2013 Load Impact Evaluation of the California Statewide Permanent Load Shifting Program

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Abstract

This evaluation documents the ex ante load impact analysis and results for the California Statewide Permanent Load Shifting (PLS) program at Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E). The PLS program provides a one-time incentive payment ($875/kW shifted) to customers who install qualifying PLS-TES technology on typical central air conditioning units or process cooling equipment. Because program implementation recently started in October 2013, there are no current PLS program installations on which to base ex post impact estimates for 2013. As such, this evaluation focuses on the 2014–2024 ex ante load impact estimates. As of January 2014, the utilities received 13 complete applications. The ex ante impact estimates rely on information in these pipeline applications to improve upon the analysis that was done for the 2012 evaluation, which necessarily relied largely on assumptions. Nonetheless, this year's forecast is still uncertain and relies on assumptions about impacts and further enrollment in the program. If future ex post evaluations show that the PLS-TES technology works differently than expected or if enrollment proceeds at an unexpected pace, this forecast may not reflect the load impacts that the PLS program ultimately delivers. This evaluation attempts to reflect this high degree of uncertainty in the forecast by providing low case, base case and high case enrollment and load impact scenarios. In the base case scenario for the 2017 August monthly system peak under 1-in-10 weather conditions, the program is expected to deliver a 6.7 MW load impact for PG&E, a 8.4 MW load impact for SCE and a 2.2 MW load impact for SDG&E, totaling 17.3 MW statewide.

1 Introduction

This evaluation documents the ex ante load impact analysis and results for the California Statewide Permanent Load Shifting (PLS) program at Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E). The statewide PLS program design and rules were finalized and adopted by the California Public Utility Commission (CPUC) in May 2013.[1] Because program implementation recently started in October 2013, there are no current PLS program installations on which to base ex post impact estimates for 2013. As such, this evaluation focuses on the 2014–2024 ex ante load impact estimates. The program features a technology incentive to encourage thermal energy storage (TES) technology that allows commercial, industrial, agricultural or residential buildings to shift cooling load from on-peak times to overnight.[2] PLS-TES technology can promote system stability, reduce stress on transmission and distribution systems and/or reduce customers' overall energy costs by shifting load from higher cost on-peak hours to lower cost overnight hours.

1.1 Background

Prior to this statewide program, each of the three IOUs conducted PLS programs similar to the currently proposed program, but with different incentive levels and technologies. These programs arose out of CPUC Decision (D.) 06-11-049, Order Adopting Changes to 2007 Utility Demand Response Programs, which was part of the 2006–2008 Demand Response Application (A.) 05-06-006, et. al. This Decision, among other things, ordered the IOUs to pursue requests for proposals and bilateral arrangements for PLS installations to promote system reliability during the summer peak demand periods. A four-year PLS program was approved for all the IOUs from 2008–2011. The details of those pilot programs are not revisited here; it should just be noted that each IOU has recent experience with PLS programs and technologies, although the proposed program design is new and stems from lessons learned and a different Decision.

In November 2010, a Statewide PLS Study, authored by Energy + Environmental Economics (E3) and StrateGen, provided information to the utilities for use in developing a new proposed PLS program. On April 30, 2012, D.12-04-045 ordered the utilities to work collaboratively to develop and propose a standardized, statewide PLS program. As part of the PLS program design process, the utilities incorporated the findings from the Statewide PLS Study into the 2012–2014 PLS program design. On July 30, 2012, the utilities submitted a joint PLS program design proposal to the Commission Staff. The Commission Staff sought feedback from interested parties by facilitating a PLS Workshop that was held on September 18, 2012. As a result of the PLS Workshop and comments received from interested parties, Energy Division (ED) provided the utilities program design feedback on November 13, 2012. The IOUs incorporated ED's feedback in their final version of the program design proposal submitted on January 14, 2013. The most noteworthy ED input resulted in limiting eligibility to thermal energy storage technologies for cooling. On May 9, 2013, Resolution E-4586 adopted the PLS program rules, budget and implementation details proposed by the IOUs, with modifications.

[1] CPUC Resolution E-4586 issued on May 9, 2013.

[2] Direct access and Community Choice Aggregation customers are also eligible.

1.2 Key Considerations for Program Year 2013 Load Impact Forecast

As explained above, there are no current PLS program installations to produce ex post impact estimates for 2013 or to use for estimating ex ante impacts. Despite that, the ex ante load impact estimates in this document conform to the timing and requirements of the CPUC Demand Response Load Impact Protocols for non-event based programs.[3] Since the program rules have been finalized and some customer feasibility studies and applications have already been submitted, the ex ante impact estimates rely on information in these pipeline applications to improve upon the analysis that was done for the 2012 evaluation, which necessarily relied largely on assumptions. Nonetheless, this year's forecast is still uncertain and relies on assumptions about impacts and further enrollment in the program. If future ex post evaluations show that the PLS-TES technology works differently than expected or if enrollment proceeds at an unexpected pace, this forecast may not reflect the load impacts that the PLS program ultimately delivers. For example, this forecast assumes that each utility receives a certain number of PLS program applications for low, base case and high scenarios. However, these assumptions carry a high degree of uncertainty because projecting uptake of any utility program is inherently uncertain. This uncertainty is compounded here by the fairly high initial capital investment and custom nature of each installation. The actual number of applications that each utility receives could be quite different than these projections.

Finally, there is additional uncertainty regarding future funding for PLS program incentives. A key input for the forecast of PLS program installations is the percent of the program incentive budget that is expected to be committed before funding expires. All three IOUs have filed requests that any uncommitted 2012-2014 incentive budget be included in the bridge funding that will extend the expiration of those funds until the end of 2016. However, this request has not yet been approved. Therefore, for PG&E and SCE, this evaluation will only consider installations that had incentives reserved or funded by the end of the 2012-2014 program cycle. SDG&E, on the other hand, assumes that the installations in this evaluation can be supported by the uncommitted 2012-2014 incentive budget that may get rolled into the 2015-2016 bridge cycle.

The current PLS program design specifies a set of measured data to be collected from participants to optimize TES system performance and enable load impact evaluation. In future years, these measurements will be the basis for the ex post and ex ante impact evaluations; although how to collect the data beyond the current program cycle is a question still being addressed. The basis for ex ante impact estimation for this evaluation is simpler, and relies primarily on estimates from program managers and evaluation, measurement and verification (EM&V) staff, combined with knowledge of the proposed rules of the program and building simulation modeling. As the PLS program evolves and actual PLS-TES installations come online over the next few years, evaluators will gradually phase out the assumptions-driven approach and transition to a data-driven approach, which will reduce the uncertainty of future ex ante load impact estimates.

[3] CPUC D.08-04-050 issued on April 28, 2008 with Attachment A.

1.3 Program Overview

The PLS program provides a one-time incentive payment ($875/kW shifted) to customers who install qualifying PLS-TES technology on typical central air conditioning units or process cooling equipment. Incentives are determined based on the designed load shift capability of the system and the project must undergo a feasibility study prepared by a licensed engineer. The load shift is typically accomplished through shifting of daytime chiller load to overnight hours. All electric customers on time-of-use electricity rates are eligible for the program, including residential, commercial, industrial, agricultural, direct access and Community Choice Aggregation customers.

To qualify for the PLS program incentive payment, customers must go through the program application, approval and verification process, which includes all of the stages that are required for customers to apply for, and receive a verified incentive amount. These stages are:

1. Customer submits complete application
2. Customer submits feasibility study
3. IOU reviews feasibility study and approves application
4. IOU conducts pre-installation inspection and sets aside incentive funds
5. IOU and customer sign agreement (SCE only)
6. Customer submits project design and installs PLS-TES system
7. Customer submits commissioning report
8. IOU reviews commissioning report and conducts post-installation inspection, tests and cost verifications
9. Customer receives final PLS program incentive

After a customer submits an application, customers participating in the program must provide, in advance of installation, a feasibility study prepared by a licensed engineer. This study must include an estimated cooling profile. Energy models should be used to determine a customer's cooling load profile over a year (8,760 hours). To accomplish this, building simulation models should be used to determine hourly cooling needs over the course of a year, based on building specifications, regional temperatures, occupancy and other inputs. Both retrofit and new construction customers will be subjected to the energy modeling process, unless utility approved cooling usage data is available.

The total incentive amount will be determined using a customer's peak load shift on their maximum cooling demand day (based on the on-peak hours). A conversion factor will be used to convert the cooling load shift tons to electricity load shift (kW). This methodology will be used for both full and partial storage systems. The incentive levels for the program are $875/kW for all IOUs.

The incentive payments are intended to offset the cost of installation and thereby make the system more attractive financially. Under the program rules, the incentive cannot exceed 50% of the total project cost, and the incentive for a customer cannot exceed $1.5 million. Customers' incentives will be determined as the least of (1) the incentive reservation amount calculated from the approved feasibility study and post-installation approval; (2) 50% of the actual final installed project cost; or (3) $1.5 million.

In addition, customers will be required to be on a time-of-use rate and provide trend data to the IOU's about their TES system for the first five years after installation. In the participation component of the program, customers are required to run their TES system on summer weekdays for five years after installation and submit monitored system data to the IOU. The systems are expected to have a lifetime of about 20 years.

The incentive budgets are $13.5 million for PG&E, $12.7 million for SCE and $3 million for SDG&E. At a minimum, these incentive budgets provide an expected upper limit on the amount of peak period shifting that the program could ultimately provide as a result of funding during this program cycle.

Customers are required to shift load by running the TES system on weekdays during summer months, which are defined slightly differently for each utility. Table 1-1 shows the On peak periods and summer months for each utility, as approved in the Statewide PLS Program Proposal.[4] PLS program participants are encouraged to shift load during non-summer months to maximize their energy bill savings.

Table 1-1 On-peak Periods for Each Utility

Utility	Summer Months	On-peak Hours
PG&E	May 1–October 31	12–6 PM
SCE	June 1–September 30	12–6 PM
SDG&E	May 1–October 31	11 AM–6 PM

1.4 Current PLS Program Status

Table 1-2 provides the PLS program status by utility and by stage in the PLS application and verification process. As of January 2014, the utilities received 13 complete applications that are likely to move forward in the verification process. Since these applications have already been received by the utilities, they are referred to as *identified projects* in the ex ante forecast. If these 13 customers end up installing a PLS-TES system, those installations are expected to provide nearly 11 MW of total load shift, resulting in incentives of around $7.9 million being spent across the three utilities. However, as these customers move through the verification process, the load shift amount is likely to change, so the 11 MW total load shift amount is simply an indicator based on the most recent available information. SCE received eight applications, and for one of these applications, the feasibility study has also been received. The other seven SCE applications were approved and are expected to reach the feasibility study stage in the first half of 2014. PG&E has approved four applications, but as of January 2014, no feasibility studies were received. SDG&E received one application, and that project has reached the feasibility study stage. While this year's PLS evaluation benefits from this information on applications that have been received, it is important to recognize that there are six or seven time-consuming stages from the time an application is submitted by the customer to the time when the installation comes online. All of these stages are illustrated in Table 1-2. It can take up to two years or more for some applications to go through all of the stages and result in an installation. Based on the current applications, the time period

[4] 2012 – 2014 Statewide Permanent Load Shifting Program Proposal. July 30, 2012. Jointly proposed by: Pacific Gas and Electric, San Diego Gas & Electric and Southern California Edison Company.

for each project (application) is expected to vary with the size of the PLS-TES installation, from 6 months for small projects to 24 months for large projects. Therefore, the forecast for these identified projects is still uncertain, as the kW load shift can change during the verification process and customers may choose not to continue through the process.

Table 1-2: PLS Program Status by Utility and Stage in Verification Process (as of January 2014)

Stage #	Stage Description	SCE Totals			PG&E Totals			SDG&E Totals		
		Apps	Incentive	kW	Apps	Incentive	kW	Apps	Incentive	kW
1	Customer submits complete application	7	$4,420,325	5,052	4	$1,934,700	4,040			
2	Customer submits feasibility study	1	$305,375	349				1	$889,000	1,016
3	IOU reviews feasibility study and approves application									
4	IOU conducts pre-installation inspection and sets aside incentive funds									
5	IOU and customer sign agreement (SCE only)									
6	Customer submits project design and installs PLS-TES system									
7	Customer submits commissioning report									
8	IOU reviews commissioning report and conducts post-installation inspection, tests and cost verifications									
9	Customer receives final PLS program incentive									
Total		**8**	**$4,725,700**	**5,401**	**4**	**$1,934,700**	**4,040**	**1**	**$889,000**	**1,016**

1.5 Confidentiality Concerns

The ex ante forecast presented in this report is aggregated over two key sources of information – the 13 projects for which complete applications have been received (identified projects) and the projects for which applications are forecasted (referred to as *unidentified projects*). This forecast has been developed based on discussions with program and EM&V staff at each utility. As a result, including hourly impact estimates that are dominated by one or two large identified projects (in some cases) could reveal confidential information about those customers. Therefore, the ex ante impact estimates in this report focus on the summer peak period that is defined by the resource adequacy window (1–6 PM).

