March 27, 2003

Attn: Commission's Docket Office
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

RE: Docket # I.00-11-001, Order Instituting Investigation Into Implementation of Assembly Bill 970 Regarding the Identification of Electric Transmission and Distribution Constraints, Actions to Resolve Those Constraints, and Related Matters Affecting the Reliability of Electric Supply

Dear Clerk:

Enclosed for filing please find an original and eight copies of the Comments of the California Independent System Operator on the Proposed Decision of Judge Gottstein and the Alternate Proposed Decision of Commissioner Lynch Both Mailed on March 7, 2003 in Docket # I.00-11-001. Please date stamp one copy and return to California ISO in the self-addressed stamped envelope provided.

Thank you.

Sincerely,

Jeanne M. Solé
Regulatory Counsel

Cc: Attached Service List

PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation into implementation of Assembly Bill 970 regarding the identification of electric transmission and distribution constraints, actions to resolve those constraints, and related matters affecting the reliability of electric supply.)	I.00-11-001

COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR ON THE PROPOSED DECISION OF JUDGE GOTTSTEIN AND THE ALTERNATE PROPOSED DECISION OF COMMISSIONER LYNCH BOTH MAILED ON MARCH 7, 2003

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Dated: March 27, 2003

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I. Introduction.

In accordance with California Public Utilities Commission Rules 77.2 and 77.3, the California Independent System Operator ("CA ISO") respectfully submits its comments on the Proposed Decision of Judge Gottstein ("Proposed Decision") and the Alternate Proposed Decision of Commissioner Lynch ("Alternate") both mailed on March 7, 2003. The CA ISO strongly supports the outcome set forth in the Alternate, which orders that "Pacific Gas and Electric Company [("PG&E")] may proceed to construct [the Path 15 upgrade] on a stand-alone basis or in participation with other entities". Alternate at 47. Nonetheless, except as to the order and a few additional paragraphs throughout, the Alternate and the Proposed Decision are very similar; both contain substantially flawed analysis of the record and of the CA ISO's position as set forth in the CA ISO's testimony and briefs.[1]

The CA ISO respectfully urges the California Public Utilities Commission ("CPUC") to retain the order from the Alternate that PG&E may proceed to construct the Path 15 upgrade on a stand-alone basis or in participation with other entities, but to substantially revise the body of the Alternate consistent with these comments. These revisions are necessary to ensure that the CPUC's decision in this matter accurately sets forth the rationale for and benefits of the Path 15 upgrade. The Path 15 upgrade is a facility critical to support, over the long term, a workably competitive wholesale electricity market.

The Path 15 upgrade is a cost-effective and key component of a concerted, multi-pronged effort that should be put into place, consistent with state and federal law, to correct the market power problems that have existed in California over the past few years and to put into place an adequate transmission infrastructure. The upgrade has been demonstrated, using an innovative and robust methodology, to be a very cost-effective, long-lasting structural improvement to the California market that will benefit consumers by significantly improving market competition. Specifically, by providing greater transfer capabilities between Northern and Southern California, the Path 15 upgrade increases the ability of suppliers in both these regions to compete against each other and thereby reduces the ability of suppliers to exercise market power. While transmission

[1] These comments are a few pages over the 15 page limit that the cover letter that accompanied the Proposed Decision states should apply. In fact, Rule 77.3 states that a 25 page limit applies "in general rate cases, major plant

projects typically have lives that exceed half a century, the record indicates that using a reasonable set of assumptions, the Path 15 upgrade would pay for itself in market power mitigation benefits within four normal hydro years. The upgrade will also at a relatively low cost to consumers mitigate the risk of significant costs from the exercise of market power if the there is once again a confluence of adverse market conditions as existed in year 2000.

The Proposed Decision and Alternate argue that strong, aggressive regulation should address market power. The CA ISO wholeheartedly agrees. However, at the same time it is important to put into place the structural elements to support a well-functioning electric market. Relying on regulation alone could once again place California consumers in the position of requiring action by federal regulators who may have limited ability and/or will to effectively control market power. The gradual stabilization of the electricity market in California from the energy crisis of 2000 has at least as much to do with a change in market fundamentals (e.g. increased supply and greater forward contracting) as with the suite of market power mitigation measures that are currently in place[2]. The current mitigation measures (a $250 soft cap and Automatic Mitigation Procedures) have not been tested under persistent adverse conditions such as those experienced in year 2000 and thus it remains unclear how effective these or other mitigation tools would be in controlling market power. Moreover, as emphasized in the record, there is no guarantee that these measures will remain in place for the indefinite future. The most effective and safest strategy for avoiding a repeat of year 2000 is to correct the structural deficiencies that enabled suppliers to exercise market power. A Path 15 upgrade is a cost-effective key component of such a strategy.

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addition proceedings, and major generic investigations". The Path 15 upgrade qualifies at a "major plant addition"; thus the limit should be 25 pages in any event.

[2] These measures were put into place after briefs were submitted in this matter. Nonetheless, the CPUC can take administrative notice of the FERC July 17, 2002 order which provided for the implementation of the current suite of measures. 100 FERC ¶ 61,060 (2002)

Consistent with California Public Utilities Commission Rule 77.3 the CA ISO has attached its proposed revisions to key sections of the Proposed Decision and the Alternate and the respective Findings of Fact, Conclusions of Law, and Orders in these documents[3]

II. The Proposed Decision and Alternate Err in Ignoring the Evidence in the Record that a Comprehensive Solution, Including the Path 15 Upgrade, Is Required to Reduce the Ability of Suppliers in California to Exercise Market Power and State Law that Supports Use of Transmission Facilities to Facilitate an Effective Electricity Market.

The Proposed Decision and Alternate argue that the benefits of Path 15 as a mechanism to mitigate market power are unpersuasive because regulation should be adequate to curb the ability of suppliers to exercise market power in the wholesale market. See Proposed Decision at 27; Alternate at 30. To be clear, the CA ISO agrees wholeheartedly that regulators have the obligation to assure just and reasonable rates; in competitive markets, this means that prices should reflect competitive outcomes. In fact, the CA ISO (working in concert with key California state agencies including the CPUC) has filed volumes of testimony and briefs before the Federal Energy Regulatory ("FERC") Commission making this very argument. Nonetheless, particularly in the context of a constraint with regional implications, such as that represented by Path 15, the record supports the need for a comprehensive strategy to reduce market power. State law supports putting into place the structural elements to support a competitive market including transmission upgrades such as the Path 15 upgrade. Building the Path 15 upgrade is also consistent with the evidence in the record that it is most effective to control market power as part of a comprehensive strategy including long-term contracts, increased demand response, increased supply (controlled by entities other than the supplies having key holdings in the California market) and critical transmission upgrades.

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[3] The CA ISO notes moreover that neither the Proposed Decision nor the Alternate discuss the question of whether PG&E requires a Certificate of Public Convenience and Necessity ("CPCN") from the CPUC to proceed with its contribution to the project as currently constituted, even though this issue was briefed in June 2002 by PG&E and the Office of Ratepayer Advocates. The Alternate includes a conclusory paragraph of dicta on pages 12 and 13 to the effect that Trans-Elect is a public utility subject to the jurisdiction of the Commission but no through analysis for this conclusion and no discussion of whether PG&E requires a CPCN from the CPUC to proceed with its share of the project. Without a determination by the CPUC about whether PG&E requires a CPCN for its contribution to the project, it is not clear why the CPUC would make a determination of need for the Path 15 upgrade in the first place.

The Proposed Decision and Alternate, while dismissing the CA ISO's support of the Path 15 upgrade as a long term, structural approach to reducing the ability of suppliers to exercise market power, on the basis that regulation alone should preclude the exercise of market power, cite with approval other initiatives by the state to put into place the structural elements needed to reduce supplier market power including demand-response, forward contracting, and recent efforts by the California Attorney General to reduce the market share of certain California suppliers. Proposed Decision at 31, Alternate at 32. It is not logical to state on the one hand that certain structural approaches to address market power are to be commended (notwithstanding the existence of regulation), but that adding transmission to support a competitive market is unacceptable because regulation alone should assure just and reasonable prices.

Particularly in the case of regional market power problems, transmission capacity is likely the most durable solution, and in the case of Path 15 has the added benefit of facilitating operation of the system. The Proposed Decision and Alternate provide no support for dismissing transmission upgrades, as opposed to other structural approaches, to reduce the ability of suppliers to exercise market power. In fact, this determination is contrary to the policy of the state since the commencement of the electricity crisis, which includes the elimination of key transmission constraints as one of several important initiatives to stabilize the California electricity market. Public Utilities Code § 454.1 (First of two) specifically provides that "[r]easonable expenditures by transmission owners that are electrical corporations to plan, design, and engineer reconfiguration, replacement, or expansion of transmission facilities <u>are in the public interest and are deemed prudent if made for the purpose of facilitating competition in electric generation markets</u>, ensuring open access and comparable service, or maintaining or enhancing reliability . . . " (Emphasis Added.) The determination in the Proposed Decision and the Alternate that eliminating market power, or in other words facilitating competitive markets, is not an adequate justification for the Path 15 upgrade is simply contrary to state law as set forth in Public Utilities Code § 454.1st of two).

Further, Public Utilities Code § 379.5 required the CPUC and the CA ISO to work together to "[i]dentify and undertake those actions necessary to reduce or remove constraints on the state's existing electrical transmission ... system" and to "give first priority to those geographical regions where congestion reduces or impedes electrical transmission and supply." Again, the dismissal by the Proposed Decision and the Alternate of transmission upgrades as legitimate structural approaches to promote competitive markets is contrary to the Legislature's recognition that reinforcing the transmission system is one element of an overall strategy to stabilize the California electricity market.

Further, the dismissal by the Proposed Decision and the Alternate of the Path 15 upgrade as a mechanism to create the structure for the competitive wholesale electricity market is contrary to the record. The record supports aggressive multi-pronged action, including strategic transmission upgrades, to redress all the key structural deficiencies that allow suppliers to exercise market power. CA ISO witness Casey described the components of a multi-pronged effort to reduce the ability of suppliers to exercise market power, in addition to providing for adequate transmission infrastructure, as follows: increasing demand responsiveness, improving supply adequacy (keeping in mind the concentration of market share by particular suppliers); and encouraging utilities to enter into long-term contracts for supply. Tr. (Casey) at 581: 19-28; at 582: 1-14; at 769: 12-28; at 770: 1-17.

