Chapter III: Testimony of Doug Boccignone Regarding the Economic Justifications Advanced for the Project.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to assess the testimony and analysis of SDG&E and the ISO with regard to the economic justifications for the Valley-Rainbow Project. Based on my review of the testimony and analysis of the ISO and SDG&E, I conclude that those project proponents have not demonstrated that the proposed Valley-Rainbow Project is justified based on economic factors.

Q: Please describe your qualifications as they relate to this proceeding.

A: I am a registered professional electrical engineer in the State of California. I hold a B.S. in Industrial Engineering and Engineering Management from Stanford University and a B.A. from Claremont McKenna College in Management-Engineering. I am presently a principal at Flynn & Associates, where I provide strategic advice on complex energy-related business issues to municipal utilities, independent power producers, and large energy consuming companies. I have extensive experience in the development and application of financial models to energy issues. My resume detailing my qualification is attached to my testimony as Exhibit 1.

I. Assessment of Economic Rationales for Project

Q: Please summarize your conclusions regarding the economic justifications put forward for the proposed Valley-Rainbow Project.

A: SDG&E sets forth its economic justifications for the Valley-Rainbow Project (i.e., alleged benefits other than reliability) in a few pages of Chapter II and all of Chapter IV of its testimony. S*ee* SDG&E's October 5, 2001 Testimony at II-17 through II-19; Chapter IV. According to SDG&E, those alleged economic benefits are:

1. "significant economic benefits to the State" in the form of "significant reductions in energy costs" as described in Chapter IV;
2. "substantial cost benefits to ratepayers" in the form of "avoided customer outage costs;" and
3. reduced reliability must run ("RMR") costs.

I will briefly summarize my assessment of each of these alleged economic benefits in this answer and elaborate on my conclusions in the sections that follow.

SDG&E's principal economic justification for the Valley-Rainbow Project (item 1, listed above) is its claim that the project will confer significant economic benefits on the State in the form of reduced energy costs. Much of my testimony is dedicated to evaluating this claim. Based on my review of SDG&E's testimony and analysis, it is my opinion that the project is very unlikely to produce economic benefits for the State in the form of reduced energy costs that exceed the project's considerable costs. SDG&E's economic analysis, which focuses on a few highly unlikely scenarios in an attempt to justify the project, actually reveals that the project's substantial costs are very unlikely to be outweighed by the uncertain project benefit of potentially lower electricity costs. Projects such as this one, with greater costs than benefits, are not justified on economic grounds and should not be approved by the Public Utilities Commission ("Commission") based on that rationale.

SDG&E provides only a cursory description of the alleged avoided customer outage costs and reduced reliability must run costs (items 2 and 3, listed above). As explained in detail below, I do not believe SDG&E has provided a sufficient assessment of these alleged benefits for the Commission to determine the economic value (if any) that would likely derive from the Valley-Rainbow Project in these areas. As such, these rationales do not justify Commission approval of the project.

A. Economic Rationale #1: Reduced Energy Costs.

Q: What is your assessment of SDG&E's argument that the Valley-Rainbow Project benefits the State by reducing energy costs?

A: Chapter IV outlines SDG&E's argument that the Valley-Rainbow Project would lead to lower market prices for electricity by relieving a transmission constraint. SDG&E supports this argument by referencing a production cost model economic analysis performed by Henwood Energy Services, Inc. ("Henwood") for the project. The Henwood analysis calculates the cost to serve the ISO area load with and without the Valley-Rainbow Project under a number of scenarios. Each scenario is based on different assumptions regarding factors, including: (1) new generation resources (i.e., how much generation will get built and where); (2) the availability of hydropower (i.e., whether there will be medium or high amounts of hydropower available); and (3) whether or not proposed upgrades to Path 15 (a transmission link between northern and southern California) will be built. The results of the Henwood study indicate that the Valley-Rainbow Project would produce widely varying levels of benefits depending on which scenario actually comes to pass. *See* SDG&E October 5, 2001 Testimony, Chapter IV, Henwood Report Tables 1-1, 1-2.

The first thing to note about the SDG&E testimony and the Henwood study on which it relies is their failure to offer any assessment of the likelihood that each of the various scenarios considered will actually come to pass. So, for example, based on the

Henwood study, SDG&E takes the position that the Valley-Rainbow Project would offer economic benefits under a scenario in which significant new generation is built in the San Diego/Baja Mexico region and the Pacific Northwest suffers a drought for the entire study period (6 years), but does not indicate the probability of such conditions actually occurring. Estimating the probability of occurrence for every scenario is critical in the economic analysis because the project's potential benefit under a given scenario must be discounted to reflect the less than certain probability of that scenario occurring. SDG&E's failure to provide such probability information in its economic analysis makes the Commission's review more difficult.[1] Notwithstanding this lack of scenario probability information, I have attempted in my testimony to assess the likelihood of some of the scenarios. *See* Sections B(1) and B(2), below.

Another notable aspect of the SDG&E testimony and the Henwood study is that, although they speculate regarding the potential economic benefit of the project attributable to reduced energy costs under each of the scenarios considered, they offer no direct comparison of those alleged benefits to the expected Valley-Rainbow Project costs. Although SDG&E's testimony does not focus on that comparison, the Commission must evaluate whether the Valley-Rainbow Project is economically justified by carefully considering whether the economic benefits derived from the project can reasonably be expected to exceed the costs associated with the project. The annual cost (a.k.a. the "annual carrying charge") of projects such as the Valley-Rainbow Project vary somewhat, but are generally approximately 18% of the total project cost. If the total cost of the Valley-Rainbow line were between $300 million[2]

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[1] SDG&E's decision not to provide probability information for the scenarios considered in its economic analysis is also inconsistent with the direction given in the Assigned Commissioner's August 13, 2001 Scoping Memo, which directs SDG&E to "include scenario analyses assuming various levels of new generation, transmission additions, and demand, and provide some assessment of the likelihood of the scenarios coming to fruition." Scoping Memo at 5.

[2] The actual cost of the project is likely to be higher than the approximately $300 million estimated by SDG&E, because SDG&E has excluded from its cost estimate an allowance for

and $350 million, the annual carrying charge for the project would likely be between $50 and $60 million. Thus, for the project to be economically justified, the benefits from the project must, on average, exceed $50-60 million per year.

Also notable is the fact that, although the Henwood study considered several scenarios (and many other scenarios are possible, including wet hydro years and alternative generation location build-out scenarios), for most of the scenarios described in the Henwood report, the costs of the Valley-Rainbow Project greatly exceed the economic benefits calculated by Henwood. Specifically, under most of the scenarios run by Henwood, project costs are between 3 ½and 250 times the projected economic benefits. This is a remarkable result, which dramatically undercuts any argument that the Commission should approve the project on economic grounds.

