1. 2004 Market Structure Changes

1.1 MRTU Phase 1B

The CAISO implemented Phase 1B of its Market Redesign and Technology Upgrade program (MRTU) on October 1. This program effectively overhauled the entire CAISO real-time balancing market and dispatching system. Phase 1B utilized real-time market application (RTMA) software using an economic dispatch methodology that allowed control room operators and market participants to automate the routine generation procurement and dispatch activities of the real-time market. Phase 1B also incorporated uninstructed deviation penalties (UDP), a system of fines to be used, except under extraordinary circumstances, to ensure that generators adhere to CAISO dispatch instructions. However, UDP implementation was postponed until at least mid 2005.

The dispatch changes implemented in Phase 1B were all related to real-time operations. When the CAISO completes all phases of MRTU, its forward schedules and markets will all operate using the same methodology.

The CAISO's use of economic dispatch is intended to ensure that the best resources are selected to meet the demand for electricity. In this case, we define "best" as the most reliable and cost effective. This method will benefit California consumers by meeting their need for dependable and affordable electricity in the most economic way. The upgrade will result in greater consistency and efficiency in grid operations, while, at the same time, keep energy costs as low as possible.

Phase 1B, and the MRTU program in total, are key to the future of the CAISO and provide several benefits to both the ISO and its clients including:

- California's utilities and consumers get what they are seeking, reliable and cost-effective electric service;
- Generation owners are better able to manage their units because they are clear about how CAISO systems operate and what is needed from them; and
- The job of the CAISO's control room operators is more defined and consistent, requiring less "guess work" and individual interpretation of procedures.

Real-Time Market Application (RTMA)

RTMA software replaced the previous Balancing Energy Ex-Post Price (BEEP) auction system that was used to balance generation with load in real-time. It was the software that selected generators to ramp up or down based upon the imbalance between actual system load and forward-scheduled energy.

The RTMA software automatically balances electricity requirements in every dispatch interval. It will dispatch units for ramping up to two hours in advance if it estimates that would result in minimum cost to load. Previously, the CAISO manually dispatched resources according to lists of offer prices to increment (INC) and decrement (DEC) energy output every ten minutes. Operator systems have been expanded to collect detailed information about generation units and their production capabilities so that CAISO dispatch instructions can be more specific and generator response more dependable.

The use of economic dispatch also changes the way the CAISO evaluates offers from generators in balancing generation with load in real-time. Economic dispatch enables RTMA to minimize cost on an interval basis by exchanging costly energy for less-expensive energy. In particular, RTMA will issue decremental instructions to units that bid to sell at high prices whenever lower-bid-priced energy is available to replace it. This directly decreases total costs to load.

Other changes involve implementation details and rules. For example:

- Replacing the ten-minute dispatch interval with a five-minute dispatch interval allows for more accurate load following.
- Quoting a single market-clearing price (MCP), rather than separate prices at which INC and DEC energy are procured.

Uninstructed Deviation Penalties (UDP)

UDP improves grid reliability by encouraging generators to follow the CAISO schedules and dispatch instructions. UDP provides motivation for generators to adhere to CAISO dispatch instructions. It imposes a fine whenever the generator's rate of energy output is significantly different from the CAISO's established dispatch operating point (DOP).

The process that will be used by the CAISO to implement UDP is:

- Hour-Ahead Schedules submitted by the Scheduling Coordinator (SC) and accepted by the CAISO will be considered dispatch instructions.
- Each generation unit is assigned a tolerance band above and below their DOP and the unit is required to operate within those parameters.
- SCs will not be paid for over-generation (megawatts produced above the upper level of the tolerance band).
- SCs will be charged 150 percent of the market clearing price (MCP) for under-generation (megawatts not delivered so generation falls below the lowest level of the tolerance band).
- SCs can avoid the penalty by reporting changes to their resource operating capability in advance to the SLIC Web Client or providing replacement generation from an alternate unit.

The benefits of UDP are:

- Better control over grid resources, reducing the need for CAISO operators to scramble in real-time to compensate for generators that do not adhere to dispatch instructions.
- SCs bear the costs associated with resolving operating problems created by their non-compliance.
- Overall energy costs are reduced as less replacement energy will be needed when SCs comply with CAISO dispatch instructions.

UDP is integral to achieving the goal of Phase 1B: greater consistency and efficiency while keeping energy costs as low as possible.

In summary, Phase 1B changes to the real-time market include:

- Dispatch of the lowest cost resources following a forward-looking analysis of the next two hours of grid operations and a determination of the best generation mix to maintain system stability.
- Calculation of a single market clearing price (MCP) based on incremental cost and eliminating the need for two prices – an INC and DEC – for each market interval.
- Installation of new grid operations software (Real-Time Market Application or RTMA) that increases the consistency of real-time operations by automatically:
  - Clearing the real-time market every five minutes by calculating the electricity requirement, selecting the best resources based on price and performance to meet the need, and revising the load forecast for the next two hours.
  - Dispatching generation resources with simplified, specific instructions and monitoring the compliance of each unit.
  - Pinpointing transmission constraints by comparing scheduled and real-time path flows and flagging problem areas for grid operators so that paths are not overloaded.
  - Monitoring and adjusting import and export levels within the service territory.
  - Introducing a new web interface – the SLIC Web Client – that enables scheduling coordinators (SCs) to login and update operating parameters for their units.

The benefits of economic dispatch are:

- Increased reliability due to more proficient dispatch selection and communication, followed by more dependable generator response.
- More consistent and efficient control room operations; automation of routine activities and timely information about unit capabilities require less "guess work" and individual interpretation of procedures.
- Lower total energy costs with resource decisions optimized according to energy balancing requirements and resource bids over a two-hour period.

RTMA became the tool used for real-time operations on October 1, 2004, and was initially somewhat unstable. After several days of tuning, facing lower loads and the return of some large system resources that had been out on planned maintenance outages, real-time market prices stabilized and price volatility decreased. Recently, there were brief price spikes predominantly occurring during rapid ramp periods, which tended to last for a single five-minute dispatch interval. RTMA ramped units quickly to manage steep imbalances, but then was able to replace the more expensive units after lower cost units had ramped to higher generation levels. This occurred most frequently during the morning, afternoon, and evening load ramp periods and around the top of the hour schedule changes. It can also occur at other times, usually due to contingency events.

One notable feature of the market since the implementation of the RTMA software has been price spikes.[1] Price spikes can be caused by several factors and often provide valuable economic signals to market participants. While price spikes have become more frequent since the implementation of RTMA, they have also largely become more predictable. Price spikes most often have been one or two five-minute dispatch intervals in duration. These spikes tend to occur in the first interval in each hour, and occasionally last into the second interval. This is especially the case during increasing load periods during the morning and evening when generators are ramping between hourly schedules. To cover the rapidly changing imbalance between the generation and load, RTMA often calls upon numerous real-time energy bids. In that case, the highest dispatched bid sets the market clearing price for that interval. However, the efficient-clearing feature of RTMA enables it to back down these high-bidding units as the lower-bidding units continue to ramp upward to a level that enables them to cover the imbalance. (Under the old BEEP system, units would be ramped as needed, without exchanging high-priced bids for low-priced bids, so that the highest-priced dispatched bid would set the price for the remainder of the period of imbalance, resulting in a prolonged price spike. At the end of the imbalance period, BEEP would have backed down all units concurrently.) See Chapter 3 for more discussion on RTMA and the real-time energy market.

