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Technologies and Strategies for Agricultural Load Management to Meet Decarbonization Goals

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PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission and distribution and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation and bring ideas from the lab to the marketplace. The CEC and the state's three largest investor-owned utilities — Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company — were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The CEC is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emission in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

Technologies and Strategies for Agricultural Load Management to Meet Decarbonization Goals the final report for Contract Number: EPC-16-045 conducted by Polaris Energy Services. The information from this project contributes to the Energy Research and Development Division's EPIC Program.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the CEC at ERDD@energy.ca.gov.

ABSTRACT

This research project demonstrated the ability of agricultural pumping load to respond to energy market price signals which can be used to incentivize consumption patterns that help meet California's energy policy goals for decarbonization and renewables integration. The project demonstrated the use of the Polaris platform to schedule irrigation in response to these signals and operate pumps and associated systems through the Polaris Pump Automation Controller or generic irrigation management systems.

The project implemented a simulated transactive energy market during six months of operation and demonstrated that agricultural energy users would respond to clear price signals with sufficient automation and the opportunity to reap financial and operational benefits. In the pilot, participants shifted two thirds of load from the 4-9 p.m. ramp hours to other times of the day to reduce energy costs and carbon intensity. The research demonstrated, on a limited scale, that 80 percent of peak demand for agricultural pumping load can be shifted, which would eliminate 1.8 percent of total carbon emissions from power generation. That reduction can be achieved at a lower cost than battery energy storage or load shift from many other sectors.

The research analyzed all aspects of demand response programs and agricultural operations that limit or inhibit sectoral participation in load management and developed recommendations do address them. Simplification of programs and processes and alignment with agricultural operations are prerequisites to realizing the significant potential of latent flexibility in pumping schedules. Key recommendations include implementation of a pricing mechanism, such as transactive energy, that bundles all costs in hourly prices, expansion of automation incentives to include response to time-of-use and market pricing, and replacement of the current demand response programs with a simple program that eliminates the incongruities of the current slate.

The research demonstrated the feasibility of agricultural load shift in real-world operations. Lessons learned are documented and alternatives for further research are developed, as well as estimates of costs and benefits to ratepayers.

Keywords: Agricultural load management, irrigation management, Demand Response, Transactive Energy, demand management, load shift, duck curve, agricultural energy user, irrigation pumping, water-energy nexus, irrigation automation, IoT, pump automation.

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EXECUTIVE SUMMARY

Introduction

To meet state decarbonization goals by 2045, California must integrate more renewable energy while addressing the gaps between when energy is produced and when it is used. Energy storage is an effective but expensive solution so policy makers are seeking to shift energy demand to the times when renewable generation is abundant and build resources that can respond to variable conditions, such as the supply-demand imbalance experienced in the August 2020 grid emergencies that led to urgent calls for conservation and rolling blackouts.

Electricity use for irrigation pumping by the agriculture sector represents a significant share of California's electrical use (about 7 percent) and exhibits characteristics that, on their face, are compatible with demand response (programs that pay energy users for occasional curtailment of energy usage when the supply of electricity is insufficient to reliably meet demand or is very expensive) and load shift (frequent adjustments to operating schedules to adapt demand to supply). Yet, while leading researchers in demand response at Lawrence Berkeley National Labs estimated in 2015 that the sector could contribute 1.1 gigawatts (GW) of load flexibility in 2020, agricultural pumping is underrepresented in current programs with only 16 percent of that potential participating in demand response. Lawrence Berkeley National Laboratory further assessed in 2020 that "sufficient load flexibility exists in California today to utilize much of the surplus renewable energy that would otherwise be curtailed, and substantially reduce flexible generation needs, for a lower cost than installing behind the meter battery storage" and estimated that irrigation pumping can provide 850 gigawatt-hours (GWh), which is 13 percent of that flexible load.

The growing challenge of integrating more renewable generation and the potential for irrigation pumping to address it meet the agriculture sector at an opportune moment. Farmers are beginning to adopt technology at scale for remote management of irrigation. The implementation of well-designed flexible demand programs and markets can ensure that irrigation management systems incorporate grid-responsive capabilities.

Polaris Energy Services is a leader in connecting agricultural energy users with energy markets. The company manages a network of more than 350 irrigation and water conveyance pumps in California--connected in the field to Polaris Pump Automation Controller gateways--that represent 65 megawatts of flexible load that can be dispatched by grid operators through demand response programs. The company applied its experience in the agricultural sector, in the operation of demand response programs to developing technology and recommending solutions that will enable the agriculture sector to meet these grid management challenges.

Project Purpose

This project developed technologies and strategies to facilitate agriculture sector participation in demand response and recommends program improvements and market mechanisms that can increase the sector's contribution to renewable integration and decarbonization goals.

The research includes analysis of existing and emerging programs and participation in discussions and regulatory proceedings to define future load shifting constructs, leading to recommendations presented in this report. To address operational and behavioral challenges, the research includes ongoing engagement with participating customers, analysis of their needs, and application of these findings to the hardware, software and market solutions developed and recommended in this project.

This research is important to ratepayers because widescale use of the technology developed and adopting at least the major policy recommendations will increase flexible load with existing infrastructure, improving electric grid reliability and facilitating a transition to renewable energy sources.

The primary audience for this research is California policy makers. The technology developed in the project has value in the current program and market environment, primarily in responding to new time-of-use (TOU) rates, but the full demand response and load shift potential identified above can only be exploited by addressing the program and market hurdles detailed in the report.

During the project, the project team recognized that changes were being implemented that could make it even more challenging for the state to achieve its decarbonization goals. Polaris engaged with policy leaders, utilities, program implementers and independent researchers to limit or reverse the damage, with limited success.

Secondary audiences for the research are agricultural energy users and the technology providers and utility representatives who serve them, who can achieve greater success with new TOU rates and existing demand response programs by employing the technologies developed under this project.

Project Approach

Polaris fielded an internal team of employees and contractors with expertise in energy, agriculture, hardware, and software. Three representative agricultural energy users (Angiola Water District, Terranova Ranch and Campos Brothers Farms) that participate in existing demand response programs provided insights, tested new technologies and participated in the project. The research team formed a technical advisory committee to provide a wide range of perspectives from the California energy and agricultural industries, including utility account managers, growers, technology providers and market experts.

The research consisted of three topics: technology development, customer engagement, and program and market analysis. The three merged in a pilot implemented for six months to test whether, with sufficient automation and market integration technology, agricultural energy users would shift irrigation pumping load in response to dynamic price signals, typically incentivizing shifting consumption from the late afternoon ramp hours.

For technology development, the research team built on existing Polaris control hardware and software and expanded it to integrate with energy markets, customer relationship management systems, third-party platforms and big data visualization and analytics solutions. The technology strategy was to incorporate all the components that an individual user requires to operate irrigation systems in coordination with the electrical grid. Technology strategy also included overlaying capabilities to manage large portfolios of irrigation pumps and utility meters at scale.

The customer engagement area focused on the three participants — two growers and an irrigation district — and was supplemented by ongoing work with more than thirty agricultural energy users, including irrigation districts, and growers of nuts and row crops in the Central Valley, that participate in demand response programs. The research was enriched by analysis of customer data from 1,200 agricultural meters, in addition to the three participating customers (17 meters). Ongoing management of demand response programs and interaction with utilities, regulators and stakeholders informed and was supported by the research. Unlike purely scientific research, this project was conducted with ongoing market interactions that enhanced the results and enabled the use of interim results to inform program management and regulatory proceedings.

Project Results

The researchers achieved the project goals for technology development, customer engagement, and program and market analysis.

Technology Development: The system was successful and far exceeded the original project goals, engaging agricultural energy users in daily use of the system during six operating months. Agricultural energy users shifted two-thirds of load or 1.1 megawatt for eight pumps from the 4 p.m. – 9 p.m. ramp window compared to previous years' peak demand.

- Usage during the ramp window — when solar generation decreases and electricity demand peaks — decreased from 21 percent to 7 percent of total load.
- The 66 percent of load that was shifted compares with the theoretical maximum of 94 percent that could be shifted at participating pump sites without reducing total weekly irrigation.

Customer Engagement: The participants realized significant financial and operational benefits. Participants plan to add automation across their operations, dozens of pumps, increasing participation in programs, responding to TOU rates and reaping operational benefits, including labor cost reduction and increased irrigation precision.

- Todd Ayerza of Campos Brothers Farms said, "if we can irrigate around those peak hours…that's a big part of our cost…. if we can save 10[percent], 20 percent, that's huge."
- Patrick Pinkard, Terranova Ranch, commented "our irrigation guys were actually pretty skeptical about using it at first but later down the line they said 'oh, we like that a lot better.'"
- Discussing the impact on crop yield, Don Cameron, Terranova Ranch, said "the uniformity is fantastic and reducing labor is really important," and Patrick Pinkard added "we probably saved, I don't know, 30[percent], 40 percent on labor."
- Don Cameron summarized "long term we'd like to automate more out here."

Program and Market Analysis: Current market mechanisms and automation incentives can entice only a small portion of agricultural pumping load shift potential. The accompanying policy analysis and recommendations provide the pathway to strategies that can achieve policy goals and offer sufficient value to customers to drive adoption.

The analysis identified numerous unintentional consequences of energy policy, planning decisions and execution that hinder contribution of flexible load by agricultural customers and recommends a path forward to achieve widescale market participation, including:

- Unambiguous, strong price signals, minimal customer effort to participate, and the elimination of program constructs that conflict with agricultural operations.
- Incentives to adopt technology that integrates energy markets with behind-the-meter systems and user workflows.
- Significant investment in customer education and support to effect changes to long-standing processes and procedures.

Technology/Knowledge Transfer/Market Adoption (Advancing the Research to Market)

The research team shared project findings such as policy and marketing recommendations with key stakeholders, including regulatory bodies, to help increase market adoption of the technology features that are dependent on the implementation of dynamic pricing. Other features are valuable for growers and ratepayers under existing programs and tariffs and actively marketed by Polaris. To deliver these benefits beyond the Polaris slice of the irrigation controls market in California, demand response event dispatch and program management are accessible to any control technology via an application programming interface.

The research showed that greater adoption and participation are possible if energy management features are incorporated into the tools and workflows that agricultural energy users employ for daily operation. To this end, Polaris expanded its partnership with Netafim, applied for and won an Israel-U.S. Binational Industrial Research and Development grant to build an embedded energy application in the NetBeat platform. The project extends through 2021 with the resulting technology expected to be commercialized in 2022.

Benefits to California

This project delivered enabling technology and a roadmap to unlocking a large resource to contribute to reshaping California's electrical load profile to meet its policy goals at a lower cost than known alternatives. Greater automation, monitoring and data analytics for irrigation pumping also helps in the state's efforts to manage scarce water resources while maintaining the viability of its agricultural sector.

The research demonstrated, on a limited scale, that 80 percent of peak demand for agricultural pumping load can be shifted—which would eliminate 1.8 percent of total carbon emissions from power generation. That reduction can be achieved at a lower cost than battery energy storage or load shift from many other sectors.

Energy and water management are interwoven in the agriculture sector and technology applied to reduce energy costs and help the grid will also provide valuable water management benefits.

The agricultural sector represents about two percent of California's economy and employs 2.5 percent of workers. The sector faces challenges from climate change, labor scarcity, water scarcity and trade policy so any reduction in key costs is important. The technology developed by this project enabled participants to reduce labor costs by 30 percent. In the pilot, farmers also earned incentives that reduced their electricity bills by 9 percent, with expected future savings of between 10 and 20 percent, depending on how dynamic pricing is implemented.

Conclusions and Recommendations

Load shift of agricultural water pumping in California can contribute significantly to decarbonization and, with the advances made by this project, there are no remaining technology hurdles to the sector's participation at scale. The research demonstrated that with strong price signals, grid-integrated automation. and clear operational benefits, the agriculture sector can shift two thirds of load from the afternoon ramp hours, contributing to grid stability and decarbonization while improving the viability of California farms.

Most of this potential can be realized without large capital investments in physical infrastructure, like pumps and reservoirs, but requires modest investment in controls, communications and information technology, and in engagement with the agricultural sector.

Agricultural energy users need to be engaged, incentivized, and their consumption measured in ways that are compatible with their operations--which frequently differ from the other non-residential segments with which they are grouped. The current regime of programs, markets and tariffs has evolved over time as a series of initiatives to address the challenges that existed at the time. Together, they present an incoherent offering at times in conflict with itself. The cost, effort and risk of participation inhibit widescale participation by agricultural energy users.

Regulatory efforts have prioritized cost-effectiveness and avoiding any risk of paying excess incentives over improvements that would increase participation and drive scale. The state has invested extensively in researching flexible load but not in proceeding from small-scale pilots to larger pilots and full implementation.

The bill for these choices came due in August 2020 when the oft-forecasted scenario became reality as extreme heat across the West caused demand spikes and supply constraints and there was insufficient flexible load to meet the moment. These events have focused attention on the urgent need to improve programs and increase participation. Polaris Energy Services is engaged in recommending quick fixes that can be made for the 2021 season and fundamental improvements to demand management:

- Model automation incentives for flexible load on the successful California Solar Initiative and Self Generation Incentive Program, with a generous incentive to attract vendors and participants that declines over time to reward performance and efficiency. Allow energy users to use these incentives to respond to tariff/market pricing *and* to demand response programs.
- Implement hourly (or sub hourly) pricing that enables transactions in timeframes that meet grid and customer requirements and bundle transport (demand charges) into the price to provide the greatest leverage on behavior. The transactive energy model provides a good framework but does not need to be adopted entirely to meet these goals.
- Meet the remaining reliability and economic needs for demand response with a simplified program that complements, rather than conflicts with, price-responsive load shift.

CHAPTER 1: Introduction

To meet decarbonization goals, California must do three things: produce usable energy from non-carbon emitting sources (for example use solar and wind generators), shift energy usage to rely on these sources (for instance vehicle and home electrification), and address the temporal gaps between the production of energy and its usage while addressing technical challenges presented by the type, number and location of generators.

To address these temporal gaps and technical challenges, California is implementing strategies to store energy produced when clean generation is plentiful, shift energy demand to those times, and build resources that can respond to variable conditions on a more dynamic grid.

Agricultural pumping for irrigation purposes represents a significant share of California's electrical usage and can potentially make a significant contribution to load shift goals. "On paper," irrigation pumping is perfectly positioned as a resource to fulfill these requirements; it is large (about 7 percent of load[1]), nearly binary (most pumps are "off" or "on", not highly sensitive to time of day or day of week (unlike an office, store or home), use relatively simple controls (compared to a building management systems (BMS) or factory supervisory control and data acquisition (SCADA) system) and is concentrated near much of the solar generation capacity that needs to be complemented.

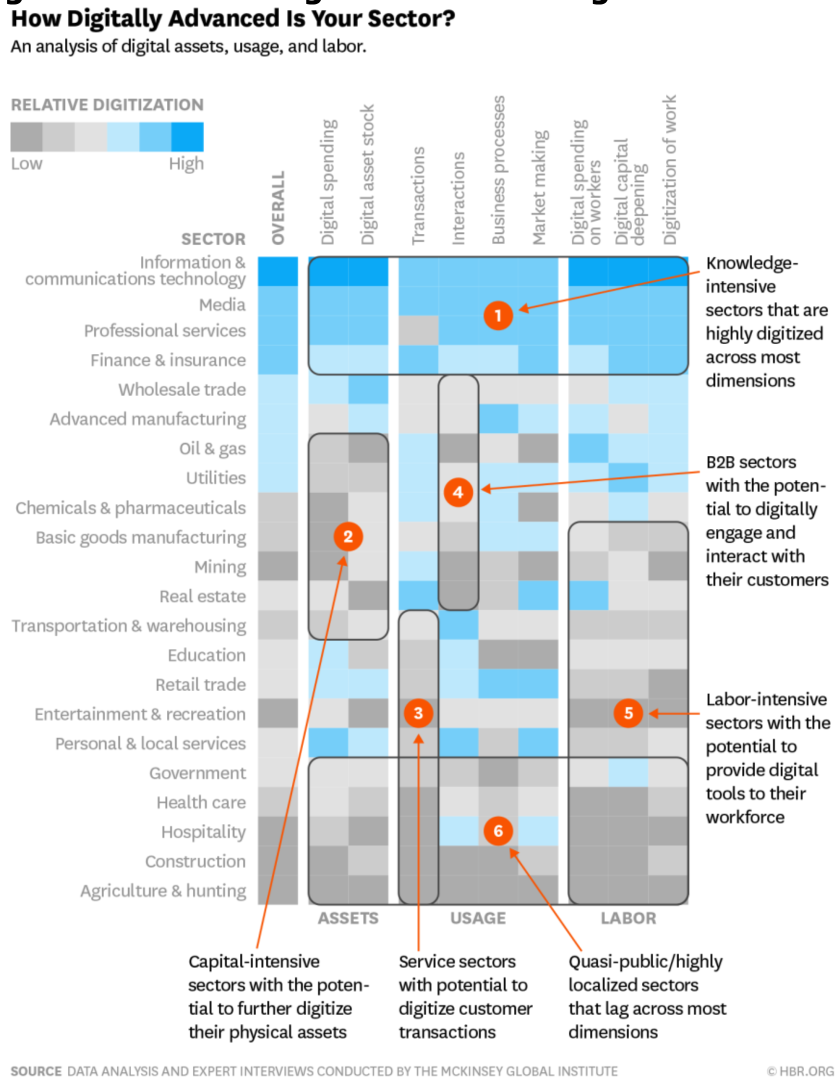
Yet, while LBNL estimates that the sector can contribute 1.1 GW of load flexibility, it is underrepresented in current programs with only 16 percent of that potential participating in demand response (DR) programs.[2] By investigating the market, technology and operational hurdles to ag sector participation in DR and load shifting programs and developing and recommending solutions, this project aimed to increase participation of irrigation in load shifting to help the state meet its decarbonization targets.

