**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

In the Matter of the Application of The Nevada Hydro Company for a Certificate of Public Convenience and Necessity for the Talega-Escondido/Valley-Serrano 500 kV Interconnect.	)))))	Application 10-07-001 (Filed July 6, 2010)

Direct Testimony of Doug Bergman

on behalf of

The Nevada Hydro Company

November 30, 2010

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Subject Matter Index

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Introduction

Q. Please state your name, title, and business address.

A. My name is Doug Bergman. I am employed by ZGlobal, Inc. as its Chief Economist. Our office is located at 604 Sutter Street, Suite 250, Folsom, CA 95630.

Q. Please describe your employment and other relevant experience.

A. I have served in my current position, and with my current employer, since July 2010. Prior to that, I was employed by the California Independent System Operator (ISO) since 2001, most recently as Lead Market Monitoring Specialist. In that role, I was lead or contributing author in over 50 reports and documents covering many aspects of the California wholesale power markets. Most or all of these documents are available on the California ISO web site. I have doctorate and masters degrees in economics and a baccalaureate degree in mathematics. I have been qualified as an expert witness in economic analysis before the U.S. District Court in San Francisco.

Q. On whose behalf are you submitting this testimony?

A. I am submitting testimony on behalf of The Nevada Hydro Company (TNHC).

Q. What is the purpose of your testimony?

A. TNHC has retained ZGlobal to conduct an economic benefit-cost analysis for the Talega-Escondido / Valley-Serrano 500kv interconnect ("TE/VS") project. I conducted this analysis and am presenting it to the Commission. The TE/VS line would interconnect and create a new 500 kV link between the Southern California Edison (SCE) and San Diego Gas & Electric Company (SDG&E) electric systems and would connect the Lake Elsinore Advanced Pump Storage project (LEAPS) with California's high voltage transmission grid.

Q. How is your testimony organized?

A. First, I summarize my opinion on the economic benefits of TE/VS. I then provide an overview of our approach in evaluating the economic benefits of TE/VS. Next, I present some fundamental concepts of the methodology used for the evaluation. Third, I provide explanations and detail the quantified benefit calculations of each component in the TE/VS project.

Q. What is your opinion of the economic benefit of the TE/VS project?

A. I estimate that the TE/VS project would provide a net benefit to California ratepayers of approximately $38.2 Million per year. Overall, the annual savings in energy production, renewable portfolio compliance, and local reliability costs of approximately $191 Million is substantially greater than the annual infrastructure cost of $153 million that they will bear, resulting in net savings.

The analysis is summarized in the following table:

Annual Benefits	**Base Case**	**TE/VS Case**	**Savings**	**Net Benefits**
Consumer Benefit				
Load market cost	$ 9,585,379,425	$ 9,506,225,312	$ (79,154,113)	
Less Marginal Loss Surplus	$ (254,985,049)	$ (257,313,473)	$ (2,328,424)	
Net cost of energy to load	$ 9,330,394,376	$ 9,248,911,838	$ (81,482,537)	
Producer Benefit				
Production surplus (all generators)	$ 6,813,262,328	$ 6,779,904,389	$ (33,357,939)	
Transmission Owner Benefit				
Congestion revenue	$ 113,749,679	$ 93,546,988	$ (20,202,691)	
Societal Benefit (total savings due to lower energy production costs)				**$ 68,327,289**
33% RPS Compliance Costs	**$ 6,872,218,280**	**$ 6,784,242,159**	**$ (87,976,120)**	
SDG&E Area local RA Compliance Costs	**$ 50,139,849**	**$ 15,276,985**	**$ (34,862,864)**	
Quantified Annual Benefit of TE/VS Project				**$ 191,166,273**
Annual Costs (Revenue requirements of TE/VS, SCE and SDGE upgrades, P42 recond.)				**$ (152,966,570)**
Net Annual Benefit of Project				**$ 38,199,703**

Q. What do you mean by "Consumer Benefit"?

A. Consumer benefit is the savings that consumers will enjoy due to the lower cost of energy production. A new transmission line will enable low-cost generation resources to reach a wider customer base. When low-cost generation displaces high-cost generation, prices fall, and energy consumers save money. Ms. Vangelatos has calculated that the "Net cost of energy to load" in the Base Case, in which the TE/VS and Path 42 projects are not modeled, is approximately $9.330 billion in 2015. With TE/VS and Path 42 modeled, this cost decreases to $9.249 billion, resulting in an annual savings of approximately $81 million.

Q. What do you mean by "Producer Benefit"?

A. The producer benefit, or *production surplus,* is the difference between the price at which energy is sold and the price that it costs sellers to create it. Loosely speaking, production surplus is sellers' profit.[1] As new transmission enables lower-cost generation to reach new customers, the ensuing decrease in prices typically results in a decrease in sellers' profit. In the Base Case, the production surplus totals approximately $6.813 billion. With TE/VS and Path 42 modeled, the production surplus decreases to approximately $6.78 billion. In other words, the introduction of the TE/VS and Path 42 projects results in a decrease in production surplus of approximately $33 million.