There is no evidence in the record that any one of these strategies alone will adequately address market power. Instead, the record supports the conclusion that these strategies will reinforce each other if implemented together. The CA ISO's Department of Market Analysis ("DMA") study of the benefits of a Path 15 upgrade, "Potential Economic Benefits to California Load from Expanding Path 15 -- Year 2005 Prospect", Exh. 201, Attachment 4 ("DMA study") indicates the level of market power that would exist with and without the Path 15 upgrade in a number of scenarios. The DMA study shows that while upgrading Path 15 will significantly reduce the ability of suppliers to exercise market power in all cases, the upgrade will not, in itself, entirely eliminate the ability of suppliers to exercise market power in any case. Exh. 201, Attachment 4, Tables 3 and 4, lines A and B; Tr. (Casey) at 769: 1-8. This is true even though the upgrade represents the addition of 1500 MW of transmission capacity between Southern California and Northern California, Exh. 200, Testimony of Perez, Greenleaf and Casey at 5, footnote 2, a significant enhancement to the competitiveness of the market. There is no evidence to suggest that the other measures available to address structural deficiencies in the market would, in isolation, cost-effectively eliminate all or even most of suppliers' ability to exercise market power.

To the contrary, Mr. Casey explained that demand response programs had limited success in 2001. Tr. (Casey) at 777. The CA ISO certainly hopes and expects that future programs will be much more successful, and strongly supports the CPUC's latest approach for coordinated activities among key state agencies and the CA ISO to develop effective demand response programs. Nonetheless, there is no evidence in the record that there will be adequate demand response in place in the future to obviate the need for the Path 15 upgrade. Similarly, with regards to long-term contracts, Mr. Casey explained that while long-term contracts, once they are in place, help reduce market power, they are themselves influenced by market power if such market power can be predicted at the time the contracts are entered into. Tr. (Casey) at 598: 20-25.

The Proposed Decision and Alternate support a statement that there is little benefit to the Path 15 upgrade based on testimony in the record regarding the development by London Economics of a methodology to evaluate the benefit of transmission upgrades. Tr. (Casey) at 604-06. In that testimony, Mr. Casey was describing a tool used by London Economics to simulate a market with suppliers having different capacity concentrations. Mr. Casey explained that London Economics ran a series of cases with and without the upgrade and under different assumptions about demand responsiveness and contract coverage. Mr. Casey did note that London Economics found that with sufficient demand response, market power would be diminished to a point that a transmission upgrade would provide little additional benefit. However, there is no evidence in the record of what level of demand-response was sufficient to achieve this point, or whether this level is achievable or cost-effective. Rather, Mr. Casey was illustrating (as the CA ISO has stated repeatedly) that demand-responsiveness is one of the key structural elements that must be pursued along with others to reduce the ability of suppliers to exercise market power. Moreover, the record is clear that the London Economics methodology was still under development at the time of Mr. Casey's testimony, and that it would have to be expanded significantly to incorporate a real-world transmission project. Tr. (Casey) at 606: 7-11[4].

[4] The methodology to assess the benefits of transmission projects has in fact evolved significantly since the hearings on the benefits of the Path 15 upgrade were held over a year ago, as documented in recent filings by the CA ISO in this docket, including an update filing made on August 16, 2002, and the filing made on February 28, 2003 of a final report on a methodology to assess the economic benefits of transmission projects.

Moreover, although there is little discussion in the record of the relative benefits and costs of alternatives to reduce supplier market power[5], it is reasonable to conclude that each alternative has associated costs that would limit the extent to which it could be used cost-effectively to mitigate the ability of suppliers to exercise market power. For example, demand responsiveness has costs associated with the customer behavioral changes that are required; long-term contracting can have costs both in terms of the risk of locking in a price that over time proves to be uneconomical and locking in the effects of market power if these effects are prevalent at the time the contracts are signed. New generation development involves significant capital costs as well as environmental and community cost impacts.

Further, the Proposed Decision and Alternate ignore the record on how, undertaken in concert, structural market power mitigation measures can be more successful than in individual application. In particular, CA ISO witness Casey explained that long-term contracts ultimately reduce the ability and incentive of suppliers to exercise market power by reducing 1) the level of load exposed to short-term price volatility and 2) the benefit suppliers obtain from exercising market power. Tr. (Casey) at 769: 24-28; at 770: 1-17. However, Mr. Casey explained that, if conditions prevail in which suppliers know they can exercise market power, and believe they will continue to be able to do so, these circumstances will be factored into the negotiations for the long-term contracts, and the long-term contract prices will themselves reflect market power. Tr. (Casey) at 598: 16-28; at 599: 1-2. If suppliers are aware however, that steps are underway that will reduce their ability to exercise market power, such as the expansion of transmission capacity or programs to increase demand response, these circumstances too will be factored in the contract negotiations and the contracts are more likely to reflect reasonable prices. Thus, different strategies applied in concert can have a complementary effect.

In sum, the Proposed Decision and Alternate err in ignoring the record evidence of the need for a multi-pronged approach to effectively reduce market power and in concluding, contrary to state law, that only strategies <u>other than</u> transmission upgrades should be pursued. The Proposed Decision and Alternate provide no basis for dismissing strategic transmission

[5] In its responses to CA ISO data requests, ORA witness Scott Logan listed ongoing FERC mitigation measures as low cost alternatives to transmission upgrades to curb market power, although he could not quantify the costs of these "low cost measures". Exh. 218, ORA Responses to CA ISO DR, Answer to Question 14. The concerns associated with relying over the long term on West-wide mitigation measures imposed by FERC action are described in section II below. Mr. Logan did not address any other "low cost" measures.

projects such as the Path 15 upgrade, alone from the quiver of mechanisms that the state should use to put into place long-lasting structural elements that reduce the ability of suppliers to exercise market power.

III. The Proposed Decision and Alternate Err in Ignoring the Evidence in the Record that, Because the Market Power Problem Addressed by Path 15 is Regional in Nature, Relying Over the Long-Term on West-wide Mitigation Mechanisms to Keep Market Power in Check is Inappropriate.

The Proposed Decision and Alternate err in ignoring the evidence in the record of Path 15's regional significance and the difficulties of relying on regulation to address the regional market power problems associated with the Path 15 constraint. Further, the Proposed Decision and the Alternate err in concluding that west-wide market power mitigation measures should replace (as opposed to complement) steps by California to correct structural deficiencies that have allowed suppliers to exercise market power in California.

Path 15 plays a major role in the seasonal exchanges that take place between Northern and Southern California, and between California and the Pacific Northwest, supporting seasonal exchanges of thermal and hydro generation, with power typically flowing from south to north during late summer through winter periods to enable northern hydroelectric resources to restock and conserve their water suppliers for critical peak periods. Exh. 200, Testimony of Perez, Greenleaf and Casey, at 3: 9-16. There record is clear that Path 15 has often been limited by its operating capacity, and has been, since the commencement of CA ISO operations, an Inter-Zonal Interface; hence transmission customers that submit schedules over Path 15 must pay a usage charge to use the scarce capacity available. Exh. 200, Testimony of Perez, Greenleaf and Casey, 3: 17-24. In fact, during 2001, extreme congestion on Path 15 contributed to load curtailments. Exh. 200, Testimony of Perez, Greenleaf and Casey, at 4: 8-10.

The record shows that in the case of a significant regional constraint such as Path 15 broad on-going, West-wide mitigation would be necessary to address market power concerns.[6] Exh. 202, Rebuttal Testimony of Perez, Greenleaf and Casey, at 5: 22-25. California depends on the broader regional market for imports, and without a West-wide mitigation program, in-state suppliers can sell to the Southwest or Northwest to avoid mitigation measures that are in effect only in California. Tr. (Casey) at 775: 1-28; at 776: 1-24. Thus, an effective market power mitigation approach requires a program that is West-wide in its application. Id.

Although in Spring and Summer 2001, after much prodding from California state agencies and the CA ISO, FERC instituted a package of market power mitigation measures that were extended to cover the entire West, see 95 FERC ¶ 61,115 and 95 FERC ¶ 61,418, in adopting the package, FERC stressed that the measures are temporary in nature; are intended to give time to California to put into place structural improvements that will support a workably competitive electricity market; and would expire on September 30, 2002. Exh. 202, Rebuttal Testimony of Perez, Greenleaf and Casey, at 4: 5-28, at 5:1-4. After reiterating several times that West-wide mitigation measures would expire on September 30, 2002, on July 17, 2002, FERC extended certain key West-wide mitigation measures until long-term market-based solutions can be fully implemented.[7] 100 FERC ¶ 61,060, 61,240 (2002).

Nonetheless, while FERC extended key West-wide mitigation measures without a specific sunset date, it continued to stress that structural improvements including the elimination of transmission constraints must continue to be made to support a competitive market. Id. at 61,239. FERC noted that while "[t]he failure of infrastructure improvement to keep pace with California's demand" left it with little choice but to maintain West-wide mitigation measures, FERC remains concerned that by intervening in the market with broad mitigation measures, it affects other markets and prevents, rather than supports, the development of efficient, competitive bulk markets. Id. at 239-40. FERC noted that mitigation should be in place until adequate infrastructure is in place, but made it clear that the mitigation measures should complement rather than substitute for putting into place adequate infrastructure. Id.

In sum, the Proposed Decision and Alternate err in ignoring the regional nature of the Path 15 constraint and the challenges and risks of addressing market power problems associated with such a regional constraint through regulation rather than structural changes.

IV. The Proposed Decision and Alternate Ignore the Record Evidence Regarding the Validity of the CA ISO's Analysis.

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[6] The CA ISO has supported limited, on-going mechanisms such as the Reliability Must Run contracts to address transmission constraints that are local in nature. Exh. 202, Rebuttal Testimony of Perez, Greenleaf and Casey, at 5: 10-17.

The Proposed Decision and Alternate improperly assess the record regarding the robustness of the CA ISO's market power analysis. The Proposed Decision and the Alternate level two criticisms against the CA ISO's market power analysis: 1) that it fails to properly account of forward contracting and 2) that it was not adequately validated. In fact, the Proposed Decision and the Alternate ignore significant portions of the record in concluding that the analysis overstates the benefits of the upgrade, and is inadequately validated.

The Proposed Decision and the Alternate list one bias in the analysis that would result in an over prediction of benefits, the method of accounting for long term contracts entered into by the California Department of Water Resources ("DWR"), without considering the biases in the analysis that would result in an under prediction of benefits. To be clear, the CA ISO's analysis did take into account one of the effects of long-term contracts, that of reducing the level of load that would be exposed to spot prices. The CA ISO "book-ended" its analysis by assessing the benefits of the upgrade under two sets of scenarios: one in which no long term contracts are in effect and one in which all the load subject to long term contracts would be shielded from market power in the spot market. See Exh. 201, Attachment 4, Tables 3-4. In synthesizing the record in its opening brief, the CA ISO explained that because only half of the capacity under long-term contracts is firm in 2005, Exh. 228, Third Quarterly Report of the CA ISO, at 92, Figure 24, the most reasonable assumption is that only 50% of load will be shielded from the exercise of market power based on the CDWR long-term contracts[8]. Thus, the record clearly shows that one effect of the long-term contracts was incorporated in the CA ISO's analysis.