SDG&E identifies only two categories of scenarios (Henwood's E and A/D scenarios) in which it argues that the Valley-Rainbow Project would produce significant economic benefits.[3] Of the scenarios in the Henwood study, these are the only two categories in which the alleged economic benefits even begin to approach or slightly exceed project costs. As I describe in detail in response to the immediately following question in Sections B(1) and B(2), below, Henwood's E scenarios are extremely unlikely to occur and Henwood's A/D scenarios are implausible. The fact that even SDG&E's unlikely and implausible scenarios produce such marginal (or

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funds used during construction ("AFUDC") and other factors. ORA has estimated that the total project cost with AFUDC would be approximately $350 million. ORA February 4, 2002 Testimony, Appendix B; *see also* Testimony of Mr. Gimmy (Chapter 5) regarding the high cost of land acquisition for the project.

[3] In Chapter IV of SDG&E's October 5, 2001 testimony, J. Richard Lauckhart states: "The [Henwood] study concludes that under certain scenarios the Valley Rainbow line brings significant economic benefit. In particular, the Valley Rainbow line brings significant benefit under a scenario where some new generation is built in the San Diego/Baja Mexico area and the California/Pacific Northwest region goes through a drought situation like that which occurred in the year 2001. In addition, the study indicates that the line can bring value under non-drought situations if new generation resources are constructed to take advantage of the line's increased export capability. I refer to the report for the details on these findings." *Id.* at IV-2.

nonexistent) economic benefits in comparison to the Valley-Rainbow Project costs, is a strong indication that the project is not justified on economic grounds.

Henwood's E scenarios (presented in Henwood's Table 1-1), which are relied on by SDG&E to justify the project, are unlikely to materialize because they assume 2 in 70 year drought conditions for six years in a row. As Table 3.1 (below) illustrates, in these unlikely E scenarios, the economic benefits of the Valley-Rainbow Project calculated by Henwood are marginal in comparison to the project costs; the economic benefits are approximately equal to project costs if Path 15 is not upgraded, and they are approximately 1 ½times the project costs if Path 15 is upgraded.

Table 3.1: Cost/Benefit Comparison for Henwood's E Scenario

Scenario	**Alleged Project Benefit (2005-2010)[4]**	**Project Cost Range (annual carrying charge of project x 6 years)**	**Cost/Benefit Comparison**
E1/E3 (no path 15 upgrade)	$ 340,811,000	$ 300,000,000 to $ 360,000,000	costs and benefits approximately equal
E2/E4 (with path 15 upgrade)	$ 504,677,000	$ 300,000,000 to $ 360,000,000	benefits approximately 1 ½ times costs

Henwood's A/D scenarios (presented in Henwood's Table 1-2), which are also relied on by SDG&E to justify the project, are implausible because they assume that 1700 MW of additional resources in San Diego (displacing 1700 MW that Henwood expected in its reference case to be built outside of San Diego) would be built ONLY IF the Valley-Rainbow Project is constructed. As Table 3.2, below, illustrates, in these implausible scenarios, the economic benefits of the Valley-Rainbow Project calculated by Henwood are less than the project costs if Path 15 is not upgraded, and approximately equal to the project costs if Path 15 is upgraded.

Table 3.2: Cost/Benefit Comparison for Henwood's A/D Scenario

Scenario	Alleged Project Benefit (2005-2010)	Project Cost Range (annual carrying charge of project x 6 years)	Cost/Benefit Comparison
A1/D3 (no path 15 upgrade)	$ 224,882,000	$ 300,000,000 to $ 360,000,000	costs greater than benefits
A2/D4 (with path 15 upgrade)	$ 368,456,000	$ 300,000,000 to $ 360,000,000	costs and benefits approximately equal

As the foregoing analysis makes clear, even when SDG&E makes unlikely and implausible assumptions that would increase the project's value, in comparison to the project's costs, the economic benefits are nonexistent or marginal. I will describe in Section B(1) and B(2), below, why I believe these unlikely and implausible scenarios should not be relied upon. Moreover, as the results of the scenarios presented by SDG&E make clear, whether or not the proposed Path 15 upgrades are completed has dramatic implications for whether or not the Valley-Rainbow Project produces even marginal economic benefits in relation to the project costs. My analysis therefore will include a discussion of Path 15 and its implications for the Valley-Rainbow Project.

B. Assessment Of Henwood's Production Cost Modeling Analysis

Q: Please provide your assessment of the production cost modeling analysis conducted by Henwood and included in SDG&E's October 5, 2001 testimony.

A: The Henwood study (the results of which were discussed above) is based on production cost modeling, an analytical approach that has been used for many years to simulate the operation of power generation systems. As in any modeling, the

[4] Values given are the opportunity costs calculated by Henwood. *See* SDG&E October 5, 2001 Testimony, Chapter IV, Henwood Report Table 1-1.

assumptions used in the analysis drive the modeling results. Key variables for this type of analysis usually include the amount of load and generation, transmission access to alternative markets, the variable operating costs of the marginal generation units, and hydro conditions. I have identified significant problems with the assumptions used in the Henwood analysis, which I address in detail below.

1. Hydro Conditions

First, although the Henwood report relied on by SDG&E appropriately used expected load and generation levels for its base case, it inappropriately evaluated "dry hydro" conditions without considering the full range and probability of occurrence of possible hydro conditions, including wet years. The failure to evaluate the full range of hydro conditions overstates the value of relieving any transmission constraint with new transmission such as the Valley-Rainbow Line.

Further, for several scenarios (scenarios C1/C3, C2/C4, E1/E3, E2/E4), Henwood assumed that the "dry hydro" state would exist for each year of the entire 2005-2010 study period. Hydro conditions vary from year to year, but on average, one would expect to experience "median hydro," rather than "dry hydro" conditions. The Henwood analysis does not reflect this reality. Henwood instead should have studied the full range of hydro conditions and calculated a probability-weighted result. Such an approach would show economic benefits significantly lower than assuming "dry hydro" conditions for all six years.

In its response to ORA Data Request #2, SDG&E stated that for the "dry hydro" conditions assumed by Henwood, the "…level of drought is approximately what was experienced in the recent power crisis in the WSCC.[5] Runoff was represented as being the second worst in recorded history. Therefore, the probability would be approximately 2 out of 70…" (less than 3%) that the reduction in hydro generation would be as great or greater than that assumed in the dry hydro scenarios <u>for any one year</u>. The probability that so little hydro power would occur in 6 consecutive years would be significantly lower than 2 out of 70. If the hydro conditions from one year to the next were independent events, the probability would be less than 1 in 1 billion ((2/70)^6). Even if they were not independent events, the probability of having a 2 in 70-year drought for six consecutive years would be extremely small.

