions and gas prices, but not their joint density. Consequently, we must pick values for the joint probability of each set of future system conditions. We choose these probabilities using a nonlinear program that maximizes the logarithm of likelihood (the sum of the logarithm of the joint probabilities) of observing the 17 scenarios subject to the constraint that the joint probabilities replicate the first two moments of the marginal distribution of each variable. Mathematically, we choose the Pr_i for cases $i = 1, 2, \dots, 17$ to maximize $\Sigma_i \ln(Pr_i)$ subject to the constraints:

- $\Sigma_i \, Pr_i = 1$, and
- the mean and standard deviation for each variable implied by these joint probabilities match the assumed values for the marginal distribution of each variable.

Table 7.1 shows the resulting probabilities.

7.3.3.5 Market Price Derivation The third TEAM principle ("market prices") requires that energy prices be projected considering the potential for market power and how it might be affected by the proposed upgrade. Although it is a great challenge to model strategic bidding by suppliers in a full network model, we were able to rely on California's experience with markets over the past seven years. We chose to ground projections of market competitiveness on empirical analysis of past behavior, as opposed to theoretical models with unproven forecast ability. Using historical data, we were able to demonstrate a stable predictive relationship between market price-competitive price mark-ups and key variables that measure system supply/demand conditions. This regression approach may lack the rigorous foundation in economic theory that characterize other studies [24–26], but its simplicity and robustness together with its ability to capture the impact of system conditions and competitor behavior on prices on an hourly basis make it a useful tool here.

We estimated this mark-up relationship from observed data during two critical periods: from 1999 to 2000 when suppliers had few long-term commitments to supply energy to load, and the year 2003 when some suppliers had large long-term contractual commitments.[5] We estimated regressions predicting how hourly prices are marked up over the variable cost of the highest variable cost unit operating during that hour for every hour in each of three California regions (south, central, north), based on the amount of supply relative to demand, accounting for potential import quantities into that zone. These estimated relationships allow us to build a dynamic bid mark-up mechanism into PLEXOS in which suppliers' price bids are determined by their variable costs and the mark-up over these costs implied by the relationship relevant for this generation unit. More importantly, because this mechanism varies the bid mark-up with hourly system conditions, we can capture the impact of major transmission upgrades, such as PVD2, on import capability into the CAISO control area, thus reducing the ability of suppliers in the CAISO control area to bid above their variable cost. After incrementing bids by the mark-ups implied by these estimated relationships, we then ran PLEXOS to obtain market prices, which were then used in our assessment of energy benefits.

In the mark-up and system and market conditions relationship, mark-ups were expressed as a Lerner index $(P_a - P_c)/P_a$, where P_a represents the actual observed price and P_c is the price that would result from price-taking behavior by suppliers. The *RSI* is the variable in this relationship that can change as a result of a transmission upgrade. The *RSI* is defined as the ratio of total market supply minus the supply from the largest firm, divided by the load. Only flexible supplies were included, netting out obligations to one's own load and contractual obligations. Likewise, the denominator excluded such obligations from the load.[6] $RSI < 1$ indicates that the largest supplier is pivotal because system demand cannot be met without this supplier producing some energy regardless of the amount of energy produced by its competitors. When these circumstances occur, the pivotal supplier can name the price at which it would like to supply this electricity and be assured that it will receive this price. CAISO experience indicates that values of *RSI* less than 1.2 are associated with significant mark-ups [23].

7.3.3.5.1 An Example An example of a regression relationship used is:

$$\begin{aligned}(\mathrm{P_a} - \mathrm{P_c})/\mathrm{P_a} = {} & 0.14 - 0.53\mathrm{RSI} + 0.65\mathrm{LUH} + 0.086\mathrm{D_{peak}} + 0.15\mathrm{D_{sum}} \\ & (0.013)(0.0073)\ (0.0092) \quad (0.0036) \quad (0.0031)\end{aligned} \tag{7.5}$$

where LUH is the fraction of the load that is unhedged, $\mathrm{D_{peak}}$ is a binary variable indicating whether the hour occurs during the peak period (1 = yes, 0 = no), and

[5]Even though these were very divergent periods, the relationships were stable over time, giving us confidence in their usefulness.