The CA ISO admitted without reservation that the analysis did not consider a second potential effect of long-term contracts, that of reducing the incentive of a supplier to exercise market power because the supplier has less capacity that would benefit from such exercise. Tr. (Casey) at 909-10. While this omission would result in an overstatement of the benefits, the degree of overstatement is unclear absent additional analysis. Moreover, this omission is balanced by a number of factors that resulted in an understatement of the benefits, including that

[7] This FERC decision was issued after briefs and reply briefs were submitted on this matter.

[8] Although additional long term contracts beyond the CDWR contracts may be signed by 2005, if suppliers can expect that they may be able to exercise market power in 2005 and beyond, these additional contracts will likely reflect this expectation. Tr. (Casey) at 598: 20-28. Thus, it is appropriate to consider in determining the impacts of market power in the future, the contracts that are in effect now because although long-term contracts reduce the load subject to further market power once they are in place, they can themselves reflect market power if suppliers can predict that they will be able to exert market power in the future. Tr. (Casey) at 598: 20-28.

the analysis did not quantify the market power benefits South of Path 15, see tr. (Casey) at 662: 5-12; that the analysis did not account for the fact that the proportion of operating transfer capability ("OTC") to total transfer capability ("TTC") would likely be higher after the upgrade, see tr. (Perez) at 884: 12-20; and that the analysis assessed a 1400 MW increase in capability rather than a 1500 MW increase, tr. (Casey) at 590:1-8. The Proposed Decision and Alternate do not address these countervailing biases in the analysis.

Moreover, the Proposed Decision and the Alternate misunderstand or mischaracterize the information that the CA ISO presented initially to show the validity of its analysis which indicates that during the period studied, RSI values and load account for a significant proportion of the price-cost mark ups (or the difference between competitive prices and actual prices). Further, the Proposed Decision and Alternate dismiss the important additional validation that was provided by applying the estimated regression relation to predict price cost mark ups in the period November 1998 to October 1999, a period that the CA ISO argued provided a more reasonable benchmark of the model's predictive capability, and comparing the outcome to actual prices. They imply contrary to the record that there is an upward bias in the analysis. In fact, the record strongly supports the validity of the CA ISO's analysis.

The Proposed Decision and Alternate state that "the only validation of the model conducted by the ISO prior to the ALJ's request was to examine the "t-statistics" for variable coefficients and the "R-squared" for the regressions that were used to estimate the Lerner Index (price-cost markups)." Proposed Decision at 32; Alternate at 35. They portray that CA ISO Witness Casey testified that an R-squared of 0.5 is considered "pretty good" for time series data, observe that the R-squared values for Off-Peak Season, Peak-Hours and Off-Peak Season, Off-Peak Hours are only 0.42 and 0.34, and conclude that the regression results do not meet the ISO's own criteria for statistical validation during six months out of the year. Proposed Decision at 33; Alternate at 36.

To begin with, the final conclusion is statement is quite simply incorrect. While Mr. Casey did state that in his experience an "R-squared" value of .50 or greater is "pretty good" for a time series analysis, he did not state that a value less than .50 indicates imply results that are statistically insignificant. To the contrary, Mr. Casey testified he did not believe there is a statistical validity threshold for "R-squared". Tr. (Casey) at 935.

Moreover, given the complexity of the transmission system and the numerous factors other than load and RSI values that can affect prices, Exh. 221, Further Testimony of Keith Casey at 7: 18-20, finding a combination of factors such as RSI and load that account for a significant proportion of the difference between competitive prices and actual prices is very significant. As Mr. Casey explained, the "R-squared" value indicates the extent to which the variables in question account for the variation in the factor under examination, in this case price cost markups (or the difference between the prices experienced and competitive prices). Tr. (Casey) at 935-935. The analysis shows that for the peak season, RSI values and load account for 63 and 58% of price-cost mark ups during on-peak and off-peak hours respectively. Exh. 201, Appendix 4, Table 2. The analysis also indicates that for the off-peak season, although the explanatory power of the regression equation is less, RSI and load still explain 42% and 34% of the variations in price-cost mark ups, during on-peak and off-peak hours respectively. Exh. 201, Appendix 4, Table 2. Thus, RSI and load explain a significant proportion of the variation in price cost mark ups in all periods. The Proposed Decision and Alternate simply focus on the proverbial "half-empty glass" and conclude on this basis that the analysis is unduly validated. They ignore the record evidence of the significant explanatory power of RSI and load in the context of very complex systems and a large number of factors that can affect prices.

The discussion in the Proposed Decision and the Alternate also confuses the "R-squared" values with the "t-statistic"; see Proposed Decision at 32 and Alternate at 35, so it is best to address the significance to the "t-statistic" as well. As opposed to the "R-squared" value that assesses the overall explanatory power of the entire regression equation (i.e. RSI and actual load), the t-statistics set forth in Table 2 of the DMA study indicate the statistical significance of RSI and actual load individually. As Mr. Casey explained in his testimony, a "T statistic" of around 1.98 is generally accepted as providing statistically significant evidence that the coefficient estimates are significantly different than zero. Tr. (Casey) at 908: 28; 909: 1-3. As is shown in Table 2 of the DMA study, the T statistic for each of the parameters (RSI and load) for each period studied, is statistically significant (above 1.98 – and markedly so) except in the case of actual load, in the off-peak season during on-peak hours. The fact that one of two parameters assessed was not statistically significant in one of the four periods studied does not of undermine the statistical significance of the entire regression. Again, the Proposed Decision and Alternate ignore the record evidence that shows the strong statistical significance of the analysis undertaken by the CA ISO and focus instead on a statistical weakness of one parameter in one period only to inaccurately attempt to undermine the value of the entire study.[9]

Finally, the Proposed Decision and Alternate inaccurately denigrate the further validation undertaken by the CA ISO at the direction of the judge, again ignoring the good news, citing only the anomalies that can be expected given the complexity of influences on prices, and ignoring the results that show that there is no systematic bias towards overestimating benefits.

The Proposed Decision and Alternate fail to consider the record evidence that when the methodology was validated against an appropriate comparison period, November 1998 through October 1999, the validation showed that predicted prices closely matched actual prices for 9 of the 12 months assessed. Exh. 221, Further Testimony of Keith Casey at 7: Figure 3. Again, given the large number of influences on prices, this correlation is remarkable. Only in three months, December 1998, August 1999 and October 1999, were results appreciably different and the predicted results were lower than actual prices in one of these three months, id, contrary to the implication in the Proposed Decision and the Alternate that there is an upward bias in the analysis.

Further, the CA ISO amply explained that using 2001 to try validate the study would be problematic even before undertaking the analysis. Tr. (Casey) at 623: 17-28; at 624: 1-7. The CA ISO set forth cogent explanations for the expected anomalies that resulted and these are documented with references to the record in the CA ISO's Opening Brief at 13-14. Further, contrary to what is suggested in the Proposed Decision and the Alternate, the predicted price cost mark ups in 2001 were lower than actual price cost mark ups in six of the twelve months studied and only higher than the actual price cost mark ups in five of the twelve months studied, again dispelling the implication in the Proposed Decision and the Alternate that there is a bias in the methodology towards over-predicting price-cost marks ups. Exh. 221, Further Testimony of Keith Casey at 7: Figure 1.

In sum, the Proposed Decision and Alternate ignore the strong record support for the validity of the CA ISO's study. They cite selectively to the few anomalies that can be expected

[9] One standard test for the significance of a regression is a joint test of the hypothesis in which all of the coefficients except the constant term are zero, commonly referred to as an "F-test". While the record does not reflect an F-test for the entire regression or its results, such a calculation can be performed easily using the information provided in Exh. 201, Appendix 4, DMA Study, Table 2, and shows that the regression is in fact statistically significant even in the Off-Peak Season, Off-Peak hours.

in assessing a problem as complex as the factors that drive prices, and ignore the bulk of the record that shows the strong explanatory value of RSI and loads in accounting for price cost mark ups.

V. The Proposed Decision and the Alternate Err in Ignoring the Record Evidence that Shows that the Path 15 Upgrade Will Pay for Itself in Four Normal Hydro Years Using Reasonable Assumptions.

The Proposed Decision and the Alternate provide further support for rejection of the CA ISO's analysis by indicating that the benefits of the project exceed the costs only in implausible scenarios. In leveling this critique, the Proposed Decision and the Alternate mischaracterize the analysis undertaken by the CA ISO, the CA ISO's position as presented during the hearings and briefs, and ignore the record evidence that the Path 15 upgrade would pay for itself within four normal hydro years using a reasonable set of assumptions even after applying a 25% plus or minus factor to account for uncertainties.

The CA ISO's Path 15 analysis assessed 24 different scenarios. Many of these were intended to represent extremes to bound the potential benefits of the project; they were not intended to indicate likely cases. See Tr. (Casey) at 591-92, 597, 610, 890, 947. Thus, the fact that many of the scenarios are either unduly optimistic or unduly pessimistic is inapposite; the CA ISO's position that the Path 15 upgrade is cost effective was based on developing a reasonable scenario and estimating its benefits using the ranges of benefits provided by the bookend scenarios.

Based on the record in the case, the CA ISO set forth its position of the most reasonable scenario, which adopted mid-points between many of the scenarios assessed: including four normal years to reflect a one-in-ten year drought, a moderate new generation scenario, an assumption that 29% of the capacity reserved for Existing Contracts in 2000 would remain unavailable and unused in 2005, and an assumption that 50% of the load backed by CDWR contracts would be shielded from the exercise of market power. The rationale for these assumptions and the citations to the record supporting these moderate assumptions are set forth in detail in the CA ISO Opening Brief. Further, the CA ISO applied a 25% plus or minus factor to account for uncertainties.

Using this approach, the CA ISO demonstrated that the Path 15 upgrade would pay for itself within four normal hydro years even after applying a 25% plus or minus factor. See CA ISO Opening Brief 33-35. In other words, the CA ISO used the bookend assessments to estimate benefits in the most reasonably foreseeable scenario and determined that the benefits of the upgrade are so significant that they would exceed the project costs within four normal hydro years. For a transmission line that can be expected to have a life exceeding half a century, this level of benefits is extraordinary.

The Proposed Decision and the Alternate err in failing to address in any way the CA ISO's conclusions about the projected benefits in the most reasonable scenario. Instead, the Proposed Decision and Alternate focus on rejecting the book-end scenarios which did not provide the basis for the CA ISO's conclusions regarding benefits. Neither the Proposed Decision nor the Alternate cite to any record evidence that is contrary to the CA ISO conclusions about what a reasonable scenario would be, or the benefits that could be expected in this scenario using the book-end information as the basis for the calculation of benefits.

Further, the record demonstrates that in worst case scenarios the benefits of the project (or the risk of not going forward with the project) could be twice the project cost in one year, see CA ISO Opening Brief at 35, whereas the cost of the project would cap the risk to consumers of proceeding with the project. Neither the Proposed Decision nor the Alternate address this aspect of the record or discuss the asymmetry of the risks to consumers in terms of potential costs versus benefits of proceeding with the project.