Q. What do you mean by "Transmission Owner Benefit"?

A. Energy in a specific location on the grid may sell for higher prices than other areas on the grid, to signal a greater need for energy resources, when the only available generation in the area is costly and transmission to the area is limited. In this case, all available transmission is used to move energy to the high-cost area, and the transmission is said to

[1] Reflects profit before taxes, costs not attributed to power generation, and other deductions.

be *congested.* The difference in price between the high-cost area and other low-cost areas is the cost of transmission congestion, and reflects the *transmission owner benefit* or *transmission congestion revenue.* Congestion revenue effectively reflects the short-term cost of transportation of energy from generation to load, due to the oversubscription of the transmission resource. As new transmission is built, the frequency and/or severity of transmission congestion may decrease, since new transmission will offset this oversubscription. This results in a decrease in congestion revenue. In the Base Case, transmission owners earn approximately $114 million in congestion revenue in 2015. In the TE/VS and Path 42 case, transmission owners earn $94 million, resulting in a decrease of $20 million.

Q. What do you mean by "Societal Benefit"?

A. Consumers' wealth increases when energy prices fall, but this gain is partially offset by lower surplus enjoyed by producers and transmission owners. As the Commission noted in its 2006 Decision, the societal benefit represents the net change in total benefit of consumers, producers, and transmission owners.[2] The total societal benefit from the construction of TE/VS and the Path 42 reconductoring is approximately $68 million in 2015.

<u>Analytic Approach</u>

Q. Does your analysis utilize the approach to transmission economic analysis directed by the California Public Utilities Commission (CPUC),[3] which has an empirical basis in the Transmission Economic Assessment Methodology ("TEAM") developed by the CAISO?

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[2] CPUC, *Opinion on Methodology for Economic Transmission Projects,* Decision 06-11-018, November 9, 2006.

[3] Ibid.

A. It does. The TEAM approach is intended to evaluate the economic benefit of a new transmission project. It compares the quantified costs of the project, as borne by ratepayers subject to the PUC's jurisdiction, to an estimate of quantified benefits that those ratepayers are likely to enjoy. If the estimate of benefits exceeds the estimate of costs, the project is said to have net economic benefit.

TEAM is a constrained optimization problem in which the economic modeler (resource planner) picks the least-cost transmission and generation resource capacity plan (and energy delivery plan) that satisfies three sets of constraints. The three sets of constraints are:

- A model of the existing and projected infrastructure and network topology;
- Economic and financial input assumptions (e.g., projected demand based on an adopted load forecast); and
- Policy and regulatory standards.

Another way of explaining the TEAM approach is that the objective of the TEAM modeler (resource planner) is to find the resource plan (generation and transmission capacity) that minimizes total expected consumer expenditures on generation and transmission, while satisfying forecasted energy demand and all network, financial and regulatory constraints.

Q. How does the TEAM modeler (resource planner) account for and value the expected stream of future costs (expenditures) associated with a resource plan?

A. The resource planner calculates the present value of the stream of expected expenditures across the entire planning horizon. As an alternative, the resource planner may calculate and use the annual equivalent. Lastly, the resource planner may also rely on a snapshot in time, such as 2015.

Q. How should the resource planner satisfy, or obey, the existing and projected network topology and regulatory requirements?

A. The TEAM modeler (resource planner) should obey the projected network topology and regulatory requirements by imposing reliability and regulatory constraints (standards) on the transmission and generation infrastructure capacity plan, and by solving a constrained least cost dispatch problem for the present and future financial delivery of energy. Lastly, the TEAM modeler (resource planner) should obey the State of California's imposed energy procurement constraint - the Renewable Portfolio Standard (RPS), as well as the State's loading order, which includes Demand Response (DR) and Energy Efficiency (EE) programs.

Q. Has the CAISO modified the original TEAM approach to evaluating transmission and generation projects?

A. Yes. The 2006 CAISO CSRTP for the Sunrise Project added a CAISO and WECC reliability constraint to the TEAM approach. In addition, CAISO's written testimony in the Sunrise Proceeding also includes system RA and RPS constraints to comply with the Commission's resource adequacy policy.

<u>Evaluation of Costs and Benefits</u>

Q. How do you evaluate the economic benefits of TE/VS?

A. TEAM brings to the table a standardized approach for quantifying benefits of a transmission network. Generally speaking, the approach compares the cost of the upgrade to the benefits that will accrue from the upgrade.

We are using a target model year of 2015, and comparing benefits to the revenue requirement for that year. Using a single year of analysis provides a simplified approach that balances the competing objectives of representing future enhancements to the grid, while avoiding the uncertainty that would ensue under more distant scenarios.

Determining the cost of a transmission upgrade is relatively straightforward, since the cost is borne by TNHC, whose revenue requirement is passed to utilities (and in turn ratepayers). The TE/VS cost analysis was performed by TAG Energy and included in the testimony of Mr. Scott Medla. In addition, we included the cost of reconductoring Path 42, another project that is necessary to obtain the RPS benefits of TE/VS. Mr. Jim Drzemiecki of FTI Consulting calculated the annual revenue requirements to be borne by ratepayers based on these capital costs. I am using Mr. Drzemiecki's 2015 revenue requirements calculations as the cost of the upgrade.