[6]There are must-run and must-take generators in California that are required to run regardless of market prices because of local reliability constraints or contractual obligations that predate the start of the California market.

D_{sum} is a binary variable indicating whether it is summer. All of the parameters estimates are very large relative to their standard errors, shown in parentheses under the coefficients. The data used to estimate the regressions consisted of 31,333 hourly observations from November 1999 to October 2000, and from January to December 2003. The fit (R^2 = 0.46) is close to that of models of the Italian market (e.g., R^2 = 0.61 for ENEL's mark-ups in Sicily) [30].

Because our regression specification is used to derive future market prices for all the various scenarios considered, it is important to test the model's validity. For this purpose, we estimated several different specifications (linear, nonlinear, and with different sets of variables) and compared their predictive ability using an out-of-sample test. First, we divided the entire sample into two parts: an in-sample data set and an out-of-sample data set. The out-of-sample set consists of hourly data for a total of 60 days in 2003 (5 days for each month in 2003). The in-sample set consists of the remaining 2003 data along with the 1999–2000 data. Using the in-sample data set, we generated regression estimates for each regression specification. The specifications differed in terms of which variables were considered and the inclusion of nonlinear terms for RSI. Then, for each specification, we computed the projected Lerner Index for the out-of-sample data. Finally, we compared the projection results from each specification with the actual Lerner Index, and chose the one that generated the best out-of-sample fit. The linear specification (1) performed best. Thus, on the basis of both predictive power and simplicity, the simple model is preferred here; however, in other circumstances, more complex specifications may perform better.

The estimated relationship (7.5) was used obtain bid mark-ups for use in PLEXOS by inserting the appropriate values for the independent variables for each hour and each zone into the equations, rescaling them so that larger suppliers had higher mark-ups.[7] The PVD2 addition of 1200 MW in each direction increased estimated total market supply in Southern California, yielding a higher RSI for that region and, as a result, lower values of $(P_a - P_c)/P_a$ because of the negative coefficient for the RSI variable in (7.5).

To account for uncertainly in mark-ups implicit in our regression, we used ranges of mark-ups derived from the distribution of the error term in (7.5). In particular, we calculated the mark-ups used in particular scenarios as follows:

$$(P_a - P_c)/P_a = \mathrm{MAX}[0, f(RSI, LUH, D_{peak}, D_{sum}) + t_{value}S] \qquad (7.6)$$

where $f()$ is the function in (7.5); S is the standard deviation of the error term in (7.5); and t_{value} is chosen to represent a particular mark-up scenario. For the L mark-up scenario, a t_{value} corresponding to the lower 90% confidence interval (–1.645) was

[7] Instead of applying the same bid-cost mark-ups to all strategic suppliers in the same region, we used a "proportional mark-up" approach, assuming that the largest supplier had the highest bid-cost mark-up in the region. According to the supply function equilibrium model [34], the price mark-up of a supplier is proportional to the quantity it supplies and inversely proportional to the sum of residual supply elasticity and absolute value of demand elasticity. This indicates that the largest supplier has more incentive than other suppliers to mark-up its bid. The same implication can be also drawn from Cournot-type models [22]. Thus, we scaled the result of (2) by the ratio of each supplier's uncontracted capacity to the uncontracted capacity of the largest supplier.

used, while for the H mark-up case, the upper 90% limit (+1.645) was applied. For the B mark-ups, $t_{value} = 0$.

7.3.3.5.2 Project Costs SCE estimated the capital cost of the PVD2 upgrade to be $680 million, including allowance for funds used during construction, assuming an in-service date of early 2009. In 2008 dollars, this was $667 M, based upon a 2% inflation rate. This is about $2.5 M/mile. These capital costs were then converted to an equivalent stream of annual revenue requirements. We estimate that the levelized revenue requirement for the PVD2 project will be $71 million per year for 50 years, assuming a real carrying charge of 10.43%/yr, accounting for taxes and administrative costs and adding fixed operating costs. This is the value that we compare the benefits to in order to determine the economic viability of the project.

7.3.4 Results

As noted at the start of this section, we made estimates of five benefit components: (1) energy savings; (2) operational benefits; (3) capacity savings; (4) system loss reductions; and (5) emission reductions. We derived the energy savings using the PLEXOS market simulation model. We estimated operational benefits, capacity savings, system losses, and emission benefits separately, outside of the market modeling process. Detailed results are available in [32].