In sum, the Proposed Decision and the Alternate err in assessing the CA ISO's analysis. They ignore or distort the record evidence of potential benefits in the most reasonable scenario, without even setting forth any citation to the record that is contrary to the CA ISO's conclusions regarding what is the most reasonable scenario; and ignore the significant risk mitigation value of the Path 15 upgrade which the CA ISO's assessment demonstrates.

VI. Conclusion.

The CA ISO respectfully urges the CPUC to retain the order from the Alternate that PG&E may proceed to construct the Path 15 upgrade on a stand-alone basis or in participation with other entities, but to substantially revise the body of the Alternate consistent with these comments. The Path 15 upgrade is a facility critical to support over the long term a workably competitive wholesale electricity market and has been demonstrated to offer substantial market power mitigation benefits to California electricity consumers.

March 27, 2003

Respectfully Submitted:

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APPENDIX A

APPENDIX A

PROPOSED CHANGES TO THE ALTERNATE

Additions indicated in underline, and deletions indicated in redline.

Body of the Decision

Page 1

In this decision, we address benefits to ratepayers of constructing transmission improvements along the Path 15 corridor. ~~Based on the record in this proceeding, it is clear that the Path 15 upgrades are not necessary to improve system reliability. There was no disagreement among parties on this conclusion.~~ All parties agree that the existing capacity of Path 15 (3950 MWs) meets system reliability criteria, as defined by the Western Systems Coordinating Council and the North American Electric Reliability Council. Therefore, ~~increasing the line capacity to approximately 5400 MWs is not needed for system reliability purposes. T~~the issues we address today relate to the *economic need* for the project, i.e., whether adding 1500 MWs of capacity to the path produces cost savings to ratepayers that more than offset the project costs.

There was significant dispute among parties as to whether the Path 15 improvements would provide economic benefits (i.e., cost savings) to customers. Pacific Gas and Electric Company (PG&E) and the ISO assert that in circumstances where generation levels are low, such as poor hydroelectric conditions, or where market gaming is occurring, the economic benefits of improving Path 15 are significant. The Office of Ratepayer Advocates (ORA) disputes these assertions and argues that there are other options for dealing with market power problems that are less costly than upgrading Path 15. ~~In fact, as ORA points out, four out of ten of the ISO's analyses show that in normal conditions, the Path 15 upgrades will cause an increase, not a decrease energy costs.~~

We conclude today that Path 15 improvements ~~are not warranted to improve system reliability. This is the consensus view of all parties in this proceeding. However, we find that Path 15 may~~ provide~~, under certain circumstances,~~ economic benefits to ratepayers, in particular as an insurance policy ~~(albeit an expensive one)~~ against market gaming abuses such as those that occurred in 2000 and 2001. We reach this conclusion because it is the policy of the state of California and this Commission to put into place the transmission infrastructure needed to facilitate effective competition in the wholesale electricity market, particularly in the case of constraints having regional significance and to ~~based on the uncertainty that the ISO and the Federal Energy Regulatory Commission (FERC), which regulates wholesale electric transactions, have or will~~ institute sufficient safeguards to prevent a reoccurrence of the problems which plagued California in 2000 and 2001. Therefore, we approve PG&E's request to upgrade the Path 15 transmission system.

. . . .

Pages 4-10

Although the Commission's concerns over congestion on Path 15 during 2000 and 2001 were expressed in terms of "system reliability" problems, it became clear during the course of this proceeding that Path 15 upgrades are not needed to meet the reliability criteria as defined by the ISO, the Western Systems Coordinating Council and the North American Electric Reliability Council. ~~The ISO testified that the project is not required for reliability purposes, and that it does not plan to conduct any further reliability studies regarding Path 15.[1]~~

~~While the ISO's testimony appears to run counter to the conventional wisdom regarding Path 15 -- and counter to the factual assumptions underlying the Assigned Commissioner's Ruling that commenced this proceeding -- it was not contradicted by any party. Conventional wisdom must give way when it is contradicted by sworn testimony of the responsible party, subject to the rigors of public scrutiny and cross-examination by knowledgeable experts.~~ Therefore, we ~~conclude that this project is not needed for reliability and~~ focus on the economic need for the project.

By today's decision, we consider the economic benefits to ratepayers of adding 1500 megawatts (MW) of capacity to Path 15. More specifically, we examine the economics of the project on a "stand-alone" basis, i.e., without considering the manner in which PG&E and other entities will participate in the project.[2] In doing so, we have

[1] Reporter's Transcript (RT), Vol. 6, p. 538, 576, 589.

[2] PG&E is the entity which will receive the certificate issued pursuant to this order. See below for a discussion of the requirement that any private entity that owns or controls, directly or indirectly, the facilities authorized by this order be a utility subject to the Commission's jurisdiction.

carefully evaluated the assumptions and methodology underlying the ISO's economic analysis in this proceeding. ~~Based on our review, we conclude that the proposed upgrades are not cost-effective to ratepayers under normal circumstances~~. Our assessment ~~conclusion~~ is based on the assumption that Path 15 upgrades will cost $323 million (or approximately $50 million per year on an annualized basis). ~~However,~~ We find that the project is valuable to customers as a means of reducing the potential impact of market abuses in the future, both via the physical benefits of the project and as a signal to market players that California will take all actions necessary to prevent a repeat of the blackouts and horrific price increases that occurred in 2000 and 2001 due to market manipulation. It should also reduce the potential for market participants to engage in the creation of false congestion, using the "Death Star" and other strategies used by Enron and others in the past.

As explained in today's decision, the ISO conducted two studies of the Path 15 upgrades in this proceeding. They differ substantially with respect to the estimated values of market clearing prices in 2005, particularly during hours of congestion over Path 15. In the first study, the ISO examined the economics of the upgrades assuming a competitive wholesale electric market in 2005 and beyond. Under this assumption, suppliers bidding in the market are unable to establish market prices above the marginal costs of production. During hours of congestion over Path 15, market clearing prices in northern California reflect the higher costs of less efficient resources that need to be dispatched from locations other than southern California. By reducing congestion in the south-north direction, the Path 15 upgrade reduces the market price for power flowing in that direction. However, the analysis indicates that these benefits are very small relative to project costs in all but two scenarios that assume one-in-ten year drought conditions and that low levels of new generation are built in northern California and in the Pacific Northwest.

In the second study, the ISO evaluated the benefits to consumers that would result from reducing the ability of suppliers to exercise market power. ~~assumed that the market power abuses experienced in 2000 would continue unabated in 2005 and beyond, resulting in market prices that reflect very large price-cost mark-ups, particularly during the hours of congestion over Path 15. As a result,~~ The ISO's estimate of the economic value of reducing congestion over Path 15 in the second study is dramatically higher than in the first. Based on the results of this study, the ISO concludes that the project would pay for itself in ~~one drought year and~~ ~~three~~ four normal years.

As discussed in this decision, we find based on ~~that~~ the ISO's second study that constructing Path 15 is beneficial to rate payers.~~is questionable, for several reasons.~~ First, Path 15 plays a major role in seasonal exchanges that take place between Northern California and Southern California and between California and the Pacific Northwest. Path 15 has often been limited by its operating capacity; in fact during January 2001 extreme congestion on Path 15 contributed load curtailments. Given its regional significance, to address the market power problems that result from limited capacity over Path 15, West-wide market power mitigation measures are needed. The Federal Energy Regulatory Commission (FERC) has indicated repeatedly that such measures should be viewed as an interim solution to redressing market power. Thus, upgrading a regional constraint such as Path 15 to reduce over the long term the ability of suppliers to exercise market power is consistent with our broad program to stabilize the electricity markets in California. This program includes in addition ~~the ISO fundamentally errs in its market power assessment by putting arguably the most expensive fix – construction of a $323 million transmission project – as the *first* step in mitigating the market abuses experienced in 2000. This sequence results in inflated project benefits because those benefits are measured when market power is at its maximum. It presumes that regulators will fail to take any other action to address market power abuses or transmission congestion in the future *and* ignores the initiatives that have been put in place by this Commission and other agencies since 2000 to address these issues, such as~~ forward contracting, demand-responsiveness programs, and incentives for distributed generation.

Second, the ISO's approach to estimating the impact of market power on prices has been demonstrated to be reasonable. The study identifies cases in which suppliers are able to exert market power, estimates the price-cost markups that such suppliers may be able to obtain in such cases, and uses the resulting market-abuse baseline to evaluate the project. Absent anomalous conditions, the ISO's methodology was shown in this proceeding to do a good job of predicting price-cost markups given particular levels of loads, and generation market concentration. ~~omits an important modeling parameter that~~

~~further biases the results of its market power study in favor of project construction. The omission affects the ISO's calculation of market concentration in 2005, which is then used as a predictor of market prices in 2005 in a regression analysis. The upward bias in the model is further substantiated by a comparison of estimated and actual price-cost markups in 2001 prepared at the direction of assigned Administrative Law Judge (ALJ). (See Figures 2 and 3.) As discussed in this decision, the predictive weakness of the model is also consistent with our observation that the ISO's regression analysis does not meet standards of statistical validation in six months out of the year.~~

Third, the ISO's assessment shows that under reasonable assumptions the market power benefits of upgrading Path 15 could range between 104 million dollars in a normal hydro year to 305 million dollars in a drought year. The assessment ~~of the 24 scenarios conducted under the market power study, we find that 12 scenarios are simply implausible. These twelve assume that *all* load will be met in 2005 and beyond through spot market transactions exposed to price-cost markups, i.e., none of the Department of Water Resources (DWR) long-term contracts will continue (or be replaced by DWR or utility bilateral contracts) in 2005 and beyond.~~

~~Six others assume that "phantom congestion" will continue to impede the efficient use of existing Path 15 capacity in 2005 and beyond in the same manner that it did in 2000. While these six scenarios may overstate the impacts of phantom congestion, they~~ provides a useful insight into the potential ratepayer benefits of mitigating attempts by market participants to create artificial congestion on this and other transmission paths and otherwise game the market. Enron, and other market participants have engaged in strategies to create false congestion in the past, such as Enron's infamous "Death Star" scheduling system. ~~Absent~~ In addition to other actions to preclude such behavior in the future, the Path 15 project should help mitigate the impact of such strategies.

