Agricultural Demand Response Study

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ABBREVIATIONS AND ACRONYMS

ADR	Automated demand response
BES	Business Energy Solutions
BIP	Base interruptible program
CBP	Capacity bidding program
DR	Demand response
FSL	Firm service level
PDP	Peak day pricing
PG&E	Pacific Gas and Electric
TRC	Total Resource Cost
UTC	Utility Cost Test
VFD	Variable frequency drive

EXECUTIVE SUMMARY

The agricultural sector in CA represents a substantial portion of peak load[1]: about 1.6 GW during summer peak hours (4 to 9pm). However, this sector is also characterized by uniquely intermittent load patterns associated with seasonal irrigation pumping and process loads that may or may not be available for load reduction dispatch on system peak days. As such, existing programs[2,3] present challenges for agricultural participants because program rules that require nominated load reductions assume that loads will be present for reductions on event days. This research focuses on assessing program design options for structuring compensation and dispatch rules from the lenses of customer preferences, stakeholder preferences, and cost-effectiveness.

PROJECT GOAL

To address the gap in current demand response product offerings, PG&E has undertaken a research study to inform demand response program design for agricultural customers. The research was designed to explore how dispatch rules and of different compensation elements including performance payments, penalties, and guaranteed capacity payments affect expected program participation. The preliminary gap analysis identified that a firm service level approach for quantifying performance, is much better suited to the intermittent loads of the agricultural sector.[3] As such the research focused on structural compensation options and defined performance as the ability to stay below a certain load level, e.g. firm service level. From there, the research was designed to answer the fundamental question: which program configuration (comprised of participation terms, incentive levels, and dispatch rules) will produce the most DR value? The next step will be to pilot test a program design in the field which closely resembles the optimal program configuration.

PROJECT DESCRIPTION

The study focused on quantitative research examining agricultural customer load patterns and program design preferences. In addition, the study was supplemented by qualitative feedback from stakeholders (agricultural technology providers and aggregators) and by benchmarking of utility programs. The quantitative research elements included:

- An analysis of agricultural customer loads, which was used to estimate load patterns and load reduction potential. The load analysis also allowed us to include customer specific values in the conjoint study.

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[1] Specifically, 9% of net system load on peak days

[2] Capacity Bidding Program (CBP)

[3] the existing firm service level program, Baseline Interruptible Program (BIP), is not accessible to many agricultural customers due to its large minimum capacity requirements for eligibility

- A conjoint choice experiment which enabled testing of 108 distinct product designs via a customer survey.

The conjoint experiment produced a choice model that simulated uptake for each design and, once coupled with cost-effectiveness calculations, identified the design that maximized social net benefits. At each step, qualitative insights from benchmarking and interviews with four aggregators and one technology provider informed key research decisions, including the direct response survey design and the conjoint choice experiment design.

PROJECT FINDINGS/RESULTS

The results of the conjoint choice experiment study are fundamentally a reflection of relative customer preferences for some program attributes over others: stronger preferences drive enrollment likelihood. The strongest respondent preferences included:

- Performance-only participation terms (relative to terms with penalties): 3 to 5 fold relative preference, depending on the penalty magnitude
- Earlier notification (24 hour v. 30 minute): 3 fold preference

Preferences within other attributes (incentive level, expected event frequency, or expected event duration) were relatively less pronounced, as summarized in Table 1 along with other key findings for the quantitative key research questions. These findings are based on the conjoint choice experiment study and cost-effectiveness modeling and were focused on quantifying program design preferences and differences between customer segments.

TABLE 1. QUANTITATIVE KEY FINDINGS FOR PROGRAM RESEARCH QUESTIONS

RESEARCH QUESTION	KEY FINDINGS
What is the tradeoff relationship between program incentives and program rules for agricultural customers?	**A performance-only design is preferred three to five fold over a design with penalties**, depending on the penalty magnitude. Given the expected boost to enrollments, a performance-only design is therefore expected to yield greater MW load reduction and greater net benefits than a design with a penalty, even after factoring in assumptions for lower performance with a performance-only design.
How much notice should customers receive before being dispatched?	**Event notification is a key driver of enrollment likelihood, with one day ahead (24 hour) notification strongly preferred to day of (30 min) notification**.
How does the duration and volume of event dispatch impact enrollment likelihood for agricultural customers?	**Event duration and event frequency are not the primary drivers of enrollment likelihood**, though respondents preferred fewer event hours in general. Given that longer and more frequent events also deliver more avoided capacity value, moderate event duration (4 hour) and frequency (12 events) balance net benefits with dispatch flexibility.
Would alternative incentive units ($/hp) resonate better with Ag customers than usage based units ($/kW, $/kWh)?	**Horsepower (hp) is best understood by most agricultural customers**. When discussing peak load, water district customers were most familiar with kilowatts (kW), whereas all other agricultural customers were most familiar with horsepower (hp) as units.

RESEARCH QUESTION	KEY FINDINGS
How do preferences and load reduction potential differ by agricultural segment, e.g., small v. large firm?	**Smaller customers may be able to curtail a larger portion of their peak load**. Program element preferences were directionally similar for small respondents (bottom 20% of peak load) compared to large respondents. The main difference is that small respondents were open to curtail a larger percentage of their peak load. **Tree growers may be most able to curtail load. Barriers may exist for some water district customers**. Nut and fruit tree growers were willing to shift a large portion of their peak load, significantly more than agricultural customers with other activities. In contrast, water/irrigation districts (often very large customers) were most likely to have peak loads that are manually controlled and left on all the time, though this was still a minority.
What program design is likely to deliver the greatest net benefits to PG&E and society?	**A performance-only design with day ahead notification is expected to maximize MW load reduction and net benefits** for PG&E (Utility Cost Test (UCT) perspective) and for society (Total Resource Cost (TRC) perspective). This was based on assessing costs and benefits for 108 design permutations tested.

Customer preferences were combined with cost-effectiveness assumptions to model net benefits for the 108 product configurations tested. Table 2 shows the optimal design that is expected to maximize societal net benefits among the dozens of designs tested. While this optimal program design included a single demand response product, program designs with multiple products were also explored.

TABLE 2: PROGRAM DESIGN EXPECTED TO MAXIMIZE SOCIETAL NET BENEFITS

PROGRAM ATTRIBUTE	OPTIMAL OPTION
Expected event frequency	6 / year
Event duration	4 hours
Notification	24 hour
Participation terms	Performance only
Performance price ($/kWh)	$1.88
Penalty ($/kWh)	N/A

Benchmarking research and in-depth stakeholder interviews also revealed strong preferences for earlier notification and acceptance of the performance price level. Despite the expected customer preference for fewer events, the industry trend has been towards more events to accommodate dispatch flexibility to meet grid reliability and grid economic needs. The customer preference for fewer events was not as pronounced as other program design preferences were. As a result, additional events were incorporated into the final design recommendation. Further, the stakeholder interviews revealed a strong preference for penalties, as well as for regular capacity payments instead of performance-only payments. In contrast, agricultural customers had a strong preference against penalties – they were willing to accept substantially lower incentives to avoid penalties. Because of the critical role of aggregators in particular, their preferences were also considered in the final design recommendation. As a result, the recommended program design includes two different product options, one with and one without a penalty. The options reflect the difference in participation term preferences between customers, who strongly prefer to avoid penalties, and aggregators, who strongly favor the inclusion of penalties, ideally with a capacity payment.

PROJECT RECOMMENDATIONS

The final program design recommendation is summarized in Table 3 along with expected program size and cost-effectiveness outcomes. Note that the cost-effectiveness outcomes and program size estimates are illustrative and essentially assume that respondents would enroll in a comparable program with the same likelihood indicated in the choice experiment. It does not account for more effective program marketing that might accompany a program rollout (and increase uptake) or for the tendency for surveys to somewhat overstate uptake than would be observed in the field.

TABLE 3. RECOMMENDED AGRICULTURAL DEMAND RESPONSE PROGRAM DESIGN

PRODUCT OPTION	PERFORMANCE	CAPACITY+PENALTY	WOULD NOT ENROLL
Expected event frequency	12 / year	12 / year	
Event duration	4 hours	4 hours	
Notification	24 hour	24 hour	
Participation terms	Performance only	Performance + low penalty	
Assumed capacity value ($/kW-yr)	$45	$50	
Capacity payment ($/kW-yr)	N/A	$50	
Performance price ($/kWh)	$0.94[4]	N/A	
Penalty ($/kWh)	N/A	$1.56	
Shares of Preference	52%	31%	17%[5]
Standard Error	7%	7%	5%
Expected Program Size (full enrollment)	Performance	Capacity+Penalty	Program
Expected Participants	366	189	556
Expected MW-yr	11.3	6.2	17.5
Expected MW-yr (subset automated)	8.5	4.4	12.9
Cost-Effectiveness Results			
TRC B/C Ratio	1.2	1.0	1.1

[4] Reflects 100% of an assumed capacity value of $45/kW-year spread across 48 expected annual event hours

[5] Share of customer load that would not enroll in any product

Product Option	Performance	Capacity+Penalty	Would not enroll
UCT B/C Ratio	1.0	0.8	0.9

The qualitative research further addressed considerations for the field pilot such as clarifying eligibility requirements, event forecasting and performance, event limits, and incentive payment frequency. Key recommendations for a potential field pilot are provided in Table 4

Table 4. Qualitative Recommendations to Additional DR Program Research Questions

Research Question	Recommendation
Should both direct and aggregator-enrolled customers be included?	Allow both direct-enrolled and aggregator-enrolled customers to participate in an agricultural DR program.
Should dispatch of technologies be a requirement? If yes, should this program qualify for ADR rebates?	Allow both manual and automated participation for customers without and with technology. Conjoint survey results and a review of PG&E DR enrollment data over the last 10 years data show that agricultural customers have significant interest and can successfully enroll in and participate in DR programs, both manually and automatically.
What would be the event limits?	Set DR event limits based on the total number of hours rather than the number of event days per DR event season and minimize or avoid consecutive event days. Design the program so it can be dispatched locally, by dispatch area (sublap). Thus, any single DR event affects only those customers that are located in the sublap dispatch area rather than all agricultural participants in the territory.
How can agricultural customers provide load forecasts to PG&E?	Given the challenges of forecasting agricultural loads that are intermittent in nature, we propose using a firm service level (FSL) model of participation that does not require forecasting by the customer. Based on agricultural DR programs benchmarking, utilities have not relied on forecasts provided by their agricultural customers and aggregators. These utilities have developed forecasts based on the customer FSL and AMI data.
What method would PG&E use to measure actual performance?	Adopt a FSL approach. Customers are paid when their load is at or below the FSL for the event. The payment amount could be based on the average kW demand for the month within the program hours minus the FSL
For ongoing incentives, with what frequency should (incentives) be paid out?	As an alternative to monthly payments, performance reports could be provided at regular intervals, such as monthly or quarterly, and incentives could be paid once at the end of the season. This option helps reduce the administrative burden of monthly incentive payments while balancing the desire for regular touchpoints and customer engagement.

PG&E is considering doing a field test based on these findings and recommendations and has the opportunity to do a side-by-side test of a penalty-free option (preferred by customers) and an option with capacity payments and penalties (preferred by aggregators). A side-by-side test of these two recommended product configurations would allow PG&E to quantify and compare enrollment rates, load impact performance, and ultimately identify which option delivers the most aggregate load reduction. A randomized control trial implemented by a subcontracted program administrator, in which one of the two products is randomly offered or marketed to potential participants, would ensure that the only difference between the two products would be participation terms. It would be critical that implementation is identical, including customer support and technology offers, and that the only difference between the two products is the incentive mechanism. Ultimately, the design and implementation of a field pilot would need to be carefully planned so that key research questions are addressed.

Key Research Questions and Study Methodology

The research leveraged multiple analyses to address the key research questions. Each analysis was considered holistically in the context of the full body of research. Figure 1 summarizes the quantitative research elements, in red, and the qualitative research elements, in blue. The quantitative elements were led by Demand Side Analytics while the qualitative elements were led by Energy Solutions. The quantitative research elements fed into each other, and, at each step, qualitative insights from benchmarking and aggregator interviews informed key research decisions, including the direct response survey design and the conjoint choice experiment design. The qualitative research was an important lens considered alongside the program design optimization analysis to ultimately inform the program design recommendations that were the culmination of the research process. A methodological overview for each analysis is provided below.

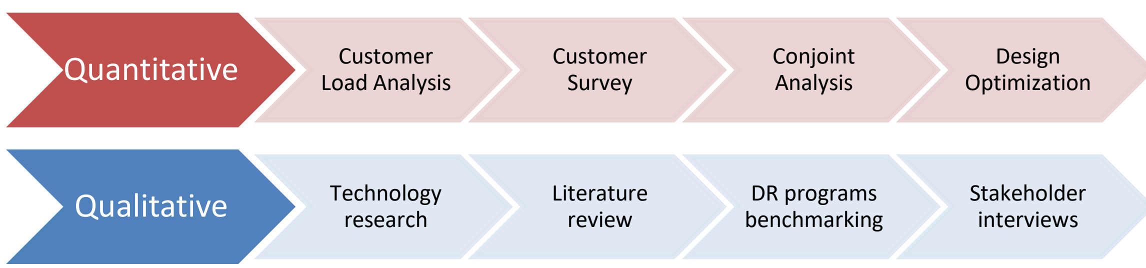


Figure 1. Research Components

Key Research Questions

The quantitative lens for the research study assessed design cost-effectiveness based on a conjoint choice model survey and analysis of agricultural customer peak loads. The qualitative lens included researching agricultural technologies, a demand response benchmarking assessment of agricultural demand response programs at other utilities, a review of selected industry reports on agricultural demand response, and interviews with agricultural technology providers and aggregators.

Quantitative Questions

The conjoint choice model survey and analysis aimed to answer the following research questions:

- What is the tradeoff relationship between program incentives and program rules for agricultural customers?
- How much notice should customers receive before being dispatched?
- How do the timing and volume of event dispatch impact enrollment likelihood for agricultural customers?

- Would alternative incentive units ($/hp) resonate better with Ag customers than usage based units ($/kW, $/kWh)?
- How do preferences and load reduction potential differ by agricultural segment, e.g., small v. large firm?
- What program design is likely to deliver the greatest net benefits to PG&E and to society?

QUALITATIVE QUESTIONS

The DR programs benchmarking assessment, agricultural technologies research, review of industry reports, literature review, and interviews with four aggregators and one technology provider aimed to answer the following research questions as part of additional program design considerations:

- Should both direct and aggregator-enrolled customers be included?
- Are there recommended technologies that should be leveraged?
- Should dispatch of technologies be a requirement? If yes, should this program qualify for ADR rebates?
- What would be the event limits?
- How does PG&E forecast intermittent load and actual performance, and what method would PG&E use to measure customers' and aggregators' actual performance?
- For ongoing incentives, with what frequency should they be paid out?
- What are common obstacles that prevent agricultural customers from joining a DR program?

CUSTOMER LOAD ANALYSIS

Agricultural customer loads were analyzed to help inform the magnitude of potential load reduction for the sector as a whole, and for individual customers. To do this, loads for summer peak hours were summarized for each customer and used for customer survey sampling. These peak load results were further incorporated into the customer survey, which was customized for each respondent, and finally combined with self-reported survey data for the design optimization analysis.

Figure 2 summarizes the process for calculating customer peak loads. Customer peak loads were aggregated based on interval data from 2019 and 2020, which estimated net consumption at the premise level. In order to estimate the total peak load for the customer, net premise loads were first aggregated to the customer level and then converted to gross loads. Gross loads were estimated in order to calculate the total energy that a customer was consuming during the peak period, regardless of any solar generation. Customer peak loads were then calculated based on the customer's 4 to 9pm consumption on PG&E's system peak days in 2019 and 2020.

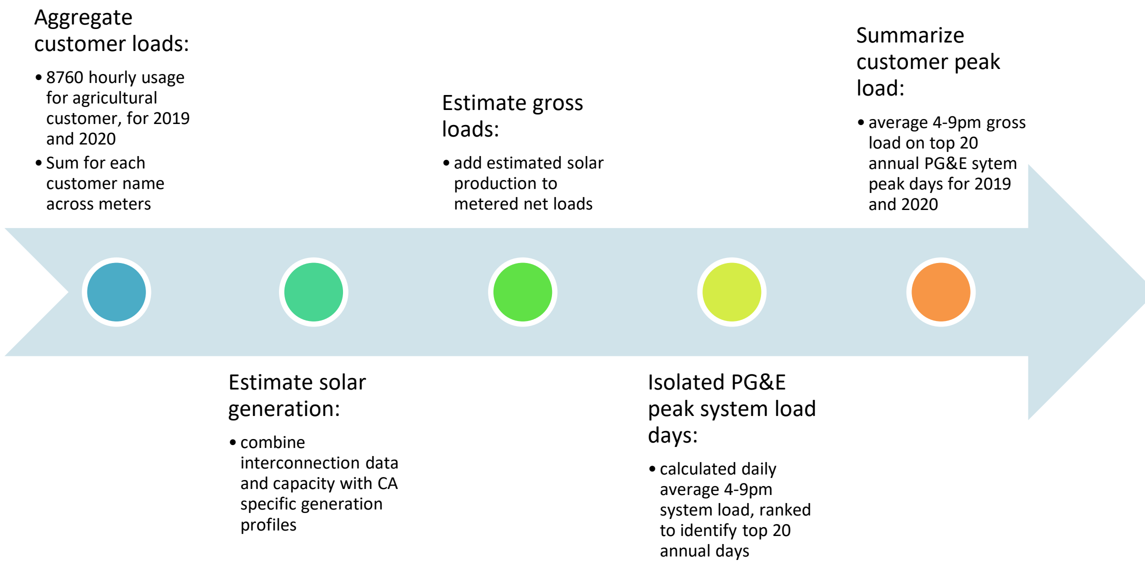


FIGURE 2: GROSS PEAK LOAD CALCULATION STEPS

The load analysis included 146,065 agricultural premises for 43,858 agricultural customers, representing 120,272 accounts and 1,681 MW of peak load. Customers with peak demand below 1 kW, 17,556 customers in total, were excluded from the potential analysis and survey sample. These excluded customers accounted for 4 MW out of the 1,681 total MW.

Customers were segmented into five equal groups (quintiles), each encapsulating 20% of peak load capacity. Thus, each quintile represents 335 MW of the total 1680 MW. The bottom group or "quintile" is comprised of the smallest customers, while the top "quintile" is comprised of the largest customers. As discussed in more detail in Agricultural Customer Load Analysis, the top four quintiles (the top 80% of peak load) represent fewer than 10% of all customers. The customer survey respondent pool was constructed to include all customers in the top four peak load quintiles and a sample of the more numerous customers in the bottom peak load quintile.

CUSTOMER SURVEY

The customer survey was designed to collect information about how agricultural customers operate their loads and their preferences regarding a potential demand response program. As summarized in Figure 3, the survey included six distinct sections, including a conjoint choice experiment exercise which is described in more detail in the following section.

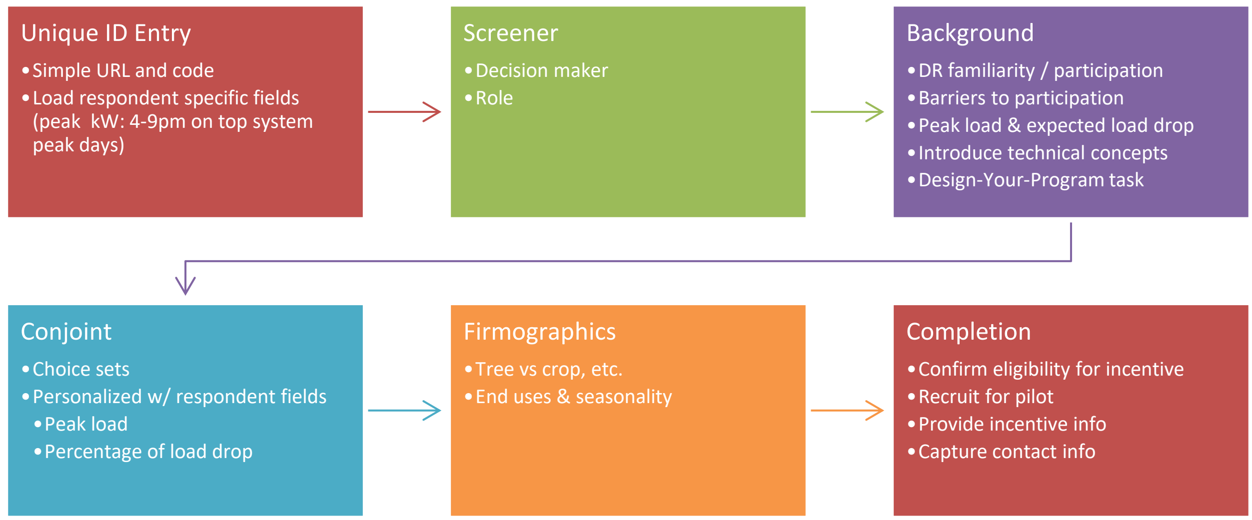


FIGURE 3. DIRECT RESPONSE SURVEY STRUCTURE FLOW

SAMPLING PLAN

The customer survey respondent pool was constructed to include all customers in the top four peak load quintiles and an 8% sample of the more numerous customers in the bottom peak load quintile. This sample was also stratified based on climate zone, past demand response participation, and agricultural activity (NAICS code groupings).

TABLE 5. AGRICULTURAL CUSTOMERS SAMPLED FOR SURVEY PEAK LOAD QUINTILE	CUSTOMER COUNT SAMPLED
Q5 (Top 20% of Capacity)	44
Q4	200
Q3	536
Q2	1,633
Q1 (Bottom 20% of Capacity)	2,014
Total	**4,427**

INCENTIVES

Based on previous experience with the agricultural sector, the research team expected survey completion rates to be low, in part due to the challenge in identifying and contacting the appropriate decision makers. As such, the 4,427 customers invited to complete the survey were offered a $50 e-gift card incentive if they qualified for and completed the survey. To qualify for the survey, invited customers needed to identify themselves as a decision maker on the first survey question.

Fielding Schedule

Figure 4 shows the implementation schedule for the direct response survey. The survey was distributed in two waves: a smaller initial wave of 300 customers for testing purposes and a second, larger, wave that included the remainder of sampled customers. The test wave confirmed that response rates would be low as expected. It also enabled a test of follow up communication methods, by randomly assigning customers in the test wave to receive either a follow-up email or phone call. No significant improvement was observed for the phone call outreach, so the email follow up method was selected for use with the full outreach wave.

Initial outreach for survey fielding consisted of paper mail letters and emails inviting respondents to complete the survey, along with a simple URL and unique access code. As determined in the test wave, the initial outreach was followed by two email reminders, spaced about two weeks apart. Customers in the top four peak load quintiles also received personalized outreach from their assigned Business Energy Services representative. The survey officially closed on July 25 for the smallest load quintile and was kept open an additional two weeks for the top quintiles.

	JUNE					JULY			
	wk1	wk2	wk3	wk4	wk5	wk1	wk2	wk3	wk4
ACQUISITION VEHICLES									
Letter Mailed		6/10		6/21					
Email Invitation		6/10		6/23					
BES Phone call follow up			6/15-6/18				7/1-7/22		
DSA to provide completion data ES to remove completed customers from mailing			6/17			7/7			
2nd Email - Reminder			6/18			7/8			
DSA to provide completion data ES to remove completed customers from mailing				6/28				7/19	
3rd Email - "Last Chance"				6/29				7/20	
Test Cohort: Phone all- "Last Chance"				6/23-6/25				n/a	
Survey Closes								7/25	

Figure 4. Direct Response Survey Fielding Schedule

Survey Completion and Weighting

Figure 5 shows the customer survey completion rates. The survey was entered by 5.2% of the 4,427 invited customers and completed by 3.6% of invited customers, or 75% of qualified respondents. In total, 160 decision-makers completed the survey. The average time to completion was 14.3 minutes.

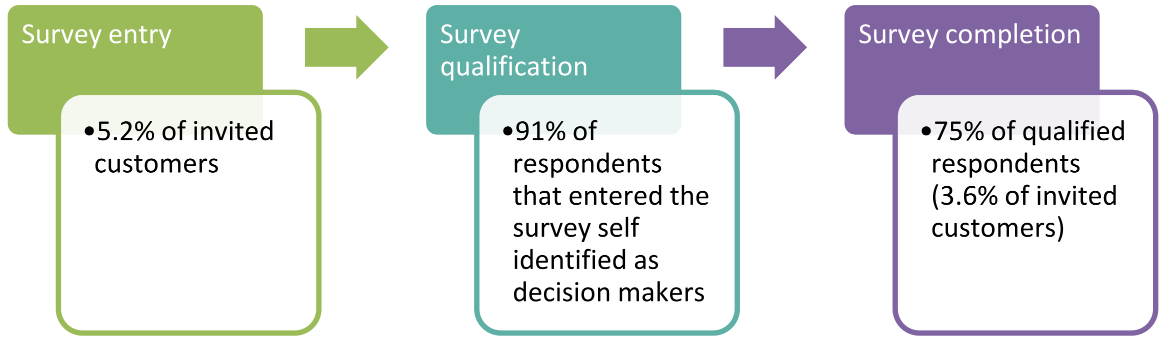


FIGURE 5. CUSTOMER SURVEY RESPONSE AND COMPLETION RATES

As described above, all agricultural customers from the top four peak load quintiles and a sample of the bottom peak load quintile were invited to complete the survey. While completion rates were similar within each quintile, the number of customers and respondents varied substantially. Survey responses were weighted based on peak load quintile so that each quintile was equally represented in the survey results, i.e., so that each peak load quintile represented 20% of the responses.

Table 6 shows the number of respondents in each quintile and associated weights. The weights were calculated by dividing the quintile share of peak load by the share of the survey responses. Quintiles four and five were combined due to the small number of respondents: 14 in the fourth peak load quintile and 1 in the top peak load quintile.

TABLE 6. PEAK LOAD QUINTILE WEIGHTING FOR CUSTOMER SURVEY

QUINTILE	SHARE OF PEAK LOAD	SAMPLE COUNT	SAMPLE %	WEIGHT
Q4 and Q5	40%	15	9%	4.27
Q3	20%	19	12%	1.68
Q2	20%	56	35%	0.57
Q1	20%	70	44%	0.46
All Quintiles	**100**	**160**	**100%**	

CONJOINT CHOICE EXPERIMENT

A conjoint is a choice experiment methodology used to isolate and quantify the influence of individual factors on a decision. It is a commonly used product design tool that essentially enables researchers to model uptake likelihood for each combination of factors tested, without having to test each combination directly. A conjoint experiment is the gold standard for product design and is directly applicable to program design. To conduct a conjoint experiment, the product or program must be distilled into a set of attributes, each with mutually exclusive levels. Each survey respondent is shown a series of choice sets (one per screen) with multiple design configurations (usually with one level defined for each attribute) simulating a real-world choice the respondent might be faced with. Across multiple choice tasks, logistic regression coefficients can be estimated to quantify the respondent's preference for each attribute-level, all else equal. These coefficients form a choice model that can be estimated for each respondent. Using results from all participants, the conjoint produces data for dozens of program feature combinations which can be used to identify the optimal design for defined goals, e.g., to maximize revenue or profit. Background on conjoint parameter estimation, preference share calculations, and statistical significance of these estimates can be found in Appendices A and B.

