FILED
12-16-11
04:59 PM

Attachment 1

February 7, 2006

An Economic Evaluation of the LEAPS Project and Associated Transmission For the Elsinore Valley Municipal Water District

Samuel A. Van Vactor
Stefan Brown
David Ramberg

Table of Contents

1. Executive Summary 4
2. Objective of the LEAPS Study 10
3. The Economics of Pumped Storage 11
   3.1. Revenue Prospects for Pumped Storage Facilities 11
      3.1.1. Revenue from energy sales 11
      3.1.2. Revenue from balancing the grid and the reserve 12
      requirement 12
   3.2. Economic Analysis by Nevada Hydro 13
      3.2.1. The value of Energy 13
         3.2.1.1. Assumptions concerning peak prices 13
         3.2.1.2. The on-peak and off-peak periods 14
         3.2.1.3. Reservoir size 15
      3.2.2. The value of Capacity 15
         3.2.2.1. Capacity Payments in CDWR Contracts 15
         3.2.2.2. Capacity to follow load 16
4. The Cal ISO Ancillary Services Market for Capacity 18
   4.1. Day-to-day and minute-to-minute procurement 18
   4.2. Types of capacity and reserves 19
      4.2.1. Regulation up and down market 19
      4.2.2. Spinning and non-spinning reserves market 20
5. How LEAPS would operate in the Cal ISO Market 21
   5.1. Modeling LEAPS revenue 21
      5.1.1. Key Assumptions 21
      5.1.2. Energy sales and revenue 24
      5.1.3. A/S Sales 24
   5.2. Uncertainty regarding key assumptions 25
   5.3. Sensitivity analysis 26
   5.4. Long-term trends that could improve the LEAPS market 26
6. Alternative Sources of Revenue 28
   6.1. Reliability Must-Run (RMR) Contracts 28
   6.2. Firming Renewable Energy Projects 28
   6.3. Potential Long-term contracts with nearby LSEs 28
   6.4. Placing LEAPS in the rate base 29
   6.5. Marketing A/S in the off-peak period 31
   6.6. Qualifying Facilities (QF) Sales 31
7. Revenue, cost, and profitability of LEAPS 32
8. Conclusion on Pumped Storage 33
9. Objective of the review of Transmission 34
10. Could the project stand-alone? 35

10.1. Comparison of TE/VS and LEAPS capacities 35
10.2 Improved reliability 35
10.3 Economic need for transmission 36
10.4 Significance of SDG&E integrated resource plan 37
11. Nevada Hydro analysis of transmission flows 39
11. 1 Reasons for the low flow 39
11.2 Use of phase shifters 39
12. Analyses by the California Energy Commission and the Cal ISO 40
12.1 California Energy Commission 40
12.2 Comments by the Cal ISO, SCE, and SDG&E 41
13. Nevada Hydro s pro-forma rate analysis 42
14. Conclusion on Transmission 43

1. Executive Summary

1.1 The Pumped Storage Project

Although the fundamental economics of the Lake Elsinore Advanced Pumped Storage (LEAPS) Project are sound, development may be constrained by the type of market structure it faces. For the Southern California electricity grid, the project offers improved reliability, the flexibility to balance load and generation fluctuations, and crucial swing transmission between Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E). Nonetheless, unless the project can obtain a long-term sales contract or is "rate-based," it is unlikely to secure financing.

It has been assumed that primary revenue from the project would be derived from on-peak energy sales. To make such sales profitable, however, there must be a large differential between on-peak and off-peak energy prices. Some years ago, there was such a differential. However, the improved efficiency of combined cycle gas turbines and higher gas prices have moderated much of the distinction between base-load and peaking units. In recent years off-peak power prices have been nearly as high as on-peak prices. High-cost pumping quickly undermines the economics of pumped storage. This makes it virtually impossible for LEAPS to enter into profitable long-term purchase and sale contracts for energy.

As a hydroelectric generator, however, LEAPS can quickly and cheaply vary its generation in order to balance the grid. Thus, there are substantial opportunities for selling into the California Independent System Operator's (Cal ISO's) balancing and ancillary service (A/S) market. Unfortunately, the revenue in the A/S market is uncertain and unlikely to be high enough to offset the lower than expected revenue in the energy market. Moreover, there is no mechanism for a long-term contract, short of rate-basing the project. Therefore, we conclude that in the present market structure, the LEAPS project is unlikely to earn sufficient revenue to cover the costs that Nevada Hydro has identified. This does not necessarily mean that the project is dead, but it does mean that its design and costs have to be re-thought and regulators must be lobbied to make key changes if it is to move ahead.

As a merchant plant, LEAPS would face a volatile market for its services, making guaranteed revenue lower than costs. In contrast, if the project is incorporated into the Cal ISO's transmission rates, i.e., if it is "rate-based," the revenue-cost perspective is quite different. The central question to be asked is: What are the benefits to ratepayers from the LEAPS facility and associated transmission? The answer is threefold: 1) LEAPS will improve reliability in the Southern California grid; 2) it will allow the Cal ISO to reduce congestion and reliability must-run (RMR) expenses in the San Diego area; and 3) it will allow the Cal ISO to cut operating costs in its ancillary services (A/S) market. Any of these benefits could be sufficient to justify

rate-basing the project, but the combination of all three is a particularly powerful argument and unique to LEAPS' project design.

We have little experience at judging Nevada Hydro's estimates of project cost, but what has been provided appears reasonable, although supporting documentation would be helpful. However, the market for LEAPS output and its expected revenue is our field of expertise, and that is the focus of this report. In this regard we have investigated the following questions:

1. Is the LEAPS facility properly designed to take advantage of existing markets?
2. Are Nevada Hydro's assumptions regarding likely prices for energy and capacity sales reasonable?
3. Has Nevada Hydro missed market opportunities?
4. What are the major economic risks faced by the project?
5. Is the present planned facility cost-effective?

The LEAPS project is designed to pump for twelve hours and generate for twelve hours. Unfortunately, this does not match the market cycle for on-peak and off-peak energy, particularly in California. The on-peak period stretches sixteen hours, from 6AM to 10PM, excluding Sundays and holidays. The off-peak period is the remaining eight hours during weekdays, and all day on Sundays and holidays. Most bilateral energy trading is in sixteen-hour on-peak or eight-hour off-peak blocks. It is, of course, possible to negotiate non-standard purchase and sale contracts, but this would reduce the differential between on-peak and off-peak prices.

Nevada Hydro's spreadsheet dated July 20, 2005 assumed an on-peak price of $65 per MWh and an off-peak price of $25 per MWh. Although these price assumptions might be reasonable under different circumstances, since the California energy crisis ended in 2001, such a high differential has existed on only a few days, and the average differential is far lower.

The planned LEAPS upper reservoir is expected to contain 16 to 17 hours' worth of water for hydroelectric generation under normal operations. This means that LEAPS cannot take full advantage of the off-peak periods to pump water. For example, if the reservoir is empty at 10 PM on Saturday, it could be refilled by 2 PM on Sunday. The facility would then sit idle until 7AM on Monday (or Tuesday if Monday is a holiday). We calculate that the small reservoir size constrains on-peak generation, dropping it to about 333 MW, far short of the 500 MW of capacity. The reservoir size is a constraint on energy sales but not necessarily on capacity sales in the Cal ISO's A/S market. As it turns out, the A/S market is the project's primary source of potential income.

In addition, the restructuring of the California electricity market has significantly changed the manner in which an IPP can market power, and unfortunately the new

system makes it difficult to obtain long-term contracts, which are usually necessary for project financing.

In its economic and financial analysis of the LEAPS project, Nevada Hydro calculated the value of capacity based on the California Department of Water Resources (CDWR) purchase contracts made by S. David Freeman on behalf of the State of California from February through June 2001. These contracts were made public in 2002 and generated considerable controversy because, within weeks of their finalization, spot power prices dropped precipitously, and it appeared that the State had bought at the top of the market. Consequently, the State of California spent considerable effort at FERC to have the contracts nullified. In the end, all of them were modified to some extent.

In any case, that window of opportunity is lost. The CDWR is no longer in the market for new purchases of power on behalf of California, and even if it were, neither it nor any of California's utilities would agree to make such high capacity payments in today's market.

Although the chances of obtaining a long-term contract with a large capacity payment are close to zero, there are important marketing opportunities in the Cal ISO's A/S market. There are two fundamental ideas behind this market: the need to balance the grid in order to accommodate fluctuations in load and generation, and the need to maintain reserves. "Regulation up" and "Regulation down" are types of capacity products marketed by the Cal ISO that are designed to balance the grid and provide reserves. "Spinning" and "non-spinning" reserves are designed to ensure adequate reserves – particularly to protect against forced outages. The Cal ISO purchases these products, and the cost is added to the tariffs charged for using the transmission system. In contrast, real-time energy costs are purchased from one scheduling coordinator (SC) and sold to another, depending on their activity and their schedules.

Our methodology for evaluating the economics of the LEAPS project is to analyze how much revenue it would have earned had it been in operation during the last year and to extend that to future years. In 2005, due in part to high gas prices, on-peak prices were only 35% higher than off-peak prices, as compared to Nevada Hydro's assumption of 160%. This margin is further constrained by scheduling and transmission fees, which can exceed $4 per hour for *both* generation and load. Based on 2005 actual prices, in our base case we project that LEAPS would have had annual net energy sales of just $0.3 million, instead of the $54.6 million Nevada Hydro calculated. (2005, however, would have been an exceptionally poor year for pumped hydro energy sales; other years would have produced higher income, as illustrated using forward prices.) The inclusion of transmission and scheduling fees explains part of our lower figure, but the difference is mostly a result of changes in the energy market, which make Nevada Hydro's on-peak and off-peak estimates outdate. .

In our base case, A/S sales dominate LEAPS revenue. Revenue is calculated by multiplying the MW volume for each product by the number of on-peak hours, then multiplying that figure by the price. Then a Cal ISO fee of $0.79 per MWh is subtracted. In the base case, the net from A/S sales is estimated at $27.4 million per year. This is much larger than the revenue from energy sales, and even slightly larger than Nevada Hydro's $25 million estimate for capacity sales.

Future prospects for the LEAPS project may be better than our analysis, which is based on current prices. The primary economics of conventional pumped storage is driven by the difference in cost between base load and peaking facilities. The shift into high-efficiency combined-cycle gas generators eroded the economics of pumped storage, because it lessened the distinction between such units. When gas prices were low, gas-fired generation was cheaper than either nuclear or coal. As a consequence, most new generating facilities built were gas-fired. High gas prices have, once again, shifted the economics. Coal and nuclear generation are now more attractive than they were in the 1990s. If gas prices remain high in North America, more coal-fired base load generating plants are likely to be built. This could widen the differential between on-peak and off-peak prices.