The timing of this research coincides with challenges and trends in California's agriculture industry that provide an opportunity to overcome the status quo. Growers are besieged by water scarcity, climate impacts, labor shortages and market forces that threaten their viability. At the same time, the agriculture sector lags significantly compared to others in the adoption of digital solutions, as shown in Figure 1.

[1] California Energy Commission, 2018.

[2] Lawrence Berkeley National Laboratory Demand Response Scoping Study, 2013.

Figure 1: Relative Digitization of the Agricultural Sector



Source: HBR.ORG

The dimensions that need to be digitized to facilitate a significant leap in energy market participation are asset stock, transactions, and the digitization of work. Most irrigation pumping is controlled manually, on site, which is typically at some distance from any central location and between pumps. Polaris has installed automation for energy market participation on more than 400 pumps and, with the exception of the pumps participating in this project, automation is only used to stop pumps (not to start them) and only in the context of infrequently dispatched DR programs, not for daily operations.

As farm management migrates to mobile devices and the cloud, the California grid writ large has an opportunity to embed energy market participation — with its inherent benefits — in the first generation of digital and internet of things (IoT) solutions implemented by the sector. Like sectors that have proceeded more rapidly on digitization, the current state of technology in the ag sector is characterized by a wide array of vendors with overlapping capabilities, point solutions and minimal standardization. There are several control technologies and multiple sensing and analytical platforms that include varying degrees of monitoring. For the most part, to the extent that external inputs are incorporated in scheduling and control platforms, they are primarily sensors that determine crop requirements for water, especially soil moisture.

There are a small number of software tools that make use of data available from utility meters for energy management and for other purposes, including as a proxy for flow measurement to calculate water usage and pump efficiency. These tools, are intended only for offline analysis because energy data from the utility is delayed by at least one day. One platform, Wexus, uses Polaris' monitoring functionality to upgrade its capability to real-time management, such as alerting ahead of peak demand intervals. One other irrigation control platform, Wiseconn, has deployed an OpenADR-compliant communications device to curtail connected pumps to earn AutoDR incentives and participate in DR programs. Adoption of these technologies remains low and, prior to this project, there was no comprehensive system that enabled the creation and implementation of pump operation schedules with consideration of time-of-use (TOU) and California Independent System Operator (California ISO) wholesale pricing.

Relevant research demonstrates that alerting alone does not induce load shift and that both engagement and response are low when the energy application is not in the operational workflow. The Wexus report showed:

- Only 10 percent of peak usage alerts led to an operational response.[3]
- Total peak period usage was unchanged or increased with use of alerts.[4]

In addition to technical gaps, there is a series of obstacles to ag sector participation in achieving the state's clean energy goals presented by operational norms in the sector and a series of obstacles presented by the way in which the utilities and energy markets engage with the agricultural sector.

As the market for irrigation control and management technology emerges, as shown in the "Smart Irrigation" section of Figure 2, vendors are not including energy management features in their offerings for several reasons. As with all first-generation digitization offerings, vendors are addressing the simplest core functions first before adding comprehensive features to provide holistic management for a business domain for function. When vendors have considered including energy management and grid integration, they confront a dizzying array of tariffs, programs and incentives that varies among utility service territories, which would force them to create many versions of technology that they aim to standardize globally. In addition, absent players to catalyze customer interest, the market is not demanding these features. This project was important to develop the technologies to bridge between the California energy market and customer systems, and to develop a roadmap for load management offerings to overcome existing deficiencies that deter participation.

[3] Terrell, 59.

[4] Terrell, 116.

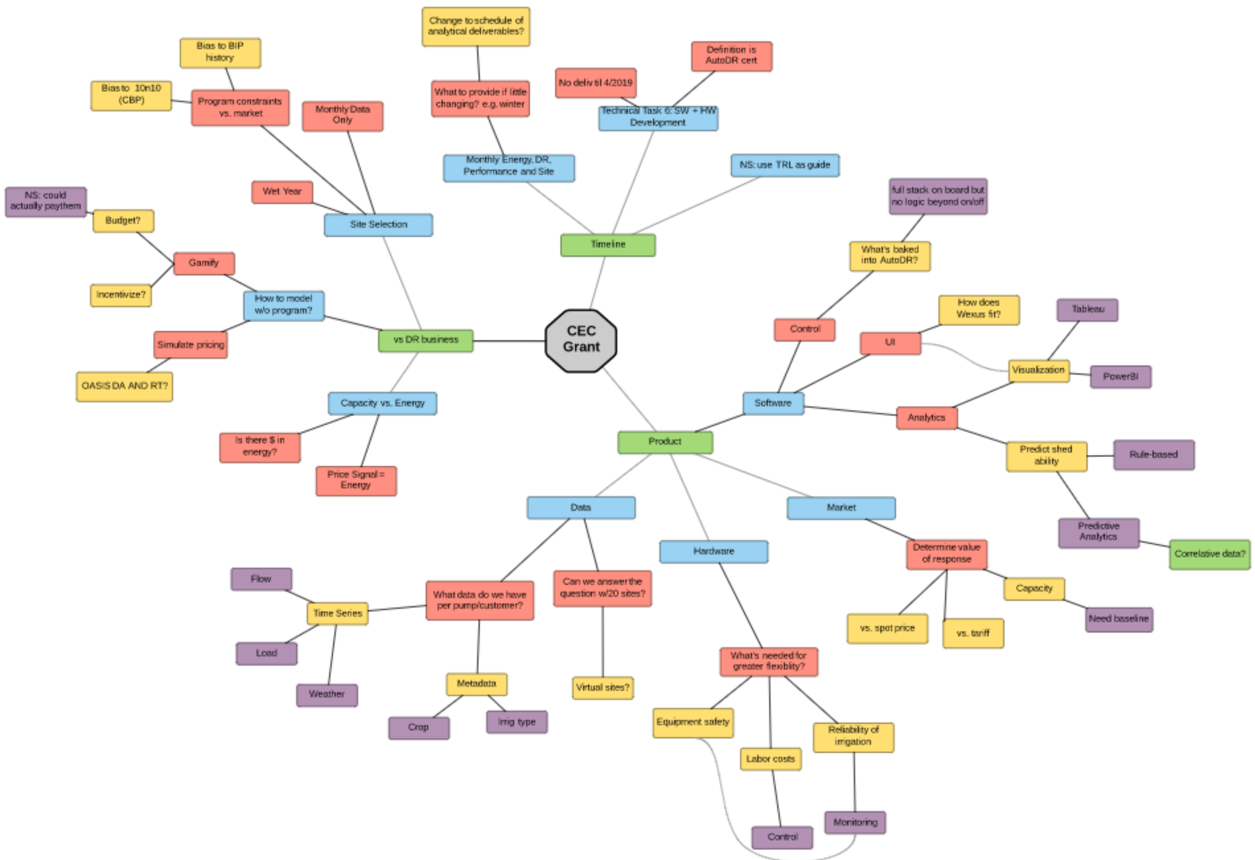
Figure 2: Digital Farming Startup Innovation Map

Source: Silicon Valley Innovation Center.

CHAPTER 2: Project Approach

The researcher's took a pragmatic approach to the project, focusing on the end goal of driving greater participation by the agricultural sector in DR and load management to meet California's energy and decarbonization goals. Key issues addressed and the thinking that led to them are shown in Figure 3. With that constant, plans and methods changed as dictated by the research to achieve as much progress as possible toward the goal within the time and budget available. This approach stands in contrast to strict adherence to the scientific method where hypotheses are put forward, tested and the results explained; the researchers believed it would be a waste of resources and a unique opportunity to follow through with unproductive experiments that yield disappointing results and explain them in a paper.

Figure 3: Project Approach – Mind Map



Source: Polaris Energy Services.

It is important to note what is excluded from this project approach. Some studies in agricultural energy management have sought to, for lack of a better phrase, reverse engineer farmers' agronomic decisions to predict energy usage, DR availability and even to calculate tradeoffs between agricultural yield and energy market revenue to induce DR participation. Or they seek to combine water and energy savings. This project too intended to develop load forecasting techniques using agricultural factors such as crop type and weather. Customer interviews, however, indicated that these approaches were unlikely to yield results. For each farm and associated irrigation pumps and utility meters, there are myriad discrete factors that drive operating decisions including the availability of surface water and the timing of its delivery, harvest timing often driven by product purchasers' schedules, labor schedules, operations taking place in the fields like pesticide spraying and more. While aggregated load is correlated with knowable surface water allocations, more granular forecasts are not feasible.

More importantly, customer interviews indicated that there are a broad array of initiatives and technologies to reduce overall water consumption but trading off agricultural revenue for energy savings or revenue goes against the grain of farming operations that prioritize the success of the crop above other considerations. To gain trust and cooperation from growers, it was clear that the researchers had to enable energy cost savings and energy market participation without necessarily attempting to reduce overall water usage. This also aligns with the policy priority of securing load shift and so the research did not focus on load shed. With this understanding, the technology and program development of the project was framed with water requirements as an exogenous factor, asking how those requirements can be met while delivering the greatest benefit to the electrical grid.

Analysis of the research problem demonstrated that the project needed to address three distinct types of challenges to yield positive results and produce an actionable strategy to achieve similar results at scale: technology, program/market design and customer engagement. Related work streams are shown in Figure 4.

Technology Development and Deployment

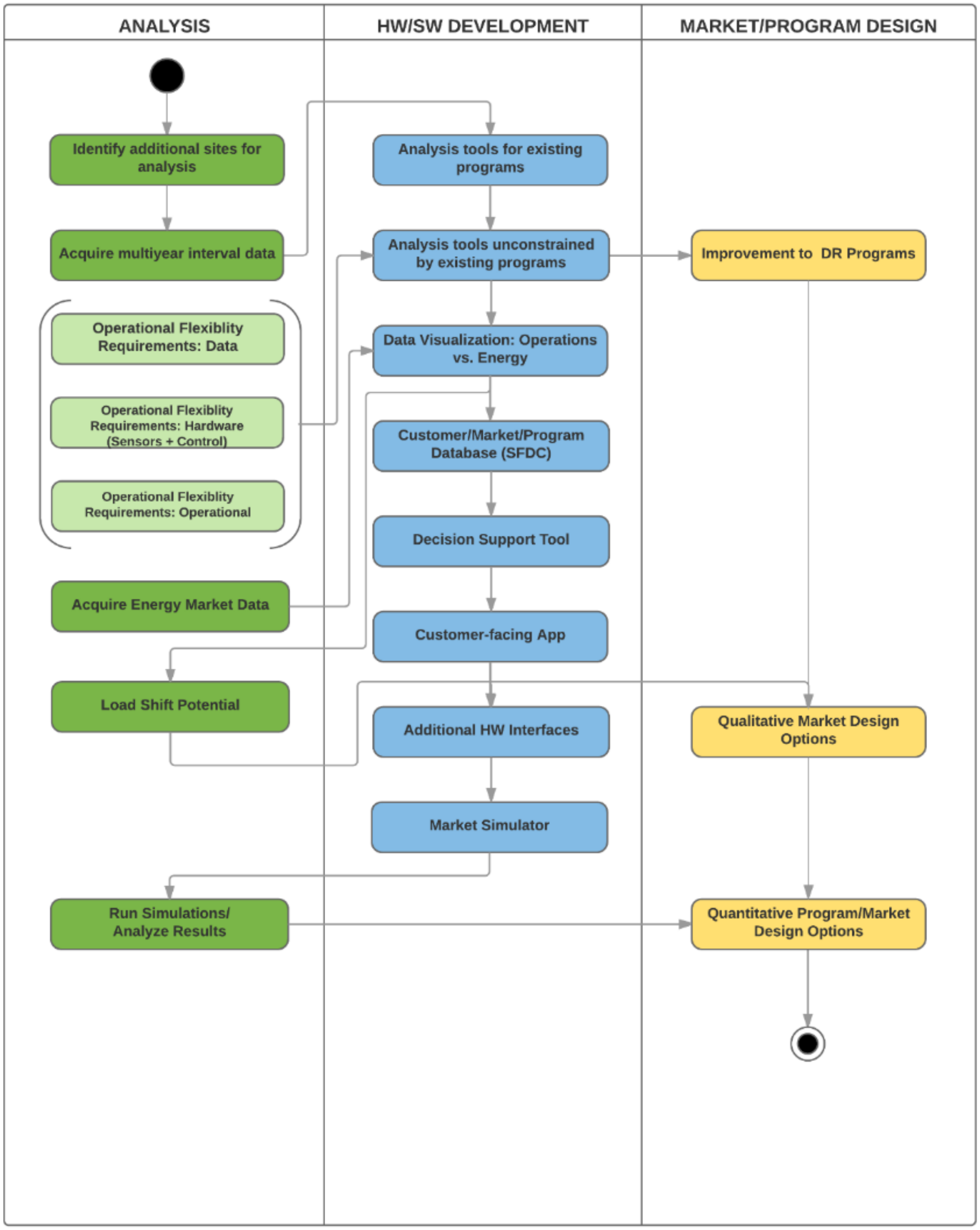
The project further refined and developed the Agricultural Energy Rewards and Opportunities (AERO) platform so that it may become the template on how DR and load shifting can successfully be implemented in the agricultural sector. A primary driver of this refinement will be ongoing customer feedback at the site level. Analysis and feedback indicated a need for two levels of technology development: hardware and software for the individual user/pump site and a layer of software to enable management of agricultural pump sites and their participation in energy markets at scale. Figure 5 shows how the technology roadmap was developed to meet the needs of internal users and customers.

Hardware Development

At the outset of the research, a suite of hardware was identified for deployment at each participating site to facilitate the research and customer participation in emerging or new DR programs. The hardware consisted of curtailment-only pump controllers, water flow meters and real-time power meters.

