Assessment of An Economic Analysis of the Palo Verde-Devers Line Number 2 (PVD2) Transmission Network Upgrade

by
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1. Introduction

We have been asked by the ISO management and Board of Governors to assess the results of the report "Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)," prepared by the ISO's Departments of Market Analysis and Grid Planning. The report describes the results of an application of the ISO's Transmission Economic Assessment Methodology (TEAM) to the PVD2 upgrade. We have previously commented on the TEAM approach.[1] We discussed aspects of its application to the PVD2 project at several MSC meetings and have met several times with ISO staff to review simulation results. We have also received written comments on the PDV2 analysis from Southern California Gas, Los Angeles Department of Water and Power, and Southern California Edison. On February 4, 2005, we held a public conference call where we received additional comments on this report[2] from stakeholders. We are grateful for this very helpful input.

We have also been asked to provide an opinion on whether the ISO Board should approve this transmission upgrade. Our overall conclusion from reviewing ISO's report on the PVD2 upgrade and stakeholder comments on this report is that the Departments of Market Analysis and Grid Planning have, for the most part, undertaken a conservative economic analysis of the expected benefits of this proposed upgrade. Their modeling results imply a wide range of plausible scenarios for future system conditions that yield significant net benefits to California ISO ratepayers from the upgrade. Appendix D of the Technical Appendices notes that substantial amount of new generation is currently planned or under construction in Arizona. The PVD2 line will provide California consumers with access to a significant share of the energy that will be produced by these very efficient natural gas-fired generation units that are less expensive to build and operate in Arizona as opposed to near Southern California load centers.

The remainder of this opinion summarizes why we believe that this application of the TEAM methodology provides credible, yet conservative, estimates of the expected benefits of the PVD2 upgrade to California ISO ratepayers and why we recommend that the ISO Board approve this transmission expansion. Based on the ISO analysis, the PVD2 upgrade represents a sound investment offering a sound rate of return and an insurance policy against future adverse, potentially catastrophic, market conditions. Because TEAM is an evolving methodology and subject to continual improvement, we also suggest enhancements that we believe are worth considering for future applications.

[1] CAISO Market Surveillance Committee, "Comments on the California ISO's Transmission Expansion Assessment Methodology (TEAM)" June 1, 2004, http://www.caiso.com/docs/2004/06/01/200406011457422435.pdf.
[2] ISO Draft PVD2 Report posted on the ISO website on Feb 2, 2005.

2. Sources of Energy Cost Savings from Upgrade

A transmission expansion typically allows cheaper distant energy to substitute for higher-priced locally produced energy. How large this benefit is depends on a number of factors that are unknown at the time the upgrade is considered. The TEAM methodology solves this problem by using its best estimate of the configuration of the transmission network and stock of generation capacity available in the Western Electricity Coordinating Council (WECC) at the time the proposed transmission expansion would be operational and computes the ex-post benefits of the expansion for a number of possible realizations of future system conditions. These system conditions differ in terms of the expected growth in electricity demand, the level of input fuel prices, hydrological conditions in the Pacific Northwest and remainder of the WECC, the amount of new investment in generation capacity, the availability of key transmission and generation facilities, and the extent of unilateral market power that suppliers are able to exercise. The ISO has forecasts for these future system conditions from a number of sources.

Load Growth: 10-year load forecasts published by the WECC are used for all regions besides California. The load forecasts used for California were computed by the California Energy Commission (CEC). These figures are used to construct three possible future load scenarios--baseline, low and high. The low and high load scenarios are designed to provide a 90 percent confidence interval on the level of future load throughout the WECC. Although future demand levels above the high load scenario and future demand level below the low load scenario are possible and are likely to lead to a wider range of benefit estimates for the upgrade, the ISO's procedure provides credible range of future demand conditions in the WECC.