1.2 Ancillary Services Market Structure Changes

The CAISO's ancillary services markets went through substantial changes in 2004. There were a number of reasons for these changes, but the most immediate was the heightened sensitivity to reserve requirements in the aftermath of the August 14, 2003, blackout in the Northeast and the reduced amount of generation in the A/S bid stack in SP15. The primary changes were zonal procurement of A/S during periods of limited transfer capability between northern and southern California, and adjusting market rules to allow units that were constrained under the provisions of the must-offer obligation to bid into the day-ahead A/S markets without losing their minimum load cost compensation and uninstructed energy payments. These market structure changes are fully discussed in Chapter 4.

1.3 Generation Additions/Retirements

1.3.1 New Generation

Only 108 MW of new generation began commercial operation within the CAISO Control Area in 2004, 98 MW of which has signed participating generator agreements with the CAISO. However, 640 MW of previously mothballed generation owned by Reliant Energy Services (Etiwanda Units 3 and 4) returned to service in 2004. The City of Pasadena, however, installed two new gas turbine generators at the Glenarm Power Plant (43 MW per generator) resulting in over 86 MW of new generating capacity. Table 1.1 shows the new generation projects that began commercial operation in 2004.

[1] Price spikes discussed here are defined as a real-time price that exceeds $100/MWh in an interval.

Table 1.1 New Generation Facilities Entering Commercial Operation in 2004

Generating Unit	*Owner or QF ID*	*Net Dependable Capacity (MW)*	*Commercial Operation Date*
Glenarm Power Plant 3	City of Pasadena	43.7	8-Jan-04
Glenarm Power Plant 4	City of Pasadena	43.7	8-Jan-04
El Sobrante Landfill Gas Generation	WM Energy Solutions	2.5	26-Apr-04
Simi Valley Landfill Gas Generation	WM Energy Solutions	2.7	2-May-04
Etiwanda Unit 4 (repowered - originally mothballed on 11/7/03)	Reliant Energy Services	320	6-Jul-04
Sycamore Canyon Landfill Plant B	Gas Recovery Systems	2.5	14-Jul-04
Sonoma County Landfill Phase 3	Sonoma County	1.6	27-Jul-04
Lincoln Land Fill Power Plant	Energy 2001, Inc.	1.2	10-Sep-04
Etiwanda Unit 3 (return from mothball status)	Reliant Energy Services	320	9-Sep-04
Caithness Dixie Valley, LLC*	Caithness Dixie Valley, LLC	10 MW	1-Dec-04
Total Generating Capacity for 2004		747.9	

*Units are Non-Participating Generators.

Source: California ISO Master CAISO Control Area Generating Capability List, March 11, 2005; California ISO Operations Engineering Department

The CAISO's 2003-2004 Winter Assessment projected that no new generation would be commercially available by May 2003. Those projections were revised to 87 MW constructed as of April 1, 2004, in the 2004 Summer Assessment with an additional 32 MW of generation projected through the end of 2004.

Reliant Energy Services' Etiwanda 3 (320 MW) and Etiwanda 4 (320 MW) facilities returned to service in 2004 after having been mothballed in 2003. As part of Reliant's settlement in the various Western Energy Markets investigations (PA02-2-000, EL03-59-000 *et al.*), Reliant had committed to auctioning capacity from its Etiwanda 3 and 4, Mandalay Bay 3 (120 MW), and Ellwood Generating Facility (56.1 MW) facilities for three twelve-month periods through unit-contingent, gas tolling contracts. When it failed to receive bids based upon the terms and conditions set forth in the Request for Bids, Reliant mothballed these facilities. In July 2004, Reliant entered into a reliability-must-run agreement with the CAISO for capacity from Etiwanda 3 and 4 through December 2004. In September 2004, Reliant entered into a bilateral power-purchase agreement with Southern California Edison for the capacity from Etiwanda 3 and 4, totaling 640 MW. Reliant additionally sought, and the FERC granted, a postponement of the auction of the remainder of the units from September 2004 to January 2005 so that Reliant may solicit additional bilateral agreements with buyers for capacity from Mandalay 3 and the Ellwood Generating Facility.

1.3.2 Retired Generation

Approximately 180 MW of generation capacity was removed from service within the CAISO control area in 2004. All but 4 MW of that capacity was located in the SP15 congestion zone. The owner of Chula Vista (41 MW) and Escondido (42 MW) went bankrupt, resulting in the shutdown of those facilities. Dynegy mothballed Division GT

1 (14 MW) when it lost the lease to the land upon which the fuel supply for the facility was located. Also, Dynegy shut down Long Beach 8 (79 MW) due to equipment failures.

Table 1.2 Retired Generation Facilities in 2004

Generating Unit	*Capacity (MW)*
Division GT 1	14
Chula Vista	41
Escondido	42
Long Beach 8	79
Texaco Exploration and Production (Fee B)	4
Total Retirements for 2003	180

Generation in the CAISO Control Area changed by the following net amounts in 2004:

Table 1.3 PGA Generation Change in 2004

Congestion Zone	*Generation Additions (MW)*	*Generation Reductions (MW)*	*Net Change*
NP-15	2.8	0	2.8
SP-15	735.1	-176	559.1
ZP-26	0	-4	-4
ISO Control Area	737.9	-180	557.9

1.3.3 Anticipated New and Retired Generation in 2005

Creation of the new WAPA sub-control area will result in the loss of Western Area Power Administration excess generation scheduled into the CAISO and the loss of Calpine's Sutter Power Plant (535 MW) as a directly scheduled generation unit within the CAISO Control Area in 2005. There are attempts underway to set up Sutter Power Plant as a dynamically scheduled facility into the CAISO.

We project the construction of 3,187 MW of generation to be completed in 2005, of which 2,231 MW is expected to be commercially available by August 1, 2005, prior to the anticipated summer peak load.

Table 1.4 Planned Generation Facilities in 2005

Generation Project	*Developer*	*ISO Net Dependable Capacity (MW)*	*Estimated Commercial Date*
El Sobrante Landfill Power Plant Expansion	Waste Management Energy Solutions	1.35	1-Jan-05
Eurus Oasis Project	Eurus Energy	65	1-Jan-05
Fresno Cogeneration Expansion Project	Fresno Cogen Partners, LP	50.5	14-Jan-05
Sunrise Power Project Phase 3B	Sunrise Power Company, LLC	19	18-Feb-05
Clearwater Combined Cycle Project	City of Corona	32	28-Feb-05
Kimberlina Power Plant	Clean Energy Systems, Inc.	5.5	28-Feb-05
Pico Combined Cycle Plant (Donald Von Raesfeld Power Plant)	Silicon Valley Power	147	18-Mar-05
El Dorado Power House Unit 1	El Dorado Irrigation District	10	1-Apr-05
El Dorado Power House Unit 2	El Dorado Irrigation District	10	1-Apr-05
Pastoria Project Phase 1	Calpine	250	1-Apr-05
Miramar Energy Facility	Ramco Generation Unit	48.5	1-Jun-05
KRCD Peaking Project	Kings River Conservation District	97	1-Jun-05
Exxon Mobile Torrance Project	Exxon Mobile	85	1-Jun-05
Metcalf Energy Center	Calpine	600	30-Jun-05
Pastoria Project Phase 2	Calpine	500	30-Jun-05
Malburg Generation Station	City of Vernon	134	1-Aug-05
Mountainview Power Project Block 4	EIX	566	1-Nov-05
Mountainview Power Project Block 3	EIX	566	1-Nov-05
Total Planned Generation Capacity		3,186.85	

Additionally, Reliant anticipates signing additional power-purchase agreements for the capacity from Mandalay 3 and Ellwood Generation Stations for an additiona1 176.1 MW.

