8.1 BACKGROUND OF PROGRAM ELEMENTS

8.1.1 AB 970 Water/Wastewater Program Element

The Peak Load Reduction Water/Wastewater program element was funded through Assembly Bill 970 (AB 970). The funding was disbursed in the form of grants to municipalities that installed peak load reduction or electricity supply augmentation projects at their water treatment facilities. Municipal applicants were considered on a first-come, first-served basis as of the funding's availability in 2001. The program's goal was to reduce the state's peak electricity demand by 20 MW as of June 1, 2001, and continue on throughout that summer.

In May 2001, funds from other AB 970 accounts were added to the original program element funding of $5 million, raising the total to $6.663 million. These additional funds allowed for second round of grant applications and funding. Two types of grants were available, focusing on demand reduction and load shedding.

As the name implies, demand reduction grants were available for those projects designed to reduce demand (kW) throughout the peak electricity period—that being non-holiday weekdays from 2:00 p.m. to 6:00 p.m. between June 1 and September 30. The program element provided funding for replacing or retrofitting inefficient pumps (as well as other energy using or energy-recovery equipment) with more energy efficient systems or equipment. Changing control systems, project commissioning and testing, as well as programming changes to the software of control systems were also eligible measures. Grants were available for up to $300/ kW of anticipated peak demand reduction.

Load shedding grants were available for those projects designed to allow applicants to participate in the California Independent System Operator (CAISO) Summer Demand Relief Program, by providing technologies that would enable the facilities to quickly curtail loads in response to Stage II or Stage III emergencies. This program funding also provided monies for water and wastewater pump retrofits in terms of offsetting the costs associated with the necessary telemetry equipment and controls, installation, and associated engineering design work. Grants for load-shed projects were available for up to $200/ kW of peak demand reduction.

8.1.2 SB 5X Water Agency Generation Program Element

With the infusion of $9.75 million in SB 5X funding effective May 2001, the Water/Wastewater program that was previously funded by AB 970 is now called the Water Agency Generation program. This program element, which began receiving project applications in October of 2001, pays municipalities or other eligible governmental entities, up to $300/ kW of new generation or peak period kW reduction for projects completed and operational by May 31, 2002. For those projects expected to be operational by May 31, 2003, the incentive level is capped at $250/kW. Applications were handled on a first come, first serve basis, with a goal of providing 30 MW of demand savings and/or system peak offsetting generation during peak periods. In this case, the peak period is defined as summer non-holiday weekdays (June 1 through September 30) during the hours from 2:00 p.m. to 6:00 p.m.

At its outset in May 2001, the program focused on funding upgrades to existing back-up generators that were within the inventories of water and wastewater agencies. Due to low initial enrollment, the program's funding eligibility was expanded to include peak load reductions (i.e., energy efficiency and load shifting measures), similar to the previous AB 970-funded program element.

is by, HDR, Inc a third party administered the SB 5X-funded program element. The AB 970-funded element had been administered directly by the Energy Commission.

8.2 STATUS OF WATER/WASTE WATER AND WATER AGENCY PROGRAM ELEMENTS

As of December 31, 2002, the combined AB 970 and SB 5X elements have achieved 52.2 MW of verified peak load reduction capability, with an additional estimated 7.8 MW underway and due for completion prior to Summer 2003.

The Energy Commission has reported that 43 projects have been approved and are participating under the AB 970 program element. Based on this reported program activity and Nexant's 2002 persistence verification activities, these projects have a verified peak demand potential of nearly 45.1 MW.

Since December of 2001, according to Energy Commission reports, the AB 970 program element activity has involved the addition of three new projects and the withdrawal of three others. The projects that withdrew are Atwater, a 69 kW efficiency project; Escondido, a 300 kW generation project; and Chino, a 124 kW load shifting project. The new projects are all in the efficiency subpopulation: Ontario, at 408 kW; Mount Vista at 364 kW; and Victor Valley, at 18 kW. Detailed discussions of the AB 970 projects can be found in Nexant's December 2001 report.

Also as of December 31, 2002, the SB 5X program administrator, HDR, Inc., reported that 35 projects have been approved and are participating under the SB 5X program element. Nexant estimates that these projects will have the capability to reduce peak demand by nearly 14.9 MW. HDR reports that of the 35 projects, 17 have been completed; representing nearly 7.1 MW of verified savings.[1] The remaining 18 projects are scheduled for completion by June 1, 2003. Table 8-1 shows the breakdown of the total peak reduction by each of the element sub-populations as well as by the stage completed in the M&V process. The estimated savings are based on SB 5X realization rates as applied to the projects in progress.

Table 8-1: Peak Load Reduction by Sub-population

Sub-population	Number of Approved Projects	Verified AB 970 Savings	Verified SB 5X Savings Installed	Estimated SB 5X Savings in-Progress	Total SB 5X and AB 970 Savings
Generation	22	2.13 MW	4.96 MW	3.59 MW	10.67 MW
Efficiency	30	3.22	0.5	0.75	3.93
Load Shifting	24	1.88	1.63	3.45	6.97

[1] Two of the 17 completed projects are still waiting for air quality permits, and another two have not completed their final report.

Sub-population	Number of Approved Projects	Verified AB 970 Savings	Verified SB 5X Savings Installed	Estimated SB 5X Savings in-Progress	Total SB 5X and AB 970 Savings
Curtailment (AB 970 only)	2	37.89	NA	NA	37.89
Total	**78**	**45.12 MW**	**7.09 MW**	**7.79 MW**	**59.99±2.9 MW**

In addition to the 35 projects noted above, four projects dropped out during the fourth quarter 2002, one remains under reevaluation, and two have changed their reported savings. The four projects that have been withdrawn include:

- The Palmdale project, a 250 kW generation project that involved the installation of a catalytic converter on a natural gas generation set, was withdrawn because the participant decided not to proceed with the project.
- The Truckee-Donner project, a 78 kW efficiency project to replace lights and motors, was withdrawn because the project was reduced in size and the new rebate amount was not worth the paperwork required.
- The City of Los Angeles withdrew their 330 kW project, which involved the installation of VFDs on aerators, because the proposed changes would have had a detrimental effect on other plant processes.
- The City of San Bernardino withdrew their 496 kW load shifting project due to an inability to meet the May 31, 2003, deadline.

The project being reevaluated, Brawley, a 275 kW solar aerator installation project is complete. Its inclusion in the program is still being reevaluated, however, because of changes made to the project to achieve the reduction in the biological oxygen demand (BOD) required by local codes. As for those applicants who have revised their savings estimates, San Bernardino increased the estimated savings for their 757 kW load-shifting project (Area 70J) by 274 kW to 1,030 kW, and Palo Alto increased the estimated savings for their 78 kW efficiency project by 231 kW to 309 kW.

Table 8-2 lists all SB 5X projects.

Table 8-2: Active SB 5X Water Agency Projects

Project Name	Reported Size (kW)	Estimated Completion Date	Project Description/Comments
Completed			
Bear Valley Springs CSD	152		New high efficiency motors & pumps; install load controllers
Big Bear Area RWA	600		Replace diesel gen set with larger natural gas unit
City of Corcoran	97		Modify aerobic lagoons, decreasing aerator HP
City of Ferndale	7.88		Replacing mechanical aerators w/ diffused air system
City of Merced	325	Awaiting AQMD approval	Refurbish cogen system to run on digester gas
City of San Diego	1,200	Awaiting AQMD	Modifying diesel gen set to run on blend of diesel and digester

Project Name	Reported Size (kW)	Estimated Completion Date	Project Description/Comments
		approval	gas
City of San Mateo	500		Refurbish cogen system
City of Santa Cruz	1,320		Replacing cogen w/ larger unit and add one cogen unit to replace three diesel gen sets
EBMUD	1,700		Installing natural gas blending to fully load two cogen units
Gridley	32		Installing two Solar Bees
June Lake PUD	78		Installing timers and aerators
North San Mateo County	180		Installing 6-30 kW microturbines on digester gas
Rancho Murieta	144		Replace surface aerators with Solar Bees
S. Bayside System Authority	200		Heat recovery & electrical modifications to fully load cogen
Vallejo S&FCD	2,400		Remove three IC diesels and install two NG gen sets
Active			
Bodega Bay PUD	200	31-May-03	SCADA and Timer controls
City of Benicia WWTP	1,000	31-May-03	Replace diesel gen set with larger natural gas unit
City of Dinuba	164	31-May-03	Replacing 4 mechanical aerators with diffused aeration
City of Torrance	201	31-May-03	SCADA control TOU on well and booster pumps
Contra Costa WD	200	31-May-03	Replacing motors and pumps
Eastern MWD 2	1,200	31-May-03	Retrofitting existing generator w/ emission controls
Eastern MWD 3	60	31-May-03	Install 2-60 kW Micro-turbines w/ heat recovery
EBMUD 2	2,200	31-May-03	Develop food waste receiving facilities to create additional digester gas fuel for 3rd cogen set
EBMUD 3	194		Automation of oxygen production system
Elsinore Valley MWD	25	31-May-03	Converting to Biological Nutrient Removal (BNR), replace blowers and reducing airflow.
Hopland PUD	34	31-May-03	Installing photovoltaics
Marina Coast MWD	369	31-May-03	Installing energy recovery system of RO plant (146 kW) & 4-60 kW micro-turbines w/ heat recovery (~223 kW)
Palo Alto WWTP	309	1-Dec-02; needs documentation	New blowers with Dissolved Oxygen control
Placer County	39	31-May-03	Changing motors on RBCs and shifting sludge pump hours
San Bernardino County	1,733	1-Jun-03	Area 70L Construct storage for off-peak pumping
San Bernardino County	1,030	1-Jun-03	Area 70J Construct storage for off-peak pumping
Santa Clara Valley WD	1,234	30-Jun-03	Installing solar cells and natural gas gen set. . Eligibility of gen set questioned
South Tahoe PUD	1,342	31-Dec-02; needs documentation	SCADA control TOU on effluent pumps
Victor Valley	168	31-May-03	Refurbishing small well to replace large well's on-peak use

Project Name	Reported Size (kW)	Estimated Completion Date	Project Description/Comments
City of Brawley	275	Pending reevaluation	Install solar aerators; inclusion in program being reevaluated
Withdrawn			
Palmdale	250		Generation
Truckee Donner	78		Efficiency
City of Los Angeles	330		Efficiency
San Bernardino	496		Load shifting

8.3 MV&E APPROACH

Verification of the demand savings achieved by the water/wastewater program element was accomplished by monitoring a sample of projects. For each project in the sample, baseline and post-installation electric demands were established either through engineering analysis of a combination of historical data and/or inventory information, or through direct measurements. For both the baseline and post-installation data, the electric demand is defined as the average electric demand between the hours of 2:00 p.m. and 6:00 p.m. on non-holiday weekdays between June 1 and September 30. Electric demand savings were determined by subtracting the post-installation electric demand from the baseline electric demand.