Perhaps the greatest hope for the LEAPS project lies in the Cal ISO's Market Redesign and Technology Upgrade (MRTU). There are two aspects to the new market structure that are favorable. First, the Cal ISO will implement a day-ahead hourly market, similar to the one previously operated by the CalPX. This would allow LEAPS to be far more selective in the hours it pumps and generates, and should improve its revenue from energy sales. Second, the MRTU plans to introduce locational marginal pricing (LMP), which will favor generators that are in strategic locations. For example, LEAPS might buy in the SCE service territory and sell in the SDG&E region, taking advantage of higher prices in a zone likely to be constrained more often. Another trend that could improve LEAPS' economics is the growth of intermittent energy sources – solar, wind, and tidal power, to name three. There is a need to "firm" power from these sources.

Once built it is possible that LEAPS could qualify for a reliability must-run (RMR) contract. These contracts concern certain generation facilities that must run either to ensure grid reliability or to prevent the facility from taking advantage of intra-zonal congestion and exercising market power. The RMR contract involves a fixed capacity payment and an energy payment for generation associated with the project's variable costs. As a hydroelectric generation facility with the ability to start generating without drawing power from the grid, LEAPS might also qualify for a "black start" payment, which is part of some RMR contracts.

It is has been suggested that LEAPS could be developed in tandem with wind farms or large solar projects as a means to "firm" their energy production and enhance their

value. However, the present size of the reservoir is too small to be effective in this manner.

The significance of the analysis of Cal ISO's A/S market is twofold. Foremost, it represents an opportunity for marketing the capacity of the LEAPS project. It can also be viewed as the "opportunity cost" for either Southern California Edison (SCE) or San Diego Gas & Electric (SDG&E,) who could self-provide their own A/S. Because utilities face risks in the A/S market, they may be willing to pay a premium for a long-term contract that guaranteed no unexpected fees from the Cal ISO. There is some reason to expect this risk to grow over the coming years along with load growth. For such a sales contract to be realistic, however, projected LEAPS sales in the A/S markets will have to come close to or exceed its expected costs.

In their November 29, 2005 FPC Section 205 filing, Nevada Hydro proposed putting the LEAPS project - along with its transmission system - into the rate base. That is, both would be treated in the same manner as Trans-electric's expansion of Path 15. FERC would approve rates and the Cal ISO would recover costs and a return on equity for the project sponsor from transmission and scheduling charges. There is adequate precedent for treating the transmission expansion in this manner, but including a generation project is another matter. Nonetheless, a good argument can be made that load-following projects, such as LEAPS, should be treated the same way as transmission projects. That is, assets are owned privately, but operational control is dedicated to the Cal ISO. The cost of the assets is then put into the general transmission and A/S tariff charged by the Cal ISO. The justification for this approach is twofold: 1) it prevents owners of strategic assets from exercising market power, and 2) it reduces market transaction costs, which are obviously quite high.

Under present rules, the Cal ISO's automatic generation control (AGC) would not allow regulation up, regulation down sales on load – the pumping part of LEAPS' activity. However, the technology does exist for the Cal ISO to control pumping rates as it now controls generation rates. If procedures are changed, it could allow LEAPS to nearly double its A/S income. Nevada Hydro should consider pursuing this option.

When revenue and cost factors are considered, we conclude that the LEAPS project, as a merchant plant, is not viable at this time. The primary problem is the low differential between off-peak energy prices and on-peak energy prices. Nonetheless, Nevada Hydro's estimate of the value of capacity, sold outright in a long-term contract, and ours, sold short-term into the Cal ISO A/S market, are nearly identical.

1.2 Associated Transmission

It has been suggested that in the event that the Lake Elsinore Advanced Pumped Storage (LEAPS) project is determined to be uneconomic, or, for whatever reason,

could not be financed, the Talega-Escondido/Valley-Serrano (TE/VS) transmission Line might be built separately. In its *2005 Energy Report,* the California Energy Commission (CEC) reviewed the TE/VS transmission proposal and commented:

> The Nevada Hydro Company, Inc. has made significant licensing progress with federal agencies…The FERC-authored Draft EIS is expected in November 2005, while the Final EIS and Record of Decision are expected in April 2006.
>
> However, the proposed LEAPS project has unresolved concerns, including:
>
> a. Incomplete economic studies.
> b. Incomplete transmission system impact studies, which could identify further environmental impacts…
>
> The transmission component of LEAPS may offer substantial benefits to California and is worthy of further monitoring and future consideration. *However, pending completion of system and economic studies, as well as FERC approval, the Energy Commission believes the project does not warrant a recommendation at this time.* The Energy Commission recommends monitoring and future consideration of the project in the 2007 Energy Report cycle. [Emphasis added.]

We are in general agreement with the CEC. Thus far, neither the California Independent System Operator (Cal ISO) nor Nevada Hydro has produced economic studies that would support the development of either LEAPS or the transmission system. Without such studies, the project may not gather the support of key California institutions, and FERC is unlikely to approve either project without their consent.

More significantly, the emphasis on various transmission options to improve north-south interconnections for Southern California has appeared to shift. Several years ago it was thought that SDG&E would need to be better connected to SCE if it were to ensure the reliability of its system. New generation projects to the south have shifted the emphasis away from connections to the north. The main advantage of the TE/VS transmission line would not be to move power to San Diego; it would be to move lower-cost power from Northern Mexico and Arizona to Los Angeles. However, the need for such south-north transmission is some years off – 2010 at the earliest. SDG&E will have to complete a transmission system east to the Imperial Valley and Arizona (the Sunrise project), as well as upgrade its existing system, before there is a need for the TE/VS transmission line.

Even this conclusion is fluid because it depends on which other transmission projects are selected by the Cal ISO. If, for example, the Sunrise project is rejected in favor of the GreenPath project, the TE/VS transmission project could be essential for SDG&E to move power from Imperial Valley, Arizona, and Mexico by looping through transmission grids to the north. In other words, the TE/VS connection would be vital for a north-south flow of power.

2. Objective of the LEAPS Study

Elsinore Valley Municipal Water District (EVMWD) has requested that we investigate the economic viability of the LEAPS project. There are a number of issues to be examined to determine viability, and a brief description of a power project's typical trajectory toward operations would be instructive. In this regard, power generation projects go through several distinct phases. In the initial phase the project is little more than a concept. Large power generation projects require site approval from state and/or federal authorities. Additionally, hydro projects require review and approval by FERC. A crucial part of the site review process is an environmental impact statement (EIS). To meet the requirements of the EIS and the licensing process, the project sponsor is usually required to provide detailed descriptions of the project, including its engineering, location, plant characteristics, etc. Unfortunately, the sponsors are seldom required to analyze the project's prospective market and its economic viability. Neither a state siting authority nor FERC normally has to exercise such oversight responsibility, because if the project is not economic it is unlikely to obtain financing. Many more projects are proposed and licensed than built. A good example is the present stampede to construct LNG receiving terminals in North America. As of this writing there are scores of such projects proposed and less than a half dozen (if that number) will be built.

Although we only briefly reviewed the materials filed with FERC it appears that the most substantive information from Nevada Hydro is contained in a spreadsheet model dated July 20, 2005 that was provided separately from the FERC filings.

We have little experience at judging Nevada Hydro's estimates of project cost, but what has been provided appears reasonable, though supporting documentation would be helpful. The market for LEAPS output and its expected revenue is, however, our field of expertise and that is the focus of this report. In this regard we have investigated the following questions:

1. Is the LEAPS facility properly designed to take advantage of existing markets?
2. Are Nevada Hydro's assumptions regarding likely prices for energy and capacity sales reasonable?
3. Are there other potential market opportunities for the project?
4. What are the major economic risks faced by the project?
5. Is the present planned facility cost-effective?

3. The Economics of Pumped Storage

3.1. Revenue Prospects for Pumped Storage Facilities

The idea behind a pumped storage facility is straightforward. Fundamentally, they are designed to store energy. In addition, because they are hydroelectric, they are extremely flexible; generation can be ramped up and down quickly to meet variations in electricity demand they can be designed to follow the load and balance the grid. In contrast, thermal units have slower ramp rates, can take a long time to reach full capacity and most need an infusion of electricity from the grid to start up. In general, the larger the thermal unit, the less flexible it is. Nuclear and coal generation units typically run twenty-four hours per day and are considered base load. Gas-fired generation can be designed to meet peak demand for a few hours per day, but they still require thirty minutes or so to come to full capacity and some time to shut down. In contrast, hydroelectric generation can start and stop quickly and at low cost.

3.1.1. Revenue from energy sales

Base load and peaking thermal generation units have distinctly different cost structures. Base load facilities typically have a high capital cost and low variable cost. Gas-fired peakers have a lower capital cost and a high variable cost (the price of fuel). Pumped storage is designed to take advantage of the cost difference in the types of thermal generation. It is a simple idea. Water is pumped from a low-lying reservoir to a high-elevation reservoir during the night when electricity is cheap, and used to generate power during the day when electricity is far more costly. In the jargon of the industry today this is referred to as an energy purchase in the off-peak hours and an energy sale during on-peak hours. The pumped storage unit takes advantage of the difference between off-peak and on-peak costs to make a profit. In a market setting, off-peak prices are virtually always cheaper than on-peak prices, reflecting the difference in demand during on-peak and off-peak hours, the cost differential described and the impact of operations on the market. (Prices can even be negative in off-peak hours because large thermal units cannot be shut down quickly. That is, the owner of a base load unit has to pay a penalty to dispose of unwanted electricity.)

In the California system the owner of a pumped storage facility could enter into two offsetting power contracts. Electricity could be bought in the off-peak period to pump water up to the higher reservoir. Then, the water could be used to generate power in the on-peak period and sold for a higher price. If this were the only source of income, for such a project to be economic the differential between the on-peak price and the off-peak price must be great enough to cover the energy loss from pumping, meet the project s debt service and administrative costs, and provide an adequate return on equity.

3.1.2. Revenue from balancing the grid and the reserve requirement

Fortunately, buying cheap off-peak power and selling it during on-peak times is not the only potential source of income for a pumped storage facility. Although many commodities have immediate spoilage, electricity is unique in that the grid must be kept in constant balance: demand (load) must match supply (generation) within a very close tolerance. Otherwise, the consequence is a blackout, in which the transmission system becomes disconnected and everyone in the disconnected area loses power. This would be an insurmountable problem were it not for the fact that load can be predicted quite accurately, depending on the time of year, day of the week, time of day, and weather. Nonetheless, the grid operator must constantly adjust generation output up and down to keep the system in balance.

When the grid is controlled by a single vertically-integrated utility, dispatchers balance the system by adjusting the generation output of the various units owned and controlled by the utility. They use a least-cost rule of thumb (□economic dispatch□) to decide how to balance the system; in doing so they consider two types of marginal costs: first, the cost of increasing or decreasing generation from each of the generating units and, second, the impact of the increased or decreased generation of specific units on transmission costs. The impact on transmission costs is usually only relevant during peak times, when the grid is congested. The industry often refers to costs (or prices) of increasing generation as □incs□ and the costs (or prices) of decreasing generation as □decs.□ This is an important concept in understanding the balancing role of a pumped storage facility.