1.6 Report Organization

The remainder of this report proceeds as follows. Section 2 summarizes the methodology for the evaluation. Section 3 provides a summary of key assumptions and the resulting enrollment forecast. Section 4 provides the ex ante load impact estimates by utility. Section 5 includes recommendations for future evaluations. Finally, Appendix A summarizes the methodology for developing the ex ante conversion factors, which are key inputs for the analysis. These ex ante conversion factors were developed in last year's PLS evaluation, so Appendix A carries over that section from last year's report.

2 Methodology

The PLS program does not currently have existing installations that can be used for modeling load impacts. Each utility had a pilot PLS program from 2007 through 2011, but the design of those programs differed from the current program design. Therefore, the PLS installations from the prior pilot programs do not provide useful information for forecasting load impacts for this program. This is because the primary sources of uncertainty in the impact forecasts are not characteristics of customers who are likely to enroll or other attributes that could be observed in existing installations. The primary sources of uncertainty are how many customers are likely to enroll in the new program, what size their installations will be, when they will be installed and where they will be located.

To produce forecasts of load impacts, we have used assumptions that are as consistent as possible with the best estimates of the program managers and EM&V staff at each utility. All these assumptions should be taken with a high degree of uncertainty because projecting uptake of any utility program is inherently uncertain, especially when there are multiple stages in the application and verification process that may require up to 24 months or more to complete. Basically, there is not enough data to predict how many projects will be installed, how big those projects will be, where they will be located or when they will start up. No market studies have been conducted to shed light on these uncertainties, and the enrollment process has not been active long enough to allow for accurate predictions. This uncertainty is compounded here by the fairly high investment cost and custom nature of each installation. Without a detailed assessment of any given site, it is hard to know whether it would be a good candidate for PLS-TES installation.

This evaluation attempts to reflect this high degree of uncertainty in the forecast by providing low case, base case and high case enrollment and load impact scenarios. The base case is the expected[5] value based on discussions with utility staff. The low case is a forecast in which PLS program uptake is up to 50% lower and the high case is up to 50% higher than the base case, depending on utility expectations. Under the high scenario, customer enrollment would significantly exceed the current best guesses of program staff. Similarly, under the low scenario, enrollment would fall short of utility expectations. Even this range may not fully cover the outcomes that the program will experience. In a case like this with such high uncertainty, it is likely that other stakeholders may make different projections or consider different assumptions reasonable. To allow other stakeholders to understand how different assumptions may produce different values, this evaluation is as transparent as possible about all of the assumptions and about how the assumptions lead to the ultimate load impact forecasts. Therefore, a concise summary of assumptions by utility is provided in Section 3.

The main alternative to the method Nexant has used would be to undertake a market research study to understand which customers would be likely to enroll in this program over the next year. This would be substantially more complicated and expensive than the method used here, and it is not clear that it would produce substantially more precise estimates, due to the uncertainty in customers' abilities to project their own uptake of a new program. Since this type of study has not been done, the evaluation

[5] Note that these "expected values" are not expected values in a statistical sense. They are literally just what utility staff expressed as reasonable expectations. The uncertainty expressed in the high and low values are also just opinions, not statistical measurements.

primarily relies on estimates from utility staff. In future PLS load impact evaluations, as more data on enrollment and system performance becomes available, the forecast will be refined and the uncertainty will be reduced.

This evaluation forecasts load impacts for two different types of projects – identified projects and unidentified projects. Identified projects include those for which the customer has either completed a feasibility study or submitted a complete application. Applications are submitted by potential PLS participants to initiate their enrollment in the program. Each application includes an initial estimate of the proposed PLS-TES installation's load shifting capacity. Feasibility studies are more in-depth analyses conducted by qualified engineers, and include a technical and cost analysis of the proposed project. Completion of a feasibility study is the next step in the PLS approval process after the initial application has been submitted and approved.

For identified projects, the ex ante load impacts are allocated to specific local capacity areas[6] (LCAs) because the actual location of the PLS-TES system installation is known. While this information on where identified projects will be installed reduces some uncertainty in the forecast, there is still substantial uncertainty regarding whether the project will successfully go through the entire verification process, given that no projects have made it through the complete process yet, including installation stage. The identified projects also have an expectation of the installation date (either in the application or the feasibility study, if available), but those dates may change throughout the verification process.

Unidentified projects, on the other hand, are projects that have been forecasted based on assumptions developed with the PLS program managers and EM&V staff, as discussed above. The forecast of unidentified projects is based on the number of applications that are expected to be submitted by the end of 2016 for SDG&E and by the end of 2014 for PG&E and SCE.[7] For unidentified projects, the number and size of the installations could be estimated for a range of scenarios, based on the expected percentage of each utility's incentive budget that will be spent (similar to last year's approach). However, additional assumptions were needed to estimate the pace of project startups and the allocation of load impacts across different LCAs, since load impacts are location and weather dependent.

Because the number and size of identified projects varied greatly between each IOU, the approach used to evaluate the program impacts was tailored to the amount of information that was available for each IOU. Primarily, the number and diversity of applications determined the methodology that was used to generate load impacts for identified projects. The methodology for determining load impacts from unidentified projects was uniform across the three IOUs, though the specific assumptions for these impacts varied and were partially informed by the applications that were received in each IOU.

The following subsections describe the methodology used to estimate the load impacts for unidentified projects (which was uniform across all IOUs) and the IOU-specific methodologies for estimating load impacts for identified projects.

6 LCA is the CAISO-defined term that represents each transmission constrained load pocket in the California IOU service territories.

7 SDG&E has opted to include bridge funding for 2015-2016 in the scope of this evaluation and forecast, whereas PG&E and SCE have decided to not forecast projects after 2014, due to uncertainty regarding the bridge funding.

2.1 Unidentified Projects

This year's methodology for unidentified projects was similar to that of the 2012 ex ante PLS evaluation, as they both attempted to quantify load impacts for customers whose building characteristics, location, project timing and load patterns are unknown. As in last year's PLS evaluation, because the main uncertainty is the number and size of projects that will be included in the program, a range of scenarios was generated for each IOU in order to capture the uncertainty related to market adoption of PLS-TES technologies.

Figure 2-1 summarizes the methodology for estimating ex ante load impacts for unidentified PLS projects. The three steps for estimating ex ante load impacts for unidentified projects are:

- **Step 1** involves forecasting the amount of incentive dollars that will be spent on unidentified projects for each IOU. The first key input for this calculation is the total PLS budget for each IOU. The total budget amount is multiplied by the percentage of each IOU's budget that will be committed to projects by the end of 2014 (for PG&E and SCE) or by the end of 2016 (for SDG&E), under the low, base case and high scenarios.[8] Finally, the budget that has been committed to identified projects is subtracted from that expected budget spend, which produces the forecast of incentives to be spent on unidentified projects.
- **Step 2** converts the incentive dollar forecast into the ex ante load impact estimates. To do this, the forecast of incentive dollars spent on unidentified projects is divided by the incentive amount per kW load shift ($875/kW). Per the program design, this kW load shift amount represents the peak load shift[9] that can be expected under ASHRAE 2% weather conditions.[10] The kW load shift is multiplied by the ex ante conversion factors, which convert the load shift under ASHRAE 2% weather conditions to the ex ante load impact estimates for monthly system peak days and average weekdays under 1-in-2 and 1-in-10 weather conditions (as per the California DR Load Impact Protocols). These conversion factors vary from 0.5 to 2 from June through September, so they do not change the initial kW load shift by more than 50%.
- **Step 3** is to forecast when each expected PLS-TES installation will come online, based on slightly different assumptions for each utility (described below). The time between when an application is received and when the installation and verification are completed varies from 12 to 24 months, so projects do not come online until 2015 or later. Five years after each forecasted PLS-TES installation, the ex ante impacts begin to degrade at a rate of 2.5% per year. Over time, the load shifting capacity of the PLS-TES technologies is expected to degrade as the system ages. This assumption was made in consultation with program managers, and it is consistent with last year's evaluation.

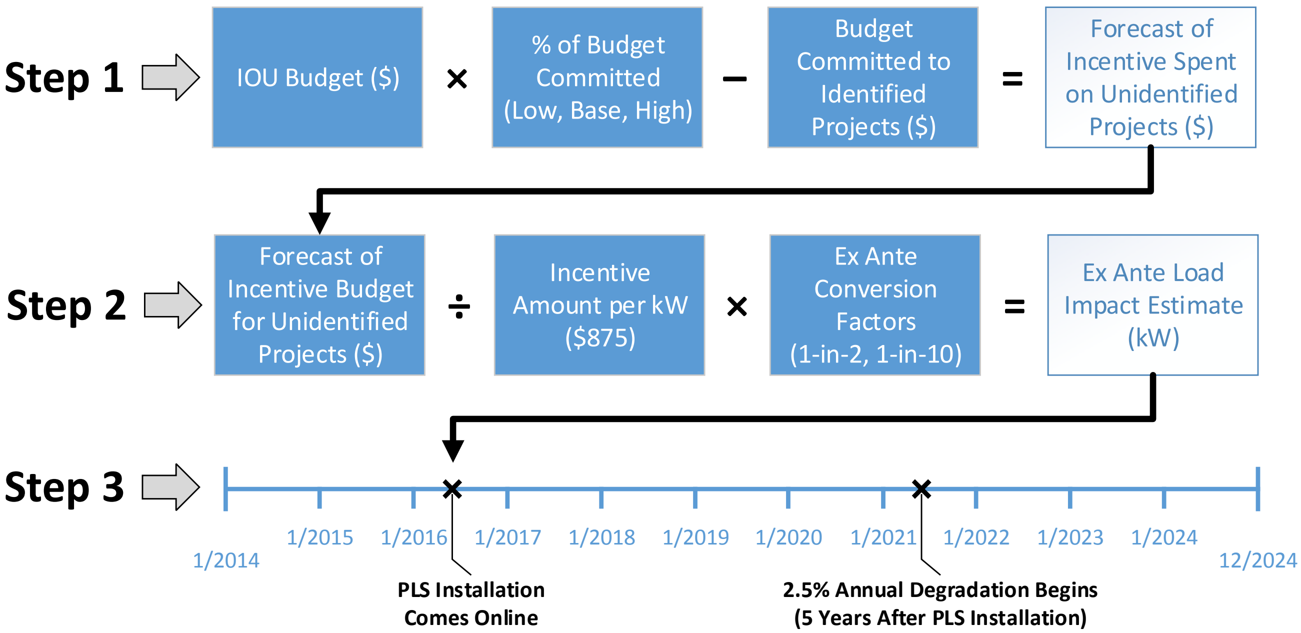
8 The percent budget commitment does not necessarily reflect the amount that will ultimately be spent, since some projects may drop from the PLS program prior to installation (for instance, if the feasibility study indicates that the project would not be cost-effective for the customer). To account for this, the forecast assumes a 10% drop off rate between projects committed and projects actually installed. This drop off rate was assumed to be the same probability for each project size and LCA within each IOU.

9 This peak load shift value is the amount of demand shifting that each utility expects to pay incentives for. This means that these are expected output from the model used in the engineering feasibility study for each site. Although we do not know with certainty what conditions the engineers performing the study will use to represent peak yearly conditions, based on discussions with PLS program managers and knowledgeable staff, we expect the engineers to use ASHRAE 2% weather conditions for the relevant geography of each site.

10 These conditions are available in the ASHRAE Handbook - ASHRAE® Handbook Online: 2009 Fundamentals.

The methodology for developing the conversion factors is described in Appendix A. It is important to note that these conversion factors were developed under the assumption that PLS would primarily involve space cooling installations. However, some of the applications that have been received thus far also include process cooling installations, which have load profiles that may differ from the typical space cooling profile. For the sake of simplicity and in the absence of any further information, we have assumed in this evaluation that the unidentified projects only include space cooling installations.