Once the electric demand savings for a project were verified using the process outlined above, a realization rate was determined by dividing the verified savings by the savings estimated for the project in the grant agreement. (Calculation of realization rates is a process that enables a sample of representative projects to be used to estimate the effects of a larger population.) To calculate the realization rate for each subpopulation, Nexant divided a) the sum of the verified savings for the sample projects in the subpopulation by b) the sum of the reported savings for the sample projects in that subpopulation. This realization rate was then multiplied by the total reported demand savings for the appropriate subpopulation to determine the overall verified demand savings for that group. The verified savings for the overall program element is equal to the sum of each subpopulation's verified savings.

It should be acknowledged that the savings estimated in the participant's applications are computed a variety of ways depending on the applicant's knowledge of the project when they are completing the application. Some already know the load reduction; others have to determine it as part of their project. A few use an educated estimate knowing that their funding will be limited by project cost. The variety of estimation methodologies is accounted for in the realization rate, which is based on a sample of projects using a variety of methodologies. Two key elements of this program element's MV&E plan warrant more explanation: first, the sampling strategy and second, the determination of baselines.

8.3.1 Sampling Strategy

Due to the diversity and number of program participants, it was impractical and not cost-effective to directly measure the demand savings achieved by each individual project. Therefore, the entire population of projects was broken down into sub-populations, based on project type. Such a breakdown of projects makes it possible to use a stratified sampling approach, which considers both the amount of variance expected between the various members of a population and the relative demand savings that the sub-population members are expected to have. A sub-population that has a large expected impact compared to the other sub-populations will receive more attention than those with smaller impacts, and a group with more variance among the data collected and analyzed will receive more attention than one with smaller variance. The result of the stratified random sampling is that fewer members of the population need to be monitored to achieve the desired level of confidence and precision of measurement.

In order to implement this approach, projects in the AB 970 program element were segmented into four subpopulations where the involved projects focused on:

1. Curtailment – the reduction of peak demand during critical periods by disconnected loads
2. Generation – repair or upgrade of existing generation facilities, or the installation of new generation facilities
3. Load shifting – moving on-peak loads to off-peak times
4. Efficiency – installation of systems or equipment that reduce energy use

Projects in the SB 5X program element were broken down into the same subcategories, with the exception of curtailment projects as there were none funded under the SB 5X program element. Sample selection was based on the population of completed projects available for inspection. Only a limited number of projects were due for completion by the end of the evaluation year 2002. In order to evaluate a statistically significant number of projects in each of the sub-populations, Nexant had to evaluate nearly all of the projects completed in 2002. Table 8-2 shows the sample population sizes for both program elements.

Table 8-2: Program Element and Sample Population Sizes

	AB 970		SB 5X		Total	
Sub population	**Projects**	**Sampled Sites**	**Projects**	**Sampled Sites**	**Projects**	**Sampled Sites**
Curtailment	2	1	NA	NA	2	1
Generation	6	1*	16	7	22	9
Load shifting	14	2	10	3	24	5
Efficiency	21	2	9	4	30	6
Total	**43**	**6***	**35**	**14**	**78**	**21**

*There were two generation projects evaluated in the AB 970 December 2001 report; the City of Pinole project was subsequently withdrawn from the program.

8.3.2 Baseline Measurements

Baseline measurement was achieved in different ways for each project monitored. In some cases, such as new generation, the baseline was zero and the savings could be determined by simply verifying the power provided by the new equipment. For other projects, the baseline electric demand or augmentation could be determined using historical meter data or through direct measurement of a single point. In some cases, engineering analysis of historical data or of existing systems was performed to estimate baseline conditions.

8.4 PROGRAM ELEMENT MONITORING AND VERIFICATION

As noted in Table 8-2 relative to the AB 970 program element, Nexant monitored and verified savings for a sample population of seven projects, although one subsequently dropped out. These activities, and our results, are reported in full in Nexant's December 2001 report to the Energy Commission. In 2002, Nexant performed persistence verification evaluations for the seven projects that we analyzed under the AB 970 program. The results of these evaluations are presented in the Persistence Verification section of this report.

For the SB 5X program element, Nexant analyzed savings from a sample of 14 projects. As of the writing of this report, two projects in the sample, South Lake Tahoe and Palo Alto, have not completed their final program documentation. Another project for which we had performed a pre-installation site visit (City of Dinuba), has postponed their project's planned completion to May 31, 2003. In addition, the City of Brawley's project is being re-evaluated as to whether it qualifies for inclusion in the program; the issues at stake are spelled out later in this chapter.

Table 8-3 lists the fourteen projects evaluated for SB 5X in 2002. The table also shows the reported and verified savings for each project, along with a brief description of the project. Detailed discussions on the evaluation of each project follow the table.

Table 8-3: Projects in the SB 5X Sample Population

Project Name	Reported Savings (kW)	Verified Savings (kW)	Project Description/Comments
Efficiency			
City of Dinuba	164*	119*	Replace 4 mechanical aerators with diffused aeration
Bear Valley Springs CSD	152	103	Install SCE load controllers and high efficiency pumps
City of Brawley	275		Install solar aerators; program eligibility being reevaluated
Palo Alto WWTP	309	325	Install new blowers with dissolved oxygen control
Generation			
Big Bear Area RWA	600	469	Replace diesel gen-set with larger natural gas unit
City of Merced	325	250	Refurbish cogen system to run on digester gas
City of San Mateo	500	495	Refurbish cogen system
City of Santa Cruz	1,320	780	Upgrade a 650 kW cogen unit to 820 kW and added a 500 kW cogen unit
EBMUD	1,700	1,117	Install natural gas blending to fully load two cogen units

Project Name	Reported Savings (kW)	Verified Savings (kW)	Project Description/Comments
North San Mateo County	180	172	Install 6-30 kW digester gas microturbines
Vallejo S&FCD	2,400	850	Remove three diesel and install two NG gen-sets
Load Shifting			
Gridley	32	32	Replace surface aerators with Solar Bees
Rancho Murieta	144	58	Replace surface aerators with Solar Bees
South Tahoe PUD	1,342	1,463	SCADA controlled TOU on effluent pumps

*Estimate, based on Nexant's pre-installation inspection; both reported and verified savings may change upon project completion (this is a performance-based project).

For each project listed in Table 8-3, Nexant's savings verification analysis is discussed below. In each case, the baseline value is defined as the average summer peak generation or demand before the implementation of a funded project. The final project demand value is defined as the average summer peak generation or demand after the implementation of the funded project. While individual projects may have generation or demand values higher or lower than the average, these numbers are used to represent the effects of a large number of projects as seen on the grid.

8.4.1 Efficiency

8.4.1.1 The City of Dinuba Water Treatment Plant

Project description: Prior to May 31, 2003, the City of Dinuba plans to replace four 75hp mechanical aerators with an 80hp diffused air system. They estimated that the installation of the diffused air system would allow them to reduce peak demand by 164 kW. The demand savings estimate is based on removing all four grid powered aerators and installing eight 10hp blowers and a diffused air piping system. The Dinuba project is being undertaken through a performance-based contract so the final realization rate will be based on the project's end results.

Findings: During the July 19, 2002 pre-installation inspection, Nexant verified that Dinuba's Wastewater Treatment Plant primary pond had four 75hp grid-connected mechanical aerators. Plant staff informed Nexant that the proposal to convert to a diffused air system had been approved by the city and bids were being reviewed. As of December 2002 (i.e., the end of this reporting period), this project was scheduled to be completed by December 31, 2002.

The project manager for the city informed Nexant that two of the 75hp aerators were in use 24 hrs per day. The other two aerators were shut down daily for only three hours each, one from noon to 3:00 p.m. and the other from 3:00 to 6:00 p.m. Dinuba expected that at the present rate of growth all four aerators will need to run 24 hours a day by the mid-year 2003.

During the pre-installation visit, Nexant took power readings for each of the four existing aerators. Readings ranged from 36 to 53 kW, with a total aggregated baseline peak demand of 179 kW.

Evaluation: The verified baseline for the Dinuba project is 179 kW based on the assumption that all of the aerators will be used fulltime during peak periods. This is 45 kW less than the project proposal's estimated 224 kW that was based on the theoretical 0.746 kW per HP.

Manufacturers' specifications for the proposed diffused air system call for 80hp of blowers with an estimated peak demand of 60 kW. The manufacturers' specifications also indicate that the system could initially operate at less than full capacity.

Based on the measured baseline and the reported final demand, the Dinuba project will, when completed, reflect a peak demand savings of 119 kW, yielding an 83% realization rate when compared to the 164 kW reported by the participant.

8.4.1.2 The City of Palo Alto Waste Water Treatment Plant

Project description: The City of Palo Alto replaced two old supplemental blowers with new high efficiency blowers and installed automated dissolved oxygen (DO) controls on the air valves for each of their four aeration basins. They estimated that the installation of the new blowers and the valve controls would allow them to reduce peak demand by 309 kW. The demand savings are based on the higher efficiency of the new blowers and the reduced flow enabled by the valve controls.

Findings: During the January 10, 2003 site visit, Nexant verified that Palo Alto's wastewater treatment plant has five blowers used for aeration. There is one primary blower with controllable output and four supplemental/backup units with fixed output, two new and two old. During normal operations, the primary blower operates continuously and is augmented by one of the supplemental units that run during peak periods, noon to 8:00 p.m.

The plant has four aeration basins that receive air from the aforementioned blowers. Each basin is served via a valve on the air supply line. Automatic controls have been installed on each of these valves. The valve controls will be connected to the DO sensors in the basin. The DO sensors have been installed, but the installation contractor has requested that the manufacturer perform the final connection. As of the inspection visit, arrangements had been made for this to take place in mid-January.

Previously, during off peak periods, the main blower was manually controlled based on the DO sensors in each of the ponds. If the DO sensor in <u>any</u> pond went below 2.0 mgO2/liter, the main blower's output was increased. Thus, the system was supplying the airflow needed by the worst-case pond to all the ponds. During peak periods, the main blower was augmented by the fixed rate output from one of the supplemental blower units.

Under the new system, the DO sensors control the valves to the individual basins and will reduce the airflow to those basins that continue to have sufficient DO. In other words, the new system can reduce the air supply to basins that meet the minimum DO criteria and thereby reduce overall blower output, thus reducing energy demand as well as consumption. In addition, the two new supplemental blowers have allowed Palo Alto to retire two of the four old blower units.

At the time of the site visit, the control panel on the main blower indicated that it was using 250 kW to produce 10,000cfm. According to the project application (and as confirmed by the City's the project manager), this variable speed blower had, during peak periods, required 414 kW to produce 13,500cfm. Concurrently, the control panel on the new supplemental peak period blower indicated that the unit in use was requiring 263 kW to produce 7,900cfm. Again, per the application and as confirmed by the project manager, the old supplemental blower that had been used during peak periods required 424 kW to produce 10,500cfm. This translates to an improvement from 24 cfm per kWh to 30 cfm per kWh on the supplemental blower output.