We estimate the quantified benefits as the sum of several individually quantified components:

a) Quantified consumer and IOU benefits due to lower energy production costs

b) Lower resource adequacy (RA) or Reliability costs

c) Lower renewable portfolio standard (RPS) costs

The benefit (a) that accrues from lower energy production cost was calculated by Christine Vangelatos, my colleague at ZGlobal.

The benefit (b) due to savings in RA requirements is based on the lower local reliability requirements that result from the construction of TE/VS, as calculated and submitted in testimony by Mr. Fred Depenbrock. I am using Mr. Depenbrock's calculation of the decrease in local RA requirements, and imputing savings based on capacity cost data that I aggregated from the FERC Electronic Quarterly Reports (EQR) database.

The benefit (c) due to savings in lower RPS costs is based on my analysis of cost savings that ratepayers in the CAISO footprint will realize in meeting RPS requirements, based on several public data sources that I identify below.

Another indirect benefit that ratepayers would enjoy is the fact the TE/VS will enable connection of the LEAPS pump storage to the grid. The cost of the pump storage unit is not included in the benefit-cost analysis, because there is at this time no reason to expect the ratepayers to bear that cost. However, the indirect benefits that LEAPS would provide include:

(1) LEAPS would increase the supply of energy in California, since it can store inexpensive off-peak energy and generate when prices are high;

(2) LEAPS would increase the supply of ancillary services, thus reduce the cost of ancillary services that ratepayers would pay.

Q. The TEAM Methodology document compares costs and benefits in multiple years. Have you only compared costs and benefits in a single year?

A. The TEAM Methodology is a process for mathematically comparing costs and benefits of transmission projects. In its example analysis, the original TEAM report performed Path 26 studies for years 2008 and 2013. That notwithstanding, this was a practical exercise of the general methodology, which leaves much of the details to the professional judgment of the analyst conducting the study.

We have conducted a quantitative study using 2015 assumptions, and provide qualitative analysis to address the benefits of the project in later years. Using 2015 as a proxy for the expected benefits over the life of the TE/VS project is a conservative assumption, since all the benefits of energy, congestion, RPS and reliability savings increase with load growth. These benefits are determined by load and existing transmission infrastructure, not generation. In other words, TE/VS benefits will likely increase as San Diego load increases, whereas the revenue requirement will not increase.[4]

The TEAM Methodology report cites five- and ten-year planning horizons as transmission planning landmarks. The five-year horizon reflects the limit of transmission planning, and the ten-year horizon "is required to facilitate identification of longer-term transmission needs."[5] Given the fact that load has decreased each year between 2006 and 2010, a ten-year planning horizon may be less critical than it has been in the past, when load reliably increased at a rate of approximately 2 percent per year.

In addition, the TE/VS and many current transmission projects are driven largely by RPS and resource adequacy standards; whereas load growth was a much more significant factor at the time the TEAM methodology was developed. With the recent and consistent negative growth in load that presumably was not anticipated during transmission planning projects of five to ten years ago, the transmission that was planned at that time will likely provide the load-growth-driven infrastructure for several years beyond the study period of 2015.

Q. Can you please describe your post-2015 qualitative analysis?

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[4] While additional transmission enhancements would offset the benefits, the current study accounts for all planned enhancements,and additional enhancements would be subject to CPUC proceedings.

[5] CAISO, *Transmission Economic Assessment Methodology*, http://www.caiso.com/docs/2004/06/03/2004060313241622985.pdf, page 1.4.

A. We selected a study year of 2020 and considered the impact of the various changes in inputs that are likely to prevail at that time. Five main variables are likely to impact the TE/VS benefits calculation:

1. Load growth: higher load is likely to make local RA requirements more stringent. TE/VS will mitigate that effect.

2. RPS goals: By 2020, RPS is expected to reach 33% of load. Again, as load increases, the renewable requirement will increase proportionately. Since the SDG&E area is transmission-constrained, TE/VS will help SDG&E meet the standard.

3. Natural Gas Prices: All else equal, TE/VS has the effect of lowering energy production costs and substituting renewable energy for gas-fired energy. Gas prices have been relatively low in recent years. If they are to increase, the effect of TE/VS will be to substitute away from higher gas costs. A NYMEX projection of gas prices in 2020 ranges from \$6.3 to \$8.4/mmBtu. This range is within 2015 assumptions and we do not see that gas prices will have a materials impact on TE/VS benefits.

4. Transmission and Generation upgrades in the San Diego areas: Additional transmission projects that provide for increased import capacity or allow for lower LCR in San Diego installed beyond 2015 could adversely impact the future benefits of TE/VS. We have reviewed the CAISO 2010 Final CAISO Transmission Plan, which assesses scenarios for 2014 and 2019 respectively. The plan contains no proposed Transmission projects that

would provide decreases in SDGE RPS costs or LCR requirements, nor a transmission path that provides SDGE with access to less costly energy.