In short, Henwood's assumption that "dry hydro" conditions would persist for six years in a row improperly inflates the level of benefits calculated for the project under those scenarios and contributes to the general overstatement of the potential economic benefits of the Valley Rainbow Project. Similarly, Henwood's evaluation of "dry hydro" conditions without considering the full range of hydro conditions (i.e., wet years) skews its results in favor of the project.

2. Assumption that Generation Would Not Be Built But For the Project.

One of the key sets of scenarios relied on by SDG&E to justify the project (scenarios A1/D3 and A2/D4) assumes that an additional 1,700 MW of generation would be built in San Diego and Baja as a direct result of the Valley-Rainbow Project (i.e., assumes that the significant new generation would not be built <u>but</u> <u>for</u> the transmission project).[6] *See* SDG&E October 5, 2001 Testimony, Chapter IV, Henwood Report Table 1-2. For the reasons outlined below, scenarios A1/D3 and

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5 WSCC is the Western Systems Coordinating Council.

6 The scenarios also assume that there would be a corresponding 1700 MW reduction in the northwest and southwest generation to maintain the capacity balance and that no new generation will be added in Northern California.

A2/D4 incorrectly overstate the economic benefits derived from the Valley-Rainbow Project, and should be disregarded by the Commission.

SDG&E's A1/D3 and A2/D4 scenarios calculate the <u>combined</u> benefits deriving from co-occurrence of two factors:

1. the addition of 1700 MW in San Diego/North Baja, and
2. the addition of the Valley-Rainbow Project.

SDG&E's testimony incorrectly attributes the <u>combined</u> benefits calculated by Henwood for these scenarios solely to the existence of the Valley-Rainbow Project. SDG&E takes this position based on the premise that <u>but for</u> the Project, the 1700 MW of additional San Diego/North Baja generation would not be built. This premise is flawed.

My analysis of the results of the Henwood study shows that between 90% and 99% of the <u>combined</u> benefits should actually be attributed to the existence of the additional 1700 MW of generation in San Diego/North Baja, rather than to the Valley-Rainbow Project (*see* Table 3.3, below). As Table 3.3 illustrates, if Path 15 is not upgraded, Henwood's analysis shows that locating an additional 1700 MW in San Diego/North Baja provides $221.7 million of economic benefits over the 6 year study period, <u>without the Valley-Rainbow Project</u>. These benefits represent approximately 99% of the $224.9 million of economic benefits calculated by Henwood resulting from the combination of the additional 1700 MW and the Valley-Rainbow Project, if Path 15 is not upgraded. If Path 15 is upgraded, Henwood's analysis shows that locating an additional 1700 MW in San Diego/North Baja provides $335.3 million of economic benefits over the 6 year study period, <u>without the Valley-Rainbow Project</u>. These benefits represent approximately 90% of the $368.5 million of economic benefits calculated by Henwood resulting from the combination of the additional 1700 MW and the Valley-Rainbow Project, if Path 15 is upgraded.

Table 3.3: Differentiation of Benefits of Adding 1700 MW of Generation in San Diego/Baja v. Combined Benefits of Valley-Rainbow Project and New Generation

Scenarios	**ISO Benefits[7] 2005-10 ($2001)**	**Comparison to Henwood's A/D Scenarios**
Scenarios Assuming Path 15 Upgraded		
A1/D1 Without Valley-Rainbow in place, add 1700 MW SD/Baja generation	$221,682,000	Offers 99% of the benefit offered by A1/D3 scenario
A1/D3 Simultaneously add Valley-Rainbow and add 1700 MW SD/Baja generation	$224,882,000	
Scenarios Assuming no Path 15 Upgrade		
A2/D2 Without Valley-Rainbow in place, add 1700 MW SD/Baja generation	$335,257,000	Offers 91% of the benefits of the A2/D4 scenario
A2/D4 Simultaneously add Valley-Rainbow and add 1700 MW SD/Baja generation	$368,456,000	

[7] As in the Henwood report, the "ISO Benefits" listed do not consider the costs of the Valley-Rainbow Project, or of constructing the additional San Diego/Baja generation.

This analysis shows that the incremental benefits of the Valley-Rainbow Project are miniscule in comparison to the economic benefits of locating additional efficient generation in San Diego/North Baja if Path 15 is not upgraded, and are marginal if Path 15 is upgraded. By combining the economic benefits of these two factors considered in scenarios A1/D3 and A2/D4 (additional generation and the Valley-Rainbow Project), SDG&E has obscured the true source of the vast majority of the benefits. Given that the vast majority of the economic benefits attributed to the combination of the addition of 1700 MW of new generation and the Valley-Rainbow Project can be achieved without the additional cost of building Valley-Rainbow (whether or not Path 15 is upgraded), it is inappropriate to attribute all of the benefits to the project. Furthermore, it is implausible to assume that the presence (or absence) of the Valley-Rainbow Project would be a critical factor in a generator's decision to locate a project in San Diego/North Baja.

As SDG&E itself stated in its response to ORA Data Request No.2, "For cases D and E, the amount of generation in California was reduced. Approximately 1700 MW of generic generation (over and above the Otay Mesa and LRPP projects) was assumed to be interconnected in the San Diego area, and located in either San Diego or Baja. This 1700 MW of generation was deemed reasonable for analysis based on projects in the SDG&E interconnection queue and system upgrade queue. Projects that SDG&E is aware of are:

- SER1 – 600 MW
- AEP1 – 250 MW
- AEP2 – 250 MW
- LREP – 350 MW
- SER2 – 600 MW
  Total 2050 MW
- Other recent potential proposed projects could total 1100-1600 MW."

(SDG&E December 13, 2001 Response to ORA Data Request No. 2 at Answer 2.18)

SDG&E offers no evidence that any of the above-listed projects would be cancelled as a direct result of the Valley-Rainbow Project not being built. In fact, numerous generation projects are already under construction including the new in-basin generation listed in Mr. Schmus' testimony and Sempra's Imperial Valley Generation Project I (600 MW) and InterGen B Generating Facility Project (Phase I = 160 MW, Phase II = 440 MW). The development of these projects in the absence of the Valley-Rainbow Project confirms the conclusion that I derived from the Henwood analysis: developers already have adequate incentives to locate new projects in the San Diego/North Baja border area to offset the relatively high-cost steam generation located in the San Diego basin.