Evaluation: The verified baseline for the Palo Alto project is 838 kW from the combined demand of the primary (414 kW) and old supplementary (424 kW) blower units. After the replacement of the supplemental units and oxygen demand control, the verified final demand is 513 kW based on the combined demand of the primary (250 kW) and new supplemental (263 kW) blower units. Thus, the verified peak reduction for this project is 325 kW, yielding a 105% realization when compared to the 309 kW reported by the participant. This realization rate may change pending the connection of the DO sensors to the auto valve controls.

As noted during the inspection visit, all the requisite equipment has been installed but all the connections have not been made. Once that has been accomplished, the applicant will need to inform the program administrator and complete all the program documentation.

8.4.1.3 City of Brawley Water Treatment Plant

Project description: In order to better address the effluent emanating from a local meat processing plant, the City of Brawley's plans were to install three sequential pretreatment aeration ponds along with six solar aerators, two in each pond. The ponds and aerators were to reduce the biological oxygen demand (BOD) treatment required before the effluent reached the main treatment plant. The city estimated that the new ponds and aerators would reduce power demand at the main plant for BOD reduction by 275 kW. The estimated savings were based on average plant energy consumption per unit of BOD processed.

Findings: During the July 26, 2002 site visit, Nexant confirmed that the pre-treatment plant consisted of three ponds. Pond-1 is an anaerobic pond fit with a cover for odor control. At the time of the inspection Solar Bee circulation devices were not installed in this pond. Pond-2 is aerobic with six 40 HP aerators and two Solar Bee circulation devices. The surface aerators were installed on or about April 24, 2002. At the time of the inspection, only four of the six Pond-2 surface aerators were in operation. Pond-3 is for effluent finishing with four Solar Bee circulation devices providing all of the circulation in the pond.

According to Brawley sources, the reason for developing the upgraded pre-treatment facilities discussed in this application was to deal with the effluent coming from Brawley Beef, a nearby meat processing plant that was undergoing renovation. The Solar Bees as well as the addition of the third pond were incorporated into the pre-treatment plant's process during the design phase associated with preparing for the anticipated increased volume of the Brawley Beef effluent. The inclusion of the third pond was built upon the concept of increasing the effluent retention time rather than increasing the number of aerators. The Solar Bees were included in the design in order to mitigate a serious odor issue associated with the meat processing plant, while it was undergoing expansion. Upon completion of the plant's expansion, Brawley staff identified that additional remedial steps were required in order to more effectively address the odor and BOD effluent volume issues. These included: (1) converting Pond-1 to and anaerobic pond by moving the SolarBees from Pond-1 to Pond 3 and placing a cap on Pond-1; (2) installing six grid connected 40HP aerators on Pond-2.

The capacity of the packing plant is 1,600 head of cattle per day. According to plant staff, the current production rate is 1,000 head of cattle per day. The production rate of the facility is variable and directly related to the effluent production, thus is an important consideration when attempting to model the project savings.

In addition the findings noted above in relation to the Brawley Beef pre-treatment facilities, Nexant's noted during its site visit that the City of Brawley's Wastewater Treatment Plant (WWTP) is being renovated and no longer operated as described in the application. The primary clarifier and digesters are not in operation. Treatment capacity has been maintained by expanding the aeration treatment into the three 12,800K gallon stabilization ponds. To increase their plant's aeration capacity, the city purchased and installed twelve 15 HP and six 30 HP surface aerators.

At the WWTP, the city monitors dissolved solids daily; BODs and suspended solids are monitored twice a week. Nexant was provided with these numbers along with a summary of outflow concentrations from the Brawley pre-treatment plant for dissolved oxygen (DO), pH, Biochemical Oxygen Demand (BOD) and ammonia. However, the data provided can be very misleading. Prior to May of 2002, the city sampled 8-hour composites of BOD during plant operating hours when the concentrations are highest. They later switched to 24-hour composites, which lowered the reported average concentration (mg/L). Also, the city temporarily treated the waste with hydrogen peroxide to mitigate the odor problem. Addition of the chemical resulted in significant increases in DO concentrations recorded on March 27, 2002 and April 3, 2002. The chemical treatment was halted after construction of the pre-treatment plant was completed. The city's involvement in the pre-treatment process has been to help the plant meet the Wastewater Pretreatment Ordinance (November 20, 2001) at the lowest installation and operating cost possible. The pre-treatment plant at the nearby meat packing facility is located on a city easement. The Wastewater Pretreatment Ordinance requires that beef plant effluent that is going to the Publicly Owned Treatment Works (POTW) does not contain BOD or Suspended Solids (SS) concentrations in excess of 250 mg/l.

Evaluation: Due to the significant changes from the project proposed in the application, the CEC's program administrator is reevaluating this project. Evaluation of the peak savings for these projects is on hold pending a decision by the program administrator.

8.4.1.4 Bear Valley Springs Community Services District

Project description: The Bear Valley Springs CSD installed timers on five water wells that restricted their use to off-peak hours as well as replaced six inefficient booster pumps with premium efficiency pumps. They estimated that the timer and pump replacement efforts would reduce peak demand by 152.4 kW. Their demand savings estimate is based on all five wells being turned off during peak times along with the cumulative kW savings of all six of the booster pump replacements.

Findings: During the August 29, 2002 site visit to Bear Valley Springs (near Bakersfield), Nexant verified that four of the five well operation timers had been installed by the local utility's contractor. The fifth well timer installation was delayed due to a change as to which additional well would be involved. The new well being considered is larger than the prior candidate and operates a greater number of summer hours; therefore, it will represent a greater savings.

Nexant also verified that all six of the replacement pumps had been installed and were operational. Each involved pump station initially had two pumps, one primary and one backup. With the inclusion of the new efficient pumps fulfilling primary pumping role, the old primary pump was retained for back up, while the redundant back-up pump was retired. With the exception of the newly selected well pump, all of the pumps in this project are operated on an as-needed basis. That is, when the water in the holding tank drops below a certain point, the pump turns on until the tank is filled to the full level. Each pump serves a different tank and therefore they each operate on a different schedule.

During the site visit, Nexant also reviewed the test results gathered by the local utility on the pumps, and verified the demand data for each booster pump. In addition, Nexant reviewed billing data for the wells and confirmed their respective peak demands. Data was also gathered on annual hours of operation for each pump; these results are shown in Table 8-4.

Evaluation: Analysis of the data gathered during the Nexant site visit verified that the demand of each of the well and booster pumps are the same as those in the application. This data also showed, however, that none of the booster pumps and only one of the wells was operational during all of the summer peak hours.

Following standard industry practice, Nexant calculated an effective demand that reflects the impact of intermittent operation of the various pumps during the peak period. In order to do this, Nexant derived a peak period demand modifier that represents the portion of the pump's yearly operational activity that can be expected during summer peak periods. In deriving this modifier, Nexant utilized pumping load data available from the California Department of Water Resources 1996 and 1997 Reports of Operation (published in 2000 and 2001 respectively) to develop an estimate that the operation of these pumps during the four summer months represented half (0.5) of the annual pumping load. In addition, it is estimated that one quarter (0.25) of the daily use occurs during the four-hour peak of this program. These assumptions are used together with calculating 122 summer peak days per year and four peak hours per day to derive the demand modifier factor. Note the following equation:

$$\text{Demand Modifier} = \frac{0.5*0.25}{122*4} = 0.000256 \text{ kWp / kWh / yr}$$

Where:

0.5 = fraction of operation occurring during the June – September timeframe

122 = days in the June – September timeframe

0.25 = fraction of daily operation occurring during the 2:00-6:00 p.m. time frame
4 = hours in 2:00 p.m. to 6:00 p.m. time frame

This demand modifier was used along with data that included the pump demand and hours of operation that Nexant obtained during the site visit to determine the effective peak demand for each pump as follows:

EPD = PD*Hrs*DM

PD = pump demand
Hrs = annual hours of operation
DM = demand modifier (as determined above)

For example, consider well #2 with a demand of 14 kW and 2823 hours of annual operation:

EPD = 14 kW * 2823hrs/yr * 0.000256 kWp / kWh / yr = 10.1 kWp

This process was repeated to determine the baseline for each of the well and booster pumps as well as the final demand for each of the booster pumps. The results of this analysis are presented in the far right columns of Tables 8-4 and 8-5. Note that the well pump CV3 is operated fulltime in the summer only and therefore the pumps' actual demand was used for the average baseline value.

Table 8-4: Bear Valley Springs Well Pump Baseline Data

Well #	Rated HP	Demand (kW)	Hrs/year	Operation	Baseline (kW)
2	20	14	2823	Year round	10.1
11A	40	26	3162	Year round	21.1
31	40	37	953	Year round	9.0
36	15	16	1267	Year round	5.2
CV3	50	38	4000	Summer only	38.0
Total	**165**	**131**			**83.4**

Table 8-5: Bear Valley Springs Booster Pump Baseline Data

Booster #	Rated HP	Demand (kW)	Hrs/year	New hrs/yr	Baseline (kW)	Final (kW)
3C	40	36.2	2628	1644	24.4	15.2
6A1	30	27.5	1030	687	7.3	4.8
6C	50	36.1	1686	992	15.6	9.2
7B	5	3	1228	560	0.9	0.4
9A1	7.5	6.4	1082	572	1.8	0.9
9A2	5	3	1552	641	0.2	0.5
Total	**137.5**	**112.2**			**51.1**	**31.1**

The verified baseline for the Bear Valley Springs project is 134.5 kW, which is the sum of the average baseline kW for the well and booster pumps. After the installation of the well controls and high efficiency booster pumps, the system has an average verified peak demand of 31.1 kilowatts. Thus the verified peak reduction for this project is 103.4 kW, yielding a 68% realization when compared to the 152.4 kW reported by the participant.

8.4.2 Generation

8.4.2.1 City of San Mateo – Digester Gas Engine

Project description: The City of San Mateo project called for modifying an unused digester gas engine to “lean burn” operation, which would allow the use of either natural gas or digester gas. The project also called for upgrading the associated generators’ capacity from 335 kW to 500 kW in order to take full advantage of the engine’s potential output. The changes were designed to enable San Mateo to obtain air permits for operating the engine/generator plant during peak periods. The city estimated that, based on the potential of the system generation, this project would generate 500 kilowatts during peak periods.

Findings: During the June 12, 2002 site visit, Nexant verified that the generation system was in place, operational, and producing about 485 kW of power. The engine was running on 100% NG and will continue to do so until the completion of the planned digester in 1-2 years. At the time of the visit, plant staff were taking power readings every few hours and recording them by hand. These records showed that the system was consistently producing between 485 kW and 495 kW. The city is working with the utility to obtain a real-time meter for the unit. Plant staff confirmed that the original generation system was used only for emergency generation.

Evaluation: The verified baseline for the San Mateo project is 0 kW based on the understanding that the original generation system was not used during peak periods. After upgrades, the system had an average verified generation of 490 kW. Thus, the verified peak reduction for this project is 490 kW, yielding a 98% realization rate when compared to the 500 kW reported by the participant.