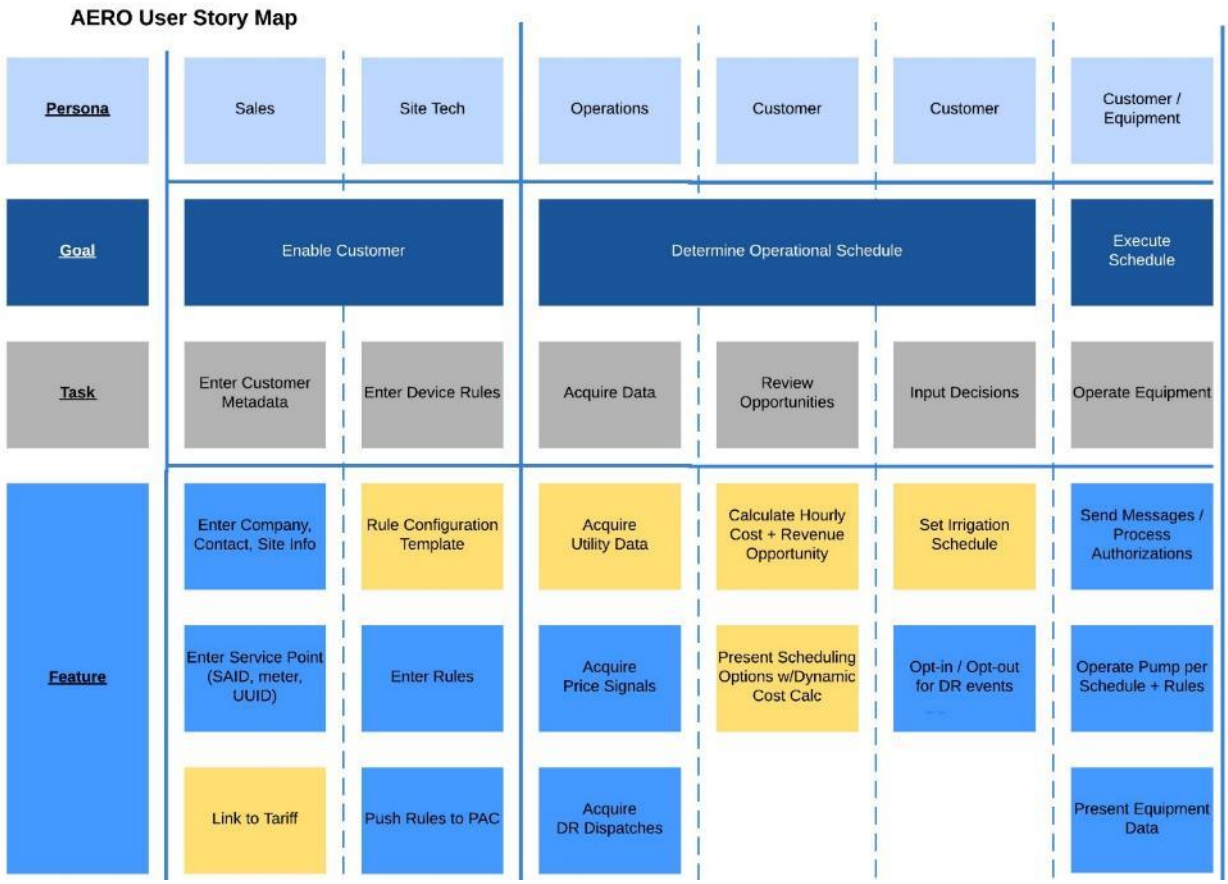
After the baseline data collection and engagement task, additional hardware solutions were developed to enable frequent changes to schedules required by dynamic load management approaches. The researchers developed capabilities for the Polaris Pump Automation Controller (PAC), where feasible and economical, and integrated components from partners and vendors where those solutions were preferable.

Figure 4: Project Approach Swim Lanes



Source: Polaris Energy Services.

Figure 5: User Story Map



Source: Polaris Energy Services.

Software Development

The software product development encompassed several discrete efforts to achieve the project's goals.

- The core gio control platform (AERO) was built "by engineers for engineers" and enabled Polaris to build and maintain a reliable DR portfolio but was limited in usability for other internal and external users and in its capabilities to support the business processes and analytics needed for scale.
- Development of the myPOLARIS web and mobile application providing customers and internal users with robust tools for managing portfolios of pumps during daily operations and for DR events.
- Development and integration of platforms and tools for acquisition, storage, analysis, and visualization of large quantities of time series data, integration and customization with a customer relationships management (CRM) system, implementation of Green Button (Share My Data), and implementation of the OpenADR Cloud virtual end node (VEN).
- Integration with the TeMix RATES platform for the transactive energy (TE) pilot to receive tenders for energy and execute simulated transactions based on schedules created by users in the myPOLARIS application, followed by processing of settlement data for measurement and verification (M&V).

Program and Market Analysis and Design

From the outset, it was clear that technology innovation alone is insufficient to significantly increase ag participation in load management in California. Evidence from operating DR portfolios in three programs and developing the largest share of AutoDR projects in the program, supplemented by customer interviews, clearly indicated that new or, at a minimum, vastly improved programs and approaches were needed to tap into the sector's latent operational flexibility. Efforts were directed at three fronts:

- Ongoing – as part of its ongoing engagement with utilities, program implementers and regulators, Polaris advocated for policies, rules, procedures and access to information that make DR easier and more attractive for agricultural energy users (AEU). The analytical tools developed for the project enabled Polaris to deliver more compelling, insightful, and accurate input to these bodies, often serving as the voice of a sector that is underrepresented in decision making. The timing of these efforts was event-driven rather than planned as, in many cases, Polaris responded to changes dictated by the program and regulatory calendars. In some cases, Polaris initiated engagement and advocacy as issues emerged or as the analyses were developed to support advocacy.
- Experimental programs – the initial project approach was to enroll participating pump sites in one or more of the newer DR programs (Demand Response Auction Mechanism (DRAM), Excess Supply Pilot (XSP), Supply Side Pilot (SSP), Reliability Demand Response (RDR), Proxy Demand Response (PDR)) designed to address emerging grid needs and shortfalls of the existing slate of programs (Baseload Interruptible Program (BIP), Capacity Bidding Program (CBP), Peak Day Pricing (PDP)). There were significant process hurdles to participation in these programs and analysis showed serious flaws in them for the ag pumping sector. These findings led the researchers to reject the programs as vehicles for testing dynamic load shifting technologies and seek alternative models.
- Emerging models – the limitations of existing and new programs led the researchers to seek alternative models both to test the efficacy of the technology they were developing and as solutions to the larger problem. Even as the researchers' analyses were well-received and considered, they saw deterioration in the conditions for agricultural participation in DR and stubborn problems that did not seem to have realistic medium-term resolution. As a result, the researchers sought out models that would bypass rather than fix the inherent problems in DR and focused on models that are emerging and in various stages of pilot and policy consideration. The team also sought paradigms that better fit the renewables integration goals of the grid that require more frequent shift than the current shed-focused programs provide. In particular, the researchers focused on dynamic pricing, the work of the Load Shift Working Group (LSWG) and the Retail Automated Transactive Energy System (RATES) pilot project with Southern California Edison (SCE) completed under EPIC grant EPC-15-054.

Dynamic Agricultural Load Shift Opportunity

The first hypothesis the researchers tested was exposing AEU to existing market pricing published by California ISO and available to commercial, industrial and institutional (CI&I) energy users at limited scale through direct access. The questions were what savings opportunity market pricing would provide? How much load shift would be required? On its face, from analysis of a small cohort of irrigation pumps, it appears that load can be shifted away from price spikes to adjacent windows of time, as shown in Figure 6 from April 2016, an important shoulder month where solar generation increases faster than cooling load between the winter and summer seasons.

Figure 6: Load Shift Example with Locational Marginal Price Pricing

Source: Polaris Energy Services analysis of AEU and California ISO data.

To quantify the opportunity, the time frame in which shift can occur needs to be defined. Based on customer interviews, the researchers determined that shift within a weekly time frame meets the crop needs of farmers and the scheduling routine that they follow. In this analysis, data from calendar year 2016 for ten pumps and the spring season for two pumps were analyzed. 2016 was the most recent dry year available when the analysis was performed (2017 was wet and pumping load was significantly reduced).

- Energy cost (excluding demand charges) was calculated for each meter according to the relevant TOU tariff (PG&E AG-5B).
- Energy cost was calculated using LMP data from California ISO. Because these costs vary significantly from tariff-costs, the analysis focused on the percentage savings opportunity, not actual dollars.
- The number of pump operating hours was calculated for each pump on a weekly basis and the cost of operating the same number of hours in the week during the least expensive hours was calculated.
- The number of hours shifted was calculated as a percentage of the original running hours.

The analysis showed that across this cohort, AEU could save 4.6 percent of energy charges if they shifted all of these hours but energy charges account for approximately 50 percent of total bill cost so the actual savings available would be closer to 2.3 percent and require shifting 12 percent of the operating hours. Achieving this optimized schedule would require frequent start/stop operations of the pumps which introduces logistical challenges and technical risks so simpler '80/20' optimization of schedules — implementing a small number of changes that achieves most of the benefit--would further reduce the savings opportunity.

Figure 7: Market Pricing Savings Potential

Market Pricing Savings Potential

Pump	Peak kW	Total kWh	TOU Energy Cost	Original LMP Energy Cost	Optimized LMP Energy Cost	Pct of Hours Shifted
Irrigation District A P1	145	702,620	$79,061	$19,750	$19,342	10%
Grower C P1	112	11,187	$1,320	$415	$265	82%
Grower C P2	71	8,852	$1,024	$272	$208	66%
ID C P1	203	960,646	$109,669	$27,051	$25,477	10%
ID C P2	109	283,546	$34,127	$8,548	$7,814	13%
ID C P3	168	502,271	$57,941	$13,214	$12,869	11%
ID C P4	195	506,726	$61,294	$15,995	$15,409	11%
ID C P5	212	607,882	$69,156	$17,791	$17,398	11%
ID C P6	205	1,143,843	$130,828	$31,854	$30,777	7%
ID C P7	260	1,127,086	$128,690	$31,897	$30,419	9%
ID C P8	212	1,027,529	$119,232	$29,720	$29,129	7%
Grower T P1	175	509,361	$63,939	$14,037	$11,123	33%
Grand Total	**260**	**7,391,550**	**$856,280**	**$210,545**	**$200,952**	**12%**

Energy Cost Savings Opportunity	-4.6%
Energy Cost % of Bill	50.0%
Bill Savings Opportunity	-2.3%

Source: Polaris Energy Services analysis of AEU and California ISO data.

Participant interviews indicated that significant technical upgrades and operational changes would not be justified by ~2 percent bill savings, especially when DR programs deliver two to five times greater incentives for as few as a single event per year.

The analysis summarized in Figure 7 led to the preliminary conclusion that new models would have to provide a different incentive model to induce the frequent load shift that the grid needs, and the researchers were keen to test. The contemporary market pricing did not provide the variability needed to do this and the exclusion of demand charges from the shift opportunity 'shortened the lever' that could be applied to AEU operational flexibility.

Also, as explained in the EPIC RATES project report, "The time-of-use retail tariff, demand-side approach cannot provide the necessary price variability to cover the full range of prices, from negative to thousands of dollars per megawatt-hour."[5]

[5] Cazalet, 1.

Transactive Energy Pilot

Opportunity

The researchers learned of the TE paradigm developed by TeMix and the EPIC RATES pilot[6] at the 2018 OpenADR Symposium and initiated analysis of the technical feasibility, customer cost/benefit and contribution to grid requirements. The rationale for and mechanics of TE are well documented in the RATES final report and are incorporated by reference. This report focuses on the opportunity for the agricultural pumping segment in California, adaptation of the TE model for this project and the pilot results and recommendations.

The researchers used a sample of one year of hourly prices provided by TeMix and adjusted for current Pacific Gas and Electric (PG&E) agricultural tariffs to estimate the savings opportunity. "The methodology used to derive hourly TE prices RATES uses granular scarcity pricing to develop the tender prices for the SCE distribution operator and load-serving entity. The concept is simple: recover more of SCE's fixed costs (long-run marginal capacity costs) at higher prices in intervals when the use of generation and distribution is high and less at lower prices when usage is low. The intervals can be for an hour, 15-minutes, or 5-minutes' duration."[7]

The researchers assessed that there is a 20-25 percent savings opportunity for AEU by shifting load on a daily or weekly basis based on prices that represent the over-generation and ramp problems that need to be addressed. The savings opportunities--and potential contribution to the grid--are greatest in key shoulder months April, May and October because at the same time that the duck curve is most pronounced, pumps tend to be operating enough to consume significant energy but not so much that there is no shift opportunity. Figure 8 shows the cumulative shift opportunity for four growers and nine irrigation district pumps for one week in April. Shifting load to optimize energy costs would save the customers 41 percent in that week.

Pilot Approach

With the potential identified and an apparent qualitative fit with the attributes of AEU that had been documented, the researchers needed to adapt the approach to address the key questions of the project and conform to the constraints of budget and schedule.

To achieve the research goals, the model needed to be simplified to maximize the likelihood that AEU would respond to the TE signals in a meaningful way and focus on the key benefits that were hypothesized.

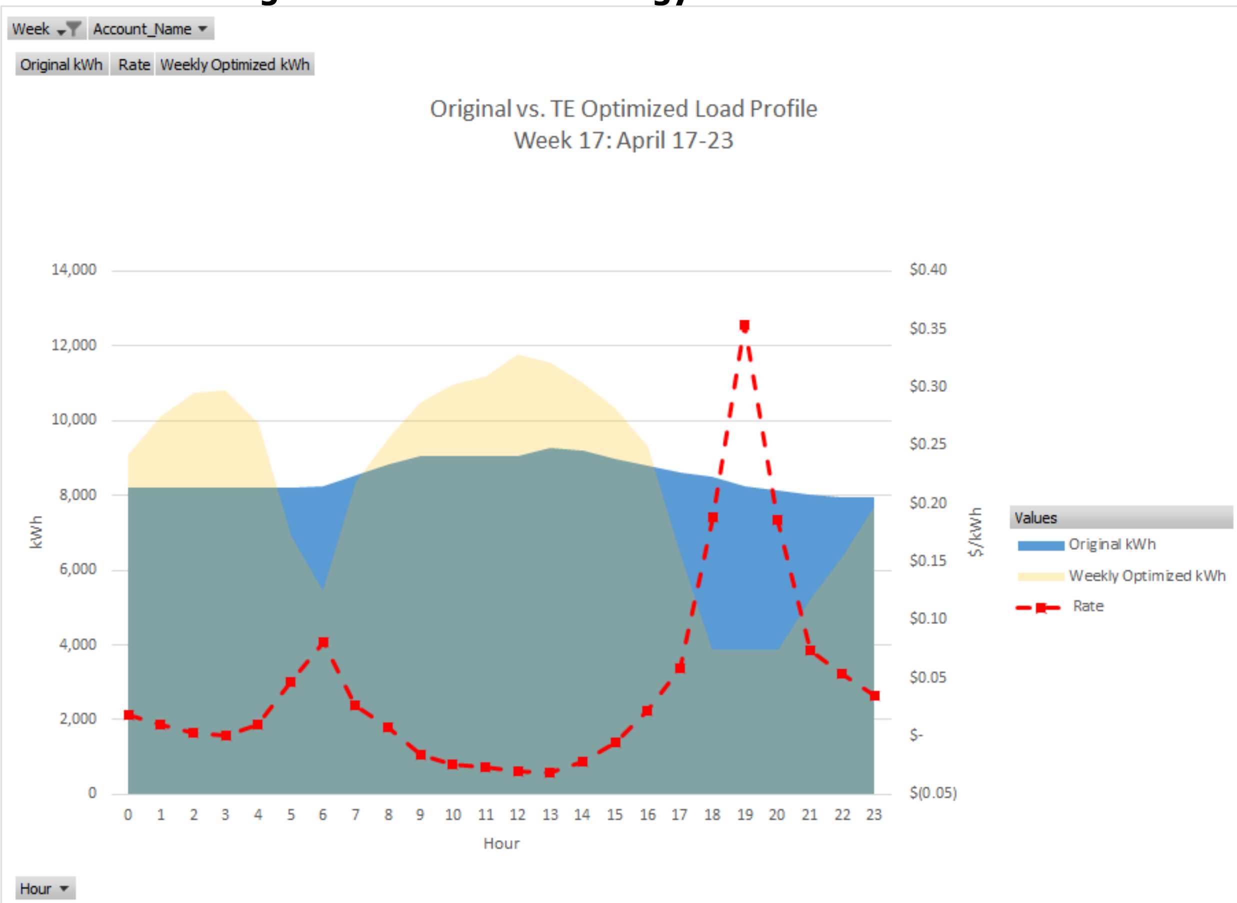
- Specific time frame – one of the attractive features of TE is the ability to purchase energy in a time frame that aligns with the energy user's operational decisions. Within TE, this is flexible with tenders offered and transactions executed at any time on a continuum. For this project, the researchers wanted to test the ability of AEU to

[6] Cazalet, Edward, Michel Kohanim, Orly Hasidim. 2020. A Complete and Low-Cost Retail Automated Transactive Energy System (RATES). California Energy Commission. Publication Number: CEC-500-2020-038.

[7] Cazalet, 15.

respond to price signals that align with the growers typical weekly planning cycle and structured the pilot to provide that.

Figure 8: Transactive Energy One Week Potential



Source: Polaris Energy Services analysis of AEU and TeMix RATES data.