We have reviewed qualitatively the effect of these five potential events on the benefit of TE/VS. We have found that none will adversely affect TE/VS benefits seen in the 2015 modeled year. Rather, based on load growth alone, TE/VS benefits are expected to exceed the 2015 level in the 2020 model year. The growth in load will cause the LCR and RPS requirements to become more binding, if anything. In addition, higher gas prices will result in a more substantial decrease in societal benefit.

Q. What is the basis for increased LCR in San Diego?

A. CAISO performs annual LCR studies to assess the LCR determinations. The CAISO assessment shows that the relationship between LCR and load growth is approximately linear. For instance:

1. The CAISO 2011 San Diego LCR evaluation states the changes in 2011 LCR requirements from the 2010 LCR requirements and concluded that the "Load forecast went down 91 mw, LCR decreased by the same amount"[6]

2. CAISO 2010 San Diego LCR evaluation states the changes in 2010 LCR requirements from the 2009 LCR requirements and concluded that "Overall the load forecast went up by 60 MW and that lead to an increase in the LCR by same amount"[7].

Q. How do you apply Mr. Drzemiecki's cost calculations?

[6] http://www.caiso.com/2788/2788ab565da00.pdf, page 95

[7] http://www.caiso.com/2052/2052e20b2b8a0.pdf, page 6

A. I am taking the combined revenue requirements of the TE/VS project, as well as the necessary transmission upgrades to the SCE and SDG&E networks that will be paid for by TNHC, and the cost of reconductoring Path 42. This is the combined cost that ratepayers will be required to bear each year for the 30 years following the completion of TE/VS in 2014. Mr. Drzemiecki has estimated this combined revenue requirement to be approximately $153 million per year. If the total annual benefits that accrue from TE/VS exceed this annual cost in each year, I would recommend that the project be approved.

Q. How do you apply the production cost calculations provided in the testimony of Christine Vangelatos?

A. Ms. Vangelatos has provided estimates of CAISO customer payments for 2015, both without the TE/VS project (the "Base Case") and with the project (the "TE/VS Case"). The change in consumer surplus is equal to payments under the TE/VS Case, minus payments under the Base Case. This number is offset by generation cost reductions in congestion costs, utility-retained generation margin, and excess loss payments. If this number is positive, consumers will enjoy a net benefit from TE/VS due to a decrease in production costs. This can be broken out by utility.

Q. The production cost calculations also included a LEAPS case. Should the benefits that stem from LEAPS be included in the TE/VS benefit-cost analysis?

A. No, since the instant TE/VS case does not address the cost of the LEAPS project. A benefit-cost analysis should only consider the benefits that result directly from the costs of this project. That said, facilitating construction of LEAPS is a positive and important externality that results from the TE/VS project. In other words, the construction of TE/VS results in an additional benefit that can only be captured after LEAPS is constructed. My analysis has found that TE/VS, with the reconductoring of Path 42, meets the benefit-cost test without the potential benefits of LEAPS. That said, the additional benefits of the two projects together bolster the benefits of each project in isolation. Construction of TE/VS will facilitate this pump storage project which will provide additional energy and ancillary services to the grid.

Q. What is the estimated market value of LEAPS regulation services?

A. Based on Ms. Vangelatos' analysis of LEAPS dispatch, I estimate the market value of LEAPS regulation services to be in the range of $37.4 to $64.3 million per year.

Q. What are the joint Societal Benefits of both the TE/VS and the LEAPS projects?

A. Ms Vangelatos estimates the 2015 Societal Benefit to be <u>$116.7 million</u> in 2015, which includes $18 million in congestion cost savings. The total consumer benefit is $133.7 million per year.

Q. Is it necessary to model strategic bidding in the production cost model?

A. In my opinion, it is not necessary. The Commission has not required that strategic behavior be modeled in a transmission study, and has specifically noted the challenges of modeling such behavior accurately, at considerable length.[8] The TEAM approach was developed following the California energy crisis, when market power was an important issue in the modeling of economic dispatch within California. Since then, and particularly since the introduction of the Market Redesign and Technology Upgrade in 2009, wholesale power markets in California have been much more competitive, with prices at or below a competitive benchmark price.[9] In competitive double-auction

[8] CPUC, *Opinion on Methodology for Economic Transmission Projects,* Decision 06-11-018, November 9, 2006.

[9] California ISO Department of Market Monitoring, 2009 *Annual Report on Market Issues and Performance,* http://www.caiso.com/2777/27778a322d0f0.pdf.

markets, such as the CAISO's integrated forward market, bidding one's true cost is a profit-maximizing strategy. Adding a new transmission line such as TE/VS is likely to maintain the existing level of competition among generators at a minimum, and perhaps increase it.