1.4 Transmission System Enhancements/Operational Changes

1.4.1 Intertie (Between Zone) Enhancements

1.4.1.1 Path 15

Before being upgraded in 2004, Path 15 consisted of two 500kV transmission lines between Pacific Gas and Electric (PG&E)'s Los Banos Substation in California's central valley (the northern terminus of the path) and the Gates Substation (the southern terminus of the path). Path 15 used to be one of the State's worst transmission bottlenecks – and one of the CAISO's biggest operational headaches. In January 2001, the bottleneck contributed to capacity shortages in northern California when energy available from the south couldn't be transmitted to northern California because of Path 15 limitations. Table 1.5 summaries the total congestion cost on Path 15 during the past five years. Congestion costs on Path 15 were unusually low in 2002 and 2003 due to the scheduling practice used by Pacific Gas and Electric (PG&E) to mitigate "phantom congestion" on Path 15. PG&E often submitted preferred day-ahead schedules for energy that included zero-priced adjustment bids to decrease load in the NP15 zone, and zero-priced Adjustment Bids to increase load in the ZP26 zone. If phantom congestion on Path 15 was expected in the south-to-north direction based on preferred day ahead schedules, then these adjustment bids were exercised, thereby increasing scheduled PG&E load in ZP26, and decreasing scheduled PG&E load in NP15 by a like amount. Adjustment bids for Load from NP15 to ZP26 had the effect of reducing projected south to north congestion on Path 15, and allowing PG&E to rely on its resources in SP15 to serve Load in NP15. In 2004, PG&E informed the CAISO that it would cease this scheduling and adjustment bidding practice due to an increase in energy schedules from the southwest over Path 15 to northern California as a result of significant day-ahead bilateral price divergences between the regions. This resulted in significantly higher congestion costs in the latter part of 2004 compared to the previous two years.

Table 1.5 Historical Inter-Zonal Congestion Cost on Path 15

Year	Congestion Cost ($)
2000	$ 170,494,425
2001	$ 43,260,325
2002	$ 480,209
2003	$ 678,000
2004	$ 9,763,589

In June 2002, the CAISO Governing Board unanimously approved the Path 15 Upgrade Project as a necessary and cost-effective addition to the CAISO Controlled Grid. The project consists primarily of a new, single, 83-mile, 500 kV transmission line and associated substation facilities extending between the Los Banos Substation and the Gates Substation. The $300 million project is a partnership among PG&E, the Western Area Power Administration (WAPA), and a private company called Trans-Elect. WAPA set new towers and conductors, and PG&E upgraded substations on either end of the new line. PG&E, WAPA, and Trans-Elect each own a portion of the transmission rights to the new line. The CAISO will operate the new facility in conjunction with the existing infrastructure. The new line increases the Path 15 capacity from 3,900 MW to 5,400 MW for the south-to-north direction.

The long-awaited Path 15 upgrade was completed and turned over to CAISO operation on December 7, 2004. Upgrade of Path 15 began commercial operation at 12:01 a.m. on December 22 in the hour-ahead market. The day-ahead market use began on December 23. The upgrade of Path 15 significantly reduced congestion cost and increased flows on the path especially during peak hours. The average daily maximum final flow is 3,154 MW from December 22 to December 31 (all in south-to-north direction), a 40 percent increase compared to average daily maximum flow during December 1 to December 21.

1.4.1.2 Pacific DC Intertie (NOB)

The 3,100 MW, 500 kV Pacific DC Intertie (also known as the branch group NOB [Nevada Oregon Border]) runs from the Celilo substation in the northwest to the Sylmar substation close to LADWP’s area. This is a jointly owned project with multiple transmission rights stakeholders. Los Angeles Department of Water and Power (LADWP) and the Bonneville Power Administration (BPA) jointly operate the PDCI facility and control their portions of the Nevada Oregon Border (NOB).

There are seven entities with firm rights on the PDCI Transmission Line. They are the three PTOs: PG&E, SCE, and SDG&E; and four public entities that share LADWP’s portion: LADWP, Burbank, Pasadena, and Glendale. Some of the PTOs sold portions of their firm rights to other agencies not listed above. The City of Anaheim and City of Riverside have firm scheduling rights on a portion of Burbank and Pasadena’s PDCI capacity. The City of Vernon has firm scheduling rights on a portion of PG&E’s PDCI capacity. All remaining PDCI capacity from PG&E, SCE, and SDG&E has been converted to the CAISO. The CAISO indirectly controls rights to approximately 2,070 MW (1,416 MW S-N) of the available 2,990 MW N-S (2,860 MW S-N) capacity of the line, depending on conditions, and allows scheduling in its system to that limit.

The line has a full capacity rating of 3,100 MW (power order at Celilo) north-to-south and 3,098 MW (power order at Sylmar) south-to-north with all equipment in service. The maximum scheduling capacity of the PDCI is 2,990 MW north-to-south and 2,858 MW south-to-north as measured at NOB with all equipment in service. The actual scheduling capacity of the PDCI is also limited by BPA Standing Order 306 and the CAISO T-116 Procedure which limits the total COI + PDCI California import based on current seasonal operating transfer capability (OTC) studies.

The PDCI participants, including SCE, City of Burbank, Glendale, Los Angeles, and Pasadena, worked together to modernize infrastructure at the Sylmar Converter Station, the southern terminal of the PDCI. BPA’s Transmission Business Line worked to modernize infrastructure at the Celilo Converter Station, the northern terminal of the PDCI, in conjunction with the southern terminal work. They instituted a nine-month outage from April 2004 through December 2004. For the first six months of the outage, capacity on the Intertie was reduced by 1,100 MW from 3,100 MW to 2,000 MW. For the remaining three months, the line was taken out of service completely and capacity dropped to zero.

The Celilo and Sylmar Modernization projects were needed to maintain the DC Intertie's transfer capacity at 3,100 MW instead of degrading it to 1,100 MW. BPA's Celilo modernization project began in 2001 and was completed in April 12, 2004. The project cost $65.1 million. This project replaced the last of the original vacuum-tube mercury-arc converters at the Celilo Converter Substation with solid-state silicon-based thyristors. Now Celilo will be able to keep the DC Intertie's transfer capacity at 3,100 MW instead of having to degrade it to 1,100 MW. If the older converters were not replaced, they would have possibly failed and reduced transfer capacity further.

1.4.1.3 WAPA/SMUD Transition

Western Area Power Administration (WAPA) sells Bureau of Reclamation California Central Valley Project power plant generation, including those at Shasta, Folsom, Trinity, and New Melones dams. WAPA also imports additional power over their share of the Pacific AC Intertie and the California-Oregon Transmission Project – 500 kV lines linking northern and central California to the Pacific Northwest.

On December 31, 2004, three existing long-term contracts between WAPA and PG&E expired. WAPA began reviewing options and conducting a stakeholder process in June 2003. On July 13, 2004, WAPA announced its decision to leave the CAISO Control Area and to join the Sacramento Municipal Utility District (SMUD) as a sub-control area effective January 1, 2005. WAPA intends to schedule power deliveries for project use loads and customers directly connected to its transmission system and manage net power flows at sub-control area interconnection points.

The WAPA transition to the SMUD Control Area is scheduled to be accomplished in two phases: Phase 1) Western 230 kV system and USBR's northern California hydro generation, implemented on January 1, 2005; and Phase 2) Olinda-Tracy 500 kV line (COTP portion of the COI), currently under discussion to ensure it does not impact reliability. The CAISO remains, for now, the path operator of the 500 kV lines owned by WAPA including the California-Oregon Intertie. SMUD will operate the 230 kV system for WAPA and its preference power customers.

The CAISO defined new inter-connection points and new branch groups for the WAPA/SMUD transition. It placed a new network model in service on December 31, 2004, incorporating several market and system changes. The model incorporated the WAPA transmission system and USBR's northern California hydro generation into the SMUD Control Area. As the result of WAPA transition to SMUD control area, the CAISO's SA network model B5 has eight new branch groups to replace the 2 expiring branch groups. Table 1.6 summaries the expiring and new branch groups related to WAPA/SMUD transition.