The Cal ISO combined the operating area of California□s three largest investor-owned utilities. The utilities, Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E), retained ownership of the transmission lines, but dedicated operational control to the Cal ISO. The separation of the control of high-voltage transmission lines from generation and distribution allows other companies to use the transmission system on a non-discriminatory basis and, thereby, buy and sell electricity to and from remote locations. Most generation is sold through bilateral contracts; typically from a power generator, like AES or Williams, to a load serving entity (LSE), like SCE or SDG&E. Either the buyer or the seller of power in the bilateral market (or their agent) will act as a □scheduling coordinator□ (SC) and schedule the expected electricity flows through the Cal ISO□s grid. Schedules are required to balance, but in real-time actual generation and load may deviate from the plan. When this happens the Cal ISO has to step in on behalf of the SC and buy or sell additional generation. In order to fulfill its balancing role, the Cal ISO buys and sells both energy and capacity. For energy purchases, the Cal ISO acts as a market intermediary (an auctioneer), buying or selling energy for SCs that are short or long.

In addition to balancing the grid, the ISO is required to maintain reserves, amounting to 5% of hydroelectric generation and 7% of thermal generation. This works out to an average of about 6.2% in California. Reserves are generation capacity that stands by ready to generate, in the event of a forced outage or unexpected surge in the load. Capacity, however, cannot be attributed to a specific SC (unless it is self-provided) and this cost is distributed as a pro-rata expense in the Cal ISO's transmission tariffs. The purchase of capacity is made through the Ancillary Service (A/S) Market, which will be described in the next section. Before turning to an analysis of that market, however, it would be useful to describe Nevada Hydro's economic analysis and how it differs from the present reality of the California market.

3.2. Economic Analysis by Nevada Hydro

3.2.1. The value of Energy

3.2.1.1. Assumptions concerning peak prices

A comprehensive analysis of expected project revenue cannot be completed given the limited economic analysis of the project available at this time.

Nevada Hydro explained in their FERC filing that adequate information on pricing was not available to do a full-scale analysis: "Forecasting the on- and off-peak value of project power assumes either a market in place with pricing history, or contracts for the purchase and sale of project power well into the negotiation stage. There is no market price history in California and it is premature for the applicant to enter into negotiation for the purchase and sale of energy or capacity. However, in Section 5.1.2 above we attempt to estimate project energy values."[1]

Nevada Hydro's Section 5.1.2 did not include a step-by-step breakdown of how key assumptions were made. However, the spreadsheet output dated July 20, 2005 and provided separately assumed an on-peak price of $65 per MWh and an off-peak price of $25 per MWh. As will be explained, these price assumptions are far too optimistic, given high gas prices and changes in generation technology. Most importantly, there are a variety of sources that report on the bilateral market for electricity and, of course, the Cal ISO also runs both energy and capacity markets.

In our analysis to follow, we examine three types of energy prices that would be relevant to the LEAPS project: daily bilateral prices, forward long-term prices, and prices from the Cal ISO.

[1] Nevada Hydro, Lake Elsinore Advanced Pumped Storage Project, Exhibit D, Project Costs and Financing, p. D-17.

The primary sources of on-peak and off-peak day-ahead prices are from the bilateral spot market for electricity delivered to Northern and Southern California. The trade press has collected these data since 1996. Bilateral prices are negotiated every business day and vary significantly depending on the time of year, gas prices, and weather.

In addition to daily prices, the trade press publishes forward prices for northern and southern California. Forward prices are for a one-month, one-quarter, or one-year block covering either the on-peak or off-peak period. This allows the buyer or seller to lock in prices, stabilizing cost or revenue.

From April 1998 through February 2001, the California Power Exchange (CalPX) operated a market for energy, which set a price for each hour in the next day. In 2000 the exchange added a block forward market, which set monthly and quarterly forward prices. Unfortunately, the CalPX terminated operations in 2001 during the crisis.

As noted, the Cal ISO operates a balancing, or real time, market that sets energy prices every five minutes.[2] The Cal ISO divides its operating area into 24 zones (with more to come), but there are only two important ones: NP-15 (north of path 15) and SP-15 (south of path 15). Path 15 is the transmission line that connects the service territory of PG&E with the service territory of SCE. The LEAPS project is located in SP-15. Cal ISO real-time prices are not, however, suitable for valuing the cost of energy for pumping and its value for resale. It would not be practical to buy or sell into this market, except in the manner outlined in Section 5, which supports capacity sales. Nonetheless, it is another source of pricing information.

3.2.1.2. The on-peak and off-peak periods

The LEAPS project is designed to pump for twelve hours and generate for twelve hours. Unfortunately, this does not match the market cycle for on-peak and off-peak energy, particularly in California. The on-peak period stretches sixteen hours, from 6AM to 10PM, excluding Sundays and holidays. The off-peak period is the remaining eight hours during weekdays, and all day on Sundays and holidays. Most bilateral energy trading is in sixteen-hour on-peak or eight-hour off-peak blocks. It is, of course, possible to negotiate non-standard purchase and sale contracts, but this would reduce the differential between on-peak and off-peak prices.

The uneven distribution between on-peak and off-peak hours means that the full generation potential of LEAPS may not be utilized for energy sales. Applying the

[2] Source: CAISO document at http://www.caiso.com/docs/1998/12/02/1998120218223715047.pdf, page 5 of 8.

standard definitions results in approximately 4,910 on-peak hours and 3,850 off-peak hours per year.[3] If LEAPS pumps full time in the off-peak hours (without any reservoir constraints), on-peak generation would only average 392 MW per hour, considerably less than the rated capacity of 500 MW.

It is anticipated that the Cal ISO will have developed a day-ahead hourly market for energy within the next few years. This would be less constraining to the LEAPS operation, but there would still be the problem of weekends and holidays where sales prices would be low and unlikely to cover the cost of pumping.

3.2.1.3. Reservoir size

The planned LEAPS upper reservoir is expected to contain 16 to 17 hours' worth of water for hydroelectric generation under normal operations. This means that LEAPS cannot take full advantage of the off-peak periods to pump water. For example, if the reservoir is empty at 10 PM on Saturday, it could be refilled by 2 PM on Sunday. The facility would then sit idle until 7AM on Monday (or Tuesday if Monday is a holiday). We calculate that the small reservoir size further constrains on-peak generation, dropping it from an average of 392 MW to about 333 MW.

The reservoir size is a constraint on energy sales but not necessarily capacity sales in the Cal ISO's ancillary service market. This will be explained and analyzed in detail in Sections 4 and 5.

3.2.2. The value of Capacity

Nevada Hydro's conclusion regarding the value of capacity and how it is priced in the California market has been superceded by the end of the 2001 electricity crisis and the state's regulatory changes. The Restructuring of the electricity market has significantly changed the manner in which an IPP can market power, and unfortunately the new system makes it more difficult to obtain long-term contracts, which are usually necessary for project financing.

3.2.2.1. Capacity Payments in CDWR Contracts

In its economic and financial analysis of the LEAPS project, Nevada Hydro calculated the value of capacity based on the CDWR purchase contracts made by S. David Freeman on behalf of the State of California from February through June 2001. These contracts were made public in 2002 and generated considerable controversy because within weeks of their finalization, spot power prices dropped

[3] This varies slightly from year to year; for example, 2005 had 3,848 off-peak hours.

precipitously and it appeared that the State had bought at the top of the market. Consequently, the State of California spent considerable effort at FERC to have the contracts nullified. In the end, all of them were modified to some extent. By 2005, however, high gas prices had reversed the economics once again and many of the contracts were in the money. That is, prices in some of the CDWR contracts are below spot or forward prices being offered in the market. In a final twist of irony, California is seeking to force Calpine to honor its CDWR contract, despite the fact that the company had to declare bankruptcy in part because of it.

Table 3.1 summarizes the capacity payments and other terms of the CDWR contracts. In 2001 California was willing to pay more for capacity than Nevada Hydro assumed for a LEAPS long-term contract. As mentioned, however, most of these contracts were renegotiated, so the earlier public versions may be misleading, i.e., these capacity payments are probably higher than CDWR's actual obligation. In any case, that window of opportunity is lost. The CDWR no longer purchases power for California, and even if it did, neither it nor any of California's LSEs would agree to make such payments in today's market.

Table 3.1

Summary of Major CDWR Contract Terms

Company	Capacity Payment Period	Years in Period	Average Payment per Period (thousands)	Number Payment Periods	Total Payments in Period (million)	Capacity (MW)	Capacity Payment kW/year	Daily Obligation (Hours)	Package	Yearly Obligation (Hours)	Lead Time
Alliance	Contract Average	10.0	$3,139	57	$178.9	80	$224	16	Peak	1,000	1 day
CalPeak Border	Contract Average	10.0	$480	120	$57.6	48	$120	4-24	Any	1,200 (Peak), 1,300 (Other)	1 day
CalPeak El Cajon	Contract Average	10.0	$480	120	$57.6	48	$120	4-24	Any	1,200 (Peak), 1,300 (Other)	1 day
CalPeak Enterprise	Contract Average	10.0	$480	120	$57.6	48	$120	4-24	Any	1,200 (Peak), 1,300 (Other)	1 day
CalPeak Midway	Contract Average	10.0	$480	120	$57.6	48	$120	4-24	Any	1,200 (Peak), 1,300 (Other)	1 day
CalPeak Mission	Contract Average	10.0	$480	120	$57.6	48	$120	4-24	Any	1,200 (Peak), 1,300 (Other)	1 day
CalPeak Panoche	Contract Average	10.0	$480	120	$57.6	48	$120	4-24	Any	1,200 (Peak), 1,300 (Other)	1 day
CalPeak Vaca-Dixon	Contract Average	10.0	$480	120	$57.6	48	$120	4-24	Any	1,200 (Peak), 1,300 (Other)	1 day
Calpine #1	Contract Average	20.0	$51,642	31	$1,600.9	481.5	$166	4-16	Peak	2,000	1 day/10 min. (500 hrs. only)
Calpine #2	Contract Average	3.0	$4,120	36	$148.3	207.5	$238	4-16	Peak	4,000	1 day/10 min. (1,000 hrs.
Coral Power	Contract Average	11.1	$21.16 / MWh	133	NA	43-850	$100 - $121	16-24	Both	up to 8,760	45 days
Dynegy	Contract Average	3.0	$20.25 / MWh	36	NA	200-1,500	$99 - $178	24	Both	up to 8,760	1 day
Fresno Cogen	Contract Average	10.3	$289	124	$35.8	21	$165	16	Peak	4,000	1 day
GWF	Contract Average	10.3	NA	124	NA	430	$180 - $240	0-24	Both	up to 4,000	1 week

3.2.2.2. Capacity to follow load

It is also essential to recognize that the demand for capacity inherent in the CDWR contracts is fundamentally different than the capacity LEAPS will provide. In their

economic analysis, Nevada Hydro compared LEAPS peaking capacity to a gas-fired peaker unit. The analogy does not hold, because a gas peaker can, if necessary, provide power in both the on-peak and off-peak periods, while LEAPS cannot. This point is crucially important in the Western power market due to the region's dependence on hydro generation.

