ASSESSMENT OF THE VALLEY-RAINBOW TRANSMISSION PROJECT

Prepared for

Office of Ratepayer Advocates, California Public Utilities Commission

By

Sierra Energy & Risk Assessment, Inc.

Jerry B. Bagley
Harrison K. Clark
William S. Stephenson
Kenneth Z. Tang
Kenneth J. Weatherwax
Robert K. Weatherwax, Project Director

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I. INTRODUCTION

A. PROJECT BACKGROUND

In march of this year SDG&E filed its application for a Certificate of Public Convenience and Necessity for the Valley-Rainbow Transmission Project (VRTP), A.01-03-036. This proposed project is described as consisting of the following six major elements:

- SDG&E's proposed 500/230/69 kV Rainbow substation that would be located in northern San Diego County and would interconnect the new 500 kV transmission line initially with SDG&E's existing 230 kV transmission systems.

- A new single-circuit 500 kV transmission line, initially rated at approximately 1,000 megawatts ("MW") which would interconnect SDG&E's proposed Rainbow Substation with SCE's existing Valley Substation. This transmission line has the capability to increase the imports to or exports from SDG&E by from 700 to 800 MW in each direction.

- Edison's existing 500/230 kV transmission substation in south-western Riverside County would be modified to accommodate the proposed 500 kV transmission line from the proposed rainbow substation.

- The existing Talega – Escondido 230 kV line would have another circuit added, the new circuit tried into both substation and then looped into the new Rainbow Substation.

- A 7.7 mile section of the existing 69 kV transmission circuit, currently installed on one side of the existing double-circuit Talega – Escondido 230 kV transmission line structures and interconnecting SDG&E's existing Pala and Lilac substations, would be rebuilt on new 69 kV wood and steel pole structures adjacent to the existing 230 kV line. The rebuild of the 7.7 mile section of the 69 kV transmission circuit would make room for the proposed second 230 kV circuit just described.

- A 230 kV Static Synchronous Compensator ("STATCOM") would be added at the existing Mission Substation. Shunt capacitors would be added at the Miguel and Sycamore Canyon substations (230 kV). The STATCOM would provide dynamic voltage support and the shunt capacitors would provide continuous voltage support.

Our best estimate of the total cost of the project is about $350 million (See Appendix B) or roughly $450 per kW of effective capacity.

The project was first thought by the Applicant to be needed by the summer of 2004. Late last summer the on-line date was slipped to the summer of 2005 due to what the Applicant noted to be some reduction in the forecast of expected annual peak load in the SDG&E service area. The Applicant maintains that the project is justified on both reliability and economic grounds. The proposed 2005 on-line date is apparently attributable to the Applicant's concern that the SDG&E system would otherwise violate beginning that year an ISO reliability requirement which mandating that no loss of firm load shall occur following the combination of the worst line loss (*i.e.*, N-1) along with the outage of the area's largest unit on a summer peak day so severe that it would be expected with only a ten percent probability. In SDG&E's case the largest generator in Encina 5 and the largest single transmission contingency is the loss of the 500 kV Southwest Power Link (SWPL) which connects SDG&E's Miguel substation with the Palo Verde switchyards in Arizona via the Imperial Valley and Yuma substations. According to the Applicant's calculations, the amount of generation needed to endure this contingency in 2005 would be short by about 46 MW and would grow increasingly more deficit in the ensuing years thanks to load growth.

B. SCOPE AND PURPOSE OF THE INTERVENTION

The CPUC must render a decision as to the Need for the project later this year after considering its reliability and economic value and environmental impacts. Should it be determined that the project is needed then a determination of an authorized cost cap for the project has to be determined. To deal with these issues the proceeding has been split into two phases. During this first phase the need for and the cost effectiveness of the project is to be determined. In the second phase the appropriate cost and needed environmental mitigation would be determined for the project if is found to be needed.

The Office of Ratepayer Advocates (ORA) has the state delegated responsibility to participate in the examination of the economic value of the project relative to various alternatives maximize Ratepayer benefits. To assist them in this intervention they contracted with Sierra Energy and Risk Assessment, Inc. (SERA) to perform economic and engineering analyses specific to the reliability and economic need for the project and its appropriate cost. This report documents the data gathering and analyses perform by the SERA team to assist ORA and the overall Commission in their deliberations.

C. OVERALL STUDY DESCRIPTION

The major tasks that the SERA team is charged with carrying out during the course of this engagement are:

1. Perform reliability analyses appropriate to evaluate the claims of the Applicant as to the reliability benefits of the project. The primary tool that is employed for this task consists of power flow modeling of the SDG&E system in the context of the overall Western System Coordinating Council (WSCC) of which SDG&E is a member.

2. Perform economic assessments of the project and evaluate its potential contribution to reducing future ratepayer payments for power. In the quantifying of the possible economic value of the

project, the key tool being employed is the production cost model which can produce estimates of how much the presence of the project would annually reduce the cost of serving California's load.

3. Conduct a study of the components proposed for use in the project and their estimated cost of installation and maintenance. This runs the gamut from cost estimation to very sophisticated assessments of the functionality and value of each of the major components proposed for inclusion in the project.

4. Perform an integrated assessment of the project and all of its components. This assessment needs to consider carefully all potential alternatives including the No Project alternative, a range of delayed or modified Project alternatives and the substitution of other alternatives that might be either more cost effective or more more suitable for the required conditions.

5. The last major function of this engagement is to document our findings, critique the filings of the Applicant and other Intervener and be available for cross examination of the topics discussed in this report.

D. REPORT ORGANIZATION

The second section documents our findings, the rationales for those findings and the recommendation following therefrom. The third section tries in mostly qualitative discussions to describe the SDG&E system as we think it will be in about 2005, what are its major challenges and the role that the VRTP might play in meeting those system challenges. In this section reliability criteria are considered and applied, and various aspects of the overall electrical situation in SDG&E defined. This chapter should provide a good general understanding of the SERA team's view of the SDG&E system.

Section IV discusses the results of original powerflow modeling that was performed for this engagement and compares our determinations with those of the Applicant and their Consultants. Reliability benefits such as reduced susceptibility to voltage sags are described and to the degree possible quantified along with the level of losses savings from the project. Possible minor or major alternatives are also considered in the course of the analyses reported in this chapter and in Chapter III. As a adjunct to the reliability assessment, Appendix A provides a detailed critique of Applicant's pref-filed testimony on the reliability benefits of the project.

Section V provides a detailed assessment of expected total economic benefits of the project through 2010. The inputs to and the results of independent simulations of scenarios measuring VRTP's value are discussed and conclusions drawn. This section also discusses the Applicant's economic study presented in Section IV of their testimony. It compares their analysis with the one reported upon in this Section and describes reasons for and implications of specific results.

Appendix B provides a comprehensive summary our best current as to what the project would cost based upon Applicant's design and estimates. Additional detailed assessments of cost related issues and the need for specific, proposed components were from this report due to the bifurcation of the proceeding and the opportunity to present those analyses in the second phase of the proceeding.

II. SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

A. PROPOSED PROJECT

The Valley-Rainbow Transmission Project (VRTP) is a large, expensive and complex project that is being supported by arguments and scenarios that are only slightly less convoluted. In this sub-section we discuss the background for the project and how it evolved into the unusual state in which it is now found.

1. Background

VRTP has a very long and unusual history. It was being discussed and evaluated during the mid-1980s as one of a class of possible northward running transmission lines that would enable SDG&E to import more power into the system that also included consideration of a possible lines to Devers which is still further east.[1] These potential lines were initially most seriously considered during the period that the second Devers to Palo Verde line (DPV2) was under serious consideration.

After DPV2 was shelved the interest in the line outside of SDG&E lapsed until much more recently when San Diego had left the generation business, was aware of the extreme difficulty of any developer getting the pollution offsets necessary to site a new plant in the area and was concerned as to how it could continue to reliably serve its ratepayers. In this context it identified the need for the project based upon the combination of continued relatively strong demand growth in its Orange and San Diego county franchise area and the perceived difficulty in increasing the amount of firm power that could be imported from either of its north or south/east portals. Starting with the 1999 transmission planning process, SDG&E formally identified the project with an on-line date scheduled for 2004 assuming a continuation of business as usual for the late 1990s. This situation, of course, changed markedly starting in 2001 and extending through today. The high prices for power stimulated the market and initiated a huge increase in development of new generation. The high power costs were eventually translated into huge rate increases that coupled to scarcity triggered, increased conservation to depress current demand by ten percent or more. This combination of unforseen events has had a significant impact in San Diego as well as the remainder of the state and has thrown the prior SDG&E calculus for the need for the line into two disparate lines of orthogonal reasoning; *viz*, the perceived shortage was only postponed and will return soon or there is going to be such a surplus of power in San Diego and in Baja Norte that another portal to the north is needed to relieve the congestion through the San Diego area for the benefit of all.

The difficulty with these two positions is that they represent the two extremes when plotted on a continuum of possible load and resource balances in San Diego. Between them lies the vast majority

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[1] Even in the mid-1980s concerns over siting and the objections of those along the ROW were considered a serious deteorent to the building of the line.

of the possible outcomes. Currently San Diego plans in the context of being able to receive a firm 2500 MW of imports from their SONGS lines even in the face of the loss of the SWPL line. Before there is the meaningful need for greater export potential, the full 2500 MW imports to San Diego would have to be satisfied from other sources and the additional net about 350 MW of generation that could be exported north of SONGS from San Diego in addition to SDG&E's 420 MW share of SONGS output. This more than 2800MW of effective exports permitted under the current SDG&E grid is the first increment of increased generation into the San Diego service area that would have to be absorbed before any export project, VRTP included, would be needed in order to relieve any putative "bottled-up" generation in the San Diego Basin.

With this backdrop we turn to the analyses of the two tails of the load resource balance continue that are at the heart of the Applicant's case for the need for VRTP.

2. Project Need/Benefits

a Generation Shortage Scenario

As indicated in the previous subsection the initial reason that SG&E gave for proposing VRTP was based upon a simple numbers balance: The difference between a one in ten year summer peak load and the sum of all of its generation and permitted non-simultaneous import limit this became negative in 2004 by 408 MW if, at the time of annual system peak, the SWPL line was lost while SDG&E's largest indigenous generator (Encina 5 at 330 MW) was unavailable.[2] Needless to say this is a rather improbable event but does comply with the ISO G-1/N-1 reliability requirements for weathering a disturbance without the need to drop load. Not only was the design event for which the line was proposed unlikely but other key factors also changed thereby requiring a recalibration and a one year postponement of the on-line date.

In SDG&E's testimony they changed the shortage margin due to a reduction in the projected one in ten year load, and increase in the non-simultaneous import limit and some increase in the amount of generation present. The sum total of these changes delayed the negative margin until 2005 when it is now forecasted to be 46 MW growing to 199MW in 2006 assuming that no additional new generation is built after this fall.

Three elements of the load and resource equation have coincidentally to move against SDG&E's planning and now suggest that, based on SDG&E's balance algorithm approach, the line will not be needed for at least several years. As can be seen on the following table, a simple balancing of current events predicts that there will be a surplus of many megawatts well into the future.

[2]Page 1-5 of SDG&E's Proponents Environmental Assessment date March 2001

The difference between this load and resource and that propounded by Applicant are very straightforward and quite conservative. The 1-in-ten year load forecast was reduced by 29 MW in 2005 and 48 MW in 2006 based upon the latest CEC demand forecast.[3] Two other changes were made. The increase in local generation was a simple augmentation of Attachment 2 of Section II of Applicant's testimony to reflect two new peakers just now on-line in San Diego. The extra unit shown is the biggest single change and is extremely conservative. It can be viewed as the Otay Mesa Generation Project (OMGP) currently under construction or power from the new Rosita 7 550 MW power plant in Baja or generation from the Las Rosita 750 MW power plant currently under construction near Mexicali or some mix of generation from the first of two of the SEMPRA power plant, the AEP power plant, or the second Intergen power plant. The key concept is that with the upgrades to the interconnections between SDG&E and CFE, the equivalent of the full output of the OMGP will be able to be imported into SDG&E even in a G-1/N-1 event.

CONSERVATIVE SDG&E LOAD AND RESOURCE BALANCE WITHOUT VRTP

LOAD/RESOURCE CONTRIBUTOR	2005	2006
1-10 YEAR PEAK DEMAND	4491	4625
ASSUMED OUTAGE OF ENCINA 5	329	329
TOTAL LOAD	4820	4954
NON-SIMULTANEOUS IMPORT LIMIT	2500	2500
EXISTING GENERATION AS OF 1/2002	2486	2486
NEW GENERATION FROM OTAY OR BAJA	550	550
TOTAL SUPPLY	5536	5536
NET SURPLUS	**716**	**582**

Since there is so much generation coming into the Baja area in the next couple of years along with the 500 MMcf/d North Baja Pipeline which is complete below the border and planned to be completed and opened this summer. This pipeline will provide the equivalent fuel for about 3000 MW of combined cycle generation and almost the entire supply of the pipeline is subscribed to electric generators. Thus, it is certain that VRTP's value will need to be established on economic grounds if at all. We examine this question in summary next and in some detail in Section V.

b Generation Surplus Scenario

[3]CEC, Attachment A, California Energy Demand 2002-2012 Forecast, October 2001

For the Applicant's generation surplus scenario to obtain two critical elements must be present: (1) There must be generation available that exceeds the 2800 MW swing that constitutes the current capabilities of the SDG&E system north and south of SONGS and (2) there must be a market for the production from the SDG&E steam units. Both of these elements are quite implausible for different reasons.

In order for there to be more than 280 MW of surplus generation either a tremendous amount of new generation must come on line or the load in SDG&E's service area must be very low. Since the load will be very rarely below 2000 MW in the year 2005 and on those occasions -in the middle of the night in the shoulder months - there is almost certain to be no takers for even the cheapest generation from SDG&E. Thus it is reasonable to assume that there must be at least 2000 MW of extra generation before there would even be a load and resource surplus enough to export any generation. Further even if one assumes that the steam boiler generation would be marketable the total generation needed would have to be greater than 2000 MW to serve load + 2800 MW to fill the currently available export capability - 1682 MW in the steam units = 3118 MW The maximum that can be imported to SDG&E from the south after the second line between Mission and Miguel is built will be about 2360 MW or almost 800 MW less than the amount needed to initiate exports through VRTP. Thus, on a deterministic basis the line is useless for exports.

Conditions do varying unpredictable ways so various combination of situations can result in some higher levels of export than a deterministic calculation. Production cost modeling does permit just such a probabilistic assessment. As reported in Section V we have produced simulations using unrealistically high levels of cheap generation and have found no benefits in the early years and negligible benefits in the period after 2007. The reason for this result in that the model only very rarely encountered situations where the generators in SDG&E could export more than about 1500 MW due to the high cost of the Steam generation in the San Diego Basin.

Our analysis was done for median water situations. The Applicant's analysis looked at a 1-in-35 year drought case and did find some benefits in that highly unlikely case. However, as discussed in Section V the assumptions about increased generation in Baja was always coupled to the elimination of generation in areas from which otherwise, other generation would flow and thereby eliminate the benefit measured. Both modeling agree that in the absence of very peculiar resource growth, expected benefits are essentially none existent in the first few years and very modest at best around 2010.

One further surplus scenario by the Applicant deserves further mention. In the "If we build it, they will come scenario" they assume that only in the presence of VRTP will 1700 MW of incremental generators build at, or near the border. With that unsupported assumption more substantial benefits are seen. To test this scenario we modeled the first 600 MW of the Applicant's scenario to see if the generator actually benefitted from the VRTP. The answer was clearly no. In fact, it had no effect on the operation of the generator who ran by backing down the expensive steam units within San Diego and on occasion export a bit via the existing export capability. The same would apply to additional new generators. Thus, our results show absolutely no benefit to the N^{th} plant from the transmission line.