For this conjoint experiment, the goal was to identify a demand response program design for agricultural customers that would be expected to maximize net societal benefits. This conjoint design tested preferences for five major program attributes: dispatch frequency, event duration, notification timeframe, participation terms, and incentive level. Table 7 shows the attributes and levels tested in the study. Full descriptions can be found in the survey instrument in Appendix D.

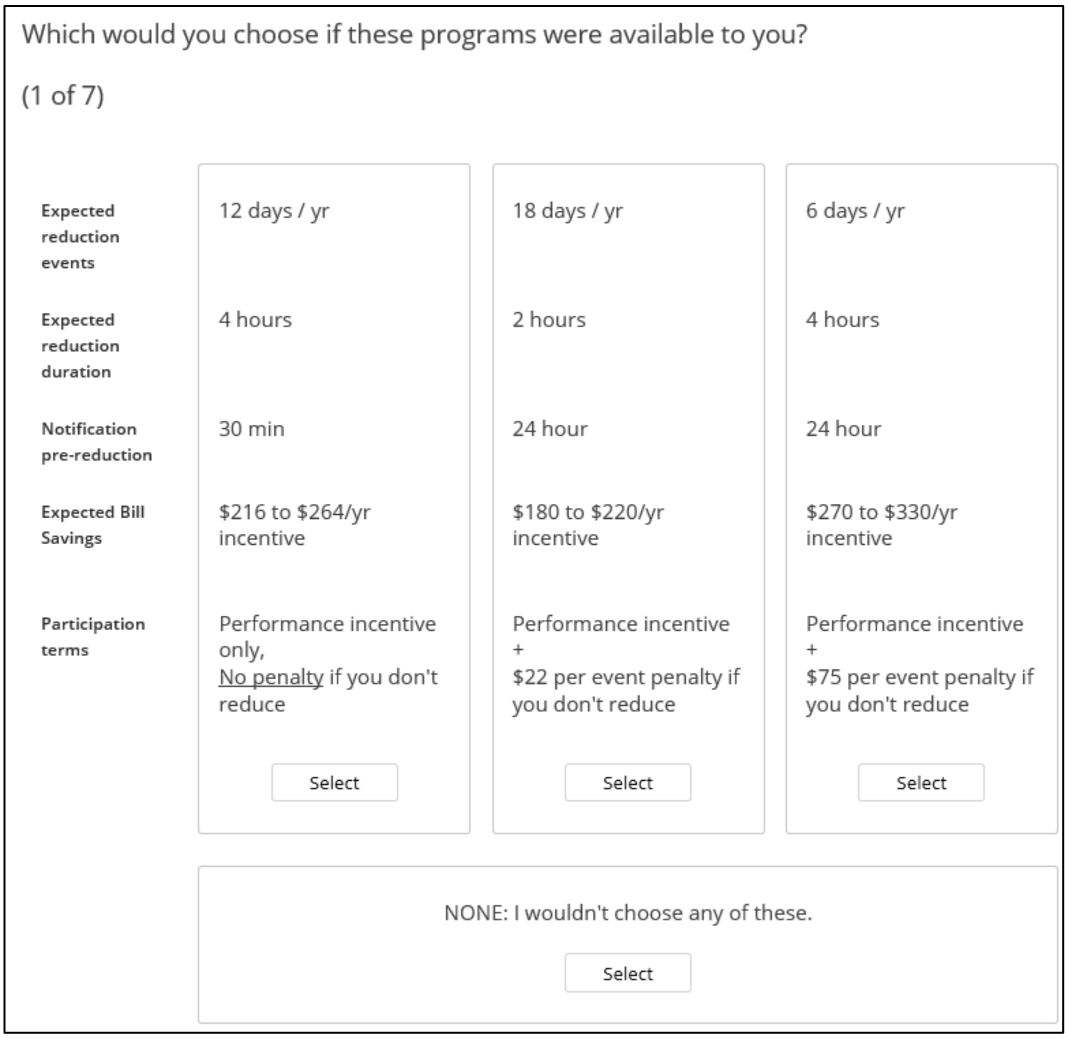
TABLE 7. PROGRAM ATTRIBUTES TESTED BY CONJOINT SURVEY

ATTRIBUTE	LEVEL
Expected Dispatch Frequency	6 events expected per year
	12 events expected per year
	18 events expected per year
Expected Event Duration	2 hours
	4 hours
Notification	24 hours ahead
	30 minutes ahead
Participation Terms	Performance + high penalty
	Performance + low penalty
	Performance only
Expected Bill Savings (Incentive Level[6])	Low: $50/kW-year
	Medium: $75/kW-year
	High: $100/kW-year

Figure 6 shows an example choice task from the survey. The incentive level displayed was personalized for each respondent based on his or her expected load drop. The expected load drop was estimated dynamically in the survey using the

[6] Used to calculate performance price per kWh and penalty. Respondents were not shown capacity prices and the program was clearly described as a firm service level design with performance payments. Values were derated by 40% for the performance only design.

calculated peak load and the share of load the respondent reported could be curtailed during a demand response event. To avoid mental calculations, the survey showed each respondent an expected bill savings value which was a function of the expected average load reduction (in kW) and the incentive level, which was derated by 40% for "performance-only" designs. This was characterized as an average expected savings range, assuming the respondent participated in every event. For designs including a penalty, the penalty was characterized as the cost of not responding to a single event. The underlying calculations for the example are laid out in Table 8.



Which would you choose if these programs were available to you?

(1 of 7)

Expected reduction events	12 days / yr	18 days / yr	6 days / yr
Expected reduction duration	4 hours	2 hours	4 hours
Notification pre-reduction	30 min	24 hour	24 hour
Expected Bill Savings	$216 to $264/yr incentive	$180 to $220/yr incentive	$270 to $330/yr incentive
Participation terms	Performance incentive only, No penalty if you don't reduce	Performance incentive + $22 per event penalty if you don't reduce	Performance incentive + $75 per event penalty if you don't reduce
	Select	Select	Select

NONE: I wouldn't choose any of these.

Select

FIGURE 6. SAMPLE CONJOINT CHOICE TASK

TABLE 8: CALCULATIONS FOR SAMPLE CONJOINT TASK

COMPONENT TYPE	DESCRIPTION	NOTES	OPTION A	OPTION B	OPTION C
Respondent specific input	Respondent expected reduction (kW-year)	peak load (5 kW) * % of load curtailable (80%)	4	4	4
Product configuration inputs	Capacity level ($/kW-year)	$50=low, $75=med, $100=high	$100	$50	$75
	Capacity multiplier	1=performance + penalty, 0.6 = performance only	0.6	1	1
	Expected events		12	18	6
	Penalty multiplier	0=None, 1.5=low, 2=high	0	2	1.5
Interim Calculations	Payment uncertainty	Plus or minus	10%	10%	10%
	Assumed capacity value ($/kW-year)	capacity level * capacity multiplier	$60	$50	$75
	Expected annual savings ($/year)	assumed capacity value * expected load reduction	$240	$200	$300
Values Displayed	Low annual savings ($/year)	expected annual savings * (1-uncertainty)	$216	$180	$270
	High annual savings ($/year)	expected annual savings * (1+uncertainty)	$264	$220	$330
	penalty ($/event)	Expected annual savings / expected events * penalty multiplier	$0	$22	$75

BENCHMARKING RESEARCH AND STAKEHOLDER INTERVIEWS

The research team conducted benchmarking research on agricultural DR programs offered in the U.S. as well as agricultural controls technologies available for automated demand response. For the DR programs benchmarking, staff collected information from program websites and available evaluation studies from seven utilities and conducted telephone interviews of five DR program managers in March and April, 2021. Six of the DR programs reviewed were agricultural specific and one was a non-residential program that included agricultural participants. Interviews with the DR program managers from the following utilities were also completed:

- Southern California Edison
- Entergy Arkansas
- Pacific Power Oregon
- Idaho Power
- NV Energy

For the agriculture technologies benchmarking, the research team surveyed irrigation and non-irrigation technologies. Staff reviewed websites of 19 irrigation control products and 16 non-irrigation controls products. The team reached out to 12 manufacturers for phone interviews and completed four interviews in June. Review of 19 agriculture technology reports supplemented the benchmarking and research effort.

The objective of the interviews with stakeholders was to collect market input on proposed agriculture program designs. Staff engaged in multiple conversations throughout the study with three stakeholders who provide agricultural technology. During the benchmarking stage, the stakeholders shared challenges and learnings from past DR implementation experience. Stakeholders were also invited to provide feedback to the conjoint survey design and reviewed a draft of the survey questions in May 2021. Preliminary program design results were also shared with the stakeholders to provide feedback on the program design recommendations in July 2021.

AGRICULTURAL SECTOR OPERATIONS AND TECHNOLOGIES

This section provides an overview of intermittent agricultural operations in California that can be targeted for demand response and discusses the technologies that can be leveraged for automated participation. The objective is to explore the select agricultural operations, their applicable crop types, associated peak seasons, and technologies. Also of interest is whether each operational activity is used by current or potential agricultural demand response customers. The scope is limited to intermittent load operations and focuses on two major categories of agricultural operations and their associated technologies: irrigation and non-irrigation. For each technology category, we describe related products, key technology features, and potential for demand response participation. We also discuss different market actors who work with agricultural customers to provide energy management services and information.

The irrigation and non-irrigation technologies are shown in Figure 7, along with the technology subcategories. Our research included identifying key companies in the technology subcategories as well as their products. We discuss the research and findings for each category below.

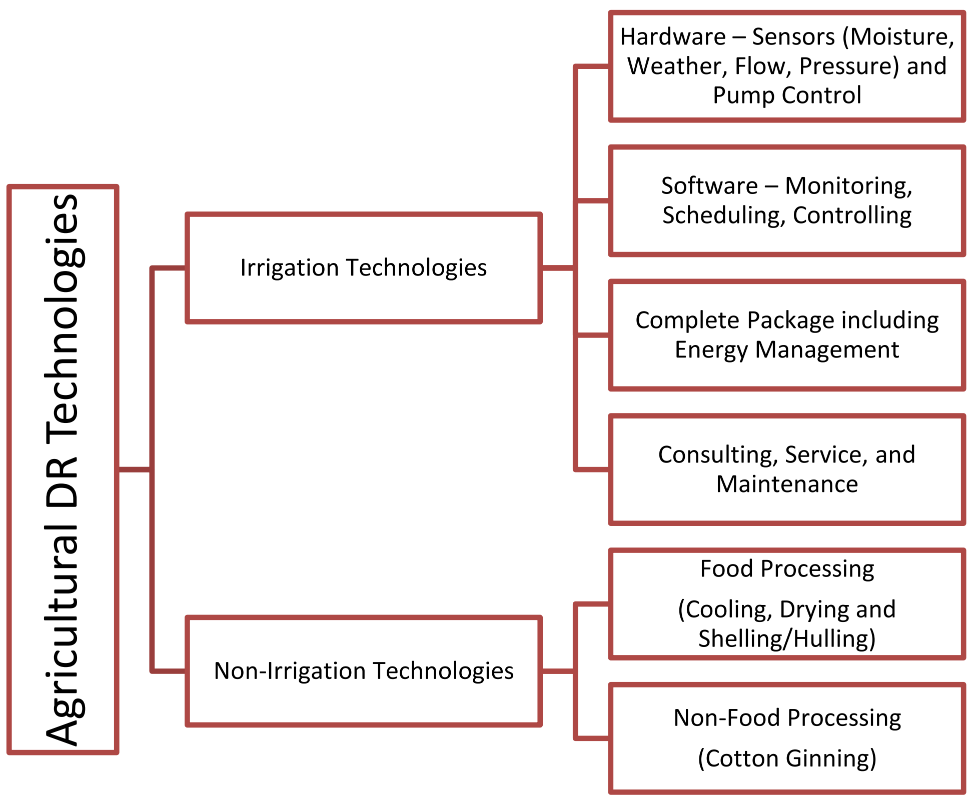


FIGURE 7. AGRICULTURE TECHNOLOGY RESEARCH, TECHNOLOGY CATEGORIES

IRRIGATION TECHNOLOGIES

Irrigation technologies were categorized into four additional subcategories: hardware only, software only, hardware and software with energy management services, and consulting services companies, shown in Figure 7. In the irrigation technologies category, the team identified 28 irrigation products from 12 companies working in the agriculture industry. Table 25 in Appendix G provides full details on these companies and their products. The table does not contain an exhaustive list of all the products offered by each company; rather, they show high level information on the main products. Five companies we reviewed do not offer any controls products. Only one company offers a Software-as-a-Service (SaaS) subscription but does not sell any hardware, software or network products. Almost all the products have remote communication capabilities. Seven companies have technology that can monitor pumps remotely and provide energy management features. Eight companies do not have any products that offer remote irrigation control. Three companies provide irrigation and pump scheduling. Note that some companies offer products that are compatible with other company products in addition to their own products. For example, a software product company would partner with a hardware company or a complete package company to provide a comprehensive solution for a grower. Note also that soil moisture and plant moisture sensors by themselves are insufficient without weather-based forecasting and education for the growers to implement demand control strategies.

While existing demand response program participation by growers has mostly targeted irrigation pumping-related controls, there is opportunity to further increase this participation. Dieter et al. (2018) indicated more than 70% of California irrigation water demand is met by groundwater. Per Olsen et.al (2015), estimated 1,200 megawatts (MW) as the peak day electrical demand for pumping water for agricultural irrigation in California. This is 2.5% of the total California peak load as estimated by the California Energy Commission. According to House (2007), agricultural pumping is almost 60% of water supply-related peak day electrical demand with the majority (80%) of this demand in Pacific Gas and Electric territory.

Surface and drip irrigation pumps have less load flexibility than well pumps because these systems are designed to run long hours. On hot days, they must run 24 hours; therefore, they have less flexibility to be turned off. Relatedly, growers whose crops can tolerate lower irrigation capacity temporarily (e.g., nuts and other tree crops) have more flexibility for pump irrigation control. According to (FAO, n.d.), water requirements vary by the growing phase of the crop. A mature crop has the highest watering needs. Some fully grown crops such as beans, eggplants, peas, and fruit and nut trees demand more water during peak months. For fresh-harvested crops like leafy vegetables, the water requirement remains the same during mid-season and late-season. For dry-harvested crops such as maize, no irrigation or less irrigation is required late in the season. The grower should select a technology solution that fits their irrigation method and the crops being grown/harvested. The demand shed potential for peak demand wet harvesting is much higher compared to dry harvesting (FAO, n.d.).

While almost all farms have some sort of water scheduling, most irrigation practices are not based on data-driven applications of soil and crop science or the use of technology. According to NASS (2019), 15% of the total 134,363 responses showed some sort of science-based irrigation schedule was used for farm irrigation. The computer simulation method was adopted by only one percent. The remaining 85% of the responses included one or more non-scientific methods such as the conditions of the crop, feel of soil, supplier schedule, personal calendar schedule, neighbors' irrigation schedule, and commercial or government schedule. This survey shows there are a lot of opportunities for load-shedding if growers use science-based scheduling and upgrade their irrigation control system to turn off the irrigation pumps during peak times and shift irrigation to off-peak hours.

As highlighted by Boman et al. (n.d.), additional parameters of pump technologies include mode of operation (manual or automated), type of pump (constant speed or variable speed), number of pumps (single or multiple), remote or on-site control, compatibility of pumps with generic sensors, and control platforms. Automated pump controls make it convenient for growers to participate in demand response. Pumps are installed many miles from each other, and without remote control, growers can spend 2 to 4 hours just driving to a single pump to turn it off. Although not required for automated demand response participation, remote soft start for pumps as stated by Price (2019), is beneficial to have because the feature helps growers minimize potential damage to the irrigation system from excess line pressure. If the irrigation pump system has constant speed pumps, turning pumps off will suffice as the demand response strategy. However, if turning off the pumps is not an option, variable frequency drives (VFDs) offer more flexibility (Aghajanzadeh 2019) to reduce load during peak periods by reducing peak time pumping and instead pumping more during off-peak times. Since the water requirement varies for different crops at different growth stages, sequencing pump operation and controlling pump speed offer greater demand savings for systems with multiple pumps.

On-site reservoir storage is a strategy for load shifting by pumping water from deep wells during off-peak periods. The water is stored in an on-site reservoir and then distributed to crops during peak periods using smaller (lower power) pumps. This strategy could be effective for the Central Valley region since the majority of the water supplied serves agriculture farms as identified by Johnson et al. (2015).

NON-IRRIGATION TECHNOLOGIES

In the non-irrigation technologies category, the research team looked at four categories of post-harvest, non-irrigation technologies: pre-cooling, drying, and nut hulling and shelling which are related to food processing, and cotton ginning which is not related to food processing (see Figure 7). The team identified 15 products from 7 companies working in the food-processing industry. Table 26 in Appendix G provides full details of these companies and their products. The table provides high-level information on the main products but do not contain an exhaustive list of all the products offered by each company. Three companies provide controls for both new and retrofit installations. Almost all the companies provide some sort of automation capabilities. Most of the non-irrigation processes already have advanced monitoring and controls to track throughput, yield, and energy. However, it is not known whether load shedding is included or is capable of being integrated into these automation systems since none of the manufacturers identify load shedding in their product specification documents. The team contacted eight non-irrigation manufacturers and secured an interview with just one. Further investigation is required to understand the key factors.

According to Navigant Consulting (2013), Between 1963 and 2011, the number of cotton gins in the state has declined from 300 to 30. According to Navigant Consulting (2013), Between 1963 and 2011, the number of cotton gins in the state has declined from 300 to 30. Cotton ginning activity doesn't start until October, during harvesting season. For a farm owner, energy is the second highest cost in post-harvest food. The rest of this section therefore focuses on discussion of post-harvest food processing.

According to the NASS (2020) survey, almonds (12.3%), grapes (8.3%), pistachios (3.7%), walnuts (3.7%), rice (5%), and cotton contribute to more than 40% of the harvested acres (10.1 million acres) in California. Another article by Johnson et al. (2015) mentions that these products are also harvested in more than 50% of the irrigated acres. Over time, the acreage trend has shifted from low-value crops such as rice to more permanent, high-value crops such as orchards (e.g., nut trees). The orchard crops cannot be fallowed in dry years. As such, the potential for demand response through irrigation and non-irrigation technologies is higher for these crops. The team focused its research on irrigation and post-processing technologies for these crop types.

Post-harvest food processing activities include crop cleaning, sun drying, shelling, fumigating, curing, sorting, grading, packing, and cooling as defined in Center for Food Safety and Applied, Nutrition (CFSAN) (2016). Cooling and drying activities are needed for fresh market fruits and vegetables to prepare them for shipment and storage. All cooling activities demand high peak electricity loads and require significant hours of operation. Any delay in quickly cooling products can result in quality deterioration. Because of this, companies in this segment are unlikely to entertain delaying cooling to reduce peak period electricity use. Mobile trailer units that provide on-farm product pre-cooling are major energy users, as these units refrigerate products in the field in preparation for transport to centralized cold storage facilities. However, these units typically supply their own power and do not plug into the farm's power. As such mobile pre-cooling does not present a significant source of DR potential.

Drying processing has low potential for demand response since it uses mostly natural gas energy. Based on a Navigant Consulting (2013) report, 85% of consumption from drying was from natural gas. The report also mentions that only 10% of total electricity used for post-harvest processing was for drying.

Post-harvest nut processing including shelling and nut hulling offer DR opportunities to be further explored. A report by Navigant (2013) indicates that post-harvest food processing constitutes the second largest electricity consumption of any agricultural market segment in the California IOU service territories, totaling 15% of all electricity consumption in the agricultural sector. California is the largest almond producer in the world and is the only place in North America that grows almonds commercially. The Almond Board of California (2016) states that more than 450,000 acres in the San Joaquin and Sacramento valleys are used for almond cultivation. The harvest season for almonds runs from late August to early November, which aligns well with the DR season from May through October.

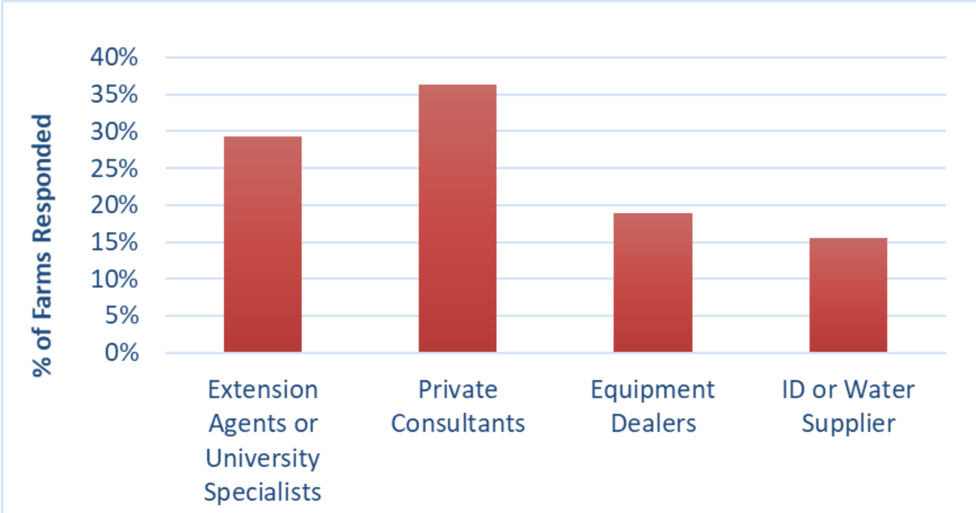


FIGURE 8. SOURCES OF COST REDUCTION INFORMATION FOR AGRICULTURAL CUSTOMERS

Finally the technology research looked into the various market actors who provide operating cost (water and energy) savings and education to agricultural customers (Figure 8). Based on NASS (2019), only 20% of the survey responses identified equipment dealers as the source of information. Other information sources included private consultants (36%) and extension agents or university specialists (29%). The least consulted sources are the irrigation districts (ID) at 15%.

AGRICULTURAL CUSTOMER LOAD ANALYSIS

As described in the previous section, agricultural loads in general are primarily driven by irrigation technologies, but there are also other potentially curtailable technologies. PG&E agricultural customer loads were analyzed to quantify these loads and assess how agricultural loads contribute to system peak, and which could be potentially valuable demand resources. An important first step to assessing the potential for load reduction is to identify what loads are present during peak hours (4-9pm summer system peak load days), with the understanding that only a subset of total loads will be available for curtailment. Agricultural sector loads were analyzed to quantify this peak load and how it varied across customer, geography, and segment. This is a key input to estimating load reduction opportunity as well as targeting customers with greater potential.

AGRICULTURAL PEAK LOAD CHARACTERISTICS

For the load analysis, peak demand is defined as estimated gross average customer peak load during the 20 highest PG&E system load days in both 2019 and in 2020[7]. Estimated customer gross loads were calculated by adding estimated solar consumption to the net load. Because customers can have multiple meters, loads were summed across meters for each customer name. Average peak load capacity is the average load during peak hours (4-9pm). The highest PG&E system load days were chosen based on average system load during peak hours.

Customers were segmented into five equal groups (quintiles), each encapsulating 20% of the total 1,677 MW peak load capacity analyzed. Thus, each quintile represents 335 MW of the total 1680 MW. **Error! Reference source not found.** s hows the percentage of customers by quintile. The bottom group or "quintile" (Q1) is comprised of the smallest customers, while the top "quintile" (Q5) is comprised of the largest customers. As shown in **Error! Reference source not found.**9, the top f our quintiles (the top 80% of peak load) represent fewer than 10% of all customers. For the analysis, the top four quintiles were analyzed together as "large" customers, and the smallest quintile is referred to as "small" customers. Over 90% of customers included in the load analysis were small customers.

As described in Key Research Questions and Study Methodology, the survey sample included all customers in the top four quintiles, which represent 20% of customers but 80% of load reduction potential, and a subset of customers from the bottom quintile.

[7] Days were ranked based on their average load from 4 to 9pm

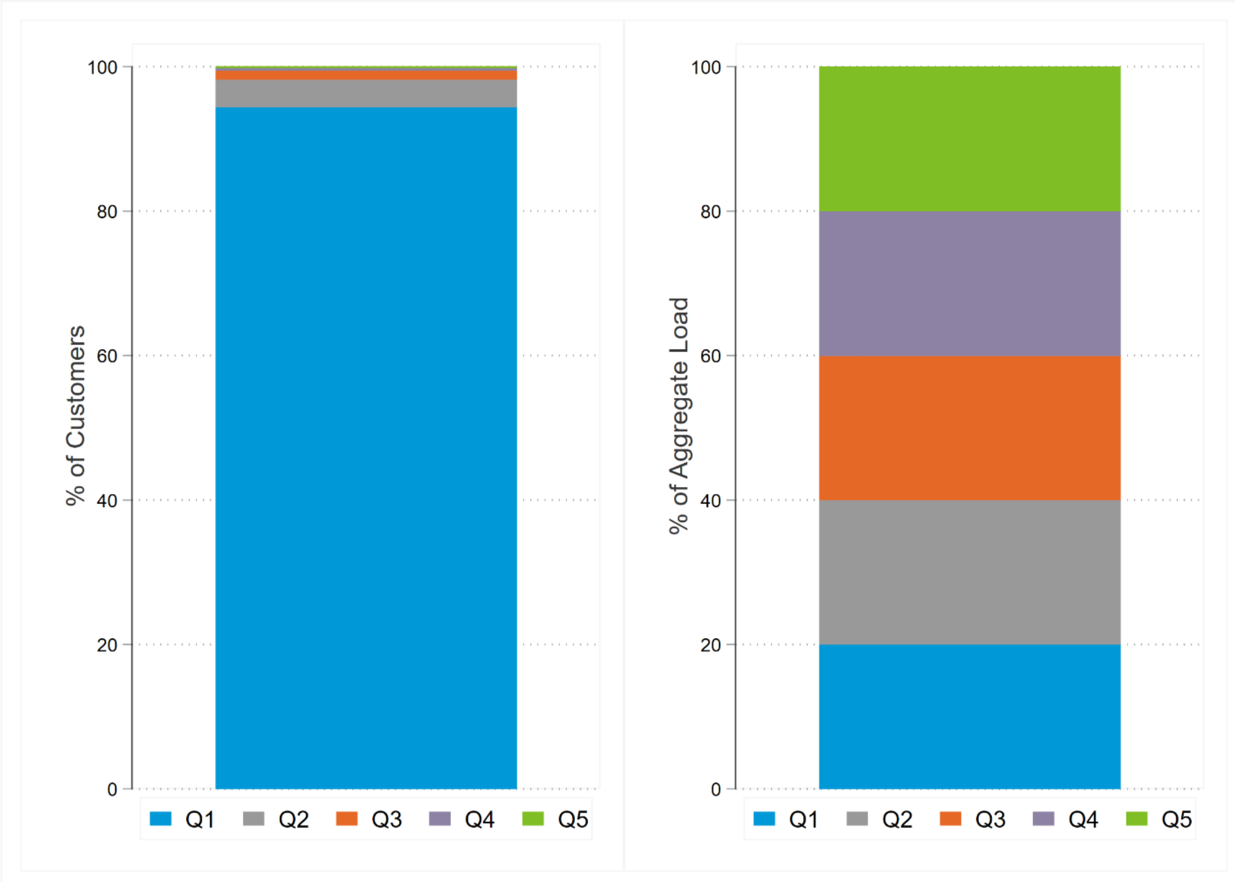


FIGURE 9. SHARE OF CUSTOMERS BY CONTRIBUTION OF PEAK LOAD (PEAK LOAD QUINTILES)

Figure 10 illustrates the aggregate hourly load profile for agricultural customers on the average PG&E system peak day[8].In practice, only a subset of this peak load is available for potential curtailment. In the agricultural sector, demand is highest in the morning, from approximately 7am to 12pm. This peak period is earlier in the day compared to PG&E system load, which peaks between 4pm and 9pm. However, there is also a significant amount of peak load in the agricultural sector from 4-9pm.