The bulk of western hydro generation is located in the Pacific Northwest (PNW), but is connected directly to Southern California by a large direct current (DC) Intertie. The idea behind the system is simple. When the PNW has surplus hydro power (usually in the spring and early summer), it backs down Southern California's high-cost thermal generation. In the fall and winter, when hydro output is low, Southern California ships power to the PNW. This variation is seasonal, not night to day. Thus California's gas-fired generation often runs at night and during periods of drought. That is, the gas-fired capacity may be needed twenty-four hours per day in all seasons.

Although the LEAPS project does not satisfy the same demand as gas-fired generation, it is superior for following the load. Thus, it is ideal for supporting the Cal ISO's ancillary services market. The revenue opportunities from this market are discussed in Sections 4 and 5.

4. The Cal ISO Ancillary Services Market for Capacity

According to PG&E officials, the Helms pumped storage facility is used in two ways. First, it provides the utility with the means to "self-provide" its own ancillary services, thus avoiding Cal ISO's fees. Second, it has surplus capacity, so a portion of the facility is marketed to the Cal ISO and would, under some circumstances, be a competitor to the LEAPS project in this market. Again, according to PG&E officials, straight energy sales are highly unlikely to provide adequate revenue for a project like LEAPS; it is likely to garner far more revenue from A/S sales.

Before getting into the detail of the A/S market, however, it is worthwhile to summarize the major uncertainties of this market. They are:

- Will the technical specifications of the LEAPS project meet the Cal ISO's requirements for any or all of its A/S products? The issues include minimum regulation of the facility, the correlation between the rate of water flow and generation, the ramp rate of the generators, the size of the reservoir, etc. We have assumed that there are no serious technical constraints to A/S sales, except those identified.
- Can LEAPS' pumping load be controlled in a manner that would allow LEAPS to sell A/S capacity in the off-peak period? The CPUC is now encouraging the adoption of real-time load management. This would vastly expand the opportunities for A/S revenue, because the LEAPS load is proportionally larger than generation. However, it would also expand the number of market entrants and would put additional downward pressure on the prices of A/S. We have assumed that LEAPS could only sell non-spinning reserves in the off-peak market, consistent with present rules.
- What will be the trade-off between the volume of A/S products and their price? LEAPS is large enough to impact the existing on-peak A/S market and it is highly unlikely that all the available capacity can or should be sold. We have assumed a modest price discount will occur.

4.1. Day-to-day and minute-to-minute procurement

The Cal ISO markets for capacity and energy are extraordinarily complex. There are over 200 categories of prices and fees, twenty-four price zones, and some prices that are recalculated every five minutes. When the Cal ISO completes its new market structure for energy purchases and sales, it will have locational marginal pricing (LMP), making the system even more complex. Thus, it is understandable that Nevada Hydro would not be able to easily estimate likely revenue from the balancing market. Following is a discussion of key elements of the Cal ISO market and how they would relate to the LEAPS project. Then, in Section 5, we estimate how LEAPS

would operate in the Cal ISO market and how much revenue it would make. In this discussion PG&E personnel, who operate the only comparable facility in the California market, the Helms pumped storage in Northern California, have assisted us. Without their guidance, it would have been impossible to sort the wheat from the chaff. The responsibility for any errors, however, rests with the authors of this report.

4.2. Types of capacity and reserves

As already explained, there are two fundamental ideas behind the Cal ISO's A/S market: the need to balance the grid in order to accommodate fluctuations in load and generation, and the need to maintain reserves. "Regulation up" and "Regulation down" are types of capacity products marketed by the Cal ISO that are designed to balance the grid and provide reserves. "Spinning" and "non-spinning" reserves are designed to ensure adequate reserves – particularly to protect against forced outages. The Cal ISO purchases these products, and the cost is added to the tariffs charged for using the transmission system. In contrast, real-time energy costs are purchased from one SC and sold to another, depending on their activity and their schedules.

4.2.1. Regulation up and down market

In the regulation up and down markets, a generator first enters into a bilateral contract to sell some energy. This is referred to as the "preferred operating point" (POP). The generator then offers capacity up and down to the Cal ISO and gives the ISO operational control of the facility – automatic generation control (AGC). The ISO is allowed to increase generation beyond the POP by any amount up to the MW offered. Likewise, the ISO may cut back generation from the POP by any amount down to the MW offered. During 2005, the average regulation up price paid by the Cal ISO for capacity in Southern California during on-peak hours was $22.93 and the average regulation down price was $11.79 per MW. The regulation market is not, however, a large market. During this period regulation up sales averaged about 402 MW per hour and the regulation down market averaged about 378 MW for all of the Cal ISO operating area.

The generator gets paid for the capacity offered, whether or not it is used. If the ISO dispatches more generation than the POP, then the generator is paid the real time price for the energy in addition to the capacity payment. Similarly, if the ISO orders the generator to operate below the POP, the ISO then delivers energy from another source to the generator's customer and charges the generator the real-time price.

A pumped storage facility accepts a certain amount of risk in this arrangement. If the real-time price is below pumping costs and the facility is ordered to generate at levels above the POP, then it will cost more to refill the reservoir than the generator will be

paid. Likewise, if the real-time price is above pumping costs, the facility will take a loss on its bilateral sales if it is ordered to reduce its generation below the POP. Although there is some risk involved, we have assumed that the benefits and costs would cancel out over a year's operation.

4.2.2. Spinning and non-spinning reserves market

The primary distinction between spinning reserves and the regulation up and down markets is the extent of control given to the Cal ISO. The ISO defines regulating reserves as: "Sufficient spinning reserve that is immediately responsive to automatic generation control to provide sufficient regulating margin to allow the control area to meet NERC Control Performance Criteria." In contrast, non-spinning reserves must be capable of being loaded in ten minutes and must be able to run for two hours.

Because hydroelectric generation is so flexible it is suitable for the regulating reserve market. However, many hydroelectric producers have little control over reservoir levels, which is why pumped storage (particularly in Southern California) is the ideal solution. Spinning and non-spinning reserves can, however, be offered by a wider class of generators, which makes these products less valuable. In 2005 the Cal ISO bought an average per hour of about 887 MW of spinning reserves for $13.02 per MW and 882 MW of non-spinning reserves at $4.28 per MW in the on-peak period. Since these markets would not be the most lucrative for LEAPS they are largely ignored in the analysis to follow. The principal advantage of the spinning reserves market is that its larger size means prices are unlikely to be discounted if LEAPS enters the market.

There is an important final point concerning the Cal ISO's A-S markets. In general, there is a surplus of supporting resources in Northern California (PG&E's hydroelectric and the Helms project, for example), but Southern California is considered in deficit. The Cal ISO intends to more aggressively split procurement between the two zones, which should advantage a project like LEAPS.

5. How LEAPS would operate in the Cal ISO Market

5.1. Modeling LEAPS revenue

We have gathered historical price information from the trade press and the Cal ISO to model how LEAPS could market energy and capacity. Given LEAPS planned configuration, there are a variety of constraints on its operation that must be taken into consideration. In addition, there are a great number of unknowns, not the least of which is what the future price of on- and off-peak power will be.

Table 5.1 on the next page summarizes a base case for LEAPS revenue. There are a wide number of possible scenarios. The base case, however, seeks to establish a middle ground or most likely outcome. The base case assumes that all of the ISO product specifications can be met or already have been met by the LEAPS design. In the next section, we will describe some alternative sources of income and strategies that might be considered. Since the base case annual revenue is less than that assumed by Nevada Hydro it is important to explore other alternatives, even if they are not well defined at this time. In many instances, revenue-enhancing alternatives mean adjustment in the LEAPS design, particularly with respect to upper reservoir size.

5.1.1. Key Assumptions

Table 5.1 has price data for six years. The first year is based on actual daily prices from the trade press and Cal ISO hourly prices from 2005. Subsequent years are based on forward prices for on-peak and off-peak energy delivered in Southern California, as published in the *Energy Market Report* on December 29, 2005 and the same average 2005 Cal ISO prices for A/S products. In other words, future years, 2006 through 2010, are based on a mix of forward-looking prices that could have been obtained in the market in December and historical Cal ISO prices.

The first section of the model is labeled Assumption Inputs. The figures in blue are assumed variables. Figures in black are the results of the interaction of these assumptions with the specifications of the LEAPS project, energy prices from the trade press and Cal ISO prices from the 2005 A/S market.

The first line of the model is the assumed level of energy sales for each on-peak hour. Nevada Hydro assumed that the full output of the project s 500 MW would be sold, but this is based on twelve hours of pumping and twelve hours of generation, which as previously explained is likely to be sub-optimal. Full generation would also preclude the sale of regulation up and spinning reserve A/S products. Regulation down could be sold, but the huge volume would likely depress the price to nearly zero and it is not as valuable as Regulation up. Experimentation with the model suggests that the optimum level of energy sales will be less than the midpoint of