3. Project Costs

TOTAL COST OF VRTP BASED UPON APPLICANT'S ESTIMATES

VRTP Total Estimated Cost				
		2001 $	**Escalated to 2005$**	**Escalated $ w/AFUDC**
a	Rainbow Substation	$112,420,000	$115,277,000	$131,767,000
b	Valley-Rainbow 500 kV Transmission Line	99,385,000	105,504,000	125,974,000
c	Edison & VRTP Substation Additions	28,340,000	28,552,000	34,592,000
d	230 kV System Upgrades (230 kV 2nd ckt)	14,591,000	15,334,000	16,915,000
e	230 kV System Upgrades (move 69 kV)	3,631,000	3,726,000	4,123,000
f	Voltage Support Additions	28,991,000	31,314,000	36,244,000
	TOTALS	$287,358,000	$299,707,000	$349,615,000

NOTES

1. Basic cost data and escalation rates from SDG&E's November 16, 2001 response to ORA data request 74 as modified by errata provided on November 30, 2001.

2. Allowance for funds used during construction was assumed to remain at the current SDG&E level of 7.92 percent which was provided via e-mail from Mr. Steven Nelson, Esq., SEMPRA on January 18, 2002.

Using a realistic fixed charge rate of on the order of 18 % suggest that the cashflow from the ratepayers will be about $60 million per year. Generally speaking, a project such as VRTP should be brought on-line at a time when it can demonstrated that there is a high likelihood of it immediately producing the level of reduced costs necessary to satisfy the otherwise increase in rates that would result from the project.

4. The Evolving CAISO Position

Historically speaking, the ISO has been a strong supporter of the VRTP since it was first put forward by SDG&E during the course of the 1999 5-Year Planning Cycle. A separate stakeholder, stand-alone study was then conducted in early 2000 to more closely evaluate the need and timing for VRTP and this report confirmed that violation of the ISO Grid Planning Criteria were "expected to occur (starting) in 2004 as a result of serving the increasing local load in San Diego County and southern Orange County."[4] Since then the planning for VRTP has been anything but quiescent. Almost immediately after approving the project, the ISO Board issued a Request for Proposal for "non-wires" alternatives to the project which was then subsequently rescinded and the need for the Project reaffirmed as recently as March of 2001by the ISO Board for the Reliability purposes set forth in the original approval action.

The latest Board approval was concomitant with a major sea change in the electricity landscape in California. This change resulted in the rapid approval of many major Applications for Certification by the CEC, the invention and very rapid implementation of special peaker agreements that were to go through the CEC in less than about 90 days and featured relaxed emission standards and the full imposition of rate increases on the retail ratepayers including increases as high as 60 % for some of the SDG&E rate classes. these actions had a profound impact on the SDG&E franchise area. The AFC for the 550 MW Otay Mesa Generating Project (OMGP) in San Diego County was approved and construction initiated. A total of eight peakers with 380 MW of total capacity were licensed at the CEC by this summer and subsequently constructed and brought on-line by January, 2002. (See Table V-1) for details. Between the rate increases and a heightened awareness of energy use, the load in San Diego dropped precipitiously. There is a reasonable expectation of some "snap back" of a portion of the current load lost but even taking that effect into account, the SDG&E planners recognized the overall impact by reducing their 1-in-10 year peak load forecasts for 2004 and 2005 by 280 and 249 MW respectively.

This reduction in total net resource balance by 280 +380 = 909MW in 2004 and by 249+380 = 629 MW in 2005 excluding the contribution from OMGP of 550 MW in both years. SDG&E acknowledged this sea change by proposing to postpone the project by one year, The ISO response, in our opinion, was more in keeping with the extreme magnitude of the change as noted in the following response to an ORA data Request:

> *"As stated in the ISO's opening testimony, the 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.*** *(emphasis added) 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*

[4]Fluckiger, Kellan and A. J. Perez, Memorandum to ISO Grid Reliability/Operations Committee dated May 11, 2000.

> *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."*[5]

We, of course agree with the ISO's sentiments that the project is not needed for Reliability reasons in 2005 - at least. We also understand why the ISO would include the proviso that they think the project would be economic at the time this statement was made. However, based upon our more recent production cost analysis discussed in Section V the project in no where near economical.

5. Alternative Options

a Deferral Option

SDG&E presented several 500 kV alternatives to V-R, all of a similar or larger scale. We are inclined to accept SDG&E's evaluation of these alternatives. All appear more costly and/or less effective than V-R.

However, we believe there are a myriad of alternatives between a no project alternative and the V-R alternative. These alternatives could allow significant deferral of the V-R project or possibly full avoidance of it and any similar large scale project. Since there is much uncertainty about the future import and export needs of SDG&E, deferral can only lead to a better transmission system. A deferral is likely not only to reduce the cost of transmission, but would help ensure that when a major project is deemed necessary, the correct project will be chosen based on long-range planning and a better defined need.

b El Centro to Highline Project Option

We have identified one project alterative that could provide 70% of the import capability of VRTP for a small fraction of the cost of VRTP. We have also suggested several techniques for increasing the capability of the SONGS corridor, again at far less cost than the VRTP. Those options will be discussed *infra*. Here we focus on the alternative that we feel has probably the most merit based upon our state of knowledge at this time.

An El Centro to Highline 115 to 230 kV upgrade would provide 70% of the import capability of the VRTP. The El Centro to Highline project cost is dominated by a 20 mile Transmission line upgrade from 115 kV to 230 kV. This upgrade will likely cost less than $20 million. Substation and other costs in the area could double this figure. The total cost is likely to be less than one years' carrying charges on the VRTP of about $60 million.

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[5]CAISO, Response to ORA DR 1.6 responded dated November 21, 2001.

The export benefit of an El Centro to Highline 115 to 230 kV has not been examined and may be modest. However, were high exports needed with little advance warning, a remedial action scheme or special protection scheme could be used to drop some generation when certain outages occur. Such schemes are in wide use in WSCC.

B. RESULTS OF ORA SPONSORED BASE CASE ASSESSMENT

1. Likely Future Generation/Load Balance in SDG&E Service Area

As discussed, *supra*, we expect that in 2005 and 2006 the effective surplus for the SDG&E service area for most stressing L-1/G-1 event is 716 MW in 2005 and 582 MW is 2006. In subsequent years were there to be no additional generation built then the margin would decay with growth in demand. Regardless, there is a large generation surplus for sufficiently long to defer the VRTP indefinitely.

It is important to establishing the credibility of this conclusion to examine the two areas where SERA and SDG&E staff have different number; the total existing SDG&E generation and the ability to count on 550 MW from OMGP or its equivalent. Our estimate of existing generation exceeds that employed by Applicant by a total of 183 MW. Applicant's number is too ow for two reasons. They exclude the capability of two Ramco units with a total of 91 MW merely because they do not have, currently, contracts for more than three years of operations.[6] This is a real stretch in our opinion. These new units are reasonably efficient by steam boiler standards and extremely efficient as compared to other combustion turbines. It is far fetched to think they will not be able to operate during 2005 and 2006. If nothing else, SDG&E could treat them as a "non-wires" option and put them under contract for much less cost than the carrying cost of VRTP.

The Applicant fails to included two other new peakers possibly because they had yet to come on line when the testimony was filed. They are there now and must be factored in to the load and resource balance.

The other difference is our inclusion of 550 MW from OMGP or some combination of existing Baja units or those under construction. Two issues are related to this problem: availability of resources and appropriateness of counting such a resource in SDG&E's loss of SWPL critical disturbance. Until very recently, the question of OMGP failing to come on line by 2004 was not an issue. Calpine bought the rights to plant from approved from PG&E in much the say way that it bought what is now Los Medonos from Enron and proceeded to build it post haste. In addition, one of the Calpine contracts from DWR explicitly calls out Otay among others. Since those contracts are assignable by Calpine, it seems very unlikely that Calpine will walk away from this plant without, at least selling it along with its

[6] SDG&E Testimony, Chapter II dated October 5, 2001.

contract to a more financially stable entity such as Duke or Mirant which wold make its power easily available by 2005 to help SDG&E's N-1 Reliability.

Even were OMGP to be postponed for a couple of years, the new peakers would tide SDG&E over. In addition, the new upgrades that have already occurred and are in process on the interface between SDG&E and CFE will permit the Tijuana to Miguel line to be operated without being crossed tripped in case of the loss of SWPL as was heretofore the procedure. The new interface is rated at 800 MW and when the SDG&E Operations personnel get around to estimating its firm value in the face of the loss of SWPL, we are confident that they will find at least 550 MW can be treated as firm as discussed *infra*. We are confident that there would be sufficient generation ins Baja to provide the 550 MW if needed since, CFE has much new generation including the 550 MW Rosarita 7 which came on line this year, the Los Rosita 750 MW power plant is currently under construction and numerous other projects including two owned by SDG&E's parent company, SEMPRA, are either currently under construction or in an advanced planning stage.

2. Reliability Impacts

The VRTP can only affect transmission-related outages, so only those are discussed here. There are two approaches to evaluating the Reliability impacts of VRTP: one is based on rigidly applying the applicable criterion; the other is determining whether VRTP would be cost-effective. In addition, there are two basic scenarios to consider--(1) a significant amount of new generation will be operating by 2005, and (2) no new generation will be added.

Based on the Reliability Indexes provided by SDG&E (in response to our Data Request # 35), the frequency of transmission-related outages is about 6.5 percent of all outages, and the duration of transmission-related outages is about 4.2 percent of all outages. For simplicity, it is assumed that the amount of transmission-related outages is about six percent of all outages, representing a reasonable level of the proportion of the total energy that is not served due to outages.

If transmission outages were cut by half—from six percent to three percent--the overall reduction in customer outages would also be on the order of three percent. It can be seen that relatively large changes in transmission-related outage rates would have relatively minor effects on overall Reliability.

Regarding whether the project is cost-effective, some simple analysis can readily be done to shed some light on that. If VRTP were to cost something like $350,000,000 as presented in Appendix B then the annual cost would be about $63,000,000 per year, based on an annualizing factor of eighteen percent. The ISO has stated that a reasonable implicit unit customer cost for outages is about $25 per kilowatt-hour, or $25,000 per MW-hour. Dividing the annual cost ($63,000,000 per year) by the unit customer outage cost ($25,000 per MW-hour) gives a breakeven level of expected unserved energy (customer outages) of abut 2520 MWh per year. If VRTP would serve that much (or more) expected unserved energy (EUE) then it would provide an absolutely certain measure that it was needed. Unfortunately for the project, the Applicant has never asserted such a claim and since the project is being targeted at a 1-in-10 year weather event, the actual breakeven using this metric is ten times as much EUE or about 25,200 MWh

It should be noted that if additional generation were developed, as indicated above, the difference in unserved energy would essentially be zero, since there would be no supply shortfall. Next, assume no generation was added (such as Otay Mesa). There is no information indicating that even with this scenario, the combined events of having Encina 5 down followed by the loss of SWPL—each unlikely in its own right—have a high enough joint probability to remotely approach the break-even target of 25,200 MW-hours per year.

It should be noted that a somewhat detailed probabilistic analysis, using a load-duration curve and typical and/or expected outage rates (for Encina 5 and SWPL), could have been done. However, based on our opinion that sufficient generation will almost certainly develop—which will eliminate any transmission outages that could be attributed to not having VRTP--that analysis is not seen as necessary. Further, even if the generation did not develop past the existing levels reported by SDG&E, there is no information indicating that the difference in customer outages would approach the 2520 MW-hours required to make VRTP have sufficient Reliability benefits.

In summary, based on the information provided, the Reliability benefits of VRTP are either non-existent (if sufficient generation develops), or minor (if generation is frozen at present levels). The only argument that seems to support Reliability benefits for VRTP is strict adherence to planning criteria, combined with the premise that no new generation will develop and that some new generation will actually depart.

3. Project Benefits and Costs

a Production Cost Modeling Assumptions

As discussed in some detail in Section V we ran a series of production cost runs with the SERASYM/SERAM II WSCC modeling system to measure the benefits that might accrue to the California region from the presence of VRTP as a tool for export. To see what the benefits might be we prepared two sets of resources and ran both sets with and with out VRTP. The first set is called "High Generation" (HG) and it reflects a relatively robust installation of new generation that is under construction and expected to be on-line by 2003. The second scenario is entitled "Very High Generation" (VHG) and it increases the number os generators from that found in the High Generation case to pick up all the new generation being planned for Baja and some selected increased generation in the remainder of the state. In both cases here reported the transmission ratings for the VRTP were set at 800 MW and the export rating for the SONGS plant was set at 720MW. For the low generation case the import limit from Baja was set at 800 MW consistent with the current rating. In the VHG case the transmission rating from Baja was raised to 1400 MW to reflect the assumed rating consistent with the Development agreement between SDG&E and the Cross Border Generation group.

The second Mission Miguel Line was assumed in the VHG case only. This set of runs was done at median water conditions and with no enlargement of Path 15.

Natural gas prices and availability are important features in these simulations both in Baja and SDG&E and especially in comparison to the SoCalGas rate for electric generators. We chose to assume that the North Baja Pipeline (NBP) would be completed well before 2005 and at 500 MMcf/d in size, was pooled with SDG&E's supply including its recent 700 MMcf/d increase in deliverability after SDG&E's core, non-electric non-core and cogeneration loads were netted out along with residential and commercial demand in Mexicali. Interestingly because the SERASYM limited fuel algorithm was employed on these runs, it was determined that in the later years in the VHG case especially, there were some limitations on fuel use in the region and some minor use of residual oil by the SDG&E steamers, who were assumed to be able to continue to fuel switch as they did in the last two years.

Before reviewing the results it is important to recognize that we intentionally selected cases that were high in new generation in order to bias the outcome in favor of the proposed line. If these cases were not high in generation especially in Baja, it is obvious that the existing export capability which was normally used to import up to 2500 MW from the north could be turned around and increased to 2800 MW of actual export and displacement before VRTP would be needed to accommodate further exports. Were OMGP and others of the planned units in Baja not constructed then the need for the line for export would be non-existent and the absence of a Reliability need based upon new generators just now on-line.

b Economic Results

Table II-1 presents the results for the HG case. It can be seen that VRTP has absolutely no net impact on the system until 2007 when there is am estimated $200 thousand benefit. Troubling, there is an actual negative benefit in 2008 though it is only $144 thousand. (In reality, the addition of a new tie line should never cause a negative benefit as distinguished from some lines that actually increase Reliability risk.) The benefits in 2009 return to being positive but are minuscule. Overall, the total mixed year dollar benefits are $114 thousand. The results are little better for the line as presented in Table II-2. The overall

TABLE II-1

SYSTEM COSTS FOR HIGH GENERATION CASE

NO PG&E UPGRADE YEAR	NO VRTP $MILLION	VRTP $MILLION	VRTP BENEFITS $MILLION
2005	6882.424	6882.424	0.000
2006	7588.090	7588.090	0.000
2007	7830.275	7830.472	0.197

2008	8560.322	8560.178	-0.144
2009	9109.917	9109.978	0.061
2010	9909.942	9909.942	0.000
			0.114

TABLE II-2

SYSTEM COSTS FOR VERY HIGH GENERATION CASE			
NO PG&E UPGRADE YEAR	NO VRTP $MILLION	VRTP $MILLION	VRTP BENEFIT $MILLION
2005	6679.481	6679.481	0.000
2006	7341.628	7341.560	0.068
2007	7510.826	7510.452	0.374
2008	8215.031	8214.641	0.390
2009	8784.343	8784.702	-0.359
2010	9503.567	9503.567	0.000
			0.473

net benefit was $473 thousand. Much too small an amount to justify any portion of the line.