8.4.2.2 Vallejo Sanitation and Flood Control District – Wastewater Treatment Plant

Project description: The Vallejo Wastewater Treatment Plant replaced its three standby diesel generators with two natural gas powered generators. The standby systems were used only for emergency back up generation. The new systems each have a 1.2 MW rating and run on 100% natural gas. In its application, Vallejo estimated that the combined new systems would have a peak generation of 2.4 MW.

Findings: During the June 13, 2002 site visit, Nexant verified that both 1.2 MW generation systems had been installed. Only one system was in operation at the time of the visit. This unit was producing 800 kW. Plant staff informed Nexant that the summer peak demand of the plant was around 1 MW. Details of the interconnection with PG&E’ grid were still under negotiation at the time of the visit. Therefore, during peak periods, the treatment plant load was manually disconnected from the grid and served directly by the new generation system. Nexant obtained billing data from plant staff showing a summer peak demand of 1.1 MW. The 2.4 MW capacity is required for winter storm flood control needs. Plant staff confirmed that the original generator system was used only for emergency generation.

Subsequent discussions with Vallejo staff indicated that they eventually signed a contract with PG&E to import 100 kW during peak hours, and are producing the remaining power needed to operate the plant through the new system. Vallejo staff reported that under these conditions the new system has been operating at 850 kW.

Evaluation: The verified baseline for the Vallejo project is 0 kW based on the understanding that the original generation system was not used during peak periods. After upgrades, the system had an average verified peak generation of 850 kW. Thus the verified peak reduction for this project is 850 kW, yielding a 36% realization when compared to the 2.4 W reported by the participant. The district had applied for the installed capacity of the two new generators as opposed to the plant's summer peak demand.

8.4.2.3 City of Santa Cruz – Wastewater Treatment Plant

Project description: The City of Santa Cruz wastewater treatment plant refurbished the engine of one of its generation systems thereby increasing the overall generator potential from 650 kW to 820 kW. They also installed a new 500 kW generation system. Both systems run on mixed natural gas/digester gas. Santa Cruz estimated that the combined refurbished and new systems would increase the average onsite generation by 1320 kW, based on their full generation potential.

Findings: During the July 15, 2002 site visit, Nexant verified that both generation systems had been installed and that they were operational. During the site visit, both systems were in use and producing near their peak power: 820 kW and 500 kW. Plant personnel reported that due to low natural gas and high electricity prices, both systems were running continuously at full output. Each system has its own control with logging capabilities.

Plant personnel reported that, during previous summer seasons, the original generator's peak production had been consistently near its capacity of 650 kW. Staff also indicated that, while there were maintenance issues, those were generally dealt with during off-peak periods. The reliability of the old generator had been decreasing over the years and was expected to get worse due to the unavailability of replacement parts.

Evaluation: The verified baseline for the Santa Cruz project was based on a 20% reduction in availability for the old 650 kW generation systems due to the noted reliability issues. This reduction yielded a verified 520 kW baseline peak generation. After upgrades, the system had an average verified peak generation of 1320 kW. Thus the verified peak reduction for this project is 800 kW, yielding a 61% realization when compared to the 1320 kW reported by the participant.

8.4.2.4 East Bay Municipal Utility District (EBMUD) – Wastewater Treatment Plant

Project description: The EBMUD wastewater treatment plant refurbished its generation system to allow for the supplemental use of natural gas. This change allows the plant to operate, to the full capacity of its air permits, two 2.15 MW generators, 24-hours per day. In its application, EBMUD estimated that the refurbishment would increase the average onsite generation from around 2.6 MW, the average annual peak generation using digester gas only, to the 4.3 MW potential of the two generators, yielding a peak generation increase of 1.7 MW.

Findings: During the August 12, 2002 site visit, Nexant verified that EBMUD had installed the equipment required for mixing natural gas with digester gas, as described in their application. At the time of the visit, the two units were operating, one at nearly 2 MW and one at approximately 1.9 MW. Logger data obtained from EBMUD showed that the generators were generally being operated at less than their combined 4.3 MW capacity, averaging around 3.87 MW during peak periods. Communications with plant staff indicated that this lower operating level was necessary to avoid dangerous power spikes.

The logger data also showed that the historical average summer peak period production was 2.75 MW. This is 150 kW higher than the 2.6 MW presented as the baseline in the application. The 2.6 MW baseline presented in the application was based on the older generation unit's average annual peak.

Evaluation: The verified baseline for the EBMUD project is the average summer peak of 2.75 MW. After upgrades, the system had an average verified peak generation of 3.87 MW. Thus the verified peak reduction for this project is 1.12 MW, representing a 65% realization rate when compared to the 1.7 MW reported by the participant.

8.4.2.5 Big Bear Area Regional Wastewater Agency (RWA)

Project description: The Big Bear RWA's project involved replacing a diesel-fired 550 kW emergency generation system with a 600 kW natural gas generation system. The new system enabled the operators to obtain an Air Quality Certificate that would allow the system to be operated during peak hours, generating 600 kW of electricity. This estimate is based on the new system operating at full capacity during peak periods.

Findings: During the July 26, 2002 site inspection, Nexant verified that the natural gas-fired generation system was installed and operational. Nexant also obtained 30-minute interval data from the appropriate SCADA system. The data indicated that the system was operating between 450 and 500 kW, with an average system output of 469 kW. This output represents the generation required to meet the demand of the Big Bear water treatment plant. Plant staff confirmed that the original generator system was used only for emergency generation.

Evaluation: The verified baseline for the Big Bear Area project is 0 kW, since plant staff confirmed that the original generation system was not used during peak periods. After upgrades, the system has an average verified peak generation of 469 kW. Thus, the verified peak reduction for this project is 469 kW, yielding a 78% realization when compared to the 600 kW reported by the participant.

8.4.2.6 City of Merced – Wastewater Treatment Plant

Project description: The City of Merced wastewater treatment plant application involved refurbishing a non-operational 325 kW generation system to reduce the plant's NOx production.

The reduced NOx production will allow Merced to obtain an air permit for sufficient operating hours to maximize their use of digester gas. Merced estimated that the refurbished plant would be able to generate 325 kW during peak periods. This estimate is based on the new system operating at full capacity during peak periods.

Findings: During the July 18, 2002 site visit, Nexant verified that the system had been refurbished as planned and that the new equipment had been installed. However, there had been some difficulties during testing and the equipment was not yet operational. The installation contractor suspected that the wrong turbo unit had been delivered and one of the circuit breakers associated with the system was found to be faulty. A new turbo unit and a breaker had been ordered. Plant staff also confirmed that the old system had been inoperable prior to this project.

During follow-up communications, plant staff reported that all repairs had been made and that the generator had been operational since early September 2002. The generator was being operated 4 hours per day during peak times, and the output of the system was being limited to 250 kW. This limitation is necessary because output above this amount causes problems with the local grid. Plant staff also reported plans to operate the generator both in the morning and during peak periods. The new schedule would enable the plant to utilize more of the available digester fuel and would bring the total operating time to 6-7 hours per weekday.

Evaluation: The verified baseline for the Merced project is 0 kW, since the original generation system was not operational, let alone used during peak periods. After the upgrades, the system has an average verified peak generation of 250 kW. Thus, the verified peak reduction for this project is 250 kW, yielding a 77 percent realization rate when compared to the 325 kW reported by the participant.

8.4.2.7 North San Mateo County Sanitation District – Wastewater Treatment Plant

Project description: The Sanitation District's wastewater treatment plant application involved replacing a 350 kW back-up generation plant with six 30 kW microturbines. The back-up generation plant was unused due to insufficient levels of fuel (digester gas) and air permit issues. North San Mateo County estimated that the microturbines' installation would allow them to generate 180 kW during peak times. The generation is based on running all six micro turbines at full capacity during the program defined peak period of 2:00 p.m. to 6:00 p.m.

Findings: During the June 12, 2002 site visit to the plant located in Daly City, Nexant noted that the six 30 kW microturbines had been installed. Five out of the six turbines were operational at the time of the visit. The combined output of the five operational units was 136 kW. The sixth unit was inoperable due to having difficulties with blower pressure, and the installer had been scheduled to make repairs. In follow-up communications, the program element administrator informed Nexant that the problems had been rectified and that all six turbines were running consistently with an average output of 172 kW.

Evaluation: The verified baseline for the North San Mateo County project is 0 kW, due to the fact that the original generation system was not used during peak periods. After upgrades, the system has an average verified peak generation of 172 kW. Thus the verified peak reduction for this project is 172 kW, yielding a 96% realization rate when compared to the 180 kW reported by the participant.

8.4.3 Load Shifting

8.4.3.1 City of Gridley – Wastewater Treatment Plant

Project description: The City of Gridley application involved installing two Solar Bee circulation devices at their water treatment plant to replace the peak time usage of six 10 HP grid-connected aerators that have a combined demand of 32 kW. Each of the Solar Bees has a 200 W back-up system for continuous operations when sunlight is insufficient. Gridley staff reported that one Solar Bee circulation device would be installed in the primary pond, the other in the finishing pond. Gridley estimated that the Solar Bee installation would allow them to reduce peak demand by 31.6 kW. The demand savings are based on 32 kW for turning off all six grid-powered aerators during the program-defined peak period of 2:00 p.m. to 6:00 p.m., minus 400W for running the Solar Bees.

Findings: During the June 19, 2002 site visit, Nexant verified that Gridley's wastewater treatment plant consists of one primary pond, one finishing pond, and a series of percolating ponds. The primary pond has two grid-powered aerators and one Solar Bee. The city's project manager reported that two grid-powered aerators from the primary pond had been removed when the Solar Bee was installed. The finishing pond has one grid-powered aerator and one Solar Bee. An additional grid-powered aerator in the finishing pond had been removed when the Solar Bee was installed.

At the time of the visit (about 4:00 p.m.) both of the Solar Bee aerators were in operation along with one grid-powered unit in each pond. The city project manager indicated that the grid-powered units were not supposed to be operating at this time and that he would look into the issue. The system has timers for each unit so it was more than likely due to human error. The project manager later reported that a new staff member had manually turned on the connected aerators. The staff member has been trained as to the new protocol for operating the aerators and signs have been posted on the aerator switchboard to avoid this problem in the future.

The project manager also reports that the solar aerators are working so well that the grid-connected aerators are only needed intermittently. In addition, the project manager provided a detailed report showing the time of use and power consumption demand of the six original grid-connected aerators, indicating a total demand of 32 kW.

Evaluation: The verified baseline for the City of Gridley project is 32 kW, since all six aerators were used fulltime during peak periods. After installation of the Solar Bees, the system has an average verified peak demand of 0 kW. Since there is no shortage of sunlight expected during the summer peak period of 2:00 p.m. to 6:00 p.m., the 400 W capacity back-up system for the Solar Bees is not a factor. Thus, the verified peak reduction for this project is 32 kW, yielding a 101% realization when compared to the 31.6 kW reported by the participant.