7.3.4.1 Benefit Category 1: Energy Savings Energy savings are based on differences between generation costs and prices calculated with and without the proposed PVD2 upgrade. For market-based pricing scenarios, PLEXOS was solved by inserting bid functions for California independent power producers (constructed using the supplier's variable cost and the bid mark-ups implied by (1), (2)) and production (variable O&M) costs for everyone else into the objective function. However, costs for the purposes of the societal benefits calculations are based on assumed fuel costs, not as-bid costs.

To perform the expected benefits calculation, we evaluated the benefits for 17 different cases for each of the years 2008 and 2013 (Table 7.1). Each case is composed of two simulations, "without" and "with" the proposed PVD2 upgrade. As mentioned, we also considered a set of 16 contingency cases, representing extreme events for which it is difficult to assign a probability.

Consistent with the first TEAM principle ("benefit framework"), we quantified the benefits from four perspectives:

- *Societal.* Represents the WECC production cost savings resulting from adding the transmission upgrade. The total WECC benefit is also equal to the sum of the consumer, producer, and transmission owner benefits.
- *Modified Societal.* Represents the enhancement to overall market competitiveness in the WECC resulting from the upgrade. This is the same as societal benefits, except that producer benefit includes the net generator revenue from competitive prices only, and excludes generator net revenue from uncompetitive market conditions (i.e., bid mark-ups).

- *CAISO Ratepayer (LMP Only).* Demonstrates whether benefits outweigh costs for CAISO ratepayers. This perspective is used to decide whether ISO ratepayers should fund the transmission expansion. This calculation is based on locational marginal pricing, and the congestion revenues that such pricing would imply throughout the WECC.
- *CAISO Ratepayer (LMP + Contract Path).* Same perspective as above but the flow-based or LMP market is modified to reflect actual transmission pricing rules for selected contractual paths between CAISO and the Southwest region, rather than congestion pricing.

PLEXOS' geographic detail makes finer breakdowns possible, for example, by individual generating company or state. The focus here, however, is on the breakdown between California and the rest of the western US.[8]

The CAISO Ratepayer (LMP Only) analysis is performed assuming congestion revenue is based on WECC physical flows. An important assumption is that locational marginal pricing will be uniformly implemented by all WECC entities. However, this pricing mechanism may not be implemented in the immediate future. At present, most of the WECC instead operates based on contract path scheduling.

The distinction between LMP and contract path-based pricing is important. The CAISO Ratepayer (LMP Only) computes transmission congestion revenue for each line in the WECC. In some cases, this congestion revenue can be very high; the PLEXOS simulations show that the upgrade would lower those revenues. However, today some congestion is actually managed in real-time, resulting in uplift charges to load rather than congestion revenue to transmission owners. The net result is that the LMP method as applied to the CAISO Ratepayer perspective exaggerates the amount of congestion revenue that California transmission owners would receive, which turn inflates the loss of congestion revenue in today's environment due to the upgrade. This means that the LMP Only approach understates the net benefits to California consumers, since lower congestion revenue means that transmission owners must recover more of their fixed costs from load.

The CAISO Ratepayer (LMP + contract path) perspective corrects this problem by adjusting transmission congestion revenue both before and after the upgrade. The net impact of the adjustment was usually an increase in transmission upgrade benefits for the CAISO ratepayers, more closely reflecting the upgrade benefits that ratepayers would receive under present WECC scheduling rules.

Table 7.2 summarizes the energy benefits for 2008 and 2013 from these four perspectives. (Table 7.1, above, presented values for individual uncertainty cases for

[8]It is crucial in any benefit-cost analysis to avoid double-counting of benefits. For instance, consumer expenditures on energy need to be adjusted downwards for any increases in congestion revenues as a result of the transmission change because such charges are refunded as decreases in transmission portions of consumer bills. Such adjustments are also made for changes in the transmission loss surplus (which is also returned to consumers) and for changes in profits earned by regulated utility-owned generation (which, under average-cost regulation, are, in effect, returned to consumers). If demand is perfectly inelastic, then the decrease in WECC production costs should equal the sum of producer and consumer benefits, properly accounting for these refunds; this check was made to ensure that double-counting did not occur.