Table 5.1
LEAPS Revenue Model
Base Case

Year	2005	2006	2007	2008	2009	2010
Assumption Inputs						
Energy Sales (MWh per hour)	175	175	175	175	175	175
Spinning Reserves (MW/hour)	125	125	125	125	125	125
Expected Price Discount	10%	10%	10%	10%	10%	10%
Assumed Price - Offer Coefficient	10.0	10.0	10.0	10.0	10.0	10.0
Assumed A-S Capacity Unsold	0%	0.0	0.0	0.0	0.0	0.0
On-Peak Spinning Price 2005	$13.02	$13.02	$13.02	$13.02	$13.02	$13.02
On-Peak Regulation Up Price 2005	$22.93	$22.93	$22.93	$22.93	$22.93	$22.93
On-Peak Regulation Down Price 2005	$11.79	$11.79	$11.79	$11.79	$11.79	$11.79
Minimum Regulation (MW/hour)	50	50	50	50	50	50
Maximum Available Capacity (MW/hour)	450	450	450	450	450	450
Maximum On-Peak Hourly Sales (MWh per hour)	333	333	333	333	333	333
Maximum On-Peak Regulation Up Sales (MW/hour)	150	150	150	150	150	150
Forced Outages	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Generation Transmission & Scheduling Fees	$3	$3	$3	$3	$3	$3
Load Transmission & Scheduling Fees	$4	$4	$4	$4	$4	$4
Energy Purchase and Sales						
On-Peak Sales Price*	$73.12	$92.00	$91.75	$85.00	$79.00	$74.50
Off-Peak Buy Price*	$54.14	$69.00	$67.25	$60.75	$55.50	$51.00
Sales Volume						
On-Peak Hours	4,910	4,910	4,910	4,910	4,910	4,910
MWh per hour	175	175	175	175	175	175
Total Revenue	$60,250,610	$76,473,250	$76,258,438	$70,458,500	$65,303,000	$61,436,375
Purchase Volume						
Off-peak Hours	3,850	3,850	3,850	3,850	3,850	3,850
MWh per hour	268	268	268	268	268	268
Total Cost	$59,948,154	$75,270,300	$73,465,875	$66,763,725	$61,350,450	$56,710,500
Net Energy Revenue	**$302,456**	**$1,202,950**	**$2,792,563**	**$3,694,775**	**$3,952,550**	**$4,725,875**
A/S (Capacity) Sales						
A/S Volumes and Prices						
On-Peak Spinning Reserve MW/hour	125	125	125	125	125	125
On-Peak Regulation Up MW/hour	150	150	150	150	150	150
On-Peak Regulation Down MW/hour	125	125	125	125	125	125
Off-peak Non-Spinng Reserve MW/hour	268	268	268	268	268	268
On-Peak Spinning Price**	$11.72	$11.72	$11.72	$11.72	$11.72	$11.72
On-Peak Regulation Up Price**	$20.64	$20.64	$20.64	$20.64	$20.64	$20.64
On-Peak Regulation Down Price**	$10.61	$10.61	$10.61	$10.61	$10.61	$10.61
Off-peak Non-Spinng Reserve Price**	$1.09	$1.09	$1.09	$1.09	$1.09	$1.09
A/S Revenue						
On-Peak Spinning Reserve Revenue	$7,191,923	$7,191,923	$7,191,923	$7,191,923	$7,191,923	$7,191,923
On-Peak Regulation Up Revenue On-Peak	$15,199,151	$15,199,151	$15,199,151	$15,199,151	$15,199,151	$15,199,151
On-Peak Regulation Down Revenue	$6,512,501	$6,512,501	$6,512,501	$6,512,501	$6,512,501	$6,512,501
Off-Peak Non-Spinning Reserves	$1,123,899	$1,123,899	$1,123,899	$1,123,899	$1,123,899	$1,123,899
Cal ISO Fees	($2,590,400)	($2,590,400)	($2,590,400)	($2,590,400)	($2,590,400)	($2,590,400)
Total Net A/S Revenue	**$27,437,073**	**$27,437,073**	**$27,437,073**	**$27,437,073**	**$27,437,073**	**$27,437,073**
Contingency Costs						
Forced outages	($1,386,976)	($1,432,001)	($1,511,482)	($1,556,592)	($1,569,481)	($1,608,147)
Other Total	**($1,386,976)**	**($1,432,001)**	**($1,511,482)**	**($1,556,592)**	**($1,569,481)**	**($1,608,147)**
Grand Total	**$26,352,553**	**$27,208,022**	**$28,718,154**	**$29,575,256**	**$29,820,142**	**$30,554,801**
Six year Average	**$28,704,821**					

*Source for Fwds: EMR, 12/29/05, 2005 Daily EMR
**Cal ISO at www.caiso.com

LEAPS generation capacity, leaving room for regulation up and spinning reserve sales. (This depends mainly on the level of transmission and scheduling fees LEAPS would have to pay. The figures in Table 5.1 are estimates from Coral Energy, but seem high.) For the base case presented here, we have assumed an average generation of 175 MW during on-peak periods. (In bulk power markets, energy is normally sold in 25 MW blocks for sixteen hours (the on-peak block) or eight hours (the off-peak block or the super-peak block).

The level of spinning reserves is another assumption; here we have assumed 125 MW. In practice this assumption does not make too much difference to revenue. This is because either spinning reserves or regulation up can be sold, but not both. Regulation up has a higher price, but the more sold, the more likely the price will fall. Thus, choosing a balance between spinning reserves and regulation up will likely maximize revenue. PG&E officials said that it is hard to sell both spinning reserves and regulation up, because the ramp rate requirements for spinning reserves constrain regulation up sales for Helms. This may or may not be true for LEAPS, and we believe it is one of the technical characteristics that can be adjusted before the project is built. In general, the base case tries to strike a balance between the three types of capacity sales in order to minimize the price impact. The assumption in the base case is that such a level of marketing would reduce A/S prices by an average of 10%, but all capacity could be sold.

There are two other important assumptions that constrain operations: minimum regulation, and maximum available capacity. The Helms facility has a minimum regulation of 50 MW, i.e., generation cannot fall below that level. Thus, if Helms is generating at 200 MW, it is limited to 150 MW of regulation down sales. We have adopted the same constraint, but once again it depends on the specific project design.

The average maximum available capacity constraint arises because of off-peak weekends and holidays. If, for example, LEAPS sold all available regulation up capacity on Monday and the Cal ISO called on the capacity, it would not be able to fill its reservoir completely full Tuesday night, constraining future sales of regulation up capacity. It is hard to estimate exactly what the figure for maximum available capacity should be, but a 450 MW average is a reasonable and conservative estimate. This modest constraint in sales would also help keep A/S prices up so it likely has little if any impact on potential revenue.

Once the key assumptions have been determined, the maximum amount of regulation up and regulation down available for sale in the on-peak period is a fixed number given the operational constraints. Still, the managers of the LEAPS project may choose to hold back a portion of the capacity in order to get a higher price.[4] As

[4] We have assumed that LEAPS does not hold back capacity, but balances it among multiple markets to maximize revenue. Under present FERC and CPUC oversight, "economic withholding" could constitute a regulatory violation.

noted, marketing a greater volume of capacity would result in a bigger price discount. At this point, we can only guess as to what the optimum purchase and sales configuration for LEAPS would be, but we do know there would be an inverse relationship between price and the volume of capacity offered. As noted, the volume for most A/S products is about 400 MW, less than the potential capacity from the LEAPS project for some products in some circumstances. In other words, an attempt to sell the entire LEAPS capacity as one type of product into the A/S market is unlikely to be optimum. Likewise, holding nearly everything back might preserve the price, but would not maximize revenue.

5.1.2. Energy sales and revenue

Data in the first line in the section labeled "Energy Purchases and Sales" are average on-peak prices from the daily 2005 market and forward on-peak prices. As noted, these prices are significantly different from those assumed by Nevada Hydro, and without A/S sales, the project has no hope of meeting its debt service, let alone making a profit. In 2005, on-peak prices were 35% higher than off-peak prices, as compared to Nevada Hydro's assumption of 160%. This margin is further constrained by scheduling and transmission fees, which can exceed $4 per hour for *both* generation and load. Based on 2005 actual prices, in our base case we project that LEAPS would have had annual net energy sales of $0.3 million, instead of the $54.6 million Nevada Hydro calculated. (2005, however, would have been an exceptionally poor year for pumped hydro energy sales; other years would have produced higher income, as illustrated using forward prices.) Including transmission and scheduling fees explains part of our lower figure, but mostly the difference is a result of an apparently outdated estimate about the price of on-peak and off-peak power.

5.1.3. A/S Sales

As explained earlier, in today's market Nevada Hydro is unlikely to obtain a long-term contract with a significant capacity fee. On the other hand, it appears Nevada Hydro has not analyzed the potential revenue from A/S sales, which we conclude would be LEAPS' primary source of income.

In our base case, A/S sales dominate LEAPS revenue. The assumptions in the first section of the model set the volumes of each type of A/S product to be sold and the price discount assumption sets the expected price. It is worth making a brief point about the way in which the Cal ISO manages A/S. Sellers are required to enter a "blind" auction in which they bid to provide the service. The Cal ISO determines the volumes required for each hour and ranks the bids by price. The Cal ISO sets a single price for the product where the demand and supply schedules intersect. Anyone who bid more than the winning price does not get to supply the product. But everyone who bids less gets to supply at the single winning price. LEAPS could

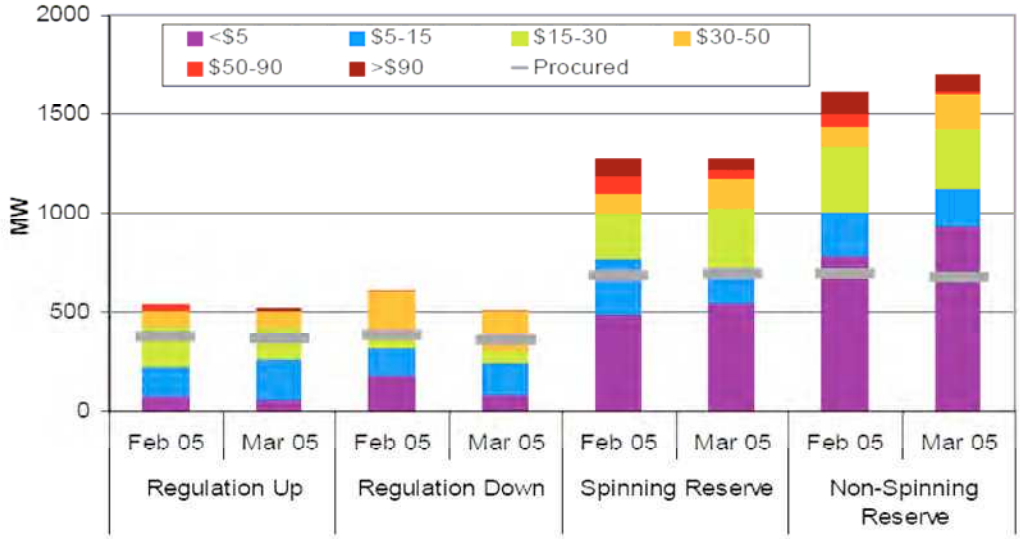
assure that its volume bid would always be accepted by bidding a zero price. Or, it could bid a portion of its capacity at low prices and a portion at higher prices and hope all would be selected. For the base case, we have assumed that LEAPS is a price taker and attempts to market all its capacity.

Revenue is calculated by multiplying the MW volume for each product times the number of hours in the block (16 for on-peak, 8 for off-peak), times the price. Then a Cal ISO fee of $0.79 per MWh is subtracted. In the base case the net from A/S sales is estimated at $27.4 million per year. This is much larger than the revenue from energy sales and even slightly larger than Nevada Hydro s $25 million estimate for capacity sales.

One final adjustment to the revenue is made a 5% reduction for forced outages. It is assumed that standard maintenance can be conducted during portions of the year when the energy and A/S markets are the weakest and it would not have a significant impact on revenue. It is worth noting that day-to-day and hour-to-hour marketing combined with sophisticated bidding strategies would likely improve revenue but at a somewhat higher cost.