In addition, modeling strategic behavior is extremely complex and prone to error. Game-theoretic equilibria tend to be very sensitive to model conditions and parameters, and minor perturbations in parameters may have dramatic consequences in resultant market equilibrium outcomes. Also, the types of strategies that software such as Plexos are programmed to model are usually limited to a few simplistic strategies that themselves require very specific assumptions on behavior and information, and we can't reasonably expect all or even any market participants to adhere to these strategies, let alone with the parameters that we specify. Since it is not possible to simulate actual participant behavior perfectly in a simulation model, the modeling of strategic behavior in a simulation may result in effects that are not reflective of the actual system, and could thus be misleading.

Q. How do you determine the decrease in RA costs from Fred Depenbrock's LCR calculations?

A. Mr. Depenbrock has provided us with San Diego basin LCR requirements for both the Base Case and the TE/VS Case. I have queried the FERC Electronic Quarterly Reports database for all payments for capacity contracts delivered in the San Diego basin between October 2009 and September 2010, to determine a volume-weighted average capacity price in the Base Case.[10] The Base Case capacity cost is the LCR basin requirement multiplied by the basin average capacity price. To determine the savings under the TE/VS Case, we multiply the decrease in LCR requirement by the average price for capacity delivered anywhere within the CAISO system, also queried from the FERC reported EQR database.

Since the volumes and formats of capacity payments in the EQR database varied, due to inaccurate reporting, data inconsistencies, or other reasons, I summed the average capacity price between October 2009 and September 2010 to arrive at an annual capacity price per kilowatt-year. The following table shows monthly local RA capacity payments queried from FERC EQR.

Monthly San Diego LCR Capacity Payments

Month	Reported kw-months	Reported capacity payments	Avg monthly price	
Oct-09	999,500	$ 3,303,755	$ 3.31	
Nov-09	999,500	$ 3,293,054	$ 3.29	
Dec-09	999,500	$ 3,580,905	$ 3.58	
Jan-10	967,550	$ 3,911,612	$ 4.04	
Feb-10	965,775	$ 2,916,047	$ 3.02	
Mar-10	965,775	$ 2,916,047	$ 3.02	
Apr-10	1,931,550	$ 6,757,030	$ 3.50	
May-10	1,931,550	$ 7,351,419	$ 3.81	
Jun-10	1,931,550	$ 9,710,349	$ 5.03	
Jul-10	2,141,300	$ 22,805,730	$ 10.65	
Aug-10	2,176,800	$ 25,479,938	$ 11.71	
Sep-10	2,176,800	$ 16,672,612	$ 7.66	
Average across all months			$ 5.22	per kw-mo
Estimated annual San Diego LCR Capacity Payment			$ 62.61	per kw-year

[10] FERC EQR Database, http://www.ferc.gov/docs-filing/eqr/data.asp. Some data that appeared to be miscoded or specified with units incorrectly was corrected, per independent verification.

The average RA price for capacity deliverable to SP15 used in our analysis was $27 per kw-year.[11] Conversely, the price for local capacity within the SDG&E region averaged $62.61 per kw-year, as shown in the above table. This results in a total savings of $35.4 million or $34.9 million per year, depending on the contingency loss scenario used. While these two numbers are similar, I used the lower of them in the benefit-cost calculation.

Q. Did you take into account the increase in LCR requirements that would result from load growth after 2015?

A. No. The $44.9 million benefit of reducing Local Resource adequacy requirement was held constant. This is a conservative assumption.

Q. Are RA costs subject to inflation?

A. In this analysis, both system and local RA are in 2010 dollars and are held constant for the life of the project.

<u>RPS Benefits</u>

Q. How do you determine the decrease in RPS costs?

A. Based on current renewable contracts and requirements under the 33% RPS standard, we can estimate renewable costs under the Base and TE/VS + Path 42 Reconductoring cases.

According to the Renewable Energy Transmission Initiative (RETI), the 33% renewable requirement in 2020 equals annual renewable energy production of 99,651 gigawatt-hours per year. As of January 2010, the utilities had arranged for the annual procurement of 36,807 GWh, leaving a *net short* of 52,764 GWh unprocured.[12] The

[11] This was the RA price used in the Sunrise case. http://www.caiso.com/1c43/1c43e68414ce0.pdf

[12] "RETI Net Short Update," http://www.energy.ca.gov/reti/steering/2010-01-19_meeting/documents/04-Net%20Short%20Draft%202010-01-18.pdf

California Transmission Planning Group identified the planned renewable capacity by Competitive Renewable Energy Zone (CREZ) that are most likely to meet the net short in the "RETI Best CREZ Portfolio".[13] I used this listing to identify the resources in the *CREZ Name and Number* Table, which also provides delivered costs of generation, integration, and transmission of renewable resources by project. Using only the resources identified in the "Best CREZ Portfolio", I constructed a supply curve of renewable projects based on the delivered cost.[14,15] This supply curve represents the Base Case, and the total delivered cost up to the net short quantity represents the Base Case RPS cost of $6,872 million.