TABLE 7.2 Estimated energy benefits (millions Per Year, 2008 dollars)

Perspective	Expected value, 2008	Range across cases, 2008	Expected value, 2013	Range across cases, 2013
Societal	$41	$4–$200	$54	$20–$200
Modified Societal	$61	$6–$400	$81	$20–$600
CAISO Ratepayer (LMP)	$39	–$3–$300	$56	–$3–$400
CAISO R.P. (LMP + contract path)	$110	$10–$600	+$200	$50–$1,000

2008.) For perspective, the values shown in these tables can be compared to total power costs for the CAISO system. For 2013, we estimate the total wholesale energy costs to be about $12 B, about two orders of magnitude larger than these benefit estimates.

The table shows several interesting results. Consider for instance the 2008 benefits. Societal benefits (cost savings throughout the west), by coincidence, almost precisely equal CAISO ratepayer benefits (LMP). Societal benefits are $20 M higher if decreases in "market power"-based profits are disregarded. However, considering how transmission of imports to California is actually priced, CAISO ratepayer benefits ($110 M) are almost three times the societal benefit of $41 M. This means that independent generators in California along with ratepayers and generators in other states appear to suffer a decrease of $69 M in their benefits.

The benefits in Table 7.2 cannot be directly compared to the annual costs since they have not been levelized over the 50-year project life. Nor do they include the other benefits described later in this paper. To obtain a levelized annual benefit, we need to assume a discount rate and to extrapolate benefits beyond 2013 through the remainder of the 50-year project life. A real discount rate of 7.16% was used based on SCE's weighted cost of capital. A 1%/yr real escalation rate for benefits was selected for the period after 2013. The main reason is that most of the commodity costs that are a factor in setting market-clearing prices are likely to escalate in real terms in the long run (natural gas, labor, steel, concrete, land, emission offsets, etc.). The resulting levelized energy benefits are shown in Table 7.3. Assuming zero rather 1% escalation decreases both Societal and CAISO Ratepayer Benefits (LMP only) by about 5 $M/yr.

7.3.4.2 Uncertainty in Energy Benefit Estimates The ranges of benefits shown in Table 7.2 provide perspective on how uncertain the benefits are for the four perspectives, but they provide no information regarding the relative likelihood of different levels of benefits. Since we assigned probabilities to many of the cases (e.g., Table 7.1), we can use that information to characterize the distribution of benefits. In Figure 7.4, we illustrate the relative probabilities of various benefit ranges for the CAISO Ratepayer (LMP Only) perspective in 2013. The highest benefits resulted from those cases where several adverse events occur simultaneously, such as high load, gas price, and market power together with dry hydro (Table

TABLE 7.3 Derivation of PVD2 benefit-cost ratios (expected levelized value, millions per year, 2008 dollars)

Component of B-C ratio	Societal	Modified societal	CAISO ratepayer (LMP only)	CAISO ratepayer (LMP + contract path)
Levelized benefits				
1. Energy	$56	$84	$57	$198
2. Operational	$20	$20	$20	$20
3. Capacity	$12	$12	$6	$6
4. System Loss	$2	$2	$1	$1
5. Emissions	$1	$1	$1	$1
Total	$91	$119	$84	$225
Levelized costs	$71	$71	$71	$71
Benefit-cost ratio	1.3	1.7	1.2	3.2

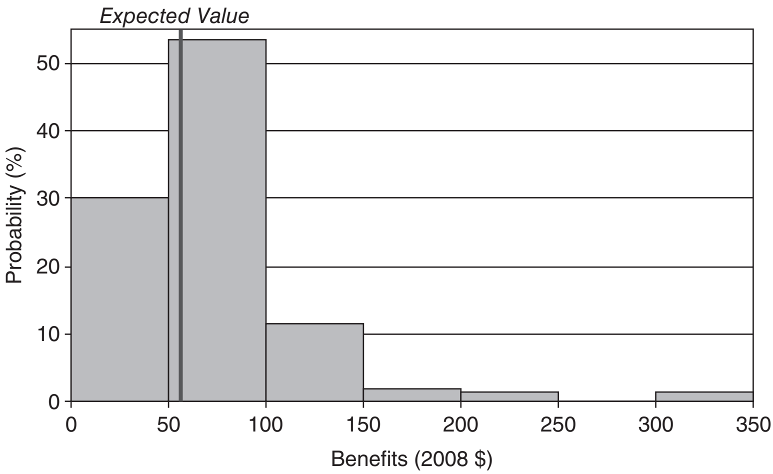

Figure 7.4 Energy benefits distribution (2013, CAISO Ratepayer—LMP Only)