Figure 2-1: Methodology for Estimating Ex Ante Load Impacts of Unidentified PLS Projects



The forecast of incentive dollars spent on unidentified projects was also used to estimate PLS program enrollment, which is defined as the number of PLS-TES installations that have come online. Before a project comes online, the customer is still going through the application and verification process, during which some customers may drop off. Therefore, customers are not defined as enrolled until their PLS-TES installation has come online. Nonetheless, for each IOU, the applications that have been received thus far were used to inform assumptions about the following:

- Peak load shift of typical unidentified projects. Depending on the number and diversity of applications for each IOU, unidentified projects were either classified as small, medium and large (PG&E), or were simply assumed to be of uniform size (average of current applications – SCE and SDG&E);
- Number of projects of each size; and
- Expected project installation and verification timeline (the time between when an application is received and when the installation and verification are completed).

These assumptions were IOU-specific and were formulated using the current applications for identified projects. Section 3 provides a summary of these assumptions and the resulting enrollment forecast.

Finally, because local weather conditions heavily influence the load shift that is actually experienced, the ex ante load impacts are dependent on the specific geographic region in which an installation is located. As such, it was necessary to allocate the unidentified projects to LCAs within each utility's service area. Without any information on where these projects will be located, the aggregate peak load shift was allocated to each LCA in proportion to the distribution of nonresidential customers located in each LCA. Considering that the utilities have received applications from customers that are located in LCAs that are not usually associated with having high cooling load, the expectation regarding where these PLS-TES installations will come online has become unclear. Basically, with process cooling being eligible for PLS program incentives, the program is viable in many different climates, as the current applications have shown.

2.2 Identified Projects

The PLS program evaluation used two different methodologies for estimating ex ante load impacts for identified projects. For SCE and SDG&E, Nexant used an approach that was similar to that of unidentified projects. For PG&E, Nexant conducted building simulation modeling to estimate load impacts under the various ex ante weather conditions. Each approach is described in this section.

2.2.1 PG&E Approach

PG&E received four applications at the time the evaluation was conducted, with a wide range of expected peak load shifts. One of the projects was quite large (well over the 1,714 kW load shift that would yield the maximum incentive amount of $1.5M). Three of the projects were for process cooling loads. These process cooling loads may be quite different from the space cooling loads for which the ex ante conversion factors are designed to be used. Given the unexpected nature of these projects and the fact that a single project is expected to deliver a large portion of the load shift, PG&E opted to use building simulation modeling to estimate the ex ante load impacts for identified projects.

For this building simulation modeling work, the evaluation team used the Quick Energy Simulation Tool (eQUEST), which is a software package designed in collaboration with the Department of Energy (DOE) and Lawrence Berkeley National Laboratory (LBNL).[11] This software is used extensively throughout the industry to simulate building energy usage for a wide variety of climates, building types and cooling technologies (including various TES designs). The remainder of this section summarizes the step-by-step approach that was applied to the four identified PG&E projects.

Step 1: Populate Initial eQUEST inputs

To populate the initial eQUEST inputs, Nexant used information from the PLS program applications, PG&E data, discussions with the PLS program manager and, in some cases, discussions with the utility account representative and/or customer. These initial eQUEST inputs included the following:

- Facility square footage;
- Type of cooling (process/space);
- Type of thermal energy storage to be installed;

[11] eQUEST, <http://www.doe2.com/equest/>

- Capacity of thermal energy storage tank;
- Number of thermal energy storage tanks;
- Thermal energy storage charge/discharge schedule;
- Chiller capacity;
- Chiller type (air-cooled/water cooled, centrifugal/screw/reciprocating);
- Chiller supply temperature;
- Chiller operation schedule;
- Project site address;
- North American Industry Classification System (NAICS) code;
- Rate schedule;
- LCA;
- Assigned weather station;
- 2013 hourly temperature data; and
- 2013 hourly usage data.

Step 2: Calibrate eQUEST Model

Using these initial eQUEST inputs, Nexant predicted each building's 2013 hourly usage based on the 2013 hourly temperatures for each customer. This initial model prediction was compared to the actual 2013 hourly usage in order to assess the accuracy of the model. Then, Nexant calibrated the model by adjusting some of the default eQUEST inputs. In addition to the inputs described above, eQUEST includes other variables that affect the model predictions. The calibration process involved adjusting some of the default values for those other variables, based on the 2013 building usage patterns and, in some cases, other information such as satellite imagery from Google maps. The inputs that were adjusted in the calibration process included:

- Lighting load density (W/sq. ft.);
- Lighting operating schedule (weekly operating hours);
- Building equipment/plug load density (W/sq. ft.);
- Equipment/plug load operating schedule (weekly operating hours);
- Process load (kW);
- HVAC system operating schedule (weekly operating hours);
- Air handling unit (AHU) fan static pressure;
- Minimum outside air flow ratio for AHUs (%);
- Design air flow rate for variable air volume (VAV) boxes;
- Minimum air flow ratio for VAV boxes (%); and
- Space temperature set point (°F).

Ideally, Nexant would have been able to visit the facility in order to populate these remaining inputs, but given that customers are scheduled to go through a similar process as part of the feasibility study, the evaluation team did not want to impose additional burden on PLS program applicants. Either way, this calibration process is common for building simulation modeling, even when more in-depth information is available.

Regardless of some data limitations, the calibrated eQUEST models produced highly accurate predictions of hourly and monthly building usage for the identified PLS facilities. Figure 2-2 provides a comparison of the simulated and actual 2013 monthly building usage for identified PLS facilities. From May through October, the months in which the PLS-TES system will be operated, the simulated building usage falls within 5% of the actual usage. Similarly, Figure 2-3 shows how simulated and actual 2013 hourly building usage compare during the summer time period (May through October). With hourly usage that falls within 3% of the actual usage, the building simulations are also quite accurate across the hours of the day during the summer. Therefore, while the building simulation modeling work would have ideally involved a site visit, by calibrating the model to 2013 hourly interval data, Nexant was able to develop models that accurately reflect how each building's usage varies by temperature throughout the day and year. Therefore, we can have confidence that the model accurately predicts the underlying cooling usage.

Figure 2-2: Comparison of Simulated and Actual 2013 Monthly Building Usage for Identified PLS Facilities

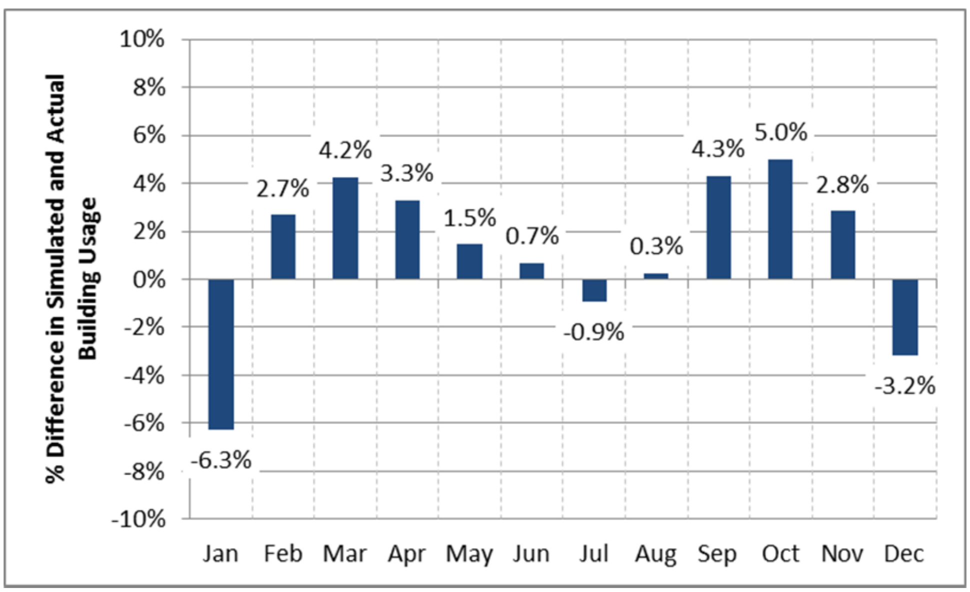
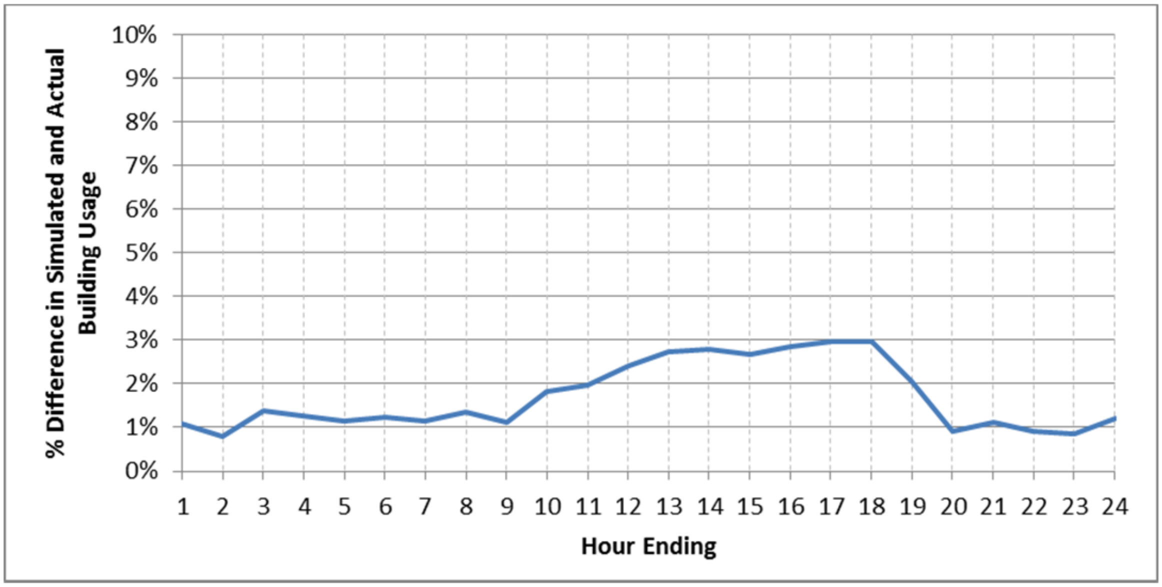


Figure 2-3: Comparison of Simulated and Actual 2013 Hourly Building Usage for Identified PLS Facilities (May through October)



Step 3: Predict Cooling Usage Under Ex Ante Weather Conditions

The final step was to predict cooling usage with and without the PLS-TES system, under the ex ante weather conditions that are required by the DR load impact protocols. By subtracting the cooling usage with the PLS-TES system from the cooling usage without the PLS-TES system, Nexant estimated the hourly impacts for each ex ante weather condition. As a result, the forecast for these identified PG&E projects did not rely on the ex ante conversion factors described in Appendix A. Finally, considering that the location and installation date are known for these projects, the forecast incorporates this information by having the project come online on the expected installation date and by assigning the ex ante load impacts for that project to the customer's LCA.

2.2.1 SCE and SDG&E Approach

At the time of the evaluation, SCE received applications for eight projects, and one has reached the feasibility study stage in the application and verification process. SDG&E received one application, and that customer has submitted a feasibility study. All of these projects are similar in size, with an expectation to deliver around 1 MW of load shift or less for each one. Given the relatively small size of these projects and the large time commitment that is required for building simulation modeling (even without a site visit), SCE and SDG&E decided to not use building simulation modeling for forecasting the ex ante load impacts that these projects will deliver. Although building simulation modeling may produce more accurate ex ante load impact estimates, it is not certain until these projects come online and the ex post impacts are evaluated. Instead of building simulation modeling, the ex ante conversion factors were used to convert the expected load shift from the application/feasibility study to ex ante weather conditions. This methodology was nearly identical to Step 2 and Step 3 in the methodology used for unidentified projects, except that the incentive amount was taken from the latest available information for that project (the application or feasibility study). In addition, considering that the location and installation date are provided in the application for identified projects, the forecast for SCE and SDG&E identified projects incorporates this information by having the project come online on the expected installation date and by assigning the ex ante load impacts for that project to the customer's LCA.

3 Summary of Assumptions and Enrollment Forecast

Table 3-1 provides a summary of the ex ante forecast assumptions by utility. In the base scenario, PG&E forecasts that 50% of the total PLS incentive budget will be committed to projects by the end of 2014.[12] SCE projects a 65% budget commitment by the end of 2014. Finally, SDG&E expects 75% allocation of its PLS incentive budget by the end of 2016. The uncertainty associated with the percent of the total budget to be committed is reflected in the low and high scenarios. Using the applications that have been received thus far as a guide, three PLS-TES installation sizes were assumed for PG&E's unidentified projects – small (65 kW of load shift), medium (377 kW) and large (1,714 kW). In the base case, PG&E commits to two large, four medium and nine small projects, in addition to the current identified projects. In the low case, PG&E commits to three additional medium projects and eight additional small projects. In the high case, an additional 3 large, 6 medium and 30 small projects are identified. SCE and SDG&E assumed a uniform installation size of 675 kW and 750 kW, respectively, which was informed by their somewhat homogenous mix of applications thus far. In the base case, these assumptions yield six additional projects for SCE and two additional projects for SDG&E. Regardless of the assumed installation sizes, the total ex ante load impact estimates are primarily a function of the percent of the total budget to be committed by scenario. Therefore, while the uniform project size assumption is most likely unrealistic for SCE and SDG&E, it does not affect the main results of interest – the ex ante load impact estimates.