5.2. Uncertainty regarding key assumptions

Chart 5.1



The primary uncertainty regarding revenue from A/S sales is the trade-off between the volume offered and likely price discounts. Chart 5.1 is taken from an analysis by the Cal ISO of bids made into the ancillary service market during February and March of 2005. It is not directly comparable to our analysis, because it averages both on-peak and off-peak periods. Nonetheless, the chart demonstrates that an increase of 200 MW in the regulation up and down markets could cause a substantial price

discount. The precise dynamic is unknown for two reasons. When a new facility enters the market, existing companies will likely change their bidding strategies. In addition, at least half of the ancillary service market is self-provided. This activity may be reduced if it is cheaper to obtain the service from the Cal ISO, thus enlarging and stabilizing the market.

5.3. Sensitivity analysis

Although there are a great number of uncertainties, it is worth examining how revenues would change in response to changes in key assumptions. LEAPS not only has to show a profit, it has to maintain its debt service. The risk of defaulting on its debt is increased if the cash flow is erratic and unpredictable. Given that on-peak and off-peak energy prices as well as A/S prices are volatile, cash flow will be uncertain.

LEAPS revenue could be higher than the base case by making highly optimistic assumptions. As noted, energy sales produce little or no net income (particularly based on 2005 on- and off-peak prices). LEAPS could generate at a minimum level, such as an average of 50 MW, and sell 400 MW of regulation up, the highest-priced A/S. Assuming there was no price response, revenue would rise from the base case of $26.3 million to $42.0 million. Unfortunately, this is a completely unrealistic scenario. The regulation up market could not absorb that much volume without a price break. Even if that level of revenue were sustained for a while, the project's cash flow would be constantly at risk.

Although it is unlikely that LEAPS revenue could increase much beyond the base case (given prevailing market prices for energy) it is also unlikely that revenue would be much lower, unless there are major forced outages. LEAPS has the option to vary its offers into multiple A/S markets and flexibility in daily pumping and generation.

5.4. Long-term trends that could improve the LEAPS market

As explained earlier, the primary economics of conventional pumped storage is driven by the difference in cost between base load and peaking facilities. The "dash for gas" (the British expression for the shift into high-efficiency combined-cycle gas generators) eroded the economics of pumped storage, because it lessened the distinction between such units. When gas prices were low, gas-fired generation was cheaper than either nuclear or coal. As a consequence, most new generating facilities built were gas-fired.

High gas prices have, once again, shifted the economics. Coal and nuclear generation are now more attractive than they were in the 1990s. If gas prices remain high in North America, more coal-fired base load generating plants are likely to be built. This could widen the differential between on-peak and off-peak prices.

Perhaps the greatest hope for the LEAPS project lies in the Cal ISO's Market Redesign and Technology Upgrade (MRTU). There are two aspects to the new market structure that are favorable. First, the Cal ISO will implement a day-ahead hourly market, similar to the one previously operated by the CalPX. This would allow LEAPS to be far more selective in the hours it pumps and generates and should improve revenue from energy sales. Second, the MRTU plans to introduce LMP, which will favor generators that are in strategic locations. For example, LEAPS might buy in the SCE service territory and sell in the SDG&E region, taking advantage of higher prices in a zone likely to be constrained more often.

Another trend that could improve LEAPS economics is the growth of intermittent energy sources solar, wind, and tidal power, to name three.

6. Alternative Sources of Revenue

6.1. Reliability Must-Run (RMR) Contracts

Once built it is possible that LEAPS could qualify for an RMR contract. These contracts concern certain generation facilities that must run either to ensure grid reliability or to prevent the facility from taking advantage of intra-zonal congestion and exercising market power. The RMR contract involves a fixed capacity payment and an energy payment for generation associated with the project's variable costs. As a hydroelectric generation facility with the ability to start generating without drawing power from the grid, LEAPS might also qualify for a "black start" payment, which is part of some RMR contracts.

RMR contracts are negotiated once a year for a period of one year. There is often competition among a number of generation plants to receive a contract. In the case of San Diego, generation inside the SDG&E service territory is less than its load, so the region depends on inbound transmission to meet the existing load and to meet growth. The LEAPS project and its associated transmission system is well situated to take advantage of these circumstances and probably could qualify for an RMR contract. We could not analyze the possible revenue from an RMR contract because the details of existing arrangements are confidential. Moreover, there are two serious constraints: the project must be in place and the contract is for no longer than one year. Thus, an RMR contract would not solve the LEAPS financing dilemma.

6.2. Firming Renewable Energy Projects

It is has been suggested that LEAPS could be developed in tandem with wind farms or large solar projects, as a means to "firm" their energy production and enhance their value. The present size of the reservoir is, however, too small to be effective in this manner.

Solar power is already attuned to the day and night cycle of on-peak and off-peak value. Obviously, the power is only generated when the sun shines. There are, however, seasonal and weather cycles. Solar generation potential is at its maximum in the summer (coinciding with peak demand) and at its minimum in the winter. Weather is by its nature unpredictable, but tends to bunch, i.e., multiple cloudy days in a row. Wind also depends on the weather and in the opinion of a wind expert who was consulted, 16 hours of storage is too small to firm the resource.

6.3. Potential Long-term contracts with nearby LSEs

The significance of the analysis of Cal ISO's A/S market is twofold. Foremost, it represents an opportunity for marketing the capacity of the LEAPS project. It can also be viewed as the "opportunity cost" for either SCE or SDG&E, who could self-

provide their own A/S. Because utilities face risks in the A/S market, they may be willing to pay a premium for a long-term contract that guaranteed no unexpected fees from the Cal ISO. There is some reason to expect this risk to grow over the coming years along with load growth. For such a sales contract to be realistic, however, projected LEAPS sales in the A/S markets will have to come close to or exceed its expected costs.

6.4. Placing LEAPS in the rate base

In their November 29, 2005 FPC Section 205 filing, Nevada Hydro proposed putting the LEAPS project along with its transmission system into the rate base. That is, both would be treated in the same manner as Trans-electric's expansion of Path 15. FERC would approve rates and the Cal ISO would recover costs and a return on equity for the project sponsor from transmission and scheduling charges.

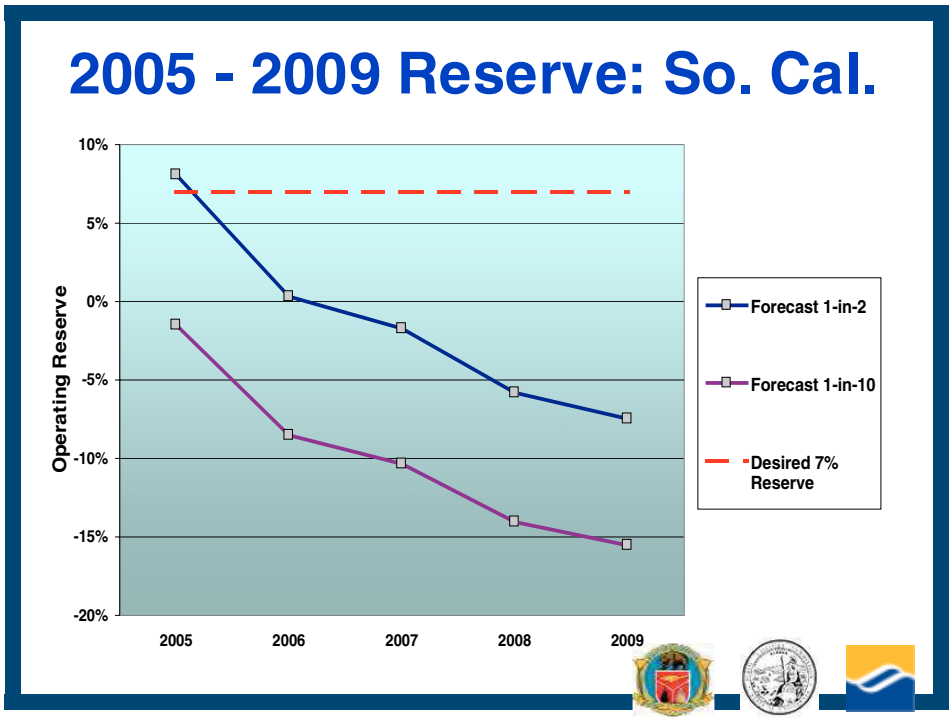
There is adequate precedent for treating the transmission expansion in this manner, but including a generation project is another matter. The Helms project is in PG&E's rate base, but that is regulated by the CPUC, not FERC, and is used to serve its native load.

A good argument can be made that load-following projects, such as LEAPS, should be treated the same way as transmission projects. That is, assets are owned privately, but operational control is dedicated to the Cal ISO. The cost of the assets is then put into the general transmission and A/S tariff charged by the Cal ISO. The justification for this approach is twofold: 1) it prevents owners of strategic assets from exercising market power, and 2) it reduces market transaction costs, which are obviously quite high. Put another way it can reduced Cal ISO's costs.

If the project is incorporated into the Cal ISO's transmission rates, i.e., if it is "rate-based," the revenue-cost perspective is quite different. The central question to be asked is: What are the benefits to ratepayers from the LEAPS facility and associated transmission? The answer is threefold: LEAPS will improve reliability in the Southern California grid, it will allow the Cal ISO to reduce congestion and reliability must run (RMR) expenses in the San Diego area, and it will allow the Cal ISO to cut operating costs in its ancillary services (A/S) market. Any of these benefits could be sufficient to justify rate-basing the project, but the combination of all three is a particularly powerful argument and unique to LEAPS' project design.

Chart 6.1 from a presentation by the CEC, CPUC, and Cal ISO, demonstrates the reliability problems of Southern California over the coming years. The LEAPS facility can help resolve this difficulty by providing 500 MW of generation capacity readily available during peak summer hours. In this regard, LEAPS competes with many other generation projects. LEAPS, however, has a superior location, halfway between SCE and SDG&E.

Chart 6.1



It is not possible for us to quantify the reduction in congestion and RMR costs that the LEAPS project could bring about, because such data are confidential. However, this savings could be estimated by working with the Cal ISO. Based on regulatory filings it appears that initially LEAPS could reduce congestion into San Diego by improving north to south flows. After SDG&E completes its Sunrise transmission project, LEAPS could help SCE gain access to renewable energy projects in Imperial Valley and potentially cheaper electricity from Northern Mexico.

During 2005, the Cal ISO paid about an average of $23 per MW for regulation up, $13 for regulation down, and $12 per MW services during on-peak hours. If LEAPS were dedicated to the Cal ISO, it could substantially reduce its A/S procurement costs, by as much as $45 million per year in the on-peak periods. Pumping during the off-peak period could also be placed under Cal ISO's control, allowing it to reduce its need for regulation down, which sold for about $25 per MW in 2005. Varying LEAPS pumping with load in the off-peak hours could save Cal ISO up to an additional $38 million. The total of the two could be as high as $83 million per year.