- Demand charges – based on the analysis of existing market pricing it was important that the rates offered to participants include demand charges.
- Non-automated decisions – AEU scheduling decisions are complex and always have a human in the loop so the use of rules and automated responses to tenders is not possible. To address this, the model was adapted to present pricing within a scheduling application and enabling the user to determine schedules manually, in contrast to the automated agents used in the RATES project.
- Energy sales – one of the important features of the TE model is the way in which it supports distributed energy resources (DER) and enables all participants to buy and sell energy. Solar penetration is high in California's agricultural sector but, to keep within the scope of the project, only energy purchases were included in the pilot.

In addition to adapting the approach to match the research goals of the project, significant adjustments were required to implement the pilot within the constraints of the project scope, timeline and budget.

- The EPIC RATES project tariff developed for Southern California Edison (SCE) commercial customers was adapted for PG&E agricultural customers.

- The RATES project provided day-ahead tenders and the research goal was to provide weekly pricing, so the model was adapted to provide seven day-ahead tenders.
- In the RATES project, the researchers implemented an experimental tariff that was approved by the California Public Utilities Commission (CPUC) and replaced, for the duration of the project, customers' regular tariff. This project attempted to gain interest for PG&E to do the same but there was neither interest nor time so the researchers developed an incentive structure that could work alongside the rates in effect.
- The objectives in designing the incentive structure were:
  - Conform to the budget within the grant.
  - Provide a sufficiently strong price signal to drive behavioral change, with a bill savings opportunity between 10 – 25 percent.
  - Require significant behavioral change to earn the incentives by avoiding concentrating them in a very small number of hours.
  - Remove conflicts between the actual PG&E tariffs and the pilot incentive structure.
- To achieve these objectives the incentives were determined as follows and highlighted in Table 1:
  - Calculate the average hourly price for a calendar week from the TeMix tenders.
  - Calculate the incentive as the difference between the weekly average price and the hourly price.
  - Using a target budget per participating kilowatt of load, based on 120 running hours per week over an 8-week pilot
    - Set a maximum price (revised price) of $0.50
    - Scale the incentive to 25 percent of the resulting calculated incentive

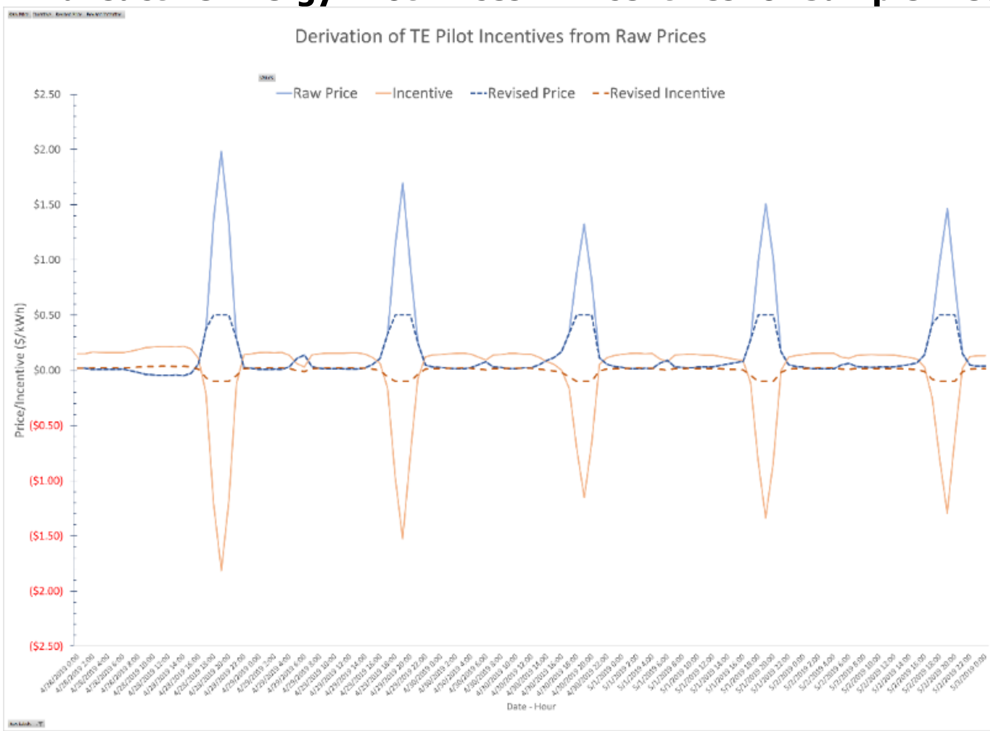
Table 1: Transactive Energy Pilot Incentive Calculation

Calculation	Value
Avg TeMix Price	$0.20
Weekly Run Hours	120
Raw Weekly Incentive ($/kW)	$28.06
Set Maximum Price	$0.50
Avg Revised Price	$0.10
Set Incentive Scale Factor	0.25
Revised Weekly Incentive ($/kW)	$2.50
Count of Positive Incentive Hours	126
Estimated Savings	14%

Source: Polaris Energy Services analysis.

  - These levels were set by trial and error using sample data from one week in April, 2018, and were calibrated so that the participant would earn positive incentives during 126 hours of the week and negative incentives (penalties) during 42 hours of the week, which approximates avoiding the ramp hours of the duck curve. The "revised incentive" is what participants were offered in the myPOLARIS app and earned in the pilot. The prices and adjustments for a sample week are shown in Figure 9.

Figure 9: Transactive Energy Pilot Prices + Incentives for Sample Week



Source: Polaris Energy Services analysis.

- Incentives were aggregated on a monthly basis so negative incentives offset positive incentives and participants were paid if the monthly total was positive but not penalized if the monthly total was negative (a penalty). Budget was also reserved to compensate participants if responding to the pilot's price signals incurred TOU costs above those of normal operations.

Customer Engagement

The project's approach to customer engagement was self-contradictory. On the one hand, the researchers endeavored to provide extensive support and education to participants to help them understand and capitalize on latent operational flexibility. On the other hand, during the TE pilot, the researchers aimed to wean participants of prompts so that their responsiveness to price signals could be assessed in circumstances that approximate real market conditions.

Market Development and Engagement

The researchers' approach to market development and engagement was, of necessity, opportunistic and driven by exogenous factors. Given the sectoral focus of this project and the broadly stated objective, the researchers, participants, and target market were exposed throughout the project to the full range of program, regulatory and market changes and processes. It would have been counterproductive to conduct the research under 'laboratory conditions' and publish recommendations only to find that the ground had shifted in the meantime.

Accordingly, the researchers engaged throughout the project with regulators, utilities, program implementers and industry groups, adjusting and applying the research activities to address emerging challenges and take advantage of emerging opportunities in real time. The team provided comments, proposals, and recommendations on a large number of topics:

- Proposal (with TeMix and ZNE) to PG&E for Transactive Energy pilot.
- Comments (with CEDMC) to CPUC Proposed Decision Resolving Remaining Application Issues For 2018-2022 Demand Response Portfolios.
- Proposal to PG&E and Energy Solutions regarding AutoDR qualification criteria and process.
- Proposal (with Irrigation for the Future (IFF), TeMix and Lawrence Berkeley National Laboratory (LBNL)) to SCE for Transactive Energy Pilot.
- Negotiation with PG&E to apply CloudVEN rules in AutoDR Program Manual to agricultural pump sites.
- Agricultural DR Overview for LBNL staff.
- RFI Response to PG&E for Solicitation for Agricultural Control Technologies.
- Agricultural DR Overview for CEC Commissioner McAllister.
- Agricultural DR Overview for CPUC staff.
- Proposal (won) to the BIRD Foundation to develop an integrated energy and irrigation management systems.
- Comments to CEC Load Management Rulemaking.
- Recommendations to Energy Solutions for new ADR incentive calculation.
- Agricultural DR Overview for California ISO staff.
- Protest to PG&E Advice Letter changing BIP eligibility criteria.

CHAPTER 3: Project Results

Transactive Energy Pilot

The TE pilot was proposed in November 2018 and envisioned to take place over eight weeks during the 2019 season. Delays attributable to a number of factors including partner deployment schedules, problems with the first version of the PM-32 pump monitor that required shipment back and forth from Mexico. There were also software bugs that pushed the potential start date into the season, when it is difficult for agricultural energy users (AEU) to begin working with new technologies, and a wet year with reduced groundwater pumping exacerbated the situation.

The TE pilot started for the first user at the end of August 2019, with one pump, and a the second joined in October 2019 with four pump sites totaling five pump sites through November 2019. This nominally met the defined scope but took place at the tail end of the irrigation season, in a wet year and before all the automation systems were deployed. To obtain the richest data possible for answering the research questions, the pilot was extended into the 2020 season and ran from April through June, exceeding the total planned duration of the pilot by a factor of 3X. During 2020, four additional pump sites participated once commissioning of the Netafim system was completed at the 413 boosters and 52 was added as a participant without automation.

Of the three participating AEU, the two growers participated fully in the pilot. The third customer, Irrigation District 1, deployed the automation technology and tested schedules but did not regularly implement them for reasons discussed below.

Table 2: Participating Pump Sites

Pump Site	Application	Automation
#4-03E - CEC	Well to Reservoir	Super PAC, Oiler
401 - CEC	Well to Reservoir	Super PAC, Oiler
4-03W - CEC	Well to Reservoir	Super PAC, Oiler
412N - CEC	Well to Reservoir	Super PAC, Oiler
413 Booster - M – CEC (single meter includes Boosters M, W, E)	Reservoir to Orchard (almonds)	NetBeat Controller + Valve Automation
56S - CEC	Well to Orchard (almonds)	Netafim NMC Controller + Valve Automation
52 - CEC	Well to Field (annually rotating vegetables)	PAC + Manual Valve Operation

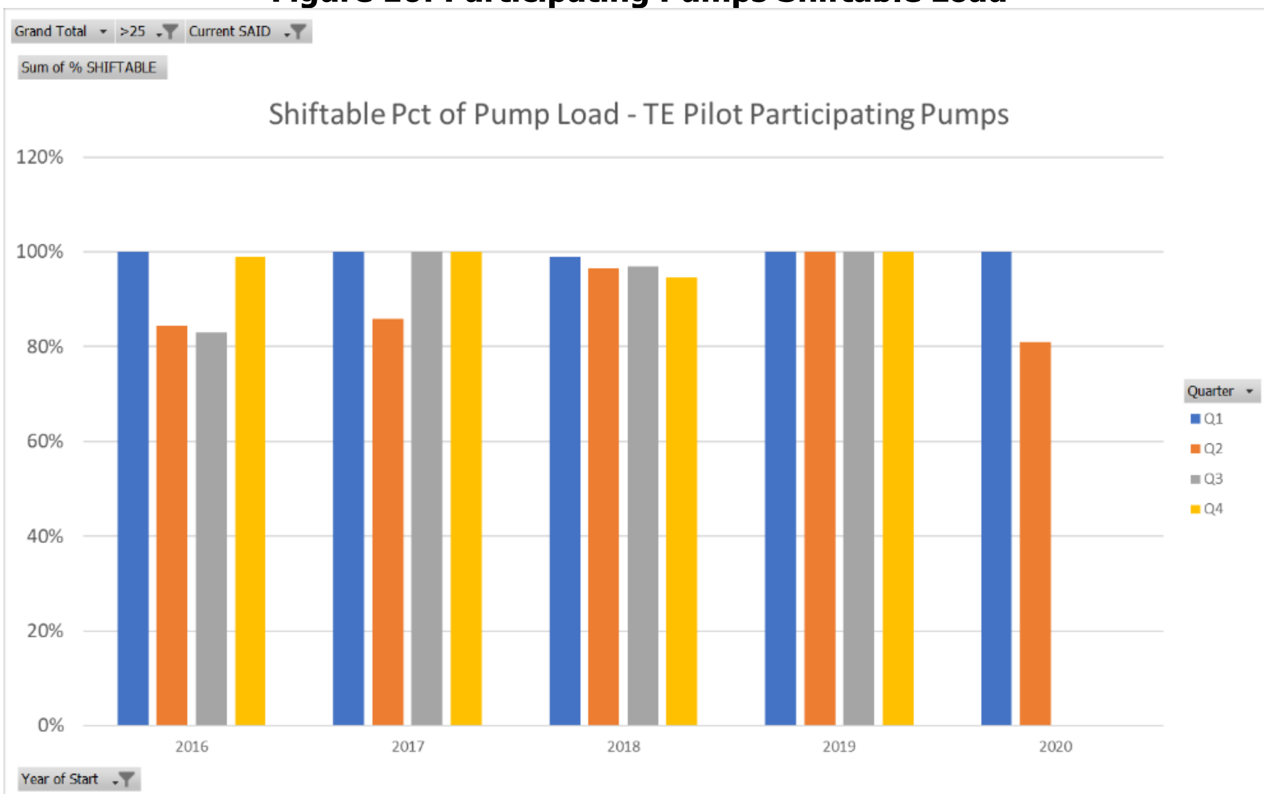
Polaris Energy Services

The pilot aimed to answer several questions to reach conclusions and recommendations on increasing sector participation in programs and markets to help facilitate renewables integration on California’s grid:

- Load Shift Potential – did participating pump sites have options to deliver the same amount of water to district members or crops while implementing the load shift indicated by hourly prices? For purposes of policy recommendations, what is the potential across a large sample of irrigation pumps?

  Analysis of participating pump sites' load showed that 94 percent of load in the 4:00 – 9:00 p.m. window could be shifted, as shown in Figure 10, while providing the same number of operating hours and kilowatt-hours in each week. This potential does not account for scheduling constraints such as the timing of water deliveries or other operational requirements.

Figure 10: Participating Pumps Shiftable Load



Source: Polaris Energy Services analysis.

To apply findings from the pilot to reach conclusions about the agricultural sector writ large, the researchers analyzed data obtained from customers through the Share My Data implementation in aggregated and anonymized form. This data is comprised of interval readings from 986 PG&E service points in the Central Valley with load greater than 25 kW belonging to 45 customer accounts, representing 235 MW of peak load. The size of the data set is represented graphically over time in Figure 11. Based on LBNL's analysis[8] that there is ~1,100 MW of agricultural DR potential in California, the researchers believe that this is a large and important sample. The sample is biased in two ways that need to be considered in applying conclusions broadly.

- All the customer accounts represented participate in DR or are in the process of deploying and enrolling in programs. Only ~1/3 of service points participate (because

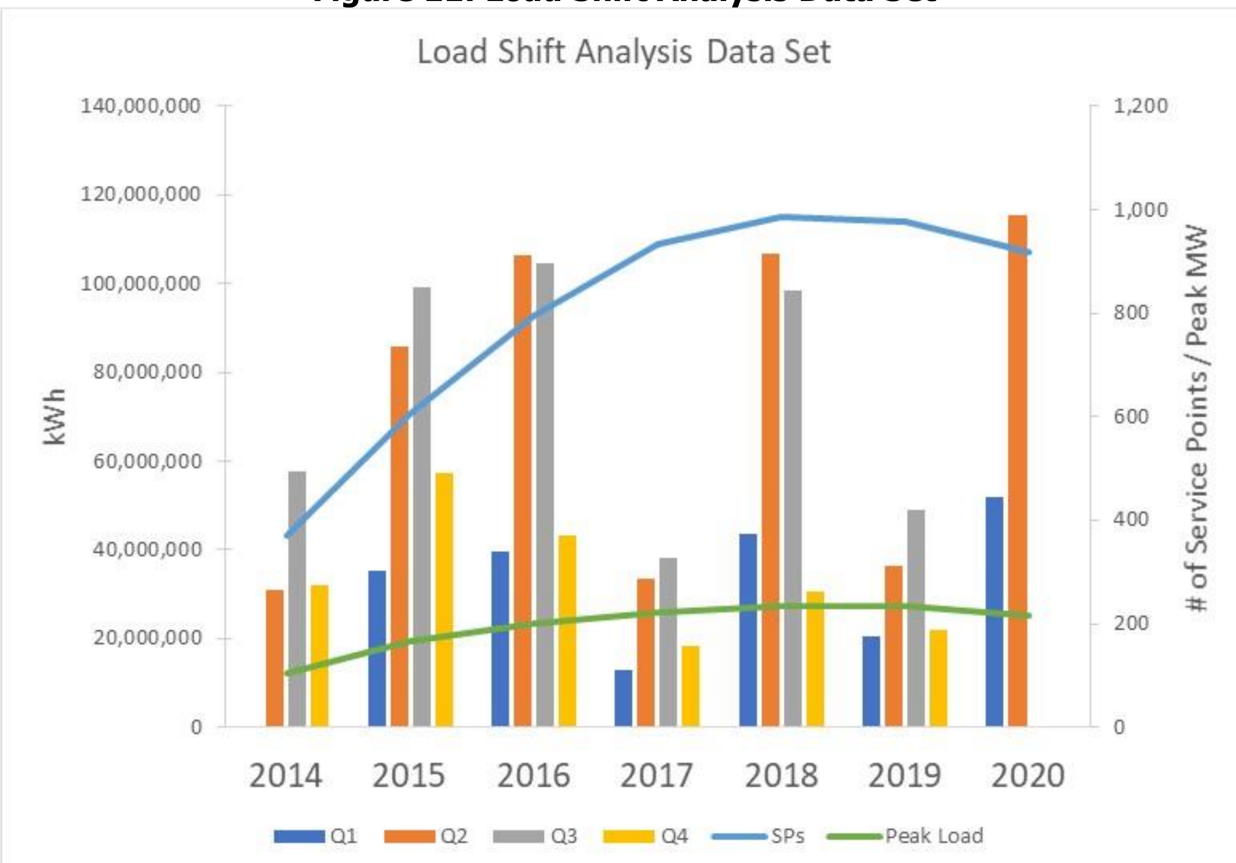
[8] Opportunities for Automated Demand Response in California Agricultural Irrigation , 2015.

customers provide Polaris with access to all of their data, not just for participating meters) but there is a bias toward AEU that have not completely shifted usage off peak or have operational flexibility among at least some of their pumps.