Table 1.6 Expired and New Branch Groups Due to WAPA/SMUD Transition

BRANCH GROUP	FROM ZONE	TO ZONE	INTERCON-NECTING CONTROL AREA	TIE_POINT	EFFECTIVE
ELVTHRLY _BG	SMDW	NP15	SMUD	ELVRTA_2_ELVRTW HURLEY_2_ELVRTW	Expired on 1/1/2005
OLNDAWAPA_BG	SMD1	NP15	SMUD	OLNDWA_2_OLIND5	New on 1/1/2005
CTNWDWAPA_BG	SMD2	NP15	SMUD	CTNWDW_2_CTTNWD	New on 1/1/2005
CTNWDRDMT_BG	SMD3	NP15	SMUD	CTNWDW_2_RNDMTN	New on 1/1/2005
TRACYWAPA_BG	SMD4	NP15	SMUD	TRCYPP_2_TRACY5	New on 1/1/2005
TRCYTESLA_BG	SMD5	NP15	SMUD	TRCYPP_2_TESLA	New on 1/1/2005
TRCYWSTLY_BG	SMD6	NP15	SMUD	TRCYPP_2_WESTLY	New on 1/1/2005
LLNLTESLA_BG	SMD8	NP15	SMUD	LLNL_1_TESLA	New on 1/1/2005

1.4.1.4 Municipal Additions

The City of Vernon became a participating transmission owner (PTO) of the CAISO on January 1, 2001. The Cities of Anaheim, Azusa, Banning, and Riverside became PTOs of the CAISO on January 1, 2003. The City of Pasadena became a PTO starting January 1, 2005 and turned over its transmission facilities to the CAISO operation. The City of Pasadena owns about 200 MW of capacity set aside for it on transmission paths into California. Together these 6 PTOs are called the Southern Participating Transmission Owners (SPTOs).

On September 16, 2004, the CAISO implemented “Step 1” of its network model, which enabled the CAISO to model scheduling flexibility and exporting capability to the best of the existing system’s ability. The “Step 2” SPTO Transmission was modeled as radial networks and has a capability for point-to-point scheduling for transmission under CAISO Operation Control but external to the CAISO Control Area (i.e., Cities of Anaheim, Riverside, Azusa, Banning, Vernon, and Pasadena). The new transmission network model was successfully implemented into the day- and hour-ahead and real-time markets. This network model provides immediate and necessary scheduling enhancements and increased transmission availability for the SPTOs. Table 1.7 summarizes the expiring and new branch groups related to SPTOs.

Table 1.7 Expired and New Branch Groups Due to SPTOs

BRANCH GROUP	FROM ZONE	TO ZONE	INTERCON-NECTING CONTROL AREA	TIE_POINT	ACTIVE / INACTIVE
LUGOMKTPC_BG	LC4	SP15	WALC	LUGO_5_MKTPLC	Expired on 12/31/2004
LUGOMONAI_BG	PC2	SP15	PACE	LUGO_5_MONAIM	Expired on 12/31/2004
LUGOGNDRI_BG	SR5	SP15	SPP	LUGO_5_GNDRIM	Expired on 12/31/2004
LUGOWSWGI_BG	AZ7	SP15	APS	LUGO_5_WSWGIM	Expired on 12/31/2004
LUGOMONAE_BG	PC3	SP15	PACE	LUGO_5_MONAEX	Expired on 12/31/2004
LUGOGNDRE_BG	SR6	SP15	SPP	LUGO_5_GNDREX	Expired on 12/31/2004
LUGOWSWGE_BG	AZ8	SP15	APS	LUGO_5_WSWGEX	Expired on 12/31/2004
WSTWGMEAD_BG	AZ6	LC5	ARIZ	WSTWNG_5_MEAD	New on 1/1/2005
MKTPCADLN_BG	LC4	LA7	LDWP	MKTPLC_5_ADLNTO	New on 1/1/2005
IPPDCADLN_BG	LA5	LA7	LDWP	IPPDC_5_ADLNTO	New on 1/1/2005
MONAIPPDC_BG	PC1	LA5	PACE	MONA_5_IPPDC	New on 1/1/2005
GONDIPPDC_BG	SR4	LA5	SRRA	GONDER_5_IPPDC	New on 1/1/2005
MEADMKTPC_BG	LC5	LC4	WALC	MEAD_5_MKTPLC	New on 1/1/2005
MEADTMEAD_BG	LC6	LC5	WALC	MEADT_5_MEAD	New on 1/1/2005
MCCLMKTPC_BG	LA6	LC4	LDWP	MCCLUG_5_MKTPLC	New on 1/1/2005
ADLANTOSP_BG	LA7	SP15	LDWP	ADLNTO_5_LUGO	New on 1/1/2005
ADLANTOSP_BG	LA7	SP15	LDWP	ADELNT_2_SYLMAR	New on 1/1/2005

1.4.2 Intra-zonal (Within Zone) Transmission System Enhancements

1.4.2.1 South of Lugo

South of Lugo has long been an intra-zonal constraint. The constraint consists of three 500 kV lines that emanate from the Lugo substation and feed into the LA basin area. The path operates under the N-2 operating criteria, meaning that if any two lines fail, the remaining line has to be able to absorb the energy that shifts onto it.

The internal limit on this grouping of lines was 4,400 MW. On May 27, 2004, the CAISO upgraded the path rating of 4,400 MW to 4,800 MW. On July 29, 2004, it upgraded it from 4,800 to 5,100 MW [depending on grid conditions]. The CAISO plans further upgrades for 2005. The rating should rise in the second half of 2005 to approximately 5,600 MW.

1.4.2.2 The Pacific DC Intertie and Sylmar Substation

The Pacific DC Intertie is a 3,100 MW line that runs from the Celilo substation in the northwest to the Sylmar substation, where LADWP and SCE share ownership. Starting in September 2003, the PDCI had an extensive rebuild as it had been in operation for thirty years and there was sufficient interest in maintaining it. The rebuild lasted from September 2003 to the end of 2004. The line was almost completely out of service for the last quarter of 2004. Prior to that, it experienced intermittent derates and outages of varying sizes and durations. For this entire period there was intermittent Sylmar bank congestion due to the equipment outages. Most of the mitigation for this consisted of incrementing units in the Ventura County area and the LA basin area.

Prior to the rebuild, the SCE and LADWP systems at Sylmar were connected via two transformer banks, which converted power between LADWP's nominal 220 kV system and SCE's 230 kV system. These two transformer banks were a constraint. During the rebuild period, a third transformer bank was added to reduce congestion between the SCE/LADWP interface at Sylmar. The CAISO is hopeful that congestion at the Sylmar bank will become negligible in the near future.

1.4.2.3 Miguel Substation

The Miguel substation and its associated congestion has been one of the CAISO's most significant intra-zonal problems since July 2003. The nature of the constraint has been twofold.

First, the substation was limited by the 500/230 step-down transformer bank capacity at the Miguel substation itself. This limit was approximately 1,120 MW.

Second, the substation was limited by the N-2 criteria on the two 230 kV lines emanating from the substation, meaning that if both of these lines tripped the remaining 138 kV system had to absorb the total energy. This limit was 1,100 MW.