We also ran these cases with a enlargement of the Path 15 by 1000 MW in each direction . The results for these cases were unremarkable and showed nearly negligible benefits for the six year period.

Another interesting sensitivity cases was run in response to the Applicant's scenario in which they postulated that the presence of VRTP would eluctably lead to the siting of 1700 MW of additional generation in southern San Diego county. We refer to this case as the "If we build it, they will come" case. Since there were no reported cases of looking at the value of this case from the eyes of the generator with or with the VRTP in place, we choose to make a set of runs that tried to quantify the benefit from the line from the context of the developer.   To do this we started with the HG case and added a single 550 MW generator in both cases. We then compared the level of operations of that single unit in the presence or absence of VRTP. The results are presented in Table II -3 below:

TABLE II-3

BENEFITS TO NTH PLANT FROM VRTP						
	WITH VRTP		WITHOUT VRTP		VRTP BENEFIT	
YEAR	GWH	MILLS/kWh	GWH	MILLS/kWh	GWH	MILLS/kWh
2005	3537.50	23.81	3537.50	23.81	0.00	0.00
2006	3720.48	24.80	3720.48	24.80	0.00	0.00
2007	3606.91	26.30	3606.91	26.30	0.00	0.00
2008	3724.58	27.75	3724.58	27.75	0.00	0.00
2009	3727.43	29.19	3727.41	29.19	0.02	0.00
2010	3734.87	30.76	3734.51	30.76	0.36	0.00
	22051.77		22051.39		0.38	

Reported on Tab le II-3 are the annual generation and average cost of generation for each of the cases for the new plant. It is apparent from these results that the 380 MWh benefit is far too small to have any appreciable impact on the locational decision by a developer.

c Natural Gas Limitation and Environmental Impacts

As discussed above we assumed that there would be a pooling of the natural gas supply in San Diego and Baja with the presence of the NBP. We also assumed that all gas fired generation would draw from the same supply. As shown in Section V this supply varies somewhat with the month due to higher priority users and is most plentiful in the summer months. Especially in the VHG case but also in the HG case to a lesser degree we found that in the summer, the supply was not fully adequate to the demand. Our modeling assumed that the new CCs and CTs would not have a separate distillate or propane supply so their levels of generation would decline. We did, however, model the Encina and South Bay Plants in San Diego and Presidente Juarez Units 5 and 6 as being able to switch to residual fuel oil. In the HG and VHG cases that happens. Oil generation appears in San Diego in the summer so, if it were to occur, the emission problems would be substantially worse than as a result of the winter gas shortages that have occurred with some frequency in San Diego in the winter.

d Why is the VRTP of So Little Economic Value ?

Based on our detailed study of the project in the context of the San Diego system we believe that the explanation is as follows for the current system:

1. The persisting bottleneck between Mission and Miguel will trap efficient generation in Baja and

2. All the generation that is free to be exported via VRTP is north of Mission and not economically competitive with generation from the LA Basin.

See Section V.F for an example of how this might occur.

4. Cumulative Impacts of Project

The project *per se*, would have no cumulative impacts because the line would be little used and of very limited usefulness. To make it useful would require that it be at the terminus of inexpensive power. This could eventuate through the building of a 500 kV line to Rainbow from Miguel or some other portal for cheap Baja generation.

C. ALTERNATIVES

1. No Project Alternative

As discussed above. The line does not seems to be need for either Reliability or economic transfer of generation. Thus, the No Project option seems highly appropriate.

2. Highline to Imperial Transmission Link

a Thumbnail Description

An El Centro to Highline transmission line upgrade could provide 500 MW of import capability, 70% of that which VRTP would provide, at a small fraction of the cost of VRTP.

b Detailed Discussion

Edison purchases a large quantity of QF generation from geothermal QFs around El Centro. That generation is delivered to Edison through a relatively substantial 230 kV transmission system which is largely within the Imperial Irrigation District (IID). The generation is connected to two IID, 230 kV Substations, Highline and Midway--about 104 MW is connected at Highline, and 261 MW is connected at Midway, making a total of about 365 MW. That power goes north through the IID transmission system, connecting to two additional IID 230 kV Substations, Coachella Valley and Avenue 42, which are connected to the IID grid at 92 kV. Power continues north at 230 kV, past the IID substations, and ultimately goes to Edison at Mirage and Devers Substations. Any power not absorbed at the IID substations, or Mirage Substation, is generally absorbed at Devers Substation. Devers Substation is connected at 500 kV, to the west, to Valley Substation (the proposed terminal for the Valley - Rainbow project).

SDG&E owns and operates the Imperial Valley Substation. The SWPL, a 500 kV line connecting Palo Verde to Miguel Substation, is terminated at Imperial Valley Substation. (There is another 500 kV terminal at North Gila Substation, which is relatively small, and not a big factor in this discussion.) In addition, from Imperial Valley there is a 230 kV line to CFE's La Rosita Substation near Mexicali, and a 230 kV line to IID's El Centro Substation. It should be noted that although El Centro Substation is fairly close to the Highline Substation, there is no direct connection between them. From La Rosita there is a substantial local transmission network, and also two lines that go to the west, ultimately connecting to CFE's Tijuana Substation. El Centro is connected through a 230/161 kV transformer to a fairly substantial 161 kV network that ties the IID system together.

The original rationale for requiring the Valley - Rainbow project is an outage of SWPL. Loss of SWPL east of Imperial Valley resulting in a complete loss of the power source from the east. Virtually all power that was on SWPL prior to the outage would be shunted around the system to enter SDG&E from SONGS. An outage of SWPL west of Imperial Valley does not, in itself, sever the tie between Palo Verde and SDG&E. However, the effect is presently the same. Loss of SWPL west of Imperial Valley would cause much of the pre-outage SWPL power flow to go through the CFE 230 kV transmission system, which-for critical conditions--would have significant overloads. To avoid those overloads there is a RAS to open one of the ties between CFE and SDG&E, between Tijuana and

Miguel. That action keeps power from going through the CFE transmission system, eliminating the overloads. However, opening the CFE tie also removes all SWPL sources. Therefore, for a SWPL outage--east or west of Imperial Valley--no power from Palo Verde can presently get directly to SDG&E.

Building a relatively short (about twenty miles) 230 kV line from Highline to either El Centro or to Imperial Valley would create another source to the Imperial Valley. For an outage east of Imperial Valley, this would allow a significant amount of power to go from Highline (and also from Devers) to Imperial Valley and on to Miguel. Hence, there is a prospective solution that would allow at least some power from the Palo Verde area to get directly to Miguel Substation. This prospective new line-Highline to Imperial Valley-is not sufficient, though, without other reinforcements, since the CFE interface and some 230 kV lines within CFE could still overload.

The "Interconnection Capacity Expansion Agreement Between Comision Federal De Electricidad and San Diego Gas & Electric Company" dated August 15, 2001, seems to solve the problem of CFE overloads quite well. This agreement would reinforce the CFE/SDG&E ties between the two transmission interfaces, at Imperial Valley/La Rosita and Miguel/Tijuana, and also reconductor between CFE's Metropoli and Tijuana Substations. This would solve the transmission overloads described above, so that an outage of SWPL (east of Imperial Valley) would still result in having a tie which would allow a substantial amount of power to get to Imperial Valley, from Highline Substation. These reinforcements would also mitigate an outage of SWPL, to the west of Imperial Valley, by allowing power to get to Miguel via the CFE system. Based on power flow analysis, the above-described connection and reinforcements would allow something like 500 MW to get to Miguel for a SWPL outage.

Though this alternative seems to provide a significant amount of capability, at a reasonable cost, it may not be necessary.. Rather, the CFE reinforcements, in conjunction with expected generation additions in the Imperial Valley, La Rosita, and Tijuana areas, might suffice to mitigate the problem of a SWPL outage. However, if there were uncertainty about the generation development or the expected generation does not materialize in a timely fashion, then a Highline tie is an attractive potential solution.

In addition to its import capability, this proposed tie in conjunction with the CFE upgrades might have the potential for permitting more exporting from Baja as well. These grid components may provide a 230 kV path from La Rosita to the IV substation and on up to Highline and Devers and points north that would relieve the need for the power to flow through the SDG&E or be trapped in Baja should substantial development actually occur. This capability has been studied only very briefly by us so it would need to be carefully evaluated before its capability could be gauged accurately.

3. North of SONGS Upgrade

a Thumbnail Description

Currently it is generally agreed that there is a significant limitation on the ability to import more than about 2500 MW into the SDG&E service area from SONGS. This 2500 MW non-simultaneous import limit spawned the original argument for the VRTP. It appears that the limitations on the NSIL arise north of SONGS and may to susceptible to upgrade thereby increasing the amount of possible imports further postponing any possible need for VRTP from a Planning Criteria perspective.

b Detailed Discussion

SDG&E had indicated as recently as in its Year 2000 vintage of it Five Year Transmission Plan that it would construct projects to reinforce the transmission south of SONGS to increase its NSIL to about 2800 MW. This position has now changed to one where such upgrades are no longer useful, since there is a limitation north of SONGS that is more restrictive However, there seems to some contradiction about what that north of SONGS restriction is. At least some documents directly state that the north of SONGS restriction is caused by a contingency that would be in addition to the overlapping loss of Encina 5 and SWPL. Though beyond the scope of this analysis, we suggest that the various causes of the north of SONGS restriction be identified, and if it can be demonstrated that the restrictions are based on contingencies beyond a T-1 outage overlapping with a G-1outage then the NSIL should be increased accordingly because the Grid Planning Criteria do not impose the same performance requirements following an N-2 especially coincident with a G-1

As an example, in a document sponsored by SDG&E,"Comprehensive Progress Report of the 'South-of-SONGS Path Re-Rating", the following statement is made on page 9:

"The south-of-SONGS 2500 MW rating was established based on the following limiting conditions, in SCE system:

> 1. Under 2500 MW South-of-SONGS flow and SWPL open conditions, the loss of the SCE Del Amo - Ellis 230 kV line loads the Barre - Ellis 230 kV line to 99.8 % of its N-1 contingency "A" rating of 2850 amps. However, this is within the N-2 contingency "B" rating of 3210 amps."

The above seems to clearly have two T-1 outages--SWPL, and the Del Amo - Ellis 230 kV line. This seems a violation of the use of accepted criteria. First, an outage of SWPL is assumed, which is required to load the south of SONGS transmission to 2500 MW in the first place. (It seems very unlikely that the transmission south of SONGS could load to anything like 2500 MW without SWPL being out. In fact, if it did load that heavily with SWPL in service, then the subsequent loss of SWPL would cause an overload that may be now mitigated by the reinforcements being made in the SDG&E and CFE system.) Based on the above, restricting the south of SONGS flow to 2500 MW seems to be based on a spurious event. That situation is (1) loss of SWPL, so the transmission south of SONGS actually carries 2500 MW, and then (2) a subsequent outage of the Del Amo - Ellis line, which then causes the Barre - Ellis line to load virtually to its full capacity.

Another point is that the Del Amo - Ellis line is only 23 miles in length, so it should not have a particularly high outage rate. The historical record should be examined to determine if that line has a sufficient number of outages to justify using an N-2. Also, the overloaded Barre - Ellis line is only 13 miles in length. If the prospective overloading of that line is indeed the rationale for the limitation, the cost of reconductoring such a short line should also be considered.

There is no apparent ambiguity about whether an overlapping N-2 was the determining factor in establishing the above cited limitation on the path north of SONGS. We strongly recommend that it be definitively stated exactly what situations cause the south of SONGS to be limited to 2500 MW. Further, if the limitation is indeed caused by an N-2 condition, then the rationale for using an N-2 condition should be adequately and coherently made.

4. Other Options & Combinations

In the table below we list options and alternatives that should be investigated before a $350 million project such as V-R is undertaken. Even if one or more of these options and alternatives is used only to defer the V-R project or a similar costly project, a year or two they have great value at a $60 million annual carrying charge. As we've mentioned repeatedly, since there is, at least, great uncertainty as to the short and long-term need for V-R, deferral should be a goal.

All of the alternatives that we list below would require some engineering to define their import/export benefits and costs. For a few of them we have estimated the benefits and costs without benefit of such studies. Our estimates are thus very rough. Very low cost would generally be a few million dollars or less. Modest cost implies five to ten million dollars or somewhat more. High cost implies tens and in some cases hundreds of millions of dollars.

While some of these alternatives could be individual projects and make a significant contribution, most of them will be most effective when done in concert with one or more others. We have not done the engineering that would indicate how they could best be grouped.

We have not ascertained the relative impact of these options on imports and exports. Most are listed with imports in mind but would likely improve export capability to some extent as well.

TABLE II-4

No.	Project	Benefit/ Function	Cost
1	PARs on the SONGS or SWPL or other 230 kV lines	Maximizes use of SWPL & other lines	Modest cost
2	Bifurcation at SONGS to better utilize existing 230 kV lines	Potentially hundreds of MW	Modest cost
3	Dynamic line ratings or dual overload ratings, perhaps utilizing monitoring equipment	Potential increase of hundreds of MW	Very low cost
4	Load balancing north and south of SONGS (using series reactors or PARs)	Several hundred MW	Very low cost
5	Fixed phase shift PARs on V-R or projects similar to V-R. Easy design for 30 or 60 degrees but others possible at modest cost.	Much less costly than adjustable PARs	Reduces cost of projects
6	Remedial Action Schemes to drop generation on high export (excellent hedge to defer large projects)	Many hundreds of MW of export	Very low cost
7	Demand side alternatives	Depends on existing	low cost
8	Re-tension lines to eliminate sag bottlenecks to increase thermal capability of 230 kV lines	Potentially hundreds of MW	Very low cost
9	Standby/Peaking generation/power barge as a hedge against rapid load growth	Defers investment that may not be needed	Modest cost
10	Series reactor or PAR on the 230 kV path through Mexico to optimally use this path on loss of IV-Miguel	Potentially several hundred MW	Low cost
11	Uprate/rebuild the Escondido-El Centro ROW (currently operated N.O.)	Potentially many hundred MW	Moderate cost
12	Replace 230 kV with compact 500 kV, eventually from Serrano to Miguel and possibly two circuits. Would compliment a second SWPL line or deliver large MW from Mexico to SDG&E & Edison load areas. Reduces 230 kV necessary to reach SDG&E customers	Potentially much more productive than VRTP	High line cost but saves cost of new ROW
13	Fixed phase shift PARs. Easy design for 30 or 60 degrees but others possible at modest cost.	Much less costly than adjustable PARs	Reduces cost of projects

D. FINDINGS

1. Conclusions

a. Is the project needed for local/grid reliability?

The project is almost certainly not needed for grid reliability in the 2005 to 2007 period. The decrease in load observed in San Diego and the expectation that it will continue to be depressed in the future, the installation of nearly 400 MW of new peaking units in San Diego in the last year, the ongoing reinforcement of the CFE - SDG&E interface, the near completion of the North Baja Gas Pipeline and the large number of combined cycle plants currently under construction all combine to made the likelihood of the project being needed quite remote.

b. Is the project cost effective?

The project is expected to cost about $350 million by the SDG&E planners. For VRTP to be cost effective it would need to be expected to have value greater than its cost and to have annual benefits somewhat concomitant with the carrying charges. Our analyses conclude that the project have essentially no value in reduction of losses and it value in economic dispatch through 2010 is essentially negligible except under extreme conditions with very probabilities of occurrence.

c. How does the project compare with alternatives?