- Polaris' customers are all in PG&E's service territory, in the Central Valley, and have at least some pumps that are larger than 100 kW.

The data set shows the annual and seasonable variability of load.

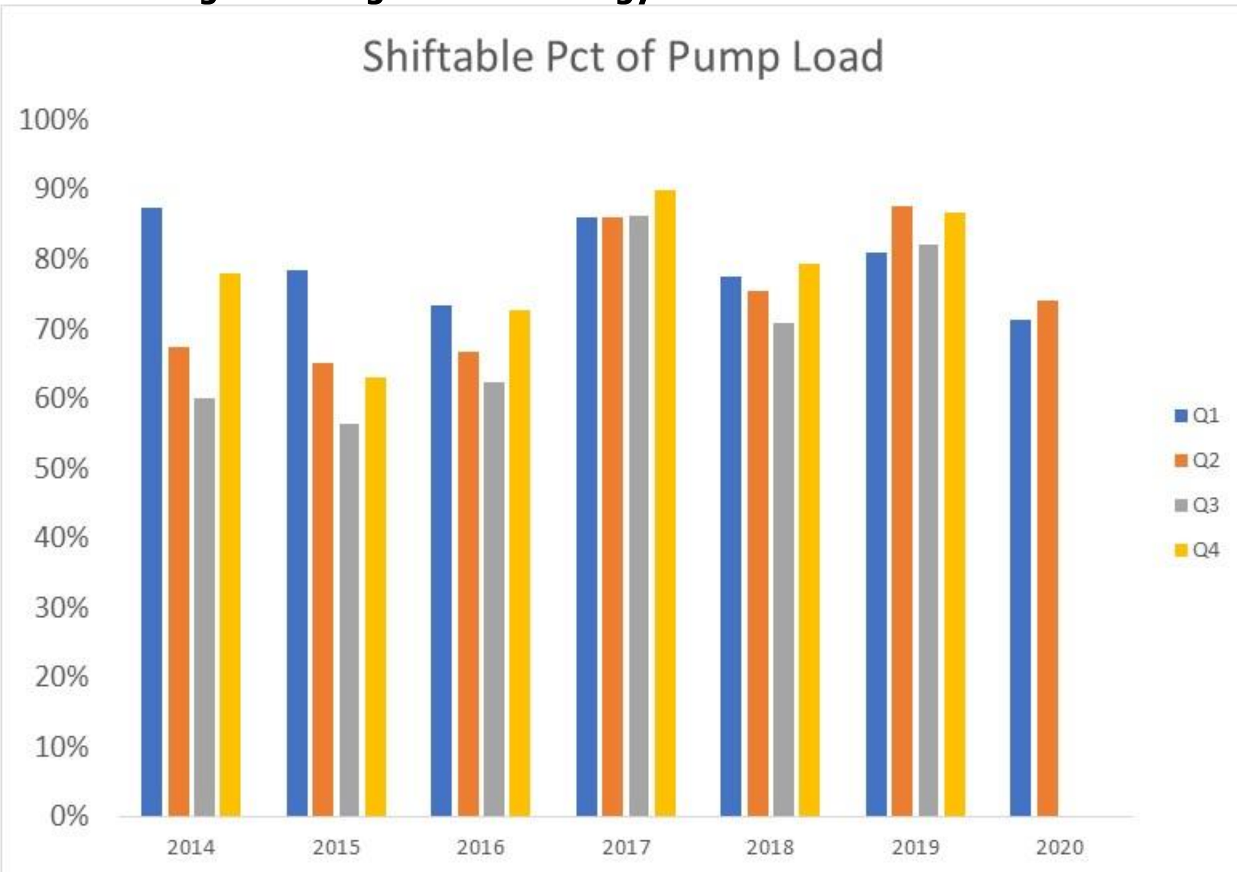
Figure 11: Load Shift Analysis Data Set



Source: Polaris Energy Services analysis of AEU usage data.

The analysis showed that, on average, 74 percent of load during the 4:00 – 9:00 window could be shifted to other hours during the same week with significant annual and seasonal variability. In an irrigation-intensive season in a dry year, Q3 2016, 62 percent of load can be shifted and in irrigation-intensive seasons in a wet year, such as Q3 2019, 82 percent of load can be shifted. Annual and seasonable variability in shiftable load is shown in Figure 12.

Figure 12: Agricultural Energy Users Load Shift Potential



Source: Polaris Energy Services analysis of AEU usage data.

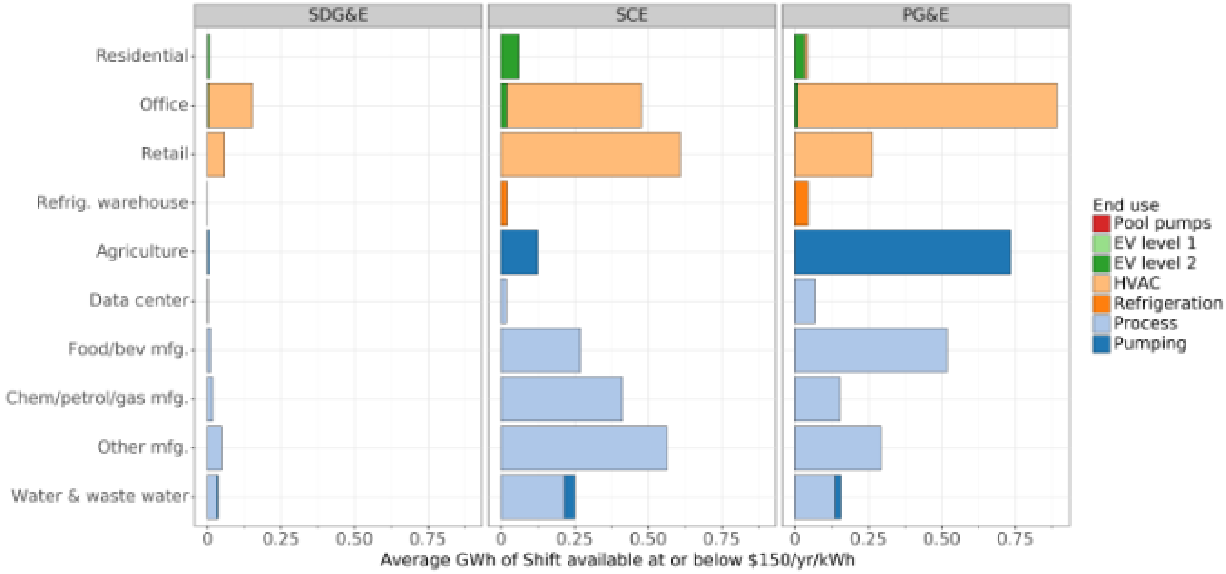
Based on this data, total agricultural load shift potential is calculated in Table 3 and compared to LBNL's estimate. . Figure 13 compares LBNL's estimate with other sectors across investor-owned utilities (IOU).

Table 3: Calculation of Agricultural Load Shift Potential

Value	Item
1	kw
8,760	hrs/year
22%	load factor *(analysis of 1,200 customer meters)*
1,927	hrs/yr
25%	5 hrs in shift window (16-21)
74%	operational shift potential *(analysis of 1,200 customer meters)*
357	shift hrs/yr
1,100	peak MW *(LBNL 2020 DR technical potential)*
392,185	MW-h shift/yr
1,000	MW/GW
392	GWH Shift Total From Ramp Hours (16-21)
1.074	GWH Shift/Day *(Polaris estimate from calculation above)*
0.875	GWH Shift/Day *(LBNL P. 21)*

Source: Polaris Energy Services analysis and LBNL 2020 California Demand Response Potential Study Phase 3.

Figure 13: Load Shift Availability x Sector x IOU



Source: LBNL 2020 California Demand Response Potential Study Phase 3.

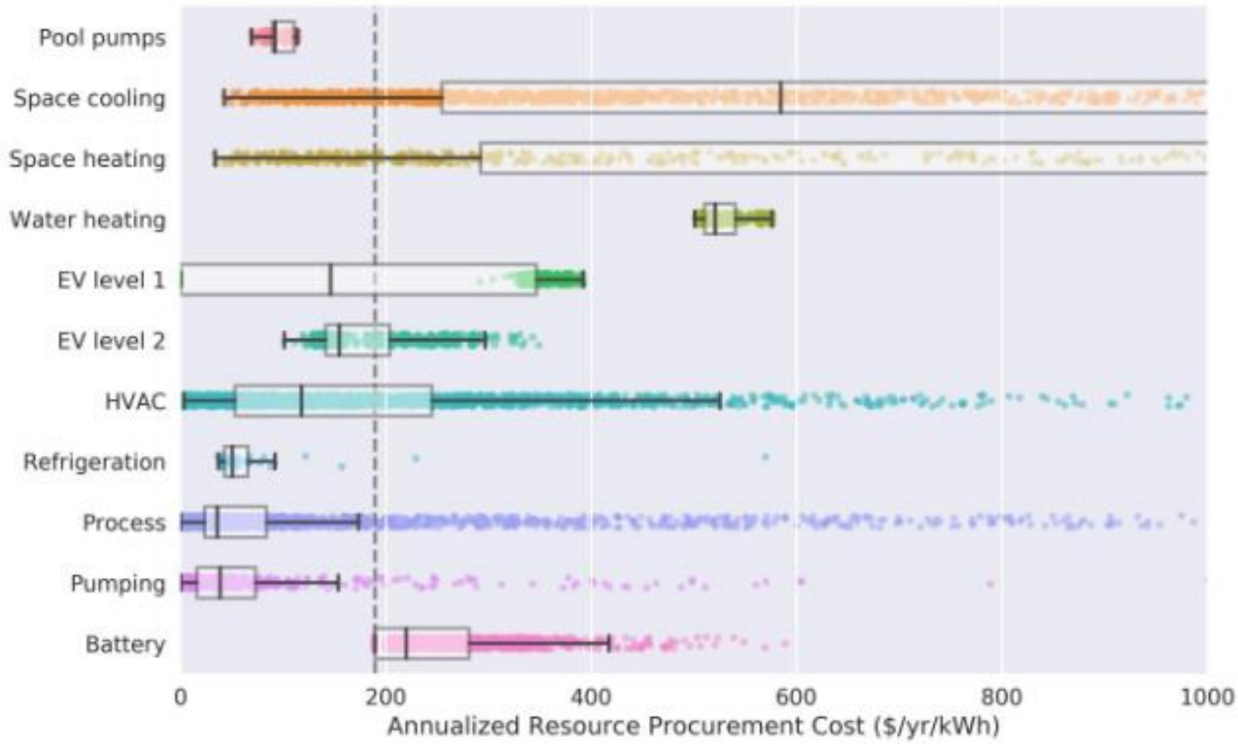
Table 4 shows the potential bill savings to AEU at the LBNL benchmark cost of shift for 2030. LBNL points out that "the cost benchmark represents the total procurement cost from the utility perspective, including the costs of the enabling technology, operating costs, program administration costs, and customer incentives." Assuming that shift is achieved using dynamic pricing, without program costs and that customers pay for enabling technology out of bill savings, the team can estimate the savings potential for energy users up to the threshold at which battery storage is expected to be less expensive to the grid. Figure 14 shows the cost of agricultural pumping load shift favorably compared to other applications.

Table 4: Agricultural Load Shift Savings Potential

Value	Calculation
$150	$/yr/kWh Benchmark
$33	$/kW at load factor above
$0.153	$/kWh avg all in energy rate
$295	$/kW-year avg bill
11%	Savings

Source: Polaris Energy Services analysis, 2020 California Demand Response Potential Study Phase 3.

Figure 14: Load Shift Cost x Application



Source: LBNL 2020 California Demand Response Potential Study Phase 3.

Use of Automation – would participants adopt new technologies and operating processes to enable schedules that require more frequent start/stop operations?

The three participants provided detailed information on their equipment and operations and reviewed the researchers' recommendations for automation. At the outset, all twenty pumps in the project were operated manually with no remote monitoring or control. The participants presented several obstacles and objections to overcome and after developing solutions to address them, all three initially agreed to deploy automation and participate in the TE pilot.

During the commissioning process, the irrigation district participant was concerned that the pump monitor — installed to address concerns about remote operations — shut down the pump when a fault was detected. The participant set a handful of schedules with the help of the researchers but encountered obstacles to using the system (just for remote operation, not changing schedules at this point). There was clear institutional inertia within the participant's organization that resisted changing procedures or adopting new technologies and these are representative of a significant but shrinking share of AEU. The incentives and organizational structures of the two types of participants also drive different behaviors. Irrigation districts are cooperatives and behave more like utilities in that they are risk averse and less likely to pursue a high probability of significant operational savings against a very low probability of a bad outcome.

The experience of the two grower participants was different from that of the irrigation district. Both had considered automation and were in some stage of exploration or experimentation but had not moved forward. They were eager to find ways to shave costs and relieve burdens on strained resources, most notably labor. Both growers agreed to the automation upgrades proposed by the researchers for pump control. In addition, both growers required additional automation of field valves to achieve full remote control and the researchers partnered with Netafim to provide these controls. Because they were not included in the original scope, the full cost could not be covered by the project budget and in both cases the growers contributed approximately 50 percent of the cost of controls. This was both evidence of their interest in automation and a motivator to employ the systems when they were deployed.

Both grower participants agreed to the changes to processes and procedures that adopting automation entailed. In both cases, there was a learning curve of several weeks, both for the growers and to address gaps and bugs in the systems deployed but by the end of the pilot, both growers regularly used the systems and only reverted to local/manual control in the event of a problem with the automated systems.

Notably, pump site 52 was not automated with the other pump sites; it was surveyed for a Netafim deployment, but the complexity of the hydraulic system was not a fit for the available technology at the time. During the winter of 2020, the Polaris PAC was upgraded to a super PAC, supporting full remote control and scheduling with the idea that the pump would be scheduled and controlled remotely with irrigators operating the valves manually, saving half of the labor usually required. The result is that operation of this pump site was largely manual and provided a good reference for the ability to respond to price signals without full automation.

Figure 15: myPOLARIS Logins and Commands Sent

Source: Polaris Energy Services.