The above cost savings are only a rough estimate, but we believe that when all the benefits outlined here are properly analyzed and totaled LEAPS and associated transmission will make a substantial contribution toward reducing Southern California's generation and transmission costs, as well as improving reliability. Thus, there is an excellent case for rate-basing the project.

6.5. Marketing A/S in the off-peak period

Under present rules, the Cal ISO's automatic generation control would not allow regulation up, regulation down sales on load the pumping part of LEAPS activity. However, the technology does exist for the Cal ISO to control pumping rates as it now controls generation rates. If procedures are changed, it could allow LEAPS to significantly increase its A/S income. Nevada Hydro should consider pursuing this option.

This point is significant not only in calculating LEAPS potential revenue, it is also important in determining SCE's and SDG&E's avoided costs in the A/S market.

6.6. Qualifying Facilities (QF) Sales

Because LEAPS is hydroelectric facility with capacity larger than 80 MW, it would not qualify for a QF sale.

7. Revenue, cost, and profitability of LEAPS

Table 5.1, base case revenue, is compared to annual costs in Table 7.1. Under the current market structure, LEAPS does not appear to be able to cover costs. The disparity is large enough that minor adjustments in marketing strategy will not change the conclusion.

Table 7.1
LEAPS Revenue and Cost
(1000s)

Year	2005	2006	2007	2008	2009	2010
Revenue Net of Pumping Cost						
Energy Sales Revenue	$302	$1,203	$2,793	$3,695	$3,953	$4,726
A/S Sales Revenue	$27,437	$27,437	$27,437	$27,437	$27,437	$27,437
Contingencies	($1,387)	($1,432)	($1,511)	($1,557)	($1,569)	($1,608)
Total	**$26,353**	**$27,208**	**$28,718**	**$29,575**	**$29,820**	**$30,555**
Cost in Full Operation						
O&M	$3,556	$3,556	$3,556	$3,556	$3,556	$3,556
S, G&A	$1,286	$1,286	$1,286	$1,286	$1,286	$1,286
CT Management Fee	$600	$600	$600	$600	$600	$600
Insurance	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
Lake Management Fee EVMWD	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800
Operating Reserves	$1,200	$1,200	$1,200	$1,200	$1,200	$1,200
Depreciation	$14,853	$14,382	$13,925	$13,483	$13,055	$12,641
Debt Service Principal	$9,762	$10,153	$10,559	$10,981	$11,420	$11,877
Debt Service Interest	$16,262	$15,871	$15,465	$15,043	$14,604	$14,147
Total	**$51,319**	**$50,848**	**$50,391**	**$49,949**	**$49,521**	**$49,107**
Gross Profit or (Loss)	**($24,966)**	**($23,640)**	**($21,673)**	**($20,374)**	**($19,701)**	**($18,552)**

There is also the possibility that some of the costs in Table 7.1 are underestimated. We think it is unlikely that LEAPS could obtain long-term financing at 4%, nearly 2 percentage points below current thirty-year mortgage rates and 1.5 percentage points below twenty-year AAA corporate bonds. Thus, annual interest payments are understated. There is also some risk that there will be construction cost overruns, especially with the tunnels and upper reservoir. In the event that the expected LEAPS market improves and the project is thought to be viable, we recommend that all the cost assumptions be carefully reviewed.

Table 7.1 is presented in abbreviated detail. Since we believe that annual revenue is unlikely to cover basic costs, tax calculations, return on equity, and other details are omitted.

8. Conclusion on Pumped Storage

When revenue and cost factors are considered we conclude that the LEAPS project, as a merchant plant, is not viable at this time. The primary problem is the low differential between off-peak energy prices and on-peak energy prices. Nevada Hydro's estimate of the value of capacity, sold outright in a long-term contract, and ours, sold short-term into the Cal ISO A/S market, are nearly identical.

9. Objective of the review of Transmission

Elsinore Valley Municipal Water District (EVMWD) has requested that along with our analysis of the economic viability of the LEAPS project we investigate the TE/VS interconnection project. Regarding this investigation, there are four important questions:

- Could the TE/VS transmission project stand alone, or is the LEAPS facility an essential part of its economic viability?
- How would the transmission line be used without LEAPS and what would be the expected flows on the line?
- How do California officials at the CEC and Cal ISO view the project?
- How would the TE/VS transmission project be rate-based and would the same procedures apply to the combined TE/VS-LEAPS rate-basing proposal?

10. Could the project stand-alone?

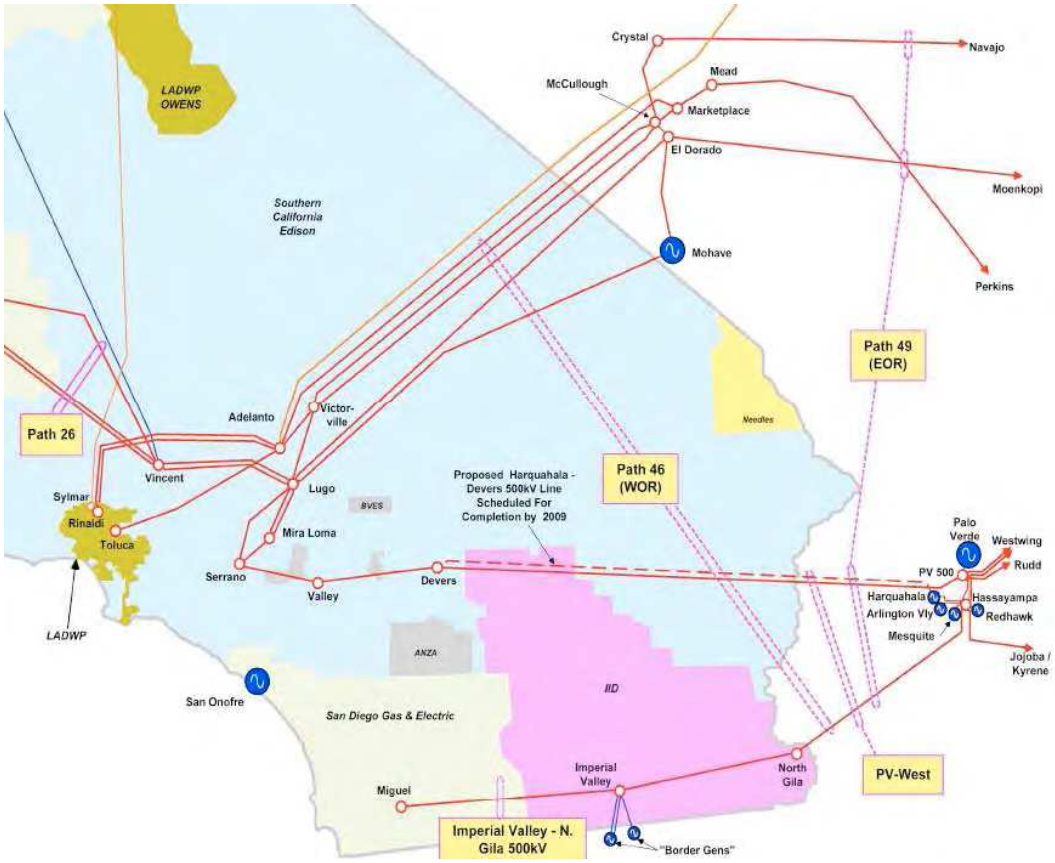
10.1. Comparison of TE/VS and LEAPS capacities

According to Nevada Hydro's engineering plans, the TE/VS interconnection project would have a transfer capacity of 1,600 MW between the SCE and SDG&E service territories. This is, of course, considerably larger than 500 MW of generation capacity and 600 MW of load (pumping) planned for the generation and storage facility. And, without these power flows there might not be much use for the new line in the immediate future.

10.2 Improved reliability

There is no technical reason why the TE/VS interconnection project could not be built separately from the LEAPS facility. The primary problems are, once again, economics and the shift in focus by the industry and California state officials.

Chart 3.1



Source: Navigant 2005

It is well known that the SDG&E operating area is in deficit. That is, within the SDG&E service territory, native load exceeds generation. Three years ago the deficit was expected to grow, creating the possible problem of meeting peak demand in a hot summer. For example, according to the April 2003 testimony of David Korinek, SDG&E has a reliability deficit beginning in 2005. The deficit was to be relieved by a near-term interconnection project, the Rainbow Project from SDG&E to SCE, to be completed in 2008. The SDG&E proposal was to run parallel to where the TE/VS transmission line is now planned. Mr. Korinek's testimony was also written just after the Rainbow Project was rejected/delayed by the CPUC in 2002. Since then the emphasis appears to have changed. Although SDG&E's deficit is expected to continue to grow, it is now expected that it will be relieved by generation from the south and east.

There are two justifications for expanding transmission reliability and economic. Reliability is improved by ensuring there is sufficient transmission and generation capacity to meet the extreme peak demand that might occur once in five years and by diversifying load and generation. For example, if SCE and SDG&E are better interconnected the Cal ISO has a much broader range of generation plants with which to meet peak demand or a system emergency. An improvement in reliability can be measured by a reduction in both ancillary service costs and congestion on existing transmission lines. Unfortunately, these benefits may not accrue to the sponsor of the transmission expansion. The more obvious and classic reason to expand transmission is that power will flow along a path for which a transmission rate can be charged.

In Chart 3.1, a transmission line built by either SDG&E or Nevada Hydro from the SCE system at Serrano-Valley to the SDG&E service area would improve the reliability of both the SCE and SDG&E systems. It would also ensure that SDG&E could meet extreme peak demand, should it occur. Although reliability would be improved, it is unclear if power flows would be sufficient to cover costs at expected transmission rates. Apparently, the CPUC did not think that the similar Rainbow project was worth the cost, and its attention has turned elsewhere.

10.3 Economic need for transmission

The traditional reason to construct transmission lines is to connect generation with load. In the longer term, despite the immediate reliability benefits, the TE/VS proposed line would likely serve loads in SCE's service territory rather than SDG&E's. The reason for this is the location of generation projects under construction and expected to be built. However, it also depends on SDG&E's transmission expansion plans.

It is well known that siting a generation project in California is difficult and costly. Developers also fear the state's regulatory process. As a consequence most new

generation is being sited east of California or in Northern Mexico. Chart 3.1 identifies the locations of many of the trading centers and generation locations. Of particular interest are the solar energy projects in Imperial Valley, the expansion of coal and gas-based generation east of California and the LNG projects (leading to gas-fired generation) in Northern Mexico. Both Sempra and Chevron-Texaco have major LNG re-gasification sites under development in Northern Mexico.

The fundamental point is that generation will be fed into SDG&E from the south and from the east. This is why the CEC has identified SDG&E's Sunrise Powerlink 500 kV transmission project, which parallels the existing line along the Northern Mexican border, as one of four with a high priority for completion. This transmission project, along with de-bottlenecking transmission within the SDG&E system at Miguel, is also important for the TE/VS transmission project. Timing appears, however, to have changed.