For the TE/VS Case, I included in the supply stack an additional 4,062 GWh of geothermal energy production in the Imperial North-B CREZ that TE/VS and the Path 42 reconductoring will enable to be delivered[16]. These resources have a delivered cost of approximately $153/MWh, including the per-MWh cost of the TE/VS and Path 42 Reconductoring annual revenue requirements, as calculated by Mr. Drzemiecki.[17] This delivered cost is lower than 13,028 GWh (25%) of the net-short portfolio. The TE/VS effectively shifts the supply curve to the right, and reduces the cost of meeting the RPS

[13] California Transmission Planning Group, *Final 2010 Phase 3 Study Report*, http://www.ctpg.us/public/images/stories/downloads/2010-09-10_final_phase3_study_report.pdf.

[14] The CTPG table of Best CREZ Portfolio lists planned renewables by CREZ, not by project. The specific resources selected from the CREZ Name and Number spreadsheet are best approximations of those identified in the CTPG table; however, there may be some minor discrepancies. These are not likely to have a significant impact on the conclusion.

[15] Project costs exclude RA credits, since the analysis calculates local capacity requirement savings separately.

[16] The inclusion of Imperial Valley North resources and Path 42 reconductoring is consistent with CAISO's approach in analyzing TE/VS benefits during the Sunrise proceeding. At that time, CAISO modeled TE/VS in conjunction with the proposed Green Path North project. Since Green Path North is now cancelled, we used the Path 42 upgrade, the project proposed by SCE/IID to bring geothermal resources to the CAISO grid.

[17] Resources are in the Imperial North B CREZ. As a proxy for costs and energy production, I used 600 MW of geothermal resources located in Imperial North A region (projects CACA 049613 and CACA 050613). These resources are estimated to produce a total of 4,370 GWh per year. Of this total, 4,062 GWh are expected to use TE/VS to serve SDG&E load. Based on annual transmission cost of $150 million, the average transmission cost is $40/MWh.

requirement. Under the TE/VS and reconductored Path 42 Case, the cost of meeting the RPS requirement is \$6,784 million. This is a net savings of \$88 million.

The following chart compares the two cases. The area between the curves represents the cost savings due to the TE/VS and Path 42 reconductoring.

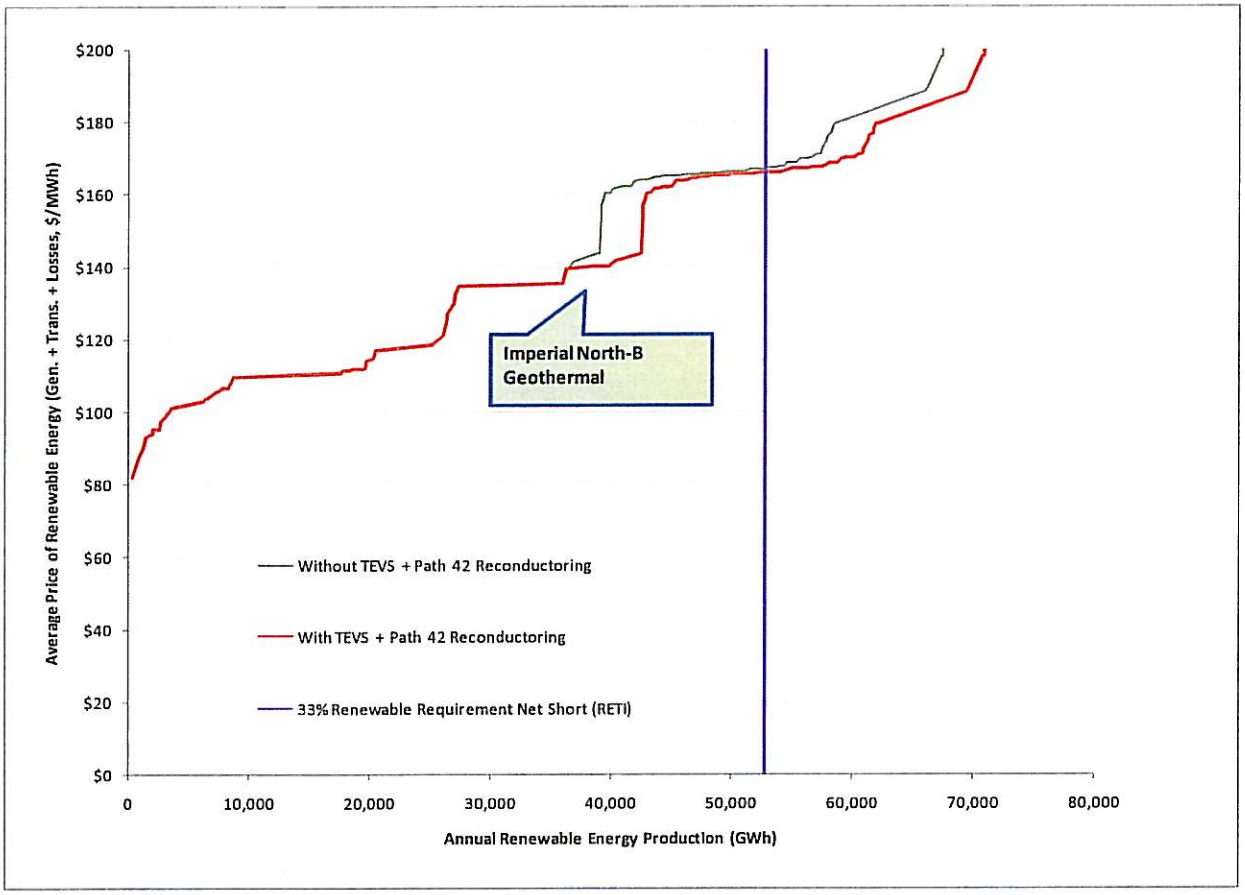
Our renewable capacity information is based on existing installed renewable capacity (per CEC power plants database)[18], and current planned renewable capacity (per California Transmission Planning Group)[19]. CTPG also provides SDG&E's current renewable contract position relative to the requirement. We estimate costs based on a CEC study of electricity generation by technology,[20] but also account for the rapid decrease in solar technology costs.