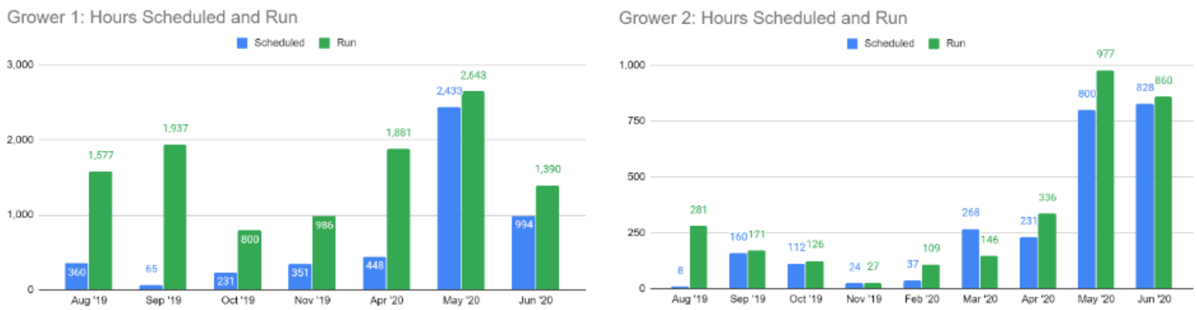
Figure 15 shows logins and commands sent by each participant. The high number of logins by Grower 1 and commands sent, distinct from schedules set, indicates the dynamic operational environment requiring frequent adjustments and changes to plans.

Setting schedules – would participants set weekly schedules in the myPOLARIS system?

The use of weekly schedules, vs daily or monthly, was determined by participant input to the pilot design and was validated as a good fit with existing AEU operational practices. Using the myPOLARIS system had different implications for four of Grower 1’s pump sites than the other three and Grower 2’s pump site. Four of Grower 1’s sites could be scheduled and controlled within myPOLARIS. The other sites required the use of myPOLARIS to see energy prices and set schedules for the TE pilot transactions and use of the Netafim application to implement those schedules, requiring a second step. The increasing share of running hours scheduled in the system is shown in Figure 16. Adoption by Grower 2 was rapid; as soon as the pilot started, usage was virtually 100 percent except when there were occasional faults in the automation system. Grower 1's adoption was slower and is attributable to organizational and pilot execution factors. Grower 1 had four pump sites deployed with the myPOLARIS system before the other three pump sites were commissioned with the Netafim system so for the first three months of participation (October 2019, November 2019 and April 2020), they were still operating three of the pumps with the old manual procedures which made enforcing new processes difficult as they were not reaping operational benefits (still had to go to the field to manually operate those pumps). Organizationally, Grower 1 has more distributed decision-making and operations so getting everyone on board and focused on the new process was more difficult.

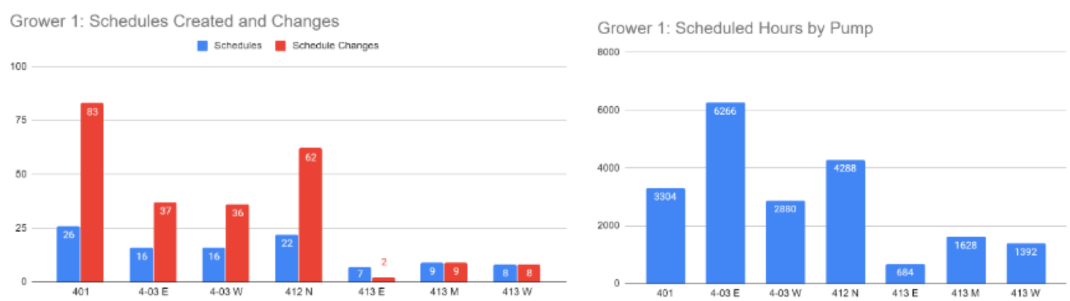
In both cases, by the end of the pilot, the growers' teams were accustomed to the new technology and processes and greatly preferred them to manual operations. Even though adoption was slower, Grower 1 became very refined in its usage of the system, identifying even small savings opportunities and adjusting schedules accordingly. This is evident by the frequent changes made as shown in Figure 17.

Figure 16: myPOLARIS Schedules Created and Run

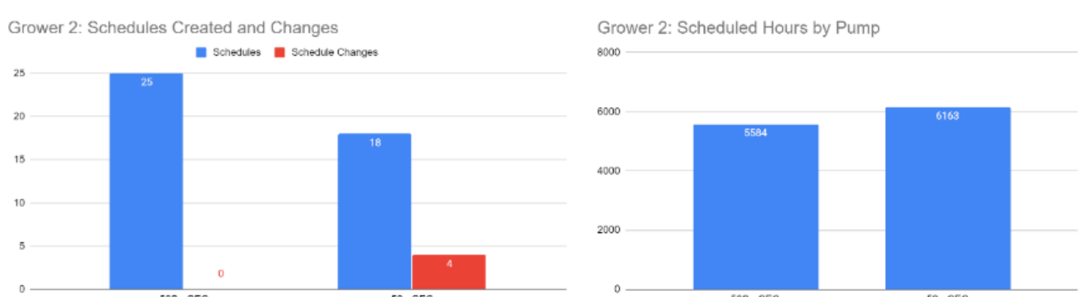


Source: Polaris Energy Services.

Figure 17: myPOLARIS Schedules Created and Run



Source: Polaris Energy Services.

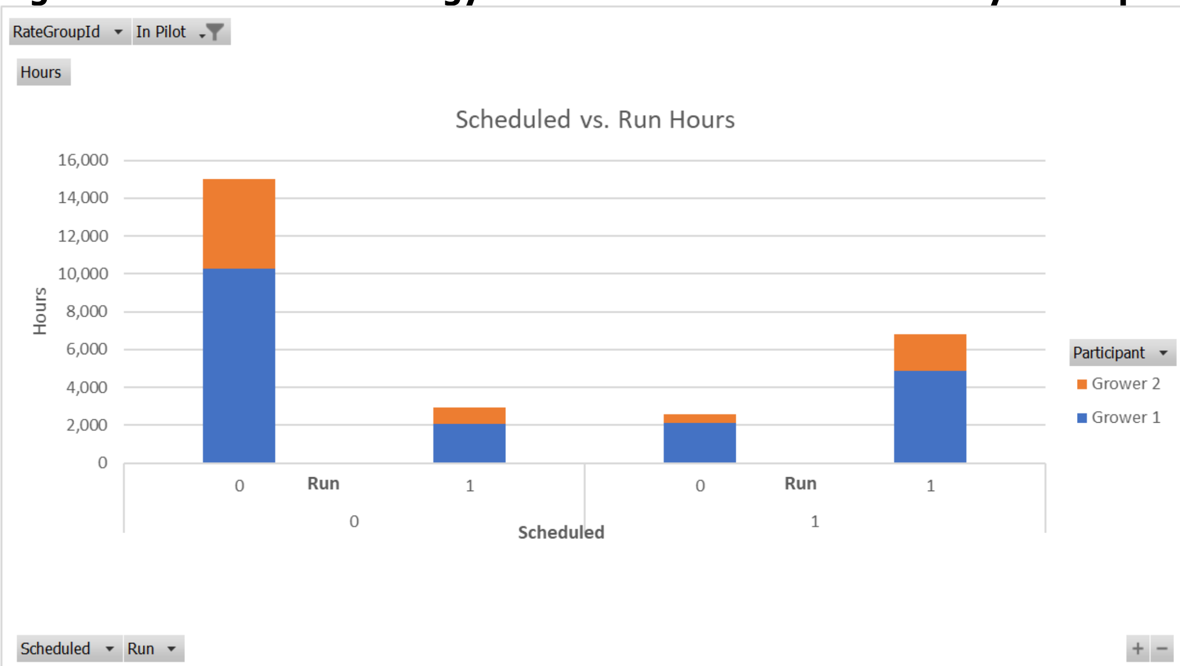


Source: Polaris Energy Services.

Following schedules – would participants follow the schedules that they set and, when making changes, would they use the automation or revert to manual operations?

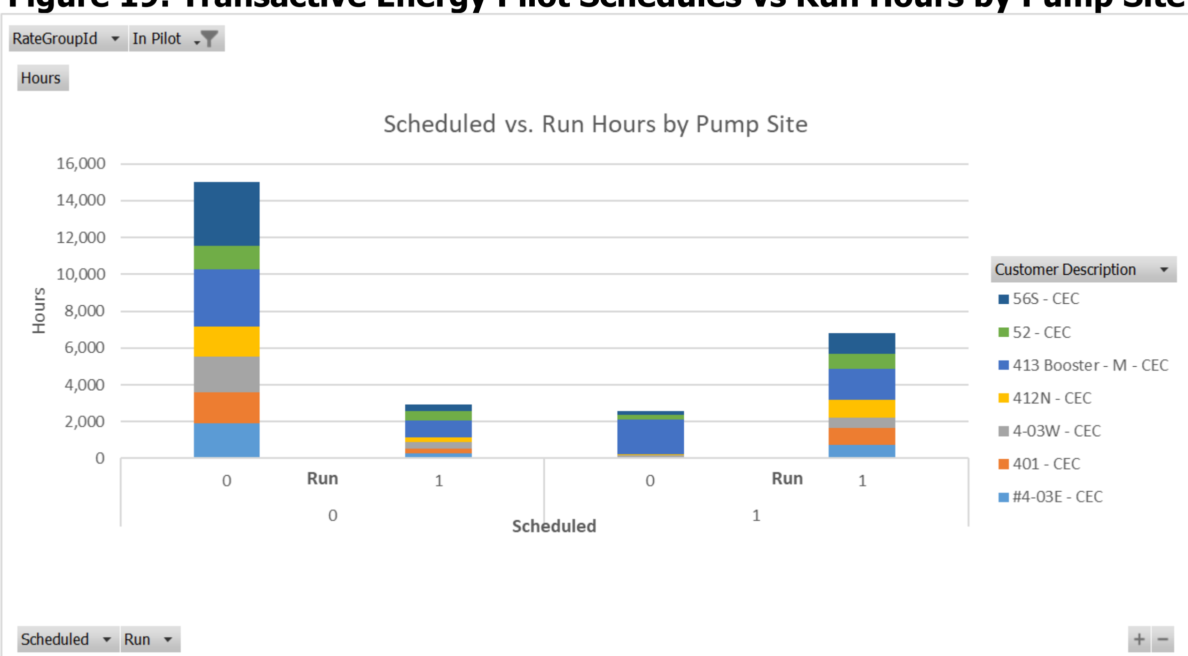
During months in which pumps participated in the pilot, the hours scheduled and run for each were tracked and bucketed as compliant (actual on/off matched schedule) and non-compliant (actual on/off did not match schedule); 80 percent of hours were compliant with the schedules entered by users as shown in Figure 18 by participant and in Figure 19 by pump.

Figure 18: Transactive Energy Pilot Schedules vs Run Hours by Participant



Source: Polaris Energy Services.

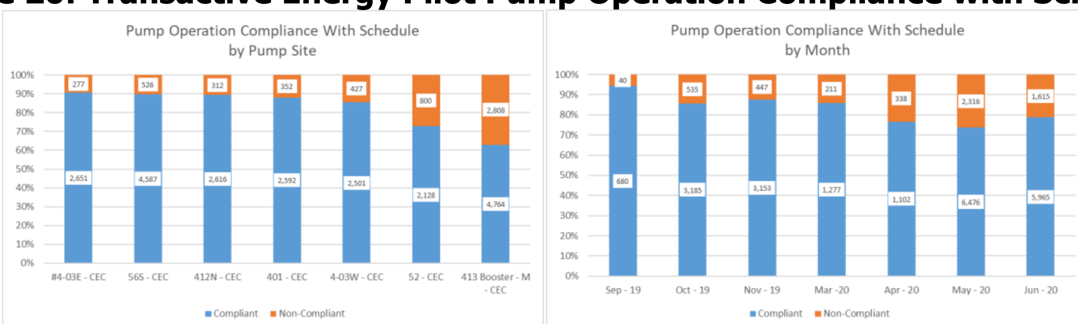
Figure 19: Transactive Energy Pilot Schedules vs Run Hours by Pump Site



Source: Polaris Energy Services.

Digging into schedule compliance on a per pump basis, 80 percent of the non-compliant hours are attributable to 413 and 52. Scheduling of 413 requires viewing energy incentives and scheduling in the myPOLARIS application and creation of schedules to physically operate the pumps in the NetBeat system. The data showed that the non-compliance was primarily during the intensive month of June 2020 and that the schedules implemented by the user in NetBeat were responsive to price signals but did not take the time to enter them in myPOLARIS as well, as shown in Figure 20. This non-compliance is an artifact of the pilot structure and will be resolved by integration of the systems and not be a factor in dynamic pricing regimes that do not require scheduling of energy purchases. As noted above, 52 was operated manually and the results reflect that. Compliance of the other five service points was 90 percent.

Figure 20: Transactive Energy Pilot Pump Operation Compliance with Schedule



Source: Polaris Energy Services.

Purchase vs used – did the quantities of energy purchased in the TeMix system based on user-input schedules match actual usage?

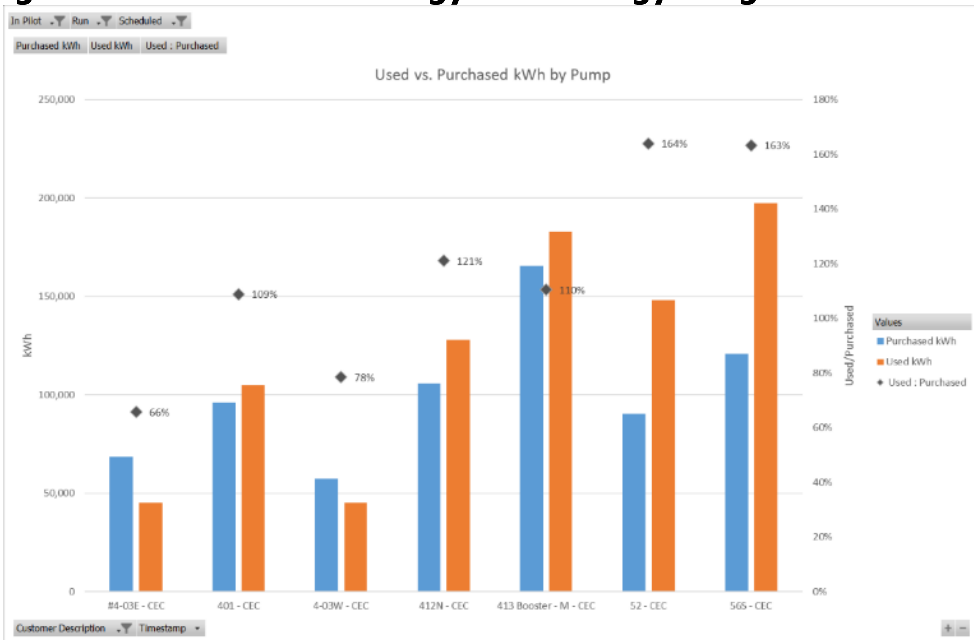
Predicting energy usage is necessary in a TE scenario and so algorithms were implemented in the software to determine a purchase quantity from a user-set schedule. The quantities of energy used compared to purchased varied across pump sites from 66 percent to 163 percent (Figure 21) and most of the variability was due to one of two factors: schedules set in the application that were not executed but not canceled and a pump site that could be one or both of two pumps for which the purchase quantity was set as the average of the two. These variations can be addressed with more granular scheduling of system components if market structures require greater adherence to purchase quantities. Dynamic pricing without the transactive market would not require this improvement.

Load Shift– how close was actual usage to optimum schedules as indicated by TeMix prices?

The prices tendered by the TeMix RATES project engine provided strong incentives to avoid ramp hours and little variability among other times of the day. Figure 22 shows the hourly prices on a monthly basis that comprise the hourly average in Figure 23. The pilot, therefore, did not test AEU ability to shift load *to* the potential overgeneration hours.