In the second half of 2004, a number of upgrades were made to the system in the vicinity of the Miguel substation. A new 500/230 step-down transformer bank was added to the substation, new series capacitors were added to the Southwest Power link (SWPL) line that feeds into the substation (this reduces line impedance and increases power flow), and a small part of the 138 kV system was re-conductored. This new equipment went into service on October 31, 2004. Unfortunately, this did not significantly change the capacity of the substation. The static rating of the substation increased from 1,100 MW to 1,200 MW and the dynamic rating increased from 1,400 MW to 1,500 MW. The new 500/230 transformer bank resulted in more power reaching Miguel, so the Miguel congestion remained a significant cost issue and intra-zonal constraint. In addition, the N-2 criterion still remains as a significant constraint.

The CAISO remains hopeful that the Miguel congestion will be substantially ameliorated by the early energization of the Miguel Mission #2 230 kV line. This transmission line has been approved by the CPUC and is under construction. The early energization project consists of taking one of the pre-existing 69 kV lines and increasing its voltage to 230 kV prior to the building of the second line. This should relax the N-2 constraint, but we are not certain of the extent of the amelioration.

1.4.2.4 Other Upgrades

There were two other upgrades made during 2004:

1. Path 26 received a RAS (Remedial Action Scheme) upgrade from 3,000 to 3,400 (N-S) on May 12, 2004. This should increase to 3,700 MW by the summer of 2005.
2. The Path 15 upgrade from 3,900 MW to 5,400 MW became operational on December 7, 2004.

1.5 Resource Adequacy Requirements

Resource adequacy has been addressed in the eastern United States ISOs by placing explicit responsibility on the load serving entities (LSEs) to procure sufficient generation capacity (steel in ground) to serve their annual peak load plus a margin. Since the majority of California load is currently served by the three investor-owned utility distribution companies (UDCs), the California Public Utility Commission (CPUC) is spearheading the development of a resource adequacy (RA) obligation on the LSEs under its jurisdiction.[2] This effort is ongoing, and its salient elements at present are embodied in CPUC's October 28, 2004, Resource Adequacy Decision described below.

1.5.1 Nature and Phase-In of the Obligation

The CPUC's October 28, 2004, Order establishes a year-round obligation on LSEs to procure sufficient capacity to serve their load plus a planning reserve margin. The level (MW) of the LSE's obligation varies by month and is based on the LSE's coincident monthly peak load plus a 15-17 percent planning reserve margin. The LSEs have the obligation to satisfy 90 percent of their capacity requirements for the summer peak season of May through September one year in advance (no later than September 30th of the preceding year[3]), and 100 percent of their capacity requirements one month in advance of each month throughout the year.

The CPUC order also provides that the details of the annual and monthly reporting requirement – monthly due date, nature of filing, review process and penalties – will be developed in Phase 2 (i.e., the next release of the Decision slated for mid-2005).

An important issue that is ambiguous and problematic in the CPUC Order is the number of hours in each month that the obligation applies to the LSEs. The CPUC required that LSEs acquire a mix of resources capable of satisfying the number of hours for each month that their loads are within 10 percent of their maximum contribution to monthly system peak. At the same time, the obligation of all LSEs is supposed to meet the system-wide obligation (system peak plus a 15 to 17 percent reserve margin during the hours when the system load is within 10 percent of the system peak). These two requirements are mutually inconsistent, and collectively insufficient to ensure resource adequacy.[4]

The CPUC's October 28th Order establishes June 1, 2006, as the date for LSEs to achieve full implementation of the resource adequacy requirements. As a consequence,

2 It is anticipated that the CPUC RA will be adopted by local regulatory agencies in conjunction with other (non-CPUC jurisdictional) LSEs in California.

3 For the first round of filings for the May-September 2006 period, the CPUC order stated that the deadline for compliance will be the later of September 30, 2005, or 90 days after the date of the Phase 2 decision. The CPUC also provided that, in the future, it may adopt a rolling 12-month-ahead definition of year-ahead.

4 Although this aspect of the obligation was apparently motivated by some earlier proposals from the CAISO, it represents a misunderstanding. In our ACAP era we had talked about the requirement being established based on a strip of hours the system load exceeds 90 percent of the system peak. But we did not emphasize an important related issue that we had assumed, namely that since the hours comprising this "system peak strip" were not known in advance, there would be a must-offer obligation, practically all the time. However, one thing was quite clear, namely that the strip of hours would apply uniformly to all LSEs; it was never meant to be LSE specific. A related point that we did not explicitly clarify was that we were entertaining the idea that the level of obligation (MW) of each LSE could be based on its contribution to the system peak during a set of critical hours (when the system load exceeded 90 percent of the system peak) rather than a single hour (the system peak point). For example, if two LSEs had 100 MW of load coincident with system peak, but the hourly load forecast for LSE1 was on the average 80 MW during the "system peak strip" hours and that of LSE2 was on the average 120 MW during the same hours, the obligation of LSE2 would be higher than that of LSE1.

the CPUC's resource adequacy program will be in place prior to full implementation of the CAISO's new market design in February 2007.[5]

1.5.2 Load Forecasting Protocols

Throughout the CPUC's procurement proceeding, the CPUC and parties to the proceeding acknowledged the importance of accurate load forecasting for the purpose of determining each LSE's obligation. Recognizing the critical expertise the California Energy Commission (CEC) has on such matters, the CPUC's October 28th Order requests that the CEC perform "coincidence analysis" for LSEs based on each LSE's best estimate of future customer loads. The order also states that the CPUC will develop a tracking system that compares forecasts to actual loads and create penalties for excessive deviations and that LSE forecasts with significant load reductions will be subject to justification.

The CPUC order also states that LSEs must include all losses in load forecasts, including distribution losses, transmission losses, and estimates of unaccounted for energy. The CPUC directs South California Edison Company (Edison) to prepare a methodology for consideration in Phase 2.

The CPUC's October 28th Order provides that energy efficiency impacts be included in each LSE's load forecast. The CPUC states that the detailed methodology for doing so will be determined in Phase 2 through coordination with the CPUC's pending energy efficiency rulemaking.

1.5.3 Resource Counting Conventions

The CPUC adopted a "net dependable capacity" basis for determining how much each specific resource will count towards satisfying a LSE's obligation. However, the CPUC's October 28th Order states that, at this time, the availability of resources will not be derated based on actual forced outage rates. The CPUC's order specifies that the CPUC will evaluate whether the use of unit-specific differential adjustments from the average forced-outage rate provides cost-effective incentives for generators to make investments to improve performance during the second-generation resource adequacy efforts.

The CPUC's October 28th Order establishes no limitations on the use of firm liquidated damages (Firm LD) contracts to satisfy the resource adequacy requirements. The CPUC states that in Phase 2, it will review proposals for contract language or other contract methods that can substitute for liquidated damages contracts and will explore whether audit methods can be developed that would allow the CPUC to place greater confidence in relying upon liquidated damage contracts. Consistent with its long-held position that LSEs identify the actual physical resource(s) used to satisfy their resource adequacy obligations, the CAISO has reiterated the necessity of a provision that, as long as firm LD contracts are eligible towards satisfying the obligation, there must be a requirement that the physical resources supporting the firm LD contracts for each day/hour be identified by the designated SC (representing the LSE or the seller) no later than the close of the CAISO's day-ahead market.

5 This requires a transition mechanism to implement the RA in the absence of a forward energy market using the existing must-offer waiver procedures.

The CPUC order adopts a historic performance approach for valuing/counting the amount of capacity available from solar and wind-based resources that do not have backup arrangements in place with utilities.

The CPUC order also states that QFs qualify at historic performance at peak and, for energy-limited resources, a unit must be able to (1) operate for 4 hours per day for 3 consecutive days and (2) run a minimum aggregate number of hours per month based on the number of hours that loads in the control area exceed 90 percent of peak demand in that month. The order states that this rule is limited to the summer months and an appropriate rule for energy-limited resources for non-summer months will be developed in Phase 2.