Input Fuel Prices: Natural gas prices are a major source of uncertainty in assessing the benefits of this upgrade because so many existing generation units in California burn natural gas at heat rates significantly above that of a state-of-the-art combined cycle natural gas turbine (CCGT) facility, the typical unit currently being constructed in Arizona. Although oil prices tend to fluctuate with natural gas prices, very little energy is produced from oil-fired units in the WECC. Although coal produces a significant amount of the electricity produced in the WECC, its price is unlikely to change significantly, and coal is rarely on the margin. Three scenarios for gas prices are selected based on the CEC natural gas price forecasts and the estimated forecast errors. The baseline price scenarios are for 2008 and 2013 are broadly consistent with recent futures prices for Henry Hub natural gas for 2008 to 2010 from the New York Mercantile Exchange. The average of the high scenario natural gas prices is approximately double the level of average prices for the baseline scenario, although these high scenario prices are well below the levels of natural gas prices reported in California during the period December 2000 to May 2001 and are approximately equal to the historical highs for Henry Hub natural gas prices. The average price for the low price scenario is roughly half the average for the baseline scenario. These prices seem overly optimistic in terms of a future low price scenario. Anticipating too low of a price scenario would tend to underestimate the benefits of the transmission upgrade because the benefits of substituting high heat rate units in California for low heat rates units in Arizona is much less with lower natural gas prices. The reasonableness of the baseline and high price scenario and the overly optimistic low price scenario all imply that the methodology yields conservative estimates of the future benefits of the transmission upgrade.

Hydrological Conditions and Future Generation Resources: A major driver of the benefits of transmission upgrades is the mix of available generation resources in California and the rest of the WECC. In particular, the amount of hydroelectric energy available in British Columbia, the

Pacific Northwest and California is a major driver of the benefits of the transmission expansion. The methodology assumes that California meets its renewable portfolio standards. In addition, California is also assumed to have enough new thermal generation capacity to meet a 15 percent planning reserve margin. Known generation retirements in California were built into these planning reserve scenarios. The reserve margin assumption limits the magnitude of potential benefits from the upgrade because it eliminates insurance value that the upgrade provides against years in the future when there is less than a 16 percent planning reserve. The methodology accounts for uncertainty in future hydrological conditions by specifying energy availability under baseline, wet and dry hydro conditions using data compiled by the Seams Steering Group--Western Interconnection (SSG-WI) Planning group. The total amount of hydroelectric energy assumed available in the Pacific Northwest under the low hydro scenario is significantly above the levels observed in 2000 and 2001. Because lower hydro conditions yield higher benefits from the upgrade, this implies that the ex-post benefits associated with low hydro scenarios are likely to be a lower bound on the ex-post benefits of the upgrade under actual low hydro conditions, which can be considerably more severe than those assumed in the methodology. Again, these modeling assumptions imply conservative estimates of the benefits of the upgrade.

Impact of Market Pricing: Transmission upgrades typically increase the number of independent suppliers able to compete to sell energy at a specific location in the transmission network. For the PVD2 upgrade, suppliers located near the Southern California load centers will face greater competition from suppliers located in Arizona. The ISO's methodology accounts for the greater competition suppliers face as a result of the upgrade by using historical data on California price-cost margins to model the impact of this increased competition on the level of price-cost margins reflected in market prices. The level of mark-ups anticipated by the methodology are relatively low, as a result of the comparatively high levels of forward contracting assumed in the ISO's analysis. Nevertheless, the results show that CAISO participants and consumers benefit significantly from the modeled decreases in those mark-ups. We note that it is possible that the assumption of no mark-ups outside of California might result in some error in the estimates of the value of the PVD2 upgrade, but it is not clear a priori if this would bias the benefit estimates upward or downward. As we have stated in our previous opinions on transmission evaluation, estimating mark-ups is an uncertain and ambiguous task, and basing mark-up projections on past behavior and allowing alternative scenarios as has been done in the TEAM methodology is an appropriate approach. We encourage the ISO to continue to explore alternative approaches to modeling the impact of transmission upgrades on market prices. We look forward to working with ISO staff on modeling this very important component of the value of transmission upgrades in a wholesale market regime.

3. Other Sources of Benefits from Transmission Upgrades

The ISO's methodology incorporates other sources of benefits from a transmission upgrade besides those due to energy cost savings. These include system operation benefits, transmission loss savings, capacity cost benefits, emissions savings benefits, and additional benefits from alternative congestion management paradigms outside of California. Although these benefit sources clearly exist, they are significantly more difficult to quantify in a rigorous manner. Therefore, in the PVD analysis, they were quantified outside of the PLEXOS runs used to quantify energy cost savings. Potentially, improvements in PLEXOS or other market simulation models would allow these other benefits to be quantified simultaneously and consistently with energy savings. We encourage the ISO to consider the development or use of such improved methods and stand willing to assist the ISO staff in this effort.