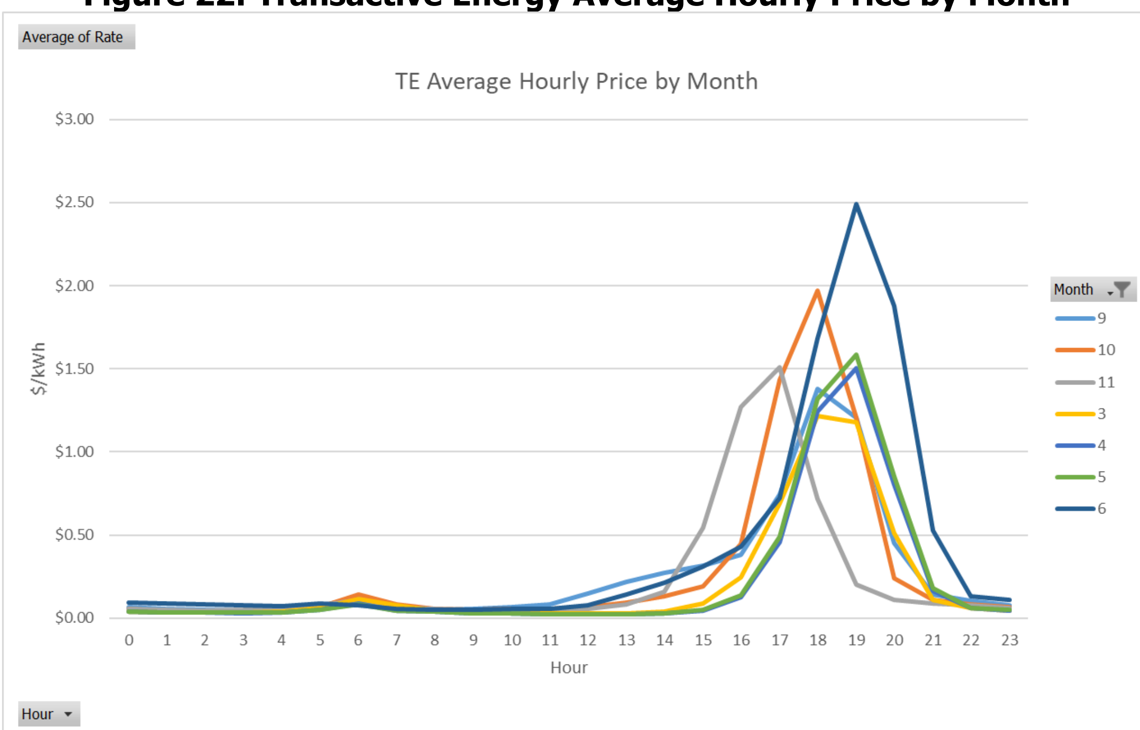
The results showed that when implementing schedules (excluding technical issues with the automation), participants were able to avoid the ramp hours in almost all cases, as shows in Figure 23, Figure 24, and Figure 25. One participant selected the hours to shift *to* based on operational ease and sacrificed a small amount of incentive while the second tailored schedules to earn the greatest incentives possible. The notable exception is pump site 52 where full automation was not deployed.

Figure 21: Transactive Energy Pilot Energy Usage vs Purchased



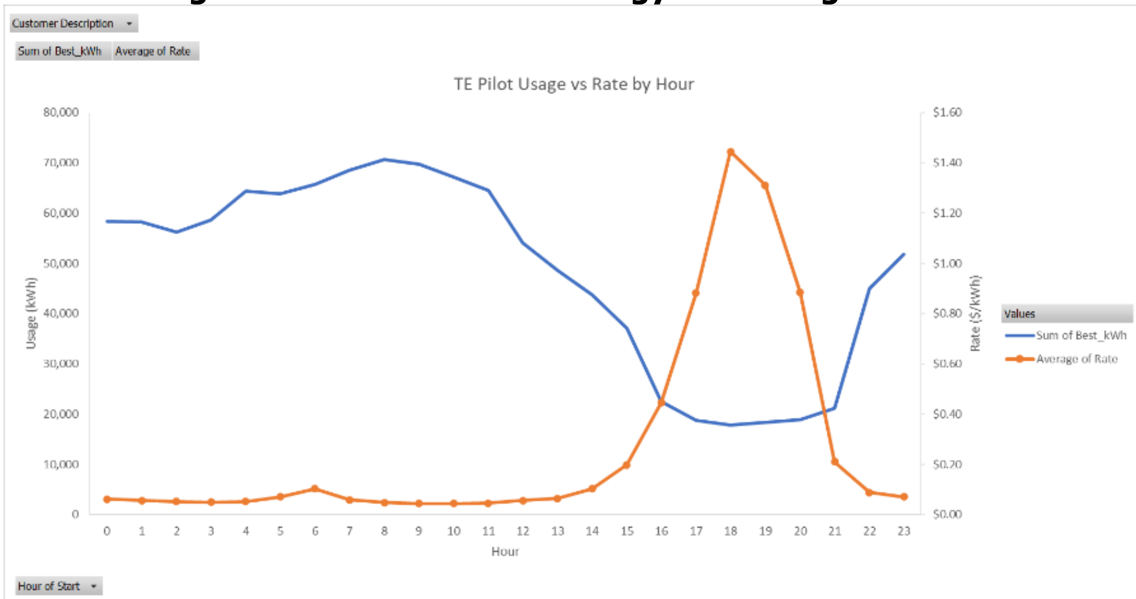
Source: Polaris Energy Services.

Figure 22: Transactive Energy Average Hourly Price by Month



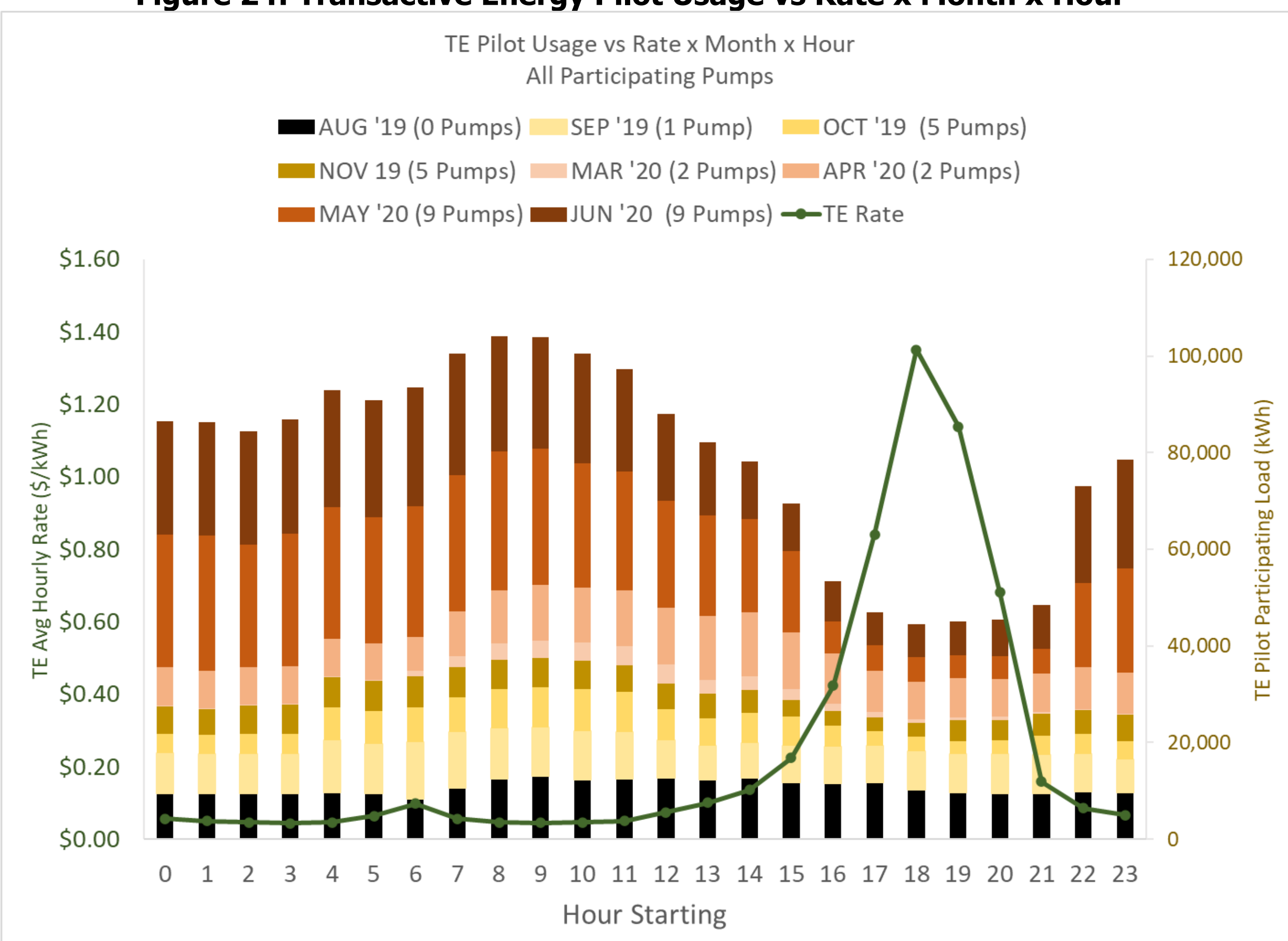
Source: Polaris Energy Services

Figure 23: T Transactive Energy Pilot Usage vs Rate



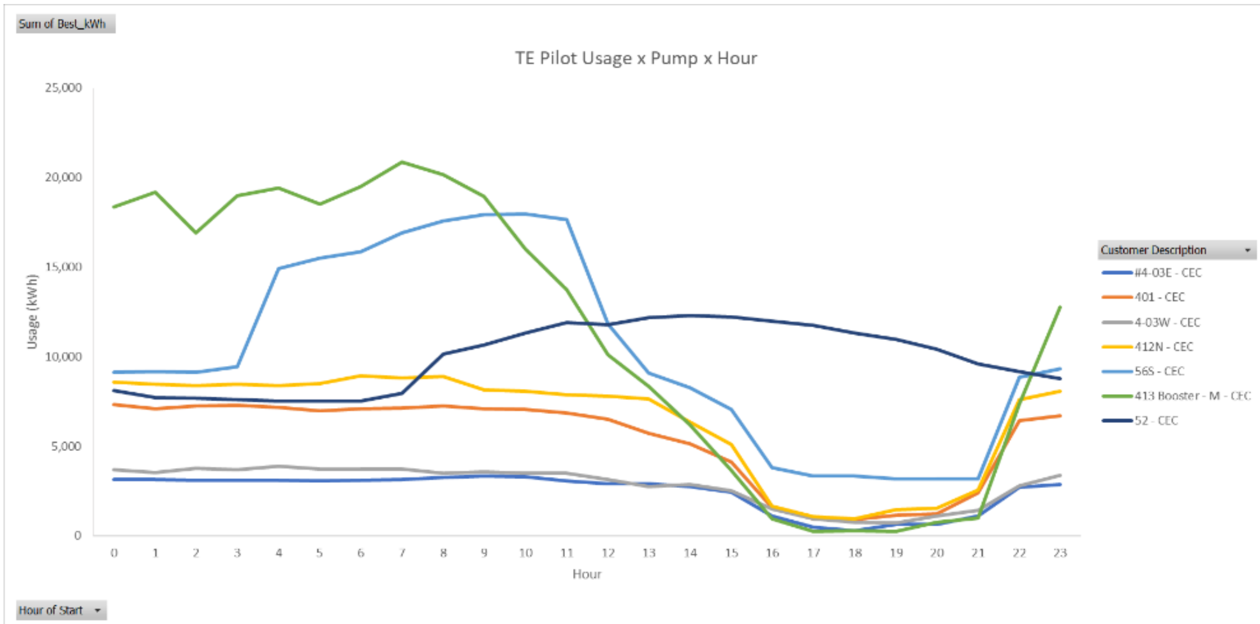
Source: Polaris Energy Services

Figure 24: Transactive Energy Pilot Usage vs Rate x Month x Hour



Source: Polaris Energy Services.

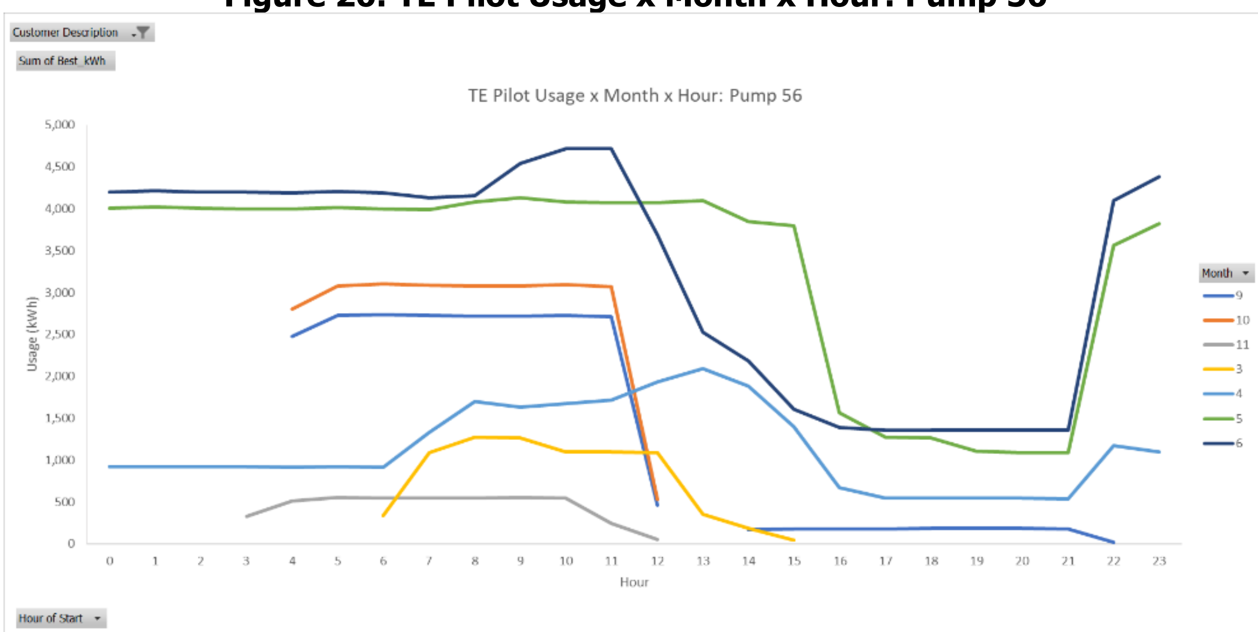
Figure 25: Transactive Energy Pilot Usage x Pump x Hour



Source: Polaris Energy Services.

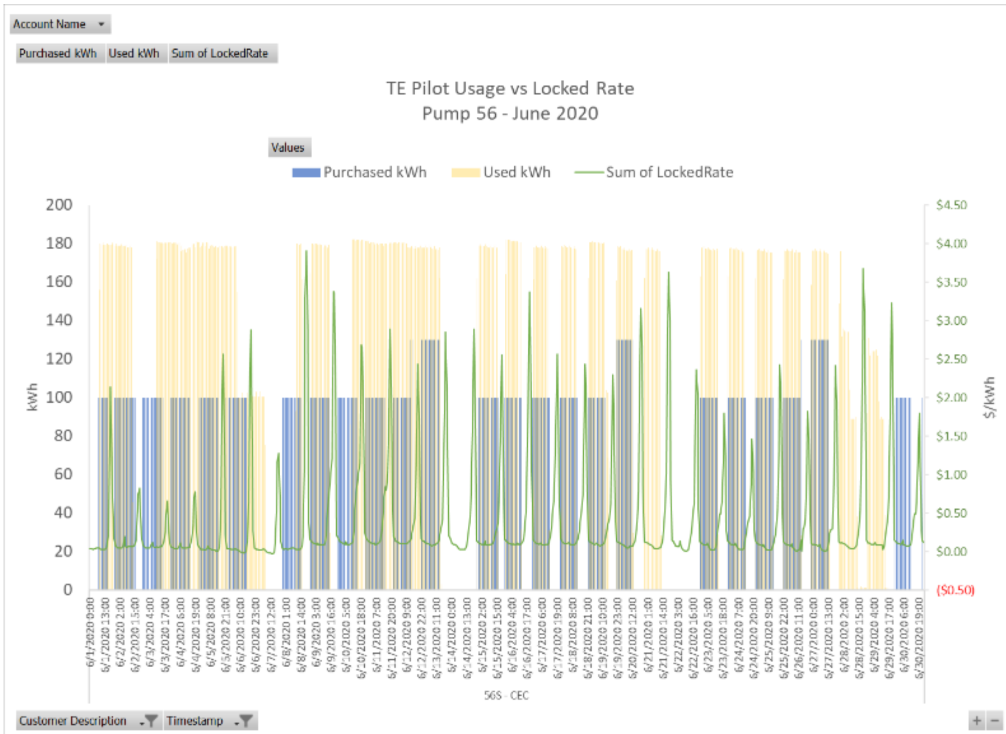
Figure 26, Figure 27, and Figure 28 show the hourly load profiles by hour for one pump and how they align with the rate generated by TeMix for a single pump in two different months.