3. The Impact of Proposed Path 15 Upgrades on the Project.

As I noted earlier, SDG&E's economic assessment of the project differs depending on whether or not Path 15 is upgraded. The Path 15 upgrade project would increase the transfer capability between northern and southern California by approximately 1,400 MW at a cost of approximately $330 million. In some of the scenarios, the economic benefit of the Valley-Rainbow Project calculated by Henwood is higher with the Path 15 upgrade, while in others it is lower. In the median hydro scenarios, Henwood's analysis shows that the Valley-Rainbow Project tends to have more economic benefit (but still less benefit than costs) if Path 15 is upgraded. Conversely, in the dry hydro scenarios, the Valley-Rainbow Project has more economic benefit if Path 15 is not upgraded, unless 1,700 MW of additional new generation resources in San Diego are assumed to displace 1,700 MW that otherwise would be expected to be built outside of San Diego (to the north and east).

The Path 15 upgrade provides a valuable benchmark against which to assess the anticipated costs and potential benefits of the Valley-Rainbow Project. My review of the results of Henwood's analysis shows that although the estimated cost of the Path 15 improvements is comparable to the estimated cost of the Valley-Rainbow Project, the economic benefits calculated by Henwood for the Path 15 improvements far exceed the economic benefits calculated by Henwood for the Valley-Rainbow Project.

In my analysis, I used the results from Henwood's analysis to compare the economic benefits of the Path 15 upgrade project to the economic benefits of the Valley-Rainbow Project. While the costs of these projects are similar (approximately $330 million each), Henwood's model of the increase in the south-to-north transfer capability resulting from the Path 15 upgrade is approximately 80% greater than that of the Valley-Rainbow Project (1400 MW vs. 780 MW). For the same hydro and regional capacity build-out scenarios evaluated by Henwood that show a cumulative 6 year economic benefit (not considering costs) of between $1.2 million and $505 million for the Valley-Rainbow Project, Henwood's results show a cumulative 6 year economic benefit (not considering costs) of between $406 million and $11.6 BILLION for the Path 15 upgrade.[8] The economic benefits of the Path 15 upgrade shown by Henwood's analysis are between 23 and 670 times the economic benefits of the Valley-Rainbow Project (*see* Table 3.4). This dramatic difference in economic benefits resulting from the same analysis methodology and underlying assumptions is astounding. Based on the results of the Henwood analysis, the economic benefit of the Valley-Rainbow Project is just a fraction of the economic benefit of the Path 15 upgrade for all scenarios shown by Henwood. Since the estimated costs of these projects are similar, and under the ISO tariff all ratepayers in the State will pay those costs, it is not reasonable to allocate limited resources to the Valley-Rainbow Project in light of its meager economic benefits relative to the Path 15 upgrade. Even if unlimited resources were available for transmission projects, SDG&E's economic analysis finds only two categories of scenarios in which the economic benefits of the Valley-Rainbow Project calculated by Henwood even slightly exceed the costs. As was shown above, the probability of having 6 consecutive years of drought is extremely small, and the argument that 1700 MW of additional generation would not be located in San Diego/North Baja but for the Valley-Rainbow Project is implausible; therefore, even the scenarios which show marginal benefits should be disregarded.

[8] As I noted previously, these project benefit numbers do not take into account the estimated costs of each project, which are essentially the same for the Path 15 upgrade and the Valley-Rainbow Project (~ $330 million).

Table 3.4: Path 15 Economic Benefits with and without Valley-Rainbow v. Valley-Rainbow Economic Benefits with and without Path 15 [9]

Group	Scenario	VRI Added	Path 15 Upgrade	SIO Benefits 2005-10 (2001$)	Scenario	VRI Added	Path 15 Upgrade	SIO Benefits 2005-10 (2001$)	Ratio of Path 15 Upgrade Benefits to V-R Benefits
1	**A1**	No	No	**$ 868,832,000**	**A1**	No	No	**$ 1,632,000**	532
	A2	No	Yes		**A3**	Yes	No		
2	**A3**	Yes	No	**$ 866,357,000**	**A2**	No	Yes	**$ (844,000)**	NA
	A4	Yes	Yes		**A4**	Yes	Yes		
3	**B1**	No	No	**$ 405,541,000**	**B1**	No	No	**$ 1,222,000**	332
	B2	No	Yes		**B3**	Yes	No		
4	**B3**	Yes	No	**$ 410,448,000**	**B2**	No	Yes	**$ 6,130,000**	67
	B4	Yes	Yes		**B4**	Yes	Yes		
5	**C1**	No	No	**$ 5,760,513,000**	**C1**	No	No	**$ 93,491,000**	62
	C2	No	Yes		**C3**	Yes	No		
6	**C3**	Yes	No	**$ 5,675,496,000**	**C2**	No	Yes	**$ 8,475,000**	670
	C4	Yes	Yes		**C4**	Yes	Yes		
7	**D1**	No	No	**$ 982,408,000**	**D1**	No	No	**$ 3,200,000**	307
	D2	No	Yes		**D3**	Yes	No		
8	**D3**	Yes	No	**$ 1,012,407,000**	**D2**	No	Yes	**$ 33,199,000**	30
	D4	Yes	Yes		**D4**	Yes	Yes		
9	**E1**	No	No	**$ 11,469,289,000**	**E1**	No	No	**$ 340,811,000**	34
	E2	No	Yes		**E3**	Yes	No		
10	**E3**	Yes	No	**$ 11,633,155,000**	**E2**	No	Yes	**$ 504,677,000**	23
	E4	Yes	Yes		**E4**	Yes	Yes		

[9] Benefits represent the sum (in 2001$) of the annual opportunity cost difference between grouped scenarios for the period 2005 - 2010.

I believe Henwood's analysis shows significantly greater economic benefits from investing $330 million to upgrade Path 15, than from spending a similar amount for the Valley-Rainbow Project for several reasons. The Path 15 project would increase the transfer capability between northern and southern California by approximately 1400 MW, as compared to Valley-Rainbow increasing the transfer capability between SCE and SDG&E by approximately 780 MW. This difference in transfer capability does not, however, completely explain the magnitude of the difference in calculated benefits. The larger Path 15 increase has the additional benefit of linking two very large load areas, with diverse and large generation resource pools; thus providing greater opportunity for economic interchange. Conversely, the Valley-Rainbow Project would link the relatively small SDG&E load (and its relatively small generation resource pool) only to the rest of southern California.