With respect to demand response resources, the CPUC order provides that:

- Reserve requirements will not be imposed for demand response counted as resources (i.e., dispatchable demand response);
- To qualify as a demand response resource, a resource must have a minimal summer seasonal performance level of 48 hours;
- Demand response products with 2-hour availability can only constitute 0.89 percent of monthly system peak of a LSE's portfolio; and
- Quantification of such resources will be performed by an inter-agency staff team.

With respect to all resources, the CPUC's October 28th Order provides that, for purposes of counting resources under construction, parties should use the commercial operation date data published by the CEC and the CAISO. Details of this requirement will be determined in Phase 2 workshops.

Finally, with respect to the existing California Department of Water Resources' long-term power contracts (CDWR Long-term Contracts), the amount of qualifying capacity from these contracts will be determined through application of the deliverability screens that are ultimately adopted by the CPUC. We discuss this issue below.

1.5.4 Deliverability

The CAISO has long held the position that all resources procured by LSEs to satisfy their resource adequacy obligations must be deliverable, both on a system-wide as well as local level. The CAISO proposed three deliverability screens: (1) aggregate to load for evaluating control area resources, (2) imports, and (3) load pocket.

The CPUC's October 28th Order supported the CAISO's baseline analyses proposals to implement the first two screens described above. With respect to allocation of limited export capacity for the aggregate to load analysis, the CPUC agreed that such allocation should occur on the basis of the CAISO transmission access charges. The order also provided that the issue of import capacity allocation will be addressed in Phase 2 workshops.

With respect to the all-important issue of local deliverability, the CPUC's decision stated that creating local reliability requirements is consistent with the CPUC's prior decisions and directed the parties to address implementation of such requirements in Phase 2 [Local resource adequacy requirements, including identification of load pockets, generator performance in load pockets, transmission import capabilities, and various adjustments to the current LARS process that results in RMR contracts]. The

CPUC's order also stated that reliability must-run contracts should remain available in the future to address local market power concerns.

1.5.5 Availability of Resources to the CAISO

The CPUC's October 28th Order approved a sequence of requirements that qualified capacity first be scheduled by the LSE pursuant to the CAISO's day-ahead scheduling process, then bid into CAISO's day-ahead markets if not scheduled, and then subject to the CAISO's residual unit commitment (RUC) procedure if its bid is not accepted in the day-ahead integrated forward market. The CAISO fully supports the CPUC's established requirements, and has offered the following clarifications: 1) The must-offer obligation starts in day-ahead and continues through the last market consistent with the resource start up time (thus for short start units the obligation continues through the hour-ahead scheduling process or HASP); 2) the must-offer obligation applies to all hours, allowing for reasonable exemptions provisions for resources that can be logically available during certain hours only (e.g., solar resources would be exempted from must-offer obligation at night); 3) the must-offer obligation cannot be satisfied by scheduling against a wheel out; 4) to the extent a resource is not otherwise constrained, the CAISO will include proxy bids for the unscheduled capacity of the resource in the relevant market (day-ahead and/or HASP).

The CPUC order also provided that contracts executed after completion of the Phase 2 proceedings should include such provisions in order to be eligible to count as qualified capacity in satisfaction of forward commitment obligations. The CPUC order identified the following issues to be addressed in the Phase 2 workshops:

1. What specific standard language, if any, should be included in future contracts between load serving entities and generators that will sufficiently obligate generators to bid into day-ahead markets and be subject to RUC and other appropriate processes?
2. How should intra-day scheduling flexibility be accommodated in existing contracts, and whether and how to accommodate intra-day scheduling flexibility in new contracts, e.g., through "self-provided RUC"?
3. How unscheduled resources are made available to the CAISO?
4. What CAISO tariff provisions must be established in order to complement the contractual language that the CPUC will impose?
5. What provisions are appropriate to protect energy-limited resources?
6. Should demand response and other non-generation resources be subject to such requirements? If so, to what degree and under what provisions?

1.5.6 Reporting, Reviewing and Sanctions

The CPUC's October 28th Order also contemplates a review process intended to become a simple checklist or verification process. The CPUC was explicit that it did not intend to conduct a prudence review as part of the annual compliance filing. The CPUC order stated that the resource tabulation templates and system of penalties would be addressed in Phase 2.

1.6 Transmission Economic Assessment Methodology (TEAM)

1.6.1 Transmission Economic Assessment Methodology

The CAISO is responsible for evaluating the need for all potential transmission upgrades that California ratepayers may be asked to fund.[6] This includes construction of transmission projects needed either to promote economic efficiency or to maintain system reliability. The CAISO has clear standards to use in evaluating reliability-based projects. To fulfill its responsibility for identifying economic projects that promote efficient utilization of the grid, the CAISO developed a methodology called the Transmission Economic Assessment Methodology (TEAM).

The goal of TEAM is to significantly streamline the evaluation process for economic projects, improve the accuracy of the evaluation, and add greater predictability to the evaluations of transmission need conducted at the various agencies. The methodology is intended to be a tool that will provide market participants, policy-makers, and permitting authorities with the information necessary to make informed decisions when planning and constructing a transmission upgrade for reliable and efficient delivery of electric power to California consumers.

This methodology was filed with the CPUC in June 2004 in a report. The report demonstrates the methodology by applying it to a proposed transmission expansion between central and southern California called Path 26.

The TEAM methodology represents the culmination of over two years of research and development led by the CAISO Department of Market Analysis and Grid Planning with support and input from industry experts and the CAISO Market Surveillance Committee. It integrates five key principles for defining quantifiable benefits into a single comprehensive methodology to support decisions about long-term investments required for transmission upgrades. The process also included many daylong stakeholder meetings and conference calls in subgroups to define many aspects of the methodology.

1.6.1.1 The Five Key Principles

1. *Benefits Framework*

The methodology utilizes a framework to consistently measure the benefits of a transmission expansion project to various participants. It provides policy-makers with several options or perspectives on the distributional economic impacts of proposed transmission expansion projects on consumers, producers, and transmission owners (or other entities entitled to congestion revenues), considering congestion both within and between regions.

[6] The Legislature, pursuant to Public Utilities Code § 345, assigned the CAISO the responsibility of "ensur[ing] [the] efficient use and reliable operation of the transmission grid." To achieve this goal, the CAISO can compel Participating Transmission Owners to pursue construction of transmission projects deemed needed either to "promote economic efficiency" or to "maintain system reliability" (CAISO Tariff § 3.2.1.).

Transmission expansion can have different impacts on consumers, suppliers, and transmission owners from different regions in the system. The TEAM specifies four measures of benefits. They are the societal, modified societal, CAISO ratepayer, and CAISO participant.

The *societal benefits* are the decrease in the total system costs of serving load throughout the WECC due to the transmission upgrade. They represent the traditional total system production cost savings which is also the algebraic sum of the increase in consumer surplus (benefit to the load); increase in producer surplus (benefit to the generators); and increase in transmission rental (benefit to the transmission owners) due to the transmission upgrade. This identity holds system-wide, but not necessarily at the individual regions due to the changes in imports and exports throughout the region.

The *modified societal* perspective measures the benefits from increased competition. It is the societal benefits net of monopoly rent. The monopoly rent is the profit of the generators from exercising market power.

The *CAISO ratepayer benefits* are the modified societal benefits to the CAISO ratepayers that are the consumers under the CAISO controlled grid.

The *CAISO participant benefits* are the modified societal benefits to all of the CAISO participants, including ratepayers and all those who own and operate generators in the CAISO controlled grid.