Table 3-1: Summary of Ex Ante Forecast Assumptions by Utility

Assumption		PG&E	SCE	SDG&E
Total PLS Incentive Budget		$13,500,000	$12,690,000	$3,000,000
$ Committed to Identified Projects		$1,934,700 (14% of total)	$4,725,700 (37% of total)	$889,000 (30% of total)
Budget Remaining for Unidentified Projects		$11,565,300	$7,964,300	$2,111,000
% of Total Budget to be Committed by Scenario	Low	25%	40%	60%
	Base	50%	65%	75%
	High	75%	90%	90%
Time Period of Budget Commitment		2014	2014	2014-2016
% of Projects Dropped After Budget Commitment		10%		
Annual % Degradation (After Year 5)		2.5%		
Installation Size (kW)		Small – 65 kW, Medium – 377 kW, Large – 1,714 kW	675 kW	750 kW
Timing of When Projects Come Online	Identified	Based on most recent information regarding proposed project		
	Unidentified	Small – 2015, Medium – 2015-16, Large – 2016	2015-2016	2015-2016
Location of Installations		Distributed by LCA, proportional to C&I population		

12 The cost-effectiveness analysis filed along with the Statewide PLS program proposal (D.12-04-045 and Resolution E-4586) assumed that the total incentive budget would be spent by end of 2014. The assumptions made in this evaluation differ significantly from that scenario, and are based on the best available information at this time.

As discussed in Section 2.1, five years after each forecasted PLS-TES installation, the ex ante impacts begin to degrade at a rate of 2.5% per year. Over time, the load shifting capacity of the PLS-TES technologies is expected to degrade as the system ages. This assumption was made in consultation with program managers, and it is consistent with last year's evaluation. In addition, without any information on where these projects will be located, the aggregate peak load shift was allocated to each LCA in proportion to the distribution of nonresidential customers located in each LCA. Considering that the utilities have received applications from customers that are located in LCAs that are not usually associated with having high cooling load, the expectation regarding where these PLS-TES installations will come online has been unclear. Basically, with process cooling being eligible for PLS program incentives, the program is viable in many different climates, as the current applications have indicated.

Based on these assumptions, Figure 3-1 provides the enrollment forecast by utility and type of project for the base scenario. As discussed in Section 2, customers are not defined as enrolled until their PLS-TES installation has come online. Given the timeline required for the PLS application and verification process, the enrollment forecast does not show any projects coming online until 2015. In 2015, most of the enrollment comes from PG&E's small and medium unidentified projects. Most of the PG&E and SCE identified projects are expected to come online by the end of 2015 as well. Enrollment reaches a steady state in 2017, with around 32 projects in the Statewide PLS program. Again, this evaluation only includes projects that SDG&E commits to in 2014–2016 and projects that PG&E and SCE commit to by the end of 2014, so if the PLS incentive budget expands or if funding is extended past the current deadlines, the program will have higher enrollment potential.

Figure 3-1: Enrollment Forecast by Utility and Type of Project – Base Scenario

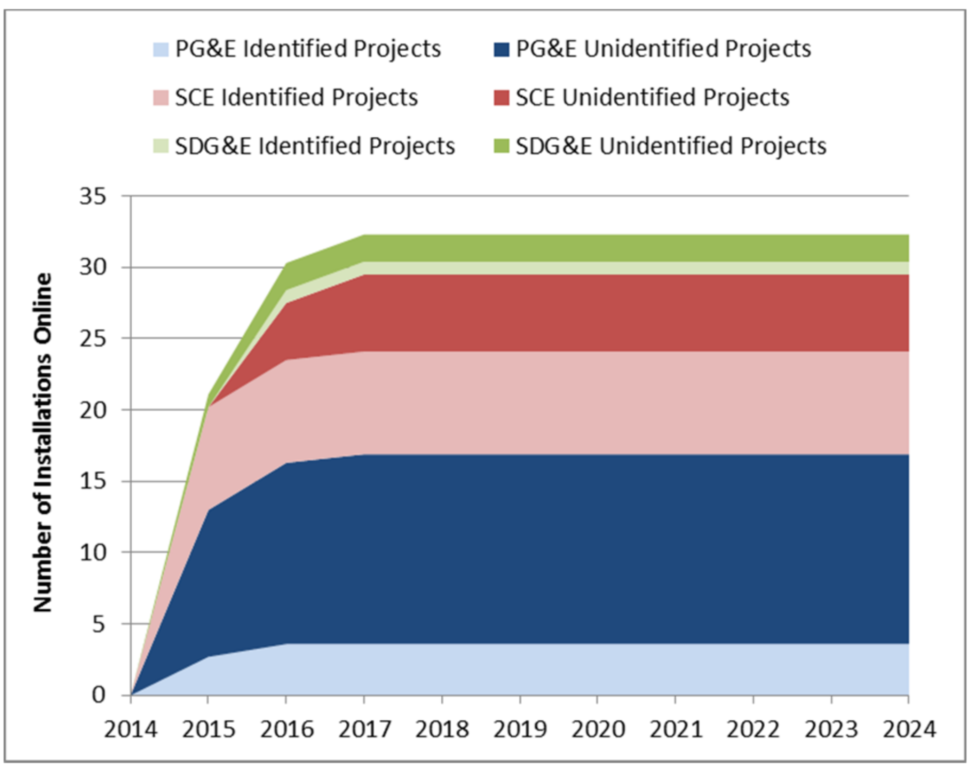


Table 3-2 provides the PLS program enrollment forecast by utility and LCA, for the months in which impacts are estimated. As discussed, given the timeline required for the PLS application and verification process, the enrollment forecast does not show any projects coming online until 2015. Of all the LCAs in California, the greatest number of PLS program installations is expected to occur in the LA Basin LCA (11 of 32 installations). The Greater Bay Area is the only other LCA in California that is forecasted to have more than four PLS program installations. Within two of the LCAs, the expected number of PLS program installations that will come online is less than one. While fractions of installations are not possible in reality, these projected enrollment numbers properly reflect the uncertainty of the forecast. In this case, the realistic expectation is that every LCA has a chance of ultimately having a PLS program installation. However, because two of the LCAs are so small in terms of the number of IOU customers that are located there, the expected number of installations is less than one in those two LCAs.

Table 3-2: PLS Program Enrollment Forecast by Utility and LCA – Base Scenario

Utility	LCA	2015							2016							2017-2024						
		Apr	May	Jun	Jul	Aug	Sep	Oct	Apr	May	Jun	Jul	Aug	Sep	Oct	Apr	May	Jun	Jul	Aug	Sep	Oct
PG&E	Greater Bay Area	3	3	3	3	4	4	4	5	5	5	5	5	5	5	6	6	6	6	6	6	6
	Greater Fresno	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Humboldt	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Kern	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Northern Coast	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	Other	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	Sierra	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Stockton	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Total (PG&E)	*12*	*12*	*12*	*13*	*13*	*13*	*14*	*16*	*16*	*16*	*16*	*16*	*16*	*17*	*17*	*17*	*17*	*17*	*17*	*17*	*17*
SCE	LA Basin	1	1	1	1	5	7	7	9	9	9	10	10	10	11	11	11	11	11	11	11	11
	Outside LA Basin	0	0	0	0	0	0	0	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Ventura	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1
	Total (SCE)	*1*	*1*	*1*	*1*	*5*	*7*	*7*	*9*	*9*	*10*	*10*	*11*	*11*	*12*	*13*	*13*	*13*	*13*	*13*	*13*	*13*
SDG&E		1	1	1	1	1	1	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total (Statewide)		**14**	**14**	**14**	**15**	**19**	**21**	**22**	**28**	**28**	**29**	**29**	**30**	**30**	**31**	**32**	**32**	**32**	**32**	**32**	**32**	**32**

4 Ex Ante Impact Estimates

This section provides the ex ante impact estimates for peak period (1–6 PM) conditions from April through October. In accordance with the CPUC Demand Response Load Impact Protocols,[13] the peak period is defined as 1 to 6 PM, even though PLS program participants are required to shift load from 12 to 6 PM (for SCE and PG&E) or 11 AM to 6 PM (for SDG&E). Estimates for average weekdays can be found in the Excel load impact tables that are available upon request.[14] The results are provided separately for each utility. A comparison to last year's ex ante forecast is also provided for each utility. The forecast runs from April 2015 through October 2024. Based on the most recent available PLS program application information, the forecast currently shows zero impacts in 2014. While two of PG&E's small identified projects may come online in the third quarter of 2014, given that project delays are possible, these impacts have been shifted into 2015. If these two small projects come online in 2014, PG&E would show small impacts in 2014, but the remainder of the forecast would remain the same.

Load impacts during the months of November through March are expected to be zero or nearly zero due to a lack of significant cooling load in most areas during those months. In addition, because customers will not be required to run their systems during those months, it is best to assume that the impacts are zero, until further information becomes available. Therefore, estimates have not been developed for those months. In the future, if installations occur in areas where there is significant winter cooling load and if customers appear to be shifting during those times, it may make sense to estimate impacts for those months.

Similarly, customers technically do not have to run their systems during April, and SCE customers do not have to run their systems during May or October (see Table 1-1). Regardless, customers may choose to simply run their systems when the cooling season begins. It is uncertain whether that pattern will develop, and it depends on how easy and financially advantageous it is for customers to run their systems when they are not required to. For that reason, April impacts for all three utilities and May and October impacts for SCE include more uncertainty than the others.

It is also important to note that these impacts represent load that is shifted, not eliminated. The evaluation assumes that all avoided peak period load, plus an additional 5%, is consumed during the hours of 9 PM – 6 AM. PLS systems are required to use no more than 5% additional energy than the baseline system. Because not all cooling load comes during the peak period and we have only added 5% to the shifted peak period load, our assumption implies that the 5% limit will be binding for many, but not all sites.

Finally, each installation is expected to last a minimum of five years, after which we have assumed a degradation in load impacts of about 2.5% per year, which corresponds to an expected life of about 20

[13] CPUC D.08-04-050 issued on April 28, 2008 with Attachment A.

[14] Due to the confidentiality concerns described in Section 1, these load impact tables are not available publicly.

years for each installation.[15] We have assumed the same degradation factor for each month within a given year so that the percentage difference measured May over May would be identical to the difference measured June over June and so forth. The degradation factor is a major simplification of what will likely become a complex issue if the program continues over the next decade. Similar to the issue of projecting PLS enrollment, this is primarily an empirical question that is unlikely to be determined accurately in advance. PLS-TES systems are too complex and their continued function is based on too many variables for a theoretical analysis to have any serious hope of accuracy. Therefore, we have chosen a simple set of values for degradation that dovetail with the assumptions that utility staff consider reasonable; and we recognize the significant uncertainty associated with these projections.

4.1 PG&E Results

Table 4-1 provides the ex ante load impact estimates for monthly system peak days in April through October of 2015, under 1-in-2 and 1-in-10 weather conditions for the base scenario. Table 4-2 provides the same results for 2016. While many of PG&E's small unidentified projects are forecasted to come online in 2015, the large unidentified projects are not forecasted to come online until 2016. As such, the aggregate load reduction is expected to grow from around 1.5 MW in August of 2015 to over 5 MW in August 2016. Throughout 2016, the Greater Bay Area LCA accounts for the largest share of load impacts, ranging from 38% of the total in April to over 50% of the total in July. It is important to note that the Greater Bay Area includes many hot areas with large commercial and industrial facilities, including Silicon Valley, Concord and San Ramon.

In some cases, the ex ante conversion factors lead to minor anomalies in the results, such as the 1-in-10 estimates being up to 1 MW lower than the 1-in-2 estimates. To be consistent with last year's methodology, the same conversion factors are used in this year's analysis. Considering that these conversion factors will be phased out in favor of ex post data analysis once actual PLS program installations come online, these minor anomalies will be mitigated in future evaluations. The only way to conclusively determine why the 1-in-10 impacts are lower in some cases would be to look at the underlying code of the building simulation software that was used to generate the ex ante conversion factors, which is not possible at this point.