4. Scarcity Premium and Market Power Considerations

In its testimony, SDG&E states that, "For this study, Henwood set aside its bidding strategies that are normally incorporated into its modeling of markets. In its place, Henwood simulated a market where all commitment and dispatch decisions and pricing of power are based only on variable costs. Henwood believes this approach provides a conservative estimate of the calculated benefits." SDG&E October 5, 2001 Testimony at IV-2. In other words, Henwood implies that the economic benefits of the Valley-Rainbow Project would be greater than predicted by their production cost modeling if they applied a "scarcity premium." This assertion depends on the assumption that if generators could collect scarcity premiums in the future, greater value would result from relieving a transmission constraint than if resources are dispatched at marginal cost. However, the value of relieving a constraint is dependent on the relative difference in the market prices on either side of the constraint. The difference between the market prices on either side of the constraint with "scarcity premiums" could actually be smaller than the difference between market prices without "scarcity premiums" depending on the resource mix in the respective areas. Without properly modeling such "scarcity premiums," one cannot assume greater value would result.

In a related argument to Henwood's "scarcity premium" argument, ISO's testimony alleges that one of the economic benefits of the Valley-Rainbow Project would be to mitigate "market power." ISO October 5, 2001 Testimony at 12 through 15. "Market Power" is the ability of an entity to raise prices above competitive levels for a sustained period of time by its own actions in the market.

The concept of "market power" would be relevant to the Commission's assessment of the Valley-Rainbow Project only if: (1) the exercise of market power were shown to be a significant and likely problem in the future; and (2) the Valley-Rainbow Project were shown to have the potential to mitigate the adverse impacts of such market power. As I explain below, the ISO and SDG&E have not established either of these points. In fact, I believe it is likely that generators will be unable to exercise market power on a sustained basis in the future due to a combination of competitive forces and regulatory interventions, and nothing in the record indicates that the Valley-Rainbow Project would cost-effectively mitigate such a problem should it exist.

a. Neither SDG&E nor ISO Has Established that Market Power Is Likely To Be a Significant, Unaddressed Problem in the Future.

In addition to competitive forces that can respond to mitigate the potential exercise of market power in the long run, the state and federal governments have at their disposal powerful regulatory tools that have and could be used to deal with the issue of market power. The availability of these tools reduces the risk that market power will be a problem in the future.

One illustration of the operation of regulatory tools to control market power can be seen in the orders issued by the Federal Energy Regulatory Commission ("FERC") following California's recent power emergency. Prior to California's power emergency, market power was controlled only through reliability must run ("RMR") contracts, which the ISO negotiated with units that were critical to the reliable operation of the ISO-controlled grid. These agreements gave the ISO the right, in exchange for specific payments, to dispatch the units based on their incremental operating costs if the units were not previously scheduled based on market transactions. As long as sufficient supply was available to meet California's demand on an aggregate, statewide basis, the RMR contracts were sufficient to mitigate individual generator's market power, since those generators' bids were not used to set the market clearing price.

Beginning in May 2000, due to a variety of factors, RMR contracts alone were not sufficient to mitigate potential generator market power.[10] Recognizing this, FERC began a series of interventions, which included the following:

- Order setting a $150/MWh breakpoint above which generators had to justify their costs. (December 15, 2000).
- Order including a "must-offer" requirement during periods of reserve deficiency (Stage 1 emergencies and above) and a price mitigation plan based on unit-specific heat rates and proxy gas and emissions credit prices. (April 26, 2001).

[10] Those factors included load growth both inside and outside California, reduced availability of hydroelectric generation, planned and unplanned generation outages, increasing natural gas costs, increasing emissions allowance costs, and alleged withholding of generation from the market.

- Order extending the price mitigation to all Western states and amending that mitigation to reflect actual gas costs, but exclude emissions costs from the calculation of market clearing price. During non-reserve deficiency hours, the maximum price allowed was based on 85% of the highest hourly mitigated price during the last Stage 1 event. (June 19, 2001).

- Order taking steps to ensure that public utility sellers with market-based rate authority do not raise prices through anticompetitive behavior or abuse of market power. The order provides that "As a condition of obtaining and retaining market-based rate authority, the seller is prohibited from engaging in anticompetitive behavior or the exercise of market power.[11] The seller's market-based rate authority is subject to refunds or other remedies as may be appropriate to address any anticompetitive behavior or exercise of market power." The blanket ability to require refunds of rates charged above competitive levels due to anticompetitive behavior or exercise of market power provides additional protections to consumers. (November 20, 2001.)

As the above list of FERC's recent regulatory actions makes clear, the government has and, if necessary can in the future, engage powerful regulatory tools to mitigate the exercise of "market power" if the market structure does not yield effective solutions.

The ISO currently is in the midst of an extensive Market Design process to redesign the California market ("MD02"). An important feature of that redesign is

[11] Anticompetitive behavior or exercises of market power include behavior that raises the market price through physical or economic withholding of supplies. Such behavior may involve an individual supplier withholding supplies, or a group of suppliers jointly colluding to do so. Physical withholding occurs when a supplier fails to offer its output to the market during periods when the market price exceeds the supplier's full incremental costs. For example, physical withholding would occur when a generator declares a forced outage when its unit is not, in fact, experiencing mechanical problems, and when the market price is above the unit's full incremental costs. Economic withholding occurs when a supplier offers output to the market at a price that is above both its full incremental costs and the market price (and thus, the output is not sold). For example, we would expect that, during periods of high demand and high market prices, all generation capacity whose full incremental costs do not exceed the market price would be either producing energy or supplying operating reserves. Failing to do so would be an example of economic withholding. Withholding supplies can also occur when a seller is able to erect barriers to entry that limit or prevent others from offering supplies to the market or that raise the costs of other suppliers. Examples would include denying, delaying or requiring unreasonable terms, conditions, or rates for natural gas service to a potential electric competitor in bulk power markets. FERC November 20, 2001 Order.

market power mitigation measures. On February 27, 2002, the ISO released a preliminary draft paper, “Options for Discussion, Steps Necessary to Promote Workably Competitive Wholesale Electric Markets and Safeguard Against Exercise of Market Power.” In this draft paper, the ISO notes that “Market power mitigation is an indispensable element of electricity markets. Conditions can always arise in a power system such that firms can raise prices considerably above competitive levels even in the absence of scarcity (that would be legitimate for prices to go up).”

Because the ISO recognizes that market power can arise even in the absence of scarcity, and because the ISO recognizes that FERC could elect not to extend the market power mitigation measures currently in effect, the ISO is developing an alternative market power mitigation approach.

> “The CAISO’s proposed market power mitigation outlined below is designed to protect and foster competition and minimize interference with open and competitive markets while providing safeguards against significant market power abuse beyond September 30, 2002. The proposed alternative includes a four step process to achieve these objectives:
>
> I. Market design changes embodied in MD02 and other initiatives;[12]
>
> II. Damage control bid cap;[13]
>
> III. Resource specific bid screens and mitigation; and
>
> IV. An explicit standard for just and reasonable rates, which if violated would trigger the automatic implementation of a more stringent market power mitigation plan (e.g., re-impose June 19th measures or alternatively, impose cost-based bid caps on only those suppliers found to have exercised market power).
>
> The first three steps of this proposal are consistent with the market power mitigation approaches FERC has authorized for other ISOs.”