8.4.3.2 South Lake Tahoe Public Utility District – Pumping Station

Project description: The South Lake Tahoe PUD's application involved installing a SCADA system to monitor and curtail demand in the Luther Pass a wastewater treatment pumping station. The South Tahoe PUD estimated that the controls installed at the treatment facility would reduce peak demand by 1.34 MW by shutting down the pumps during peak times. The savings are calculated from the minimum utility reported summer monthly peak demand minus the estimated demand from non-pumping equipment.

Findings: During the January 17, 2003 site visit, Nexant verified that all of the controls hardware had been installed at each of the pumping stations, allowing the District to shut down the Luther Pass pumps during peak periods. South Lake Tahoe personnel were in the process of testing and debugging the system. They expected to have the system fully operational by the beginning of the 2003 summer peak demand period. The equipment controlled at the Luther Pass pump station includes two 700 HP and two 1000 HP pumps.

The District's project manager stated that the Luther Pass pumps had previously operated continuously through the summer peak periods. Nexant verified this statement by using data for the average flow rate through the treatment plant and its related pump sizes. The project manager also supplied Nexant with two years of summer billing data (2000 and 2001) and a detailed list of power demand for non-pumping equipment at the Luther Pass pump station. The billing demand varied from month-to-month and averaged 1.47 MW.

The non-pumping equipment included air compressors, heaters, and lighting with a combined reported demand of 34.2 kW. Nexant discounted the amount of the reported demand that was derived from heaters (7.9 kW) since it is unlikely that the heaters would be used during the summer months. Furthermore, the remaining 26.3 kW, which was associated primarily with air compressors, was discounted by 50 percent, since it is unlikely that they would be in use 100 percent of the time. Therefore, the discounted non-pumping equipment demand was set at 13.2 kW.

The Luther Pass pump station is located midway between South Lake Tahoe's water treatment plant and Alpine Meadows. The installation of controls allowed the station pumps to be managed and curtailed remotely from the central control system at the water treatment plant. Communications were facilitated through the use of the District's radio system, which had been recently upgraded. The local control at this pump station also includes wider back-up set points, which in the event of communication loss or malfunction, will trigger the water tanks to return to their normal duty cycle based on the observed reservoir levels.

During the site visit, Nexant confirmed that the necessary remote control equipment, along with its interface at the plant's central control room were installed. The EMS was installed on two existing PC's located in the control center to provide for redundancy. The EMS included four control modes:

1. The Pump Down mode was used for curtailing demand. In this mode, the user simply inputs the start time and duration of the curtailment period. The system will then use a

flow prediction algorithm and modify the pump schedules to minimize pump operation and, if possible, eliminate the need for the Luther Pass pumps to operate during the curtailment period.

2. The Normal mode returns the pump to simple normal duty cycle control, as was used in the baseline system.

3. The Scheduled mode allows for custom scheduling, such as for special events.

4. The Emergency mode maximizes flow through the system to immediately attempt to lower all reservoir levels. This mode is primarily used for storm conditions.

Evaluation: The verified baseline for the South Lake Tahoe PUD project is 1.47 MW due to the fact that the pumps were in operation fulltime during the summer peak. After installation of the EMS control system, the system has an average verified peak demand of 13.2 kW based solely on the demand of non-pumping equipment. Thus the verified peak reduction for this project is 1.46 MW, yielding a 109 percent realization when compared to the 1.34 MW reported by the participant.

8.4.3.3 City of Rancho Murieta – Wastewater Treatment Plant

Project description: The City of Rancho Murieta's application involves installing five Solar Bee circulation devices in their treatment plant's aeration ponds. Rancho Murieta estimated that the Solar Bee installation at the treatment facility would reduce peak demand by 144 kW. The demand savings are based on shutting down 160 HP of grid-connected pumps during peak times. Rancho Murieta staff reported that one Solar Bee circulation device would be installed in each of the five aeration ponds.

Findings: During the August 15, 2002 site visit, Nexant verified that the Rancho Murieta treatment plant has a series of five aeration ponds. The first pond is the primary treatment pond and has four operational grid-powered aerators. The second pond has three operational grid-powered aerators; the third pond has two grid-powered aerators; and ponds 4 and 5 each have one grid-powered aerator. Each of the five ponds has one solar-powered aerator.

At the time of the site visit (10:30 a.m.), each of the solar aerators was operating along with all four of the grid aerators in the primary pond. Plant staff reported that the grid aerators in the primary pond were usually on with the exception of the time period from 1:45 p.m. to 8:15 p.m., coinciding with their local utility's peak period. They also reported that the other grid aerators were only needed intermittently and were not used during peak times.

Also during the visit, Nexant took demand readings on a sample motor of each size at the plant. The plant's project manager provided several digital pictures and a short video of the Solar Bees' installation along with measured current (amp) readings for each of the 12 motors used for aeration. The project manager also provided a description of operations and a plant diagram. Based on the information provided, Nexant created Table 8-6, which shows by pond, which pump is involved, the percent of peak time it was being operated before installation of the Solar

Bees, the pump's rated horsepower and kW demand, and the pump's proportional contribution to peak demand.

Table 8-6: City of Rancho Murieta Aerator Data

Pond #	Motor ID#	Rated HP	KW	On peak %	kW peak
1	2	10	6.9	100%	6.9
1	14	10	7.6	100%	7.6
1	15	15	13.1	100%	13.1
1	16	15	12.6	100%	12.6
2	13	10	8.2	25%	2.0
2	17	20	16.6	25%	4.1
2	18	20	14.8	25%	3.7
3	10	10	10.0	25%	2.5
3	12	10*	9.2	25%	2.3
4	19	10*	5.4	12.5%	0.7
5	3	10	9.7	25%	2.4
Total		**140***	**114.1**		**57.9**

Note: The total horsepower is 140 instead of the 160 listed in the application; the discrepancy is due to changes in the use of the pumps in ponds 3 and 4 that were reduced by 10hp each.

Evaluation: Following industry standard practice, Nexant determined the baseline for the Rancho Murieta project by averaging the peak demand of each motor based on the time in use during the peak period. For example, aerator #10 in pond #3 has a peak demand of 10 kW and operates 25 percent of the peak period, thus has a 2.5 kW average.

Based on this analysis, the verified baseline for the Rancho Murieta project is 58 kW. After installation of the Solar Bees, the system has an average verified peak demand of 0 kilowatts due to the fact that all grid aerators shut down during the summer peak period. Thus, the verified peak reduction for this project is 58 kW yielding a 40 percent realization rate when compared to the 144 kW reported by the participant. The district had applied for the total connected aerator load as opposed to the peak summer load.

8.4.4 Error in Measurement and Verification Analysis

All of the reported project-specific savings values noted above are estimates with an associated level of uncertainty. The "true" value of the demand reduction achieved is reported with an associated precision and confidence level. The precision represents the range of likely values and the confidence level indicates the probability that the true value is within this range. In this program, MV&E efforts were designed for a precision of 20 percent at an 80 percent confidence level; in other words, the documented demand reduction has an 80 percent probability of being within (+/-) 20% of the true value. These levels were chosen in an effort to balance the desirability of reducing the uncertainty with the associated costs (and effort) of doing so.

After Nexant's monitoring and analysis work was performed, the actual "coefficient of variation" was determined to see whether the sample sizes were sufficient to meet the intended precision and confidence levels. In general, additional sampling should be considered if the coefficient of variance (Cv) is greater than 0.5 and the population's contribution is significant enough to affect the overall result.

The C_v is calculated using the following equation:

$$Cv = \frac{SD}{AVG}$$

Where:

Cv	=	Coefficient of variation
SD	=	Standard deviation of project realization rates
AVG	=	Average realization rate

The inspections carried out under the AB 970 and SB 5X program elements indicated that the C_vs calculated for all of the usage groups were less than the assumed C_v of 0.5. These low C_v s indicate that the sample size for all usage groups was sufficiently large to represent the population of that group.

The error for each subpopulation is affected by the portion of the population sampled and the standard deviation of the sampled population. Nexant calculated this sampling error using the following equation:

$$SE_{samp} = \sqrt{(1 - n/N) * SD^2 /(n-1)}$$

Where:

SE_{samp}	=	Sampling error
n	=	Sample size
N	=	Total population size
SD	=	Standard deviation of the realization rates

The error for the subpopulation was further affected by errors in verification measurements. For each of the 14 projects evaluated, a device and an operations error were assumed. The device error accounts for errors in the actual device used to measure the power used by the sampled equipment. A two percent measurement error is associated with the one-time power draw measurements taken with a hand held device, while a zero percent measurement error is associated with average measurements taken from extended SCADA system monitoring.

The operations error accounts for uncertainty in hours of use or in level of power production either in the baseline or the verified savings. A 20 percent operations error was assigned to projects with a high uncertainty, such as projects with motors controlled by tank levels or generation systems responding to demand. A 5 percent operations error was assigned to projects with a low uncertainty, such as projects with set schedules of operation or set levels of production. A 10 percent or 15 percent operations error was assigned to projects with a moderate level of uncertainty. All error levels were assigned based on Nexant's experience with MV&E techniques and water/wastewater projects. Table 8-7 lists all the projects, the errors assigned to each, and the overall for each subpopulation. The overall errors were calculated using the root mean square of the component errors.

Table 8-7: Project Device and Operations Error Summation

Project	Measurement Errors		
	Device	Operations	Overall
Generation			
Big Bear Area RWD	0	15	15
City of Merced	2	5	5
City of San Mateo	2	5	5
City of Santa Cruz	2	5	5
EBMUD	0	5	5
North San Mateo County	2	5	5
Vallejo S&FCD	2	15	15
Overall			6
Load Shifting			
South Tahoe PUD	0	10	10
Gridley	2	5	5
Rancho Murieta	2	20	20
Overall			10
Energy Efficiency			
Palo Alto WWTP	2	10	10
City of Dinuba	2	5	5
Bear Valley Springs CSD	0	20	20
Overall			11

The C_Vs for each of the subpopulations are shown in Table 8-8. Also in Table 8-8, note the precision calculated for each administrator at 80 percent confidence. The measurement and operational errors have been added to the calculated sampling error for each subpopulation.

Table 8-8: Program Uncertainty Analysis (Coefficient of Variance)

Project Category	AB 970 Cv	SB 5X Cv	SB 5X Sampling Error	SB 5X Measurement Error	SB 5X Overall Error
Curtailment	N/A	N/A			
Generation	0.2	0.3	6%	6%	9%

Project Category	AB 970 Cv	SB 5X Cv	SB 5X Sampling Error	SB 5X Measurement Error	SB 5X Overall Error
Load Shifting	0.5	0.3	12%	10%	16%
Efficiency	0.5	0.2	10%	11%	15%

The errors presented in Table 8-8 were used to determine the standard error for this element using the following equation:

$$SE_{Water} = \sqrt{\sum (kW_{Vsamp} * ME)^2 + \sum (kW_{Vnonsamp} * OE)^2}$$

Where:

SE_{Water}	=	Standard error for the Water element
kW_{Vsamp}	=	Verified savings from each project in the sampled population
$kW_{Vnonsamp}$	=	Verified savings from non-sampled population for each subpopulation
ME	=	Measurement error
OE	=	Overall error

The results of this calculation were multiplied by 1.28, the z statistic for an 80 percent confidence, to yield a total standard error for the SB 5X water element of plus or minus 938kW. When combined with the AB 970 error the overall water element standard error is plus or minus 2.9MW

8.5 PROGRAM ELEMENT EVALUATION

Nexant used the findings from our analysis of the sample projects to determine the verified savings for the program element as a whole. Nexant determined the realization rate for each sub-population through 1) dividing the sum of the verified savings for the sample projects by 2) the sum of the reported savings for these same projects. The realization rate for each sub-population was then multiplied by the total savings reported for that sub-population to determine the verified savings for the sub-population. The verified savings for each sub-population were then summed to derive the total verified savings for the program.