We do not believe that any major transmission projects are required in the time frame of interest, since it seems apparent that the problem has almost certainly been solved with the additional generation just installed in San Diego and the generation that likely will be built within and around the area. Nevertheless, there are reasonable alternatives to VRTP that deserve some discussion, based on the possibility that the SDG&E area will experience some major, unanticipated change in conditions. (These alternatives are discussed in detail in Section II C.)

2. Recommendations

a. Should the project be approved?

Based upon current conditions in San Diego, the actions of developers in the region and the depressed load, we believe that the VRTP is not needed and should not be approved.

b. Are there other actions/alternatives needed?

Yes, we believe that the following actions are all appropriate:

1. The progress of the NBP and generation projects in the area of interest should be tracked and the progress noted. If such prefects accelerate then additional action should be initiated though not of the scope proposed in this project.

2. The limitation north of SONGS is not clearly demonstrated or defined. Some kind of independent task force should review this issue, and report back to the CPUC with independent conclusions. It might be the case that the limitation is correct, but that is not obvious at this time. If the limitation north of SONGS can be increased, at some reasonable

cost, then a number of possibilities for increasing import capability would make economic sense further obviating the need for VRTP.

3. Analysis of the Highline alternative should be done. If it makes sense from a conceptual basis, then the estimated costs of doing that should be pursued. If it still makes sense, then permitting issues should also be pursued.

4. Proper long-term studies are needed to define strategically selected cost-effective options that can address any of the credible load and generation growth scenarios.

III. SDG&E RELIABILITY OF SERVICE

A. SDG&E SERVICE OUTAGES AND LOCAL RELIABILITY

There are many issues and claims regarding the impact of the proposed Valley Rainbow Transmission Project (VRTP) on local reliability within SDG&E's service area and regionally reliability covering the ISO Control Area. Much of the confusion stems from an imprecise definition of the term reliability among the electric utilities and their regulators and the evolving nature of the reliability concerns. In the instance of VRTP:

- The ISO board found and SDG&E still claims that the VRTP is required to meet reliability criteria for one generator and one line out simultaneously;

- The ISO staff has now representing that the line is not needed to meet the reliability criteria any more but still provides great reliability benefits to the system: and

- Our initial review of all the system analysis documentation surrounding the project does not obviously identify substantial reliability benefits apart from the satisfying the reliability criteria.

In the course of our engagement one of our major objectives is to establish the facts in these areas by (1) studying past power outages in the SDG&E area and how VRTP might have affected the course of the major outages; (2) analyzing the existing SDG&E and California transmission systems with and without VRTP: (3) analyzing likely future scenarios of load, generation and transmission resources for their reliability implications; (4) analyzing whether the presence of VRTP would have a significant effect on future area reliability and (6) performing powerflow assessments of peak and sholder hours to ascertain the manner in which VRTP would fit into the SDG&E's grid and affect its operations. All of these task save the last one are reported upon in this Section, The powerflow modeling is discussed in detail in Section IV.

1. General SDG&E Considerations

Outages experienced by SDG&E customers can be divided into three groups in accordance with the disturbances that caused them. The three groups are:

- Regional transmission events
- Local transmission events
- Distribution events

SDG&E's customers experience the vast majority of their outages and outage time as a result of events within the distribution system. The V-R project does nothing to enhance distribution system reliability and thus will not reduce the frequency and duration of outages in this category. The second most prevalent source of outages and outage time for SDG&E's customers is from regional events. A good example of such events are the July 2 and August 10 events of 1996. Regional events do not occur often, but tend to be of longer and much larger duration and so are significant in terms of impact. The very small remaining category of outages is associated with local transmission. The V-R project is in this category, as are SDG&E's 230 SONGS lines and the 500 kV SWPL line.

The VRTP would fall into the local transmission category because it would be a radial feed into the SDG&E load area. Further, it would not be particularly critical to the California or Western grid (as would, for instance, an outage on the 500 kV lines running east into Arizona or the main trunk lines running from Edison north through PG&E and into Oregon). An outage of the V-R line or on the SONGS path or the SWPL line will affect primarily only SDG&E. Even were SDG&E to export 1700 MW with VRTP as their planning suggests, outages of the lines through SONGS or the V-R line would have minimal impact on systems to the north of SDG&E.

2. Actual Experience and Reliability Objectives

There is no established reliability standard set by the CPUC. It is assumed that the California investor owned utilities will follow Rule 14, which basically requires that utilities exhibit a reasonable level of diligence. Another requirement is that service will be "reliable," with no effort to quantify what that means. This procedure is reasonable since there are events beyond the control of utilities-such as earthquakes and severe storms-which can result in prolonged and wide-spread outages. Rural areas generally have more outage exposure than urban or suburban areas making it very difficult to match the Reliability that is achievable in urban areas. Lastly, while increasing investment in transmission will generally improve Reliability, each incremental investment brings a smaller Reliability improvement. Increasing Reliability from very good to excellent can be very costly, likely producing a very low cost-benefit ratio in terms of the reduced outages to customers. Hence, a specific one size fits all set of Reliability criteria would be counterproductive and exceedingly difficult to achieve.

For virtually all utilities including SDG&E distribution-related outages are considerably more frequent, and result in far more unserved energy, than transmission-outages. In response to our Data Request question # 35, SDG&E provided information, in the form of two indexes, system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI), that indicates the following, for the period from 1996 through 2000.

	SAIDI	SAIFI
Distribution-related outages	89.4 %	85.8 %
Substation-related outages	6.4 %	7.8 %
Transmission-related outages	4.2 %	6.5 %

You may note that each index sums to 100% and most of the contribution to loss of load is from SDG&E's distribution system. SDG&E's transmission-related outages represent between four and seven percent of all outages.[7] The conclusion, based on our experience, and data provided by SDG&E, is that distribution-related outages have been and will almost certainly continue to be far more prevalent than transmission-related outages. Further, transmission-related outages include impacts on SDG&E customers from event throughout the western interconnection. The major events of 1996 are thus a significant share of the transmission-related outages experienced by SDG&E customers. Few if any outages resulted from SDG&E's own transmission lines. The significance of this is that mitigations to improve transmission Reliability of SDG&E's local transmission system will have a small and likely negligible impact, from a customer perspective. That is not to say that transmission Reliability should be ignored, or that cost-effective transmission projects should not be pursued; but, the benefits of these actions must be kept in context.

3. Major Transmission Related Outages

In relatively recent history, there have been several wide-spread outages caused by transmission failures. We will review them because they were the largest disturbances in recent years; they affected significantly SDG&E ratepayers; and we do not believe that the presence or absence of VRTP would have changed their local impacts.

On July 2, 1996 there was a widespread outage that was initiated in the Pacific Northwest partially attributable to a line sagging into a tree in an orchard in an EHV right-of-way. Within the SDG&E

[7] It should be noted that generation-related outages are not included. Generation-related outage rates are usually far lower than transmission-related outages, so not including those outages does not appreciably change the above conclusion.

service area it interrupted 232.5 MW of load and resulted in unserved energy of about 110.5 MWh.[8]

On August 10, 1996 there was another widespread outage, again initiated in the Pacific Northwest. It interrupted 880 MW of load resulting in about 1566.4 MWh of unserved energy within the SDG&E service area . This outage also caused the following SDG&E generators to be tripped offline: Encina 5 (205 MW), Encina 4 (118 MW), QF Naval TC (22 MW), and Yuma Cogen (51 MW). In addition it caused SWPL to open between North Gila and Imperial Valley Substations. When SWPL opened it was carrying about 757 MW.[9]

On July 17, 2001, an SDG&E operator was upgrading a RAS, and accidentally triggered that RAS, dropping about 150,000 customers, and a load of about 208 MW. The outage ranged from 10 minutes to 40 minutes, with 90 percent of customers having service restored within 10 minutes. WE estimate that the unserved energy for this outage would be about 35 MWh.

These major outages all have one thing in common-it is extremely unlikely that having VRTP in service would have made any difference. In answering our data response regarding the July 2001 outage (question # 36), SDG&E acknowledged that having VRTP in service would not have made any difference for the 2001 outage and, we believe that the same conclusion applies to the larger, regional disturbances as well.

The California ISO has used an implicit cost of $25 per kilowatt-hour of interrupted load for evaluating the customer costs of unserved energy. Using that number, the above-cited outages would have had customer costs of about $2,800,000; $39,000,000; and $900,000, respectively. In fact, were the VRTP in some way able to eliminate all transmission outages, the implicit equivalent outage cost saving would be about $150 per kilowatt hour.[10] VRTP would thus cost six times it's benefit if it could avoid all transmission-related outages experienced by SDG&E customers, on a historical basis. There is no documentation that the proposed project would improve Reliability measurably, let alone the amount needed to significantly reduces transmission-related outages experienced by SDG&E's customers.

B. ABSENCE OF TRANSIENT STABILITY ISSUES IN SAN DIEGO

Transient stability is the analysis of disturbances that includes “dynamic” components, such as the rotors of generators that can be accelerated by faults and as a result “pull out of step” causing a rapid system

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[8]Op sit, SDG&E Response to ORA Valley-Rainbow /SERA Data Requests Set#1, No. #37.

[9]WSCC Preliminary System Disturbance Report Draft dated 8/10/96.

[10]Found by taking the project cost of $350 million times 18% to get an annualized cost. This is then divided by the average annual transmission related outages in kilowatt-hours per year roughly estimated of about 400,000 KW hour.

collapse. Going through a large number of filings, there is no indication that SDG&E has stability problems. Indeed, the study work done by GE on the VRTP project examined transient stability and found no stability problem and thus no significant stability problem from VRTP. This is not surprising since the SDG&E system is quite compact and thus less susceptible to transient stability problems than systems with long transmission lines. Of course, there can be regional stability problems, such as those that happened on July 2 and August 10, 1996. Those problems were initiated well outside the SDG&E service area, and there is no indication that disturbances within SDG&E can readily cause such disturbances, or that SDG&E can do all that much to mitigate them. It should be noted, that one of the restrictions for transmitting power west from Palo Verde is stability-related. However, VRTP—or the lack of VRTP-- will not have a significant impact on that limitation.

We thus conclude that there is no measurable ,stability benefit that would help justify VRTP.

C. SDG&E'S SUSCEPTIBLITY TO VOLTAGE COLLAPSE

There can be several causes of voltage collapse. For our purposes, these can be reasonably limited to conditions where the system is—or becomes--deficient in reactive power. In a power system, if there is a reactive power deficiency, the voltages will sag. If the sag becomes excessive, a complete system collapse can occur. If there is a surplus of reactive capability, voltages can become too high. Generators can supply or absorb reactive power, and are used to control the voltage by balancing the reactive supply. Like most utilities, SDG&E uses shunt capacitors to supply much of the needed reactive power so that the reactive capability of generators is held in reserve for events such as line or generator outages that result in a need for additional reactive power. Hence, for any reasonable contingency, the generators will have enough reactive power to successfully regulate the voltage.

Customer loads take reactive power from the network. Some require nearly as much reactive power as they do active power (MW). Again, shunt capacitors are commonly used to supply the reactive demand of customer loads so that generator reactive capability is held in reserve. In their power flows, SDG&E shows a load var/watt ratio of about .125 on the transmission side of their distribution transformers, indicating a significant amount of capacitors are installed in the distribution system. In addition, transmission lines and transformers have reactive losses, which can burden the system. SDG&E has installed, and is installing, additional capacitors at a number of transmission substations to ensure that a reactive shortage does not occur for the more likely disturbances listed in Reliability criteria.

In addition, SDG&E has or will utilize under-voltage load shedding (UVLS) in accordance with ISO criteria to ensure that if a reactive shortage does occur, it is not likely to cause excessively low voltage and a system collapse. Typically UVLS goes well beyond the Reliability criteria and can handle very severe outages. The cost of UVLS is very low and reliable so it is practical to protect against very severe events even though such events are vary unlikely.

Based on SDG&E's studies and our power flow work, we find that the SDG&E system can be protected against voltage collapse by in-basin generators, generators in Mexico, capacitors, and UVLS for import levels well above those that are projected to occur in 2005, without need for VRTP.

D. TRANSMISSION RISK ABATEMENT OPTIONS

When conditions such as load or generation growth lead to violation of operating criteria and analysis shows that the probability of troublesome events is high and the consequences severe, a major transmission project may be warranted. Alternatively, some group of lessor projects may be as effective or sufficiently effective.

When the probability of troublesome events is not high or the consequences (such as under-voltage load shedding in the case of a voltage collapse problem) are more than can be tolerated, a RAS or SPS may be a practical solution. For instance, if a one in twenty year event that causes unacceptable consequences can be covered by dropping 100 or 200 MW of specific customer load, then the RAS or SPS is an option that should be considered. This approach is particularly viable where the condition under which the event is troublesome exists only for limited hours of the year. Likewise, when the condition has a low probability, an approach of this type may be used as a hedge against sudden and rapid generation development load growth that exceeds transmission capability defined in accordance with traditional deterministic Reliability criteria. In this case, the RAS or SPS may need to be applied for only a few years while transmission catches up with need. In another example, the condition may exist for only a few years because local load growth will offset the sudden generation growth in a short period of time. In this case the need for a new line may be only temporary, making the new line a very costly solution to a short-term problem.

Probabilistic analysis on large systems can be complex and difficult. However, in situations where only a few key elements are involved (e.g., the SONGS units, the SWPL line, the path 43 and 44, and V-R), the task is straightforward. Evaluating RAS and SPS on a probabilistic bases for such situations is eminently practical. Likewise, lessor alternatives or groups of lessor alternatives can be similarly evaluated.

E. THE SDG&E SYSTEM CIRCA 2005

In this section we discuss the how the San Diego systems operates now and how it will operate in the near future at about the time that VRTP would come on line.

1. Unusual Sdg&e Generation-import Balance

Most utility systems serve a significant percentage of their load from local (a.k.a. native) generation. For example, for many years contract agreements to which Edison is a party necessitated that it maintain between 40 and 50 percent of native generation at time of daily peak. This requirement was imposed because of the problems that losing imports might cause both to Edison and its neighbors. In San Francisco for many years generation within the City was operated at all hours to serve at least 40 to 50 percent of total loads to protect critical loads downtown in case its transmission link was severed.[11]

In contrast San Diego requires a lower level of local generation and is permitted to count its 400 MW of SONGS generation. Considering a typical load of about 3000 MW, it is easy to see that with 400 MW of generation from SONGS and just a little generation in the city, the total imports will satisfy most of the total load since up to 2850 MW of imports were permitted without taking account of the Baja tie-line upgrades. This operating approach is permitted due to extensive use of automatic load shedding (up to 80% as of 2001) in case of regional disturbances that result in the islanding of SDG&E.. The incentive to operate in this fashion stems from the consideration that SDG&E's local steam and combustion turbine generation is relatively expensive to operate. It once was described as an energy desert, so it looked to the outside for cheaper firm and economy energy supply..

SDG&E is proposing to thrust VRTP into this context and thereby permit the level of imports as a fraction of load to increase still further. This planned level of reliance on imported power, were it to be realized, would be unprecedented in such a large system to the best of our knowledge. Fortunately, as discussed next we believe that other factors have overtaken SDG&E planning and such an event will not obtain.

2. Impacts of Imports on Reliability of Supply

a Developmental and Operational Risk

SDG&E ratepayers will not be directly impacted by insufficient export capability, so our comments are limited to import capability,

SDG&E ratepayers could be impacted if a combination of high load growth and low generation development results in a need for imports beyond the currently available 2500 MW.