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12 Specifically, the CAISO’s recent FERC filing seeking additional authority to mitigate local market power and seeking penalties for excessive uninstructed deviations.

13 [Footnote omitted.]

Although the ISO's market power mitigation proposal is still under development, it is clear that the ISO is aggressively pursuing the development of a comprehensive market power mitigation program, which includes key elements that are consistent with approaches FERC has authorized for other ISOs.

b. Neither SDG&E nor ISO Has Established that the Valley-Rainbow Project Would Provide Cost-Effective Mitigation for a Market Power Problem, Should It Arise.

Even if the regulatory tools to mitigate market power described above should prove to be undesirable or inadequate, the project proponents have not quantified the impacts of potential market power abuses, nor have they demonstrated that the Valley-Rainbow Project would effectively address such a potential problem. I therefore do not think the Commission can assess any potential market power benefits of the Valley-Rainbow Project based on the testimony presented in these proceedings.

SDG&E's testimony acknowledges that it has not studied whether the Valley-Rainbow Project might mitigate market power. *See* SDG&E October 5, 2001 Testimony at IV-3. ISO's testimony takes the position that if a market power study like that conducted by ISO for Path 15 were conducted for the proposed Valley-Rainbow Project, it would show that the Valley-Rainbow Project would help curb market power. *See* ISO October 5, 2001 Testimony at 14, 15. Specifically, the ISO's October 5, 2001 testimony states that ISO's Path 15 expansion study showed "a substantial cost saving to load by mitigating the ability of suppliers in northern California to exercise market power." *Id.* at 15. The ISO states that it "has not had an opportunity to conduct a similar analysis for the Valley-Rainbow Transmission Project. Nonetheless, the results of the Path 15 analysis indicate that the market power mitigation benefits of a major transmission upgrade can be very significant." *Id.*

Although expanding Path 15 might provide benefits by mitigating the ability of northern California suppliers to exercise market power, the ISO has not demonstrated that a similar problem even exists in San Diego, much less that it would be effectively addressed by the Valley-Rainbow Project. Even if power suppliers in San Diego might have the ability to exercise market power during some hours, alternative remedies exist (e.g., RMR contracts, regulatory interventions). These options for addressing market power could be more effective and substantially less costly than the proposed Valley-Rainbow Project.

In summary, without further study, it is impossible for the Commission to determine: (1) whether market power is even likely to be a problem in the region in the future; (2) whether regulatory approaches are adequate to address the potential problem; (3) whether a new transmission line between San Diego and Southern California would effectively address market power; (4) whether the specific Valley-Rainbow Project as proposed by SDG&E would effectively address market power; and (5) what the projected economic benefit would be of addressing market power with such a new transmission line. Unless and until the project proponents can point to studies showing the contrary, the Commission should disregard any justification for the Valley-Rainbow Project based on its alleged potential ability to address market power concerns.

C. Economic Rationale #2: Avoided Customer Outage Costs.

Q: What is your assessment of SDG&E's testimony that the Valley-Rainbow Project would provide substantial cost benefits to ratepayers in the form of avoided customer outage costs?

A: SDG&E points to ISO estimates of the societal cost of 3 days of rolling blackouts that affected 500 to 1,000 MW of load in January 2001, and applies the ISO's cost methodology to value the 1,200 MW of load that was unserved during the San Francisco peninsula outage of December 8, 1998 in the range of $100 to $300 million. *See* SDG&E October 5, 2001 Testimony at II-17 through II-18. SDG&E then notes that its service territory load is much larger than the amount interrupted in the San Francisco event, and states that the cost of an SDG&E outage therefore would be much higher. SDG&E then concludes that "a very significant reduction in economic risk would be realized through the increase in SDG&E import capability made possible by the Valley-Rainbow Interconnect Project…." *Id.* This conclusion is not supported by SDG&E's limited analysis.

A proper assessment of the value of avoided outage costs attributable to the Valley-Rainbow Project would calculate the value of cumulative unserved energy both with and without the Valley-Rainbow Project. This assessment would consider the probability of a range of outage events and the incremental benefit that would be provided by the Valley-Rainbow Project in reducing the likelihood of such outage events. SDG&E has provided only anecdotal evidence of outages unrelated to the SDG&E service territory and the Valley-Rainbow Project. SDG&E has provided no evidence of the reduction in the number of outages and the corresponding unserved energy that could be expected to result from Valley-Rainbow Project, nor the value of such reduction taking into consideration the probability of occurrence. The Commission thus cannot assign an economic value of avoided customer outages resulting from the Valley-Rainbow Project based on the limited testimony provided by SDG&E.

D. Economic Rationale #3: Reliability Must Run Costs.

Q: What is your assessment of SDG&E's testimony that the Valley-Rainbow Project would reduce SDG&E's reliability must run costs?

A: SDG&E states that the Valley-Rainbow Project would increase SDG&E's non-simultaneous import limit capability by approximately 700 MW and thus would reduce the amount of reliability must run ("RMR") contract capacity required by this same amount. *See* SDG&E October 5, 2001 Testimony at II-18. Based on current RMR contract costs and assuming FERC continues its present position on such contracts, SDG&E estimates that this reduction in RMR expenses will save ratepayers approximately $14 million per year. *See id.* at II-19.

RMR contracts are used to ensure that generating units that are critical for the reliable operation of the ISO-controlled transmission grid are available for dispatch. RMR agreements give the ISO the right, in exchange for specific payments, to dispatch the units based on their incremental operating costs if the units have not been previously scheduled based on market transactions.

Although SDG&E has provided no details to justify its estimate that the Valley-Rainbow Project could save ratepayers approximately $14 million per year, it is clear that SDG&E assumes that the Valley-Rainbow Project would displace fully 700 MW of RMR requirements in San Diego, that RMR contract costs otherwise would remain at current levels, and that FERC will continue its present position on such contracts.

As Mr. Schmus' testimony and SDG&E's response to ORA Data Request No. 2 make clear, however, several generation projects are currently under construction and soon will be on-line in San Diego and North Baja. These projects could lead to a reduction in RMR requirements if the ISO considers that the new projects already will be operating under market transactions when needed for reliability. Moreover, as Mr. Schmus discusses in his testimony regarding SDG&E's reliability rationale for the project, SDG&E has understated its actual NSIL by ignoring the import capacity provided by recent upgrades to Path 45. Given that SDG&E's NSIL is in the process of being reviewed following the Path 45 upgrades and that new generation under construction in the San Diego area could reduce the RMR requirements further, the Valley-Rainbow Project would be unlikely to displace fully 700 MW of RMR requirements.