Table 8-9 shows the realization rates for the AB 970 and the SB 5X program elements. It is necessary to maintain separate realization rates for the two different programs due to the differences in program requirements and application criteria. For a detailed discussion of the measurement and verification of savings for AB 970-funded projects, please see Nexant's December 2001 report to the Energy Commission.

Table 8-9: Realization Rates for SB 5X and AB 970 Sub-Populations

Sub population	Realization Rates AB 970	Realization Rates SB 5X
Curtailment	101%	N/A
Efficiency	42%	88%

Sub population	Realization Rates AB 970	Realization Rates SB 5X
Generation	71%	59%
Load Shifting	36%	102%

The low realization rate for the generation subpopulation is partially a factor of generation project funding policies. The Energy Commission determined at the start of the program to use the continuous rating of the generator as the means for establishing funding. This method was used to help simplify determining funding with the understanding that this method would result in varying payment per actual kW of reduction and that the load reduction reported would both vary from the actual achieved savings change over the duration of the program.

Tables 8-10 and 8-11 show the determination of the verified peak reduction for each sub-population in AB 970 and SB 5X, respectively. These numbers are multiplied together and equal the verified peak reduction that is shown in the far right column of each table.

Table 8-10: Application of AB 970 Realization Rates

Sub population	Reported peak Reduction (MW)	Realization Rates	Verified peak Reduction (MW)
Curtailment	37.5	1.01	37.8
Efficiency	6.38	0.42	2.68
Generation	2.99	0.71	2.12
Load Shifting	5.27	0.36	1.89
Total	**52.14**		**44.49**

Table 8-11: Application of SB 5X Realization Rates

Sub population	Reported Installed (MW)	Realization Rates	Verified Installed (MW)
Curtailment	NA	NA	
Efficiency	1.42	0.88	1.25
Generation	14.5	0.59	8.56
Load Shifting	4.97	1.02	5.01
Total	**20.89**		**14.82**

Table 8-12 shows the savings for each SB 5X sample project and the realization rate for each SB 5X sup-population.

Table 8-12: SB 5X Realization Rates

	Project Name	Participant Reported Savings	Nexant Verified Savings	Realization Rate
Efficiency	City of Dinuba	164	119	0.73
	Palo Alto WWTP	309	325	1.05
	City of Brawley	0	0	TBD

	Project Name	Participant Reported Savings	Nexant Verified Savings	Realization Rate
	Bear Valley Springs CSD	152	103	0.68
	Efficiency Overall	**625**	**547**	**0.88**
Generation	City of San Mateo	500	496	0.99
	Vallejo S&FCD	2,400	850	0.35
	City of Santa Cruz	1,320	780	0.59
	EBMUD	1,700	1,117	0.66
	Big Bear Area RWD	600	469	0.78
	City of Merced	325	250	0.77
	North San Mateo County	180	172	0.96
	Generation Overall	**7,025**	**4,134**	**0.59**
Load Shifting	Gridley	31.8	32.0	1.01
	Rancho Murieta	144	58	0.40
	South Tahoe PUD	1,342	1463	1.09
	Load Shifting Overall	**1,517.8**	**1553**	**1.02**

The relatively low realization rates for efficiency projects (0.88) and generation (0.59) are due in part to the way in which the project implementers calculated their reported savings. Nexant's analysis indicates that reported demand savings for at least 5 of the14 sites visited were not derived from measurements of the change (difference) in production or consumption during summer peak periods. Three-generation projects (EBMUD, Santa Cruz, Vallejo) used their entire new generation potential as their savings estimate instead of calculating the difference between the old and new generation. Similarly, one efficiency project (Rancho Murieta) and one load-shifting project (Bear Valley Springs) used the total potential demand from all equipment affected (even though the equipment did not typically operate concurrently or during peak hours).

8.6 COST-EFFECTIVENESS

The program's cost-effectiveness is portrayed as the levelized cost per unit of demand reduction and is expressed in terms of $/ kW-yr. The general equation for calculating levelized costs of demand reductions is taken from the Energy Commission's *Standard Practice Manual: Economic Analysis of Demand-Side Management Programs,* (1987). The formula for levelized cost at the project level is as follows:

$$LC_{CEC} = LC/DR$$

Where:

LC = total Energy Commission costs used for levelizing

DR = total discounted demand reductions of the project

Since almost all funding was paid up front, no cash flow discounting is required. Demand reductions are expected to persist from 1 to 15 years, depending on the project type. Thus, each project requires discounting the annual expected demand reductions as follows:

$$kW_{total} = \sum_{n=1}^{t} \frac{kW}{(1+d)^{(t-1)}} = kW\left[1 + \frac{(1+d)^{(t-1)} - 1}{d(1+d)^{(t-1)}}\right]$$

Where:

kW_{total} = project discounted kW
kW = expected demand reduction each year
d = discount rate, 4.1%
t = project lifetime in years

This equation does not discount demand reductions in the first year. Non-lighting equipment lifetimes are based on *1999 ASHRAE Application Handbook,* Chapter 35.3, Table 3. Lighting fixtures have been assigned a lifetime of seven years. Demand reductions based on human intervention have been assigned lifetimes of one to three years.

AB 970 Cost-Effectiveness

Using this methodology, Nexant estimated the levelized cost of the AB 970 program element to be $32/ kW-year. This rate represents only the grant monies paid to recruit participants. It does not include the administrative fees charged by program implementers.

Nexant also calculated the levelized cost for the AB 970 program element based on accounting numbers provided by the Energy Commission, which include administrative costs. This analysis is based on program-level aggregated numbers, which indicate that by the end of December 2002, $5,060,688 had been invoiced under AB 970. This figure includes both incentive payments and administration fees invoiced to the Energy Commission by the program administrator and other entities performing tasks for this element. The same Energy Commission report indicates that the program had achieved 51.2 MW of peak savings. Applying the 2002 AB 970 realization rates to this reported savings yields 45.1 MW of verified savings. Assuming an average lifetime of 10 years (except for curtailment projects, for which an average of 3 years was assumed), these numbers yield a simple cost of $112/ kW and a levelized cost of $30/ kW-yr.

Table 8-13: AB 970 2002 Water Agency Program Element Cost effectiveness Results.

	Verified Savings	Incentive	Simple Cost	Levelized Cost
AB 970 2002	45.1 MW	$5,060,688	$112/kW	$30/kW-yr

SB 5X Cost-Effectiveness

Using the same methodology discussed above, Nexant estimates the incentive-only levelized cost of the SB 5X program element to be $44/ kW-year. Generation projects were assumed to have a lifetime of 15 years. The demand reduction contribution from sites purchasing all their fuel was reduced by 50 percent in the fourth year and again in the tenth year. This reduction was based on the assumption that plant operation, after the initial three-year contract, would depend on the cost of producing electricity compared to the cost of purchasing electricity. This reduction was not implemented for projects using primarily digester gas. Efficiency projects were all assumed to have a life of 10 years.

Load shifting projects were assumed to have a life of 6-8 years. The load shifting project lifetime was based on the assumption that the operation of the equipment, after the initial three-year contract, would be based on financial drivers such as time-of-use charges or curtailment incentives and changes in water treatment demands. Load shifting projects with automatic equipment that has the potential to replace some load, such as solar aerators, were given longer lifetimes as it was assumed that they would reduce future demand even as the demand for water treatment grew.

Using the above methodology and assumptions, Nexant determined the incentive-only cost-effectiveness for the SB 5X program element. For each subpopulation and for the program as a whole, Table 8-14 shows the verified savings for projects completed by December 2002, the incentive amount reported by the project administrator, and the simple and levelized costs.

Table 8-14: SB 5X Water Agency Program Element Incentive Only Cost-Effectiveness

Project Category	Verified Savings (kW)	Incentive	Simple Cost	Levelized Cost
Curtailment	NA	NA	NA	NA
Efficiency	496	$121,314	$245	$29/ kW-yr
Generation	4,957	$2,186,250	$441	$45/ kW-yr
Load Shifting	1,633	$305,680	$187	$45/ kW-yr
Overall Total	**7,085**	**$2,613,244**	**$369**	**$43/ kW-yr**

For comparison, a 1 kW project with a 10-year life, receiving a $250/ kW incentive, would have a levelized cost of $30/ kW-yr. The generation projects have a higher cost due to the low realization rate (0.59) for these projects as well as the fact that only half of them were completed in time to receive the $300/ kW incentive ($36/ kW-yr). The levelized cost for load-shifting projects have a higher cost due to their shorter life expectancy.

The SB 5X cost-effectiveness numbers in Table 8-14 represent only incentives paid to recruit participants. They do not include administrative fees charged by program administrators or Energy Commission charges to the program. Nexant also calculated the levelized cost for the SB 5X element based on accounting numbers provided by the Energy Commission, which included administration fees. This analysis is based on program-level aggregated numbers that indicate that by the end of December 2002, $2,181,220 had been invoiced under SB 5X. This figure included incentive payments and administration fees invoiced to the Energy Commission by the program administrator and other entities performing tasks for this element. The same Energy Commission report indicates that the program had achieved 8.7 MW of peak savings. Since this number represents unknown specific projects, the program average realization rate of 0.62 (yielding 5.4 MW of verified savings) and an average lifetime of 10 years were used in the calculation. Nexant calculated a simple cost of $404/ kW and a levelized cost of $48/ kW-yr.

8.7 AB 970 PERSISTENCE VERIFICATION

Nexant conducted persistence verification for the program to verify that projects implemented under AB 970 in 2001 were still achieving their verified savings as of EOY 2002. Nexant verified persistence in two ways: by follow-up site visits and phone surveys. Questions were asked to determine whether or not the measure is still in place and operating, whether or not there have been any major operational changes to the project or the facility that would affect energy savings, and how well the project has been performing. Nexant also solicited comments and feedback on the program as a whole.

Nexant conducted persistence verification efforts for all seven projects in the AB 970 sample population, visiting one of the projects (San Bruno) and surveying the remaining six participants by phone. Each of the participants were asked a series of questions to determine if there had been any significant changes in the project since Nexant's inspection visit in 2001. If there were no significant changes in project *operation* or project *performance*, Nexant assumed that the savings verified in 2001 have persisted. If significant changes in operation or performance were reported, Nexant assumed that the verified savings have not persisted. If a project or portion of a project was withdrawn and the project implementer was no longer claiming the savings associated with that withdrawal, Nexant did not consider the withdrawal a reflection of savings persistence. In those cases, the savings were subtracted from the original verified amount and the realization rates were recalculated accordingly.