~~The ISO's remaining analyses include three scenarios where annual project benefits exceed project costs. However, these scenarios assume one-in-ten year drought year conditions or relatively pessimistic forecasts concerning new generation development north of Path 15, or both. Overall, the negative net benefits accumulated in the average hydro years are far greater than the positive net benefits accumulated in the~~

~~drought years. Put another way, for every five years of average hydro conditions, you would need eight years of drought conditions for the project to break even.~~

~~We do not consider these to be likely conditions in 2005 and beyond. Moreover, as discussed above, these results were produced by a modeling effort that, in our view, lacks convincing validation and contains the upward biases described in this decision. Based on the record, we conclude that the ISO's market power study does not produce reliable or reasonable estimates of economic benefits with which to assess the Path 15 upgrades. Even if we could rely on the estimates produced by this study, the results indicate that the costs of the project would not even catch up with estimated benefits within a ten-year period, except under implausible scenarios.~~

~~As discussed in this decision, we believe that the ISO's analysis of Path 15 economic benefits should have acknowledged that various market power mitigation strategies are currently in place and/or will be in place between now and 2005, and *then* measured the effect of Path 15 upgrades on mitigating any residual market power costs. The closest approximation in the record to what the results of such an approach would likely be is the ISO's study that assumes the wholesale market will be competitive by 2005.~~

~~Under this study, the annual benefits of the upgrade are less than costs in all of the scenarios where either (1) average hydro year conditions or (2) medium or high new generation north of Path 15 are assumed. *In scenarios that assume average hydro conditions, the project costs exceed benefits by $47 million/year or more, regardless of the level of new generation assumed.* In fact, under four out of the ten scenarios, the Path 15 upgrade actually increases market prices overall, i.e., the benefits of the project are *negative* by approximately $2.5 to $7.5 million. This is because the addition of 1500 MW in Path 15 transfer capacity increases market prices south of Path 15 more than it decreases market prices north of Path 15.~~

~~The two scenarios where annual benefits are greater than costs assume one-in-ten year drought conditions and relatively low levels of new generation north of Path 15. Even if we believed that the low new generation scenario is likely, the project would not be a cost effective investment to ratepayers unless there are a greater number of years with drought conditions in the future than there are years with average hydro conditions.~~

Based on record in this proceeding, including the project costs presented by PG&E in its testimony, we find that the proposed upgrades to Path 15 are ~~not~~ cost-effective to ratepayers. In a second phase of this proceeding held in late 2002, PG&E submitted updated project cost estimates and agreements among participants regarding the allocation of project costs and benefits. Those participants are: PG&E, Western Area Power Administration (WAPA) and Trans-Elect, Inc. (Trans-Elect). These issues were briefed in late September 2002. However, that information did not appear to change the project economics significantly.

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Page 27, footnote 29.

~~Our understanding from the record in this proceeding is that the ISO staff has taken a position, but not yet the ISO Governing Board, regarding the economic need of the project. (See RT at 533.)~~ We take administrative notice of the fact that the ISO Governing Board approved the project in June 2002, after the conclusion of hearings and briefing on the benefits of the project. ~~Therefore,~~ Our reference to the position of the ISO refers ~~only~~ to the staff position, as reflected in their testimony and during evidentiary hearings.

Pages 29-43

Over 3300 hours of congestion, comprising nearly 40% of all hours of transmission congestion in California, occurred in the south-north direction of Path 15 during 2000.[3] We initiated this phase of the proceeding to carefully evaluate the apparent transmission bottleneck on this transmission path.

All parties agree that the existing capacity of Path 15 (3950 MWs) meets system reliability criteria, as defined by the ISO, the Western Systems Coordinating Council and the North American Electric Reliability Council. Therefore, ~~increasing the line capacity to approximately 5400 MWs is not needed for system reliability purposes. T~~the issues we address today relate to the *economic need* for the project, i.e., whether adding 1500 MWs of capacity to the path produces cost savings to ratepayers that more than offset the project costs.

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[3] D.01-03-077, Attachment 1, Table 5.

We find based on the ISO study that the constructing Path 15 is beneficial to rate payers.   Path 15 plays a major role in seasonal exchanges that take place between Northern California and Southern California and between California and the Pacific Northwest. Exh. 200 at 3.   Path 15 has often been limited by its operating capacity; in fact during January 2001 extreme congestion on Path 15 contributed load curtailments. Id. Given its regional significance, to address the market power problems that result from limited capacity over Path 15, West-wide market power mitigation measures are needed. Exh. 202 at 5. California depends on the broader regional market for imports, and without a West-wide mitigation program, in-state suppliers can sell to the Southwest or Northwest to avoid mitigation measures that are in effect only in California. RT 775-776. In fact, the ISO's analysis incorporates the effects of the California only price caps that were in effect during the study time period (Nov. 1999 to October 2000), RT at 924-925 and 928-930, but these were completely ineffective in preventing extensive market power abuses.

While FERC has put into place certain key West-wide mitigation measures, FERC has indicated that these are to be in place until long-term market-based solutions can be fully implemented and has urged California to proceed with structural improvements to stabilize the electricity market. 100 FERC ¶ 61,060, 61,240 (2002).

Upgrading a regional constraint such as Path 15 is consistent with our broad program to stabilize the electricity markets in California. This program includes in addition to facilitating the addition of needed transmission upgrades, forward contracting, demand-responsiveness programs, and incentives for distributed generation. Our decision today is consistent with Pub. Util.Code § 454.1 (First of two) which specifically provides that "[r]easonable expenditures by transmission owners that are electrical corporations to plan, design, and engineer reconfiguration, replacement, or expansion of transmission facilities are in the public interest and are deemed prudent if made for the purpose of facilitating competition in electric generation markets, ensuring open access and comparable service, or maintaining or enhancing reliability . . . "

~~What is clear from the record in this proceeding is that the ISO's economic assessment of Path 15 upgrades~~ ~~*hinges on the presumption that the market abuses experienced in 2000 will persist in the industry in 2005 and beyond*~~~~. In fact, the ISO~~

~~estimates that the exploitation of market power by suppliers could cost ratepayers hundreds of millions of dollars in 2005 (and each year thereafter), even if Path 15 were built.[4] As discussed above, the ISO believes that transmission upgrades should be the first line of attack on such abuses.~~

~~We concur with ORA that this presumption is flawed. The ISO fails to recognize that the fundamental purpose of regulation is to ensure that players in the market *do not* exercise market power and harm customers. The players in the market have changed, but not this purpose.~~

<u>We note that</u> prior to the deregulation of generation, regulation focused on preventing investor-owned utilities from garnering "monopoly profits" due to their unique position in the electric power market. This was accomplished by cost-of-service ratemaking and other regulatory methods that allowed only reasonable and prudent costs of generation to be recovered in rates, including a reasonable rate of return on capital investment. In other words, the price paid by ratepayers for generation was based on production costs, not on the ability of a utility to manipulate prices above costs in the market.

Deregulation of generation does not, and should not, change this focus. Nonetheless, there is clear evidence on the record that the players in the deregulated generation market not only exerted market power in 2000, resulting in prices to ratepayers that were far from cost-based, but continue to do so today. As Figure 2, attached, illustrates, ratepayers have paid substantial price-cost markups for electric power (ranging from 10% to nearly 90%) in 2001. In its March 26, 2002 submittal to FERC, the ISO conducted an analysis of the bidding of individual suppliers through February 2002, and concludes that a significant amount of capacity is consistently being bid well in excess of marginal costs.[5]

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[4] See Tables 3 and 4 under the "costs due to exercising marketing power" rows at the top of each scenario. As one example, in Table 4 (including long-term contracts) under the dry hydro year, excluding ETC and medium generation scenario, the ISO estimates that ratepayers will continue to pay market power costs on the order of $205 million in 2005 ($611.41 million Path 15 status quo less $406.90 Path 15 expansion) even if the project is built.

[5] Exh. 228, Third Quarterly Report of the California Independent System Operator Corporation, March 26, 2002, pp. 39-52.

What this signals to us is a *failure to regulate wholesale market players effectively*.~~, rather than a failure to build transmission infrastructure~~. Market abuses by suppliers with a large share of the electric market simply should not be tolerated. ~~or presumed inevitable and yet, the ISO's analytical framework does just that: It identifies suppliers that can exert market power, assumes that they cannot be thwarted in establishing high price-cost markups by any other means than constructing more transmission, and uses the resulting market-abuse baseline to evaluate the Path 15 transmission upgrade. This is not only a "worse case" planning scenario, it is an *unacceptable* scenario, in our view~~.

The state of California has in the past and will continue to exhort FERC to effectively regulate wholesale market players to reduce the ability of suppliers to exercise market power. In addition, as stated above, we are promoting several initiatives concurrently to structurally reduce the ability of suppliers to exercise market power, including demand-responsiveness, forward contracting, encouraging distributed generation and in this decision, the addition of strategically important transmission capacity.[6] ~~In fact, upon questioning by the ALJ, ISO Witness Casey acknowledged that London Economics, the ISO consultant that is developing a generic methodology for the economic assessment of transmission lines, has considered the impact of contract coverage (e.g., DWR or utility bilateral contracts with suppliers) and demand-responsiveness (e.g., real-time prices) on the economic need for transmission upgrades. Witness Casey testified that the consultant found there was *not* a significant amount of market power in the baseline (without the upgrade) when *either* of these types of mitigation measures is put in place. As a result, adding transmission capacity provides little benefit.[7] Moreover, forward contracting and demand-responsiveness are not the only strategies for addressing market power.~~ The ISO's model indicates that market

[6] Current efforts and plans to develop more extensive demand-responsiveness programs over the next 18 months are discussed in our June 10, 2002 Order Instituting Rulemaking on policies and procedures for advanced metering, demand response and dynamic pricing. (R.02-06-001.) The Commission's distributed generation initiatives are described in D.01-03-073 in R.98-07-037.

[7] ~~RT at 604-606. The generic methodology being developed by London Economics will be subject to evidentiary hearings at the Commission this fall. See, Administrative Law Judge's Ruling dated May 22, 2002 in this proceeding.~~

power is directly proportional to the largest generation owner's market share; therefore, divestiture is another regulatory tool that may be appropriate and, in fact, is the remedy currently sought by the Attorney General in lawsuits before the United States District Court.[8]

We note that, undertaken in concert, structural market power mitigation measures can be more successful than in individual application. For example, ISO witness Casey explained that while long-term contracts reduce the ability and incentive of suppliers to exercise market power, if at the time contracts are negotiated conditions prevail in which suppliers believe they will be able to exercise market power, and the long-term contract prices will themselves reflect market power. RT. at 598-599.

~~However, the ISO did not even try to compare construction of Path 15 upgrades to other market power mitigation strategies or explore the benefit-cost of such alternatives. Moreover, the ISO analysis does not acknowledge the initiatives already put in place since 2000 by this Commission and other state agencies to increase demand-responsiveness or to address market power and transmission congestion through distributed generation.[9] Nor did the ISO attempt to project the impact of such initiatives on market clearing prices in 2005.[10] Instead, by sequencing the assessment Path 15 upgrades as the first and only market abuse mitigation measure, the ISO produced an analysis that fundamentally biases the results in favor of project construction.~~

The ISO's approach to estimating the impact of market power on prices was demonstrated to be sound. The results of the regression analysis the ISO conducted show that for the period studied, RSI values and load explain a significant proportion of the

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8 Case No. C-02-1787, People of the State of California v. Mirant, Case No. C-02-1788, People of the State of California v. Reliant, April 15, 2002.