Additionally, FERC's position regarding RMR contracts may change. SDG&E, along with the ISO, PG&E, SCE and the CPUC filed a joint complaint at FERC on November 2, 2001 requesting that FERC investigate the "fixed option payments" payable under the reliability must run agreements. SDG&E's witness, S. Ali Yari, provided a declaration showing that the annual fixed option payments for the San Diego area RMR agreements total approximately $20 million. *See* ISO, SDG&E, PG&E, SCE Joint Complaint, November 2, 2001, Appendix F. This declaration also shows that the annual RMR costs that would be payable under the "net incremental cost" method advocated by SDG&E, PG&E and others would be approximately $1 million. Thus, if FERC changes its present position on RMR contracts and adopts the approach advocated by SDG&E, even if the Valley-Rainbow Project actually were to reduce the RMR requirement by 700 MW, the maximum benefit of this reduced RMR would be approximately $700,000 in reduced annual RMR expenses, assuming that the project would provide proportionally the same reduction in RMR costs under the proposed "net incremental cost" method as under the current "fixed option payments" method [i.e., $14 million divided by $20 million equals 70% reduction in RMR costs. 70% times $1 million equals $700,000].

Because the amount of RMR requirements displaced by the Valley-Rainbow Project are likely to be less than 700 MW, and the cost of meeting those requirements may be reduced if the FERC adopts the incremental cost methodology advocated by SDG&E, the Commission should discount the RMR cost reduction benefits claimed by SDG&E.

II. Assessment of ISO Testimony Regarding the Alleged Economic Benefits of the Valley-Rainbow Project.

Q: What have you concluded from your review of the ISO's testimony regarding the alleged economic benefits of the Valley-Rainbow Project?

A: In its response to the Commission's Office of Ratepayer Advocates ("ORA") October 29, 2001 Data Request, Question No. 1.6, ISO states that:

> "[T]he VRTP was initially approved by the governing board as needed to meet the ISO Grid Planning Criteria. However, given revisions in SDG&E's load forecast, and the developments related to proposed new generation, the project is no longer needed to meet ISO Grid Planning Criteria in 2004-5. Since, although it has reliability benefits, the VRTP is not needed to meet ISO Grid Planning Criteria in 2004-5, it is important to assess the economic benefits of the project and to confirm economic need, in accordance with ISO Tariff section 3.2.1.1. While the ISO believes that the VRTP has economic benefits, without a thorough economic assessment, it is not possible to confirm economic need."
>
> "As the ISO stated in its opening testimony, the ISO is working with state agencies and Participating Transmission Owners (PTOs) to develop a methodology to assess the economic benefits of major transmission upgrades. Once this methodology is developed it should be applied expeditiously to the VRTP, in order to quantify the benefits discussed qualitatively in the ISO's opening testimony, along with any other relevant factors that are identified in the development of the economic assessment methodology."

I agree with the ISO's and Mr. Schmus' conclusion that the Valley-Rainbow Project is not needed to meet ISO Grid Planning Criteria in 2004-05. I also agree with the ISO that it is impossible to determine whether the project is justified based on economic considerations without a thorough economic assessment. Based on my review of the analysis presented by SDG&E, I do not believe SDG&E's analysis is sufficient to confirm that the Valley-Rainbow Project is justified on economic grounds. It is possible that the economic analysis methodology referred to by the ISO, if developed and applied to the Valley-Rainbow Project, could produce a different conclusion. But, at this point in time, SDG&E and the ISO have not put forth economic testimony that justifies the Valley-Rainbow Project. Unless and until the proposed methodology referenced by the ISO is developed, assessed, and properly applied to Valley-Rainbow Project, as well as competing alternative transmission improvements and non-wires alternatives (e.g., generation and load management projects), there is no basis for speculating what the results of such a study might be.

Finally, the ISO argues in its testimony that the Valley-Rainbow Project should be built as part of the ISO's much broader overall strategy to install and upgrade a 500 kV "backbone" transmission system in California and the West. *See* ISO October 5, 2001 Testimony at 21 through 22. It is important to understand that because the Valley-Rainbow Project would involve construction of only a relatively short 500 kV line, it would not, in and of itself, contribute significantly to the much larger 500 kV "backbone" transmission system envisioned by the ISO. For transmission spanning long distances in California and the West, it can make sense to use 500 kV (high voltage) lines because they offer lower line losses and greater surge impedance loading than lower voltage lines. Over shorter distances, however, 230 kV high voltage lines are frequently the more cost-effective option. In fact, the shorter the distance involved, and the more likely new load and/or generation is to connect to the line at intermediate points, the more likely a 230 kV line is to make more sense than a 500 kV line.

III. Assessment of SDG&E's Plan of Action if Valley-Rainbow Project is Not Approved.

Q: Can you comment on SDG&E's description of its plan of action should the Valley-Rainbow Project not be energized by the summer of 2005?

A: In response to a request from Commissioner Duque to describe its plan of action should the Valley-Rainbow Project not be built, SDG&E states that "Unfortunately, there are no clear options for this turn of events. It places SDG&E largely at the mercy of the merchant generation developers with little or no recourse except to try to incentivize the needed demand or generation response through various programs that would be expensive to our ratepayers, such as peaker development contracts with new merchants or demand side management contracts (e.g., $125,000-$140,000/MW-yr. based on ISO benchmarks for summer 2001)." SDG&E October 5, 2001 Testimony at II-32.

In short, SDG&E expresses concern about being at the mercy of merchant generation developers to provide generation locally if the Valley-Rainbow Project is not built to import generation. This concern lacks merit. As Mr. Schmus' testimony shows, local merchant generation projects with more than enough capacity to serve SDG&E's anticipated needs are either already on-line or under construction. Other projects, representing over 1,200 MW, are under construction, including SDG&E's sister company's Sempra Imperial Valley Generating Project I.[14] SDG&E's argument also assumes that the 91 MW of peaking capacity from the existing Ramco Escondido

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[14] In addition to the in-basin generation discussed in Mr. Schmus' testimony, the following generation projects are under construction and will interconnect with the SDG&E system at Imperial Valley Substation: Sempra's Imperial Valley Generation Project I (600 MW), InterGen B Generating Facility Project (Phase I = 160 MW, Phase II = 440 MW). These projects were not counted for purposes of Mr. Schmus' N-1/G-1 reliability assessment because they would not be

and Chula Vista projects under contract to the State would not be available, since those contracts expire in 2004. As Mr. Schmus points out, this is an overly pessimistic assumption. If, for some reason, the capacity from the other merchant generation projects is insufficient, contracts could be negotiated with these peaker generators. Even if additional air emissions controls are required by the State for those generators, the incremental costs of such controls likely would be small relative to the cost of the Valley-Rainbow Project.