Table 8-15 summarizes each AB 970 participant's survey responses. Nexant learned that one entire project and a portion of another had been completely withdrawn from the program before completion or payment. In both cases, the projects were performance based; because Nexant has no way of knowing whether or not the project implementers would have, upon completion, revised their reported savings, Nexant removed the withdrawn project and portion of a project from our persistence verification analysis. The remainder of the findings indicates that the savings verified in 2001 have persisted.

Table 8-15: AB 970 Participant Persistence Verification Survey Results

Participant	Is the project still in place?	Is the project still operating as planned?	Have there been any operating changes?	Has the project been performing as planned?
City of San Bruno	Yes	Yes	No	Yes
LA Bureau of Sanitation	Partially—motor removed, associated savings withdrawn	Yes, for the remaining portions of project	No	Yes, for the remaining portions of project
Moulton Niguel	Yes	Some problems were encountered, but have been corrected	No	Yes

Participant	Is the project still in place?	Is the project still operating as planned?	Have there been any operating changes?	Has the project been performing as planned?
Metro Water District of Southern California	Yes	Yes	No	Yes
San Diego	Yes	Yes	No	Yes
Eastern Municipal Water District (EMWD)	Yes	Yes	No	Yes
Pinole	No, project withdrawn	NA	NA	NA

City of San Bruno Project

Nexant performed one site visit, to the City of San Bruno project. During this visit, the project manager told Nexant that there had been no changes in operation and the system was performing as planned. Nexant verified these reports with a review of documentation, including the final commissioning report, and a first-hand viewing of the system in operation. The project manager also informed Nexant that the project had won the Fall 2002 California-Nevada-American Water Works Association Section Award for Energy Management.

Los Angeles Bureau of Sanitation Project

The LA Bureau of Sanitation reported on the three parts of their project affecting the blowers, lighting, and mixers. The blower and lighting efficiency improvements are still in place and operating as planned. The motor conditioners on digester mixers have been taken offline permanently because the units were not saving as much energy as hoped and were causing problems with the water treatment process.

The removal of the mixer motor from project reduced the reported savings by 146 kW and the verified savings by 15kW. In addition, in their final report, LABS revised their reported savings for the blower and lighting efficiency improvements. The reported savings for the lighting portion of the projects was raised from 21 kW to 42 kW. This increase was based on the 21 kW of lighting load affecting an equivalent savings in cooling load. In 2001, Nexant had verified the 21 kW of lighting load. Based on Nexant's experience with the interaction between lighting reduction and HVAC load reduction in office buildings, a 15% (3kW) credit was added to the verified savings. The reported savings from the blowers was revised from 80 kW to 121 kW, an increase of 41 kW, based on reported improvements in operations associated with the blowers. These newly reported savings from the project's blower component is treated as incremental reported savings and not incorporated into the calculation of project realization rates or analysis documenting persistence of savings. The new realization rate for the LABS project is based on the reported savings for the lighting portion (42 kW), the reported savings for the blower portion (80 kW), and the verified savings for each portion: 24 kW and 78 kW, respectively. All of these changes yield a new realization rate of 84.4% for the LABS project (102kW divided by 122kW).

Table 8-16: LA Bureau of Sanitation Project – Persistence Results

Sub-project	2001		2002	
	Reported kW	Verified kW	Revised kW	Verified kW
Blowers	80	78	80	78
Lighting	21	21	42	24
Mixer motors	146	15	0	0
Subtotal for realization rate	247	114	122	102
Other	-	-	41	NA
Total	247	NA	163	NA

Moulton Niguel

During the persistence telephone survey, Moulton Niguel reported that the reservoir used for peak time storage had been out of service for inspection for three weeks. During this time, it was necessary to operate the pump during the peak period. The reservoir has since returned to service and the system is operating and performing as planned, with the pump shut down and the water diverted to the reservoir during peak times.

Moulton Niguel noted that at its joint regional treatment plant, one pump had been accidentally run for one hour during the peak period. The staff responsible has been trained regarding the program requirements and the situation has not repeated itself.

During the telephone surveys with each of the following participants, Metropolitan Water District, City of San Diego, and Eastern Municipal Water District, all reported that their projects had seen no changes since 2001 and were operating as planned

Town of Pinole

The town of Pinole had withdrawn from the program. The manufacturer of the microturbine installed by Pinole under the AB 970 program had, after being bought by another company, exercised their right to buy back the unit. The town eventually purchased a new microturbine, partially funded through a PG&E incentive program. Because the Pinole project was withdrawn (and there are no longer any savings reported for this project), the project is no longer used as a factor in calculating the realization rate for the generation subpopulation.

Removal of the Pinole project from the calculation resulted in an adjusted realization rate for that subpopulation of 71.1 percent, up from 70.2 percent. The realization for the efficiency subpopulation has also changed, as a result of the adjusted realization rate for the LABS project. Nexant has calculated the new realization rate for the efficiency sub-population to be 50.4 percent, up from 36 percent. Table 8-17 compares the original realization rates and the adjusted realization rates for all the AB 970 subpopulations.

Table 8-17: Adjusted Realization Rates for Each AB 970 Sub-Population

Sub population	Realization Rate	
	2001	2002
Curtailment	101.0%	101.0%
Efficiency	36.0%	50.4%
Generation	70.2%	71.1%
Load Shifting	35.7%	35.7%

Using the adjusted realization rates, Nexant calculates that the AB 970 program element has achieved verified savings of 44.58 MW.

8.7.1 Participant Feedback

In addition to the four specific questions regarding their projects, participants were asked if they had any comments on the incentive program itself. Most respondents commented that a) the incentives were helpful, b) that the program worked well, and c) recommended that the program be extended, if possible. One respondent noted that the Energy Commission was extremely helpful. Metropolitan Water District, a curtailment project participant, expressed difficulty in scheduling coordination with the California ISO.

8.7.2 Persistence Conclusions/Lessons Learned

Based on the results of the noted persistence verification activities, Nexant concludes that the savings verified for AB 970 projects in 2001 have persisted through the end of 2002.

8.8 ADMINISTRATORS AUDIT AND PARTICIPANTS AUDITS – SB 5X

8.8.1 Administrator Audit Report

Nexant audited the SB 5X program administrator, HDR, Inc.; the AB 970 wastewater program element audit was administered directly by the Energy Commission. The audit's purpose was to determine how the administrator performed the following Energy Commission identified tasks:

1. Participant recruitment
2. Program marketing
3. Goals and accomplishment verification
4. Recordkeeping
5. Communicating to the Energy Commission about program activities

The program administrator was also responsible for ensuring that the proposed projects were installed and completed successfully prior to releasing monies to the participants.

Nexant's audit of HDR's performance took place in December 2002, and involved an on-site visit by a Nexant staff member at the administrator's office. The administrator provided Nexant access to a sample of their program files (10 of 36) to verify that a paper tracking system was in place that justified payments made on projects.

8.8.2 Administrator Audit Results

Below are the responses to each of the 14 questions used as part of the administrative audits. The questions pertain to the procedural tasks involved with running the program. The first eight questions cover areas of the administrator's responsibilities throughout the program process, such as marketing, verification, and reporting. The last six questions look at the administrator's record-keeping practices to discern their level of organization and to check that the procedures and responsibilities required by the Energy Commission have been followed. For questions one, two, and seven the respondent could give more than one answer.

Question 1: How were participants recruited?

HDR used mailing lists to send materials to the California Water Environment Association membership, National Pollutant Discharge Elimination System wastewater discharge permit holders, Department of Health potable water permit holders, and its own clients. It also posted advertisements or articles in "three or four" quarterly trade publications. HDR also sponsored a Distributed generation web site, which promoted the program.

Question 2: What marketing material did you use to attract participants?

HDR utilized an Energy Commission flyer that it sent out along with copies of the ads/articles that it had placed in trade publications.

Question 3: A two-part question: a) How many participants are participating as of December 31, 2002, and b) How many participants dropped out since the program's inception?

HDR reported 16 completed projects, with an additional 18-committed participants. Above and beyond these numbers, 8 projects were undertaken but ultimately dropped out.

Question 5: What equipment and services did you offer to participants?

No equipment or services were offered outside of the program incentive payments, as they were not within HDR's scope of work.

Question 6: Were participants offered training or any other instructional help during any time of their participation?

HDR offered assistance with applications and project definition. Training was not within HDR's scope of work.

Question 7: How did you evaluate your projects?

Applicants were required to fill out applications describing the project and its potential savings. Applications had to be verified and signed by a licensed engineer. HDR personnel reviewed each application for reasonableness.

Question 8: Question 8 had three parts: a) How did you verify installations? b) How many participants or sites were verified, and c) Did you use a sampling plan for this?

Verification of project installation was based on documentation provided in the participants' final report. These reports were turned in to the administrator upon completion of the project and included invoices and receipts for equipment and labor involved with project implementation. On-site verification was an optional task for the administrator, dependent on funding and specific requests from the Energy Commission. No site visits had been requested by the CEC contract manager or made by HDR by the time of the audit.

Question 9: What method was used to track and report project progress to the Energy Commission and/or the M&V contractor?

HDR used a spreadsheet to track projects, and reported weekly or monthly progress depending on the number of changes in the projects.

Questions 10-15 focused on the administrator's record keeping, and were based on a 5 point scale. The exact scale is described under each question. In general, a rating of "5" equals full record retention and a rating of "1" signifies a complete lack of documentation. Ten participants were selected from those with completed projects. Nexant reviewed the files for these participants, assessed their compliance, and then answered each of the questions. In each case, no discrepancies or deficiencies were found. Thus, the administrator received a score of five for each of the questions.

Question 10: Are documents available for the sampled projects in question?

The scale was 1 to 5 where 5 represented that all requested documents were available; 3=half of requested documents available; 1=no documents available.

Question 11: Were invoices valid—as shown by proper documentation and consistent with the initial agreements between parties involved and the program requirements?

The scale was 1 to 5 where 5 represented that all invoices were consistent; 3=Half of invoices are consistent; 1=Invoices completely inconsistent or not available.

Question 12: Was the verification process noted above followed?

The scale was 1 to 5 where 5 = a thorough verification process with full documentation; 3=Observed two or more significant deviations from verification process with sound explanations; 1=No verification process.

Question 13: Did the installed equipment agree with the invoice?

The scale was 1 to 5 where 5 represented complete consistency between invoices and equipment; 3=Observed two or more discrepancies between invoices and equipment; 1=Invoices completely inconsistent with equipment or not available**.**

Question 14: Were participants paid according to the customer agreement?

The scale was 1 to 5 where 5 represented that all payments were made according to customer agreements; 3=Most payments made according to customer agreements, two or more discrepancies; 1=Payments not made at all, or are not made according to agreements, or all payments made are in dispute.

Question 15: Was the tracking/reporting method noted above maintained?