System Operation Benefits: The ISO operators estimate that as a result of the PVD2 line there will be less need to keep generation units local to the Southern California load centers operating in real-time in order to manage the constraints implied by N-1 and relevant N-2 operating criteria that are not captured in the TEAM. Appendix K of the ISO's Technical Appendices discusses the current costs of managing congestion and re-dispatch costs because of these operating criterion. The annual cost of managing this constraint is just above $93 million and will decrease to just below $50 million with the short-term upgrades coming in June of 2006. The ISO operations staff estimates that it is likely that the PVD2 upgrade will further reduce these costs by 25 to 50 percent. This estimated operational cost savings yields $18 million benefits per year in 2004 dollars.

While we concur that these are the best estimates available at the present time of operational cost savings as a result of the PVD2 upgrade, we would have preferred a more detailed analysis incorporating unit commitment costs into the PLEXOS model to arrive at these cost saving estimates. However, this would assume efficient day-ahead management of congestion, rather than the real-time management given day-ahead schedules that takes place in a multi-settlement locational marginal pricing (LMP) market.

Transmission Loss Savings: The ISO's energy price benefits analysis does not account for transmission line losses in setting locational marginal prices. To the extent that the upgrade reduces the level of line losses, this is a tangible source of economic benefits. Appendix J of the ISO Technical Appendices presents a methodology for measuring benefits from line loss reductions and finds tangible, but not excessive benefits from reducing line losses. Ideally, the market simulation software would calculate losses endogenously. Although the capability to do this at the level of detail represented in PLEXOS is not now available, it is technically feasible to develop such a capability, and it should be considered in future analyses.

Capacity Savings Benefits: Appendix M of the ISO Technical Appendices provides a comparison of the estimated costs of constructing and operating a combined cycle natural gas turbine (CCGT) generation unit in California versus Arizona. Both construction costs and operating maintenance costs are assumed to be lower for units built in Arizona versus those built in California. These capacity savings are estimated to amount to roughly $12 million on an annual basis. The large amount of new generation planned and under construction in Arizona--roughly 5,000 MW of new capacity by 2008 and an additional 5,000 MW of capacity between 2008 and 2013 according to Appendix D of the ISO Technical Appendices--implies clear cost savings as a result of constructing generation capacity in Arizona versus California. However, further details on the sources of these cost differences would provide greater credibility to the capacity cost savings figures in the report. We note that these construction and operating costs have been studied extensively in the eastern ISOs as they have designed their resource adequacy mechanisms, and that despite this effort the estimates remain both controversial and uncertain.

Emissions Savings Benefits: The ISO report notes that generating more electricity from new units in Arizona will reduce the amount of natural gas consumed in the WECC because higher heat rate units located near the Southern California load centers will be displaced by the new lower heat rate units located in Arizona. Valuing the benefits of these emissions reductions is complicated by the fact that there is no transparent price for NO_X emissions permits in Southern California or Arizona. Fortunately, the ISO's estimate of the emission savings benefits is extremely modest, approximately $1 million annually, which should not impact the decision to construct the transmission line. If those benefits were considerably larger, we would recommend that the explicit modeling of emissions caps in the market modeling software be considered.

Alternative Congestion Management Schemes Outside of California: A complaint of a number of stakeholders with the ISO's methodology for determining the energy savings associated with a transmission upgrade is the fact that an locational marginal pricing (LMP) market is assumed to exist outside of California, as well as within California. There are two issues here. One is whether the dispatch and costs resulting from the LMP assumption are a reasonable approximation of operations under the actual transmission pricing systems in place in the West. The ISO's extensive calibration and validation of the PLEXOS simulations gives us confidence that the answer to that question is yes. The second issue is whether the distribution of transmission rents resulting from LMP adequately represents the actual split among market participants, given the mix of transmission pricing mechanisms. It is clear that there is at least one circumstance where there is a significant divergence that affects the welfare of California market participants.