Finally, it is worth noting that in the unlikely event that there is insufficient generation to meet the SDG&E reliability needs, applying the demand side management cost numbers presented by SDG&E (i.e., $125,000-$140,000/MW-yr.) to SDG&E's estimate of the capacity shortfall (63 MW in 2005, 216 MW in 2006) results in annual costs of approximately $9 million in 2005 and $30 million in 2006. These amounts, which are unlikely to be incurred for the reasons stated in Mr. Schmus' testimony, should be discounted by their probability of occurrence. The resulting corrected annual costs likely would be substantially less than the $50-60 million annual carrying charge that would certainly be incurred with the Valley-Rainbow Project.

CONCLUSION

Q: Please summarize your conclusions as to the economic justifications for the Valley-Rainbow Project advanced by SDG&E and the ISO.

A: Based on my review of the testimony and analysis of SDG&E and the ISO for the Valley-Rainbow Project, I conclude that neither party has shown that the project is economically justified. The quantitative Henwood Study presented by SDG&E shows

fully available during an N-1/G-1 event involving an outage of the SWPL between Imperial Valley Substation and Miguel Substation.

no net benefits for most scenarios and benefits more on par with the project's costs only under unlikely and implausible scenarios. Further, the implausible scenarios (A1/D3, A2/D4) incorrectly attribute economic benefits to the existence of the Valley-Rainbow Project, when over 90% of the calculated benefits could be obtained without incurring the significant cost of the project. The other economically based rationales put forth by SDG&E and the ISO have not been sufficiently defined, including proper estimates of the probability of unlikely events occurring. Unless those alleged economic benefits are quantified (including an assessment of the probability of unlikely events occurring) they can not be used to justify such a significant expenditure as the Valley-Rainbow Project. Given that the ISO has testified that the Valley-Rainbow Project is no longer needed to meet ISO Grid Planning Criteria in 2004-05 and Mr. Schmus has shown that the Valley-Rainbow Project likely will not be needed for reliability purposes for several years beyond that time, the prudent course of action is to deny SDG&E's application at this time.

Q:	Does this conclude your testimony?

A:	Yes.

Exhibit 1

DOUGLAS A. BOCCIGNONE, P.E.

Professional Energy Experience

Flynn & Associates, California (USA) **Oct 2001 - Present**

Principal

- Provide strategic advice on complex energy-related business issues to municipal utilities, independent power producers, and large energy consuming companies.

Dynegy Inc., Europe and USA **1997 - 2001**

Vice President, European Origination, London (UK), Oct 2000 - Oct 2001

Managing Director and Chairman, Dynegy Italia Srl, Milan (Italy), Oct 2000 - Oct 2001

- Developed and implemented Dynegy's Italian energy market entry strategy.
- Developed relationships with key market stakeholders and customers, originated power and gas transactions, developed risk management product offerings.
- Opened and maintained office, including incorporation of the company, hiring and training of staff, management of consultants and leadership and supervision of business activities.

Sr. Director, Energy Marketing & Origination, California (USA), Feb 1997 - Oct 2000

- Structured and executed transactions with energy producers, wholesalers and retailers to purchase and deliver physical and financial energy commodities and renewable resource products.
- Developed asset optimization and power purchase off-take agreements with gas-fired and renewable resource generators.
- Originated and managed Dynegy's multi-year relationship supplying renewable energy to Green Mountain Energy, the leading small customer retailer in California.

City of Palo Alto, California (USA) **1994 - 1997**

Manager, Supply Resources, 1995 - 1997

- Led a group of seven professionals in Palo Alto Utilities' supply resources group responsible for electric, gas and water commodity price risk management, contract negotiation and administration, budgeting, billing analysis and payment, transmission and transportation planning, monitoring and intervention in legislative and regulatory proceedings, and interaction with outside agencies.
- Participated in working groups developing California's new electric market structure, including power exchange and system operator market clearing price and transmission congestion pricing approaches.
- Led effort to develop Palo Alto's stranded cost assessment and recovery methodology.

Resource Planner, 1994 - 1995

- Developed the Market Clearing Price billing concept for pricing the ten member Northern California Power Agency (NCPA) power pool transactions that greatly streamlined the pool billing process, allowed greater member control over purchase decisions and more fairly allocated pool costs.

Flynn & Associates, California (USA) **1988 - 1994**

Consultant

Electric Power Industry Consultant to independent power producers, municipal utilities, power marketers and large energy consuming companies.

- Managed analysts and engineers to meet client expectations for cost-effective results. Developed project schedules, set priorities for team members, reviewed work in progress and guided analyses to meet client needs and budget constraints.
- Projects included: Developed negotiating strategies and provided analytical support for a groundbreaking control area and transmission services agreement between Destec Power Services and Pacific Gas & Electric Company.
- Developed negotiating strategies and supported negotiations with the Central California Power Agency's bankrupt geothermal steam supplier and steam field royalty holders.

The MAC Group, California (USA) **1986 - 1988**

Sr. Analyst

- Supervised analyst project work, including financial model development and industry and competitive intelligence research for a leading international management consulting and litigation support services firm.
- Evaluated the strategic, economic, and organizational feasibility of establishing an independent electric distribution company spin-off of an integrated private utility company.

Employment During Student Years

- Business Analyst for **Applied Power Technology** a renewable resource development firm, 1984-1986
- Assistant to Rate Manager, **Electric Department, City of Santa Clara,** California**,** 1983

Publications

Applying Risk Management Concepts to Utility Resource Management,
The U.S. Power Market, Risk Publications, 1997

Energy Industry Presentations

European Power Finance Conference, California Case Study, 2001
European Energy ’99, California Case Study, 1999
International Energy Producers Association Workshop on New Market Structures, 1999
California Municipal Utilities Association Annual Meeting, 1998
Power ’97 Risk Management Conference, 1997
EPRI/EPS User Group Meeting, Risk Management Techniques, 1996

Professional Registration

Registered Professional Electrical Engineer, State of California (E14640), 1994

Education

Stanford University, Palo Alto, California 1984-1986
Bachelor of Science, Industrial Engineering and Engineering Management

Claremont McKenna College, Claremont, California, 1981- 1986
Bachelor of Arts, Management-Engineering
Magna Cum Laude, Phi Beta Kappa
A five year, interdisciplinary cooperative program between Claremont and Stanford.