The 2500 MW import limit is purportedly dictated by the worst-case contingency, a "G-1/N-1" event, consisting of an overlapping outage of the Encina 5 generating unit and SWPL. Following this event only the south of SONGS corridor is presently available to handle imports, and it is purported to be limited to 2500 MW.[12] Higher imports would require that load be reduced upon disconnection of

[11]E.g., CAISO Operating Procedures T-126 dated 4/19/99.

[12] SDG&E's "Comprehensive Progress Report of the South-of-SONGS Path Re-Rating" dated March 23, 2001 indicates the SONGS 2500 MW rating is the result of reactive margin limitations on the Edison system during an overlapping outage of two of the corridor 230 kV lines. Since such outages should not be assumed to occur prior to or during an overlapping Encina 5 and SWPL outage, a higher rating for the SONGS corridor based on

Encina 5 or SWPL, whichever occurs second. If import is less than about 3000 MW load can be reduced in the minutes following the second event, possibly through operator action. Higher imports would require automatic load reduction triggered by the second event.

The probability of an overlapping outage of Encina 5 and SWPL during high load level (which dictates the high import) is low. The Encina unit likely experiences only one or two sudden outages each year, and is typically out for less than 24 hours from such events. The SWPL line likely experiences 2 or 3 sudden outages, most lasting only an hour or two. The probability of an overlapping outage is likely on the order of one event in 10 to 20 years. The probability of this happening during high load is on the order of one event in 20 to 40 years.

If the Encina outage occurs first, there will be an attempt to increase output of other generators so as to reduce the impact of a possible SWPL outage. Likewise, if the SWPL outage occurs first, the output of all area generators would be increased to lessen the import and resulting overload on south of SONGS lines should a subsequent Encina 5 outage occur. In both cases there may be limited generation, such as combustion turbines, available to reduce imports. To the extent other generation is available, the load that would have to be dropped during an overlapping outage would be reduced.

Customers that have signed up for lower rates in return for possible or occasional interruption would be interrupted first. Additional customers would be dropped in order of priority. The duration of the outage could be at least several hours, depending on the area demand, and whether it is an extreme case, where neither the generator or line can be placed back in service quickly.

b Response Time and Options

While the probability of having to drop customers as a result of the above severe contingencies is very low, it need never happen. The conditions that would require imports beyond the system capability are unlikely to come about on such short notice that nothing can be done about it. It is hard to envision a situation where the notice would be less than one or two years.

SDG&E has options that can be implemented in a year or less. Examples include:

- Series reactors in south of SONGS lines to balance loading in accordance with line thermal capability (so one line does not overload while another has yet to reach its thermal rating).

- Re-tensioning lines or adding conductor support at critical sag locations could add 100 MW or more to the SONGS corridor capability.

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all corridor lines in service would be appropriate.

- Re-visit line thermal ratings and/or implement dynamic line ratings.

- Some Orange County load could be "block transferred" to the Edison system so as to allow more room on the south of SONGS corridor for power flow to other SDG&E customers.

- Demand side alternatives might involve special temporary arrangements with large customers for rapid load reduction during emergencies.

- Adding shunt capacitors to solve any voltage problems that limit transfers.

A somewhat longer time-frame would allow the Highline-El Centro transmission project to be put into service. This option, coupled with the CFE and CFE tie upgrades that are planned soon to occur, could increase import capability by as much as 500 MW. Normally this would be a several year project, but under an emergency program, and recognizing that it involves upgrading an existing line on an existing ROW, we believe this project could be complete within two years.

3. SDG&E'S Planned and Updated Load and Resource Balance

SDG&E represents that in the near future they will not have sufficient combined generation and transmission facilities to serve their customers for a certain condition, a G-1 outage overlapping with an N-1 outage, during peak conditions. For those conditions the Applicant's planning determines that it would not be possible to serve all of the SDG&E area load. SDG&E uses a simple algorithm to demonstrate this perceived shortage. There are two supply components. One is the available area generation, which was provided as an answer (# 1.23) to our data request. The second is the amount of transmission import capability, called the non-simultaneous import limit (NSIL).

The algorithm adds the available generation capability, and the NSIL rating, and subtracts the largest generator (Encina 5), assuming that it could be out of service. The second supply component is the NSIL, stated to be 2500 MW. If the forecasted load exceeds that combined number, then it is concluded that the combined generation and transmission system is deficient. Using the results from SDG&E's testimony[13], and subtracting 329 MW for Encina Unit 5, results in available generation of 1974 MW by SDG&E reckoning which includes excluding two new peakers in the San Diego Basin because they don't currently have long term contracts. Adding the NSIL of 2500 MW gives a total capability for serving area load of 4474 MW.

SDG&E released a revised load forecast in October 2001, which contains several forecasts, based on estimated probability of occurrences. It has been generally accepted that the analysis to be used for the purpose of evaluating Valley - Rainbow will use a 1-in-10-year forecast. That means that the

[13] Attachment 2 to Section II of SDG&E October 5 testimony

forecasted load used would-on average-be exceeded about once every ten years; nine out of ten years the load would be somewhat lower than the forecast. As an example, a 50/50 forecast means that there is about an equal probability that the actual load will exceed the forecast, versus the equal probability that the load would be less than forecast. According to that forecast, load (one-in-ten) would be 4355 MW in 2004. This is lower by 119 MW than the critical level of 4474 MW, so no reinforcement is required in 2004 using San Diego's estimates. Their forecast for 2005 is 4520 MW, 46 MW greater than the presumed capability. Therefore, based on the algorithm and above information, system import reinforcements are required before summer 2005.

Here, it is useful to consider another point. It is indicated that it might not be possible to serve all area load for the above conditions. This raises a point about the utilization of interruptible loads. It is commonly thought that interruptible loads are to be interrupted only if there is a shortage of supply, usually considered to be generation. The described conditions, though, seem eminently be precisely that-a shortage of supply. There is no indication about how much interruptible load is presently within the SDG&E system. It might be enough for a one-year deferral. If not, there should be some indication of how much more interruptible load could be made available, particularly if a tariff were tailored for this particular situation. A one-year deferral would probably save enough to justify a tariff that would entice enough customers to accept interruptible service.

However, the data supplied by SDG&E does not include all new peakers on line, generation under construction, or generation that is very advanced in the permitting process. There are four different types of generation that are deserving of discussion. First, clearly units that are finished should be counted even if their contracts after 2004 are not currently nailed down. Second, we have concluded that most generation under construction will in fact be finished. Third, we have reasonably concluded that certain generation with advanced permitting-meaning that a significant financial investment has already been made-will also be built before 2005. Fourth, there are several generators which have target operating dates of 2005 or before, which seem more problematic to assume would be operating in 2005. For our analysis, this last group was not assumed to be available for 2005.

Peakers excluded consist of about 183 MW. Major generators that are likely to be available by summer 2005 include (1) 550 MW at Otay Mesa; (2) 250 MW at AEP Resources, near Otay Mesa; (3) 160 MW at Intergen B phase 1, near Imperial Valley; (4) 550 MW at Sempra # 1, near Imperial Valley; and (5) 750 MW at LRPP, near La Rosita Substation, in CFE (which is near Imperial Valley). A major generator, 550 MW, Rosarita 7, has been operating since May 2001.

The significance of these generators is that Otay Mesa and AEP Resources-totaling 800 MW are both within the SDG&E service area. This would make the available in-area generation up to 2957 MW in 2005. When the NSIL is added, the total capability for supplying the area as high as 5457 MW, some 966 MW above the CEC forecasted load for 2005 of 4491 MW.

The further addition of generation near Imperial Valley, La Rosita, and Rosarita also has a significant impact. Agreements have been made to reinforce the SDG&E/CFE transmission interfaces, and to reconductor a critical line near Tijuana. In conjunction with the added generation, this certainly should have the effect of making substantial deliveries from CFE to SDG&E firm, via the Tijuana to Miguel tie. This is discussed in more detail in Section IV. Based on power flow analysis discussed in Section IV, it seems that at least another 500 MW would be firmed from CFE, including generation connected to the SDG&E system at Imperial Valley. The net increase in capability would be the sum of 666 MW (new generation within SDG&E) plus at least 500 MW from firming CFE delivery capability, for a total of at least 1166 MW. This would push the timing of required reinforcements very far into the future. Even under very pessimistic assumptions that no new generation would be forthcoming, the surplus would be over 716 MW in 2005 and about 582 MW in 2006.

Based on (1) the additional generation within the immediate SDG&E service area, (2) other generation to the south and east, and (3) planned transmission reinforcements, there is no compelling reason to reinforce the import capability beyond that discussed, the CFE interfaces, and CFE reconductoring.

4. Some Additional Considerations about the Value of the Sil

SDG&E has five 230 kV transmission circuits from SONGS switchyard to SDG&E 230 kV substations. Three of the circuits go to San Luis Rey Substation, and two go to Talega Substation. The three circuits to San Luis Rey each have a capability of about 796 MW normal and 912 MW emergency; the two circuits to Talega each have a capacity of about 456 MW normal, and 578 emergency. There is also a 500 kV line, called the SouthWest Power Link (SWPL), which connects Palo Verde Nuclear Plant and SDG&E's Miguel Substation, with a capacity of about 1212 MW. (The ratings are, in fact, based on ampacity at nominal voltages. Also, the ratings are not based strictly on MW, but on MVA. Since the prevalent voltage is generally considered close to the nominal voltages (230 and 500 kV), and the power factor is close to unity, only a modest amount of error is introduced by assuming that the ratings can be converted to MW, a form more useful for comparisons.)

Of interest, it is stated that loss of SWPL is a major factor in the need for Valley - Rainbow. However, there is no information provided on how often SWPL is not available, or the causes of the unavailability. Outage rates for transmission lines are generally low; however, this line is 278.5 miles in length, so the length alone would create a significant amount of exposure to outages. To make the documentation more complete, information should have been provided indicating the frequency of outages, particularly during summer peak type conditions, and the causes. It is likely that there are a variety of causes; however, lacking such information, it could be seen as plausible (1) that there are very infrequent outages, and (2) they could all have the same cause. That could mean some kind of outage avoidance should be considered in lieu of building a very expensive transmission project.

For the above-described conditions, emergency ratings should reasonably be used. The total emergency rating of the five 230 kV circuits south of SONGS is about 3544 MW. However, those rating cannot realistically be achieved, since that would require a perfect split between the circuits going to San Luis Rey and those going to Talega. Also, it is represented that there can be loading problems on lower voltage lines. Most important, though, is the fact that it is represented that the south of SONGS rating is limited to 2500 MW due to loading problems north of SONGS. At this time there is not enough available information to provide conclusive comments on the 2500 MW limitation north of SONGS. It should be noted, though, that this is not a minor matter. If the limit north of SONGS were somewhat higher, it is very likely that there would be cost-effective ways of increasing the NSIL south of SONGS. For now, though, that consideration is beyond the scope of this analysis.

It should be noted, though, that based on information in the "Comprehensive Progress Report of the 'South-of SONGS-Path Re-rating'" (page 9) that limitation (2500 MW) could be based on an N-2 condition. Were this true then the import limit in SDG&E would be based upon an N-4 event and incredibly over protected.

IV. POWERFLOW MODELING RELATED TO THE NEED FOR VRTP

A. PROJECT VERSUS NO-PROJECT ALTERNATIVE

1. Introduction to the Powerflow Modeling Assessment

SDG&E and the ISO initially argued that without the Valley Rainbow Transmission Project (VRTP), the WSCC and ISO reliability criteria for the transmission system would be violated in 2004, and with VRTP the reliability criteria would be met. SDG&E and the ISO determined that the violation of the reliability criteria created a reliability need for VRTP and led to the CAISO's endorsement of this project, now said to be required by summer 0f 2005.

Following is the key reliability scenario that first triggered the asserted need for the VRTP. There was concern that an outage of the Southwest Power Link (SWPL) that overlaps the outage of the biggest generator within the SDG&E service area, during the system peak load, would overload the set of transmission lines south of SONGS. This would force operators or automatic devices to drop load to avoid damaging those lines. This would be a violation of the criteria in that loss of load is not considered acceptable for this outage.

To evaluate the claim of a reliability need, we took a close look at the potential for violation of the WSCC reliability criteria under more recent and more realistic assumptions of SDG&E loads and new generation coming on line in the San Diego Basin and Mexico.

SDG&E's studies show that this event does not involve angular stability, which would require dynamic simulations. Therefore we were able to apply power flow modeling to study the effect of recent load forecasts and forecasts of generation and transmission import capability. We modeled the SDG&E system forecasts for summer peak 2005, when SDG&E currently asserts is the necessary first year of operation of VRTP. We looked at the 2005 conditions first without VRTP and then with VRTP. In both cases we studied the one-in-ten year system peak load (a load level that is projected to have a 10% probability of being reached or exceeded in any year).

2. Key Modeling Assumptions

Power flows were run for the 2005 Heavy Summer condition.[14] They were based on a fairly recent case made available on the ISO web site, and adjusted to use SDG&E's October 2001 forecast, which

[14]Powerflows were run with GE ps Version 12.0.

showed a one-year-in-ten load level of 4520 MW for summer of 2005.[15]

The power flow cases were run with generation added in the SDG&E/CFE tier of the transmission system, as follows.

1. Seven nominal 49 MW peaking units added in the SDG&E service area.

2. Otay Mesa, 550 MW combined cycle power plant (CCPP).

3. AEP Resources, 250 MW CCPP, near Otay Mesa.

4. Intergen B Phase 1, 160 MW C/T, near Imperial Valley.

5. Intergen B Phase 2, 440 MW CCPP, near Imperial Valley.

6. Sempra, 550 MW CCPP, near Imperial Valley.

7. Rosarita 7, 550 MW CCPP, south of Tijuana.

8. LRPP, 750 MW CCPP, near La Rosita Substation.

These particular projects were modeled because we believe there exists a strong probability that they will, in fact, be developed within the time frame of concern. They are either already built, in the process of being built, or there is sufficient investment in the project. Likewise, the gas supply line, the North Baja Pipeline (NBP), seems likely to complement their timely completion.[16]

Prior to adding these generation projects, all the area steam turbines were shown as being on-line as well as some of the existing small combustion turbines. When we added the new and very economical projects listed above, we turned off all of the older combustion turbines and reduced generation at South Bay and Encina, as a reasonable approximation to economic dispatch consistent with production simulations done for this system, as reported in Section V.
New transmission projects reinforcing the CFE -SDG&E interconnect, (i.e., Path 45) were also included. Though the full extent of the just completed, in-process, and prospective reinforcements to the SDG&E and CFE transmission are not precisely known, certain of those reinforcements have been described in reasonable detail and were modeled as follow:

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[15]The case was run from RMR 2002-04 TECH STUDY - from WSCC 2003 HS2-SA.

[16]The 500 MMcf/d NBP will run from The TNP pipeline south of San Diego to Ehrenberg in Arizona. The Baja portion comprising about 75% of the pipeline is complete and the FERC just authorized the building of the American portion subject to final environmental approvals.

- The lines between Imperial Valley and La Rosita were reinforced to become two circuits, bundled ACSS conductor,
- The second Miguel - Mission 230 kV circuit was included,
- A second 500/230 kV transformer was shown at Imperial Valley,
- The Metropoli - Tijuana 230 kV circuit, reconductored to an ACSS conductor, was included, and
- The transmission between Tijuana and Miguel was assumed to be reinforced with bundled ACSS conductor

These CFE interface and CFE line reinforcements are discussed in the latest Interconnection agreement between SDG&E and CFE[17] and in the agreement between SDG&E and the Border Generation Group's Joint Milestone Schedule, filed in I.00-11-011,[18] titled Construction of New Generation Projects, executed December 3, 2001. At this time we do not know what additional transmission reinforcements will be installed. For this analysis we have assumed that no other reinforcements would be added.