7.1). There is a 70% chance that the annual energy benefits in 2013 exceed $50 million. There is a 5% probability that the project would yield an annual ratepayer benefit between $150 and $350 million, indicating that PVD2 would provide significant insurance value against extreme events.

We now ask: which uncertainty (load, gas price, hydro, mark-up) affects benefits the most? One way to answer this is to compare cases that differ in just one variables. For instance, we can compare different gas cases (BLBM, BBBM, and BHBM, Table 7.1). There are essentially no benefits to CAISO ratepayers (LMP only) if gas prices are low (BLBM), while the highest gas prices (BBBM) yield almost $80 M of benefits in 2013. This latter amount is roughly equivalent to a

\$20/MWh price difference between coal and gas-fired power for 1000 MW of imports for half of the year; clearly, imports from coal-burning regions are more valuable if gas prices are higher.

Meanwhile, comparing Case BBBB with BBBH in Table 7.1 shows that moving from a moderate to a high mark-up increases the societal benefits by only 1.7 \$M/yr (compared to a \$45.3 M/yr base), but changes the California ratepayer benefit by an order of magnitude more (from 98.7 to 124.5 \$M/yr, for the LMP + contract path metric). This can be interpreted as follows. The PVD2 project helps mitigate market power in California by bringing in competitive supply, and these benefits are greater if more market power is exercised. The benefits accrue primarily to California ratepayers, in the form of lower bills; from a societal point of view, however, those benefits are largely offset by a loss of producer surplus (profit), so that the effect on net societal benefits (fuel savings) is smaller. (This conclusion is borne out by the result that California ratepayer benefits always exceed societal benefits in Table 7.1, implying that some other parties will be worse off if the line is built.)

A more systematic way to explore the effect of the uncertainties is to perform a linear regression of the benefit estimates in Table 7.1 against the uncertain variables (coded as L = 1, M = 2, and H = 3). For societal benefits (*SB*) and California ratepayer benefits (*CRP*) (based on LMP + contract path), we get:

$$\begin{array}{l} SB = 6.7 + 5.7LD + 35.5GP - 32.9HY + 8.0MU,\ R^2 = 0.89 \\ \qquad\ (26)(5.9)\qquad (5.8)\qquad (6.7)\qquad (7.3) \end{array} \tag{7.7}$$

$$\begin{array}{l} CRB = -184.2 + 63.9LD + 98.3GP - 80.0HY + 60.9MU,\ R^2 = 0.82 \\ \qquad\quad (118.1)(27.0)\qquad (35.5)\qquad (29.6)\qquad (32.7) \end{array} \tag{7.8}$$

where *LD* = load, *GP* = gas price, *HY* = hydro, and *MU* = mark-up. The numbers in parentheses are the standard errors of the coefficients. All the coefficients have the anticipated signs: benefits increase when load, gas prices, and mark-ups are higher, and decrease when there is more hydropower. At a 5% level of significance (one-tailed test), only *GP* and *HY* significantly affect societal benefits, but all uncertainties significantly affect California ratepayer benefits. Note that the four variables have the same order of effect on ratepayer benefits. For instance, going from M to H load increases *CRB* by 63.9 \$M/yr, while going from M to H mark-up increases *CRB* by 60.9 \$M/yr. This result highlights the importance of TEAM Principle 4: the need to consider market-based pricing assessments of transmission benefits.[9]

Not considered in the expected value calculations are the 16 contingency cases in which losses of transmission or generation capacity stress the system. With one exception, each contingency case results in benefits to CAISO ratepayers (LMP + contract path) of over \$100 M/year, if the contingency is assumed to last the entire year

[9]As another indicator of the importance of market power mitigation benefits, we can compare solutions based on no mark-up (marginal cost bidding) [32] with the solutions in Table 7.1. That comparison shows that the market power case yields 6% higher societal benefits and 92% higher CAISO ratepayer benefits (LMP only) (39% higher if LMP + contract path), assuming the B case for all four uncertainties. However, the percent increase in benefits resulting from considering market power mitigation is appreciably higher under “high stress” conditions (i.e., H loads and gas prices, with dry hydro conditions).