[15] The actual assumed trajectory is for a constant amount of absolute shifting capacity loss each year after the fifth year, such that the expected total life is 20 years and the maximum total life is 35 years. If the program becomes a major part of the energy savings portfolio, then more nuanced assumptions for shift capacity degradation will be in order.

Table 4-1: PG&E Ex Ante Load Impact Estimates (1-6 PM) on Monthly Peak Days for April-October 2015 (kW) – Base Scenario

LCA	April		May		June		July		August		September		October	
	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
Greater Bay Area	[Rows removed for confidentiality reasons.]													
Greater Fresno														
Humboldt														
Kern														
Northern Coast														
Other														
Sierra														
Stockton														
Total	**506**	**616**	**736**	**1,095**	**1,347**	**1,667**	**1,505**	**1,434**	**1,511**	**1,457**	**1,322**	**1,565**	**1,254**	**1,284**

Table 4-2: PG&E Ex Ante Load Impact Estimates (1-6 PM) on Monthly Peak Days for April-October 2016 (kW) – Base Scenario

LCA	April		May		June		July		August		September		October	
	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
Greater Bay Area	[Rows removed for confidentiality reasons.]													
Greater Fresno														
Humboldt														
Kern														
Northern Coast														
Other														
Sierra														
Stockton														
Total	**1,723**	**2,099**	**2,363**	**4,329**	**4,948**	**5,906**	**5,944**	**5,115**	**5,134**	**5,641**	**5,438**	**5,774**	**4,589**	**4,385**

Figure 4-1 illustrates how the August 1-in-10 load impact estimates vary by forecast year and scenario. Figure 4-2 shows the same results for August 1-in-2 weather conditions. Across the forecast years and scenarios, the impacts are higher under August 1-in-10 weather conditions, but the difference is less than 1 MW. As described in Section 3, the three scenarios correspond to different forecasts of the percent of the total PLS program incentive budget that will be committed by the end of 2014, with 25% assumed under the low scenario, 50% under the base scenario and 75% under the high scenario. The different percentages of the total PLS program incentive budget being committed translates into different enrollment forecasts across the three scenarios. We consider these scenarios to be about the best that can be done for estimating the uncertainty associated with these estimates. The estimation method was not statistical in nature and therefore there are no standard errors to report. As a result of this uncertainty, the aggregate load reduction of the program varies substantially. When the aggregate impact peaks in 2017 and 2018 (before the 2.5% annual degradation begins), the PLS program is expected to deliver from 2.5 MW in the low scenario to over 10 MW in the high scenario. At 6.5 MW, the aggregate impact for the base scenario is in the middle.

Figure 4-1: PG&E August 1-in-10 Monthly System Peak Day Load Impacts (1–6 PM) by Forecast Year and Scenario

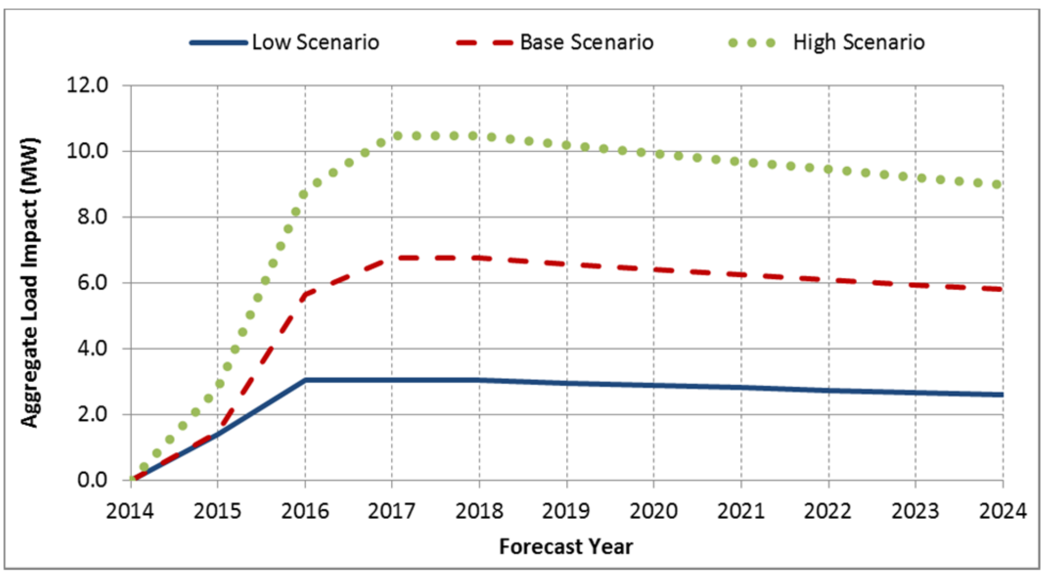


Figure 4-2: PG&E August 1-in-2 Monthly System Peak Day Load Impacts (1–6 PM) by Forecast Year and Scenario

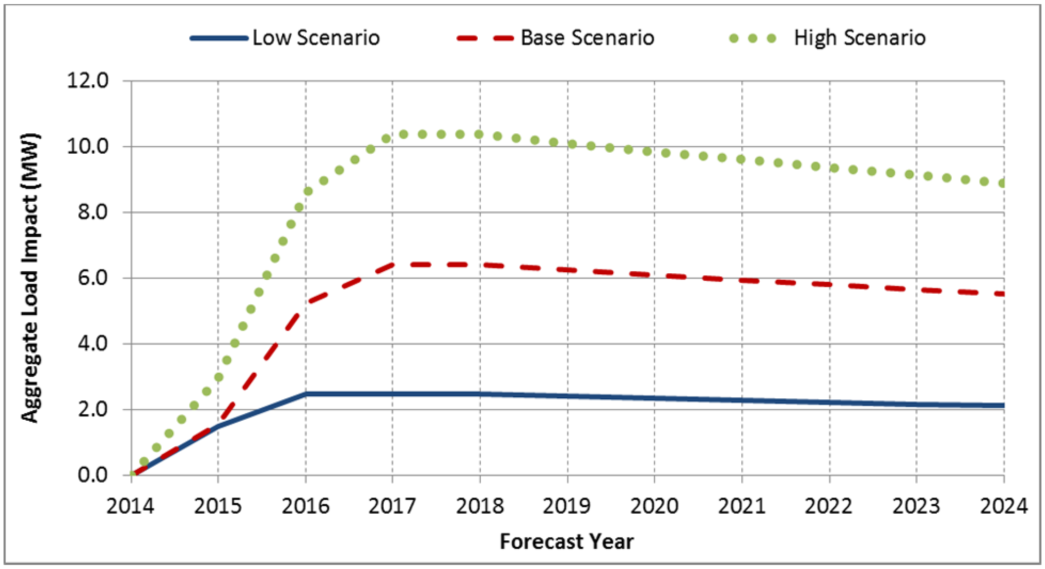


Table 4-3 shows the expected trajectory of load impacts under August 1-in-10 weather conditions from 2015 through 2024 by LCA. Table 4-4 shows the same results for August 1-in-2 conditions. The Greater Bay Area and Other LCAs combined account for a majority of load impacts throughout the forecast horizon under both 1-in-10 and 1-in-2 weather conditions. None of the other six LCAs comprise more than 10% of load impacts. As a result of the assumed 2.5% annual degradation in load impacts after year five of each installation, the aggregate load reduction decreases from around 6.7 MW in 2018 under 1-in-10 weather conditions to 5.8 MW in 2024.

Table 4-3: PG&E August 1-in-10 Monthly System Peak Day Load Impacts (1–6 PM) by LCA and Forecast Year – Base Scenario

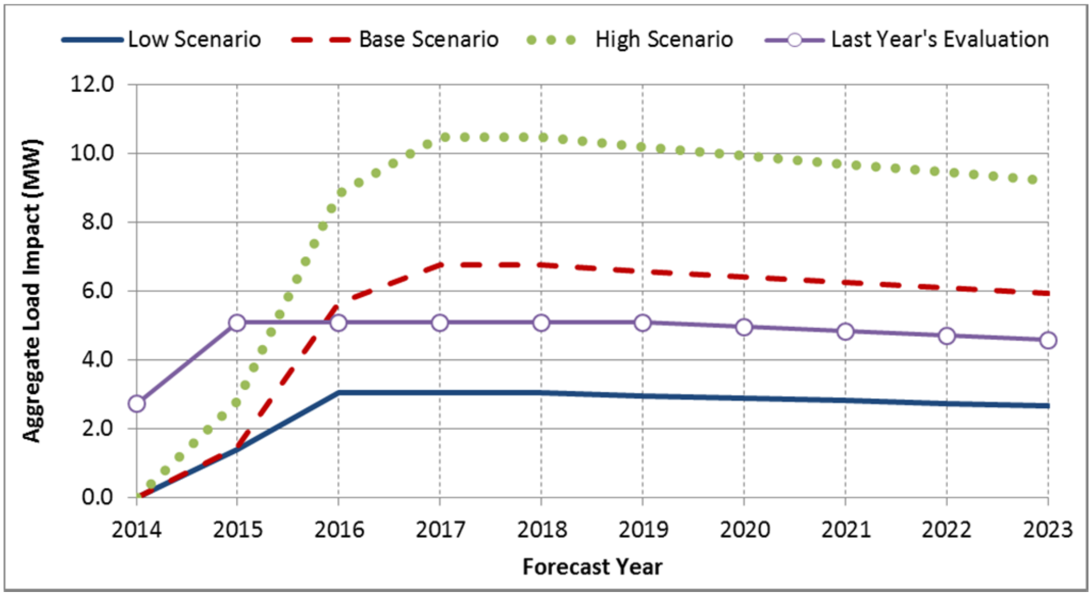
LCA	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Greater Bay Area	[Rows removed for confidentiality reasons.]									
Greater Fresno										
Humboldt										
Kern										
Northern Coast										
Other										
Sierra										
Stockton										
Total	**1,457**	**5,641**	**6,739**	**6,739**	**6,571**	**6,406**	**6,246**	**6,090**	**5,938**	**5,789**

Table 4-4: PG&E August 1-in-2 Monthly System Peak Day Load Impacts (1–6 PM) by LCA and Forecast Year – Base Scenario

LCA	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Greater Bay Area	[Rows removed for confidentiality reasons.]									
Greater Fresno										
Humboldt										
Kern										
Northern Coast										
Other										
Sierra										
Stockton										
Total	**1,511**	**5,134**	**6,275**	**6,275**	**6,118**	**5,965**	**5,816**	**5,671**	**5,529**	**5,391**

Figure 4-3 compares the ex ante load impact estimates from this evaluation to those from last year's PLS program evaluation, for the August 1-in-10 monthly system peak day. In general, the load impact estimates are similar to those of last year's evaluation. The main difference in this year's evaluation is that it forecasts projects coming online at a slower pace. This change is based on information from the PLS program applications that PG&E has received since the program opened in October 2013. Considering that this information was not available at the time, last year's evaluation forecasted that six projects would come online before June 2014 and that six additional projects would come online by 2015. Nonetheless, the two forecasts are similar from 2016 onwards. The base scenario for this year's evaluation forecasts aggregate load impacts that are roughly 30% higher than the estimates in last year's evaluation, which is due to modified assumptions regarding the percent of the total PLS program incentive budget that will be spent. Last year's evaluation assumed that 32% of the budget would be spent, whereas this year's evaluation assumes that 50% of the budget will be spend in the base scenario. This change was also based on more recent information, including the applications that PG&E has received so far and the expected number of additional applications that PG&E may receive by the end of 2014.

Figure 4-3: PG&E Comparison of August 1-in-10 Monthly System Peak Day Load Impacts (1–6 PM) to Base Scenario from Last Year's PLS Program Evaluation



4.2 SCE Results

Table 4-5 provides the ex ante load impact estimates for monthly system peak days in April through October of 2015, under 1-in-2 and 1-in-10 weather conditions for the base scenario. Table 4-6 and Table 4-7 provide the same results for 2016 and 2017, respectively. SCE's unidentified projects are forecasted to come online in 2016. As such, the 2015 aggregate impacts are attributed to the identified projects that are expected to come online, all of which are located in the LA Basin LCA. Therefore, the Outside LA Basin and Ventura LCAs do not show any impacts until 2016. Nonetheless, considering that the LA Basin LCA includes 75% of SCE's non-residential customers, most of the unidentified projects are expected to be located there. Throughout 2017, the LA Basin LCA accounts for a large share of load impacts, ranging from 82% of the total in June to 94% of the total in July.