~~9 Current efforts and plans to develop more extensive demand-responsiveness programs over the next 18 months are discussed in our June 10, 2002 Order Instituting Rulemaking on policies and procedures for advanced metering, demand response and dynamic pricing. (R.02-06-001.) The Commission's distributed generation initiatives are described in D.01-03-073 in R.98-07-037.~~

~~10 The ISO's analysis simply assumes that the level of price-responsiveness in 2005 and beyond will be the same as it was in 2000. (RT at 777.) ISO Witness Casey testified that the ISO's programs had "limited success in 2001", but acknowledged that he was not an expert in the programs or their impacts, and was not familiar with the details of the Commission's or CEC's programs. (RT at 702-705.)~~

variation in price-cost markups (or the difference between competitive prices and actual prices). In its study, the ISO examined the "R-squared" for the regressions that were used to estimate the Lerner Index (price-cost markups). Exh. 201, Attachment 4, Table 2. The "R-squared" value indicates the extent to which the variables in question, RSI and actual load explain the variation in the factor under examination, in this case price cost markups (or the difference between the prices experienced and competitive prices). RT at 935-936.

The ISO's analysis shows that for the peak season, RSI values and load explain 63 and 58% of the variation in price-cost markups during on-peak and off-peak hours respectively. Exh. 201, Attachment 4, Table 2. The analysis also indicates that for the off-peak season, although the explanatory power is less, RSI and load still explain 42% and 34% of the variation in the price-cost markups, during on-peak and off-peak hours respectively. Exh. 201, Attachment 4, Table 2. Thus, RSI and load explain a significant proportion of the variation in price-cost markups in all periods.

The accuracy of the ISO's methodology to calculate expected price-cost markups in particular conditions was further confirmed in a validation exercise ordered by the ALJ in which the study approach was used to predict prices in a past time period, and the results were compared to actual prices. For the comparison period November 1998 through October 1999, the validation showed that predicted prices closely matched actual prices for 9 of the 12 months assessed. Exh. 221, at 7, Figure 3. The ISO adequately explained the anomalies that resulted from the comparison period, 2001, which it predicted prior to undertaking the validation. Exh. 221 at 5; RT at 623-624 and 940-943. The validation exercise also confirmed that the analysis is not biased in a manner that either over predicts or under predicts pricecost markups since there were almost an equal number of months in which actual price-cost markups were above those predicted by the methodology as months in which actual price-cost markups were below those predicted by the methodology. Exh. 221, Figures 1 and 3.

~~also contains a modeling omission that further biases the results in favor of the project. The omission relates to forward contracting which, as discussed above, mitigates market power (i.e., lowers price-cost markups). As explained in Section 6.3 above, the ISO did take forward contracting into account in one sense: The ISO conducted scenarios that~~

~~estimated the impact of DWR's forward contracting on project benefits by subtracting from the total load the amount of load that is covered by the DWR's long-term contracts. Only the load remaining was subject to the price-cost markups (Lerner Index) estimated through the ISO's regression analysis.~~

~~However, the *ISO's study ignores forward contracting in the underlying calculations* of *RSI values and the Lerner Index.* That is, the ISO did not consider the extent to which suppliers' capacity was pre-sold under forward contracts (either DWR contracts or with other entities outside of California) when it developed RSI values or used them in the regression analysis to estimate the price-cost markups. This omission was discovered during evidentiary hearings when the ALJ directed the ISO to assess how well its model tracked actual price-cost markups in 2001. In presenting this assessment, the ISO acknowledged that forward contracting was "an important factor that was not considered:"[11]~~

~~"Forward contracts for significant amounts of power were signed after January 2001. However, in the 2001 analysis, we did not incorporate forward contracting into our analysis. In theory, a higher level of forward contracting at predetermined prices should result in less market power (i.e., lower price-cost markups). The model used in the CA ISO's market power study does not explicitly consider the portion of each supplier's capacity that is presold under forward contracts…. *The fact that the parameter was not added for the 2001 simulation may be a further reason why the model tends to over predict price-cost markups in the Summer of 2001*…. A more detailed 2001 RSI analysis would only include the proportion of supply with which suppliers could bid strategically."[12]~~

~~The impact of rectifying this omission cannot be quantified without researching the forward contracting position of all suppliers in 2001, recalculating the RSI's in each hour and redoing the regression analysis. However, ISO Witness Casey acknowledged during cross-examination that, on an intuitive basis, the direction of the bias would be to~~

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[11] ~~RT at 910.~~

[12] ~~Exh. 221, p. 6. (emphasis added.)~~

~~"overestimate the market power impact" of the project.[13] This is consistent with the ISO's observation that the omission of this parameter in the model could be a further reason why the model over predicts the actual price-cost markups in 2001.[14]~~ ~~The validation assessment required by the ALJ further documents this upward bias and, more generally, illustrates the predictive weakness of the ISO's market power model. Figure 2 presents a comparison of the price-cost mark-ups predicted by the ISO's model and actual price-cost markups for 2001. As indicated in that figure, the ISO model fails to reasonably predict actual price-cost markups throughout that period, and most noticeably overestimates the price-cost markups from May through September when more long-term contracts are in place. The ISO also submitted a comparison of simulated and actual price-cost markups for the period from November 1998 to October 1999, because the ISO believes that this earlier period represents a "more normal year relative to 2001", for which its model would be a better predictor.[15] (See Figure 3.) However, even though the ISO model closely tracks the price-cost markups over some of this period, it significantly overestimates the price-cost markups in November and December of 1998 and June, July, August and September of 1999.~~

~~In fact, the only validation of the model conducted by the ISO prior to the ALJ's request was to examine the "t-statistics" for variable coefficients and the "R-squared" for the regressions that were used to estimate the Lerner Index (price-cost markups). Upon further questioning during evidentiary hearings, it became clear that the regressions used to estimate the Lerner Index in the off-peak season (November 1999 through April 2000), for both peak and off-peak hours do not meet the ISO's criteria for statistical significance. In particular, ISO Witness Casey testified that an R-squared of 0.5, which means that 50 percent of the variation in the Lerner Index is explained by the variations in RSI and actual system loads, is considered "pretty good" for time series data.[16] In addition, he testified that a statistic should be 2.00 or greater in order to be confident that~~

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[13] ~~RT at 916-917.~~

[14] ~~Exh. 221, p. 6.~~

[15] ~~RT at 943.~~

[16] ~~RT at 935-936.~~

~~the relationship observed between the Lerner Index and RSIs or actual loads are meaningful (i.e., the coefficients are statistically greater than zero).~~[17] ~~However, the R-squared statistics for Off-Peak Season Peak-Hours and Off-Peak Season Off-Peak Hours are only 0.42 and 0.34, respectively. Moreover, the t-statistic for actual loads during Off-Peak Season Peak Hours is only 0.80.~~[18] ~~In other words, the regression results do not meet the ISO's own criteria for statistical validation during six months out of the year.~~

Finally, the ISO study demonstrates that using reasonable assumptions, estimated annual benefits range between 104 million dollars in a normal hydro year to 305 million dollars in a drought hydro year. Thus, even applying a 25% plus or minus factor to account for the uncertainty of several key valuables, the benefits in any year could range between 78 and 381 million dollars well above the project carrying cost.

These estimates show that the project could pay for itself in market power mitigation benefits within four normal hydro years even applying a minus 25% factor to the benefits. Thus, the project will provide market power mitigation benefits to California consumers even under the very conservative assumption that there will be no drought hydro years. These estimates also show the important risk mitigation benefits of the project since benefits could exceed project costs in one year in the context of one-in-ten year drought hydro conditions. ~~even if the sequencing bias, modeling omission and lack of confidence in the ISO's model were not of concern, we could not overlook the fact that the ISO's assessment of market power impacts includes scenarios that are simply implausible.~~

As indicated in Table 2, the ISO conducted 24 different scenarios in it market power study reflecting combinations of the following variables: long-term contract coverage, level of capacity remaining unused due to Existing Contracts, different generation scenarios and normal and drought hydro conditions.

Twelve of those scenarios assume that none of the DWR long-term contracts will continue in 2005 (and therefore all load will be met in 2005 through spot market transactions exposed to price-cost markups) and twelve assume that all DWR long-term

[17] ~~*Id.*~~

[18] ~~Exh. 201, p. 15.~~

contracts will continue. ~~This one assumption has a major impact on the level of benefits derived from ISO's market power study.~~ (See Table 2.) ~~However,~~ In opening testimony, the ISO acknowledged that a plausible scenario would assume that all DWR long-term contracts will continue in 2005. Exh. 200 at 7. In hearings however, evidence was introduced indicating that at least 50% of the MWs available from the DWR are both non-firm and non-dispatchable, and a further 10% of the MWs available from the CDWR contracts are non-firm but dispatchable. Exh. 228 at 92, Figure 24. ISO witness Casey explained that non-firm contracts provide less protection against the exercise of market power than firm contracts. RT at 912. Moreover, while additional long-term contracts are certainly likely, for purposes of the ISO study it is appropriate to consider the long-term contracts that are in effect now because although long-term contracts can themselves reflect market power if suppliers can predict that they will be able to exert market power in the future. RT at 598. Thus, it is reasonable to assume, as the ISO argued in its opening brief, that for purposes of its analysis load equal to 50% of the MWs subject to DWR contract would be shielded from market power impacts in 2005.