[32], assuming base load, gas price, and hydro conditions. Under other conditions, the benefits can be even higher. This indicates that the insurance value of the PVD2 line would be even greater than indicated by the right hand tail of Fig. 7.4.

7.3.4.3 Benefit Category 2: Operational Benefits Production cost simulations may not capture all the operational costs that are incurred in managing the electric grid. This is especially true if generation unit commitment costs and ramp rate limits are not explicitly modeled, as in the case of PLEXOS. Thus, costs required to meet an N-1 and relevant N-2 planning contingency criteria will be underestimated. This implies that some operational benefits of the PVD2 upgrade may be overlooked. Including such constraints in large network models may be possible in the future, in which case these benefits would automatically be incorporated in the energy benefits of Tables 7.1–7.3.

For contingencies that do not involve the outage of the PVD2 line, the extra import capacity on the new line reduces the need for internal CAISO on-line generation. Regarding PVD2 line outages, the CAISO operators tell us that they keep a number of units on minimum load to protect against an outage of the present (PVD1) line. In addition to committing units, and the corresponding payment of minimum load cost compensation (MLCC), re-dispatch of units is needed to address real-time congestion which is not resolved in Day–Ahead congestion management. To estimate these operational benefits, we performed a detailed review of historical MLCC and real-time redispatch costs. Accounting for other upgrades that are being implemented, we estimate that the PVD2 upgrade would result in the following reductions: 5.3% of MLCC associated with the Southern California "SCIT" nomogram; 22.5% of the system MLCC, 72% of the nuclear MLCC, and about 12.5% of the re-dispatch cost, resulting in a total annual savings of $20 M in 2008 dollars.

7.3.4.4 Benefit Category 3: Capacity Benefit One approach to analyzing transmission-generation interactions that is consistent with the fifth principle of TEAM (address resource interactions) is to add generation where simulated energy prices indicate it is profitable, and then recalculate the market equilibrium. Such an "endogenous generation investment" analysis was undertaken in the CAISO's application of TEAM to Path 26 [13]. Alternatively, scenarios of changes in generation siting that are broadly consistent with how a transmission investment would change investment incentives could be used, which was done in the Sunrise analysis in Section 7.4, below.

In the PVD2 study, a simpler approach was taken to assess changes in generation investment and the resulting benefits. Because sensitivity analyses showed that energy prices in both California and external markets would not be significantly affected by shifts in generation investment that might occur as a result of installing that line, the energy market benefits would not be altered if generation investment was modeled as endogeous. Therefore, so that study resources could be focused on other issues, the energy market analysis was based on simpler siting assumptions that were the same with and without PVD2. Then a separate analysis estimated the capacity cost savings that would result from shifting an amount of generation investment equivalent to PVD2's firm capacity from southern California to Arizona.

We derived capacity benefits using the assumption that California will continue to have a resource adequacy requirement and that Arizona can be the source of contracted capacity to serve California load. A key assumption for these savings is that the future cost of capacity in Arizona will be less than the cost in California for two reasons: lower capital and fixed operating costs for peakers and, for the early years of the project, a greater resource surplus in Arizona than in California. We expect the demand for capacity, and the resulting price, to be less in Arizona.

We estimate that the differential fixed costs for peakers to be \$15/kW/yr in 2008 dollars. If we further assume that firm summer capacity is available for the entire 1200 MW upgrade, the capacity benefit would be \$18 M million per year in 2008 dollars. To be conservative, we discount this amount by one-third, and further assume that the benefits will be split equally between the buyers and sellers of capacity. Thus, we estimate a societal benefit of 12 \$M/yr and a CAISO ratepayer benefit of 6 \$M/yr.