2. *Network representation*

TEAM recommends modeling of physically feasible flows, a full network model with at least a linearized DC approximation and nodal pricing. It is very essential to capture the loop flows and congestion essential in the transmission expansion. Previous experience in CAISO transmission additions, using a contract path flow analysis, resulted in a decision which increased the congestion in the CAISO controlled grid. This experience supports the necessity to use a full network model as an essential framework for the analysis.

3. *Market prices*

TEAM proposes the utilization of dynamic generation bidding to capture the cost aspects of non-competitive market conditions. This becomes essential in a restructured market which is not fully comprised of vertically integrated regimes. Strategic bidding can be captured through two methods: through game theoretic modeling, and through the use of estimated historic market relationships. In our example analysis, we used the estimated historic approach.

4. *Uncertainty*

TEAM addresses the uncertainty about future market conditions by providing a methodology for selecting a representative set of market scenarios to measure benefits of a transmission expansion and assigning weighting factors (relative probabilities) to different scenarios so that the expected benefit and range of benefits for a transmission expansion can be determined.

There are several approaches to capturing uncertainty: deterministic (average conditions), stochastic (distribution of conditions with probability distribution), scenario analysis (selected conditions with calculated probability from the distribution), and extreme conditions (with no known probability). The conditions examined in the example analysis were load, gas prices, hydro conditions and market price derivation. For all except the hydro conditions, we estimated distributions would follow a normal curve. We estimated high and low conditions at the 75 percent confidence interval and the very high and very low conditions at the 90 percent confidence interval. Hydro conditions, due to lack of data, were taken directly from historical data.

The economic assessment of a proposed transmission upgrade can be very sensitive to specific input assumptions. Unless the proposed project economics are overwhelmingly favorable when using “expected” input assumptions, we need to perform sensitivity studies using a variety of input assumptions. We do this to compute the following benefit measures: expected value, range, and contingency value(s).

A significant portion of the economic value of a potential upgrade is realized when unusual or unexpected situations occur. Such situations may include high load growth, high gas prices, or wet or dry hydrological years. The “expected value” of a transmission upgrade should be based on both the usual or expected conditions as well as on the unusual, but plausible, situations.

A transmission upgrade can be viewed as a type of insurance policy against extreme events. Providing the additional capacity incurs a capital and operating cost, but the benefit is that the impact of extreme events is reduced or eliminated.

5. *Resource substitution*

TEAM recognizes the need for capturing the interaction between generation, demand-side management, and transmission investment decisions, recognizing that a transmission expansion can impact the profitability of new resource investment. The methodology should consider both the objectives of investors in resources (private profits) and the transmission planner (societal net-benefits).

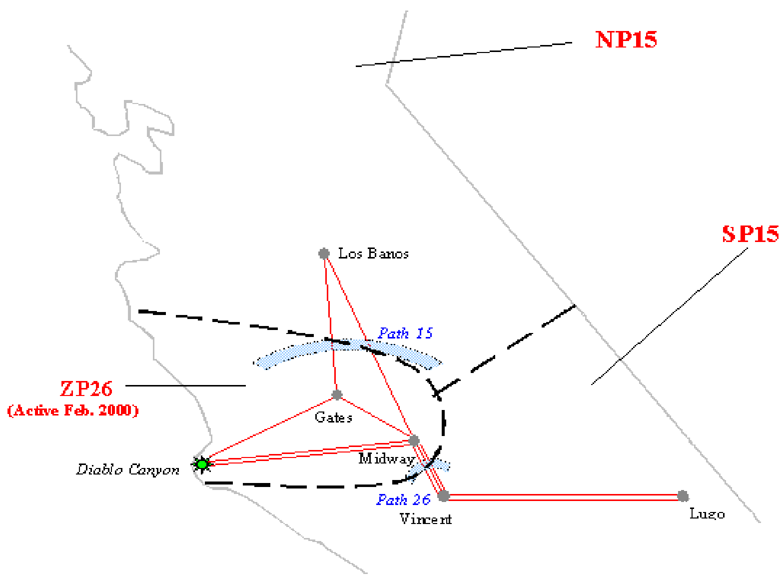
The economic value of a proposed transmission upgrade is directly dependent on the cost of resources that could be added or implemented in lieu of the upgrade. We considered the following options resources: central station generation, demand-side management, renewable generation and distributed generation, modified operating procedures, additional remedial action schemes (RAS), alternative transmission upgrades, and any plausible combinations of the above.

In addition to considering the resource alternatives described above, another important issue we considered is the decision of where to site new transmission. One perspective is that transmission should be sited after the siting of new generation. The other perspective is that the transmission should be planned anticipating various generation additions. The proposed approach we used is the latter one. Examining resource alternatives to a transmission upgrade demonstrates that an alternative can either complement the line upgrade or substitute for it.

1.6.1.2 Modeling

As mentioned earlier, the TEAM was demonstrated for Path 26. Path 26 connects between nodes, Midway and Vincent, between the CAISO regions ZP26 and SP15. The following figure shows the geographical position of the proposed upgrade of the transmission line. The upgrade consists of an increase of 1,000 MW in both directions, increasing south-to-north from 3,000 MW to 4,000 MW and north-to-south from 3,400 MW to 4,400 MW. This also required the re-conductoring of the Midway-Vincent #3 Line, replacing Midway-Vincent #3 series capacitors, replacing wave traps, breakers and current transformers, and re-conductoring the Vincent-Antelope #1 230 kV Line.

Figure 1.1 Path 26 Proposed Upgrade



We used the market simulation model PLEXOS for this analysis.[7] For data, we used the database created by the Seams Steering Group-Western Interconnection (SSG-WI)[8] transmission planning subgroup for the planning studies of 2003. We modified the data, with load data from California Energy Commission (CEC), load forecasts from WECC, gas prices also from CEC, and hydro conditions from SSG-WI. We also augmented the generation data with data from Henwood Energy Services.[9]

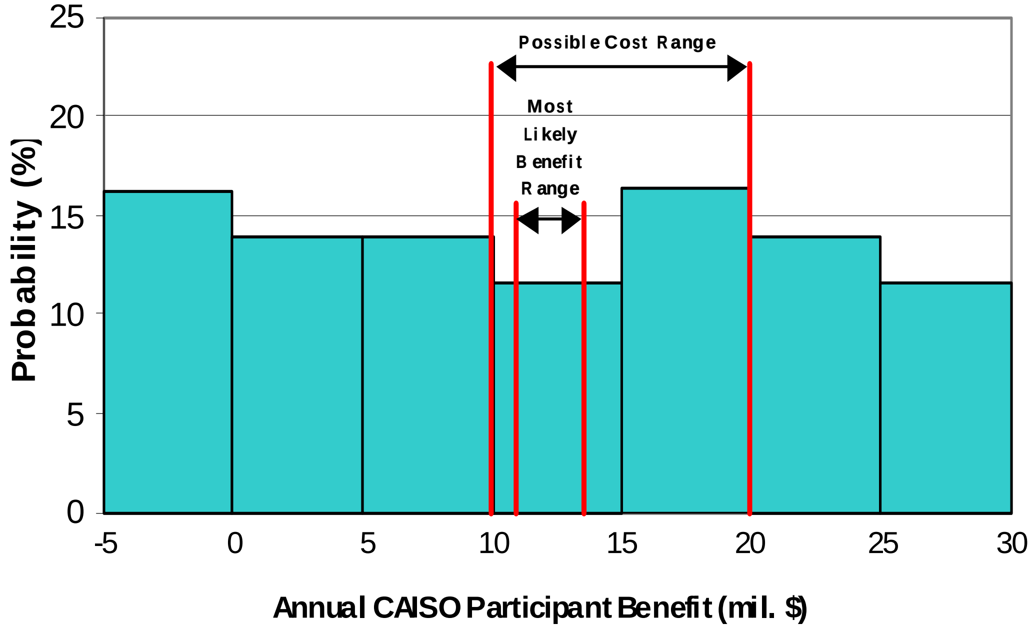
The analysis was done for two years, 2008 and 2013. We used the whole WECC system, with 17,450 lines and 13,380 nodes, in which 284 lines were 500 kV and above. The RSI approach developed by DMA was used for the market pricing by implementing it in PLEXOS for hourly dynamic bidding. We evaluated a total of 80 scenarios.