Table 4-5: SCE Ex Ante Load Impact Estimates (1-6 PM) on Monthly Peak Days for April-October 2015 (kW) – Base Scenario

LCA	April		May		June		July		August		September		October	
	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
LA Basin	135	320	182	198	163	217	220	270	2,585	3,656	4,375	3,743	4,666	4,423
Outside LA Basin	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ventura	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	**135**	**320**	**182**	**198**	**163**	**217**	**220**	**270**	**2,585**	**3,656**	**4,375**	**3,743**	**4,666**	**4,423**

Table 4-6: SCE Ex Ante Load Impact Estimates (1-6 PM) on Monthly Peak Days for April-October 2016 (kW) – Base Scenario

LCA	April		May		June		July		August		September		October	
	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
LA Basin	2,478	5,877	3,472	3,772	3,230	4,286	4,506	5,536	4,664	6,596	6,199	5,304	6,829	6,473
Outside LA Basin	66	60	92	103	125	130	148	151	175	176	197	191	158	202
Ventura	120	94	206	262	301	338	370	382	405	432	431	461	239	384
Total	**2,664**	**6,030**	**3,771**	**4,136**	**3,656**	**4,754**	**5,025**	**6,070**	**5,244**	**7,205**	**6,827**	**5,956**	**7,226**	**7,059**

Table 4-7: SCE Ex Ante Load Impact Estimates (1-6 PM) on Monthly Peak Days for April-October 2017 (kW) – Base Scenario

LCA	April		May		June		July		August		September		October	
	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
LA Basin	3,252	7,715	4,387	4,765	3,933	5,219	5,295	6,505	5,295	7,488	6,807	5,824	7,261	6,883
Outside LA Basin	199	179	222	247	250	260	255	260	262	265	262	255	189	242
Ventura	361	281	495	628	602	675	635	655	608	648	575	615	287	461
Total	**3,812**	**8,175**	**5,103**	**5,640**	**4,784**	**6,154**	**6,184**	**7,419**	**6,165**	**8,401**	**7,644**	**6,694**	**7,738**	**7,586**

Figure 4-4 illustrates how the August 1-in-10 load impact estimates vary by forecast year and scenario. Figure 4-5 shows the same results for August 1-in-2 weather conditions. Across the forecast years and scenarios, the impacts are 36% to 41% higher under August 1-in-10 weather conditions. As described in Section 3, the three scenarios correspond to different forecasts of the percent of the total PLS program incentive budget that will be committed by the end of 2014, with 40% assumed under the low scenario, 65% under the base scenario and 90% under the high scenario. We consider these scenarios to be about the best that can be done for estimating the uncertainty associated with these estimates. The estimation method was not statistical in nature and therefore there are no standard errors to report. As a result of this uncertainty, the aggregate load reduction of the program varies substantially. When the aggregate impact peaks in 2017 and 2018 (before the 2.5% annual degradation begins), the PLS program is expected to deliver from 5.2 MW in the low scenario to nearly 12 MW in the high scenario, under August 1-in-10 weather conditions. At 8.4 MW, the aggregate impact for the base scenario is in the middle.

Figure 4-4: SCE August 1-in-10 Monthly System Peak Day Load Impacts (1–6 PM) by Forecast Year and Scenario

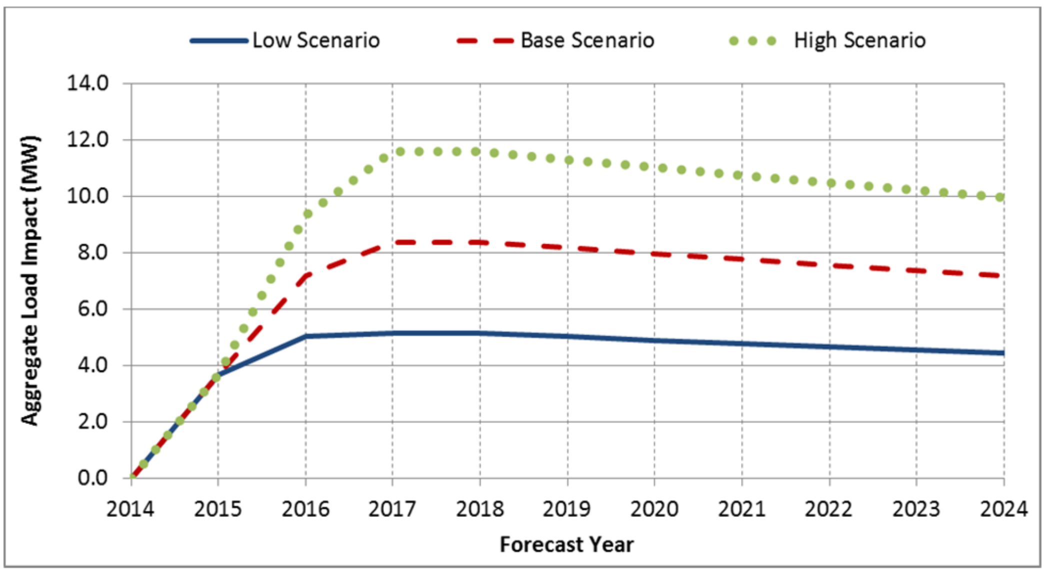


Figure 4-5: SCE August 1-in-2 Monthly System Peak Day Load Impacts (1–6 PM) by Forecast Year and Scenario

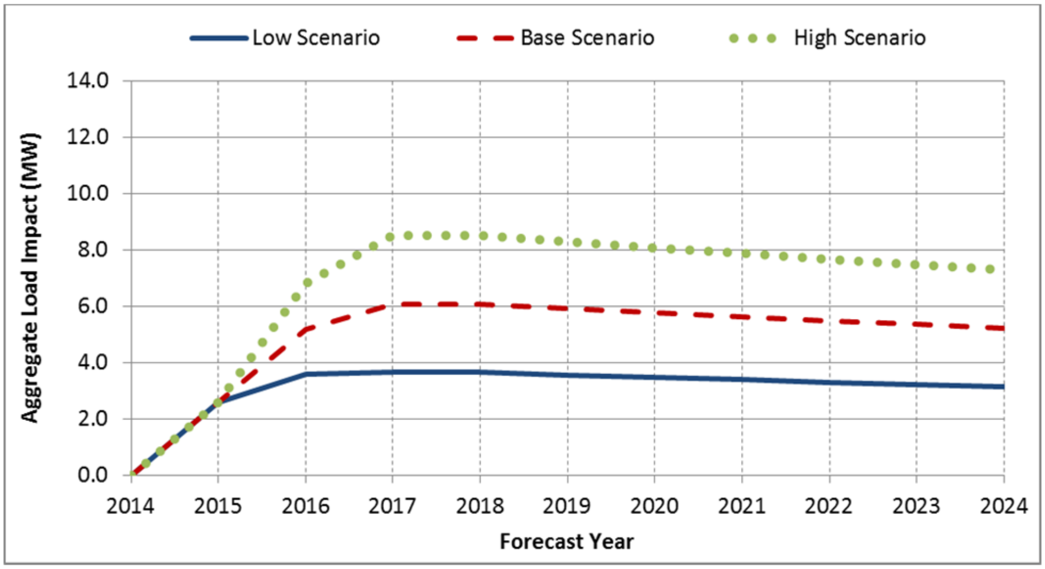


Table 4-8 shows the expected trajectory of load impacts under August 1-in-10 weather conditions from 2015 through 2024 by LCA. Table 4-9 shows the same results for August 1-in-2 conditions. The LA Basin LCA accounts for at least 86% of load impacts throughout the forecast horizon under both 1-in-10 and 1-in-2 weather conditions. As a result of the assumed 2.5% annual degradation in load impacts after year five of each installation, the aggregate load reduction decreases from around 8.4 MW in 2018 under 1-in-10 weather conditions to 7.2 MW in 2024.

Table 4-8: SCE August 1-in-10 Monthly System Peak Day Load Impacts (1-6 PM) by LCA and Forecast Year – Base Scenario

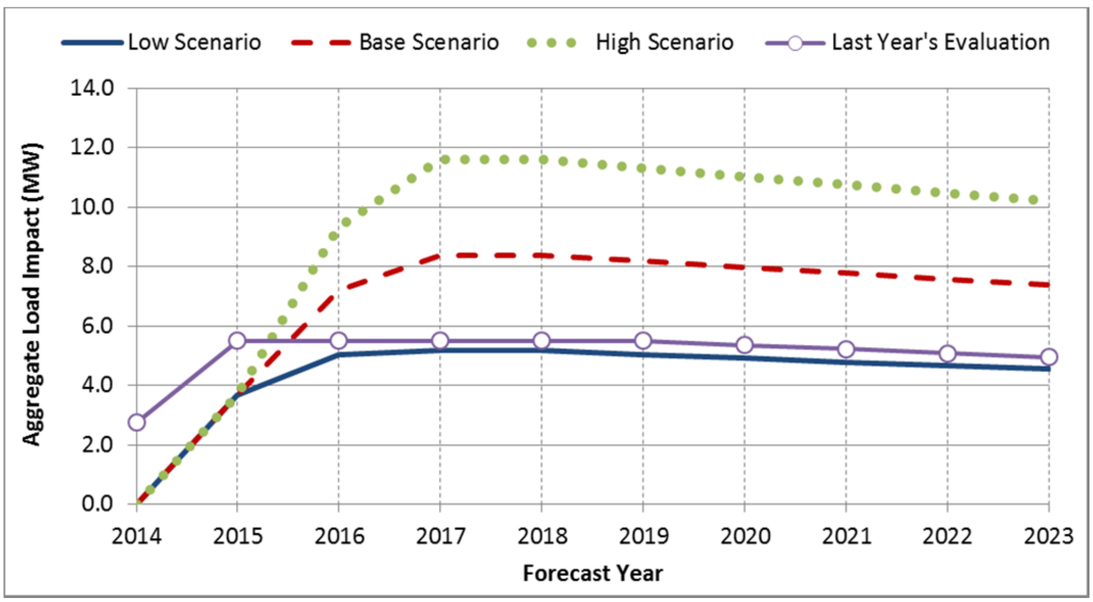
LCA	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
LA Basin	3,656	6,596	7,488	7,488	7,301	7,118	6,940	6,767	6,598	6,433
Outside LA Basin	0	176	265	265	258	252	245	239	233	227
Ventura	0	432	648	648	632	616	601	586	571	557
Total	**3,656**	**7,205**	**8,401**	**8,401**	**8,191**	**7,986**	**7,787**	**7,592**	**7,402**	**7,217**

Table 4-9: SCE August 1-in-2 Monthly System Peak Day Load Impacts (1-6 PM) by LCA and Forecast Year – Base Scenario

LCA	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
LA Basin	2,585	4,664	5,295	5,295	5,162	5,033	4,907	4,785	4,665	4,548
Outside LA Basin	0	175	262	262	256	249	243	237	231	225
Ventura	0	405	608	608	593	578	564	550	536	522
Total	**2,585**	**5,244**	**6,165**	**6,165**	**6,011**	**5,861**	**5,714**	**5,571**	**5,432**	**5,296**

Figure 4-6 compares the ex ante load impact estimates from this evaluation to those from last year's PLS program evaluation, for the August 1-in-10 monthly system peak day. From 2017 onwards, the load impact estimates for the base scenario are roughly 50% higher than those of last year's evaluation. As with PG&E, the main difference in this year's evaluation is that it forecasts projects coming online at a slower pace. This change is based on information from the PLS program applications that SCE has received since the program opened in October 2013. Considering that this information was not available at the time, last year's evaluation forecasted that five projects would come online before June 2014 and that five additional projects would come online by 2015. From 2017 onwards, the 50% increase in impacts is related to modified assumptions regarding the percent of the total PLS program incentive budget that will be spent. Last year's evaluation assumed that 38% of the budget would be spent, whereas this year's evaluation assumes that 65% of the budget will be spend in the base scenario. This change was also based on more recent information on applications that SCE has received so far, and the expected number of additional applications that SCE will receive by the end of 2014. SCE's identified projects already account for 37% of its incentive budget, so the 38% number from last year now seems conservative for the base scenario.