7.3.4.5 Benefit Category 4: Loss Savings PLEXOS used a linearized DC power flow model without losses, so loss savings are omitted in the energy savings of Tables 7.2 and 7.3. (A version of PLEXOS is available that considers losses [20], but was not applied here.) In practice, we expect PVD2 to decrease transmission losses. To estimate loss savings, we used the computed power flows before and after the upgrade, yielding an estimated reduction in losses worth \$2 million annually. This estimate implicitly accounts for the interplay between increased losses due to heavier power transfers, and loss reduction due to redistribution of these power flows among existing and new transmission paths.

7.3.4.6 Benefit Category 5: Emissions The PVD2 upgrade allows more efficient Arizona gas-fired generation to displace less-efficient and higher-emission California gas-fired generation. In theory, NO_x allowance prices should depend on energy market conditions. But PLEXOS does not presently simulate the NO_x allowances markets in the WECC, in part due to a lack of emission rate data. Therefore, the results of the model were subjected to post-processing to estimate how much NO_x emissions would decline as a result of the upgrade. Based on the generation shifts, we estimated a NO_x reduction of 390 tons per year, which at typical allowance prices is worth \$2.2 million/yr. Half that amount is considered a CAISO ratepayer benefit.

7.3.4.7 Summary of Results In Table 7.3, we summarize our findings and determine an overall benefit-cost ratio for the societal, modified societal, and CAISO ratepayer perspectives. The ratios are positive in every case, but most strongly so for the last perspective (CAISO ratepayer, considering contract path effects). These values depend on the assumed scenarios and their probabilities; as Table 7.1 shows, there is considerable uncertainty concerning these benefits, implying some probability that benefits in any particular year might be less than the cost.

On the other hand, the calculations in Table 7.3 also do not consider the generator and transmission contingency cases, which, as indicated earlier, provide additional insurance value.

7.3.5 Resource Alternatives

Consistent with fifth TEAM principle ("resource alternatives"), we need to consider alternatives to the project in the form of generation (both renewable and fossil-fueled), demand-side management (DSM), and transmission resources.

DSM and renewables are, however, not viewed as alternatives. To the extent that demand-side management (DSM) or renewable resources are technically and economically feasible, these resources should be fully developed. Only when contributions from DSM and renewable resources are maximized should traditional resources be considered. Hence, we focused on thermal generation and transmission alternatives.

In today's market, the most likely generation alternative is a new combined-cycle (CC) generating plant. The question for this analysis is whether the CAISO should promote the PVD2 upgrade, or recommend building new CC's in the CAISO area, or both. An analysis of CC construction costs, based on an assumption that fixed costs would be 10% less in Arizona, shows that when combined with the levelized cost of the PVD2 upgrade, an Arizona facility is 10% more expensive than one in California. At a 90% capacity factor, the Arizona facility is 4% more expensive. By itself, though, this information is incomplete. Other important factors include interconnection costs for fuel and transmission—which will be significantly greater in California—and the limited ability to site resources in CAISO urban areas due to siting opposition. Thus, we believe that local generating options as well as transmission solutions need to be aggressively pursued. Building PVD2 does not preclude the construction of local facilities, as California needs to add 5000 MW or more in the next five years due to load growth and generation retirement.

Turning to transmission, the Southwest Transmission Expansion Plan [33] evaluated 26 potential transmission upgrade plans during 2003. Six alternatives were subjected to further technical and economic analysis. The PVD2 500 kV line was a component of two of those. The analysis concluded that three other alternatives were not viable due to reasons such as lack of project sponsorship, inadequate technical performance, or poor economics. The last of the six alternatives included a variant of the PVD2 line with alternative termination points. We expect that none of these variants to significantly change the scope of the proposed PVD2 project.

During the TEAM review process, some stakeholders suggested an alternative ("EOR9000") that involved upgrading series capacitors on the Perkins-Mead and Navajo-Crystal 500 kV lines between Arizona and Nevada. We ran PLEXOS sensitivity cases with EOR9000 and found that it and PVD2 are complements rather than substitutes. That is, each generally increases the benefits of implementing the other.