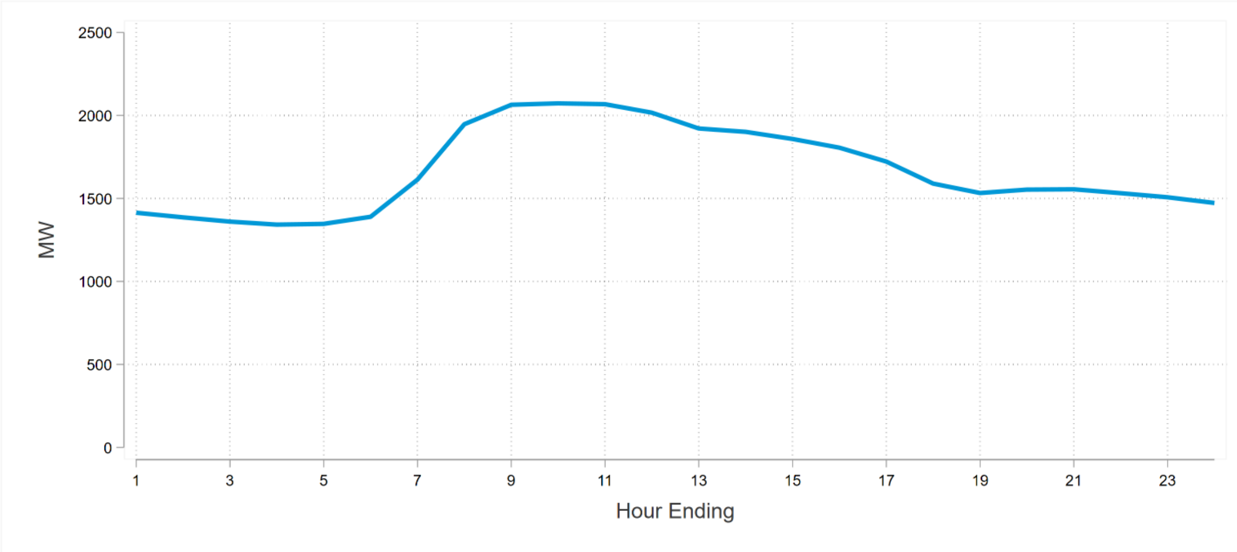


FIGURE 10. AGRICULTURAL SECTOR PEAK LOAD BY TIME OF DAY

Figure 11 shows the agricultural sector's average peak day load shape compared to PG&E's average system peak day load. As previously mentioned, the agricultural sector's daily peak does not align with the system peak, indicating that different causal mechanisms affect peak load in the agricultural sector than affect peak load in the residential and industrial sectors. Importantly, however, agricultural load still accounts for about 9% of the system load during peak hours.

[8] The "average system peak day" is the average of the 20 highest PG&E system load days in both 2019 and the 20 highest PG&E system load days in 2020.

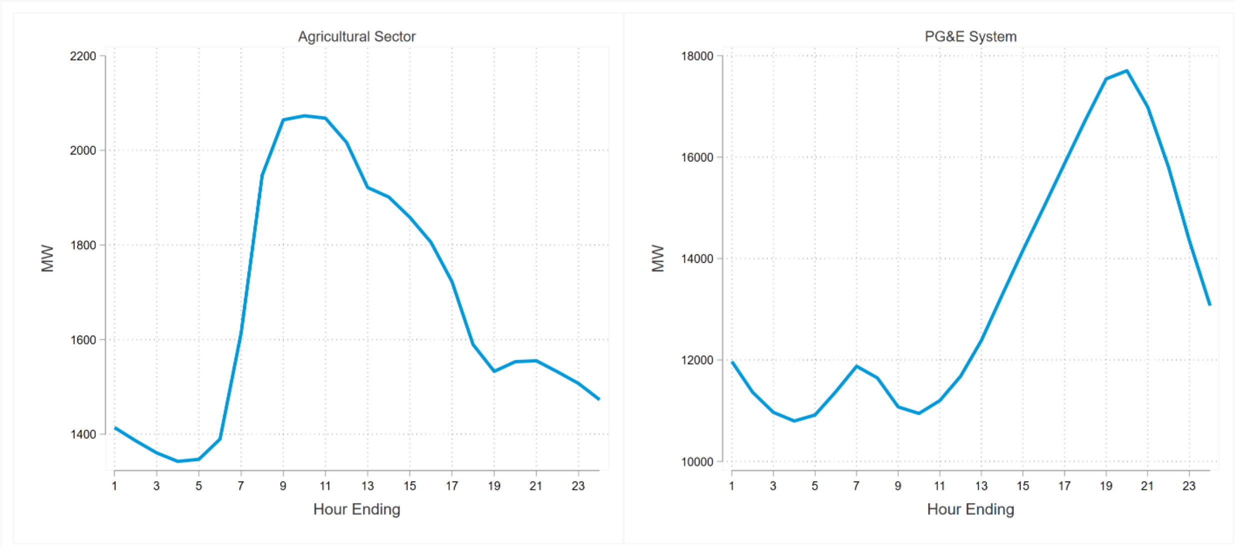


FIGURE 11. PG&E SYSTEM PEAK DAY LOAD V. AGRICULTURAL SECTOR PEAK DAY LOAD

Figure 12 shows the average 4-9pm weekday load (left panel) and aggregate monthly energy usage (right panel) for the agricultural sector in PG&E territory. This demonstrates that both load and usage are concentrated in the early summer months, peaking in July and corresponding with times when irrigation needs are highest.

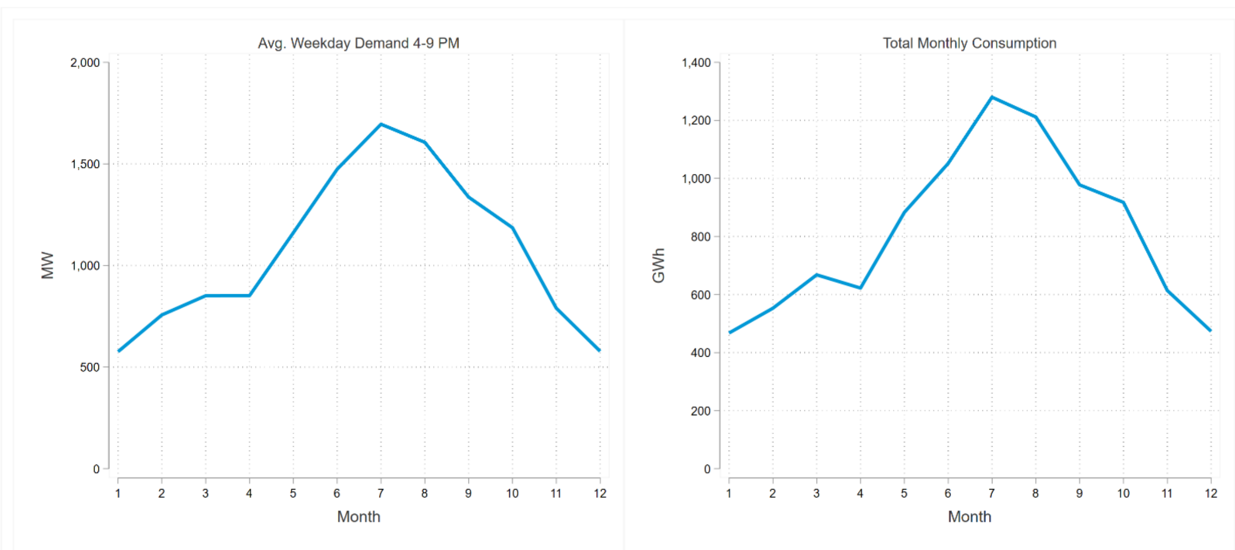


FIGURE 12: AGRICULTURAL SECTOR AGGREGATE PEAK LOAD BY MONTH

AGRICULTURAL LOAD DISTRIBUTION BY SEGMENT AND GEOGRAPHY

Table 9 shows peak load characteristics by agricultural industry. Industries included in "Other/Unclassified" are agricultural support, warehousing, food wholesale, and unspecified industries. Irrigation, vineyards, nut trees, and other crops are the most common agricultural sectors by customer count. Other crops, nut trees, and water districts have the highest aggregate coincident load levels as well as the customers with the largest average customer coincident peak demand. Notably, water districts[9] have the highest average customer peak demand by far at 520 kW.

TABLE 9. PEAK LOAD BY AGRICULTURAL INDUSTRY

AG INDUSTRY	# OF CUSTOMERS	AGGREGATE COINCIDENT (MW), 4-9 PM	AVERAGE CUSTOMER COINCIDENT DEMAND (KW), 4-9 PM
Dairy	3,243	147	45
Fruit Trees	1,865	58	31
Irrigation	7103	14	2
Nut Trees	3,996	261	65
Other Crop	3,932	302	77
Other/Unclassified	17,998	477	26
Vineyard	5,283	194	37
Water District	438	228	520
Total	**43,858**	**1,681**	**38**

Figure 13 shows the peak demand from 4-9 PM for the top 20 PG&E system load days for 2019 and for 2020 by zip code. The Fresno area and Bakersfield area include zip codes with the highest load levels. The top 5 zip codes, with peak load levels greater than 1,000 MW, were:

- 93637 (Madera County)
- 93280 (Kern County)
- 93249 (Kern County)
- 93610 (Madera County)
- 93263 (Kern County)

[9] Water Districts are defined as agricultural customers within the "Water District/Irrigation" agricultural sector who have average peak demand of at least 35 kW. This cutoff was used based on PG&E's "Electric Schedule Ag-5".

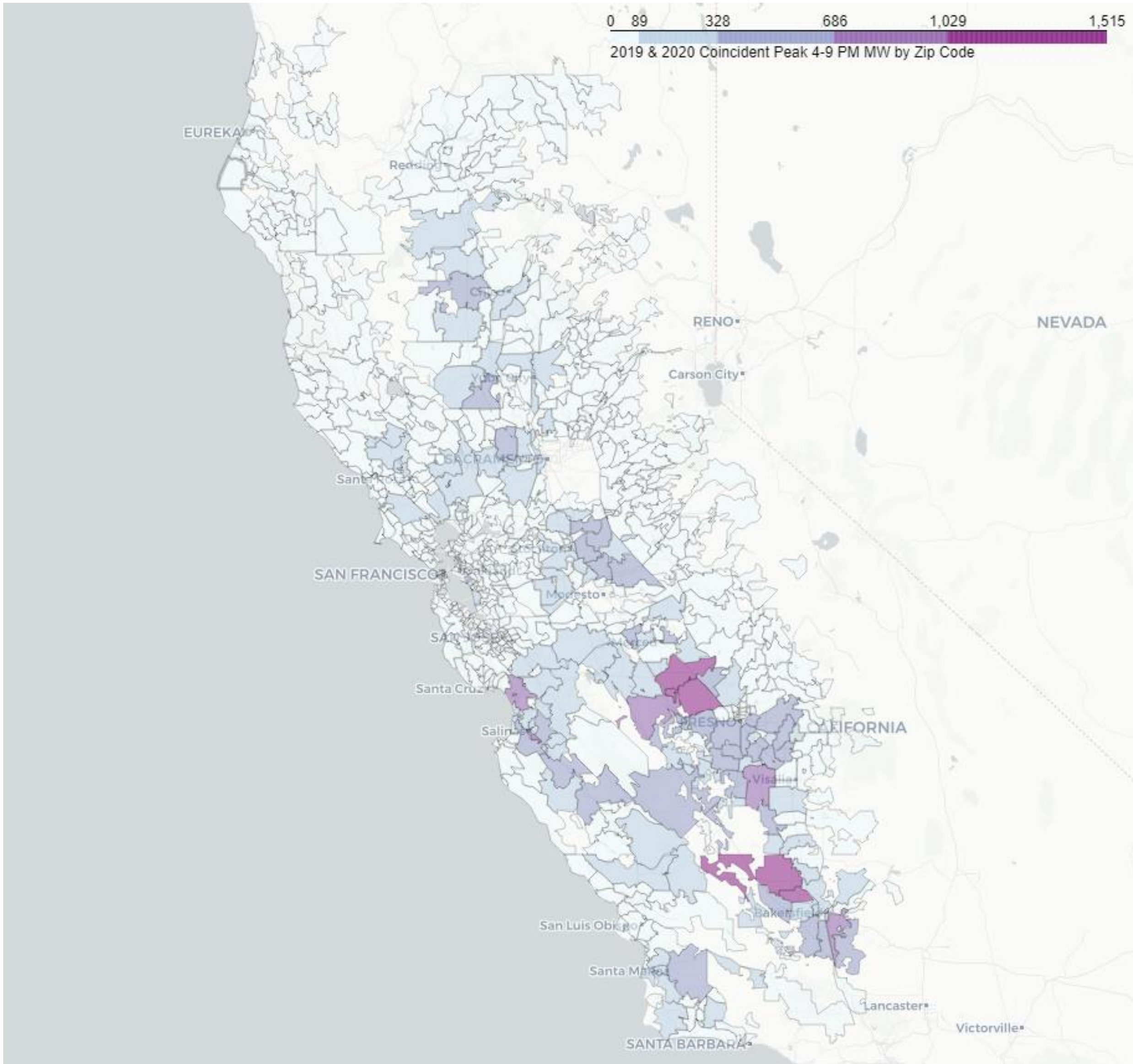


FIGURE 13. COINCIDENT PEAK 4-9PM LOAD BY ZIP CODE

AGRICULTURAL LOAD SHAPES

Figure 14 shows the six most common summer weekday hourly load patterns[10]. The most promising customers for an agricultural demand response program are those who have current loads during peak hours (4-9pm) and who could potentially shift

[10] Load patterns were segmented and constructed based on K-means clustering of normalized loads.

such loads to earlier or later in the day. As a result, customers with the most potential are those with flat loads (shape 6, representing the vast majority of customers with a peak load of 1,356 MW) or loads concentrated in the evening hours (shapes 3 and 5, about 166 MW of peak load total). In contrast, some customer load shapes indicate a U-pattern (shapes 2 and 4, about 148 MW of peak load), which indicates current shifting of load away from time-of-use peak hours. The peak window for the agricultural sector was 1 to 6pm during the time period analyzed (2019 and 2020), and these load shapes align with reductions during those hours. In 2021, the peak window shifted to 4 to 9pm, and it is reasonable to assume that the subset of customers already responding to time-of-use price signals will avoid usage during those hours going forward, leaving little incremental reduction potential for demand response.

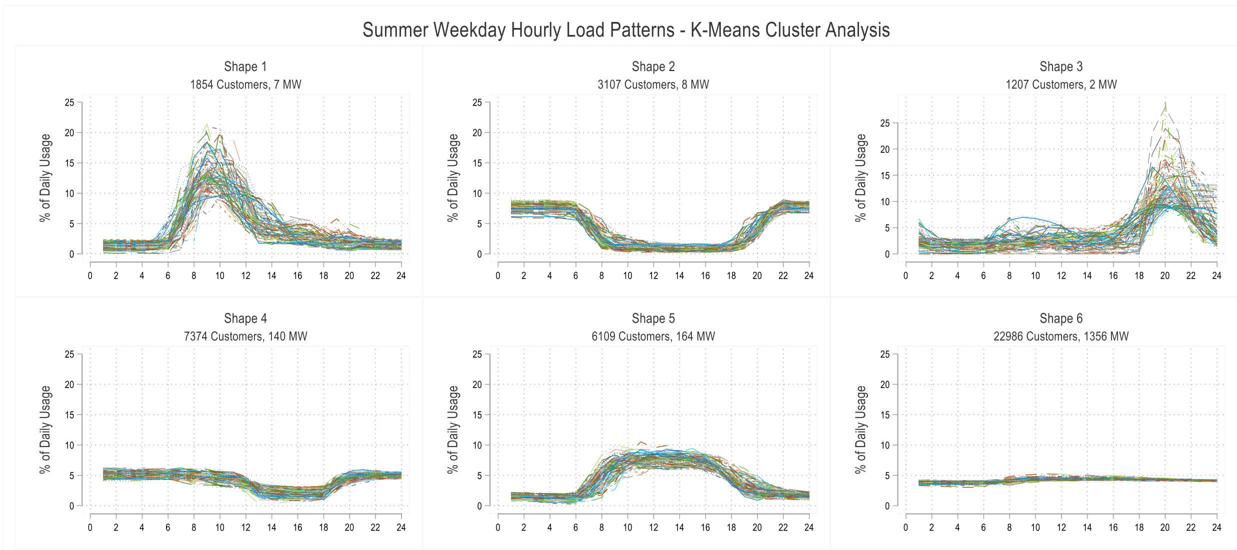


FIGURE 14. SUMMER WEEKDAY HOURLY LOAD PATTERNS

SURVEY RESULTS: DIRECT QUESTIONS

The research team fielded a survey to 4,427 agricultural customers: a census of large customers (in the top 4 peak load quintiles) and an 8% sample of small customers (in the bottom peak load quintile). One hundred sixty decision-makers completed the survey, and responses were weighted by peak load quintile so that each quintile was equally represented. Customer differences by other characteristics such as agricultural activity were investigated but only reported if statistically significant and meaningful. The survey was completed electronically (either by computer or mobile device). It included both direct questions and a choice experiment (conjoint) task (see Conjoint). The full survey instrument can be found in Appendix D.

This section covers the direct response highlights as summarized in Table 10. The survey highlights focus on questions which were most relevant to characterizing customer behaviors, preferences, and load reduction potential in the context of pilot design considerations. The results of the conjoint choice experiment portion of the survey are discussed in Survey Results: Conjoint Experiment.

The direct response survey analysis examined several different customer segments based on quintile, agricultural sector, and load automation. Respondents within quintile 1 are classified as "small", while respondents within quintiles 2-5 are classifies as "large". Statistically significant differences in survey results across customer segments are noted in the analysis.

TABLE 10. SURVEY QUESTION HIGHLIGHTS

TOPIC	QUESTION
Background	Businesses Participating in Demand Response
	Demand Response Non-Participation Reason
	Respondent Management of Equipment
	Automation Preferences by Notice
	Percentage of Peak Load Available for Curtailment
Firmographics	Primary End Use
	Primary Months for Each End Use
	Primary Agricultural Product
Completion	Interest in Learning more about Pilot

BACKGROUND

To qualify for the survey, respondents first had to answer a screening question and identify themselves as a decision maker for their agricultural electric bill and rate or the operation of electric powered agricultural equipment. Ninety-one percent (91%) of invited customers who entered the survey were qualified to complete the survey. Next, respondents were asked about their familiarity with demand response. Awareness was generally high, with 91% of respondents reporting familiarity. Awareness was somewhat higher for large respondents (98%) than for small respondents (81%).

Figure 15. summarizes self-reported demand response program participation amongst surveyed customers. This question was asked of the 146 (91%) respondents who reported awareness of demand response programs. Of the 146 respondents, 46% reported that they were currently participating in demand response programs. However, only 25% were actually participating in a demand response program at the time of the survey—meaning that perception and reality didn't entirely align, which is often the case. Water districts, respondents with automated loads, and participants in demand response programs targeted at large customers (CBP, ADR) were largely accurate in their self-identification. In contrast, Peak Day Pricing (PDP) participants and respondents not participating in any demand response programs were less accurate.

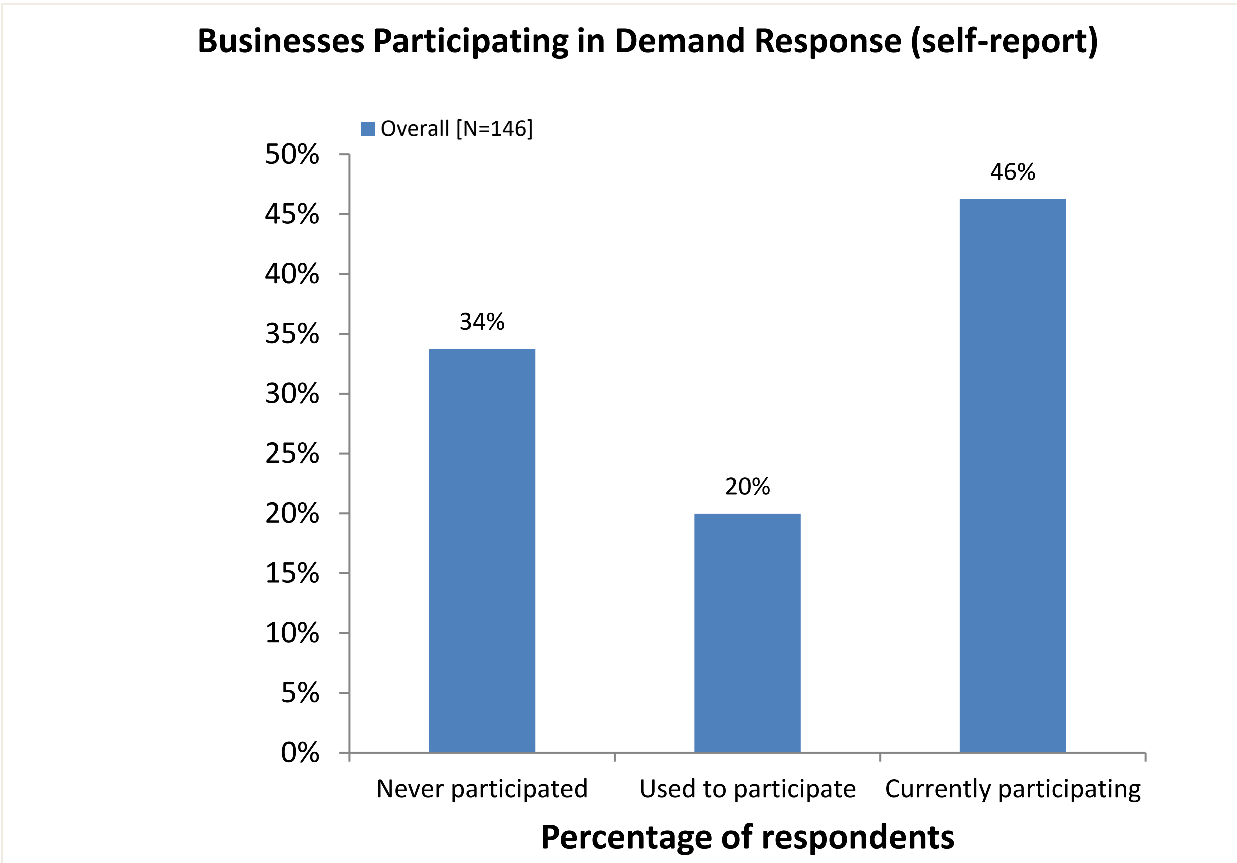


Figure 15. Have you ever participated in a peak energy use reduction program for your agricultural accounts?

Figure 16. 16 summarizes reasons for non-participation, asked of respondents who reported not being enrolled in a demand response program. Program rule incompatibility was the most common reason reported by these respondents. This explanation highlights the importance of program structure in respondents' ultimate enrollment decisions. Similarly, 20% of respondents considered the time or cost of participation to be too high compared to potential benefits. A careful cost-benefit analysis of such a demand response program could be used to educate prospective participants in the future. The third most common source of non-participation was lack of program awareness, which could be addressed by program marketing. Other

responses included low perceived importance of participation, reported usage patterns which already avoid peak hours, and reliance on solar electricity generation.

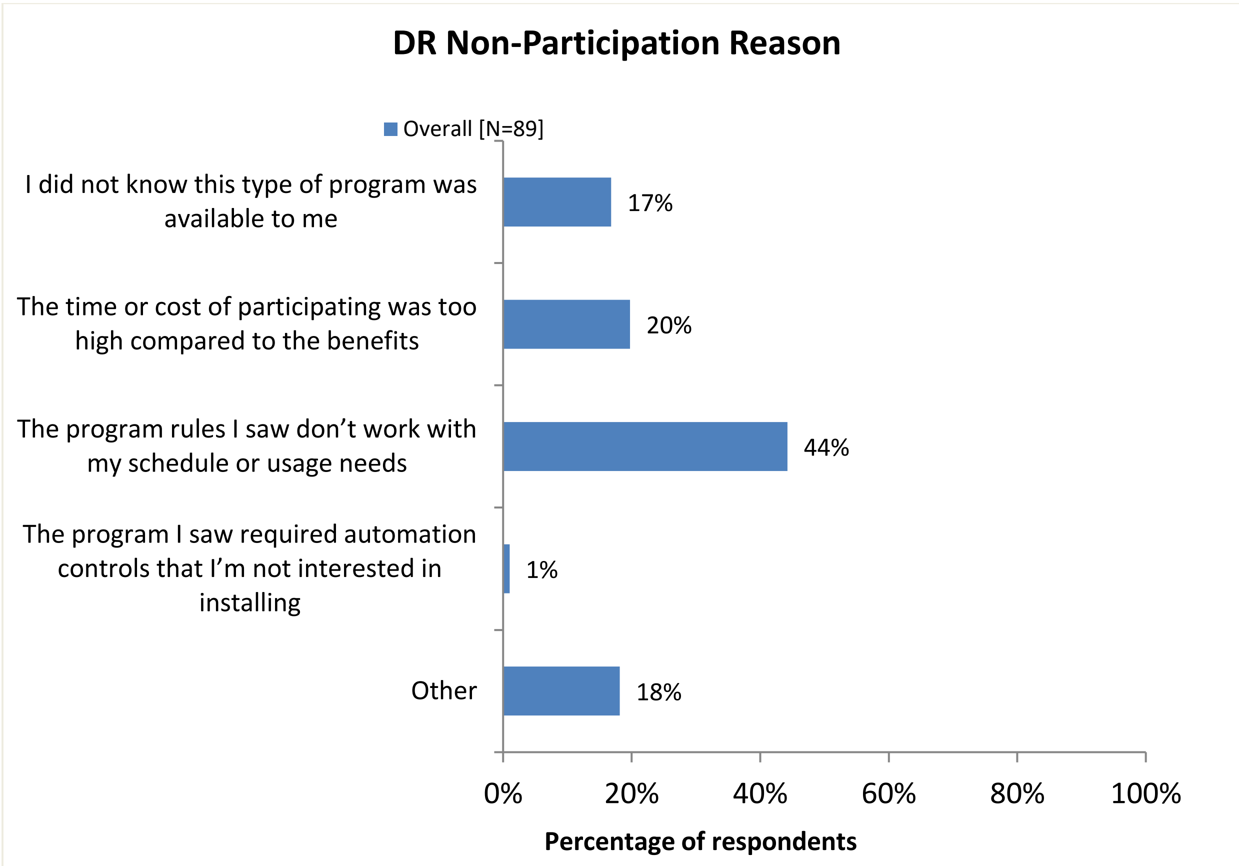


FIGURE 16. WHAT BEST DESCRIBES WHY YOUR ACCOUNTS ON AGRICULTURAL RATES ARE NOT CURRENTLY ENROLLED IN AN ENERGY USE REDUCTION PROGRAM?