Figure 4-6: SCE Comparison of August 1-in-10 Monthly System Peak Day Load Impacts (1–6 PM) to Base Scenario from Last Year's PLS Program Evaluation



4.3 SDG&E Results

Table 4-10 provides the ex ante load impact estimates for 2015-2024 monthly system peak days in April through October, under 1-in-2 and 1-in-10 weather conditions for the base scenario. SDG&E's service territory only has one LCA, so the results are not divided geographically. In the base scenario, one SDG&E unidentified project comes online in 2015 and another comes online in 2016 along with the identified project that comes online at that time. As such, the 2015 aggregate impacts are attributed to the first unidentified project, and from 2016 onwards, all three projects are included in the forecast. Table 4-10 also shows the expected trajectory of load impacts through 2024. As a result of the assumed 2.5% annual degradation in load impacts after year five of each installation, the aggregate load reduction under August 1-in-10 weather conditions decreases from around 2.2 MW in 2018 to 1.9 MW in 2024.

Table 4-10: SDG&E Ex Ante Load Impact Estimates (1-6 PM) on Monthly Peak Days for April-October 2015-2024 (kW) – Base Scenario

Forecast Year	April		May		June		July		August		September		October	
	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
2015	472	675	378	693	392	399	574	626	518	654	612	759	644	745
2016	1,562	2,233	1,250	2,291	1,296	1,319	1,898	2,071	1,713	2,164	2,025	2,511	2,129	2,465
2017	1,562	2,233	1,250	2,291	1,296	1,319	1,898	2,071	1,713	2,164	2,025	2,511	2,129	2,465
2018	1,562	2,233	1,250	2,291	1,296	1,319	1,898	2,071	1,713	2,164	2,025	2,511	2,129	2,465
2019	1,523	2,177	1,218	2,234	1,264	1,286	1,850	2,020	1,670	2,110	1,974	2,448	2,076	2,403
2020	1,485	2,123	1,188	2,178	1,232	1,254	1,804	1,969	1,628	2,057	1,925	2,387	2,024	2,343
2021	1,448	2,070	1,158	2,124	1,201	1,223	1,759	1,920	1,587	2,006	1,877	2,327	1,973	2,284
2022	1,412	2,018	1,129	2,070	1,171	1,192	1,715	1,872	1,548	1,955	1,830	2,269	1,924	2,227
2023	1,376	1,968	1,101	2,019	1,142	1,162	1,672	1,825	1,509	1,907	1,784	2,212	1,876	2,172
2024	1,342	1,919	1,074	1,968	1,113	1,133	1,630	1,779	1,471	1,859	1,740	2,157	1,829	2,117

Figure 4-7 illustrates how the August 1-in-10 load impact estimates vary by forecast year and scenario. Figure 4-8 shows the same results for August 1-in-2 weather conditions. Across the forecast years and scenarios, the impacts are roughly 26% higher under August 1-in-10 weather conditions. As described in Section 3, the three scenarios correspond to different forecasts of the percent of the total PLS program incentive budget that will be committed by the end of 2016, with 60% assumed under the low scenario, 75% under the base scenario and 90% under the high scenario. We consider these scenarios to be about the best that can be done for estimating the uncertainty associated with these estimates. The estimation method was not statistical in nature and therefore there are no standard errors to report. As a result of this uncertainty, the aggregate load reduction of the program varies. When the aggregate impact peaks in 2016 through 2018 (before the 2.5% annual degradation begins), the PLS program is expected to deliver from 1.7 MW in the low scenario to nearly 2.6 MW in the high scenario, under August 1-in-10 weather conditions. At 2.2 MW, the aggregate impact for the base scenario is in the middle.

Figure 4-7: SDG&E August 1-in-10 Monthly System Peak Day Load Impacts (1–6 PM) by Forecast Year and Scenario

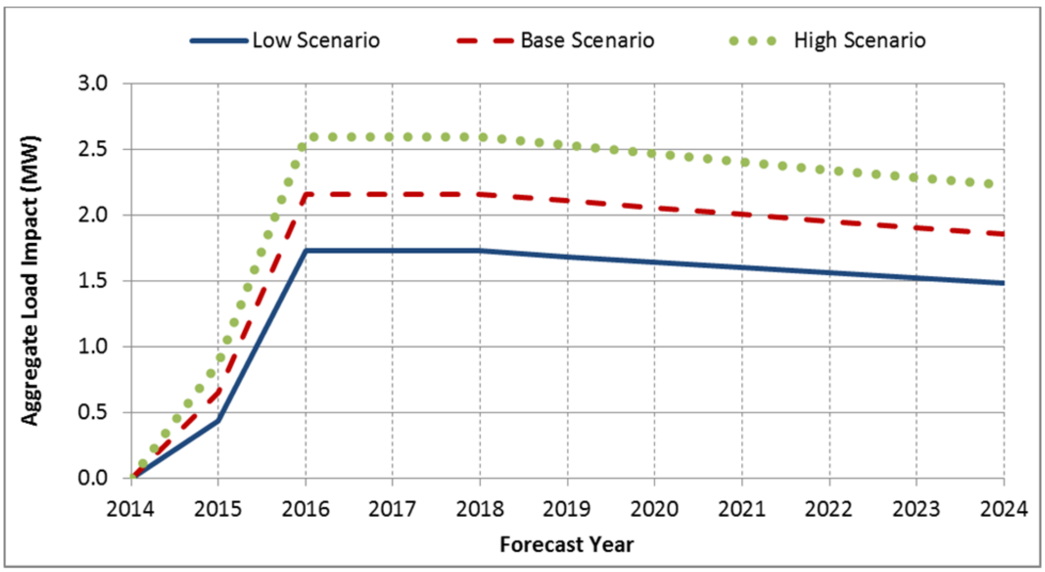


Figure 4-8: SDG&E August 1-in-2 Monthly System Peak Day Load Impacts (1–6 PM) by Forecast Year and Scenario

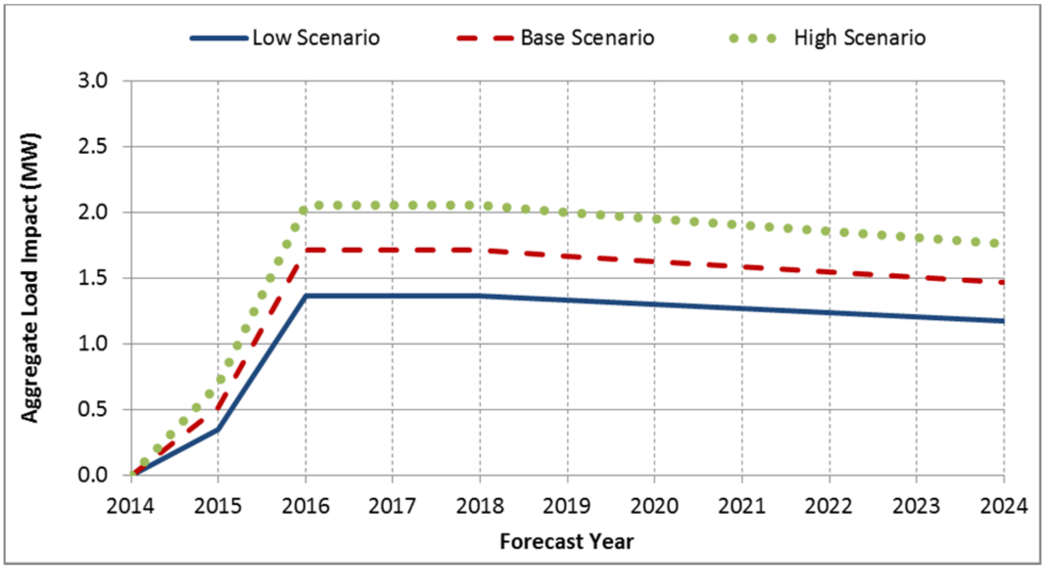
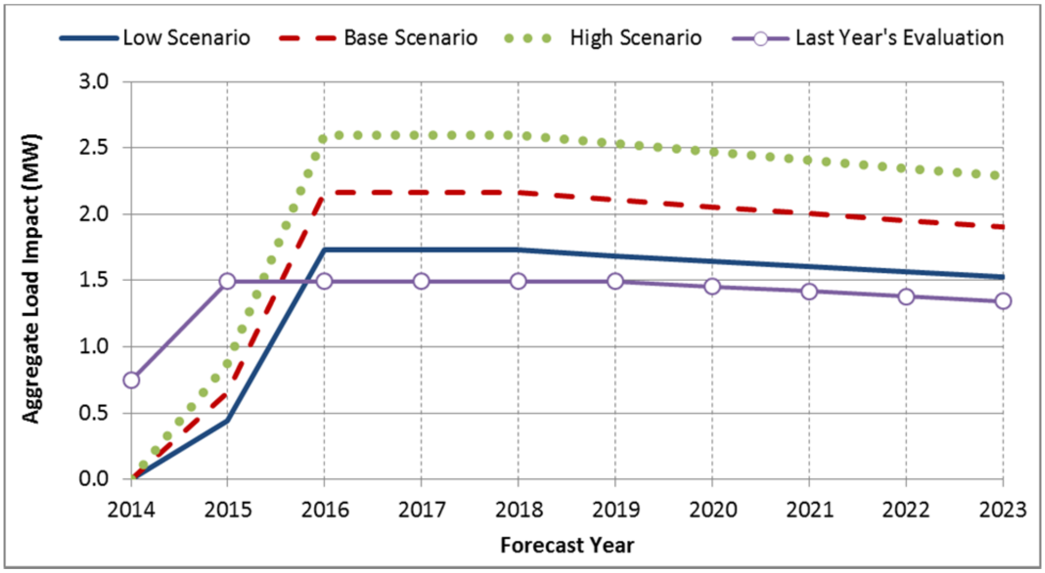


Figure 4-9 compares the ex ante load impact estimates from this evaluation to those from last year's PLS program evaluation, for the August 1-in-10 monthly system peak day. From 2016 onwards, the load impact estimates for the base scenario are 41% to 45% higher than those of last year's evaluation. As with PG&E and SCE, the main difference in this year's evaluation is that it forecasts projects coming online at a slower pace. This change is based on information from the PLS program applications that SDG&E has received since the program opened in October 2013. Considering that this information was not available at the time, last year's evaluation forecasted that two projects would come online before June 2014 and that two additional projects would come online by 2015. From 2016 onwards, the increase in impacts is related to modified assumptions regarding the percent of the total PLS program incentive budget that will be spent. Last year's evaluation assumed that 34% of the budget would be spent, whereas this year's evaluation assumes that 75% of the budget will be spend in the base scenario. This change was also based on more recent information on applications that SDG&E has received so far, and the expected number of additional applications that SDG&E will receive by the end of 2016. SDG&E's identified project already account for 30% of its incentive budget, so the 34% number from last year now seems conservative for the base scenario.

Figure 4-9: SDG&E Comparison of August 1-in-10 Monthly System Peak Day Load Impacts (1–6 PM) to Base Scenario from Last Year's PLS Program Evaluation



5 Recommendations

The main recommendation for future program evaluation is to implement a clear and detailed set of EM&V rules to ensure that the utilities know how much load drop they have received and can expect to receive in the future.

Appendix A Methodology for Developing Ex Ante Conversion Factors

As described in Section 3, the PLS program kW load shift amount represents the peak load shift that can be expected under ASHRAE 2% weather conditions. Therefore, in order to comply with the California DR Load Impact Protocols, this evaluation had to convert the forecasted load shift under ASHRAE 2% weather conditions to the ex ante load impact estimates for monthly system peak days and average weekdays under 1-in-2 and 1-in-10 weather conditions. One key detail to note is that the ASHRAE 2% weather conditions are not specified as 24-hour temperature profiles in the same way that ex ante weather conditions are specified. Instead, they are specified as a temperature threshold that is expected to be exceeded no more than 2% of hours in a given month. They do not correspond to any particular hours of the day. For all unidentified projects and the identified projects for PG&E and SDG&E, Nexant therefore makes the following assumption about how feasibility study engineers will calculate peak shift values for incentive payments – they will choose the hottest month among the ASHRAE 2% conditions for the relevant geography and then assume that the 2% conditions represent the average temperature during the period of 1–6 PM of the peak day, which is then used to simulate cooling load.

The next step is to find peak shift values for ex ante weather conditions that are consistent with the PLS program load shift value, which are based on ASHRAE 2% weather conditions. Nexant began with the assumption that the shifted load that will be measured and verified through PLS represents the full chiller load of all sites under ASHRAE 2% conditions. An alternative possibility is that the system is designed to shift only part of the chiller load under peak conditions. This distinction is referred to as *full versus partial storage*. If the partial storage alternative were true for some sites, then the ex ante impact estimates for cooler weather conditions might be understated because under Nexant's assumption, load shift automatically falls as temperature decreases. Under partial storage, the load shift might be constant over some range of ex ante weather conditions at the hotter end of the conditions. Because Nexant began with the designed peak shift as the main input, and because the designed peak shift takes place under conditions similar to the hottest ex ante conditions, the assumption is unlikely to have a significant effect on the accuracy of load impact estimates under the hottest weather conditions. Additionally, to the degree that it is inaccurate for cooler conditions, it will tend to understate load impacts under those conditions. With this assumption in place, Nexant focused on determining chiller load in a building without being concerned about the possibility that not all of it will be shifted.