7.4 RECENT APPLICATIONS OF TEAM TO RENEWABLES

The most recent applications of the TEAM methodology illustrate its flexibility. It has been used to evaluate proposed transmission additions designed to deliver California renewable energy sources, including the Sunrise and Tehachapi projects [35, 36]. California has ambitious target of producing 20% of its energy from renewable sources by 2010 and 33% by 2020. New transmission infrastructure appears necessary to bring that energy to market.

The scope of these applications was more restricted than the PVD2 study because these were internal California projects, unlike PVD2 which was designed to import power from the Southwest. The most restrictive was the Tehachapi study; in that case, the relatively low cost of the wind resource being accessed meant that the study could be framed as a cost-effectiveness study (how best to access a resource that would be developed in any case), without having to consider generation alternatives. Furthermore, market power effects would not differ among the alternatives, since the same amount of power would be brought to market. On the other hand, in the Sunrise case, the project would allow external resources to substitute for costly new turbine-based generation within the San Diego load pocket. Therefore, Principle 5 (transmission-generation-load management substitution) became more important, and that TEAM analysis was more involved.

7.5 CONCLUSION

Based on our application of TEAM to the Palo Verde-Devers 2 transmission line proposal, we conclude that the methodology and its five guiding principles have substantially enhanced the CAISO's ability to fulfill its responsibility to evaluate and recommend transmission expansion projects.

The results of the case study demonstrate that the methodology produces the comprehensive analytical information that project proponents and review authorities need to make informed decisions in shaping California's transmission infrastructure. The TEAM approach advances this objective by creating a framework to examine a project from multiple viewpoints—from those of the overall western interconnection, to the 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.

The PVD2 application of the TEAM methodology shows that a significant amount of the benefits of a transmission line can arise from market power mitigation by making markets more accessible. It may, in theory, be possible to obtain mitigation benefits by instead regulating generator bidding more stringently without incurring the investment cost of a line. However, we believe that in the long run, addressing the structural issues that create market power (e.g., grid infrastructure) is a superior approach to relying on regulatory intervention. While it is true that in the absence of adequate infrastructure improvements, long-term market power concerns would likely be addressed by more stringent market power mitigation provisions, such provisions may not be very effective (e.g., the California Experience). Moreover, relying upon excessive market power mitigation rules to compensate for infrastructure deficiencies may have other detrimental impacts in terms of discouraging new generation investment or demand response. In light of this, we believe it is useful to examine the market power mitigation benefits of a transmission project under the assumption that market power mitigation rules in the absence of the project would be essentially the same. However, we also recommend that the benefit cost analysis include cost-based bidding scenarios as well so that policy makers can consider the sensitivity of the results to market power assumptions. If a project cannot be justified based on the cost-based bidding scenarios but can be based on the market power scenarios, the policy maker can weigh this information based on their particular policy objectives with regard to fostering market competition and their confidence in the effectiveness of any current or future market power mitigation rules. A policy environment that is more oriented toward regulation could always decide against a transmission project that cannot be justified under cost-based bidding scenarios, whereas a policy environment more oriented towards developing highly competitive wholesale energy markets and minimizing regulatory intervention may decide differently.

An important question is: what is the practical effect of the large modeling effort required by TEAM? For the PVD2 study, this can be gauged by comparing the average benefits, which consider the results of multiple scenarios and the market power analyses, with the benefits under the base scenario without market power. The latter benefit estimate can be viewed as an approximation of what a simpler analytical effort might yield. The expected benefits to CAISO ratepayers (LMP only) from the full analysis ($39 M) is twice the results of the scenario with no market power and base hydro, gas, and load values ($20 M, [32, Table H.1]). Given that most of the benefit-cost ratios for the line were less than 2 (Table 7.3), this shows that the effort expended to consider uncertainty and market power made an important difference in the PVD2 analysis.

Although greater transparency and more careful analysis may increase public understanding and acceptance of transmission proposals, it does not guarantee that beneficial proposals will be approved. Indeed, despite the societal and CAISO benefits of PVD2, the Arizona Corporation Commission declined to approve it in May 2007 because it perceived that Arizona consumers would not benefit from the line. The TEAM methodology's emphasis on the distribution of benefits informed these and other proceedings, and will likely contribute to future consideration of cost-sharing arrangements for the proposed facility. That the line has an overall positive societal net benefit implies that such an arrangement should be possible that benefits both Arizona and California ratepayers.

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