Figure 17. shows the frequency of automated and manual control systems for small (quintile 1) and large (quintiles 2 through 5) customers. Roughly a quarter of respondents reported that they had at least one automated control system for their loads, with little difference between small and large respondents. Water districts (which were mostly large customers) were most likely to report using manual controls that are switched on all the time. In contrast, small customers were more likely to report using manual controls to switch on or off load flow as needed.

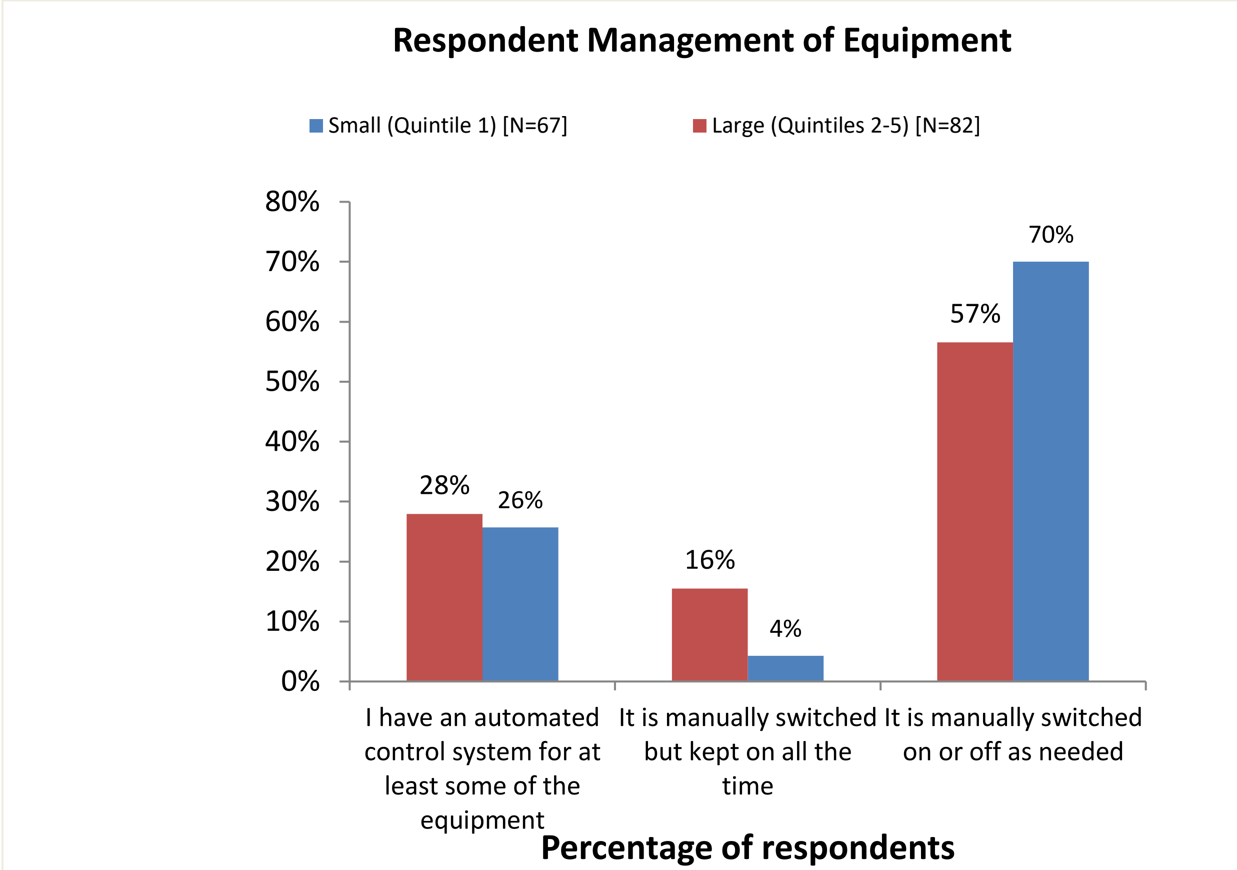


FIGURE 17. WHAT BEST DESCRIBES HOW YOU CURRENTLY MANAGE YOUR HIGH USAGE EQUIPMENT?

Figure 18 illustrates respondents' automation preferences for a program with 24-hour advance notification versus a program with 30-minute advance notification. For most respondents, preferences for automation equipment and program participation do not significantly or meaningfully differ for the longer or shorter notification, with 42% of respondents preferring some form of load automation in both cases. However, 10% percent fewer respondents would participate in a day-of notification program than would participate in a program with 24-hour advance notice. This is essentially due to a subset of respondents preferring manual control. Roughly a quarter of manual respondents who would participate with 24-hour notice would not participate with 30 minutes notice.[11]

[11] Statistically significant at the 90% confidence level using a population proportion comparison.

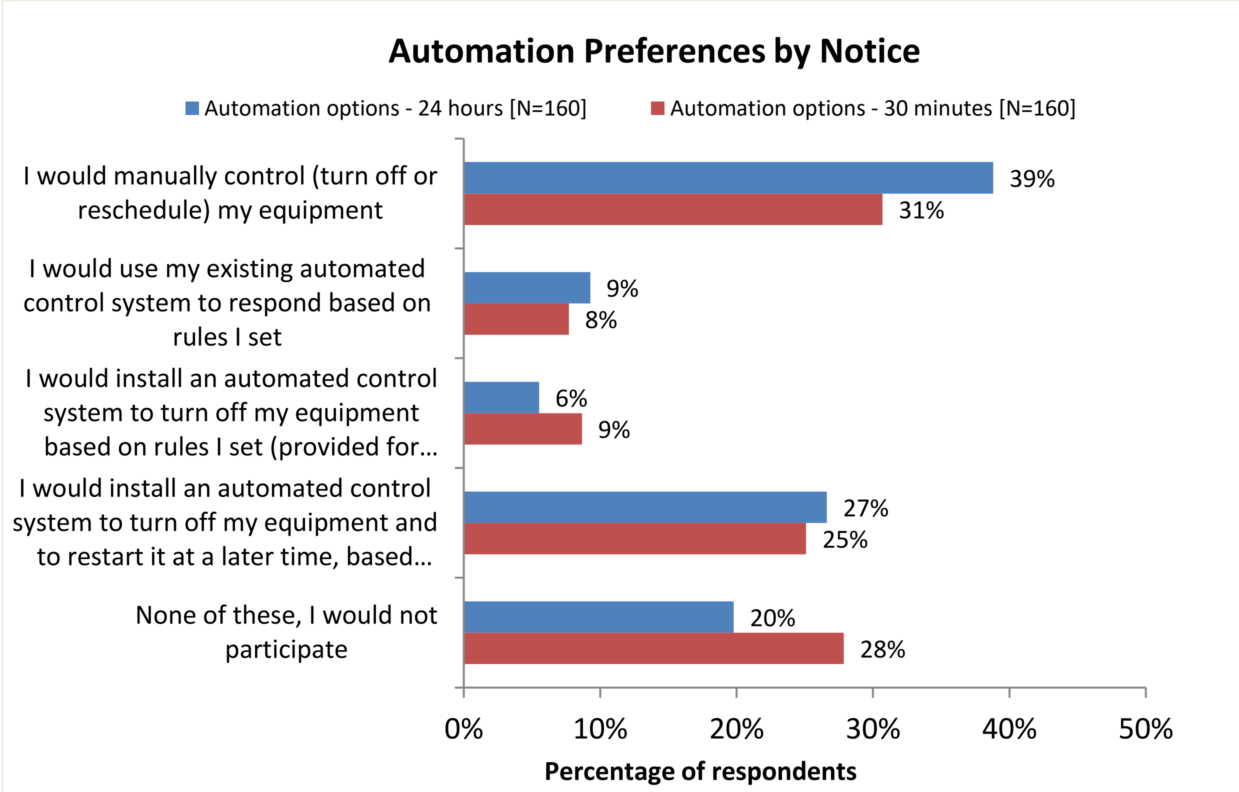


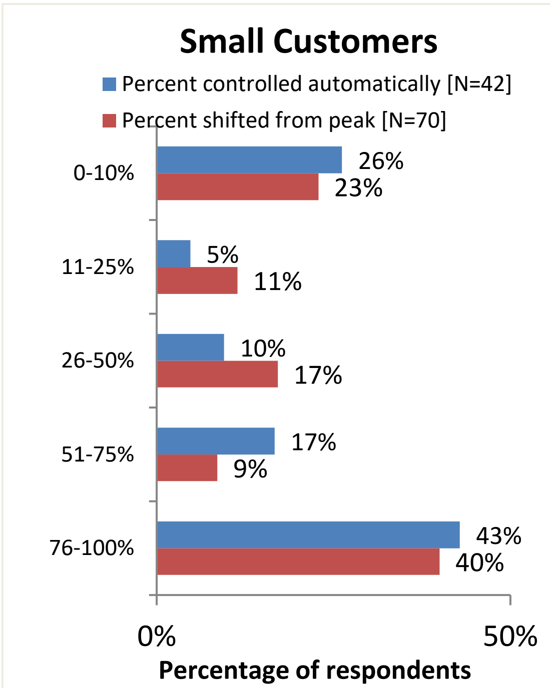
FIGURE 18. WHICH OF THE OPTIONS BELOW WOULD WORK THE BEST FOR YOU IF THE NOTIFICATION WAS SENT TO YOU [24-HOURS / 30 MINUTES] BEFORE ENERGY USE REDUCTIONS WERE NEEDED?"[12,13]

Figure 19 shows the percentage of respondents' peak loads that they were willing to curtail. It also shows the percentage of loads that the subset of respondents open to automation would be willing to curtail using an automated system. Preferences were very similar for the percent of load that could be curtailed, in general, versus curtailed using an automated system. However, small customers were open to curtailing or automating a much larger percent of their peak load compared to large customers. On average, about 33% of respondents across both groups were willing to provide 50% or more of their load for curtailment or automation. This figure was slightly lower for large customers (about 30%) but substantially higher for small customers. Forty-nine percent of small customers reported openness to curtailing 50% or more of their load, and 60% of small customers open to automation would

[12] Full text for 24-hour question: "Assume you could be well compensated for turning off or turning down your high usage equipment during a few reduction hours each year in response to a notification sent to you 24 hours before energy use reductions were needed. Which of the options below would work the best for you?"

[13] Full text for 30-minute question: "Sometimes strain to the electric system can happen very quickly, resulting in high electricity costs on short notice. Which of the options below would work the best for you if the notification was sent to you 30 minutes before energy use reductions were needed?"

automate 50% or more of their peak load for curtailment purposes. There was also some meaningful variation by agricultural activity: almost 40% of nut and fruit tree respondents amenable to automation were willing to shift 76-100% of their load away from peak hours.



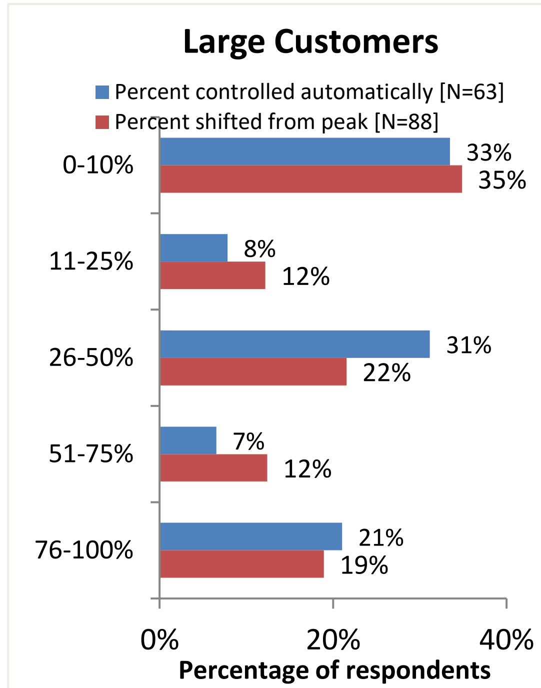


FIGURE 19. IF YOU WERE WELL COMPENSATED FOR SHIFTING YOUR ENERGY USE, WHAT PERCENT OF YOUR ESTIMATED PEAK LOAD WOULD YOU BE ABLE TO SHIFT AWAY FROM 4 TO 9 PM (MAY THROUGH OCTOBER) TO OTHER HOURS OF THE DAY DURING A FEW REDUCTION HOURS, 6 TO 18 DAYS EACH YEAR? [IN RED]

YOU SAID THAT YOU CURRENTLY HAVE OR WOULD INSTALL AN AUTOMATED CONTROLLER. IF YOU WERE WELL COMPENSATED FOR SHIFTING YOUR ENERGY USE, ABOUT WHAT PERCENT OF YOUR ESTIMATED PEAK LOAD WOULD YOU CONTROL WITH AN AUTOMATED CONTROL SYSTEM? [IN BLUE]

It is important for surveys to use units that respondents can understand. For the direct response survey, respondents were asked whether horsepower (hp) or kW were more meaningful. The units selected by the respondent were then used when displaying peak loads for the remainder of the survey. Figure 20 illustrates which energy units held the most meaning for respondents. In a future demand response program, PG&E may consider using either kW or hp to communicate performance prices. A plurality of respondents (45%) were most familiar with kW as an energy unit. Respondents with automated loads tended to be more familiar with kW (58%) than respondents with manual loads were (40%). Furthermore, water district respondents were significantly more knowledgeable of kW as an energy unit (68%) than respondents in other agricultural sectors were (40%). Some respondents were also familiar with hp as an energy unit (40%); however, only 16% of water district respondents were knowledgeable of hp. Only 15% of all respondents were unfamiliar with both kW or hp.

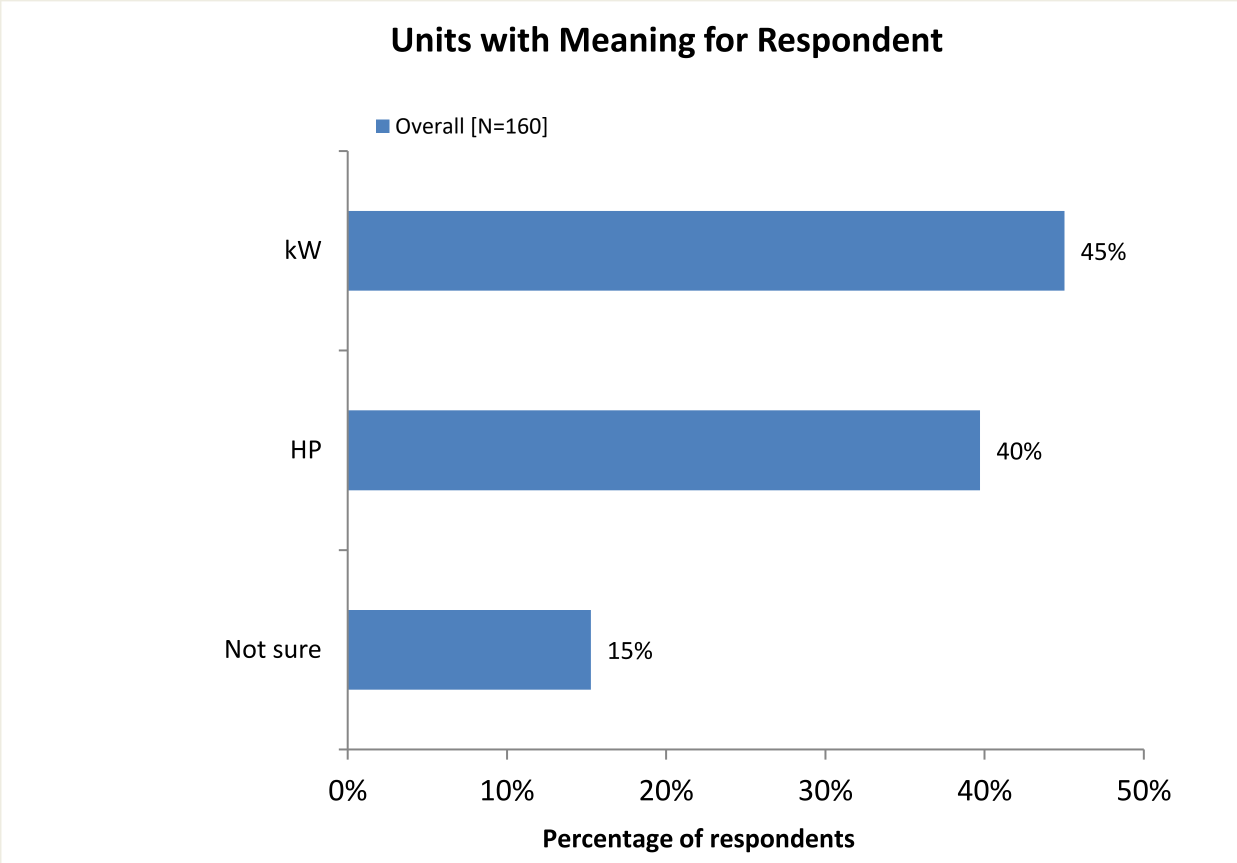


FIGURE 20: WHEN THINKING ABOUT YOUR HIGH USAGE EQUIPMENT, WHICH OF THE FOLLOWING ENERGY UNITS ARE MOST MEANINGFUL TO YOU?

FIRMOGRAPHICS

Figure 21 illustrates the most common electric powered equipment that respondents use. About 70% of respondents listed an irrigation pump as one of their primary uses. Predictably, small customers tended to select small irrigation pumps. "Other pumps and/or motors" and "refrigeration" were the second and third most frequent responses, respectively. "Other" responses included nut processing, water softening equipment, AgTech equipment, bottling lines, and lighting.

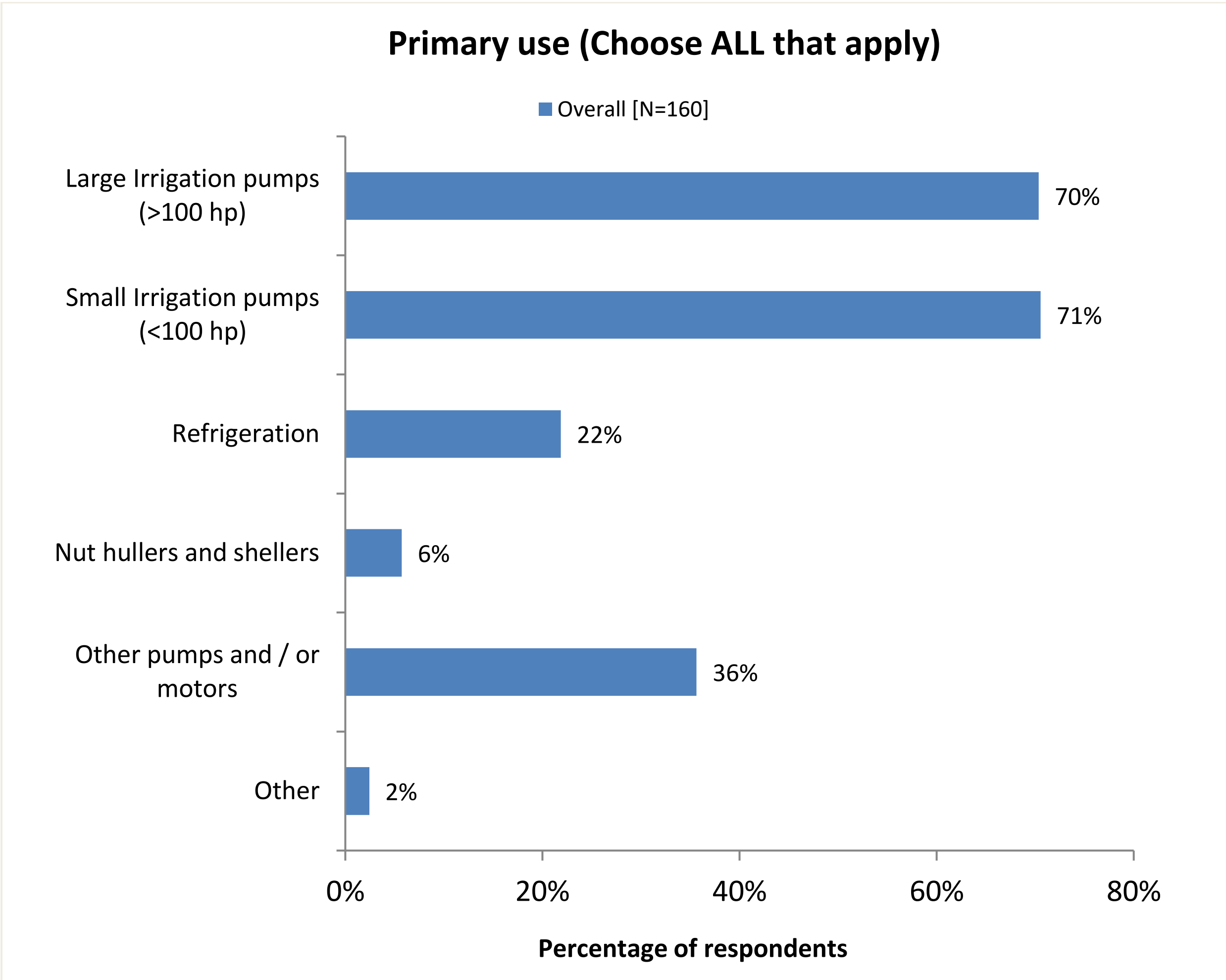


FIGURE 21. WHICH OF THE FOLLOWING HIGH USAGE ELECTRIC POWERED EQUIPMENT DO YOU USE?

Figure 22 visualizes the primary usage months for each usage category. Pumps and refrigeration followed a similar bell-shaped usage pattern, while "nut hullers and shellers" and "other" were flatter. June and July were the top usage months for irrigation pumps, the most common category. In contrast, July and August were the top usage months for refrigeration and other pumps/motors.

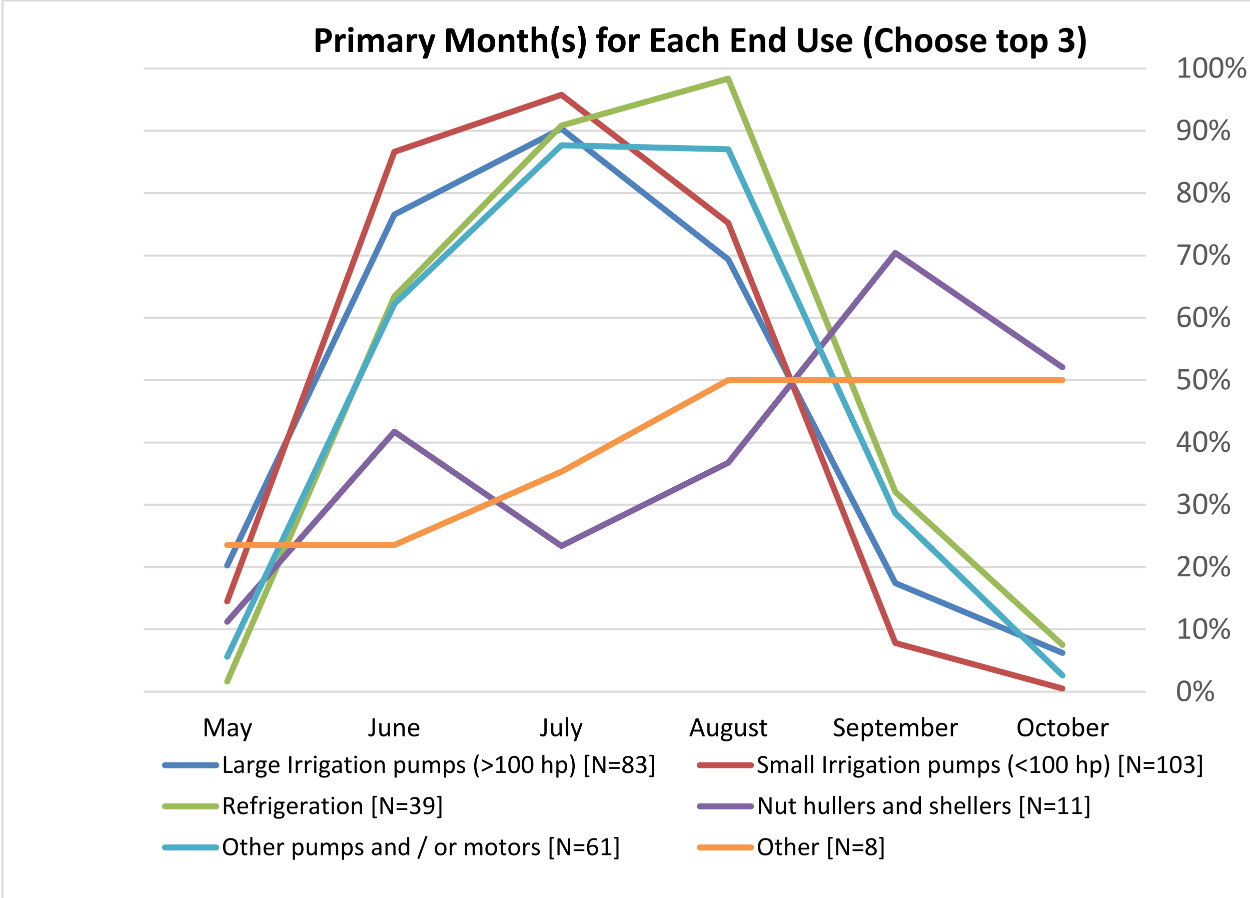


FIGURE 22. DURING WHICH SUMMER MONTHS DO YOU USE THIS EQUIPMENT THE MOST BETWEEN 4-9PM? SELECT UP TO THE 3 HIGHEST USAGE MONTHS IN EACH ROW.

Figure 23 shows the distribution of respondents' primary agricultural products. The three most common agricultural products were nut trees, produce crops, and water distribution. Most water districts were large customers, making water distribution the largest single agricultural activity by peak load among respondents. Water districts account for 77% of peak load among respondents, after applying quintile weights. Other agricultural products included vineyards (most common), diversified farms, food packing/processing, avocados, and coffee.