[18] Database of California Power Plants, from California Energy Commission web site, http://energyalmanac.ca.gov/powerplants/POWER_PLANTS.XLS.

[19] California Transmission Planning Group, *2010 Final Phase 3 Study Report.* http://www.ctpg.us/public/images/stories/downloads/2010-09-10_final_phase3_study_report.pdf

[20] California Energy Commission, *Comparative costs of California central station electricity generation: Draft Staff Report,* August 2009.

RPS Net Short Supply Curves: Base Case vs. TE/VS + Path 42 Recond. Case



The difference in cost to meet the requirement net short between the Base and TE/VS + Path 42 Cases is shown in the following table.

	Base Case	TE/VS + Path 42 Reconductoring Case		Savings	
Net Short (GWh)	52,764	52,764			
Average Delivered Cost of Energy ($/MWh)	$ 130.24	$ 128.58	$	(1.67)	Per MWh
Total cost to meet Net Short	$ 6,872,218,280	$ 6,784,242,159	$	(87,976,120)	All Net Short

Q. It appears as if only the Path 42 Reconductoring is necessary to connect the 4,062 GWh of geothermal energy production to the California grid. Why include the benefit of TE/VS, which is much more costly?

A. The aforementioned geothermal resources are the least-cost approach to meet SDG&E's RPS requirement in particular and CAISO footprint in general. TE/VS allows these or other cost-efficient renewable resources to serve San Diego. I estimate that SDG&E's share of the annual total renewable energy target of 99,651 GWh[21] is 7.2%[22], or 7,175 GWh per year. As of November 2010, SDG&E had secured 1,858 GWh of production that is already online, and another 3,270 GWh that is in development.[23] This leaves a net short within SDG&E of 4,062 GWh. It is my understanding that the Sunrise project is already fully accounted for, and cannot accept any of this additional capacity. The aforementioned geothermal production can utilize TE/VS to serve SDG&E load, since it is in the stack of the lowest-cost resources available to California load. Alternatively, SDG&E can contract with other renewable resources using TE/VS, and then the same geothermal resources will be available to meet RPS requirements of other LSEs. Another alternative is to reduce its net short without additional transmission infrastructure by installing distributed renewables in the form of rooftop photovoltaics, at a cost that exceeds the delivered geothermal cost by at least $50/MWh.[24]

Q. Does this utilization of the reconductored Path 42 exhaust its capacity?

A. No. This analysis assumes approximately 516 MW of its 800 MW capacity. Additional Path 42 capacity could be used to help other utilities meet their RPS goals.

Q. Why did you not include RPS benefits that Path 42 provides to SCE and PG&E ?

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[21] RETI Phase 2a Target, CTPG.

[22] Average of SDG&E share of peak load, CTPG.

[23] RPS Project Status Table, http://www.cpuc.ca.gov/NR/rdonlyres/B79A517F-845E-46E3-A8ED-6836A4BA588A/0/RPS_Project_Status_Table_2010_November.XLS

[24] Average cost of rooftop PV is $192/MWh. http://guntherportfolio.com/2010/08/sce-solar-rooftop-project-awards-and-solyndra-too/

A. SCE and PG&E can use the reconductored Path 42 to meet their RPS goals without the need for TE/VS. We included the entire reconductoring cost in the TE/VS cost benefit calculation even through only 64% of the reconductored Path 42 capacity is used to comply with SDGE's 33% RPS goal.

Q. Does TE/VS provide additional benefits to SCE or PG&E that were not quantified in the benfit-cost analysis?

A. Yes. TE/VS can provide benefits to SCE and /or PG&E, including:

- Additional renewable or other energy transportation from Imperial Valley and/ or the San Diego area
- Increase SCE's local reliability area, potentially reducing its RA costs
- Provide an additional source of energy during outages of the Southwest Power Link, which historically have been costly, or nuclear generators

Q. How do you determine the benefit of LEAPS ancillary services?

A. Ms. Vangelatos has provided the hourly dispatch of the LEAPS pump storage unit. Based on its output parameters, we presume that the unit can provide regulation ancillary services. Whenever the generator is operating below its maximum of its regulation range, it can provide its unloaded available regulation capacity to the day-ahead upward regulation market. Whenever the generator is operating above its minimum of its regulation range, it can provide its loaded capacity, less the regulation minimum, in the day-ahead downward regulation market.