The scale was 1 to 5 where 5 represented that actual tracking/reported method is consistent with planned method, with data available for all requested participant sites; 3=One or more deviations from planned method or half of records inadequate or missing; 1=No effective tracking method observed or data found to be completely inaccurate**.**

8.8.3 Administrator Audit Conclusions/Lessons Learned

Audit results indicate that HDR, Inc., the program administrator for the SB 5X program element, met the program guidelines for marketing the program, tracking participants, maintaining records, and reporting to the Energy Commission.

8.8.4 Participant Audit Report

The purpose of Nexant's participant audits was to evaluate the participants' compliance with the program's various rules and requirements for eligibility, the application process, reporting, and verification. These audits also provided an indication as to the participants' level of satisfaction with the administrator's program process design. The audits were conducted between December 2002 and January 2003.

Each audit was in the form of a 17-question telephone survey, performed by a Nexant staff member. The first eight questions asked participants about each aspect of the program's process such as marketing, communication, reporting, and verification. Questions 9-11 inquire about how the process went and what effect the program itself had on the participant's willingness to undertake an efficiency upgrade. Questions 12-17 use a 5-point rating system to determine the participant's level of satisfaction with each aspect of the program.

Nexant attempted to conduct participant audits for 12 of the 14 projects in the SB 5X sample population, but were able to perform only six audits (four project managers had either retired or moved on, and two projects were incomplete.) The six audits were performed for the following projects; Vallejo, Santa Cruz, Rancho Murieta, East Bay Municipal Utility District, Gridley, and San Mateo.

8.8.5 Participant Audit Results

Below is a series of explanations and charts that categorizes the participants' responses to each of 17 questions.

Question 1: How did you find out about the Energy Commission Water Agency Program?

All respondents found out about the program through the administrator/contractor, HDR. Two specifically mentioned the HDR website and one noted an HDR mailing.

Question 2: Why did you participate in the program?

Every respondent listed financial incentives as the greatest motivator. San Mateo said that this program's funding was available sooner than another program it was considering. Santa Cruz also said it wanted to generate more power.

Question 3: Did you participate in any other similar peak load reduction programs?

Five said yes, one said no. The yes answers included a PG&E program for motion sensor lights, an unspecified program for motors, and an Energy Commission programs on solar power, lighting, air conditioning, and refrigeration.

Question 4: On a scale of 1 to 5, rate the overall quality of the communication process with your administrator (5=complete/thorough; 3=sufficient/adequate 1=absent/ wholly inadequate)

The average was 4.3, with three 5s, two 4s, and one 3. Three respondents referenced weekly communications with the administrator while one said it was monthly.

Question 5: By what means did you most often communicate?

Phone and e-mail were the only answers.

Question 6: On a scale of 1 to 5, rate the reasonableness of the reporting requirements you were required to fulfill (5=Very reasonable, easy to fulfill; 3=Somewhat reasonable; some significant challenges; 1=Completely unreasonable)

The average was 4.5, with three 5s and three 4s. Three respondents indicated that they supplied monthly reports while three said just an initial and a final report were necessary.

Question 7: How long did it take for you to be notified about your application status after you submitted it?

Three respondents said it took one week to find out about their application status. One said it took more than one month. Two others were unsure.

Question 8: Did your program administrator visit your project to verify project completion?

Three respondents said no and three were unsure.

Question 9: On a scale of 1 to 5, rate the obstacles you encountered as if you were to implement the project again (5=no significant obstacles; 3=Obstacles were significant, but would conduct project again; 1=Obstacles were prohibitive)

The average was 3.4. Santa Cruz gave a 2, explaining that the availability of engineers and coordinating with PG&E were obstacles. EBMUD gave a 2, noting "delays." San Mateo gave a 3, citing coordinating with PG&E as an issue.

Question 10: What is the likelihood that you would have performed peak load-reducing actions without the Water Agency program? (5=without question; 3 =yes, though under different circumstances; 1=under no circumstances)

The average was 3.8. Santa Cruz gave a 2, saying it may have undertaken a smaller project otherwise. Vallejo gave a 3, saying that it would have had to perform the project eventually. EBMUD gave a 4, and said the grant reduced the payback to 4-5 months. San Mateo and Rancho Murieta both gave 5s, but said the projects would have been delayed without the grants.

Question 11: From your experience with this program would you participate again in a similar program? (5=without question; 3 =yes, though under different circumstances; 1=under no circumstances)

The average was 4.8, with five 5s and one 4. Santa Cruz, who gave the 4, said it was not difficult other than the timeline.

Questions 12-17 ask respondents to rate various aspects of the program on a 5-point scale, with five being the highest.

Question 12: How would you rate your experience with the Demand Responsive program on the whole?
Question 13: Your administrator?
Question 14: The application process?
Question 15: The invoicing, billing and payments process?
Question 16: The verification process?
Question 17: The implementation timeline that you were on?

The overall program and the administrator inquiries had the highest average ratings. The payment process was the only category to receive an average below 3.5. Regarding the timeline, Santa Cruz said it was tight and didn't allow time for competitive bids; Rancho Murieta said the application deadline was too short; and San Mateo said its rating would be a 3 instead of a 5 if it took into account issues with PG&E. Figure 8-1 shows the average ratings.

Figure 8-1: Program Ratings

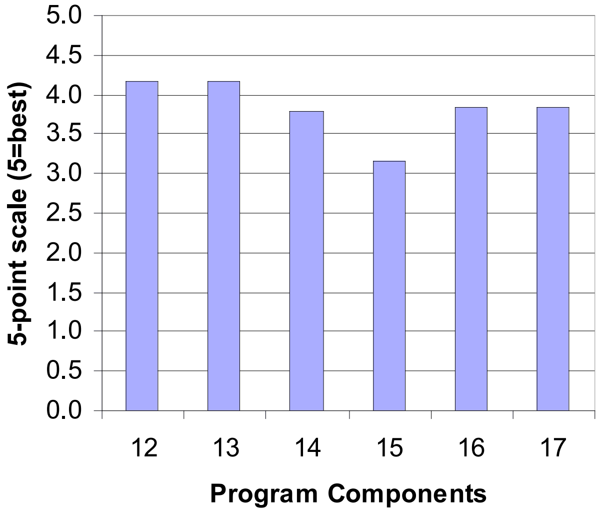

Table 8-17 shows the count of each rating for questions 12-17.

Table 8-17: Program Component Ratings Count

Question No.	Question	Low	Ranking Scale			High	Average
		1	2	3	4	5	
12	Overall program	0	0	1	3	2	4.2
13	Administrator	0	0	1	3	2	4.2
14	Application process	0	0	1	4	0	3.8
15	Payment process	1	0	3	1	1	3.2
16	Verification process	0	0	1	5	0	3.8
17	Timeline	0	1	1	2	2	3.8

8.8.6 Participant Audit Conclusions/Lessons Learned

Upon completion of the participant audit, Nexant can provide the following conclusions and key lessons learned. While the participants received the program quite favorably, enhancements for any subsequent offerings should take into account the following;

- Working with the utilities to streamline the inspection process could facilitate implementation of future projects. Several of the participants noted delays due to scheduling issues with PG&E inspectors.
- This program was instrumental in getting more savings in place sooner. Some participants stated that, without the incentives, they would have undertaken smaller projects. Others noted that their projects would have been delayed in implementation.

- Future programs, ones not pressed by emergency conditions such as the AB 970 and SB 5X initiatives, should build the project bidding process in their timelines. One participant made the observation that the short time frame limited the time allowed for a competitive bidding process.
- Identifying methods for soliciting participants that have not previously participated in energy efficiency programs may help expand participation. Most of the participants stated that they had participated in other incentive programs. Identifying and marketing to new entities, as well as old, will increase awareness of energy issues and possible alternatives in the water sector. This may, in turn, increase participation.

8.9 WASTEWATER PROGRAM ELEMENT CONCLUSIONS

As of December 31, 2002, the total savings verified from the SB 5X-funded portion of the wastewater program element is 7.1 MW; for the AB 970-funded portion, the total verified savings is 45.1 MW. With the 7.8 MW of savings estimated for the projects due for completion by June 2003, a total savings of 59.9 MW is expected from both the SB 5X and AB 970 program elements combined.

The AB 970 element was successful in restoring to operation several nonfunctional generation systems, installing new generation systems, shifting some peak loads to off peak times, and enabling one municipality to respond to curtailment price signals. Details of these successes are discussed in the AB 970 December 2001 report.

Generation is not the only source of peak reduction at water agencies. Opening the program to load shifting and efficiency projects doubled enrollment and nearly doubled expected savings from the SB 5X program element. Load shifting projects account for one third of the expected savings and had a levelized cost on par with generation. The efficiency projects accounted for a much smaller amount of overall savings than anticipated about 8 percent, but these projects were more cost effective, with levelized costs 33 percent less than either generation or load shifting.

In general, for both programs, simplified savings calculations and evaluation methods were employed to simplify administration of the funds, to the detriment of accuracy. In several cases where equipment was not used full time, project implementers reported connected load as savings. As a result, contracted savings were often overestimated, significantly contributing to low realization rates.

Equipment performance and reliability should be thoroughly researched when considering the installation of energy efficiency equipment at water and wastewater facilities. For example, after considerable testing, the City of Los Angeles learned that its variable frequency drive project would affect the treatment process downstream in a negative way, and therefore withdrew the project. By testing the project first, the city was able to avoid implementing a project that would have failed. Under AB 970, a similar project was shown to increase energy consumption due to the loading characteristics of the motors. While this project had already been implemented, the results kept the participant from expanding the project.

Lower water supply demands can have the equivalent effect of increasing capacity at no or low cost to the water utility. Some effective methods of reducing water demand are proper selection of plant material, optimization of end-use processes, installation of water meters, leak detection, and regular tracking of water consumption to identify potential problems.

During site visits and communications with participants and the project administrators, Nexant noted that the short lead-time in the initial phase of the application process was an issue for several participants. The main issues were the short timeframe for new projects to go through the planning and approval process. Participants also commented that the construction process usually took longer than planned. The effect of these issues on the program is evident in a number of projects requesting extensions or changes.

The short lead-time issues may also lead to a form of free-ridership. Projects that were already planned (and likely would have proceeded independent of the program's incentives) were able to move faster and take advantage of the higher initial rebate. Conversely, new projects that were being considered as a result of the incentive program had a much more time-consuming planning and approval process; thus, they would be more likely to receive the lower rebate.

Policies and contracts facilitating the sale of electricity back to the grid, at least under emergency conditions, would enable several of the generation projects to reach their full potential. In at least two cases, Vallejo and Big Bear, the installed capacity is not fully utilized by the plant itself. Enabling these two projects to sell back to the grid or contract for emergency power production would add nearly 1.4 MW of peak savings for this element.

Nexant has requested from the Energy Commission an extension of the SB 5X element's monitoring and verification period so that we may evaluate additional projects. We recommend the evaluation of up to seven addition projects within the efficiency and load shifting subpopulations to confirm that our verified savings are representative of the diversity of project types within these subpopulations.