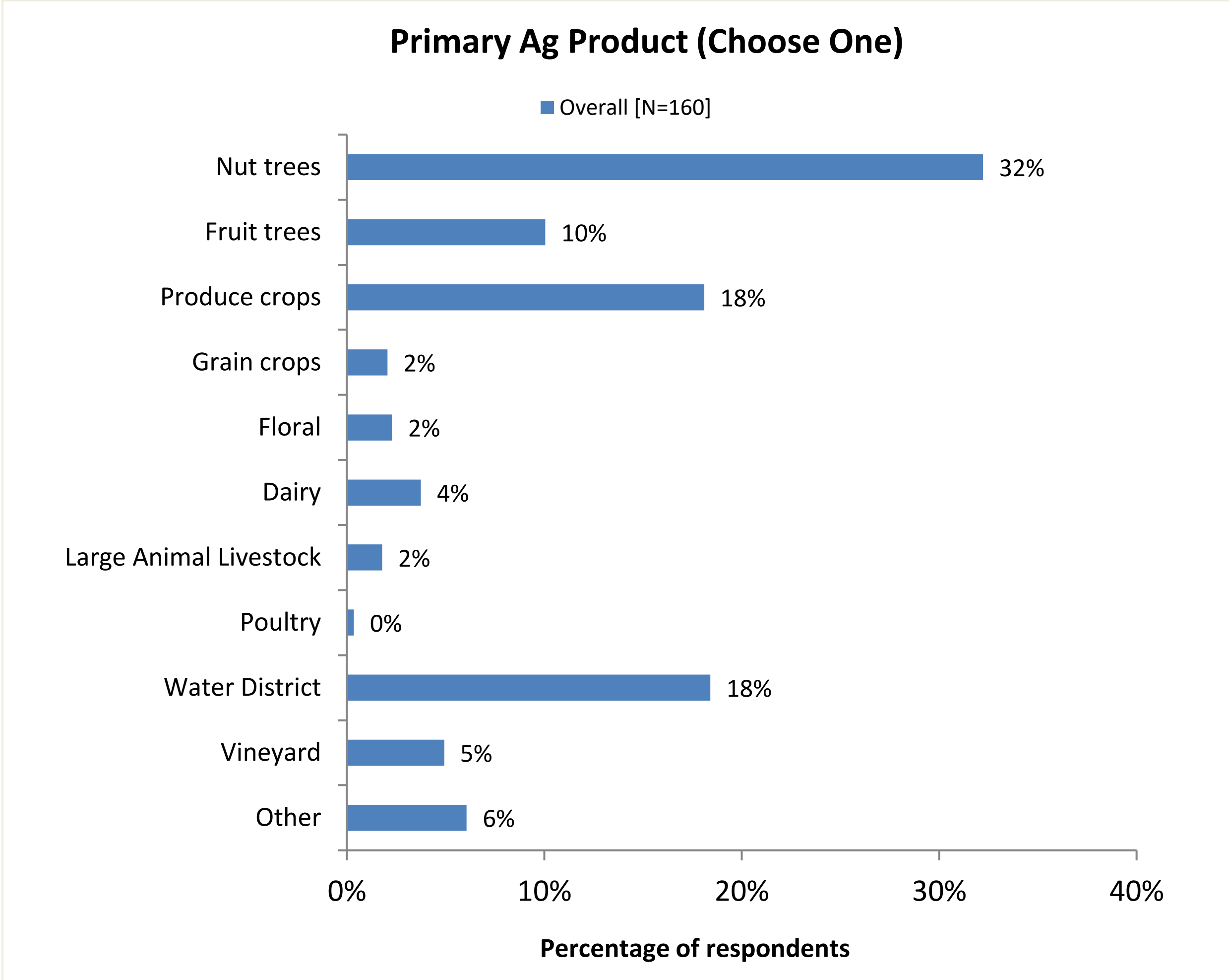


FIGURE 23. WHICH OF THE FOLLOWING BEST DESCRIBES YOUR PRIMARY AGRICULTURAL PRODUCT OR ACTIVITY?

COMPLETION

Figure 24 shows the percentage of respondents who were interested in learning more about the pilot program. A majority of respondents (56%) were interested in learning more about the pilot. Interest level was slightly higher for small customers but the difference was not statistically significant. Respondents not currently enrolled in demand response (PDP, BIP, ADR, etc.) reported above average interest (63%), while water districts reported below average interest (39%). Respondents indicating interest in learning more provided their contact information and will be contacted by the pilot implementer for a future pilot.

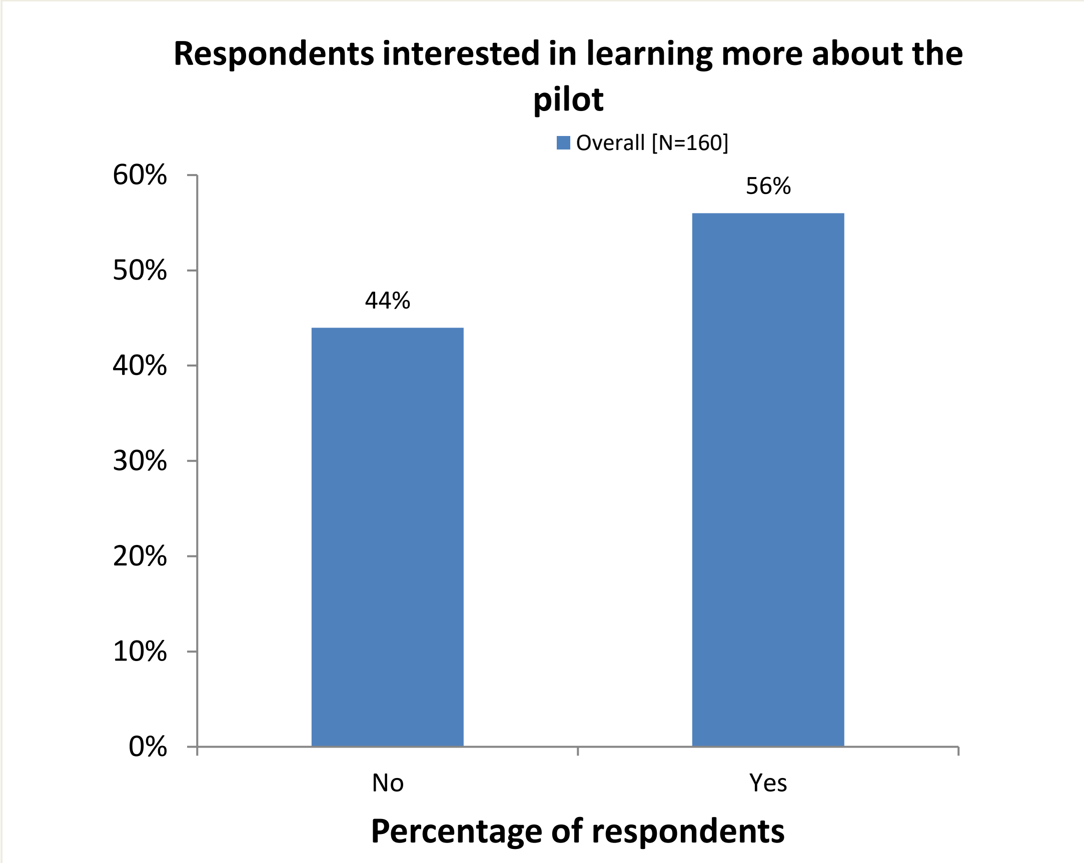


FIGURE 24. THIS INFORMATION WILL BE USED TO HELP DESIGN A PROGRAM PILOT. WOULD YOU BE INTERESTED IN LEARNING MORE ABOUT THE PILOT?

SURVEY RESULTS: CONJOINT EXPERIMENT

The conjoint choice component of the customer survey tested preferences for five major program attributes: dispatch frequency, event duration, notification timeframe, participation terms, and incentive level. As described in more detail in the Conjoint Choice Experiment methodology section, a conjoint choice experiment presents respondents with multiple sets of product choices comprised of bundles of product attribute configurations. Respondents' choices are then used to build a choice model which quantifies the relative magnitude of preferences for the attributes and levels tested. This section presents the results of the conjoint experiment and resulting choice model.

ATTRIBUTE IMPORTANCE

Attribute preferences provide a measure of how much each attribute influenced respondent choices, given the levels tested in the survey. Relative importance values for each attribute sum to 100% since they represent portions of a single decision. Figure 25 summarizes the relative importance of each attribute in the study. Because there are five attributes, the average importance is 20%; attributes with greater importance have above average importance and vice versa. Two interaction terms are included: bill savings and event frequency are both interacted with participation terms because the display of both of these attributes varied as a function of whether or not a penalty was included in the participation terms. The relative importance of attributes with interactions can be interpreted as the importance of the attribute plus the importance of the interaction.

These relative importance values appear to reflect two tiers of attributes. Participation terms and expected event frequency form a top tier which influences 70% of the enrollment decision. Notification timeframe, expected bill savings, and event duration comprise a second tier of attributes, which drive the remaining 30% of the decision. These second tier attributes do influence enrollment choices but none on its own is likely to be a key or important driver of the decision—unlike the attributes in the higher tier.

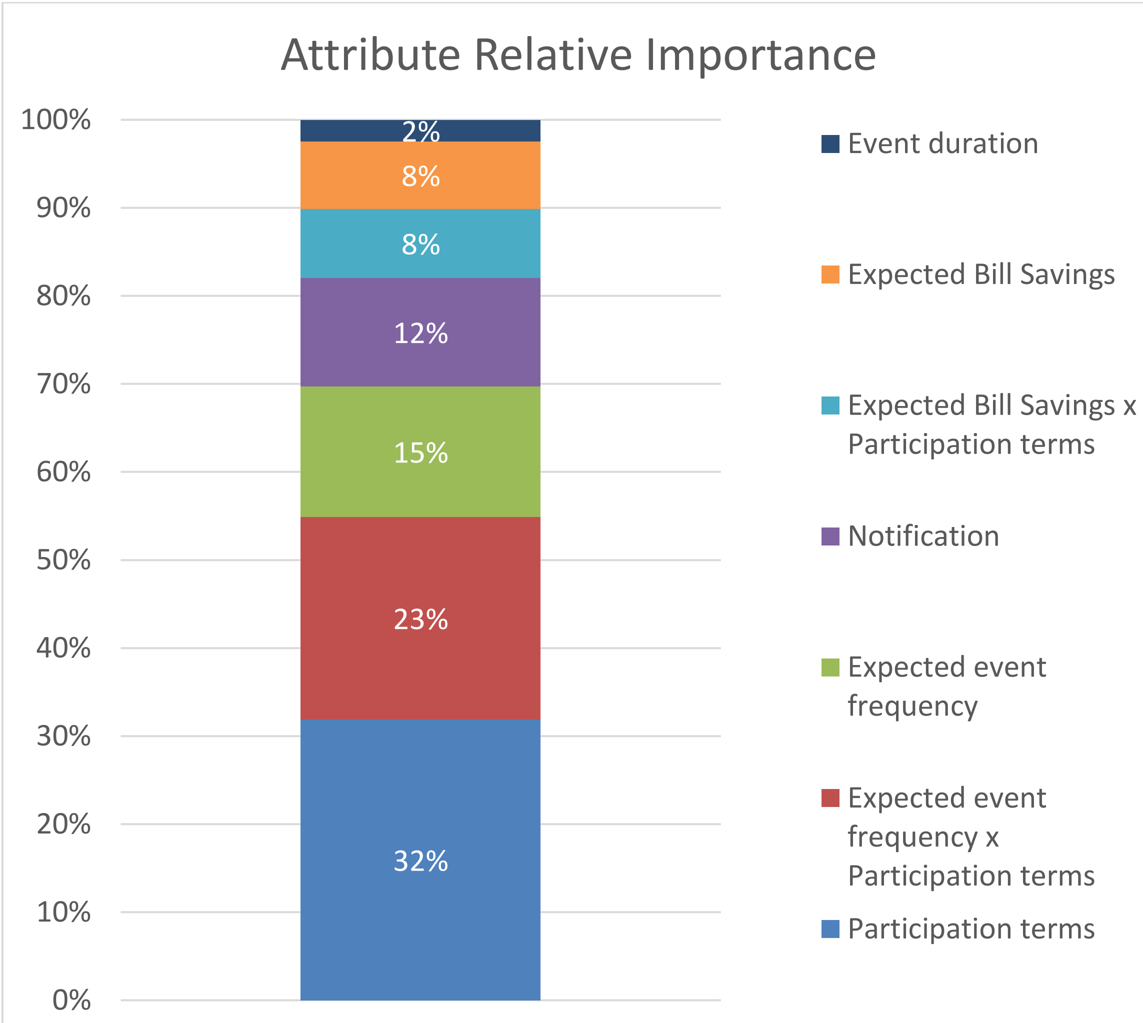


FIGURE 25. ATTRIBUTE RELATIVE IMPORTANCES

RELATIVE IMPACT FOR LEVELS TESTED

The attributes and levels included in the survey were carefully selected to construct an enrollment choice model that would allow for key research questions to be addressed. The enrollment choice model consists of predicting the impact of different attribute levels on program enrollment for each respondent, given a program design consisting of any one level for each attribute. The choice model was estimated using the survey data collected and allows for comparing predicted respondent preferences for different program designs. This section discusses the predicted impact on enrollment for each level within each attribute. This is essentially the maximum relative effect of each level on enrollment relative to the other levels, when taking each attribute individually. It is important to note that the conjoint tasks and resulting choice model include all tested attributes so the relative effect will be tempered when considering all attributes together, as is done for the cost effectiveness modeling discussed in Cost Effectiveness Results.

Figure 26 shows the relative impact of the dispatch frequency levels on the program enrollment decision (in blue) and for the interaction term (in red). Note that this attribute was characterized as the expected number of events per year rather than the maximum number of events. As expected, fewer events are preferred, but the conjoint model quantifies this: a program design with an expected six events per year is about 50% more preferred than a design with 18 events expected per year. An interaction term with participation terms was estimated because the size and inclusion of an event penalty was a function of the number of events and the participation terms. Level differences for the interaction term were not statistically significant or meaningful.

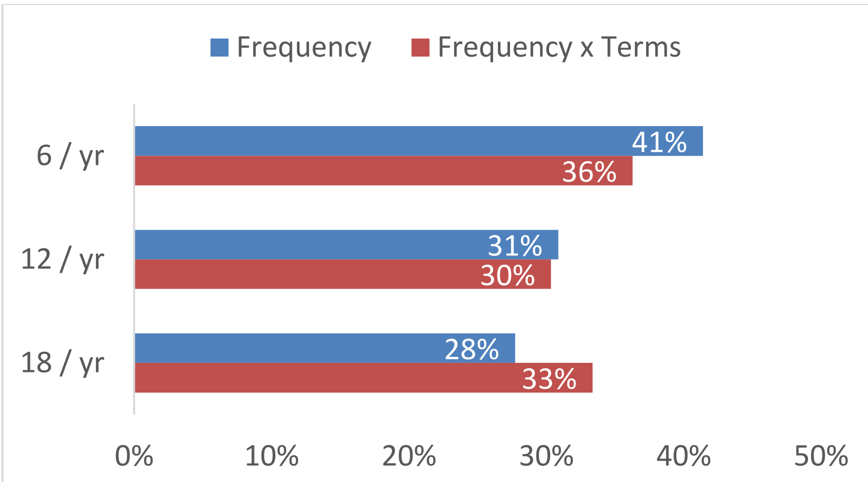


FIGURE 26. LEVEL RELATIVE IMPACT FOR DISPATCH FREQUENCY

Figure 27 shows the relative impact for the levels of the event duration attribute. As expected, the shorter event duration (2 hours) is preferred to the longer event duration (4 hours), but only by about 20%. In contrast, expected load carrying capacity (ELCC) is higher for demand response products with a four hour duration, since the longer reduction is more likely to cover hours of system need. This drives benefits and may negate incremental enrollment that could be achieved with a shorter event duration.

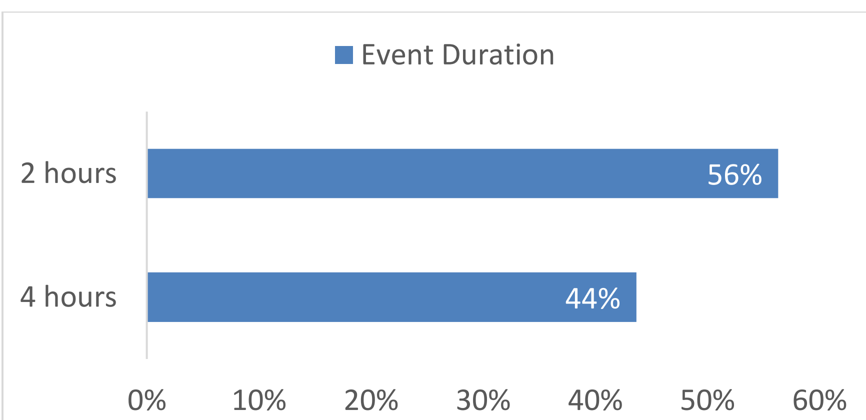


FIGURE 27. LEVEL RELATIVE IMPACT FOR EVENT DURATION

Figure 28 shows the relative impact of the two notification levels tested. Day-ahead (24 hour) notification is strongly preferred to day-of (30 minute) notification, by a factor of almost three. Though the ELCC value is lower for day-ahead notification, the difference is dwarfed by the strength of the preference for the longer notification.

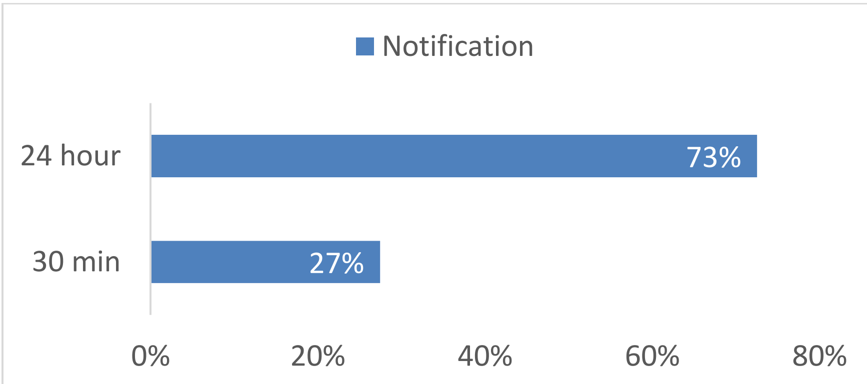


FIGURE 28. LEVEL RELATIVE IMPACT FOR NOTIFICATION

Figure 29 shows the relative impact of the participation terms tested. As expected, respondents preferred performance-only terms that do not include penalties. The choice modeling quantified the magnitude of this impact: there is a twofold to fivefold preference for performance-only participation terms compared to participation terms that include penalties. This preference exists despite that bill savings shown for the performance-only terms were 40% lower than they were for terms including a penalty. This preference is a strong driver of enrollment likelihood and resulting expected load reductions even though the expected load reduction is derated for the performance-only option in the cost-effectiveness analysis.

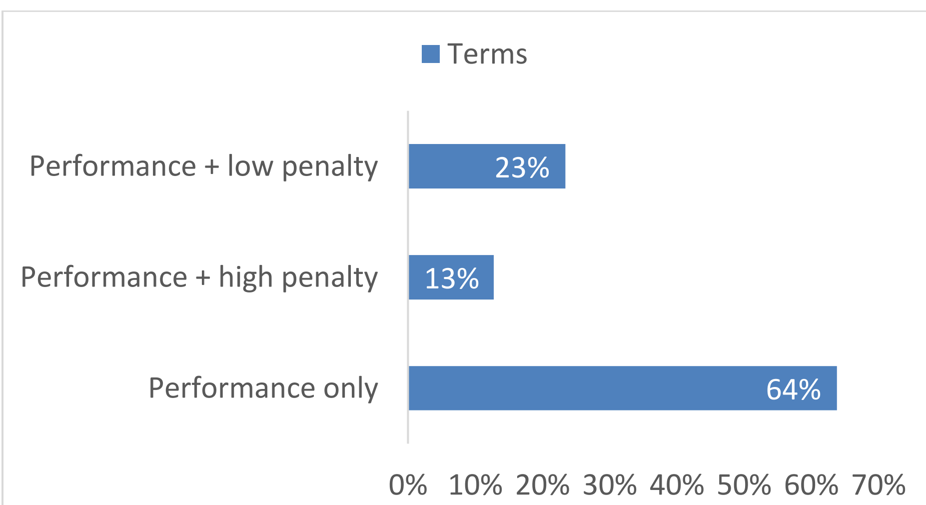


FIGURE 29. LEVEL RELATIVE IMPACT FOR PARTICIPATION TERMS

Figure 30 shows the relative impact of the expected bill savings levels on the program enrollment decision (in blue) and for the interaction term (in red). Unsurprisingly, there is a strong preference for higher incentive levels. This preference is roughly linear, with a $100 per kW-year incentive about twice as preferable to a $50 per kW-year incentive.

Note that this attribute was characterized as expected annual bill savings, which was calculated by multiplying the performance incentive in $/kWh by the participant's expected load reduction. This calculation assumed the respondent participated in all events. Respondents were not shown capacity prices and the program was clearly described as a firm service level design with performance payments. The implied performance price per kWh would be the incentive level tested divided by the number of expected event hours per year. For example, for a design with six expected annual events and a four hour duration compensated at the lowest incentive level, the implied performance price would be $2.08 per kWh ($50 per kW-year divided by expected event 24 hours per year). For a performance-only program, the implied price would be $1.25 per kWh, reflecting the 40% derating factor that was applied to performance-only designs.

An interaction term with participation terms was estimated because the size and inclusion of an event penalty was a function of the number of events and the participation terms. Level differences for the interaction term were not statistically significant or meaningful, indicating that once the program terms were accounted for, the incentive level was less important to the participants.

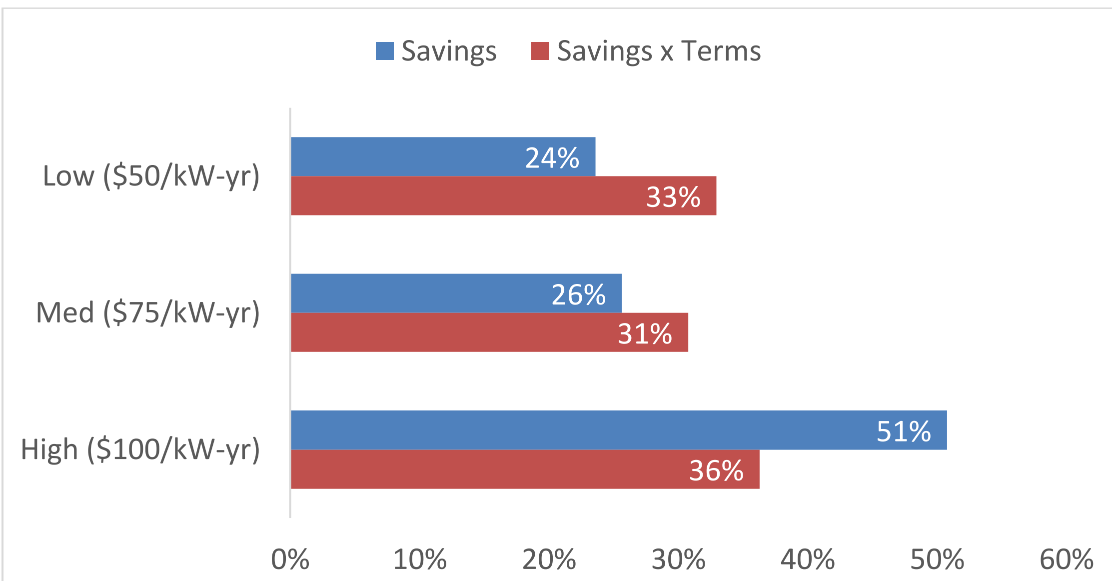


FIGURE 30. LEVEL RELATIVE IMPACT FOR INCENTIVE LEVEL

COST EFFECTIVENESS RESULTS

The attribute and level preferences described in the previous section essentially summarize average preferences across the individual choice models that were estimated for each respondent. A choice model incorporates coefficient outputs from a logistic regression run on the conjoint experiment choice tasks. These coefficients represent the effect of each attribute level on the preference for one design over another: a measure of enrollment likelihood. Though it was not possible to calibrate this likelihood to actual uptake rates for an existing product in the field, the choice model is a powerful tool for quantifying relative enrollment likelihoods from one product design configuration to another. These choice models were then incorporated into a program design simulation tool which also incorporated the expected benefits (avoided generation capacity, reflecting ELCC derating for dispatch availability, manual dispatch vs automated, etc.) and expected costs (performance payments, administrative, upfront technology costs, ongoing automation costs, etc.) for each respondent and each product design. This enabled the calculation of expected net benefits for each program design, which could include up to three products constructed of any permutation of the attributes and level tested. Detailed assumptions can be found in Appendix C.

The program design simulation tool was used to identify an optimal design: the program design which is expected to maximize net benefits, identified by calculating expected net benefits for the dozens of product configurations tested. Results are fundamentally a reflection of relative customer preferences for some levels over others; stronger preferences will drive more of the enrollment likelihood than weaker preferences. The strongest respondent preferences included:

- Performance-only participation terms (relative to terms with penalties): three to fivefold relative preference
- Earlier notification (24 hour vs. 30 minute): threefold preference
- Fewer events (6 vs. 12 or 18 events): 1.3 fold preference

Preferences within other attributes (incentive level or expected event duration) were somewhat less pronounced. Further, higher incentive levels result in higher costs, and shorter durations have a meaningful ELCC derate factor of about 20%. The "optimal" net benefit maximizing design is shown in Table 11. Note that it largely includes the levels most strongly preferred by participants but also includes the longer expected duration (four hours instead of two hours) and does not include the highest performance price ("medium" bill savings instead of "high").

TABLE 11. OPTIMAL PROGRAM DESIGN

PRODUCT OPTION	OPTIMAL	NONE
Expected event frequency	6 / year	
Event duration	4 hours	
Notification	24 hour	
Expected Bill Savings	medium	

Participation terms	Performance only	
Assumed capacity value ($/kW-yr)	$45	
Capacity payment ($/kW-yr)	N/A	
Performance price ($/kWh)	$1.88	
Penalty ($/kWh)	N/A	
Shares of Preference	87%	13%
Standard Error	5%	5%
Expected Program Size (full enrollment)	Optimal	Program
Expected Participants	578	578
Expected MW-yr	18.5	18.5
Expected MW-yr (subset automated)	13.5	13.5
Cost-Effectiveness		
TRC B/C Ratio	1.3	1.3
UCT B/C Ratio	1.1	1.1

Importantly, all designs were characterized to respondents as including performance pricing relative to a firm service level. The specific units of the performance price (e.g. $ per kW or $ per kWh) were not discussed, so there could be some flexibility in implementing the performance price level as a $ per kW per event price or a $ per kWh per event price. Importantly, the incentive was not characterized as a guaranteed capacity payment. All designs were positioned as a firm service level product where respondents could "[e]arn an annual bill credit if [the respondent kept the firm's] electricity usage *below [FSL]*[14] during reduction "events"". Respondents were shown expected annual bill savings, assuming the incentive level (based on an annual capacity value) and their expected load drop[15]. Load drop was based on the respondent's peak load and the percent thereof the respondent said could be dropped in the context of a demand response program.