3. Powerflow Results

Our power flow analysis shows that in the no project base case (with all lines in service), there would be the following loadings: 1066 MW on the south of SONGS entry; 1054 MW on SWPL; and 504 MW entering from CFE at Tijuana. The power flowing from SWPL into Miguel is about the same as for a case without the generation and transmission changes. The SONGS entry flow is reduced considerably due to internal generation and increased flow from CFE via Tijuana Substation.

We expect the SWPL outage to remain the single most critical outage. An overlapping outage of SWPL with and Encina 5, the largest single generator in the SDG&E service area, will still probably be the critical transmission scenario. This is consistent with the ISO criterion that requires survival of the most challenging overlapping transmission (T-1) and generator (G-1) outages without loss of load. It is expected that Encina 5 will remain the single largest generator in the SDG&E service area even after construction of the new projects listed above.

In addition, San Diego has assumed that outage of the largest generator cannot be compensated by an increase in output of other in-basin generators, and thus assumes imports must increase upon the generator outage. This was due to the fact that all of the in-area generators would be running at

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[17]Interconnection Capacity Expansion Agreement Between Comision Federal De Electricidad and San Diego Gas & Electric Company dated August 15, 2001

[18]I.00-11-001, San Diego Gas & Electric Company and the Border Generation Group's Joint Milestone Schedule Coordinating Construction of the Miguel Mission and Imperial Valley Upgrades with

maximum levels, hence cannot be increased. This means that if the system sustains the critical G-1/T-1 event, it is hit with both an increase in imports and a transmission outage that constrains import capability. Based on presently available information we question this assumption, given the forecast amount of generation being added in the basin and in Mexico. To the extent this new nearby generation could cover an outage of Encina 5, the import increase would be reduced, and would not so heavily compound the effects of the SWPL outage. However, for now we have assumed that an outage of Encina 5 would require an increase in imports.

Power flows were run for an outage of the section of SWPL between Imperial Valley and Miguel, with Encina 5 also being down, and with the transmission reinforcements and generation additions previously noted. There were several modest overloads in the CFE 230 kV system, from east to west. To find a mitigation for these overloads, another case was run that curtailed 300 MW of generation in the Imperial Valley area. That generation reduction mitigated all overloads. Further, it appears likely that significantly less than 300 MW of generation would need to be curtailed to remove these overloads. Thus, through the use of operator action or a very commonly implemented Special Protection Scheme (SPS) that automatically drops or reduces generation upon certain conditions and events, the system easily weathers the G-1/N-1 test without VRTP.

Based on our assumptions used in the analysis, the VRTP is not necessary to support imports in 2005, and probably for a significant period of time beyond 2005.

To explore the export benefit of the VRTP in 2005, we ran power flow cases at a load level corresponding to 70 percent of the peak load in the SDG&E service area. This load level increases potential exports, and is a credible case for investigation of whether VRTP is needed to support exports. Generation was unchanged from the peak case in order to maximize exports. This includes high running-cost peaking combustion turbines within SDG&E territory that would surely not be operating under partial peak export conditions. Likewise, older generators at Encina and South Bay are unlikely to be running at the levels represented in these power flows. Nevertheless, they were left at relatively high levels in order to overstate the export demands. In this case, the 230 kV north of SONGS (Path 43) carried a total of 2005 MW, well under its Path limit of 2440 MW.
Based on this power flow analysis of potential export needs, there seems to be no Reliability or export basis for reinforcing the system with VRTP in 2005.

4. The Impact of VRTP on System Operation and Losses

In addition to examining the Reliability benefit of VRTP, we also analyzed the project's effects on system line losses. Under the right circumstances, a transmission project can yield benefits to generators and consumers by reducing transmission line losses or other system operation costs. These benefits occur during normal operation rather than during the few hours each year when major outages stress the system. Hence normal, routine operation is studied. Our study was able to quantify such benefits associated with the VRTP, to see if they constituted a significant reason to support construction of the project.

A power flow case with the VRTP included was run for the 2005 Heavy Summer conditions. In this case the VRTP includes a 500 kV line from Edison's Valley Substation to a new Rainbow Substation; one 500/230 kV transformer at Rainbow; and two 230 kV circuits between Talega and Escondido Substations looped into the new Rainbow Substation. This forms two Rainbow - Talega circuits, and two Rainbow - Escondido circuits, for a total of four separate 230 kV circuits to deliver power to or from the VRTP. Additional station equipment at Rainbow included a phase angle regulator (PAR) to control the direction and amount of power flowing between Valley and Rainbow Substations.

For this case, the PAR was set at a "neutral" point, meaning that power was not being forced to flow in either direction (power was allowed to flow as it naturally would if the PAR were not present). The flow from Valley to Rainbow was six MW, virtually zero relative to the nominal 1000 MW capability of the overall Project. Further, with the minimal change in flows, other transmission loadings were not changed appreciably. Power entering from SONGS was reduced from 1066 MW to 1065 MW. The WSCC-wide reduction in losses was less than one MW, well within the accuracy of the data being used. Hence, for this condition the Valley Rainbow Project has no measurable impact and hence no benefit.

A similar case, including VRTP, was run with SDG&E loads reduced to 70 percent of their peak level, to test the system export capability. Under this condition the flow from Rainbow to Valley is 231 MW, with the PAR again set at the neutral position. Flow on the 230 kV north of SONGS was 1830 MW, a decrease of 175 MWW. Losses throughout WSCC were reduced by 3.3 MW. Again, the impact of the VRTP is not significant.

5. Elimination of the Simultaneous Import Limit

In the course of our study, we reviewed the SDG&E Simultaneous Import Limit (SIL). This SIL limits the power that can be imported by SDG&E and has done so since SWPL was constructed. Our review looked at this SIL in light of recent changes to the SDG&E and CFE transmission systems, and new generation being constructed in the San Diego Basin and Mexico. Independent of the construction of the VRTP, the transmission reinforcements discussed supra, along with the large amount of generation currently being installed along the border, have significantly changed the import dynamic for the SDG&E system. Previously, there were only two entry points to the San Diego system, south of SONGS and SWPL. Though there was a 400 MW intertie capability across the border to Mexico (Path 45), consideration of the possible loss of SWPL, and the resulting immediate tripping of the Tijuana to Miguel 230 kV lines, basically eliminated any significant firm import capability into Miguel Substation from either Arizona or Mexico. That left only the SONGS entry point to be considered reliable for import planning. With the Path 45 reinforcements described supra, another reliable entry point has been added-the 230 kV interconnections with the CFE system. This has a very significant and beneficial effect on total import capability. Generation in the Imperial Valley, Mexicali, and the Tijuana areas now has another path that will allow that power to get to Miguel. An outage of the SWPL segment between Imperial Valley and Miguel Substations no longer fully disables the capacity of SWPL. We have amply demonstrated this fact via our power flow analyses. The conclusion of this assessment is that use of the simultaneous import limit will need to be reconsidered and, at least, broadened in scope if not dismissed completely.

B. ALTERNATIVES TO VRTP

Based on our exploratory analysis. It is our position that neither VRTP nor any of the alternatives we are about to describe need to be constructed to satisfy Reliability requirements in 2005. We believe that the above-described transmission reinforcements, and the above-described generation, will arrive in a timely manner and delay any need for a major project such as VRTP. However, if the Commission deems there to be a need in 2005 or beyond 2005, we provide the following analyses to demonstrate that options far less costly than VRTP are available.

There are a number of possible transmission options that could replace VRTP or at least substantially defer it or any similar project. For simplicity, only a few are discussed here. A much longer list is provided in Appendix A.

1. North of SONGS Upgrade

There are now five 230 kV circuits south of SONGS that can deliver SDG&E's SONGS output and imports via the SCE system. There is an "underlying" 138 kV circuit in the SONGS-San Luis Rey corridor that could be converted to 230 kV. If that conversion were done, it would provide a significant increase in capability south of SONGS at a relatively modest cost, probably much less than the annual VRTP carrying charges that it would defer or avoid. Several of these upgrades were approved by both SDG&E and the ISO as products of the 2000 SDG&E five year transmission planning cycle, but have been taken off the table by SDG&E in their most recent transmission plan.

Recently announced limitations north of SONGS are indicated to be more restrictive than those south of SONGS, and thus supercede those to the south. Hence, based on restrictions north of SONGS, reinforcing south of SONGS would not increase transfer capability due to those limitations north of SONGS. However, if it were found to be reasonably economic to increase capability north of SONGS, then reinforcements south of SONGS might also be an economic alternative to building the Valley Rainbow Project.

Therefore, it seems that the cost of reinforcing this corridor should be considered if it would add a significant amount of capability at a reasonable cost. Also, it is our understanding that the limits north of SONGS are based on contingencies in addition to the key SDG&E G-1/N-1 (Encina 5 and SWPL) outages that limit SDG&E imports. If so, then there seems to be an error in SDG&E's analysis. What they have done is akin to double counting, since the limits both north and south of SONGS are determined by different contingencies that should not be assumed to occur at the same time. Hence, it appears that the limitations north of SONGS have been misapplied. They appear to be inconsistent with ISO Reliability planning criteria and are unduly limiting the use of the SONGS corridor (Paths 43 and 44). A proper analysis of the capability of the north and south of SONGS corridor capability is needed to ensure full advantage is take of this import path.

2. Highline to El Centro/Imperial Valley Line

While we usually speak of a G-1/N-1 event consisting of outage of Encina 5 and the SWPL, there are in fact two different SWPL outages. An outage of SWPL east of the Imperial Valley substation means no power can get from Palo Verde to Imperial Valley, and of course this power is thus also not available to Miguel. A SWPL outage west of Imperial Valley, between Imperial Valley and Miguel, on the other hand, does not fully sever the tie from Palo Verde to Miguel because there is a transmission path from Imperial Valley to Miguel through Mexico. Unfortunately this path overloads significantly when the power flowing west from Imperial Valley transfers to it following an Imperial Valley to Miguel outage. In recent years this path has been opened upon an outage of the Imperial Valley to Miguel line to solve this problem. The result has been a full break in the power flow from Palo Verde to Miguel upon outage of the Imperial Valley to Miguel segment of SWPL. Hence, with the existing system, outage of either segment of SWPL leaves SDG&E without a direct route from Palo Verde.

This problem is being addressed in part by upgrades to the path from Imperial Valley to Miguel through Mexico. Routine outages of the Imperial Valley to Miguel line will no longer require the path through Mexico to be opened. Analysis shows that more than 500 MW can be routed from Imperial Valley to Miguel via this path.

This leaves the problem of SWPL outages between Palo Verde and Imperial Valley. We have a prospective solution to this problem. It is about twenty miles from Highline Substation, in the Imperial Irrigation District (IID) system to El Centro Substation (also within IID), or to SDG&E's Imperial Valley Substation. There are several subtransmission lines that already go through this corridor and an upgrade to 230 kV is possible. Building a 230 kV tie from Highline to El Centro (or Imperial Valley) could have significant Reliability benefits. For a SWPL outage east of Imperial Valley, it would allow the significant amount of power in the Highline area to go to Imperial Valley, and thence to Miguel, rather than go north to Devers, and west to eventually go to SDG&E through SONGS as it must now.

The combination of the CFE upgrades and a Highline to El Centro tie address outage of both segments of SWPL-to the east or west. Our power flow analysis indicates this combination will provide approximately 500 MW of additional transmission capability to Miguel during outage of either SWPL segment. The cost of the Highline to El Centro upgrade would be a small fraction of the cost of VRTP, yet it would provide about 70% of the benefit (500 MW versus 700 MW). That makes this alternative deserving of attention.

3. Other Alternatives

There are numerous other alternatives. Some of them have to do with optimizing the capability of the existing system. Most of these alternatives would provide relatively small amounts of capability. However, in the aggregate, these alternatives could provide significant relief. Since these have not been analyzed in detail with power flows, their discussion is limited to the qualitative discussions in Appendix A of this report.

C. UPC JUSTIFICATION CONFIRMATION

Prelim text of section....

1. Purpose and Function

SDG&E proposes to install a unified power flow controller (UPFC) on the Valley-Rainbow line at the Rainbow substation. A UPFC is a solid state device that provides two functions. One function is to control the level of power flowing on a transmission line much like a phase angle regulator (PAR). The other is to provide voltage control the same way a static var compensator or statcom does. The UPFC thus can replace both a statcom and a PAR where both are needed.

The UPFC has a modest advantage over a PAR. The UPFC can adjust power flow quickly while the PAR does so relatively slowly. In an emergency the UPFC can change how power flows in the network in a few seconds whereas a PAR can take several minutes.

The UPFC also has a disadvantage. It costs about 33 percent more than a statcom and PAR. Additionally, only two small proof-of-concept UPFCs are in service. The SDG&E unit would be the first at its voltage and size. Finally, combining two critical elements of the transmission system in one "box" makes Reliability of this relatively unproven device a question.

2. Is it Necessary and Justified?

SDG&E has concluded that a UPFC is warranted on the V-R line at Rainbow. While a UPFC will do the job SDG&E indicates needs to done, we have not seen any analysis indicating that the faster response of the UPFC, is warranted. Indeed, the speed is a feature that addresses angular stability, a problem that does not exist in San Diego according to SDG&E's studies and reports. Hence we conclude that the UPFC need only address voltage and overload problems. The voltage problems could as well be addressed with a statcom. The overload problems to be addressed are on the SONGS corridor. According to SDG&E studies, the UPFC would normally be set to place about 400 MW flow on the VRTP. This will allow overloads to occur on the SONGS corridor upon a G-1/N-1 overlapping outage of Encina 5 and SWPL. Only after this event occurs, will the UPFC be adjusted to move power from the SONGS corridor to the VRTP to bring the SONGS line overloads down to continuous ratings. Because these lines have overload capability that allows 10 minutes or more of operation at the overload level, the high speed feature of the UPFC is thus not necessary to address overloads. A less costly PAR could do a fully adequate job.

The reader, from the above paragraph, may wonder why SDG&E would not simply set the UPFC or PAR to increase the normal flow on the VRTP so that overloads would not occur on SONGS following an overlapping Encina 5 and SWPL outage. SDG&E's reports do not indicate why this is not done. We suspect that losses would be increased if VRTP were to be more heavily loaded under normal conditions. Indeed, our brief studies indicate that losses are increased when power is shifted from the SONGS corridor to VRTP under normal conditions.

Additionally, it is at times feasible to insert a fixed phase shift transformer in a transmission line and accomplish the needed power shift. A fixed phase shift transformer is much less costly than a PAR which has two tap changing mechanisms, one to effect a change in phase, and a second one to correct the voltage ratio change caused by the phase shift. A fixed phase shift transformer needs no tap changing mechanisms and thus is far less costly than a PAR. SD&GE has not examined this option or indicated that the adjustability of a PAR is necessary.

A simple series reactor inserted in an overloaded transmission line will shift power to other parallel transmission lines and is often a very low cost alternative to a PAR. It may be quite practical to place switchable series reactors in the 230 kV lines south of SONGS to effect the necessary power shift to the V-R line when overloads occur. Series reactors offer high Reliability, low cost, and are compact and thus should always be explored before the higher cost PAR option is considered. SDG&E has not indicated that this option has been examined. The analytical work to explore this option is minimal and we suggest it be done.