To find cooling load values for ex ante weather conditions that are consistent with those for ASHRAE 2% weather conditions, Nexant used Lawrence Berkeley Lab's Demand Response Quick Assessment Tool (DRQAT) interface with EnergyPlus building simulation software. This software allowed Nexant to predict total building cooling load for a chilled water system (including both chiller and fan) based on specified weather conditions, building size, number of stories, orientation (North, South, etc.), number of windows and location. Although Nexant knew all of the relevant weather conditions that loads need to be estimated for, the building characteristics were unknown (because it is not known which customers will enroll).

However, Nexant can demonstrate that not knowing building characteristics does not affect the accuracy of the load impact estimates by noting that the designed peak shift values were used as the main anchor for load impacts. Nexant only used the simulation software to determine what the ratios are between the cooling load under ASHRAE 2% conditions and under the ex ante weather conditions for a given building. At no point in the analysis did Nexant directly use simulation software to estimate the overall level of demand shifting at a given site. These values were assumed in the enrollment forecast. The simulation software was only used to answer questions such as, “if I have a site that provides 100 kW of shifting under ASHRAE 2% conditions, then how much does the same site provide under July 1-in-2 conditions?” The ex ante conversion factors answer this question.

Ideally, we would understand exactly how the building simulation software did its calculations and use that to directly determine whether it is important to understand building characteristics, given that we are only using the tool to determine relative usage values under different conditions. That is not currently a possibility. Nexant provides evidence that it is not necessary to know the building characteristics in Table A-2, which shows that relative usage values across different weather conditions are basically insensitive to building characteristics. The table shows the ratio of average chiller load from 1–6 PM between the indicated temperature profile and August 1-in-10 peak conditions for a variety of building characteristics (which are provided in more detail in Table A-3). The point of the table is that the ratio for a given ex ante condition set hardly changes as the building characteristics vary substantially. For example, the ratio of the average chiller load under September 1-in-10 conditions to the average chiller load under August 1-in-10 conditions only varies from 0.89 to 0.91 whether the building is half its original size or twice its original size, whether it has its original window-to-wall ratio or twice that ratio, or whether it has one story or four stories. This suggests that relative usage levels in the tool are determined primarily by temperature conditions, with the building characteristics driving the overall level of usage. There is only one major deviation from this pattern, under May 1-in-2 conditions, where the values vary from 0.82 to 0.70. Given the uncertainty associated with the other inputs into the estimates, this small inconsistency seems minor.

Table A-2: Conversion Factors for a Variety of Building Characteristics Under Each Set of Ex Ante Peak Weather Conditions

	Baseline*	1 in 2 Typical	1 in 2 May	1 in 2 June	1 in 2 July	1 in 2 August	1 in 2 September	1 in 10 Typical	1 in 10 May	1 in 10 June	1 in 10 July	1 in 10 August	1 in 10 September
Original Building	0.46	0.92	0.80	0.86	0.98	0.92	0.93	0.97	0.90	0.93	1.02	1.00	0.90
Twice the Size	0.48	0.92	0.80	0.87	0.98	0.91	0.95	0.98	0.91	0.95	1.01	1.00	0.91
Half the Size	0.44	0.92	0.82	0.87	0.96	0.92	0.93	0.96	0.90	0.93	1.01	1.00	0.90
Four Floors	0.46	0.92	0.70	0.83	0.99	0.91	0.94	0.96	0.89	0.93	1.02	1.00	0.89
Twice the Window to Wall Ratio	0.45	0.92	0.80	0.87	0.98	0.92	0.93	0.97	0.90	0.93	1.02	1.00	0.90

Ex ante conversion factor = average kWh usage between 1–6 PM divided by average kWh usage during 1–6 PM on a typical August 1-in-10 day.

*Baseline is the default temperature profile on July 1 for California Climate Zone 12 in the DRQAT. It is not a monthly peak day.

Table A-3: Characteristics of Buildings in Table 2-2

Building Type	Footprint (sq. ft)	Stories	Orientation	Window to Wall Ratio				Climate Zone
				North	*East*	*South*	*West*	
Original Building	10,568	1	North	0.16	0.28	0.20	0.23	12
Twice the Size	21,141	1	North	0.16	0.28	0.20	0.23	12
Half the Size	5,329	1	North	0.16	0.28	0.20	0.23	12
Four Floors	10,568	4	North	0.16	0.28	0.20	0.23	12
Twice the Window to Wall Ratio	10,568	1	North	0.32	0.56	0.40	0.46	12

Having established that it is possible to use the DRQAT to determine relative usage levels without regard to the building characteristics, Nexant's process for producing the ex ante conversion factors is as follows.

Nexant found the ratio of chiller load under ex ante weather conditions to chiller load under ASHRAE 2% weather conditions, which varies by weather station within each LCA. Some LCAs have multiple weather stations and in those cases Nexant made assumptions about the percentage of load shift that will be associated with each station. These percentages are based on the number of nonresidential customers that are located within each weather station's area. The Table 2-4 shows those distributional assumptions. For example, within the Northern Coast LCA, 49% of the load impact would come from the customers that are assigned to the Sacramento weather station and 51% would come from customers that are assigned to the Santa Rosa weather station.

Table A-4: Weather Station Assignments

Utility	LCA	Weather Stations Assigned (percentage of assigned load shift in parentheses)
PG&E	Greater Bay Area	Concord (22%), Cupertino (21%), Milpitas (46%), San Ramon (11%)
	Greater Fresno	Fresno (100%)
	Humboldt	Eureka (100%)
	Kern	Bakersfield (100%)
	Northern Coast	Sacramento (49%), Santa Rosa (51%)
	Sierra	Auburn (100%)
	Stockton	Stockton (100%)
	Other	Salinas (100%)
SCE	LA Basin	173 (100%)
	Outside LA Basin	132 (100%)
	Ventura	193 (100%)
SDG&E		Lindberg Field (50%), Miramar (50%)

Nexant took the "Original Building" from Table A-3 and used it as the representative building for determining relative usage levels under different conditions. Nexant then estimated cooling load for that building under the following conditions for each weather station:

- ASHRAE 2% weather conditions;[16] and
- Ex ante weather conditions for each month of the year for system peak day and average weekday for 1-in-2 years and 1-in-10 years.

For both the ASHRAE 2% conditions and the ex ante conditions, Nexant took the DRQAT's baseline conditions as the conditions the day before the forecast. Table A-5 shows the average temperature during the peak period for the ASHRAE 2% weather conditions for each weather station. In general, ASHRAE 2% conditions are fairly similar to August 1-in-10, but may be hotter or cooler in some cases.

Table A-5: ASHRAE 2% Weather Conditions for Each Weather Station

Utility	LCA	Utility Designated Weather Station	ASHRAE Weather Station	August 2% Average 12-6 PM Temperature (*F)	August 1-in-10 Average 12-6 PM Temperature (*F)
PG&E	Greater Bay Area	Concord	Livermore	97	101
	Greater Bay Area	Milpitas	Mountain View/Moffett	83	93
	Greater Bay Area	Cupertino	San Jose Intl	90	95
	Greater Bay Area	San Ramon	Livermore	97	99
	Greater Fresno	Fresno	Fresno Yosemite	103	110
	Humboldt	Eureka	Eureka	67	69
	Kern	Bakersfield	Bakersfield Meadows	103	108
	Northern Coast	Sacramento	Sacramento Met	100	104
	Northern Coast	Santa Rosa	Santa Rosa AWOS	92	92
	Other	Salinas	Salinas Muni	76	73
	Sierra	Auburn	Beale AFB	100	95
	Stockton	Stockton	Stockton Metro	100	103
SCE	LA Basin	173	El Toro MCAS	91	90
	Outside LA	132	Burbank-Glendale-Pasadena	97	102
	Ventura	193	Lancaster	102	99
SDG&E		Lindbergh Field	San Diego Lindbergh Field	82	81
		Miramar	San Diego Miramar NAS	88	87

16 Because ASHRAE does not specify 24-hours of temperatures, Nexant took the ASHRAE entry as the average temperature from 1–6 PM on the peak day. The hourly temperatures were then calculated as the ratio of ASHRAE 2% temperature to August 1-in-10 average temperature from 1–6 PM times each hour's August 1-in-10 temperature. For example, if the ASHRAE 2% condition was a temperature of 100°F and the August 1-in-10 conditions had an average temperature from 1–6 PM of 102°F, then the ASHRAE 2% conditions inputted into the DRQAT would have temperatures equal to the August 1-in-10 conditions multiplied by 100/102 for each hour.

The output from the DRQAT is the estimated chiller load for each hour of the day under each of the above conditions. Since these estimates are for a representative building, they do not necessarily bear any relation to the projected peak shifting values from the enrollment forecast. Nexant then took the ratio of the DRQAT predicted loads under each set of ex ante conditions to the DRQAT predicted loads under the ASHRAE 2% conditions. These ratios were used as the conversion factors described in Section 3. Table A-6 shows these conversion factors for each set of ex ante conditions for each weather station. The table shows that the conversion factors follow the expected pattern, with higher values in the summer and lower in the spring and fall. Also, 1-in-10 conditions almost always have higher ratios than 1-in-2 conditions, as expected.

Table A-6: Summary of Ex Ante Conversion Factors for 1-in-2 and 1-in-10 Monthly System Peak days (Ratios between Peak Usage under Ex Ante Conditions and Peak Usage under ASHRAE 2% Conditions)

Utility	LCA	Weather Station	April		May		June		July		August		September		October	
			1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
PG&E	Greater Bay Area	Concord	0.57	0.77	0.72	1.00	1.03	1.11	1.12	1.14	1.09	1.07	0.72	1.05	0.72	0.99
		Milpitas	0.75	0.91	0.52	1.23	1.47	1.67	1.59	1.60	1.47	1.50	1.16	1.56	1.04	1.09
		Cupertino	0.59	0.67	0.35	0.88	0.91	1.06	0.94	0.99	0.88	0.95	0.67	1.02	0.75	0.73
		San Ramon	0.55	0.73	0.45	0.93	0.97	1.09	1.08	1.07	0.96	1.04	0.93	1.08	0.74	0.94
	Greater Fresno	Fresno	0.57	0.68	0.87	0.96	0.88	0.97	1.04	1.03	0.94	1.08	0.95	0.93	0.73	0.88
	Humboldt	Eureka	0.20	0.37	0.62	0.70	1.08	1.16	0.93	0.87	0.78	1.18	0.62	1.42	0.40	1.65
	Kern	Bakersfield	0.58	0.75	0.86	1.00	0.91	0.97	1.01	0.96	0.91	1.06	0.86	0.98	0.77	0.93
	Northern Coast	Sacramento	0.60	0.69	0.89	1.03	1.00	1.06	1.14	1.16	1.03	1.07	1.05	1.01	0.71	1.00
		Santa Rosa	0.60	0.67	0.42	0.98	1.07	1.13	1.10	1.10	1.06	0.99	0.75	1.06	0.86	0.97
	Other	Salinas	0.62	0.74	0.34	0.79	1.25	2.10	1.12	0.75	1.21	0.88	0.89	0.93	1.02	0.43
	Sierra	Auburn	0.42	0.50	0.76	0.91	0.84	0.95	1.03	1.00	0.92	0.88	1.00	0.98	0.65	1.00
	Stockton	Stockton	0.56	0.69	0.84	0.97	0.97	1.02	1.08	1.10	1.01	1.06	0.98	0.96	0.68	0.94
SCE	LA Basin	173	0.43	1.02	0.58	0.63	0.52	0.69	0.70	0.86	0.70	0.99	0.90	0.77	0.96	0.91
	Outside LA Basin	132	0.79	0.71	0.88	0.98	0.99	1.03	1.01	1.03	1.04	1.05	1.04	1.01	0.75	0.96
	Ventura	193	0.54	0.42	0.74	0.94	0.90	1.01	0.95	0.98	0.91	0.97	0.86	0.92	0.43	0.69
SDG&E		Lindberg Field	0.77	1.03	0.61	1.00	0.59	0.57	0.79	0.90	0.70	0.95	0.69	1.11	0.83	1.18
		Miramar	0.58	0.90	0.47	0.98	0.53	0.57	0.85	0.89	0.78	0.92	1.06	1.06	1.01	0.95