Q. Are there other benefits that may not be quantifiable?

A. SDG&E will have greater access to renewable energy sources with the development of TE/VS, resulting in lower emissions. However, this is partly internalized by the savings in the renewable portfolio standard requirements.

Q. Did you assume that LEAPS will be built as a Merchant facility?

A. Yes.

Q. Are there any additional benefits of LEAPS that have not otherwise been quantified here?

A. Yes. These include the provision of spinning and non-spinning reserve ancillary services, quick start capabilities, improved integration of renewables by storing off-peak intermittent wind generation, decreased potential of wind curtailments, and substitution away from thermal generation during peak hours, thus reducing emissions in Southern California.

Q. Does this conclude your testimony?

A. Indeed it does. Thank you for the opportunity to provide testimony.

Exhibit 1

Z·GLOBAL
ENGINEERING & ENERGY SOLUTIONS

Douglas Bergman, Ph.D., M.A.

Experience Summary

Insightful Ph.D. quantitative energy economist who brings novel approaches to problems and bridges gaps across financial, engineering, analytic, information technology, senior management, and legal/regulatory roles. Detail-oriented analyst, writer, and presenter. Distills complex issues into straightforward, salient concepts appropriate for non-technical audiences. Client-focused consultant who works well under time and budget constraints.

Key Assignments

Lead Market Monitoring Specialist / Economist / Analyst / Graduate Associate

Education

B.A. Mathematics, University of California,
Ph.D., M.A. Economics, University of Arizona

Professional Association

National Association of Business Economics

Experience

Over 25 years

Relevant Expertise

- *Microeconomic quantitative analyses and investigations*
- *Econometric/statistical modeling*
- *Data analysis and integration*
- *Nodal pricing and congestion analysis*
- *Application and tools development*
- *Project management*
- *Report-writing and presentations*

Professional Training

- *PowerWorld Introductory and Market Modeling classes*
- *Energy risk management*
- *Control area interchange*
- *SAS programming*
- *Electric power engineering fundamentals*
- *Combined cycle generation*
- *California ISO Nodal Market training sequence*
- *Project Management*
- *Speaking and leadership*

Principal Economist, ZGlobal, 2010 – present

Lead Market Monitoring Specialist, California Independent System Operator, Folsom, CA - 2001 - 2010

Lead Analyst of California power markets. Conduct analyses, compose reports, and prepare presentations on performance and trends in regional wholesale electric power markets for senior management and regulatory agencies, focusing on wholesale energy markets, market costs, nodal transmission congestion, reliability costs, price formation, and indices for estimation of market power. Developer and subject-matter expert in market monitoring technology upgrade for compliance with new California ISO nodal market software. Served as Project Manager for a segment of this project; directed a staff of four and two consultants in development of monitoring tools in SAS Business Intelligence Platform. Develop metrics and indices to measure market performance, efficiency, and the effectiveness of regulatory mechanisms. Prepare and deliver presentations on market activity and performance for monthly teleconferences with FERC and for public meetings of ISO Market Surveillance Committee, an expert advisory panel.

Economist and Analyst, Self-Employed Consultant - 1998 – 2006

Associate Faculty of Economics, University of Phoenix, School of Undergraduate Business and Management, Sacramento, CA

Qualified expert witness providing damages opinion in intellectual property dispute case in U.S. Federal District Court. Prepared written testimony/ letter report on trademark dispute; was deposed and stood witness. Provided an estimate of economic damages due to alleged trademark infringement. Modeled present economic value of damages suffered by client. Provided written testimony/letter report in lease litigation and created computer-based tool that counsel used to analyze negotiating points in settlement conference; resulted in favorable settlement. Managed client project. Provided written testimony/letter report for business dissolution. Estimated economic value of firm's intangible assets using income- and market-based valuation methodologies. Revised sales forecasting model for an S&P-500 technology company. Developed analytic tool for future use and provided recommendations on incorporating macroeconomic variables into next-generation forecast model. Advised a European manufacturer in strategy for entry into U.S. market. Helped CEO of the U.S. subsidiary to understand relevant economic issues, educating him with skills needed to decide whether to expand production, maintain output, or exit, based upon market conditions.

Graduate Associate, University of Arizona, Tucson, AZ - 1995 - 2005

Conducted research in microeconomics, including design and testing of an auction market. Instructor for a macroeconomics class. Teaching Assistant for experimental and introductory economics classes.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of

"DIRECT TESTIMONY OF DOUG BERGMAN ON BEHALF OF THE NEVADA HYDRO COMPANY"

on all known parties to A.10-07-001 by transmitting an electronic mail message with the document attached to each person named in the official service list who provided an electronic mail address.

Executed this 30th day of November, 2010 at Washington, D.C.

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