We would like to suggest that the UPFC, or a statcom and PAR for that matter, may not be essential in some early years of the V-R project when it does not need to provide the full 700 MW of additional import. However, as our power flows have shown, the VRTP is virtually useless without a UPFC or PAR. Hence such devices would be needed from the outset. The fact that the devices are necessary to make the line function does, however, raise questions as to whether this is the right line in the right place. It is rare that a new line require help from these devices. Usually they are applied to control loop flow or to limit flow on older lower voltage lines that can be overloaded by outage of new higher voltage lines (e.g., on the SONGS 230 kV lines, though a series reactor would likely be an adequate and much less costly option).

We also saw no analysis of the benefit or role of the UPFC or statcom and PAR in later years when further 500 kV transmission line additions will be made south of Rainbow. SDG&E has stated that there are no plans to build more 500 kV transmission lines in the area and any future expansion beyond V-R is wholly unknown. However, a costly investment in this kind of equipment should be based on both near and longer-term needs so that it does not become a white elephant and is properly sized and designed for it's probable longer-term role. If the V-R project is appropriate, then clearly a 500 kV line from Miguel to Mission is a logical future expansion and the UPFC, statcom, or PAR should be designed with at least a brief look at this probable future expansion.

In conclusion, while we have argued that the VRTP project is unnecessary in 2005 and possibly well beyond 2005 or should be deferred or replaced by other less costly projects, we also wish to say we have significant questions about the technical merits of the VRTP. A 500 kV line should increase import capability far more than 700 MW. It should at least match the SWPL line (1212 MW) or approach the south of SONGS corridor's rating of 2500 MW.

V. PROJECT ECONOMICS

This section examines whether the economic benefits ratepayers would receive if this line were built more than offset the costs of the project. This rigorous economic analysis is necessary because the applicant cannot demonstrate that the project is needed to maintain system reliability, the ISO staff no longer finds that the project is needed in the near future to meet reliability criteria, and our own analysis set forth in Sections 3 and 4 above concludes that there is no reliability need and few reliability benefits associated with this project. Surprisingly, the applicant included no rigorous analysis of the economics of this project in its filings with the ISO, nor even in its testimony accompanying its application in March, 2001. It was not until October 2001, after being ordered by ALJ Cooke to provide more analysis of the need for this project, that the applicant submitted a substantial economic analysis prepared by its consultants, Henwood Energy Associates, Inc (Henwood). [19]

We begin with a discussion of the basic economics that determines whether or not a project is cost effective and then proceed to discuss our analytical effort and analysis. The results and assumptions behind those results are then compared to those of SDG&E;s consultant and points of disagreement identified.

A. GENERIC ECONOMIC CONSIDERATIONS

1. Ratepayer Costs and Cashflow

As shown in Appendix B the estimated total cost of the project is about $350 million including materials, labor, land and interest during construction. Annual maintenance charges are very modest and can be ignored for this economic assessment. The net present value of the societal reduction in operating cost for the overall system must equal or exceed $350 million in order for the Valley Rainbow Transmission Project (VRTP) to be viewed as having a benefit cost ratio of greater than one..

Using the typical fixed charge rate of approximately 18 per cent per annum results is an annual charge to ratepayers for the line of about $60 million dollars. For the line to be ratepayer cashflow positive the savings in rates to the ratepayers must exceed $60 million in savings every year. From a purely economic perspective, VRTP should be built only if it has both a benefit-cost ratio of greater than one <u>and</u> it is immediately ratepayer cashflow positive or breakeven and no other project has a higher return on investment. If it were not immediately cashflow neutral or positive then the project should be postponed until it becomes cashflow positive unless it could be shown that the maximum net present value of future benefits is maximized by earlier construction due to some unusual cost escalation process that would obtain.

2. ISO Revenue Recovery Tariff

[19] Chapter IV, Prepared Testimony of SDG&E regarding VRTP dated October 5, 2001.

As the ISO explains in a data response to ORA:

> *"The transmission Access Charge methodology that was implemented on January 1, 2001 consists of a High Voltage Access Charge (220 kV and above) and a Low Voltage Access Charge. The High Voltage Access Charge consists of a TAC Area component and a ISO Grid-wide component. For 2001 this split is 90% TAC Area and 10% ISO Grid-wide for existing facilities. However all new High Voltage Transmission Facilities are included 100% in the ISO Grid-wide component. The VRTP would be a new High Voltage Transmission Facility and would thus be incorporated into the ISO Grid-wide component of the CAISO'S High Voltage Access Charge. When the cost is included in the Grid-Wide component, then all users (SDG&E&E ratepayers, PG&E ratepayers, generators who export, etc.) of the ISO Controlled Grid pay for the transmission project.*
>
> "The rules for the allocation of costs of a transmission addition or upgrade are set forth in section 3.2.7.of the ISO Tariff. The rules for treatment of costs for new High Voltage Transmission Facilities are set forth in section 3.2.7.4 of the ISO Tariff and Appendix F, Schedule 3 of the ISO Tariff. These rules are currently pending before FERC in Docket No. ER00-2019-000 and may change."[20]

Thus, the cost saving measured throughout the ISO region is the appropriate level at which to measure the benefits or dis-benefits. of the project.

3. Appropriate BenefitFigure of Merit

The ISO's contractor that was hire to develop a methodology for evaluating the benefits of a transmission project, London Economics, Inc. has already decided upon the appropriate economic perspective from which to estimate benefits and that is total net societal benefits.[21] For this project the benefits then should be the change in cost of total generation as it is measured over, at least, the ISO region.

B. ORA's Economic Benefit Assessment

ORA's consultant Sierra Energy and Risk Assessment, Inc. used its proprietary production cost modeling system of SERASYM/SERAM II in the independent assessment of the benefits of this project. In its application to the evaluation of the SDG&E&E region, the modeling system started from

[20]Ibid.

[21]London Economics, "Foundation Paper - Initial suggested transmission evaluation methodology dated November 18, 2001.

the model structure and data base employed in the Otay Mesa Generating Project (OMGP) report filed in 99-AFC-05.[22] To this structure in the SERASYM model was added a North Baja Control Area and transmission from that Area into the SDG&E&E Area. To simplify the model and accelerate run time, northern California was collapsed into a single region interfacing on Path 15 with the more southern portion of the state. Median hydro and weather conditions in the region were assumed. The SERASYM probabilistic mode of solution was employed..

1. Conservative Scenarios and Sensitivity Cases

Higher economic benefits will be observed for VRTP as generation in Southern San Diego County and north Baja and associated transmission is increased. This is the opposite perspective from evaluating VRTP as a reliability element permitting secure service of SDG&E&E peak load. To be conservative we decided to select two scenarios: High Generation (HG) and Very High Generation (VHG) particularly as applied to the SDG&E&E and north Baja control areas as defined *infra*. For the VHG case the second Mission to Miguel transmission line was assumed present. For both cases we studies the impact of the proposed Path 15 improvements. In all cases the North Baja Gas Pipeline was assumed installed at 500 MMcf/d with rates equal to gas rates for SDG&E&E and electric generators which were, in turn, lowered to equate them to SoCalGas rates consistent with the latest BCAP proceeding.

To specifically investigate Applicant's scenario which postulated that the building of the line would attract further generation, we included a sensitivity case consisting of the addition of one additional highly efficient, CC power plant in an area below the Mission-Miguel bottleneck. We then ran the scenarios both with and without VRTP to see if there was any increase in operations of the plant consistent with an increased economic incentive to build there in the presence of VRTP. In all scenarios all other things were kept constant in order to accurately value the VRTP in the context of the assumed scenario.

2. Use of CAISO Societal Costs

As discussed in Section V.A.1 the CAISO'S Economic Consultant has adopted social (aka societal) costs as the true measure of benefits from a transmission project. We have adopted this perspective and will report differences in the cost of generation as distinguished from the hourly market clearing price. Since we include LADWP in the modeling the net benefits will reflects impacts on the residents of LA as well.

3. SDG&E&E, Baja and California Loads

[22]Weatherwax, R. K., K. Z. Tang and K. J. Weatherwax, "Analysis of the Operational and Environmental Impacts of the Proposed Otay Mesa Generating Project" filed in CEC 99-AFC-05 dated March 25, 2001.

One-in-two year peak load and total energy for load for each area of California were updated to reflect the CEC's October 2001 forecast.[23] Hourly north Baja loads were taken directly from the information provided by SDG&E&E's consultant.[24]

4. New and Existing Generation Resources

We included in all scenarios new California generators over 300 MW that were shown as either completed or under construction in the January 12, 2002 version of the CEC Power Plant Status Report In addition we included a number of new, approximately 49 MW peakers. Information about these peakers was derived from the CEC Status Report, information from SDG&E's testimony and responses to data requests from both ORA and the CPUC energy Division, and information from each of other IOU's as filed in I.00-11-001. A special adjustment for reliability reasons was made in the San Francisco area where the remaining on-line units at Hunters Point, HP 1 and HP4 were assumed to be retired and replaced by Potrero 7 currently before the CEC. Since OMGP was included by Applicant the only differences between our assessment and theirs for the High Generation case was our inclusion of three additional peakers with about 150 MW of capacity.

For theVHG case we added an additional 2400 MW of capacity in Baja as named in Table V-1. We added only three additional plants in the remainder of the state: 3 Mountain, Metcalf and Morro Bay power plants; two of which have been already approved by the CEC.

5. Local Natural Gas Availability and Cost

We assumed that there was gas available from the existing SDG&E&E system including the recent 70 MMcf/d upgrade and the assumed completion of the 500 MMcf/d North Baja Pipeline. IN the modeling we pooled the two gas supplies and adjusted them for the demand of higher priority customers in San Diego and Mexicali. We estimate that there will be available for Electric Generators anywhere from about 1000 MMcf/d in August of 2004 to as little as 875 MMcf/d in a cold December of 2010. These are quite generous amounts of gas assumed to serve all of C.E.'s existing and planned gas fired generators, all new gas fired generators in Baja, all gas fired generation in SDG&E&E and the Blythe electric plant along the North Baja Pipeline (NBP) route.

Based upon review of these runs the NBP is indispensable to any claim by SDG&E&E that the VRTP has value for exports. Surprisingly, even with this copious amount of

[23]Op sit, CEC October Forecast.

[24]Response to ORA follow-up response to DR 2.4.

NEW GENERATION IN THE SAN DIEGO AND CFE SERVICE AREAS - TABLE V-1

SDG&E SERVICE AREA INTERCONNECTION

UNIT NAME	EQUIPMT TYPE	PRIMARY FUEL	SIZE(MW)	AVAIL @ PEAK(MW)	INTERCONNECTION SUBSTN	INTERCONNECTION VOLT(kW)	STATUS	ONLINE DATE
RAMCO Escondido	CT	NG	49.5	49.5	Escondido	69	On-Line	
RAMCO Otay	CT	NG	49.5	49.5	Otay	69	On-Line	
RAMCO Chula Vista	CT	NG	42	42	CV?	13.8	On-Line	
Wildflower-Larkspur 1	CT	NG	46	49	Border	69	On-Line	
Wildflower-Larkspur 2	CT	NG	46	49	Border	69	On-Line	
Calpeak #1	CT	NG	49	49	Border	69?	On-Line	10/26/01
Calpeak #2	CT	NG	49	49	Escondido	69?	On-Line	9/30/01
Calpeak #3	CT	NG	49	49	El Cajon	69?	Underway	1/15/02
Otay Mesa	CC	NG	595	550	Miguel/Otay	230	Underway	6/30/03
		ONLINE BY 2003	***975***					
		ONLINE >2003	***0***					
		TOTAL	***975***					

CFE SERVICE AREA INTERCONNECTION

UNIT NAME	EQUIPMT TYPE	PRIMARY FUEL	SIZE(MW)	AVAIL @ PEAK(MW)	INTERCONNECTION SUBSTN	INTERCONNECTION VOLT(kW)	STATUS	ONLINE DATE
Rosarita 7	CC	NG	595	550	PJZ	230	online	5/1/01
LRPP	CC	NG	800	750	La Rosita	230	Underway	3/31/03
AEP Resources	CC	NG	250	250	Miguel/Otay	230	?	6/1/03
AEP Resources	CC	NG	250	250	Miguel/Otay	230	?	6/1/05
Intergen B-Phase 1	CT	NG	160	160	Imperial	500	?	8/1/02
Intergen B-Phase 2	CC	NG	440	390	Imperial	500	?	6/1/03
Sempra #1	CC	NG	600	550	Imperial	500	?	6/1/03
Sempra #2	CC	NG	600	550	Imperial	500	?	6/3/05
Other EWGs	CC	NG	722.5	722.5	CFE	230?	?	2002 - 03
		ONLINE BY 2003	***1395***					
		ONLINE >2003	***3022.5***					
		TOTAL	***4417.5***					

assumed gas supply, our cases do run short of natural gas in some selected days of the latter years of the simulation.

6. Transmission Assumptions

For the HG case we assumed that the CFE.-SDG&E interconnection was rated at 800 MW. We increased the CFE intertie rating to 1400 MW For the VHG Case . In two cases the Path 15 rating was assumed not to change from its current rating. In another set of two run we explored the impact of that transmission link by increasing the bilateral rating by 1000 MW.

C. Base Cases Results

Before reviewing the results it is important to recognize that we intentionally selected cases that were high in new generation in order to bias the outcome in favor of the proposed line. If these cases were not high in generation especially in Baja, it is obvious that the existing export capability which was normally used to import up to 2500 MW from the north could be turned around and increased to 2800 MW of actual export and displacement before VRTP would be needed to accommodate further exports. Were OMGP and others of the planned units in Baja not constructed then the need for the line for exort would be non-existent and the absence of a reliability need based upon new generators just now on-line.

1. Annual Production Cost Results 2005 - 2010

Table V-2 presents the results for the HG case. It can be seen that VRTP has absolutely no net impact on the system until 2007 when there is am estimated $200 thousand benefit. Troubling, there is an actual negative benefit in 2008 though it is only $144 thousand. (In reality, the addition of a new tie line should never cause a negative benefit as distinguished from some lines that actually increase reliability risk.) The benefits in 2009 return to being positive but are minuscule. Overall, the total mixed year dollar benefits are $114 thousand. The results are little better for the line as presented in Table V-3. The overall

TABLE V-2

SYSTEM COSTS FOR HIGH GENERATION CASE			
NO PG&E UPGRADE YEAR	NO VRTP $MILLION	VRTP $MILLION	VRTP BENEFITS $MILLION
2005	6882.424	6882.424	0.000
2006	7588.090	7588.090	0.000
2007	7830.275	7830.472	0.197
2008	8560.322	8560.178	-0.144
2009	9109.917	9109.978	0.061
2010	9909.942	9909.942	0.000
			0.114

TABLE V-3

SYSTEM COSTS FOR VERY HIGH GENERATION CASE			
NO PG&E UPGRADE YEAR	NO VRTP $MILLION	VRTP $MILLION	VRTP BENEFIT $MILLION
2005	6679.481	6679.481	0.000
2006	7341.628	7341.560	0.068
2007	7510.826	7510.452	0.374
2008	8215.031	8214.641	0.390
2009	8784.343	8784.702	-0.359
2010	9503.567	9503.567	0.000
			0.473

net benefit was $473 thousand. Much too small an amount to justify any portion of the line.
We also ran these cases with a enlargement of the Path 15 by 1000 MW in each direction . The results for these cases were unremarkable and showed nearly negligible benefits for the six year period.