The ISO report addresses this second issue in Appendix N by specifying a mechanism for refunding congestion charges to various market participants located outside California and in California in a manner that attempts to replicate the existing mechanism used to manage congestion into Southern California and allocate its costs to consumers in and outside of California. The alternative congestion management mechanism implies even greater benefits associated with the transmission upgrade. Table VII.4 of the ISO report shows that the expected benefits of the upgrade to Californians under this alternative mechanism for congestion management are almost triple the expected benefits assuming that LMP is used throughout the WECC. This results from transferring selected transmission rents from ISO participants to non-ISO participants, so that decreases in those rents no longer appear as a cost to ISO participants.

Although we cannot verify the exact numbers, we do indeed expect that this alternative mechanism would result in a significant increase in benefits to CAISO participants. This is because the rents on lines into Southern California that the LMP method assumes are earned by CAISO participants instead partially accrue to Southwestern market participants. Thus, when the PVD2 line is installed and the transmission rents in that area decrease, this is not actually experienced as a loss by CAISO participants, although under LMP there would be such a loss.

4. Alternatives to PVD2

Though the projected benefits of the PVD2 upgrade appear to justify the estimated upgrade 2009 online cost of $680 million, it is reasonable to ask whether these benefits could be realized with a lower cost alternative to the PVD2 upgrade. To answer this question, the ISO considered two viable alternatives--building additional generation inside California and alternative transmission projects.

The benefits of PVD2 are estimated under the assumption that there is generation expansion in Southern California (see Table D.2, Technical Appendix D). The key issue is whether even more generation inside California could replace the transmission upgrade. The ISO report argues that additional generation inside California is infeasible and is unlikely to accrue the same benefits as the transmission upgrade, because it is cheaper to build generation in Arizona than California. This seems like a reasonable conclusion based on existing evidence. However, just as importantly, a transmission upgrade provides greater flexibility than new generation, because the PVD2 upgrade leaves a wider range of generation--both inside and outside of California--competing to provide energy to load inside California. This healthy mix of suppliers provides an important backstop against extreme market conditions, such as those observed in the 2000-2001.

As a result of stakeholder input, the CAISO analysis of PVD2 considers several transmission alternatives to the PVD2 upgrade. Most importantly, the analysis considers whether the PVD2 upgrade could be replaced by the proposed East-of-River project ("EOR 9000"), which would increase the EOR path rating from 8,055 MW to 9,300 MW, an increment of 1,245 MW. At the January 18, 2005, MSC meeting, the CAISO staff presented the results of sensitivity analyses where the benefits of the PVD2 line were estimated with and without the EOR 9000 upgrade. The analysis suggests these projects are complements and should both be pursued.

5. Conclusion

There is a wide range of realized benefits of the project, primarily because of the uncertainty in future market conditions in the Western Electricity Coordinating Council (WECC). There are a range of future system conditions--demand growth, natural gas prices, hydroelectric energy availability, and the extent of unilateral market power exercised by suppliers--where the project would have limited realized benefits, in part because of the conservative modeling assumptions made by the ISO. However, there are also ranges of future system conditions, where the project would have realized benefits substantially in excess of the cost of the project. The ISO estimates that the probability is greater than 70 percent that future system conditions will occur such that the project realizes benefits in any given year that exceed the annualized cost of the project. The strength of the TEAM approach is that it is able to estimate this probability or the entire distribution of realized values of the project over all possible future system conditions in an internally consistent manner. Although it would be desirable to have run additional scenarios, we believe that the method used to define scenarios and assign probabilities to them is reasonable.