~~during questioning by the ALJ, ISO Witness Casey acknowledged that the continuation of DWR contracts was one of the assumptions that the ISO considered "reasonable" in evaluating the project.[19] In fact, none of the evidence suggests that a scenario that assumes the disappearance of all long-term contracts in 2005 and beyond is even plausible. Even if the existing DWR contracts were to be completely voided by the FERC, we expect that DWR or the utilities under Commission order would enter into new forward contracts to prevent overexposure in the spot market. In Rulemaking (R.) 01-10-024, we are will be examining the role of forward contracting, along with other utility procurement strategies, in addressing the State's net-short position.~~

~~For the above reasons, we agree with ORA that the twelve scenarios that exclude long-term contracts should not be considered further.~~

~~That leaves~~ Twelve scenarios ~~remaining, six of which~~ assume that ETC "phantom congestion" will continue to impede the efficient use of existing Path 15 and another twelve scenarios assume no ETC "phantom congestion". (See Table 2.) The ISO

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[19] ~~RT at 591. Exh. 200, p. 7.~~

estimates that between 1145 and 1250 hours of congestion on Path 15 in the south-north direction *could have been avoided* in 2000 had unused ETC capacity been available.[20] On average, in 2000, only 30.6% of the ETC capacity reserved in the day-ahead market was ever actually scheduled by ETC holders. For the hour-ahead market, only 38.3% of the amount reserved was scheduled.[21]

All of the ISO's "exclude ETC" scenarios assume that this inefficient use of the existing 3950 MW of Path 15 transmission capacity will continue in 2005 and beyond. However, in its opening testimony, the ISO indicated that a more plausible scenario would be to assume in 2005 roughly 50% of the inefficient use experienced in 2000. Exh. 200 at 11-12. In its opening brief, the ISO further reduced the estimate based upon additional information developed in the record to 29% of the inefficient use experience in 2000. ~~We note that this assumption has a major impact on the ISO's estimate of economic benefits under the market power study. In particular, the "exclude ETC" scenario *increases* the ISO's estimate of economic benefits in 2005 by $143 million, under drought year conditions, and by $73 million, under normal hydro conditions.[22] We do not consider the results of these scenarios to be accurate, for several reasons. First, the ISO's method for trying to capture the impact of ETCs on the economics of the project appears to inflate the estimated benefits in all of the "exclude ETC" scenarios. As discussed above, ETCs cause phantom congestion on the line to the extent that the ETC holder does not schedule (use) the full amount of its day-ahead capacity reservation. However, rather than simply subtracting the day-ahead unscheduled ETC from operational transmission capacity in these scenarios, the ISO subtracts the full amount of~~

~~[20] Exh. 200, p. 10; RT at 647-648.~~

[21] Exh. 229. To understand these average annual percentage results, an example for a single hour is useful. Suppose that the day-ahead amount reserved in hour 12 pm to 1 pm on 1/1/2000 is 608 MWs. Now suppose that in the day-ahead scheduling process, the amount of ETC scheduled in this same hour is 186 MW. The percentage of ETC scheduled to the ETC reservation is 186/608 = 30.6%.

~~[22] RT at 551-552; These figures are based on the ISO's estimate of economic benefits using "the plausible assumption that at least one drought hydro year can be assumed, that there will be a medium build out of new generation in northern California, and that the State's long term energy contracts remain in effect." Exh. 200, p. 7. We note that, since the filing of written testimony and evidentiary hearings, the ISO has modified somewhat the assumptions it considers plausible. (ISO Opening Brief, pp. 33-34.) Nonetheless, we must rely on the evidence submitted in sworn testimony in characterizing the ISO's position in this case, and do so in assessing the impacts of the "exclude ETC" scenarios on that position.~~

~~ETC capacity reserved in 2000, which is more than two times the amount of the unscheduled ETC capacity in that year.~~[23] ~~We fail to see the rationale for this approach. The amount of capacity that an ETC holder reserves and schedules in the day-ahead market would not impact the potential for market power on Path 15 any more than would the amount of capacity that a new firm user schedules in that market.~~

~~Second, even if it were appropriate to subtract the full ETC reservation amount from operational transmission capacity, the evidence on t~~The record supports ~~persuades us that this amount will be significantly reduced~~ reducing the level of ETC capacity assumed to remain unused in the years 2005 and beyond, consistent with the position set forth in the ISO's opening brief. This is because the following ETC holdings completely terminate between 2004 and 2008: 300 MWs out of the 1110 MWs held by CDWR, all of LADWP and Pacificorp holdings (580 MW) plus the 32 MWs held by Turlock Irrigation District.[24] ~~It is unreasonable to assume that the amount of reserved capacity in 2005 and beyond will stay the same as in 2000 when over 45% of the contract capacity will no longer be subject to ETCs.~~

~~Finally, we must consider the underlying assumption of the "exclude ETC" scenarios, i.e., that the inefficiencies and resulting costs to ratepayers caused by phantom congestion will be allowed to persist without regulatory intervention.~~ We note moreover that addressing "phantom congestion" ~~this issue~~ is squarely before the FERC in three dockets. In California Independent System Operator Corp., Docket No. ER00-2019, the market inefficiency caused by phantom congestion has been identified and is being addressed in overall settlement negotiations.[25] The issue is also before FERC in Docket No. EL01-47-000, in which the ISO has submitted two options to resolve phantom congestion.[26] In addition, the problem of phantom congestion is before FERC in Docket

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[23] Exhs. 227, 229.

[24] RT at 853-854.

[25] See California Independent System Operator Corp., 91 FERC ¶ 61,205 at 61,727 (2000) (recognizing "phantom congestion" as a market inefficiency, and establishing settlement procedures concerning proposed Amendment No. 27 to ISO Tariff).

[26] Exh. 220, Attachment 6, p. 4.

No. EL01-89-000, a complaint filed by Morgan Stanley Capital Group (MSCG) against the ISO. In its September 28, 2001 order setting the complaint for hearing, FERC states:

> "As a preliminary matter, we disagree with the ISO that MSCG should have filed its complaint against PG&E and Edison rather than the ISO. The ISO, itself, has stated that "phantom congestion" is a problem because a significant portion of the ISO Controlled Grid Capacity is encumbered under Existing Contracts [ETCs] with non-participating Transmission Owners and that the scheduling timelines under certain of these Existing Contracts are at odds with the ISO scheduling process defined in the ISO tariff and the Scheduling Protocol. Thus, MSCG's complaint seeking interim relief to "phantom congestion" is appropriately filed against the ISO, since the ISO, not PG&E or Edison controls the transmission grid capacity and the scheduling process under its tariff.
>
> "…Therefore, we will institute an investigation on the complaint. The hearing should determine whether there are reasonable interim solutions available that would remedy this problem of "phantom congestion" for transmission users of the ISO grid absent a total market redesign. We recognize that ultimately the regional market in the West must be operated under standard scheduling procedures that will apply to all market participants."[27]

However, we have yet to see significant, coherent measures implemented by FERC ~~and/or the ISO~~ to eliminate "phantom congestion".

Finally, three generation development scenarios are assessed in the 24 ISO cases: Scenario 1 (a medium scenario for both Northern and Southern California), Scenario 2 (a low scenario for Northern California and a high scenario for Southern California) and Scenario 3 (a high scenario for Northern California and a low scenario for Southern California). Exh. 201, Attachment 3 at 21-22.

In opening testimony, the ISO policy witnesses testified that the medium scenario is the most plausible. Exh. 200 at 7. On the stand, however, Mr. Casey noted that since

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[27] *Ibid*., pp. 5-6. FERC has held hearings in abeyance pending settlement discussions, which are continuing at this time. RT at 851-852.

the opening testimony was written, his opinion about the most reasonable assumption for new generation had changed. Mr. Casey explained that the ISO market power study is most sensitive to assumptions about new generation development North of Path 15. RT at 656. Mr. Casey noted that changes in the economic conditions in California coupled with anecdotal information raise questions about the extent to which pending and announced projects would be built. Mr. Casey concluded that he now believes a more plausible scenario for generation development North of Path 15 to be somewhere between the medium and low generation scenarios. RT at 727.

Mr. Casey's conclusions are supported by the response of ORA witness Logan to the CA ISO data requests. Asked about the new generating plants ORA expected to be on line in 2005 North of Path 15, Mr. Logan listed four new plants providing a total additional 2970 MW of capacity. Exh. 218, Answer to Question 3. The 2,970 MW figure is still significantly below the low generation figure assumed in the DMA study of 4,590 MWs. Further Mr. Logan acknowledged that "what was termed the 'low' generation scenario in September may become the 'medium' scenario in at the present time". Exh. 218, ORA Responses to CA ISO DR, Answer to Question 17. Thus, a scenario between scenarios 1 and 2 is a reasonable generation development assumption.[28]

In sum, because new information suggests that projections of new generation should be reduced downward, the ISO considers the more reasonable assumption to be that new generation development would be a mid-point between Scenarios 1 and 2 for both North of Path 15 and South of Path 15.

~~the ability or financial incentives for market participants to actively game the system. After more than two years, FERC has yet to order refunds of the high costs that were charged to ratepayers in 2000 and 2001 or find that generators inappropriately abused their market power. For these reasons, we find the six scenarios in ISO's market power~~

[28] If for purposes of estimating the benefits of a Path 15 upgrade the mid point between Scenarios 1 and 2 is taken, a medium to high generation development assumption made for the South of Path 15 area. However, Mr. Casey testified that assumptions about new generation South of Path 15 affect the ISO market power study only to the extent that they affect the competitive base-line price to which any price-cost markup would be applied. Thus, even a significant error in assumptions about new generation South of Path 15 would likely have a small impact on the market power benefits analysis. RT at 727-728. If South of Path 15 generation is underestimated, the result is that market power benefits may be somewhat overstated, although the impact should be small. Id. The converse is also true.

~~study that "exclude ETCs" have merit in demonstrating the potential costs to ratepayers of continued reliance on a FERC-regulated wholesale market to provide significant portions of the electricity used in California, and the potential negative impacts to ratepayers of abuses of that market by energy traders and generation companies.~~
~~In the six scenarios that remain, the ISO estimates that only three of them produce benefits that exceed the estimated annual project cost of $50 million. These three scenarios assume one-in-ten year drought conditions, low generation development in northern California and the Pacific Northwest, or both. (See Table 2.) Overall, the negative net benefits accumulated in the average hydro years are far greater than the positive net benefits accumulated in the drought years.~~ ~~*Put another way, for every five years of average hydro conditions, California would need eight years of drought conditions for the project to break even.*~~[29] ~~We do not consider these to be "likely" conditions in 2005 and beyond. Moreover, these results were produced by a modeling effort that, in our view, lacks convincing validation and biases the project benefits upwards.~~

~~Based on the record, we conclude that the ISO's market power study does not produce reliable or reasonable estimates of economic benefits with which to assess the Path 15 upgrades. Even if we could rely on the estimates produced by this study, the results indicate that the costs of the project would not even catch up with estimated benefits within a ten-year period, except under implausible scenarios, with the exception of the potential for, and the history of, rampant gaming by market participants.~~
~~As discussed above, the ISO fundamentally errs in its market power assessment by putting arguably the most expensive fix – construction of a $323 million transmission project – as the~~ ~~*first*~~ ~~step in mitigating the market abuses experienced in 2000. This approach not only presumes that regulators will fail to take any other action to address market power abuses or transmission congestion in the future, but it also ignores the initiatives that have been put in place by this Commission and other agencies since 2000 to address these issues, such as forward contracting, demand-responsiveness programs,~~

[29] Exh. 217, p. 8; RT at 832-834.