2. Sensitivity Analyses

Another interesting sensitivity cases was run in response to the Applicant's scenario in which they postulated that the presence of VRTP would eluctably lead to the siting of 1700 MW of additional generation in southern San Diego county. We refer to this case as the "If we build it, they will come" case. Since there were no reported cases of looking at the value of this assumption from the eyes of the generator with or with the VRTP in place, we choose to make a set of runs that tried to quantify the benefit from the line from the context of the developer. To do this we started with the HG case without an upgrade to Path 15 and added a single 550 MW generator in both cases. We then compared the level of operations of that single unit in the presence or absence of VRTP. The results are presented in Table V-4 *infra*:

The total change is generation is 380 MWh over a six year period. Far less than necessary to encourage a new plant. The reason for this is quite clear transmission out of the SDG&E&E north area never exceeds the 720 MW currently present. In fact, the peak reverse flows never exceed about 500 MW due to the relative unattractiveness of the available surplus generation from the northern section of SDG&E&E service area.

TABLE V-4

BENEFITS TO FIRST PLANT FROM VRTP

	WITH VRTP		WITHOUT VRTP		VRTP BENEFIT	
YEAR	GWH	MILLS/kwh	GWH	MILLS/kwh	GWH	MILLS/kwh
2005	3537.50	23.81	3537.50	23.81	0.00	0.00
2006	3720.48	24.80	3720.48	24.80	0.00	0.00
2007	3606.91	26.30	3606.91	26.30	0.00	0.00
2008	3724.58	27.75	3724.58	27.75	0.00	0.00
2009	3727.43	29.19	3727.41	29.19	0.02	0.00
2010	3734.87	30.76	3734.51	30.76	0.36	0.00
	22051.77		22051.39		0.38	

3. Natural Gas Limitation and Environmental Impacts

As discussed above we assumed that there would be a pooling of the natural gas supply in San Diego and Baja with the presence of the NBP. We also assumed that all gas fired generation would draw from the same supply. As shown in Section V this supply varies somewhat with the month due to higher priority users and is most plentiful in the summer months. Especially in the VHG case but also in the HG case to a lesser degree we found that in the summer, the supply was not fully adequate to the demand. Our modeling assumed that the new CCs and CTs would not have a separate distillate or propane supply so their levels of generation would decline. We did, however, model the Encina and South Bay Plants in San Diego and Presindente Juarez Units 5 and 6 as being able to switch to residual fuel oil. In the HG and VHG cases that happens. Oil generation appears in San Diego in the summer so, if it were to occur, the emisison problems would be substantially worse than as a result of the winter gas shortages that have occurred with some frequency in San Diego in the winter.

4. Why is the VRTP of So Little EconomicValue ?

Based on our detailed study of the project in the context of the San Diego system we believe that the explanation is as follows for the current system:

1. The persisting bottleneck between Mission and Miguel will trap efficient generation in Baja and

2. All the generation that is free to be exported via VRTP is north of Mission and not economically competitive with generation from the LA Basin.

<u>Example 1</u>

The SDG&E system is constrained at either end. The constraint to the north towards and beyond SONGS is about720 MW south to north of SONGS and 2500 MW in the opposite direction. The constraint into the SDG&E system via Miguel is about 1700 MW. Hypothesize that there is 2000 MW of cheap CC power that can come in via the Imperial Valley to Miguel Line, the Tijuana to Miguel line and the short line from Otay to Miguel. Also hypothesize that SDG&E's 400 MW of SONGS is operating and that 200 MW of Encina And South Bay Steamers are operating. If the load in SDG&E is 3000 MW then by adding the 1700 MW at Miguel + 200 MW in Steamers + 400 MW SONGS + 700 MW of SONGS imports = 3000 MW. All the cheap generation that SDG&E can import is already being imported leaving 300 MW locked out of California.

At this time there are no exports from SDG&E and the low cost generators south and east of Miguel can't increase their sales because the line is fully loaded. The Steamers could increase their generation were the demand present. So they could displace some of the imports if any utility wanted their output. Unfortunately, with an incremental heat rates of approximately 10,000 Btu/kWh or higher, they are no more efficient, and arguably less efficient than most of the Steamers in the LA Basin and their gas supply is no cheaper; so, there is no demand for their generation. And certainly no demand for extra export capability supplied from VRTP.

<u>Example 2</u>

Now, assume that SONGS Unit 1 suddenly SCRAMS dropping about 1100 MW of power including 200 MW from SDG&E's share of SONGS. Further assume that the 700 MW of imports is now called back to support the load north of San Diego leaving SDG&E 200+700 = 900 MW short. In this case the Steamers are cranked up from 200 MW to 900 MW to balance load leaving them with about 800 MW of headroom. No exports are seen in this case even though the system lamda in the LA Basin has increased. The low cost generators south and east of Miguel can't increase their sales because the line is fully loaded. And the incremental heat rate has increased in the San Diego Basin as well. Still no need for VRTP.

<u>Example 3</u>

Finally, now assume that the PACI transmission line to the north is lost losing 3200 MW of additional generation. In this case the system is stressed and the ISO would call on all available generators including the over 600 MW of peakers now found in San Diego. To support the system the 600 MW of peakers comes on along with the

> remaining Steamer headroom of 900 MW (minus some control reserve) comes on-line as well. There is 900 +600 = 1,500 MW of exports going north. This is fully accommodated with the 720 MW of SDG&E normal export plus the 800 MW of lost generation from the down SONGS unit. The low cost generators south and east of Miguel still can't increase their sales because the line into the San Diego Basin is fully loaded. Still no need for VRTP.

Fault can be taken with the assumption in this hypothetical that one of the SONGS units conveniently SCRAMS opening up transmission capability to the north. If it were a Diablo unit then the VRTP line might be used. On the other hand, the odds of needing all of SDG&E's generation while its load is at 3000 MW is very, very small. The load throughout southern California are almost entirely coincident and the loads in the north are nearly as coincident. So, if San Diego is at 3000 MW there is plenty of headroom in existing generators outside of the SDG&E service area and many more that can be committed to carry the extra load thereby marked reducing the exports from San Diego.

If the series of problems were to occur at a higher loading, say 4000 MW then San Diego would need 1700 MW of indigenous generation (including SONGS) to meet load and there would only be about 1000 MW of head room left including some control reserve and 250 MW in the form of extremely small and inefficient peakers which would not run except in a great emergency. So even in this case it is difficult to see how the export flows would exceed 720 MW (which has a higher emergency rating) resulting in the absence of need for VRTP once again

5. Applicant's Economic Benefit Assessment

The Applicant's economic assessment is contained in Section 4 of their pre-filed October 2001 testimony. It consists of a series of production cost simulations performed by Henwood employing the PROSYM production cost simulation model. In the modeling Henwood assumed that the project would be on line for the full simulation period 2005 through 2010 They measured the Benefits as the difference in market clearing prices for SDG&E and for the CAISO region. As discussed above, the benefit to the SDG&E is too narrow a group for which to measure the benefits since the costs are distributed more widely Measuring the savings across the ISO service territory and Los Angeles is appropriate, and is similar to the scope we used in out analysis.

The Commission should note that the use of the difference in market clearing price as the measure of benefit is not the same as the social cost change. It measures the increase in consumer benefit but not the change in cost of production. Depending upon how monotonic the supply and demand curves are in the region this may or may not be a suitable way to measure relative changes in benefits between alternatives. We accept this relative element of their assessment subject to further check but believe that the benefit value is likely to be inflated to a degree determined by the actual shapes of the supply and demand curves. Clearly the Applicant's choice in form of benefit is a generous measure of the benefits of the project only slightly compensated for by reporting the results in $2001.

6. Benefits of Project vs No Project

Henwood's general approach to the simulations seems appropriate. The base-case generation resources include existing, very recently constructed and under-construction plants as determined by Henwood. However, The loads used in all cases appear too high. Rather than reflecting current load forecasts, the loads Henwood used in the modeling are reflective of peak and total net electricity for load forecasts prior to the recent enormous electric price increases and frequent appeals for conservation. These price increases and conservation efforts have resulted in the plunging of demand and the Applicant's deferral of the in-line date of this project by one year. Since the net benefits of this project are positively correlated with forecast load, the Applicant's use to excessively high load forecasts results in their overstating the benefits of the project.

Even with this overstatement of benefits, the results of the SDG&E/Henwood analysis showed surprisingly few benefits from this project. The forecast benefits were in a range of from negative $800,000 to positive $1.6 million for the entire six year period, depending upon whether the Los Banos-Gates transmission project (Path 15).[25] Even the Applicant's analysis concludes that in the absence of Los Banos-Gates, this project is not economic, although very expensive.

Additional runs were reported that increased somewhat the level of resource development in the state by 4,109 MW while increasing the postulated Baja generation by a disproportionate 1,700 MW which tends to bias the results toward the benefits of VRTP. In these scenarios the second Mission to Miguel 230 kV line is also assumed. Further impacting these scenarios was the elimination of other generation within the region equal to the total additions made. Even with these controversial assumptions, the basic total benefits for the full six year period were forecasted to range from only 1.2 to $6 million depending upon the status of Path 15 upgrades. Even in the severe drought case the expected benefits ranged from only about $250,000 to $2.5 million for the full 6 year period.[26]

We believe the extreme paucity of benefits is indicative of unavoidable physical flow limits within SDG&E&E's system and appropriate locations of new generation. Even were the second Mission to Miguel line built, the maximum amount of inexpensive generation that could be imported including Otay Mesa would be less than 2,400 MW. Since SDG&E is currently capable of exporting 720 MW north of SONGS even by their reckoning, the load is SDG&E would need to drop below 1700 MW before there would be a constriction to the north of the possible export of cheap power. Since the load in San Diego essentially never gets that low except in times when the entire state has very low load, there is no

[25]In a strictly economic assessment the benefit of any transmission line cannot be negative; thus, these negative result is anomalous and suggests that the estimation technique employed by the Applicant's consultant is subject to modest inaccuracies at the margin.

[26]SDG&E, response to ORA data request A. 2.23.3.

demand for power from SDG&E&E of any kind during normal times.

Two possible unusual circumstances have been mentioned by SDG&E&E in its testimony; the double outage of SONGS or a severe drought. In the outage of SONGS case, there is over 2400 MW of export capability from SDG&E&E; more than enough to satisfy any credible generation buildout scenario in SDG&E&E and Baja. The other scenario is a severe drought at a time when the SONGS units are operating. However, this scenario depends on the highly implausible assumption that the generation from the South Bay and Encina plants which would be exported, at least by displacement, would be of value in the Edison area or further north. In fact, the Encina and South Bay units are less efficient than some comparable units in the LA Basin when line losses and heat rates are considered. Their simulations clearly show that Encina and South Bay generation is only economic outside of the SDG&E&E service area in the most severe of droughts.

7. "If We Build It, They Will Come Scenario"

The SDG&E/Henwood analyses contain several scenarios that assume as a model input that 1700 MW of new generation would be added in the San Diego Area without any net generation additions anywhere in the western U.S. (technically in the WSCC). In other words, SDG&E/Henwood assumed that 1700 MW of generic generation was retired in the Pacific Northwest, at the California-Oregon Border near Malin and Arizona areas to retain a constant total amount of WSCC generating capacity. We think that the title of this section is apt because the addition of these is apparently, done on faith and without any analytical basis.

The Commission should disregard the results derived using these scenarios for the following three reasons:

SDG&E/Henwood have provided no analytical foundation for such an assumption and it could have been easily tested by adding one, two and then three units in both the "with" and "without" VRTP cases and see what the impact is upon the new generator. If the first new generator sees no benefit from the presence of VRTP then the remaining runs would be unnecessary. (See *supra* in this Section for the results of our scenario test which conclude that there is no benefit to the n^{th} plant).

No demonstration was made to show that, merely, by the act of shifting 1700 MW of generation from outside of California into the state, there would not be a net benefit to the state. Certainly, there would be a likely reduction in losses. The unstated assumption seems to be that gas by wire is, at least no more expensive than gas by pipeline when applied to San Diego. This assumption is not based upon facts in evidence.

This case assumes that all generation not nearing completion will be dropped and that <u>only</u> the postulated new generation in San Diego or below the border will be build within the state during the period after 2004, except possible, for that built precisely to match load. As discussed earlier, with only 1700 MW of additional cheap generation beyond that supplied by OMGP, any export will be steam boiler generation from Encina and South Bay. Our experience is that if there is an opportunity to displace relatively expensive, steam-boiler generation north of SDG&E then others will build other places within or near the state (*e.g.*, the Mojave desert, east of the river or in southern Nevada) to better and more cheaply fill this competitive opportunity.

8. Problems with Applicant's Assessment

Aside from the, what we believe to be, fatal errors in the "If we Build it they will come" scenario there are other basic limitations on the analysis undertaken that are troublesome, at best.

Gas supply limitations are not modeled or, apparently considered. In their low generation case that only includes the equivalent of OMGP and several new peakers there would not be a new pipeline due to absence of demand necessary supply[27]. therefore, there could very well be electric generator gas shortages such as occurred in 2000 even with the recent 70 MMcf/d upgrade to the SDG&E&E gas delivery system. Any generation exported would have to be steam boiler generation and it might well be residual oil fired and as such, very unpopular with the San Diego Air Quality Management District.

The resource planning assumption found in the high generation case is that if additional generation is built in California or in Baja then other generation in the WSCC will not be built.[28] Most of the reduced generation was taken from the northwest. This assumption directly impacts the results of the simulation

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[27]OMGP is only contracting for 45 MMcf/d of what would be a 400 to 500 MMcf/d pipeline.

[28]SDG&E response to follow-up DR No. 2.23.2.

and makes the presence or absence of the Path 15 upgrade much more important in evaluating the project. The problem is that there is no financial analysis or expressed economic theory suggesting that such an action would be taken by developers. The more standard approach in evaluating the merits of a project is to assume that the rest of the region is constant for a given scenario and to look at both the With and Without VRTP cases against a consistent backdrop.

To model correctly variations in hydroelectric power availability, one needs to look at average, wet, and drought hydro years, and realize that each of these types will occur some of the time, but none of these conditions will occur every years. However, SDG&E/Henwood do not do this. They analyze the drought scenario and the median hydro scenario, but fail to account for wet hydro years or the relative frequencies of wet, average, and drought conditions. The 1-in-35 year drought scenario is likely an excellent scenario for testing the gas and other fuel supply system in the region; however, its very severity may be what triggers the exportation of gas-boiler fired generation thereby resulting in the asserted benefit for VRTP. We may presume that the higher hydro cases would have even less benefits than the median water case and would, therefore, show no benefits. A correct analysis must reflect that droughts occur infrequently and sub-median hydro years occur only half the time, so the forecast benefits from the project must reflect this. SDG&E/Henwood have not done this, making it impossible for the Commission to calculate the likely benefits of the VRTP in the varying hydro conditions that will occur.

As stated before in this report, given the configuration of the SDG&E&E transmission system and load nearly all generation that could ever find its way onto the new transmission line would be either steam boiler fired generation (more likely) or peaker generation that would otherwise be displaced by cheaper power from the south. In this situation, San Diego could find itself in the position of generating much electricity in basin for export, raising serious air emission issues, and the level of change in emission should be examined and reported. This necessary action was not taken in this analysis.

9. Bottom Line of the Analysis

The situation in San Diego regarding the value of VRTP for economic exports is clear:

- VRTP only permits the exporting of unattractive generation due to the constraint on the input to San Diego from the south.
- A much enlarged Miguel point of entry could possible permit the transfer of large amounts of energy through SDG&E&E 230 kV system but probably not without significant reliability and losses problems.
- The project appears to have essentially no benefit as an export facilitator