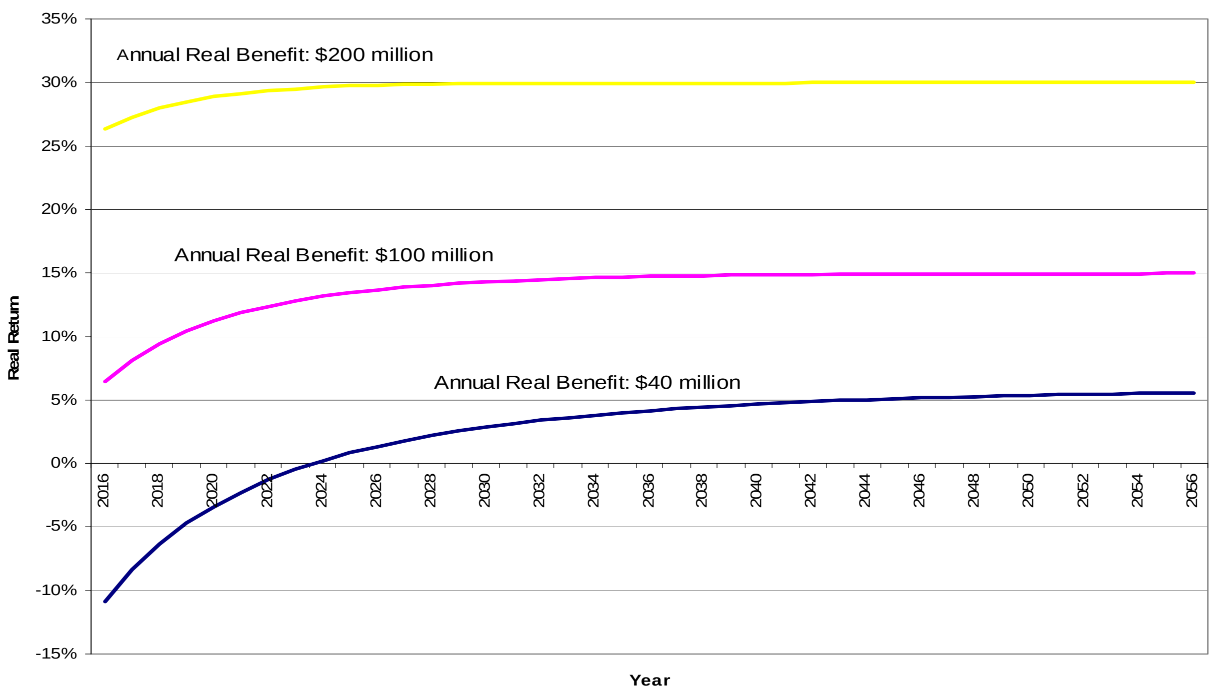
As we emphasized in our earlier discussion of the TEAM approach, transmission projects need to be viewed not just in terms of their expected benefits but in terms of the insurance they provide against adverse, and potentially catastrophic, outcomes. Extreme market conditions (e.g., high energy prices or blackouts) disrupt business and society in a way that exacts a toll beyond the high-energy prices incurred during these periods. This standard is consistent with other aspects of the State energy action plan, such as a focus on the diversification of fuel sources through extensive support of renewable energy. Thus even if the expected benefits were negative, a project can have significant value under some future scenarios. A negative expected value of a project could be viewed as the insurance premium against these catastrophic outcomes. The significant probability of realized values in excess of the annualized cost of the project suggests that this project is an insurance policy that is very likely to yield substantial ex post benefits.

Though the PDV2 upgrade provides an important insurance policy, it does so while also providing a sound rate of return and a relatively quick payback for the expected price tag of $667 million (in 2008 dollars). The ISO provides benefit savings for only two years – 2008 and 2013. A simple way to view these benefit estimates is to consider two questions (1) in how many years would the transmission project recoup its cost and (2) if the annual benefits accrue over a long horizon, what is the return on the $667 million investment. Even at the very low range of estimated annual benefits from *only* energy savings ($40 million, table VII.1), the PVD2 upgrade breaks even in 2024 and offers a real rate of return over 5% (see figure 1). At more realistic annual levels of

$100 or $200 million, the PVD2 upgrade breaks even in 2014 and 2011 (respectively) and offers an attractive long-run real rate of return of between 15 and 30 percent.

The evaluation of transmission expansion is an extremely complex task. The Departments of Market Analysis and Grid Planning have done provided a comprehensive analysis of the benefits of this upgrade using state-of-the-art methods. As noted above, a number of factors argue in favor the ISO's estimate of the expected benefits of the PVD2 upgrade being conservative. The substantially higher expected benefits of the upgrade under a congestion management mechanism for the rest of the WECC that is more representative of the current scheme argues in favor these benefit estimates being conservative. Finally, the more than 10,000 MW of new generation that are reported to be planned for Arizona by 2013 provides further evidence that there would be substantial benefits to the PVD2 line. For these reasons, we recommend that the ISO Board move forward with this transmission upgrade.

Figure 1: Real Rate of Return on PVD2 Upgrade (assuming annual real benefits of $40, $100, or $200 million and a project cost of $667 million).



Note: Assumes initial real project cost of $667 million is incurred year-end 2007, while benefits begin accruing year-end 2008.