~~and incentives for distributed generation. This sequence results in inflated project benefits because those benefits are measured when market power is at its maximum. Instead, as ORA observes, the ISO should have acknowledged that various market power mitigation strategies are currently in place and/or will be in place between now and 2005, and *then* measured the effect of Path 15 upgrades on mitigating any residual market power costs.[30] The closest approximation in the record to what the results of such an approach would likely be is the ISO's study that assumes the wholesale market will be competitive by 2005.~~

~~As indicated in Table 1, in all of the scenarios where either (1) average hydro year conditions or (2) medium or high new generation in NP15 are assumed, the annual benefits of the upgrade are less than the costs. In the scenarios that assume average hydro conditions, *annual project costs exceed benefits by $47 million per year or more*, regardless of the level of new generation assumed. The only scenarios for which annual project benefits are greater than costs are the last two scenarios. Both assume one-in-ten year drought conditions and low new generation build-out in northern California and the Pacific Northwest. One of these scenarios excludes all ETC capacity. Even if we believed the low new generation assumption to be likely, the project would not a cost-effective investment for ratepayers unless there are a greater number of years with drought conditions in the future than there are years with average hydro conditions.~~ Based on these results, we conclude the ~~project is not cost-effective assuming normal operation of the market. This conclusion is based on the assumption that Path 15 upgrades will cost a total of $323 million (approximately $50 million per year on an annualized basis). However, given the potential for future abuses of the market by FERC-regulated generators, and the uncertainty that FERC and the ISO can or will take sufficient action to mitigate such market abuses, we conclude that the~~ Path 15 upgrades ~~may~~ provide benefits by mitigating, at least in part, efforts by market participants to cause phantom congestion, unreasonably drive up market prices and even potentially cause shortages of power and blackouts in Northern California.

30 ORA Opening Brief, p. 12.

We do not agree with PG&E's assertion that it makes little difference which entity finances and builds this project. PG&E's assertion that the cost of capital is unrelated to the underlying company's financial situation, but instead rests solely on the economics of the specific project is incorrect. As PG&E itself has pointed out, PG&E's current financial status results in a higher cost of debt for PG&E and may restrict PG&E's ability to even obtain financing for this project. It is clear that the financial community is as concerned with the financial status of the company in addition to the specific costs and revenues of an individual project.

We also find compelling ORA's example that other means of financing, particularly use of all debt financing via the CPA or other means could result in a significant reduction in the annual costs to ratepayers for this project. While alternative sources of financing may be of value, as ORA has indicated, the record in this proceeding is insufficient to determine if such alternatives are available at this time.

Findings of Fact

1. The primary justification for the proposed Path 15 upgrades ("the project") is economic. ~~Parties in this proceeding agree that the proposed Path 15 upgrades ("the project") are not needed for system reliability purposes, but disagree on whether there is an economic need for the project.~~

2. The assessment of economic need assumes that the project will cost a total of $323 million, or approximately $50 million per year on an annualized basis. This cost figure is a placeholder, pending finalization of project costs by PG&E.

3. The project is evaluated on a "stand-alone" basis in this proceeding, i.e., without considering the manner in which PG&E and other entities will participate in the project.

4. The ISO's assessment of the economic benefits associated with the project evaluated the benefits to consumers that would result from reducing the ability of suppliers to exercise market power. ~~hinges on the presumption that the market abuses experienced in 2000 will persist in the industry in 2005 and beyond.~~ It identifies suppliers that can exert market power, identifies cases in which suppliers are able to exert market power, estimates the price-cost markups that such suppliers may be able to obtain

in such cases, ~~assumes that they cannot be thwarted in establishing high price-cost markups by any other means than constructing more transmission,~~ and uses the resulting market-abuse baseline to evaluate the project.

~~5. The ISO's consultant, London Economics, found that adding transmission capacity provides relatively little economic benefit to ratepayers when contract coverage and/or demand-responsiveness programs are put in place to mitigate market power.~~

~~6~~ 5. The ISO's analysis incorporates price caps that were in effect during the study time period (Nov. 1999 to October 2000). ~~ignores the initiatives that have been put in place by the Commission and other agencies since 2000 to address market power abuses and mitigate transmission congestion, such as forward contracting, demand-responsiveness programs and incentives for distributed generation. It also presumes that regulators will fail to take any other actions to address market power abuses in the future.~~

~~7. By establishing the baseline for its market power study in the manner described above, the ISO's analysis results in inflated project benefits.~~

6. Structural improvements to reduce market power are most effective if implemented in concert.

7. Path 15 plays a major role in seasonal exchanges that take place between Northern California and Southern California and between California and the Pacific Northwest, supporting seasonal exchanges of thermal and hydro generation.

8. During 2001, extreme congestion on Path 15 contributed to load curtailments.

9. In the case of a significant regional constraint such as Path 15, broad, on-going, West-wide mitigation would be necessary to address market power concerns.

10. While FERC has put into place certain West-wide mitigation measures FERC has indicate that these are to be in place until long-term market-based solutions can be fully implemented and has urged California to proceed with structural improvements to stabilize the electricity market.

11. The ISO's analysis demonstrates that RSI values and actual load explain between 34% to 63% of the variation price-cost markups during the study period (the difference between competitive prices and actual prices) depending on the time frame in question,

indicating that RSI values in combination with actual load have a strong explanation value for price-cost markups.

12. The further validation undertaken by the ISO in response to the request of the ALJ indicates that, in the absence anomalous conditions, the ISO methodology does a good job at predicting price-cost mark ups given particular levels of load and RSI values in the market.

13. The validation undertaken by the ISO in response to the request of the ALJ shows that the methodology does not contain biases that result either in systematic over or under estimates of price-cost markups.

14. Assuming four normal hydro years is conservative.

~~8. The ISO's market power study also ignores forward contracting in the underlying calculations of RSI values and the Lerner Index. This omission further biases the results in favor of project construction.~~

~~9. The validation assessment performed at the ALJ's request in this proceeding documents the upward bias of the ISO's modeling method and, more generally, illustrates its predictive weakness.~~

~~10. The regression results used by the ISO to predict price-cost markups in 2005 do not meet the ISO's own criteria for statistical validation during six months out of the year.~~

~~11~~ 15. None of the evidence in this proceeding suggests that the disappearance of all forward contracting in 2005 and beyond is plausible. ~~This assumption is used for 12 out of the 24 scenarios presented in the ISO's market power study.~~

16. At least 50% of the MWs available from California Department of Water Resources (DWR) contracts are both non-firm and non-dispatchable and a further 10% of the MWs available from the DWR contracts are non-firm but dispatchable.

17. Non-firm, non-dispatchable contracts will not, without other measures, effectively shield load from supplier market power.

18. Long-term contracts signed for periods when suppliers expect they will be able to exercise market power can themselves reflect market power.

19. Because over half of the MWs available from CDWR contracts are both non-firm and non-dispatchable, it is reasonable to assume for purposes of the ISO market power

study that load equal to 50% of the MWs subject to CDWR contracts would be shielded from market power impacts in 2005.

~~12. Six of the remaining ISO scenarios ("exclude ETCs") assume that the inefficient use of ETCs in 2000 will continue in 2005 and beyond without regulatory intervention.~~

20. In 2000 62% of transmission capacity that was reserved for Existing Contracts over Path 15 remained unscheduled in the Hour Ahead market.

21. 2422 MWs of transmission capacity was subject to Existing Contracts in 2000. 1142 MWs of transmission capacity will remain subject to Existing Contracts in 2005 and well into the future.

~~13~~ 22. In the ISO market power study scenarios labeled "Including ETC" ~~method used by the ISO to try to capture the impact of continued ETC inefficiency on the economics of the project appears to inflate the estimated benefits in the six scenarios that exclude ETCs. This is because~~ the ISO subtracts the full amount of ETC capacity reserved in 2000 from operational transmission capacity, rather than the amount of unscheduled ETC capacity.

23. For purposes of estimating the benefits of the Path 15 upgrade, it is reasonable to assume that 29% of the ETC capacity that was reserved in 2000 will remain unused and unavailable in 2005 and beyond.

24. The mid point between the new generation scenarios 1 and 2 assessed by the ISO is most consistent with current information about the recent slow down in new generation development in Northern California. The ISO market power study is most sensitive to assumptions about new generation development in Northern California.

~~14. Even if it were appropriate to subtract the full ETC reservation amount from operational transmission capacity, the evidence indicates that this amount will be significantly reduced in the years 2005 and beyond because over 45% of the ETC contract capacity will expire between 2004 and 2008.~~

~~15~~25. ~~While inflated,~~ The ISO's forecast of benefits when congestion occurs provides insight into the potential benefits to consumers of improving Path 15 should market participants be able to exercise market power and create false congestion in the future.

26. Using reasonable assumptions, estimated annual benefits range between 104 million dollars in a normal hydro year to 305 million dollars in a drought hydro year.

Thus, even applying a 25% plus or minus factor to account for the uncertainty of several key variables, the benefits in any year could range between 78 and 381 million dollars.

~~16. In the six scenarios that remain, the ISO estimates that only three of them produce benefits that exceed the estimated annual project cost of $50 million. These three scenarios assume one-in-ten year drought conditions, low generation development in northern California and the Pacific Northwest, or both. For every five years of average hydro conditions, California would need eight years of drought conditions for the project to break even.~~

~~17. The ISO's study based on competitive market prices is the closest approximation to a study that acknowledges the various market power mitigation strategies currently in place and those that will be in place between now and 2005.~~

~~18. Under the competitive market study, annual project costs *exceed* benefits by $47 million per year or more in all of the scenarios where either (1) average hydro year conditions or (2) medium or high new generation in northern California are assumed.~~

~~19. Under the competitive market study, annual project benefits are greater than costs in only two scenarios, where one-in-ten year drought conditions and low new generation build-out in northern California are assumed. One of these scenarios excludes all ETC capacity.~~

Conclusions of Law

1. It is the policy of the state of California to put into place the structural elements, including transmission upgrades, necessary to assure a well functioning competitive wholesale electricity market.

~~1~~ 2. The ISO's market power study reasonably predicts the market power benefits of adding 1500 MWs of capacity to Path 15. ~~does not produce reliable or reasonable estimates of economic benefits with which to assess the project. Even if we could rely on the estimates produced by this study, the results indicate that the benefits of the project would not catch up with estimated costs within a ten-year period, except under implausible scenarios or if market gaming is rampant.~~

~~2. Under the ISO's study that assumes competitive market pricing, the project would not be a cost-effective investment for ratepayers unless we believe that (1) low new generation build-out for northern California and the Pacific Northwest is likely *and* (2)~~

~~there will be a greater number of years with drought conditions in the future than years with average hydro conditions.~~

3. Based on the record in this proceeding, the proposed upgrades to Path 15 are ~~not~~ cost-effective to ratepayers ~~on a stand-alone basis, except potentially~~ as a means of mitigating market gaming.

PROOF OF SERVICE

I hereby certify that on March 27, 2003, I served by electronic and U.S. mail, the Comments of the California Independent System Operator on the Proposed Decision of Judge Gottstein and the Alternate Proposed Decision of Commissioner Lynch Both Mailed on March 7, 2003 in Docket # I.00-11-001.

DATED at Folsom, California on March 27, 2003.

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