The "assumed capacity value" was not shown to respondents, nor was the "performance price". Rather, each respondent was shown a range of expected bill savings that applied the assumed capacity value to their expected annual average load reduction. The performance price is derived by dividing the assumed capacity value (in $ per kW-year) by the expected number of event hours in the design (a function of expected events and expected duration) to produce a $ per kWh price.

The optimal design is the one design which maximized expected net benefits. For the optimization, expected benefits and costs were compared for all 108 product configurations tested as well as for multiple two-product program designs. However, program design is an important decision that should ideally take into account multiple considerations in addition

[14] Piped in value equal to: the respondent's peak load * (1-stated load drop percentage)

[15] Example calculations can be found in Table 8

to the quantitative customer choice modeling and cost-benefit analysis. Variants of the optimal design may have similar expected participation and economic outcomes while also taking into account qualitative considerations such as implementation feasibility, expert knowledge (e.g. from aggregators), and market trends which may serve to anchor program expectations. For example, **Error! Reference source not found.** shows a program design w hich includes two products: a day-of and a day-ahead product. The expected program size and economic outcomes for this design are similar, albeit slightly lower, than are those for the optimal design. This two-product design might be preferred if there were programmatic or other reasons for having a day-of program targeted at sites with automation technology.

TABLE 12. ALTERNATIVE, TWO PRODUCT PROGRAM DESIGN

PRODUCT OPTION	DAY OF	Day Ahead	NONE
Expected event frequency	6 / year	6 / year	
Event duration	4 hours	4 hours	
Notification	30 min	24 hour	
Expected Bill Savings	medium	low	
Participation terms	Performance only	Performance only	
Assumed capacity value ($/kW-yr)	$45	$30	
Capacity payment ($/kW-yr)	N/A	N/A	
Performance price ($/kWh)	$1.88	$1.25	
Penalty ($/kWh)	N/A	N/A	
Shares of Preference	31%	56%	13%[16]
Standard Error	3%	4%	5%
Expected Program Size (full enrollment)	Day Of	Day Ahead	Program
Expected Participants	208	364	572
Expected MW-yr	5.7	11.1	16.8
Expected MW-yr (subset automated)	5.6	7.8	13.3
Cost-Effectiveness			
TRC B/C Ratio	0.9	1.2	1.1
UCT B/C Ratio	0.8	1.0	1.0

[16] Share of customer load that would not enroll in any product

BENCHMARKING OF DR PROGRAMS

The research team examined agricultural DR programs offered in the U.S. to inform research questions developed for this study. The team focused on those agricultural DR programs that are most relevant to California. The information collected included DR program eligibility requirements, incentives structure and amounts, event triggers, event frequency and duration, use of automation technology, and more. A summary table of the six DR programs surveyed and their program details are provided in Appendix E. A discussion of additional key considerations along with strengths and challenges of each program are also included in Appendix F.

TABLE 13. AGRICULTURAL DR PROGRAMS BENCHMARKING: ANALYSIS OF DR PROGRAM ELEMENTS

DR PROGRAM ELEMENT	SUMMARY ANALYSIS
Target Measure	All of the agricultural DR programs target irrigation pump control, using switches to directly turn off pumps for demand response events.[17]
Event Trigger	Two programs are used for emergency dispatch, while the other four are called for both emergency and economic dispatch.
Notification	One program provide 30-minute notice for events, one program provides 4-hour advance notice, three programs provide day-ahead notice, and Southern California Edison's (SCE) Agricultural and Pumping Interruptible (AP-I) program turns off pumps with no advance notification.
Event Limits	The program with the fewest events is NV Energy's IS-2 Interruptible Irrigation Service program, which only calls one test event for a maximum of three hours per year. One other program will only call up to five emergency events per year. The remaining programs call between 10 and 25 events per year or a maximum of 40 to 60 event hours per year. SCE's AP-I can call the most events, with a maximum of 25 events and up to 150 event hours per year.
Participation Terms	Two programs are performance-based with no additional penalties; rather, payments are reduced based on participation as a percentage of committed load. Two other programs, SCE's AP-I and Entergy Arkansas' Agricultural Irrigation Load Control program, pay monthly, regardless of events, with no penalties. In the Entergy program, customers that opt out are bypassed for the rest of the season but given a chance to re-enroll the next year. The last two programs (NV Energy's IS-2

[17] NV Energy's program is currently manual because the paging solutions provider no longer supports the program due to age of the technology.

DR Program Element	Summary Analysis
	Interruptible Irrigation Service and Idaho Power's Irrigation Peak Rewards) levy penalties for opt outs. Four programs pay incentives in the form of capacity ($/kW) and/or energy ($/kWh) credits on customer bills. In two programs, SCE's AP-I and NV Energy's IS-2, customers are enrolled on a program-specific tariff. Entergy Arkansas' unique incentive design pays a flat monthly incentive using a schedule based on the motor horsepower of the enrolled pump.
Automated Technology	All of the program managers that were interviewed (Idaho Power, Entergy Arkansas, Pacific Power Oregon, NV Energy, and Southern California Edison) described ongoing maintenance of the automated irrigation pump switches as a challenge and cost. The switches are sometimes inadvertently knocked off the pumps by staff or livestock, and communication with the switches is regularly interrupted because the pumps are located in remote locations. One program manager shared that their failure rate is 9 to 12 percent. As noted above, for the NV Energy program, the paging solutions provider no longer provides technical support and customers are asked to participate manually.

STAKEHOLDER FEEDBACK

The research team engaged with four aggregators and one technology provider during the research study who provided feedback on grower challenges with DR participation, conjoint survey design, and program design recommendations. The goals of the interviews were twofold:

- Help the project team better understand the challenges and opportunities for agricultural DR participation, as observed in their direct interaction with agricultural customers in the field.
- Raise awareness of this research project and solicit their support for the study. For example, the stakeholders reviewed and provided feedback on the conjoint survey questions. The team also shared the conjoint survey results with the stakeholders, presented them with the cost analysis methodology, and invited them to share feedback on the optimal program design elements.

The stakeholder engagement was qualitative and was not intended to be a comprehensive market assessment. Table 14 summarizes the stakeholder feedback, organized by topic.

TABLE 14. STAKEHOLDER INTERVIEWS, SUMMARY OF FINDINGS

DR PROGRAM ELEMENT	INTERVIEW FINDINGS
Notification	General agreement among stakeholders that participation is achievable with 24-hour notice and that 30-minute notice would be difficult both for manual customers and customers with automated controls. Stakeholders anticipated difficulty in a 30-minute response for larger customers with a large number of pumps where each pump would need to be shut off individually. They expected smaller growers to have easier time for a short-notice DR event as they have fewer pumps to manage. Stakeholders suggested that a 2 or 4-hour advance notice would be preferred over 30-minute notice.
Event Limits	Stakeholders supported specifying a cap on the number of events per week. One stakeholder clarified that event limits based on frequency per week are more important than maximum events per month or per season for growers. In a month with four events, agricultural customers can manage one event a week but not four events in a single week. One stakeholder suggested also specifying a minimum number of events, so that growers can estimate the minimum incentive they will receive.
Participation Terms	Stakeholders commented that while more growers would sign up for a DR program with no penalties, performance would likely be greater if there were some type of penalties. The stakeholders added that including a penalty will help screen out less committed and low performing growers. If the goal of this new DR program is to grow DR, they noted that the tradeoff is weighed between a no-penalty program that attracts a large pool of customers but achieves low event performance or a program with penalty terms that enrolls a smaller pool of high-performing customers. Additionally, the stakeholders expressed a preference for including a capacity payment with the performance payment, with three of the actors expressing a strong preference. For the stakeholders, a capacity payment supports the cost of recruitment, enrollment, training, advanced planning of DR strategy, and the installation of equipment that enables DR participation.

DR Program Element	Interview Findings
Automated Technology	Stakeholders overall supported allowing ADR technology incentives to supplement DR program participation. Two stakeholders added that the ADR incentives is a bigger driver of DR enrollment than the performance payments in existing DR programs. Aggregators, who have been important contributors of DR program enrollment, take advantage of the upfront ADR incentives to engage agricultural customer about DR. For a customer with automated pump control but manual event notification, another stakeholder commented that a large grower would not be able to fully respond with just a 30-minute advanced notice if they had 30 or more pumps. The stakeholder said that it can take about a minute for an agricultural customer to execute a pump-off command for each pump. In this situation, the pumps are not typically networked together where one command would shut all of them off. One of the stakeholders offered a slightly different perspective, however, noting that if one works with the right customer, manual demand response is just as or more reliable than demand response with automated technology. Their perspective was that automation is helpful for smaller customers, while large customers are more concerned about workers being safe and damage to their equipment. The stakeholder noted that automation is not a significant advantage for DR events with day-ahead notice.
Miscellaneous	Stakeholders emphasized incorporating flexibility into the DR program design to accommodate customer preferences to encourage participation. For example, one stakeholder preferred the flexibility to nominate different customers for events, which gives them more control over how many dispatches for DR a grower experiences per month. Allowing flexibility for both automated and manual customers to enroll would be acceptable. Another stakeholder asked if agricultural customers would be limited to enrolling only in the new agriculture-specific DR program. Their preference is to maintain eligibility for agricultural customers in existing programs such as Capacity Bidding Program (CBP) and Base Interruptible Program (BIP). Another example is the flexibility in PG&E's current CBP to be able to update their bid price at least 3 days before the trade day, which one stakeholder noted they use to manage and mitigate back-to-back event dispatches for agricultural customers.

Discussion of Stakeholder Feedback

The feedback from stakeholders differs from the conjoint results in two significant respects, both related to the payment terms. First, the stakeholders prefer the inclusion of a modest penalty to motivate performance and screen for committed customers. Second, stakeholders prefer the addition of a capacity payment to cover their cost of project development and operations services for the customer. The difference in payment penalty terms implies a mutually exclusive program design between the conjoint analysis and stakeholder feedback. It would not be possible to design and test a program with no penalties at the same time as one that imposes penalties. It is also not possible to design and test a program that pays only a performance payment to customers against a program that pays a capacity payment. Other aspects of stakeholder feedback such as event limits, advance notification, and automated technology can be reconciled or aligned with the findings of the conjoint survey.

TABLE 15. PARTICIPATION TERMS PREFERENCES BETWEEN CUSTOMERS AND STAKEHOLDERS

PERSPECTIVE	CUSTOMER	STAKEHOLDER
Participation terms	Performance only strongly preferred	Capacity payment coupled with penalties strongly preferred

ADDITIONAL DESIGN CONSIDERATIONS

This section addresses additional qualitative research questions posed by PG&E regarding design options for an agricultural customer-specific demand response program. These include: enrollment and participation eligibility, requirements for DR event dispatch, options for dealing with forecasting of intermittent loads such as irrigation pumps, performance evaluation methods, and payment frequency. It also discusses the question of integration of the agricultural DR program with the CAISO wholesale market, barriers to participation, and offer suggestions on recruitment for a new program.

In addressing the additional qualitative research questions, the team drew from the DR benchmarking and agricultural technologies research, as well as stakeholder feedback. The research team also reviewed additional industry reports, California IOU DR program reports, and conducted analysis based on data from PG&E ADR program implementation as needed to address specific research questions not covered by the quantitative research. The research question and key findings are summarized in Table 16. Discussion of each research question as additional design considerations follows.

TABLE 16. ADDITIONAL DESIGN CONSIDERATIONS KEY FINDINGS SUMMARY

RESEARCH QUESTION	KEY FINDINGS	SOURCES CONSULTED
Should both direct and aggregator-enrolled customers be included?	Yes, both direct-enrolled and aggregator-enrolled customers should be included	DR benchmarking research, Literature review
Should dispatch of technologies be a requirement? If yes, should this program qualify for ADR rebates?	Both manual and automated technology DR projects should be included. Yes, program should qualify for ADR rebates	DR benchmarking research, Stakeholder interviews
What would be the event limits?	DR events trending more frequent (more than 12 events) and shorter duration (less than 4 hours). Event limits can be further delineated by consecutive days and by sublap.	Literature review, Stakeholder interviews
How can agricultural customers provide load forecasts to PG&E?	Three types of DR programs include: 1) A monthly nomination (e.g., CBP) 2) Dynamic rate with no forecasting required (e.g., PDP) 3) Customers set a firm service level with no forecasting (e.g., BIP)	DR benchmarking research, Stakeholder interviews
What method would PG&E use to measure actual performance?	Two alternatives to baselines include: 1) Customers must operate at or below their Firm Service Level (FSL) during an event. Performance is based on average kW demand minus FSL 2) Looking at the load 2-4 hours before the event start compared to load during the event hours	DR benchmarking research, Literature review, Stakeholder interviews

RESEARCH QUESTION	KEY FINDINGS	SOURCES CONSULTED
For ongoing incentives, with what frequency should (incentives) be paid out?	Monthly or quarterly performance reports with one payment at the end of season balances customer engagement with lower administrative burden	DR benchmarking research, Literature review
What are common obstacles that prevent agricultural customers from joining a DR program?	Insufficient irrigation capacity, labor flexibility, and financial incentives; technology constraints; and concern over impact to core operations	Literature review

ELIGIBILITY

The project team reviewed data on past agricultural customer demand response participation to inform options for customer eligibility criteria for new agricultural DR programs. These options include direct customer enrollment, enrollment with an aggregator or both enrollment pathways. Their strengths and tradeoffs are discussed below.

Allowing enrollment in the program with an aggregator could increase the number of customers that can participate in the program. Highly-motivated vendors and aggregators can boost program participation by recruiting and managing customers for the program in exchange for a share of the program financial benefits. Alternatively, direct enrollment by individual customers should also be supported. This pathway may be more attractive to customers that want more control over their program participation and that are willing to take on program participation risk in order to reap the full financial benefits of participation.

Additionally the team considered other eligibility factors such as manual versus automated DR participation. We reviewed 10 years of agricultural customer DR enrollment data for DR programs including PDP, BIP and CBP and found that for the 1,200+ participating service accounts on agricultural rate schedules for which data was available, about 19% had received ADR incentives.[18] The percentage of agricultural customers that received Automated Demand Response (ADR) incentives on a per program basis is shown in Table 17 below.

TABLE 17. AUTOMATED DEMAND RESPONSE PARTICIPATION BY DR PROGRAM FOR AGRICULTURE SERVICE ACCOUNTS

PROGRAM	ADR SERVICE ACCOUNTS	MANUAL DR SERVICE ACCOUNTS
BIP	37%	63%
CBP	60%	40%
PDP	7%	93%

[18] These estimates do not include agricultural DR customers that participated in other DR programs such as Demand Bidding Program, Aggregator Managed Portfolio Program, Excess Supply Pilot/Supply Side Pilot, and the Demand Response Auction Mechanism.

Compared to BIP and CBP, programs in which the customer must proactively enroll, fewer agricultural PDP service accounts have received ADR incentives since many customers may have defaulted to PDP rates without necessarily implementing a corresponding DR strategy that would require automation. BIP is not an ADR eligible DR program, but some BIP customers have received ADR incentives by leaving BIP and enrolling in an ADR-eligible DR program, by dual-enrolling in an ADR-eligible DR program when allowed, or by receiving an ADR incentive prior to moving to BIP. These data show that agricultural customers can successfully enroll in and participate in DR programs both manually and automatically; therefore, both manual and automated participation should be allowable in future agricultural DR programs. In at least one ADR incentive-eligible program where customers must proactively enroll (CBP), the majority of service accounts have received an ADR incentive indicating that they have used some level of automation to participate. Therefore, the availability of ADR incentives may be attractive to customers since automated participation is preferred by a large segment of potential participants.

Keeping technology eligibility options flexible allows different types of agricultural projects other than irrigation pumping to participate, such as nut processing. Allowing the program to qualify for ADR incentives facilitates recruitment of customers considering technologies. As discussed in the stakeholder feedback section, the stakeholders interviewed support allowing ADR incentives to be eligible for an agriculture specific DR program.

EVENT FREQUENCY, DURATION, AND EVENT LIMITS

PG&E has administered numerous commercial and industrial (C&I) DR programs in the past that span different levels of emergency load reduction and grid flexibility needs. Since 2009, PG&E has published interruptible load program (ILP) reports for these programs that detail, among other things, the event days, times, and sublaps called per year. Among the C&I programs listed on the ILP reports, only PDP, BIP, and CBP have maintained operation since the first ILP publication.

PDP is limited in the number of events that can be called per year (must be between nine and fifteen), the duration of the events (always three hours[19]), and the locational grid adaptation for events (all events encompass all of PG&E territory). BIP has flexibility on all three of those aspects but has historically been called for events very infrequently. CBP has flexibility on all three aspects and has been called more frequently over time compared to BIP. Because of this, to understand temporal patterns in demand response, we can look at the CBP over time, as shown in Figure 31 and Figure 32.

[19] Events were always four hours when the PDP program hours were between 2 and 6 PM, but starting in 2021 the event window changed to 5 to 8 PM.

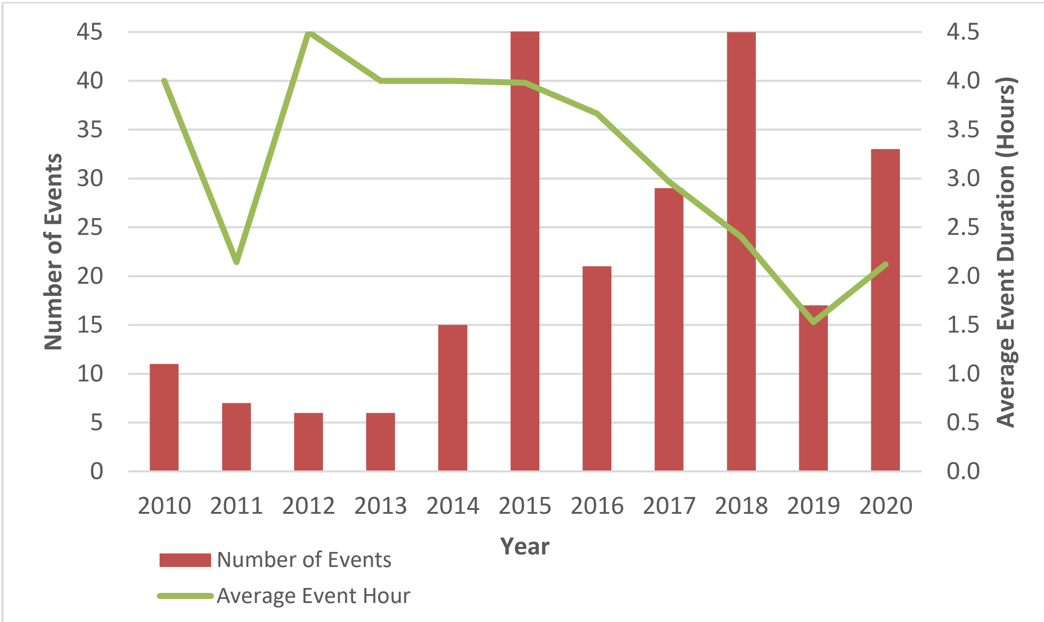


FIGURE 31: CBP ANNUAL TOTAL EVENT DAYS AND AVERAGE EVENT DURATION SINCE 2010[20]

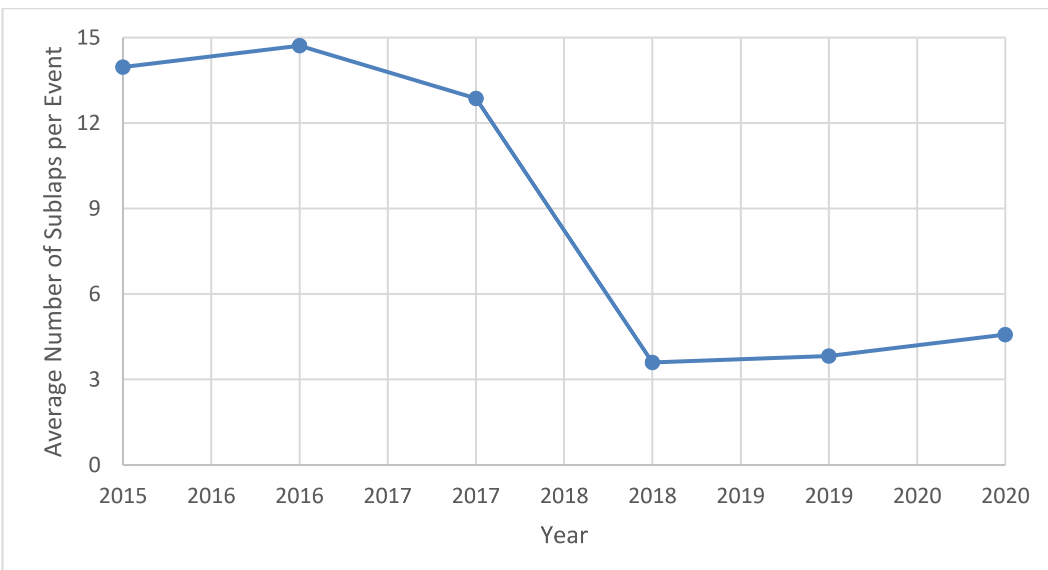


FIGURE 32: AVERAGE NUMBER OF SUBLAPS CALLED PER CBP EVENT[20]

[20] Events considered in this evaluation are all unique CBP event days. If different CBP products were called on the same day, those details were combined into a single event while expanding the event hours to encompass the earliest start time and latest end time. All data were taken from the PG&E Interruptible Load Program Reports (https://www.pge.com/en_US/large-business/save-energy-and-money/energy-management-programs/demand-response-programs/case-studies/case-studies.page)

As demand response needs can vary greatly year-over-year due to annual weather variations, we must take a long-term view to identify any meaningful trends. Figure 31 shows that from 2010 (the first ILP year with non-test CBP events) through 2014, CBP maintained a relatively consistent number of events and duration per event. However, since that time, the number of events has increased while the duration of those events have decreased. From 2010 to 2014, there were an average of nine CBP event days per year with an average event duration of 3.7 hours. From 2015-2019, the number of CBP events per year averaged 31 and event duration averaged 2.9 hours.

While these two trends started in around 2015, a third trend, as identified in Figure 32, focused on the number of sublaps (out of 15) being called for any one event started in 2018. As the number of events grew, they started being used to address sublap specific strain. In fact, starting in 2018, no CBP DR event incorporated all 15 PG&E sublaps. While in 2017, when combining CBP products to look only at unique events days, two thirds of event days called all 15 sublaps.

Based on these observations, capping the number of events or total hours called by sublap per season can offer additional program dispatch flexibility. In this approach, any single DR event affects only those customers that are located in the sublap, rather than all agricultural participants in the territory.

CUSTOMER AND EVENT LOAD FORECASTING AND PERFORMANCE EVALUATION

Agricultural load is intermittent by nature, with the majority of electrical load based on water pumping for irrigation that typically operates in an on or off state. This type of operation lends itself well to demand response since completely turning off the electrical load as an event response represents a significant load shed. This load shed can exceed that of more traditional building loads such as HVAC and lighting that are not considered intermittent and that are unable to completely shut down in response to a DR event for health, safety, and productivity reasons.

Although agricultural loads have significant DR potential, their intermittent nature creates a separate problem – how to forecast and evaluate demand response potential on an ongoing basis. For forecasting and evaluation, we can consider DR programs in three buckets:

1. The customer, aggregator, or other 3rd party provides a monthly nomination of their load shed potential and their performance is based on realizing the nominated amount, such as with the CBP.
2. The customer, aggregator, or other 3rd party provides no forecasting information and requires none for performance evaluation, such as with PDP.
3. The customer, aggregator, or other 3rd party provides a firm service level (FSL) below which the customer will reduce their load. This does not require any forecasting by the participant. Performance is based on reducing load to the FSL, such as with BIP.

While option one provides a forecast of the expected load shed, aggregators have noted the difficulty in providing an accurate value. A DR participant with intermittent load must still nominate a fixed monthly kW, but their daily operation may dictate low operation in any particular week of the nomination month due to either the normal weekly fluctuations of work (e.g., schedule changes or shifting to harvest) or unexpected operations (e.g., maintenance). Option two provides no forecasting or evaluation methodologies. Option three also provides no direct customer, aggregator, or 3rd party forecasting but does offer some reassurance of a realized event load due to the provided FSL.

Utilities across the nation that offer agricultural DR programs use different tactics for performance evaluation than the California IOUs:

- NV Energy looks at loads during the event compared to the load just prior to the event.
- Idaho Power uses a day-of adjustment based evaluation by looking at the previous three or four hours prior to the event to determine performance. This is in addition to weekly meetings with DR schedulers to understand the load they believe is available and reviewing AMI data in the two to three days prior to a potential DR event.
- Entergy Arkansas uses actual metered load compared with the load ahead of an event to report load shed and doesn't work with any baselines.

Those same utilities do not expend a significant amount of energy with event forecasting. They acknowledge that forecasting the load shed potential of agricultural loads for any one particular event is very challenging as they do not know for sure what the pre-event status of a pump will be.

While forecasting and evaluating performance for intermittent loads is a continuous challenge, instead of relying on a monthly nomination for forecasting or looking backwards at previous daily loads to develop a baseline for performance evaluation, these three utility programs take a more flexible approach with a greater focus on event day load to create realistic load reduction forecasts and performance evaluations. This approach generally implies that what is happening prior to an event is what would be happening during the event hours in the absence of that event. This is a significant assumption as daily, weekly, and seasonal operating schedules vary. Without access to the grower's schedule, it is difficult to be sure when a pump would naturally ramp up or down their operation. This can be especially difficult for DR events that intersect with time-of-use rates. If the DR event starts or ends at the same time as a time-of-use rate change, there is a second financial factor that is influencing the participant's operation.

By adopting an FSL approach, an agricultural program gets around the customer forecasts and baseline requirements. An FSL is the maximum demand in kW that a customer commits to consume during demand response. The customer thus needs to adjust their load down to or below the FSL in order to receive compensation. The payment amount can be based on the customer's average kW demand for the month within the program hours minus the FSL (e.g., BIP). If the program exacts a penalty, the customer pays it based on the amount of energy consumed above the FSL during the event period.

PAYMENT FREQUENCY FOR INCENTIVES

The agricultural DR programs reviewed for the benchmarking research were evenly split between paying incentives monthly/per billing period or paying incentives once a year. The advantages of paying incentives monthly is that it serves as a regular touch point between PG&E and the customer, and it gives customers more immediate feedback on performance following DR events when called.[21] For performance incentives, growers could be paid the month following the DR event. A drawback of monthly incentive payments is that they require a greater administrative burden particularly if the form of payment is by check or other external method. A monthly bill credit is another option that requires upfront administrative effort to set up but less burden to implement. In either case, the greater payment frequency requires a higher volume of tracking and record keeping.