In 2003 SDG&E saw the improved connection north to SCE as the first step in reducing congestion and improving reliability. Now it appears to be viewed as the second step, to be completed after the Sunrise project is completed in 2010. The expansion of generation in Northern Mexico in combination with LNG to serve California could, however, hasten the need for the TE/VS line, because it could provide SCE's customers access to cheaper power from the south, which is not well connected. Thus, while originally conceived to deliver power from the north to the south, the TE/VS line could actually end up sending cheap power north from Mexican generators.

10.4 Significance of SDG&E integrated resource plan

We believe that if either or both of the TE/VS and LEAPS projects are to be successful, Nevada Hydro will have to develop a solid working relationship with Sempra and SDG&E. As already explained, this is important for coordinating the development of transmission projects. Power generation to the east and south is going to have to move through SDG&E territory, and Sempra is going to be a key gas supplier to many of these projects.

The CEC commented that SDG&E had reviewed the LEAPS and TE/VS projects several years ago and concluded that they were neither economically nor technically feasible, given the amount of federal land the projects would traverse.[5] The technical problems may be close to resolution, but the economic one remains, and SDG&E is a key to the project's potential success.

There is another reason that cooperation would be necessary; SDG&E prepares an integrated resource plan (IRP) for its service territory. This plan proposes various

[5] *2005 Energy Report*, California Energy Commission, pp. 155-56, November 2005

generation projects and plans distribution and transmission improvements. Both the CEC and CPUC have great influence over SDG&E's plan. Nonetheless, all the planning must be integrated if a project like TE/VS is to be successful.

11. Nevada Hydro analysis of transmission flows

According to Nevada Hydro's own analysis, power flows on the TE/VS line would not be significant without LEAPS. For example: "The transmission line only alternative does not induce power to flow on this new transmission line. Modeling the transmission line in the 2009 heavy summer base case results in approximately 13 MW of flow in the north-to-south direction." Moreover, "It is apparent from these results that the transmission line would be under utilized by simply constructing a transmission line between the two proposed points of connection."[6] This is, of course, an insignificant flow on the TE/VS line, representing less than 1% of its capacity.

11. 1 Reasons for the low flow

As already noted, the primary reason for relatively insignificant north-to-south flow is the shifting location of new generation slated for Southern California. Of particular significance is the Sterling Energy Systems solar project in Imperial Valley.[7] California regulations require SDG&E to acquire a base of renewable energy in its resource plan and the Imperial Valley solar project is thought to be the best option for achieving the goal. The solar project has the added advantage of close proximity to the large thermal generation projects on the California border, so a new transmission line can serve two purposes. In either case, however, new generation supplies from the east reduce SDG&E's need for generation from the north.

11.2 Use of phase shifters

Phase shifters could be installed on the TE/VS line, which would improve system reliability and potentially improve economic feasibility in the absence of the LEAPS hydroelectric project. The phase shifters could be used to direct the flow of electricity; particularly after the transmission system expansions planned by SDG&E take place.

[6] Lake Elsinore Advanced Pump Storage ("LEAPS") System Study, Version 3.1 March 9, 2005, Prepared by USE, section 3.1.1, p. 5.

[7] The Sterling Energy Systems solar generation technology is not based on photovoltaic cells. Instead, a system of mirrors is used to concentrate the energy. It is claimed to have 30% efficiency. SDG&E agreed to purchase the output in September 2005.

12. Analyses by the California Energy Commission and the Cal ISO

12.1 California Energy Commission

In November 2005, the California Energy Commission released its *2005 Energy Report,* which covers the range of need and policy recommendations to the California Public Utility Commission. This report was available earlier in the year in draft and was commented on by a variety of companies and public interest groups. Nevada Hydro provided comments concerning the TE/VS and LEAPS projects and the Commission responded to their points in the final report. Although the CEC's recommendations are not binding on the CPUC, they have a large impact and they have made a clear summary of the situation. Thus, their view is worth quoting in total:

> The LEAPS transmission project would deliver pumped storage hydropower to the grid, reduce congestion and improve reliability in the San Diego area. The transmission component of LEAPS could complement the Sunrise Powerlink 500 kV project as a potential northern interconnection to the SCE service territory. This would require continued coordination between the project sponsors and SDG&E. Furthermore, the transmission component of LEAPS could strengthen the CA ISO grid by providing a 500 kV interconnection between the SDG&E and SCE service territories. As noted above, the state's existing 500 kV bulk transmission "backbone" runs from the Oregon border through the SCE service territory but does not connect with the San Diego area. San Diego's system currently connects to the rest of California via 230 kV lines running north through San Onofre Nuclear Generating Station and 500 kV lines running east to Imperial Valley. A northern 500 kV interconnection would improve the reliability of California's transmission system and increase the state's overall ability to import lower-cost power from Arizona, Mexico and the Desert Southwest. In its April 2, 2004, Motion to Intervene at the FERC, the CA ISO noted that "The transmission line proposed in association with the Lake Elsinore Pumped Storage Project would allow the San Diego area to import substantially more power from surrounding areas and would greatly enhance electric system reliability."
>
> The Nevada Hydro Company, Inc. has made significant licensing progress with federal agencies. According to The Nevada Hydro Company, Inc., the U.S. Forest Service (USFS) has agreed to (i) be a cooperating agency for purposes of carrying out the requirements of the National Environmental Policy Act (NEPA), (ii) produce a single environmental impact statement (EIS) for the project that will address the needs of both the USFS and the FERC, and (iii) stated their willingness to issue appropriate permits and has submitted preliminary licensing conditions to the FERC. The FERC-authored Draft EIS is expected in November 2005, while the Final EIS and Record of Decision are expected in April 2006.
>
> However, the proposed LEAPS project has unresolved concerns, including:
>
> c. Incomplete economic studies.
> d. Incomplete transmission system impact studies, which could identify further environmental impacts.

> Because the proposed transmission component of LEAPS would travel through the Cleveland National Forest and portions of Department of Defense and other public lands, the project would be subject to the requirements of the USFS, the Environmental Protection Agency, and the Bureau of Land Management (BLM).
>
> The transmission component of LEAPS may offer substantial benefits to California and is worthy of further monitoring and future consideration. However, pending completion of system and economic studies, as well as FERC approval, the Energy Commission believes the project does not warrant a recommendation at this time. The Energy Commission recommends monitoring and future consideration of the project in the 2007 Energy Report cycle.[8]

Fundamentally, if the TE/VS (or the LEAPS project itself) is going to be built, California officials at the CEC and CPUC are going to have to be convinced that the project will provide a net benefit to rate payers by improving reliability, lowering congestion costs, or lowering generation costs.

12.2 Comments by the Cal ISO, SCE, and SDG&E

Following Nevada Hydro's FPC Section 205 filing with FERC to place the TE/VS and LEAPS projects in the California transmission rate base, comments were filed by the Cal ISO, SDG&E, and SCE. All three organizations claimed that the filing was premature; noting that neither project had been approved by the Cal ISO or the state regulatory process. Following is a summary of points made by the Cal ISO that also captures SDG&E's and SCE's positions:

- The Commission should not grant TNHC's [Nevada Hydro] requests because they are premature and raise issues that need to be resolved before the relief requested in the Rate Request or any other approvals related to the Project can be given...

- The CAISO Has Not Yet Determined Whether a Need Exists for the TE/VS Interconnect Project... Moreover, the TE/VS Interconnect project is not the only potential transmission system addition or upgrade that is being contemplated in the region. In that regard, there are three potentially competing transmission projects in the region for the CAISO to evaluate - the TE/VS Interconnect project, the SDG&E Sunrise Powerlink project, and the GreenPath project. It is uncertain whether all three of these projects would be approved and built.

- The Commission Should Not Grant Incentive Rate Treatment to Transmission Projects Before the CAISO Approves Such Projects.

- TNHC Has Not Justified its Request for Cost-Based Rates for the Non-Wires Component of the Project... Also, under TNHC's proposal it is unclear to the CAISO how that resource would function within the context of the CAISO's market-based environment.

[8] *2005 Energy Report*, California Energy Commission, pp. 155-56, November 2005

13. Nevada Hydro's pro-forma rate analysis

Although Nevada Hydro's pro-forma rate analysis is the correct methodological approach, some key elements appear to require additional documentation. The return on equity is higher than FERC has previously granted, costs may need additional substantiation, and the expected interest rate on debt of 4% is lower than likely. At this time, cost cannot be accurately estimated, because not all the environmental constraints have been identified. Given the project risks and limited economic information we believe that any project loans are likely to be 6% and possibly higher.

It is also important to stress that placing the project in the Cal ISO rate base does not guarantee that the approved return on equity will be earned or that the project will even be able to cover costs. Revenue recovery may depend entirely on how the Cal ISO treats the project costs. If the costs are rolled into a Cal ISO transmission and ancillary services tariff ("socialized"), then recovery is more or less guaranteed, but that may not be the tariff form.

In the rate recovery process, the utility (or regulated entity) estimates cost and expected usage. Rates are determined by dividing cost by usage. These are, however, prospective estimates. If usage is less than the estimate, rates may not cover costs. Rate setting is based on an assumed monopoly, in which the regulated entity could charge much higher rates. In a complex transmission system, however, there are multiple paths for electricity transmission. If transmission rates are set specific to each path, there is no guarantee that a rate can be found to cover all costs if usage does not meet expectations.

14. Conclusion on Transmission

The criticisms of the CEC, Cal ISO, SDG&E, and SCE appear focused on the absence of completed economic studies by Cal ISO (or Nevada Hydro), which would support the development of either LEAPS or the transmission system. Without such studies the project may not gather the support of key California institutions and FERC is unlikely to approve either project without their consent.

More significantly, the emphasis on various transmission options to improve north-south interconnections for Southern California has appeared to shift. Several years ago it was thought that SDG&E would need to be better connected to SCE if it were to ensure system reliability. New generation projects to the south have altered the paradigm. The main advantage of the TE/VS transmission line would not be to move power to San Diego; it would be to move lower cost (or renewable) power from Northern Mexico and Arizona to Los Angeles. The need for such south-north transmission is, however, some years off - 2010 at the earliest. SDG&E will have to complete a transmission system east to the Imperial Valley and Arizona (the Sunrise project), as well as upgrade its existing system, before there is a need for the TE/VS transmission line.

Even this conclusion is fluid because it depends on which other transmission projects are selected by the Cal ISO. If, for example, the Sunrise project is rejected in favor of the GreenPath project, the TE/VS transmission project could be essential for SDG&E to move power from Imperial Valley, Arizona, and Mexico by looping through transmission grids to the north. In other words, the TE/VS connection would be vital for a north-south flow of power.