The capital cost we estimated for the project was $100 million. We estimated a possible range of costs for year 2013 between $10 to $20 million (margin of error assumed to be 50 percent). The following figure shows the range of costs and benefits

[7] More information on the model can be found at www.plexos.info
[8] http://www.ssg-wi.com/
[9] http://www.globalenergy.com/

calculated from the scenario analysis. We concluded that the upgrade appears to be economically viable given the cost/benefit ratio.

Figure 1.2 Range of Costs and Benefits for 2013



We performed additional analysis and filed a supplement with the CPUC in July 2004. We conducted further CPUC workshops for TEAM in the months of July 2004.

The detailed report that was filed with the CPUC is available at the CAISO web site at http://www1.caiso.com/docs/2003/03/18/2003031815303519270.html.

1.6.1.3 TEAM implementation of Palo Verde Devers Line #2

During July 2004 through Feb 2005, TEAM was used to evaluate the Palo Verde Devers Line #2 (PVD2), proposed by Southern California Edison (SCE).

The proposed PVD2 project is a 500 kV transmission line from the Palo Verde area (near Phoenix, Arizona) to SCE's Devers substation near Palm Springs in southern California. We expect it to come online by year 2009, increasing California's import capability from the southwest by at least 1,200 MW.

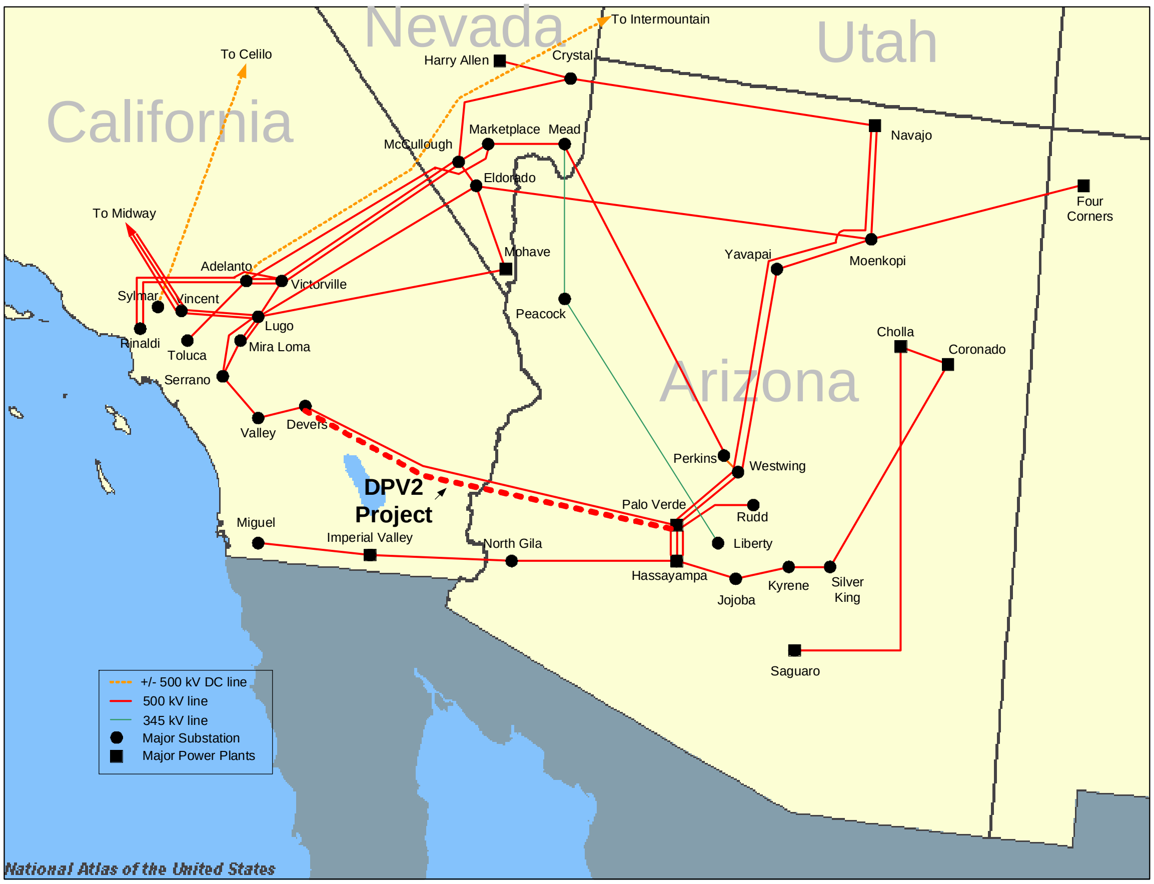
The PVD2 project includes the following facilities:

- A new 230 mile 500 kV line to be constructed between Harquahala Generating Company's Harquahala Switchyard (near Palo Verde) and SCE's Devers 500 kV Substation. The proposed route between Devers and Harquahala parallels SCE's existing Palo Verde-Devers No.1 (PVD1) transmission line. Most of the proposed line is to be constructed on single circuit steel lattice towers.

- The four 230 kV lines west of the Devers substation will be rebuilt and re-conductored:[10] the Devers-San Bernardino 230 kV lines #1 and #2, and the Devers-Vista 230 kV lines #1 and #2.
- Voltage support facilities will be added in the Devers area in southern California.

The following figure shows the location of the Proposed PVD2 Transmission Expansion Project.

Figure 1.3 Proposed PVD2 Transmission Expansion Project



For this economic evaluation, we quantified the following economic benefits attributable to the proposed PVD2 upgrade: energy cost savings, operational, capacity, system loss reduction, and loss reduction benefits.

After a comprehensive analysis, the staff found that the PVD2 project will provide a significant amount of reliability and economic benefits to CAISO ratepayers and would improve reliability by increasing voltage support in southern California, and enhance system operational flexibility by providing CAISO operators with more options in responding to transmission and generation outages.

[10] The re-conductoring will be with 2B-1033 ACSR conductor.

The total capital cost of the project is estimated to be $680 million for the 2009 online date. The following table summarizes the expected benefits and costs over the 50-year economic life of the PVD2 project for various perspectives.

Table 1.8 Summary of PVD2 Lifecycle Benefits, Costs, and Benefit-Cost Ratios for the Four Primary Perspectives (millions of 2008 dollars)

	WECC Or Societal	Enhanced WECC Competition or Modified Societal	CAISO Ratepayer (LMP Only)	CAISO Ratepayer (LMP+ Contract Path)
Energy	$56	$84	$57	$198
perational	$20	$20	$20	$20
Capacity	$12	$12	$6	$6
System Loss reduction	$2	$2	$1	$1
Emissions reduction	$1	$1	$1	$1
Total	**$91**	**$119**	**$84**	**$225**
Levelized Costs	$71	$71	$71	$71
Benefit-Cost Ratio	**1.3**	**1.7**	**1.2**	**3.2**

For details on this analysis, visit: http://www1.caiso.com/docs/2005/01/19/2005011914572217739.html.

The CAISO Board approved the PVD2 project unanimously at the board meeting of February 24, 2005, based on the staff recommendation applying the TEAM. SCE is expected to file its own justification for the line in the Certificate of Public Convenience and Necessity (CPCN) process at the CPUC by the spring of 2005.