Inversely, the once a year payment would have a lower administrative burden and less frequent opportunities for PG&E to engage with growers. This is not necessarily negative if growers prefer to be largely left alone. For smaller customers with lower committed load, a single payment for a larger incentive amount at the end of the DR season may be more attractive than smaller payments at monthly intervals. A third option that balances outreach frequency with payment frequency would be to provide monthly or quarterly performance reports to customers and a single performance payment at end of the season.

Agricultural Customer Motivations and Interest

Research reports that the team reviewed identified common obstacles among agricultural customers to enrolling in a DR program. These include:

- Knowledge gap between agricultural customers and utilities
- Insufficient irrigation capacity
- Insufficient labor flexibility
- Insufficient communications and controls
- Insufficient financial incentives
- Potential impact to core operations

There is a significant knowledge gap between the agricultural energy users, utilities, and the grid. Most farms do not have a dedicated energy manager to support energy management and usage decisions (Meyers & Hardy 2021). This lack of in-house expertise is a hurdle for agricultural customers to start and to complete the enrollment process for a DR program without the assistance of external consultants (Aghajanzadeh & Therkelsen 2019).

Insufficient irrigation capacity at agricultural sites during the peak of summer and insufficient flexibility of water delivery and application methods on farms all create constraints to DR participation and performance. Farms that rely on surface water deliveries are often unable to change delivery schedules without significant notice.

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[21] Behavior science studies show that high temporal granularity (e.g. hours or days) enables a stronger connection between specific behaviors and results. Lower temporal granularity (e.g. weeks or months) promotes reflection and comparison to self (Sanguinetti, Dombrovski, and Kurani 2018). High temporal granularity may be more useful in the short-term, while customers are connecting specific actions with performance, and lower temporal granularity may be more useful in the long term, when operators understand the effects of specific actions and are focusing on higher-level goals (Karlin, Zinger, and Ford 2015).

Certain irrigation methods such as flood irrigation are not flexible enough to stop and restart irrigation compared to other methods like drip irrigation. During DR events, onsite staff and personnel must be willing to adjust their schedules as necessary to participate.

Potential impact to core operations is another hurdle to DR participation at agricultural sites. The cost of irrigation electricity represents a relatively small fraction of the value of many of the major high-value crops grown in California (e.g., orchards, vineyards, nut trees, etc.). Agricultural customers may be less willing to participate because DR participation can be perceived to have a high risk-to-reward ratio (Olsen, Aghajanzadeh, & McKane 2015). Agricultural managers have a strong risk aversion to energy decisions that could impact crop yields and other core operations (Meyers & Hardy 2021).

The research reports discussed ways to address the obstacles identified above. Irrigation capacity constraints could benefit from reconfiguring and upgrading irrigation systems to operate more efficiently. Surface water deliveries to farms can benefit from greater flexibility with delivery scheduling from irrigation districts. Showcasing the benefits of changing irrigation methods can be a motivator to agricultural customers to enroll in DR (Olsen, Aghajanzadeh, & McKane 2015).

The installation of automated and/or remotely controlled irrigation systems are a viable solution to addressing a number of obstacles discussed. Operational constraints of conventional irrigation systems could be mitigated by greater penetration of in-field automation that can make DR participation more feasible (Aghajanzadeh & Therkelsen 2019). Automation of irrigation systems and other equipment can compensate for busy onsite staff by automatically turning off pumps and equipment for demand response (Olsen, Aghajanzadeh, & McKane 2015). Successful DR participation requires that agricultural customers receive sufficient timely notifications in order to allow agricultural customers to adjust pumping and irrigation schedules while minimizing impact on core operations. Dependable communication and notification networks can increase DR participation for agricultural customers. This constraint of insufficient communications and controls can be mitigated by installing automated controls and communication equipment (Olsen, Aghajanzadeh, & McKane 2015; Aghajanzadeh & Therkelsen 2019).

In order to make DR participation more compelling, financial incentives must be available to agricultural customers to reduce the costs to automate, control, and/or connect irrigation systems (Olsen, Aghajanzadeh, & McKane 2015). Communicating benefits of DR programs with financial incentives to customers and reducing the financial burden of participation are key elements (Olsen, Aghajanzadeh, & McKane 2015; Aghajanzadeh & Therkelsen 2019). Programs should optimize energy savings calculations taking into account agricultural adjustments such as pump operations, environmental conditions, weather, and crop conditions (Meyers & Hardy 2021).

RECOMMENDATIONS

Our recommended program design takes into account multiple research efforts, including:

- **Customer preferences.** The customer feedback was gathered via a conjoint choice experiment where 160 customers made choices between different program designs that presented tradeoffs between incentive levels, participation terms (e.g. penalties and capacity payment), dispatch frequency, event duration, and notification timeframe. Unlike regular surveys, conjoint studies are designed to quantify the relationship between customer choices and the attributes of the program design, thus identifying the program design elements that matter most to customers. The customer choice experiment quantified the impact of 108 possible program design permutations.[22] The study revealed that customers place more weight on penalty free options than all other attributes, including incentive levels.
- **An analysis of customer loads for all agricultural customers**. The analysis was designed to identify sites with loads that coincide with times when load relief resources are needed most – between 4 to 9 PM in summer months.
- **A cost-effectiveness analysis**. The cost-effectiveness analysis relied on estimates of enrollment rates (from the conjoint), load reduction potential, and costs/benefits in order to identify the optimal program design from a customer's perspective. The design that maximized expected net societal benefits (using the Total Resource Cost) among the 108 configurations tested was identified as the optimal design. The key assumptions of the benefit cost analysis can be found in Appendix C.
- **Benchmarking of agricultural demand response programs at other utilities.** The research team identified six existing agricultural programs, interviewed five program managers, and compared program designs based on targeted measures, control technology, eligibility rules, event frequency, event duration, advance notice, incentive structure and amount, and opt-out and discontinuation options.
- **Interviews with four aggregators and one technology provider.** Aggregators and technology providers were engaged throughout the study, providing input about the program attributes tested and feedback about the optimal design from their perspective.
- **Research into agricultural technologies and industry reports on agricultural demand response.** Agricultural demand response relies heavily, but not exclusively, on pump controls and other forms of automated technology. Thus, understanding the technology options is essential for program design.

Table 18 compares the directional preferences from the perspective of customers and of aggregators and technology providers. The customer perspective is based on the relative importance of respondents' preferences in the conjoint choice experiment and their relative impact on enrollment and expected program outcomes. The aggregator and technology provider perspective is based on direct interviews with four aggregators and one technology

[22] Choice experiment design specifications are described more in detail in the Conjoint Choice Experiment section

provider in which the optimal and similar designs were shared and discussed. The comparison is limited to program design attributes tested in the conjoint choice experiment.

There is reasonable alignment among these three groups of market actors regarding ranges of dispatch frequency and duration, notification, and participation payment levels. However, preferences diverge between customers, aggregators, and technology providers when it comes to participation terms. Customers strongly prefer a performance-only design while aggregators and technology providers strongly prefer a design which couples a guaranteed capacity payment with penalties.

TABLE 18. DEMAND RESPONSE PREFERENCE PERSPECTIVES

PERSPECTIVE	CUSTOMER	AGGREGATORS AND TECHNOLOGY PROVIDERS
Expected event frequency & duration	Fewer hours in general are somewhat preferred, but ~48 appears acceptable	Fewer hours are preferred, ~48 acceptable as long as there is flexibility such as limits on total hours by sublap and minimal consecutive event days
Notification	24 hour / Day Ahead	24 hour / Day Ahead
Assumed capacity value	$45/kW-year is acceptable	$45/kW-year is acceptable
Participation terms	Performance only strongly preferred	Capacity payment coupled with penalties strongly preferred $1.5/kWh penalties are acceptable

As a result, the optimal program design is an important reference point. Similar designs were also reviewed in the context of qualitative considerations such as market trends and expert feedback from a subgroup of four aggregators. Table 19 summarizes the recommended design elements, expected participation, and economic outcomes. The recommended design which includes two product options has outcomes only slightly below those for the optimal design: a TRC ratio of 1.1 as compared to 1.3 for the optimal design, and an expected load reduction of 17.5 MW as compared to 18.4 MW for the optimal design.

TABLE 19. RECOMMENDED PROGRAM DESIGN

PRODUCT OPTION	PERFORMANCE	CAPACITY+PENALTY	WOULD NOT ENROLL
Expected event frequency	12 / year	12 / year	
Event duration	4 hours	4 hours	
Notification	24 hour	24 hour	
Participation terms	Performance only	Performance + low penalty	
Assumed capacity value ($/kW-yr)	$45	$50	
Capacity payment ($/kW-yr)	N/A	$50	

Performance price ($/kWh)	$0.94[23]	N/A	
Penalty ($/kWh)	N/A	$1.56	
Shares of Preference	52%	31%	17%[24]
Standard Error	7%	7%	5%
Expected Program Size (full enrollment)	Performance	Capacity+Penalty	Program
Expected Participants	366	189	556
Expected MW-yr	11.3	6.2	17.5
Expected MW-yr (subset automated)	8.5	4.4	12.9
Cost-Effectiveness Results			
TRC B/C Ratio	1.2	1.0	1.1
UCT B/C Ratio	1.0	0.8	0.9

The recommended design of two side-by-side products incorporates the following key considerations identified in the qualitative research:

- **Include a capacity plus penalty product** for which the participation payment is equal to the full Capacity Value plus a penalty[25]. This addition reflects the strong preference of stakeholders for a product with guaranteed payments, which substantially lowers risk to the aggregators by mostly decoupling expected payments from the number of events called in a given year. Modeled cost-effectiveness outcomes for both products incorporate the assumption that penalties improve performance. A side-by-side test would provide a real world assessment of the magnitude of this difference.
- **Set event frequency at 12 events expected per year**. The adjustment to 12 expected events per year also reduces the performance price from $1.88 per kWh to $0.94 per kWh because the performance price is essentially the assumed capacity value divided by the number of expected event hours per year. More expected events per year means that the expected performance incentive is spread over more hours. Recent trends show an increase in event

[23] Reflects 100% of an assumed capacity value of $45/kW-year spread across 48 expected annual event hours

[24] Share of customer load that would not enroll in any product

[25] In the capacity plus penalty option, the capacity price is equal to the full Capacity Value ($50/kW-yr) in Table 18. However if a $ per kWh performance price is added to the participation terms, the Capacity Payment would be allocated between the Capacity Payment and Performance Price in Table 19

dispatch frequency for CBP and other DR programs as well as an increased need to use DR as a tool to meet grid reliability and grid economic needs.[26]

It is worth emphasizing that the aggregator preference for a product design with penalties is in direct opposition to the strong customer preference for the exclusion of penalties, as identified in the conjoint choice experiment. Respondents preferred a performance-only design by three to five fold over a design which included penalties, depending on the size of the penalties. Essentially, respondents demonstrated that penalties represent a strong perceived risk, even though designs with penalties were presented as offering expected bill savings that were about 70% higher.

This recommended design in Table 19 encompasses the results of the quantitative analysis and market research along with key inputs from the qualitative benchmarking and stakeholder interviews and feedback. The qualitative research, for which recommendations are summarized below, addressed additional research questions not covered in the quantitative research. The qualitative recommendations cover additional DR program design considerations such as clarifying eligibility requirements, customer and event load forecasting and performance, incentive payment frequency, and understanding obstacles that prevent agricultural customers from participating in DR programs.

TABLE 20. QUALITATIVE RECOMMENDATIONS TO ADDITIONAL DR PROGRAM RESEARCH QUESTIONS

Should both direct and aggregator-enrolled customers be included?	Allow both direct-enrolled and aggregator-enrolled customers to participate in an agricultural DR program.
Should dispatch of technologies be a requirement? If yes, should this program qualify for ADR rebates?	Allow both manual and automated participation for customers without and with technology. Conjoint survey results and a review of PG&E DR enrollment data over the last 10 years show that agricultural customers have significant interest and can successfully enroll in and participate in DR programs both manually and automatically.
What would be the event limits?	Set DR event limits based on the number of event days and total hours per season by sublap and minimize or avoid consecutive event days. Design the program so it can be dispatched locally, by dispatch area (sublap). Thus, any single DR event affects only those customers that are located in the sublap dispatch area rather than all agricultural participants in the territory. A maximum 15 events per year, or 60 event hours per year, would be a reasonable cap to implement for a program with an expected dispatch of 12 events per year on average.

[26] The expected event frequency is the expected average number of events, meaning that some years will have more events called, while others, less events per year. Further, there would be some flexibility within the constructs of the attributes tested in the choice experiment to dispatch longer or shorter events, given that event duration, like event frequency was characterized as "expected". In other words, in a typical event season 48 events hours would be expected, and a typical event would be 4 hours long, but this could vary from year to year based on dispatch needs.

How can agricultural customers provide load forecasts to PG&E?	Given the challenges of forecasting agricultural loads that are intermittent in nature, we propose using a firm service level (FSL) model of participation that does not require forecasting by the customer. Growers commit to a FSL of zero based on the strategy of shutting off equipment during DR events or a lower non-zero value if using VFD pumps. This alleviates the challenge of forecasting pump operation a month ahead, which can be highly uncertain given precipitation, water allocation, and soil and crop conditions that are in constant flux. Based on agricultural DR programs benchmarking, utilities have not relied on forecasts provided by their agricultural customers and aggregators. These utilities have developed forecasts based on the customer FSL and AMI data.
What method would PG&E use to measure actual performance?	Adopt a firm service level approach. Customers are paid when their load is at or below the FSL for the event. The payment amount could be based on the average kW demand for the month within the program hours minus the FSL.
For ongoing incentives, with what frequency should (incentives) be paid out?	As an alternative to monthly payments, performance reports could be provided at regular intervals, such as monthly or quarterly, and incentives could be paid once at the end of the season. This option helps reduce administrative burden of monthly incentive payments while balancing the desire for regular touchpoints and customer engagement.

PG&E is considering doing a field test based on these findings and recommendations and has the opportunity to do a side-by-side test of a penalty-free option (preferred by customers) and an option with capacity payments and penalties (preferred by aggregators). A side-by-side test of these two recommended product configurations would allow PG&E to quantify and compare enrollment rates and load impact performances. PG&E could then identify the product that delivered the most aggregate load reduction. A randomized control trial implemented by a subcontracted program administrator, in which one of the two products is randomly offered or marketed to potential participants, would ensure that the only difference between the two products would be participation terms. It is critical that implementation is identical, including customer support and technology offers, so that the only difference between the two products is the incentive mechanism. Ultimately, the design and implementation of a field pilot would need to be carefully planned so that key research questions are addressed.

APPENDICES

APPENDIX A: CHOICE BASED CONJOINT ANALYSIS

The choice based conjoint analysis used the conjoint survey results in order to estimate a respondent's preferences for program attributes and program designs. The choice data collected through a choice based conjoint exercise is simply the composition of each set of concepts shown to each respondent and the choices the respondent made given those concepts. Essentially, every time a respondent made a "choice" indicating a preference for a program attribute, that preference became one data point. Statistical software then constructed choice models for each respondent by using multinomial logistic regression analysis. Specifically, a Hierarchical Bayes (HB) approach was used in order to account for respondent heterogeneity.

A choice model includes an estimated impact for each parameter (each level of each attribute) on the likelihood to choose a particular concept design over alternatives. In the context of this experiment, data points were analyzed for each respondent in order to determine a respondent's preferences for a particular agricultural demand response design concept. Using a choice model, it is possible to model a respondent's relative preference, or preference share, between concept alternatives and the option to not select any concept (the "none" option). Preference shares across all modeled alternatives add up to 100% and represent the likelihood with which a respondent will prefer (or select in the survey) each option relative to the others.

It is important to note that preference share is not the same as enrollment likelihood because in a simulated survey setting there is a tendency to overstate the likelihood of actually selecting a concept. To make preference share more reflective of real world choices, it is often tied to actual observed data. Alternatively, preference shares can be compared on a relative basis, and differences can be interpreted as relative changes in enrollment likelihood or relative enrollment impact. Either method usually consists of establishing a baseline concept. For the agricultural demand response study, this would be the demand response plan design most typical among plans offered in the field pilot. Once a baseline is established, preference share for the baseline can be compared to preference share for other modeled concepts. However, because this research was pursued to address demand response portfolio gaps and was open to a range of customer sizes not eligible for current programs due to size, there was no baseline product to which to calibrate simulated uptake. As such, the reported preference shares are neither adjusted downward to temper the tendency for uptake to be overstated in a simulated experiment, nor adjusted upwards to reflect higher levels of marketing likely for an actual program rollout. To the extent that the pilot, expected to follow this research, uses direct-enrollment methods, it will be possible after the fact to calibrate the simulated uptake to observed uptake in the field.

Fundamentally, a choice model is constructed using logistic regression analysis. For an aggregate choice model, it is common to use a multinomial logit function (or similar model) to determine the average impact of each parameter on the decision to choose a concept. This would produce the average impact across respondents. However, different classes of respondents and even different individual respondents may have very different choice models from the average. That is to say that an individual's preferences may be very different than the average preference across respondents. Because of this, using an aggregate model to predict preferences for a set of individuals will introduce error to the extent that each individual's preferences differ substantially from the average.

The HB method uses an alternative approach. HB analysis produces a choice model which captures individual differences, resulting in a separate set of parameter impacts for each respondent. This method makes the critical assumption that each respondent's preferences for a given parameter come from a distribution of the overall population's preference for that parameter—or attribute level. By making this assumption, the estimation method can link all respondent's preferences for a particular attribute together and provide respondent-level impact estimates that are derived in part from population-level estimates—also called utility values as they represent the value a respondent accords to a parameter. This results in more precise estimates of each respondent's utility values[27].

The software[28] used to implement the conjoint experiment has built in HB estimation capabilities[29] and was used to produce parameter estimates. The output of the HB estimation is a set of utility estimates for each respondent for each attribute level and for the "none" option[30]. The units of these utility estimates are log odds ratios and their values represent the contribution a particular attribute level has towards the total utility of a given concept. As mentioned earlier, a concept is composed of one level for each attribute, and the total utility for a concept is the sum of the utilities for the relevant level of each attribute.

To calculate the preference share for a given concept, the total utility for the concept is exponentiated—because it represents the log of an odds ratio—and compared to the odds ratio of other alternatives. These alternatives usually include the "none" option, may also include other concepts, and in general should be a reasonable representation of the real world choice that is being modeled. For example, in a consumer product situation there may be a choice between two well-known brands, a generic brand (each with specific parameters), and "none." For a customer option such as a demand response program, a program may also offer multiple products, such as the differing windows and notification options for some CBP products. On the other hand, the only real choice facing the customer given a single program option is whether or not to participate,—as opposed to whether or not to participate given multiple plan options. In this case, only the preference shares for two options would be modeled: the choice to enroll in the program and the choice to not enroll in the program. Both single and multiple product lineups were investigated as part of this research.

Equation 1 and Table 21 detail how preference share would be calculated for the dual-alternative scenario described above. This equation could be extended to multiple options in two ways. In a pure preference share method, exponentiated utilities for other alternatives would simply be added to the denominator. This represents the respondent's preference for

[27] Note that the HB modeling assumes that respondent parameter preferences are related and normally distributed. Because of this, respondent-level choice models are different but related, rather than completely separate and unrelated.

[28] The software used was the Choice Based Conjoint module from Sawtooth Software, the industry standard for conjoint studies. Sawtooth Software has many modules and is widely used for surveying.

[29] For more technical background see https://www.sawtoothsoftware.com/download/techpap/hbtech.pdf

[30] The "none" option represents a respondent's tendency to choose nothing among a set of concepts. A key input to the estimation of this parameter is the respondent's tendency to indicate that concepts are not a possibility in the screening task.

one alternative, given a set of alternatives. The disadvantage of this method is that the preference share for a given concept is dependent upon the number of concepts modeled, since adding additional concepts to the denominator reduces the relative value of the preferred concept. This is the approach that was used to calculate preference share.

EQUATION 1: CALCULATION OF PREFERENCE SHARE FOR A CONCEPT

$$Preference\ share_{concept} = \frac{e^{U_{concept}}}{e^{U_{concept}} + e^{U_{none}}}$$

$$where\ e^{U_{concept}} = \sum_{1}^{n} U_{A_{i,l}}$$

TABLE 21: DEFINITION OF VARIABLES FOR CALCULATION OF PREFERENCE SHARE

VARIABLE	DEFINITION
U	Utility value
$U_{concept}$	Total utility of the concept
U_{none}	Utility of the "none" option
$A_{i,l}$	Level of the i^{th} attribute in the concept
n	Number of attributes

In the second alternative method, a two-step decision process is modeled. Initially, the concept with the highest utility is selected among all modeled alternatives—not including the "none" option. This represents the respondent's preferred concept. Then, the preference share is calculated for the preferred concept given the "none" alternative. This represents the respondent's likelihood of actually selecting that concept over selecting nothing at all and means that a preferred concept will always have the same preference share, regardless of the number of inferior alternative concepts also being modeled. In practical terms, this method assumes a two-step choice process starting with the identification of a preferred concept, followed by a final decision on whether to choose that concept or nothing at all[31].

[31] The two options described for calculating utilities are applicable only when modeling two or more demand response program designs that are available side-by-side.

APPENDIX B: ASSESSING STATISTICAL SIGNIFICANCE OF CHOICE BASED CONJOINT ANALYSIS

The simplest type of regression analysis, an ordinary least-squares (OLS) linear regression, has straightforward and relatively well known measures of statistical significance, namely:

- **P-values for each parameter estimate[32]:** the probability that an estimate is different from zero only due to random chance. One minus this number is the "confidence level" of the estimate, and a commonly accepted confidence level is 95%. The confidence level is a gradient, and a 94% confidence level is still indicative of reasonable confidence in an estimate.
- **R-squared for the model:** the percentage of observed variation that is explained by the model. Adjusted R-squared, a similar statistic, also adjusts for degrees of freedom (including the number of model parameters). There is no commonly accepted significance cutoff for interpreting R-squared or adjusted R-squared, and the interpretation depends on the amount of inherent variation in the variable being modeled. A value below 25% is considered small (though not necessarily indicative of an invalid model), and a value of 50% can actually be indicative of statistically valid predictive power in many situations.

Because of the complexity of a logistic regression such as a choice model, the assessment of statistical significance or model accuracy is not as straightforward as it is with linear models. That said, several measures can be used in the design and analysis process to ensure a model has statistically valid and significant predictive power.

- **Standard error of parameter estimates:** While the HB estimation method has the advantage over aggregate logistic regression analysis of including individual level variation, logistic regression does have a useful purpose. In particular, an aggregate model can be used to produce standard errors for parameter estimates. This is particularly useful in the research design phase to ensure that the sample size and number of parameters planned should produce statistically significant results. This analysis is done by running an aggregate model (such as an aggregate logit model) on randomly generated data[33]. Since the data are randomly generated, parameter estimates are not expected to be different from zero[34]. In other words, the choice impact of two

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[32] Derived by plotting the ratio of an estimate and its standard error on a normal distribution.

[33] While it is also possibly to use an aggregate model to estimate parameters using actual data once it is collected, such estimates will necessarily differ from HB estimation results, due to the fundamental differences in the two models. Therefore it is not recommended to interpret the values of such aggregate estimates other than to confirm that standard errors are still small.

[34] Therefore a p-value interpretation cannot be used since it a test for whether a value is significantly different from zero.

alternatives should be no different than random chance (or a 1:1 ratio). While there is no commonly accepted cutoff for standard error values in this context, 0.05 is a recommended[35] empirical target value, although levels below 0.10 are still deemed acceptable. The technical interpretation of a 0.05 standard error from randomly generated data is that it represents a variation of +/- 2.5%, well in the range of statistically significant validity. A parameter estimate standard error of 0.05 on actual data (not randomly generated data) would represent an even lower variation.

- **Root likelihood error:** The error used to evaluate the precision of a choice model for an individual respondent is called root likelihood (RLH) error[36] and represents the accuracy of an individual respondent's choice model in predicting the actual choices that respondent made in the choice exercise. This statistic must be interpreted in the context of the choice task structure. For example, if three alternatives were presented in each choice task, a random chance model would have correctly predicted choice about one third of the time, or an RLH value of 0.33. If a choice model has an RLH value of, say 0.67 (correctly predicting choice two thirds of the time), it can be said to be twice as accurate as a random chance model.
- **Percent certainty[37]:** Percent certainty represents the percent of variability in actual choices that is explained by a logistic model. This makes it similar in interpretation to an adjusted R-squared statistic for OLS regressions, with the important distinction that values are typically lower than for R-squared or adjusted R-squared. While there is no commonly accepted threshold for statistical significance, values from 0.2 to 0.4 (or 20% to 40% certainty) represent "excellent model fit" according to the creator of the statistic[38].
- **Standard error of preference share estimates**: The above three statistics assess either aggregate estimates for parameter utilities (as with aggregate logit standard errors) or predictive power of the model on a whole but not of individual utility estimates (RLH and Percent Certainty). An option for assessing the statistical validity of utility estimates derived using HB estimation is estimating the standard error of preference shares estimated across respondents. This provides an assessment of the variation in preference share across respondents for given a concept specification. Thus, the standard error of preference shares for a given concept is simply a measure of preference share dispersion. These standard errors are calculated

[35] According to Sawtooth Software, which has observed hundreds of studies, models with parameter estimates at or near 0.05 tend to be more stable and have better predictive power, based on external validation.

[36] Root likelihood error is the geometric mean of the probabilities corresponding to the choices made by respondents, obtained by taking the Nkth root of the product of the Nk probabilities. The best possible value of RLH is unity, achieved only if the computed solution correctly accounts for all the choices made in all tasks by all respondents.

[37] Also called rho-squared or McFadden's pseudo R-squared. "Conditional logit analysis of qualitative choice behavior." McFadden. 1974.

[38] Urban Travel Demand: A Behavioral Analysis. Domencich and McFadden. 1975. Reference to rho-squared appears in Chapter 5, Pages 122 onwards.

by using the preferences share values, appropriate respondent weights (load and quintile weights), and the number of respondents.

All four of these methods were used when designing and analyzing the Choice Based Conjoint Experiment. The choice model (consisting of the attributes and levels tested) was designed to ensure statistical validity and predictive power of the model. Analysis of the data collected also indicated that the choice model has strong predictive power as a whole, and for individual parameter estimates.

TABLE 22: RESULTS OF TESTS OF STATISTICAL VALIDITY AND PREDICTIVE POWER FOR CHOICE MODEL

STATISTIC	RESULT	INTERPRETATION
Standard error of aggregate logit utility estimates using random response data	Error estimates using 175 randomly generated responses ranged from .035 to .051	Less than 5.1% variation in aggregate parameter estimates using random data simulated to represent individual segments
Average root likelihood error of HB estimation	.673	Choice model is approximately twice as accurate as a random guess
Percent certainty	71.5% certainty	Excellent choice model fit
Standard error of preference shares across respondents	Error estimates ranged from .014 to .074	Little variation in parameter estimates, which implies a low p-value (below .01) and high statistical significance for most product configurations

APPENDIX C: COST EFFECTIVENESS MODELING ASSUMPTIONS

TABLE 23: CONJOINT SIMULATOR TOOL ASSUMPTIONS

ASSUMPTION	VALUE(S)	SOURCE
Avoided Cost of Generation Capacity ($/kW-yr)	$102 - $70 for 2022 - 2026	2021 ACC Electric model v1a.xlsm
Event Duration Factors	Average of last in, first in values and 2019-2030 values	Demand Response ELCC, CAISO, June 2021 (E3)
Notification Factors	24 hour: 88% 30 min: 100%	Typical values used for DR benefit cost analysis
Participation Terms Factors	Performance + low penalty: 95% Performance + high penalty: 100% Performance only: 80%	
No Automation Factors	24 hour: 60% 30 min: 8%	Portion of reduction expected to be delivered from non-automated load (relative to automated loads). Based on CPP and CBP load impact values
Financial Assumptions	Retention rate: 90% WACC: 7.80% Real Discount: 3.00% Inflation: 2.50% Base Year: 2021	2021 ACC Electric model v1a.xlsm
Fixed Administrative Costs	$300,000 per year. 25% reduction if only a single product is administered	PG&E
Marketing costs	$16 per kW acquired	Market Analysis of DR programs
Automation Technology Fees	$4 per meter per year	Automated Demand Response Non-Residential Incentive Structure Research Project Report
Automation Technology Costs	$261 - $381 per automated kW	Automated Demand Response Non-Residential Incentive Structure Research Project Report
Automation Technology Useful Life	7.5 years	Automated Demand Response Non-Residential Incentive Structure Research Project Report
Share of Participation Payments Applied as Participant costs	25%	2021 ACC Electric model v1a.xlsm

APPENDIX D: CUSTOMER SURVEY INSTRUMENTS

CUSTOMER SURVEY OUTREACH MATERIALS

Energy Solutions

Receive a $50 thank you for completing the survey.

Dear <<First>>

You're invited to participate in a study we are conducting on behalf of PG&E to help develop a program that could save money for businesses like yours. It could also help your community by better managing energy demand, which keeps power cleaner and more reliable for everyone. Your feedback is very important to us and it will help design a program that best meets the needs of businesses in the agricultural sector. **It will take about 10 minutes, plus, the first 200 people who complete the survey will receive $50.**

Do you help make decisions about how and when energy is used in your business? Would you help make decisions about energy programs? If so, this survey is for you. If there is another contact within your organization that you think is more appropriate to answer the survey, please invite them to complete this survey instead. If you have any questions about this survey, you may contact PG&E's Customer Service Center at 1-800-743-5000.

Visit AgEnergySurvey.com to begin the survey or use the QR code on the right. Your unique 4-digit code is <<**dsa_id**>>. We value your input and look forward to hearing from you.

Scan this QR code with your smartphone camera app to begin the survey.

Sincerely,

Kitty Wang
Technical Director, Distributed Energy Resources
Energy Solutions

Distributed on behalf of:

Demand Side Analytics

Recruitment Letter

View this email in your browser

Have your say and get $50

We're developing a program to help agricultural businesses like yours save money by avoiding the highest prices on energy, while maintaining a healthy, thriving business — and we need your opinion. **Plus, the first 200 people to respond will receive $50 as a thank you for completing the survey.**

We want to hear your thoughts on a program that will pay you to reduce your energy use during critical times throughout the year by making slight shifts in the times you use pumps and other equipment. Click the link below and enter your unique 4-digit code to begin the survey. It should take about 10 minutes to complete.

<<Link to Survey>>

Your unique 4-digit code is **XXXX**.

The survey will be most relevant for people who make decisions about energy programs and about how and when energy is used in your business. If this is you, please respond to the survey above. If there is another contact within your organization that you think is more appropriate to answer the survey, please invite them to complete this survey instead. If you have any questions about this survey, you may contact PG&E's Customer Service Center at **1-800-743-5000**.

Authorized Implementer of PG&E Programs

Energy Solutions

Demand Side Analytics

Our mailing address is:
|HTML:LIST_ADDRESS_HTML| *|END:IF|*

Want to change how you receive these emails?
You can update your preferences or unsubscribe from this list.

|IF:REWARDS| *|HTML:REWARDS|* *|END:IF|*

Email 1

View this email in your browser

Your $50 thank you gift is waiting

We value your opinion and want to hear what you have to say about a program we're developing, in partnership with PG&E, that can help businesses like yours save money. Don't forget to take our survey. **It will only take about 10 minutes and you'll receive $50 as a thank you for completing the survey.**

The proposed program would pay you to reduce your energy use during critical times throughout the year by making slight shifts in the times you use pumps and other equipment.

Click the link below and enter your unique 4-digit code to begin the survey.

Click here to take the survey.

Your unique 4-digit code is ***|UNIQUECODE|***.

The survey will be most relevant for people who make decisions about energy programs and about how and when energy is used in your business. If this is you, please respond to the survey above. If there is another contact within your organization that you think is more appropriate to answer the survey, please invite them to complete this survey instead. If you have any questions about this survey, you may contact PG&E's Customer Service Center at **1-800-743-5000**.

Distributed on behalf of:

Energy Solutions

Demand Side Analytics

You're receiving this email because you were selected as a PG&E customer to participate in a customer interest survey.

Our mailing address is:
|HTML:LIST_ADDRESS_HTML|

Want to change how you receive these emails?
You can update your preferences or unsubscribe from this list.

Email 2 - Reminder

View this email in your browser

Your $50 thank you gift is waiting

We want to hear from you about a program we're developing, in partnership with PG&E, that can help businesses like yours save money. **There are only 3 days left** to reply to the survey and give us your thoughts about a proposed program that will pay you to reduce your energy use during critical times throughout the year by making slight shifts in the times you use pumps and other equipment.

The survey will only take about 10 minutes, and you'll receive $50 as a thank you for completing it.

Click the link below and enter your unique 4-digit code to begin the survey.

Click here to take the survey.

Your unique 4-digit code is **<< Test dsa_id >>**.

The survey will be most relevant for people who make decisions about energy programs and about how and when energy is used in your business. If this is you, please respond to the survey above. If there is another contact within your organization that you think is more appropriate to answer the survey, please invite them to complete this survey instead. If you have any questions about this survey, you may contact PG&E's Customer Service Center at **1-800-743-5000**.

Distributed on behalf of:

Energy Solutions

Demand Side Analytics

You're receiving this email because you were selected as a PG&E customer to participate in a customer interest survey.

Our mailing address is:
Energy Solutions
449 15th St
Oakland, CA 94612-2821

Email 3 – Last chance

CUSTOMER SURVEY QUESTIONNAIRE

Customer Survey Questionnaire.docx

APPENDIX E: DR PROGRAMS BENCHMARKING OVERVIEW AND KEY CONSIDERATIONS

TABLE 24. BENCHMARKING OF AGRICULTURAL DEMAND RESPONSE PROGRAMS IN THE UNITED

UTILITY	PROGRAM NAME AND SEASON	TARGETED MEASURES AND CONTROL TECHNOLOGY	ELIGIBILITY	EVENT FREQUENCY AND DURATION	ADVANCE NOTICE	INCENTIVE STRUCTURE AND AMOUNTS	OPT-OUTS, PENALTIES, AND DISCONTINUATION OPTIONS
Idaho Power	Irrigation Peak Rewards Summer June 15 to August 15	Automated and Manual Irrigation Pumps Pump Control Switch (DRU Demand Response Unit)	Metered Service Point (MSP) receiving service under Schedule 24 where the MSP serves a water pumping or water delivery system used to irrigate agricultural crops or pasturage. No motor size requirements.	Min. 3 events per season Max. 4 hours per event, 15 hours per week, 60 hours per season	4 hours before event	Events 1-3 $5.00/kW and $0.0076/kWh energy credit. Events >3 energy credit of $0.148/kWh and $0.198/kWh for standard and extended interruption events, respectively. Check mailed within 45 days from the end of the program season.	Max 5 opt-outs per season per service point. First three opt-outs; $5.00/kW fee based on the current month's total billing kW (for manual controls, based on kW not turned off during event). Additional opt-outs; $1.00/kW fee. Will never exceed the total incentive received for the season. $500 fee for each service point removed from June 15 - August 15. If re-enrollment is desired,

Utility	Program Name and Season	Targeted Measures and Control Technology	Eligibility	Event Frequency and Duration	Advance Notice	Incentive Structure and Amounts	Opt-Outs, Penalties, and Discontinuation Options
							must wait until following year.[39]
Rocky Mountain Power	Irrigation Load Control Program Summer June 1 to September 30	Automated Irrigation Pumps	Rocky Mountain Power customers served on Schedule 10 tariff. No motor size requirements, one-time fee of $1,500 per pump less than 50 kW.	Max. 1 event per day, 20 events per season Max. 12 hours per week, 52 hours per season	Day ahead: 5:00 p.m. day before event	Expected kW per pump >100 kW = $25/kW (Utah) and $23/kW (Idaho). Expected kW per pump <100 kW = $21/kW (Utah) and $19/kW (Idaho). Bonus incentive if program is >125 MW. Paid monthly.	No penalties. Incentives reduced based on average available load during program hours, adjusted for the percentage of events in which they participated.
Entergy Arkansas	Agricultural Irrigation Load Control Program Summer June 1 to August 31	Automated Irrigation Pumps Pump Control Switch and Customer Portal	Must be on agricultural tariff and operate a motor a minimum of 64 hours a month during the program months.	Max. 2 events per week, 15 events per season Max. 4 hours per event	Day ahead	Based on rated hp of pump motor: 10-15 hp = $50 26-50 hp = $100 51-75 hp = $200 76-100 hp = $250 101-125 hp = $350 126-150 hp = $450 151-175 hp = $550 176-200 hp = $650	No penalties. Participants may opt out and re-enroll in the program at any time prior to June 1. For program opt-outs, field services puts control boxes in bypass mode.

[39] Idaho Power is proposing a new tariff where enrollment of 30 HP or less would be assessed a $500 fee to participate. The one-time fee is to cover installation of the DRU based on the low amount of load reduction anticipated for the smaller pumps.

Utility	Program Name and Season	Targeted Measures and Control Technology	Eligibility	Event Frequency and Duration	Advance Notice	Incentive Structure and Amounts	Opt-Outs, Penalties, and Discontinuation Options
						>200 hp = Upon request Paid monthly.	
Pacific Power Oregon	Irrigation Load Control Pilot Summer June 1 to September 30	Automated Irrigation Pumps	Must be on agricultural tariff. No official minimum motor size but difficult to connect pumps less than 10 hp.	Max. 1 event per day, 20 events per season Max. 12 hours per week, 52 hours per season	Day ahead or 1 hour before event	$18/kW for day ahead notification. $30/kW for hour ahead notification. No payment timeframe given.	Opting out lowers average participation percentage and payments proportionally.
Southern California Edison	Agricultural and Pumping Interruptible Program (AP-I) Year Round Summer = June 1 to September 30 Winter = October 1 to May 31	Automated Irrigation Pumps Pump Control Switch	Agricultural and Pumping Rate Schedule. Measured demand of ≥ 37 kW, or at least 50 hp of connected load.	Max. 1 event per day, 4 events per week, 25 events per year Max. 6 hours per event, 40 hours per month, 150 hours per year	No notice. Device automatically drops customer load.	$/kW/Meter Summer = $19.62/kW Winter = $10.87/kW Monthly credit/capacity payment.	
NV Energy	IS-2 Interruptible Irrigation Service Spring and Summer March 1 to October 31	Manual Irrigation Pumps	Must fall under IS-2 rate schedule and be an agricultural producer as determined by local government assessor.	Max. 3 hours per event	30 minutes before event	The IS-2 tariff offers lower rates, $25 per meter monthly charge is also waived.	For first opt-out, rate increased to IS-1 tariff for entire month. For second-opt, rate is increased to IS-1 for entire season. If customer voluntarily disconnects, there is a $250 fee to reconnect.

APPENDIX F: DR PROGRAMS BENCHMARKING - KEY CONSIDERATIONS

IDAHO POWER - IRRIGATION PEAK REWARDS

The Idaho Power Irrigation Peak Rewards Program has been operating since 2003 and is regarded as a successful, top-tier agricultural demand response program. With options for both automated and manual demand response, the program attempts to be inclusive to all agricultural producers operating within the program's rate schedule.

The Public Utility Commission (PUC) requires a minimum of three events per season. This is seen to keep customers engaged in the program over the need to truly reduce capacity. Triggers revolve around hot and dry weather when nearing peak load on the grid. On September 31, 2021 Idaho Power filed proposed program changes with the Idaho and Oregon Public Utility Commissions. Program parameters will attempt to better meet the needs of balancing the growing demands of electricity and solar on the system.

The program is considering how the continued growth of solar will alter the future of the electric grid. Through the recent Integrated Resource plan project, the need for demand response has shifted to a 3pm to 11pm timeframe. Additionally, the season will extend from August 15th to September 15th of each year. Participants may elect to enroll from 3pm to 10pm or to 11pm as an extended option and an additional variable payment. With the approval from the PUC, the program will also begin to add more pumps to the program. Since 2013 there have not been any new pumps added due to a 'settlement agreement' with the PUC and other stakeholders.

KEY CONSIDERATIONS

The program is flexible with its participants offering manual and automated response options. While the automated option is most sought after due to ease in participation, in a few instances irrigators with pumps in locations with limited communication availability may participate manually. With the 1:00 to 9:00 p.m. event time window, pumps are called in groups up to four at a time for 4 hours each. Depending on the timeframe during season, each group offers load reduction of 45 – 90 MW of load reduction. Actual performance is typically 50 to 75 MW based on AMI data three to four hours before the event. During DR season, Idaho Power provides weekly reports of available load to Load Servicing Operators/Day ahead schedulers based on AMI data two to three days in advance.

Program incentives haven't changed since 2013. It's believed that incentives are too low and driving customers away from the program. When compared to other agricultural DR programs in this study, this program is at the lower end of incentive amounts. Also, agricultural producers are likely to choose the health of their crop(s) over a demand response event. The program's costly penalties to opt-out of an event may further deter producers from participating. Idaho Power maintains the pump controller devices, which requires ongoing attention. Program operators regularly analyze the devices to identify, repair, and replace underperforming or missing pump controllers.

ROCKY MOUNTAIN - POWER IRRIGATION LOAD CONTROL

The Rocky Mount Power Irrigation Load Control Program is a pay-for-performance structured program which serves irrigators in the states of Utah and Idaho. Participants are compensated based on the average available load a pump can reliably shut off during an event. The load is determined by the size and run frequency of the pump in the program. The payment structure offers a base incentive for load reduced per pump, per pump size, per state with payments delivered after the end of the season.

Customers are eligible to opt out of any events with no fee applied. However, opting out lowers the average participation percentage and payments proportionally. Consequently, the potential downside is if only a small number of events are called in a season the participants' payment will suffer.

KEY CONSIDERATIONS

If an irrigator's average load per pump is less than 50 kW, then a onetime enrollment fee of $1,500 per pump applies to participate in the program. It's assumed that this fee was implemented by the program to cover the installation and/or unit cost of the demand response device. The fee is a definite deterrent for many irrigation operations with smaller loads per pump.

Participants are offered a bonus incentive per kW reduced during an event if the program exceeds 125 MW in total savings. While this incentive is only $2.00 more than the existing base incentive across the different state and pump size categories, it still provides additional funds to participants during high performance years and can also entice participation throughout the program.

ENTERGY ARKANSAS - AGRICULTURE IRRIGATION LOAD CONTROL

The Entergy Arkansas Agriculture Irrigation load Control Program offers flexibility of participation. It draws high satisfaction ratings from its participants and has a high carry-over of participants from year to year. The program modified its incentive structure from $/kW to $/hp for the relative simplicity for participants and program operators.

Opt-out and discontinue options are not penalized in this program. And unless equipment removal is requested by an irrigator, field services just place the demand response device on bypass mode which allows for future participation in the program. This provides flexibility for irrigators to participate in the program from year to year as they often rotate crops annually to maintain positive nutrient and soil conditions.

Key Considerations

The program does not pay incentives to irrigators that operate a motor less than 64 hours a month during the program year. It's assumed this requirement ensures participating motors cover the installation and/or unit cost of the demand response device. Irrigators forgo their monthly bonus when pump hours fall below 64 hours.

A potential benefit to the eligibility design is that run hours of a device may be much more relatable to farming operations compared to load. This is seen in other aspects of the program with the pricing structure being based on a pump hp. The larger the rated hp per pump the higher the incentive. The program also uses the measured load immediately before the event to report load shed. This is not reliant on utility advanced metering infrastructure (AMI) which can be delayed, and not reliant on baselines.

Pacific Power - Irrigation Loan Control Pilot

The Pacific Power Irrigation Load Control Pilot offers a pay-per-performance incentive structure focused on the notification timeframe of events. Hour-ahead dispatch notifications carry a $30/kW incentive while day-ahead notifications carry a $18/kW incentive.

The program receives a list of customers by rate class. Additional information requested, if available, includes what size circuit and substation the pump is on. As a result of this information, the program focuses on higher value loads or pumps that run during event windows. These customers are then contacted by the program operator to see if they interested in participating in the program.

The program's integrated measurement and verification technology also gives real time data to the utility and farmer. Event performance is evaluated based on measured load immediately before the event. Providing more data to all parties involved, particularly the irrigator who can better understand their operation and load per pump.

Key Considerations

One enticing aspect about the program is the high incentive amount. Another positive attribute would be the capabilities of the installed demand response device. It allows growers to see recent irrigation pump status with a reliable stop and start feature from any type of device connected to the internet. This provides a versatility to the farmers participation and allows them to remote start after an event, something that not all automated demand response programs offer.

Southern California Edison - Agricultural Pumping Interruptible Program

The Southern California Edison AP-I Program is available to agricultural pumping customers with a measured demand of 37 kW or greater, or with at least 50 hp of connected load. The program boasts a simple process for participants which includes only three steps: application, installation, and participation. The program also offers participation in other demand response programs for additional incentives. This participation comes with limitations which are described in the contract but offers additional revenue streams for the participant.

Compensation is a time-of-use credit applied to participant's accounts. Incentives are issued based on a $/kW per meter per month basis with the exact formula located in the program's contract. SCE does not calculate performance for the purposes of paying the customer the incentive. The AP-I devices are designed to totally shut down the customer's load. SCE monitors pumps that don't shut off and evaluate if device maintenance is needed.

Controller device installation is done by third party vendors who have 45 days to complete the installation. The whole process from customer enrollment to program participation generally takes two months, with some exceptions to participants where a second visit by the installation team is required.

KEY CONSIDERATIONS

No advanced notice is given to irrigators participating in the program. Devices automatically drop customer load upon a given request by the program operator. This is due to the program's no optout option in which changes or cancellations are only available during the annual adjustment windows outlined for the program. This relatively strict program rule may be seen as a deterrent to customers interested in participating in the program. It also carries the potential to threaten crop yields if water is required during an event or string of events and the irrigator has no other option.

The program also faces challenges with device maintenance and failures. Devices are triggered by radio frequency and do not always connect in remote areas due to poor service. Program operators need to constantly inspect the devices to ensure they're operating appropriately.

A benefit of this program is its readiness to emergency reliability. Resources for load reduction are available at any time during the year, providing considerable flexibility to program operators. No advanced notification requirements, no performance-based incentives and no opt-outs provide a strict, though straightforward and streamlined, process for program operators and participants.

NV ENERGY – IS-2 INTERRUPTIBLE IRRIGATION SERVICE

NV Energy's IS-2 Interruptible Irrigation Service has been operational for over a decade. Participants are placed on an IS-2 tariff, which charges lower rates and waived meter charge of $25 per month in exchange for being ready to respond to events between March 1 and October 31. This is an emergency program and events are initiated with a minimum of 30 minutes advanced notice, and last two to three hours. A customer that opts out of their first event is placed on the IS-1 rate for that month which is often a higher rate. A customer that ops out of their second event is placed on the higher IS-1 rate for the rest of the season. Initially a direct load control program targeting irrigation pumps, IS-2 transitioned to a manual program in 2019 when the controls manufacturer discontinued communication service for the switch technologies.

KEY CONSIDERATIONS

Customers who have stayed in the program following its transition from direct load control to manual participation remain satisfied with the program. This is due to the discounted rate offered by the IS-2 tariff and that only 2 events have been called since 2012. NV Energy dispatched the IS-2 once in 2020 and once in 2021 when their system was impacted by grid emergencies in California. As a manual program, customers are required to self-inspect the participating pumps and submit annual qualification information in a Self-Inspection Reply Card to renew their enrollment each year.

Event performance is evaluated by looking at the load drop at the start of the event compared to load immediately before the event. All irrigation customers including IS-2 customers have AMI. With manual participation, the utility is seeing reduced performance. Similar to Southern California Edison and Idaho Power's direct load control programs, maintenance of the pump switches has been time consuming and costly. Many pumps are located in remote locations so cellular costs can be high. Farm animals knock off the boxes and antennae or customers remove them during pump maintenance or replacement.

Appendix G: Technology Research Information

Table 25. Irrigation Technology Products Reviewed

Company	Product Name	Controls for new/retrofit	Remote Off/On control	Sensor Network/Hardware/Software	Remote communication	Remote Pump Monitoring/EMS	Pump/irrigation Scheduling
Jain	Controller (3 Models - Hermitcrab, Smartbox, Smartwork repalcement panels)	Yes/Yes	Yes/Yes	Yes/Yes/Yes	Yes	No/No	No/Yes
Jain3	Jain C3 Field Station (Monitoring and Control)	Yes/No	Yes/Yes	Yes/Yes/Yes	Yes	Yes/Yes	Yes/yes
PumpSight	pSight and rSight	Yes/Yes	No/No	Yes/No/Yes	Yes	Yes/Yes	No/No
Sentek	TriScan sensor and IrriMAX platform	No/No	No/No	Yes/Yes/Yes	Yes	No/No	No/No
Groguru	GroGuru STEM, GroGuru WUGS and GroGuru BASE	No/No	No/No	Yes/Yes/Yes	Yes	No/No	No/No
Wildeye	Wildeye	No/No	No/No	Yes/Yes/Yes	Yes	Yes/No	No/No
FloraPulse	FloraPulse	NA	No/No	Yes/Yes/Yes	Yes	Yes/No	No/Yes
Davis Instruments	Growweather, Vantage Pro2 and EnviroMonitor	No/No	No/No	Yes/Yes/Yes	Yes	No/No	No/No
Irrometer	WEM (Watermark Electronic Module)	Yes/Yes	No/No	Yes/Yes/Yes	Yes	No/No	No/Yes
Ag Monitor	Software-as-a-Service (SaaS) subscription	No/No	No/No	No/No/No	Yes	Yes/Yes	Yes/Yes
Jain2	Jain Logic (Monitoring and Control)	Yes/No	Yes/Yes	Yes/No/Yes	Yes	Yes/Yes	Yes/Yes
Hortau - Simplified Irrigation	Hortau irrigation automation	NA	Yes/Yes	Yes/Yes/Yes	Yes	Yes/Yes	Yes/Yes
Polaris	Polaris System (MyPolaris, POLR oadrPAC, Pump Automation Controller (PAC), Network Operating Center (NOC))	Yes/Yes	Yes/Yes	Yes/Yes/Yes	Yes	Yes/Yes	Yes/Yes

Company	Product Name	Controls for new/retrofit	Remote Off/On control	Sensor Network/Hardware/Software	Remote communication	Remote Pump Monitoring/EMS	Pump/irrigation Scheduling
WiseConn Engineering	Dropcontrol	Yes/Yes	Yes/NA	Yes/Yes/Yes	Yes	Yes/Yes	No/Yes
Netafim	NetBeat, NetMaize,	Yes/Yes	Yes/NA	Yes/Yes/Yes	Yes	Yes/Yes	No/Yes

Note:

Wildeye, Wisecon and Polaris mentioned about demand response in their marketing material

Most products are offered with fault detection except for Jain Controller, Sentek, FloraPulse, David instruments

Table 26. Non-Irrigation Technology Products Reviewed

Company	Technology	Product Name	Processed Products	High level description	Controls for new/retrofit	Remote off/On control
Lummus	Cotton Ginning	Lummus Gentle Ginning System (Saw Gin and Rotary Gin)	Cotton	Includes Drying & Precleaning, distribution, feeding & ginning, lint cleaning and Condensing & Moisture Restoration	Yes/NA	NA/NA
Lubbock Electric Co (LECO)	Cotton Ginning	Master Gin Console and MasterFlow™ III Gin Stand Control	Cotton	A complete automated control system with SCADA. The console also offers easy, remote monitoring and troubleshooting, advanced control, and intelligent motor load sensing to reduce the potential for downtime and achieve maximum ginning speed.	Yes/Yes	Yes/Yes
Kelley Electric	Cotton Ginning	Kelley Electric GinManager with GinStand Control	Cotton	Includes system Auto Start/Stop Sequence, Press and Tramper Control (PressManager), Indexed Belt Feeder – Adjustable (BeltManager), Auto Battery Condenser RPM Auto Seed Cotton Feed System, Module Feeder Controls (ModuleManager), Auto Wet Cotton Mode,	Yes/Yes	Yes/Yes

Company	Technology	Product Name	Processed Products	High level description	Controls for new/retrofit	Remote off/On control
				Local and Remote Gin Stand Controls, Auto Calibrating Shaft Monitor System, Real Time Alarming, Historical Data Logging (DataManager), Main Power Monitoring, Owner-Manger Remote Viewing, GinManager™ Mobile Console, Remote Support via Internet		
Brandon and Clark	Cotton Ginning	Sales and Service - Custom Gin Controls	Cotton	Complete automation system	Yes/Yes	Yes/Yes
WECO (Woodside Electronics Corp)	Hullers	WalnutTek Moisture Meters, AgTrack	Walnut	Automated moisture meter with door control and bin fill. Fan is the main electrical equipment controlled by automation. AgTrack - the software allows you to record every step of the process — receiving loads, staging loads, cleaning, drying and releasing.	Yes/No	NA/NA
Jessee Equipment Manufacturing	Shelling and Hulling	Jessee Multi-Deck Shelling Systems - Model 2400 all-nut crackers and re-crackers	Fruit, vegetable, and tree nut industries	Automated with full screen	Yes/No	NA/NA
Wizard Manufacturing Inc	Hullers	Nut cleaners, Walnut huller, dryers (distributor)	Walnut, pecan and almond	Automated	Yes/No	NA/NA

Notes:

- No company mentioned demand response in their marketing materials
- Most products are offered with many features such as fault detection, energy management service, remote communication and monitoring, sensor hardware and software.

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