Figure 26: TE Pilot Usage x Month x Hour: Pump 56



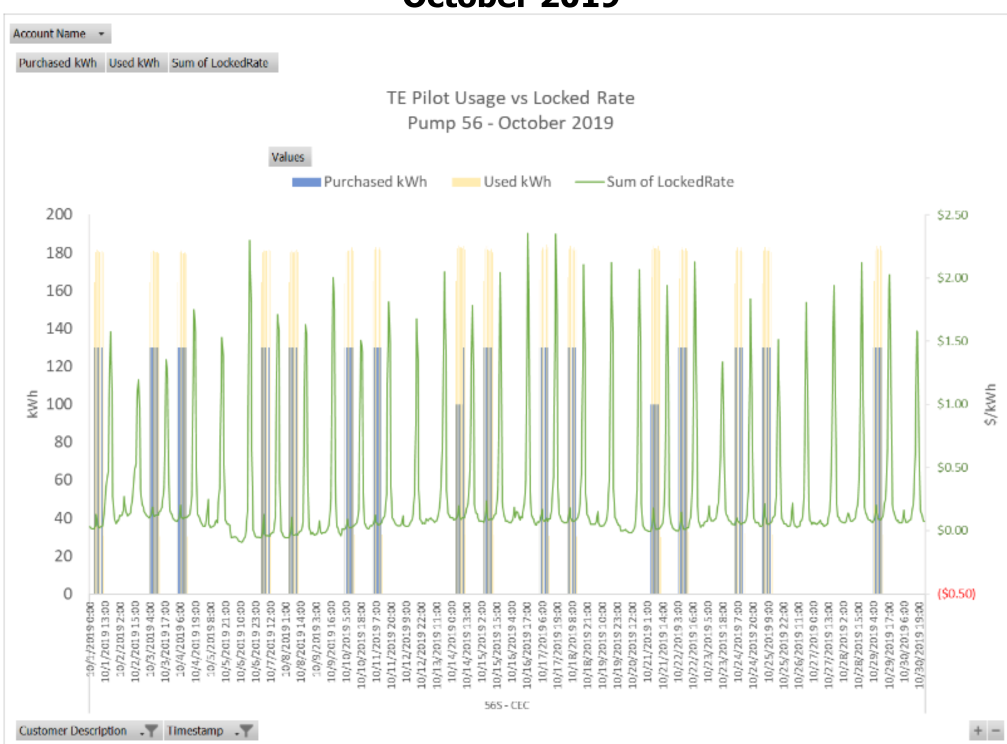
Source: Polaris Energy Services.

Figure 27: Transactive Energy Pilot Used and Purchased Energy vs Locked Rate – June 2020



Source: Polaris Energy Services.

Figure 28: Transactive Energy Pilot Used and Purchased Energy vs Locked Rate – October 2019



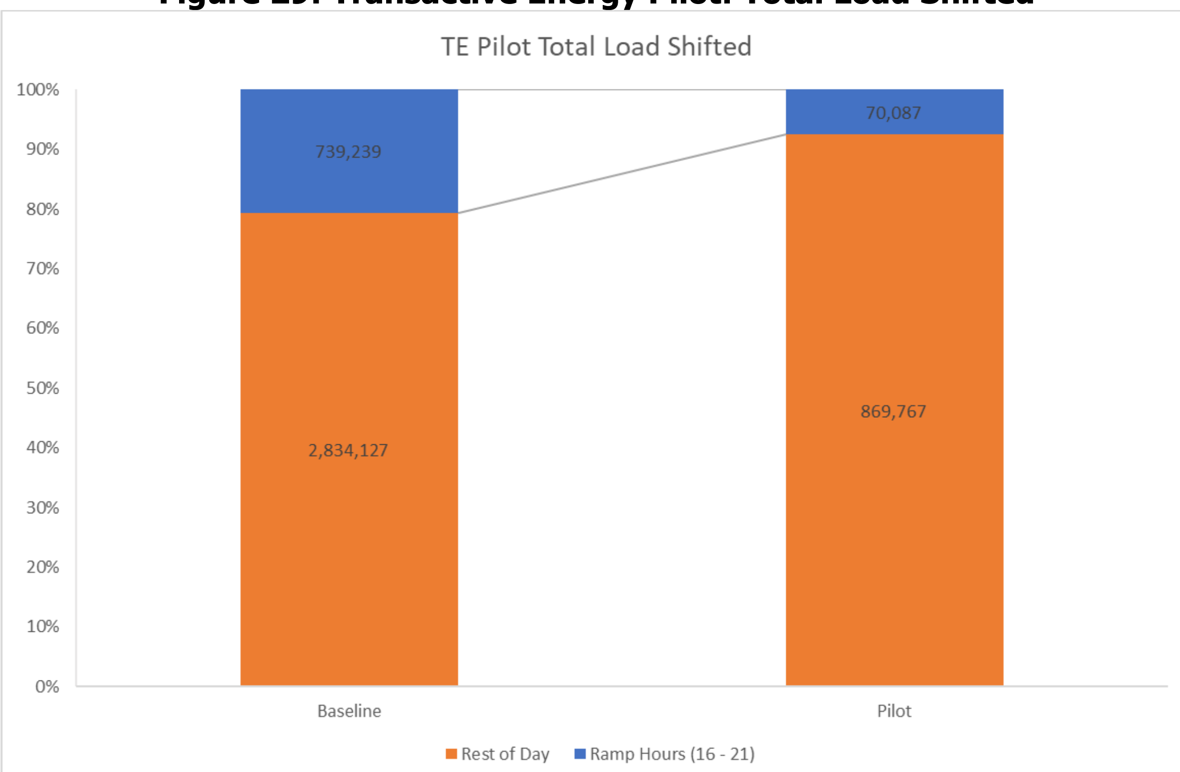
Source: Polaris Energy Services.

Used vs pre-pilot – how did usage compared to similar periods prior to the pilot?

AEU shifted two thirds of load out of the 4:00 – 9:00 p.m. ramp window compared to prior years, using all available data from 2015 and later as a baseline for eight pumps representing 1.1 MW of peak demand. Usage during the window decreased from 21 percent of total, which is proportional to the number of hours in the day, to 7 percent of total, equaling 124,345 kWh of shifted load, as displayed in Figure 29. A total of 939,854 kWh of load participated in the pilot and was compared to 3,573,365 kWh of baseline data. The cost, in incentives, to shift that load was $0.138/kWh.

This result is significant and somewhat understates the opportunity because the data includes a steep learning curve, several pump-weeks of unresponsive operations as technical issues were addressed with new technology, and the extra burden that the simulation placed on participants. The results are clear that significant load shift is possible from agricultural pumping on a regular basis with appropriate technology, customer education and simple price signals.

Figure 29: Transactive Energy Pilot: Total Load Shifted



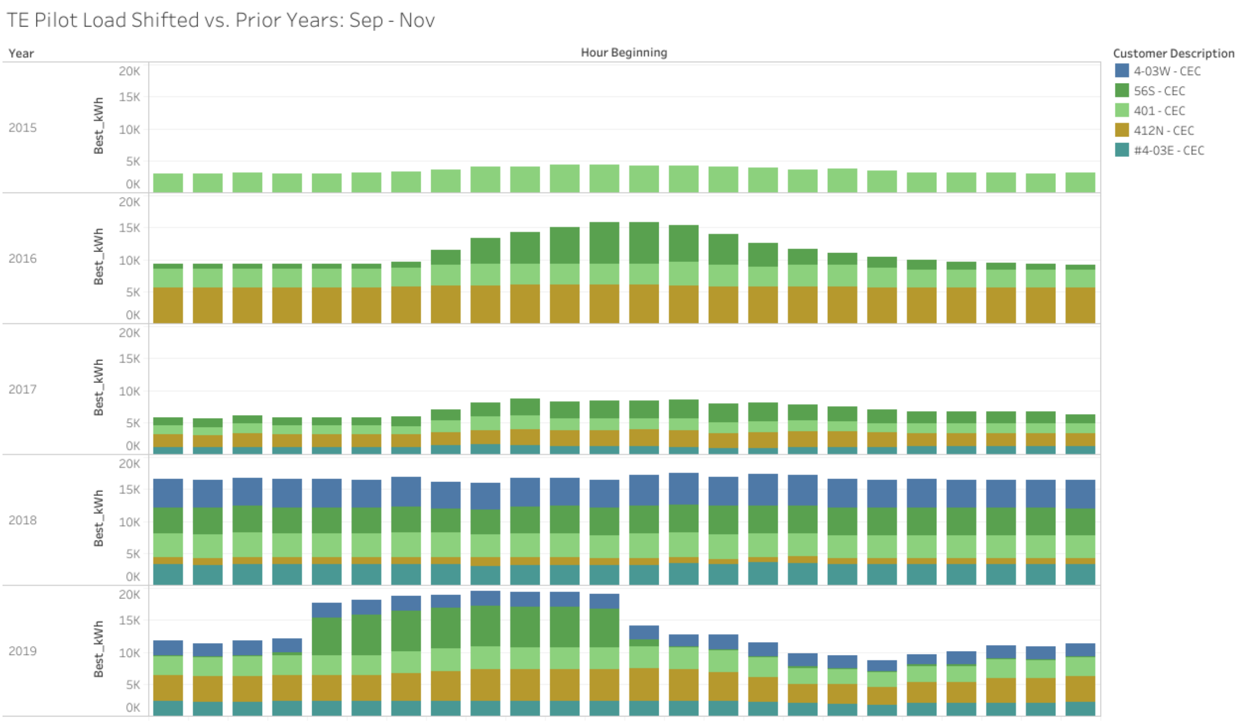
Source: Polaris Energy Services.

Figure 30 and Figure 31 show the change in hourly load profiles in two seasons across multiple years before the pilot and during the pilot. Figure 32 shows the change in the month and year before the pilot for the first participating pump.

Figure 30: Transactive Energy Pilot: Load x Hour vs Prior Years – Apr to Jun

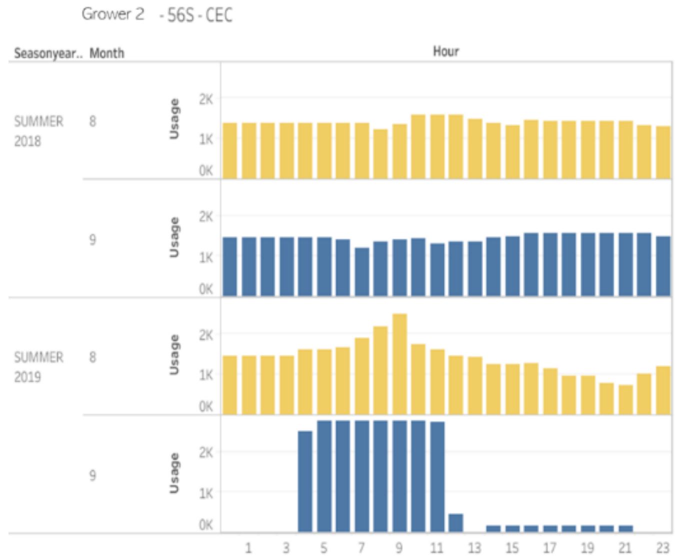
Source: Polaris Energy Services.

Figure 31: Transactive Energy Pilot: Load x Hour vs Prior Years – Sep to Nov



Source: Polaris Energy Services.

Figure 32: Transactive Energy Pilot Usage x Hour vs Previous Month and Year – Pump 56



Source: Polaris Energy Services.

Lock vs settled – what are the differences between the hourly prices locked for participants in the pilot and the actual settled prices and what implications do they have on program and market design?

Customer interviews and research indicated clearly that AEU would not be able or willing to respond to real-time or even day-ahead price signals as contemplated by Load Management Rulemaking (Docket 19-OIR-01) underway now or the dynamic pricing options developed by the Load Shift Working Group. By contrast, the TE paradigm provides a mechanism for buyers and sellers of energy to set prices at any point on a time continuum from years in advance to real-time. For the pilot, the researchers sought a pricing mechanism that would balance simplicity and feasibility for the participants and the highest degree of response possible for the grid.

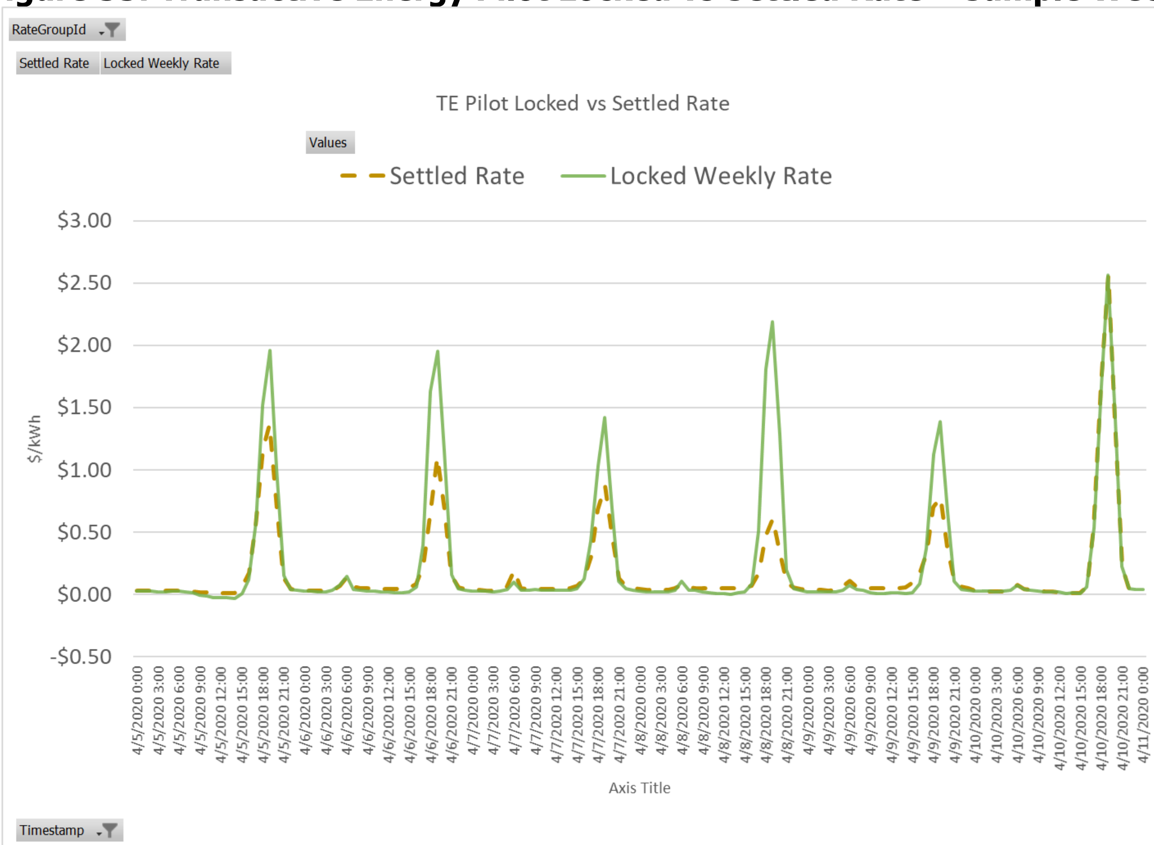
The selected mechanism was a weekly slate of hourly prices based on the latest TeMix tender for each hour. As the market maker for the simulation, Polaris arbitraged the difference between these rates and the real-time rates. To apply the results of this pilot to real markets, the impact of this arbitrage needs to be assessed.

Analysis of the hourly prices tendered by the TeMix system on a weekly basis (between one and seven days ahead of the hour for which the energy is sold) and settled prices shows virtually no difference in the timing of high and low prices during a given week, as shows in Figure 33. The only significant difference is in the magnitude of peak prices, which varied in both directions; sometimes the weekly locked price was higher and sometimes the settled price was higher. This has three important implications for rate and market design:

- The response of AEU to market pricing will not vary significantly if they are provided weekly pricing compared to day-ahead or real-time pricing. The grid will get the same dynamic load shift if AEU schedule energy consumption to take advantage of the lowest energy pricing during a given week.

- There is risk to be managed in the difference between the magnitude of the hourly prices that must be accounted for in market design. This risk could be managed by the energy user, the utility or a third party seller of energy (generator, retailer, aggregator, etc.), with some benefit accruing to that party. This is similar to any dynamic energy market, including California's Direct Access retail market, where risk and cost are traded among parties.
- Providing weekly price signals elicits virtually all of the dynamic load shifting from AEU that California policy demand compared to static rates determined for years at a time or DR programs that require bids up to seven weeks in advance.

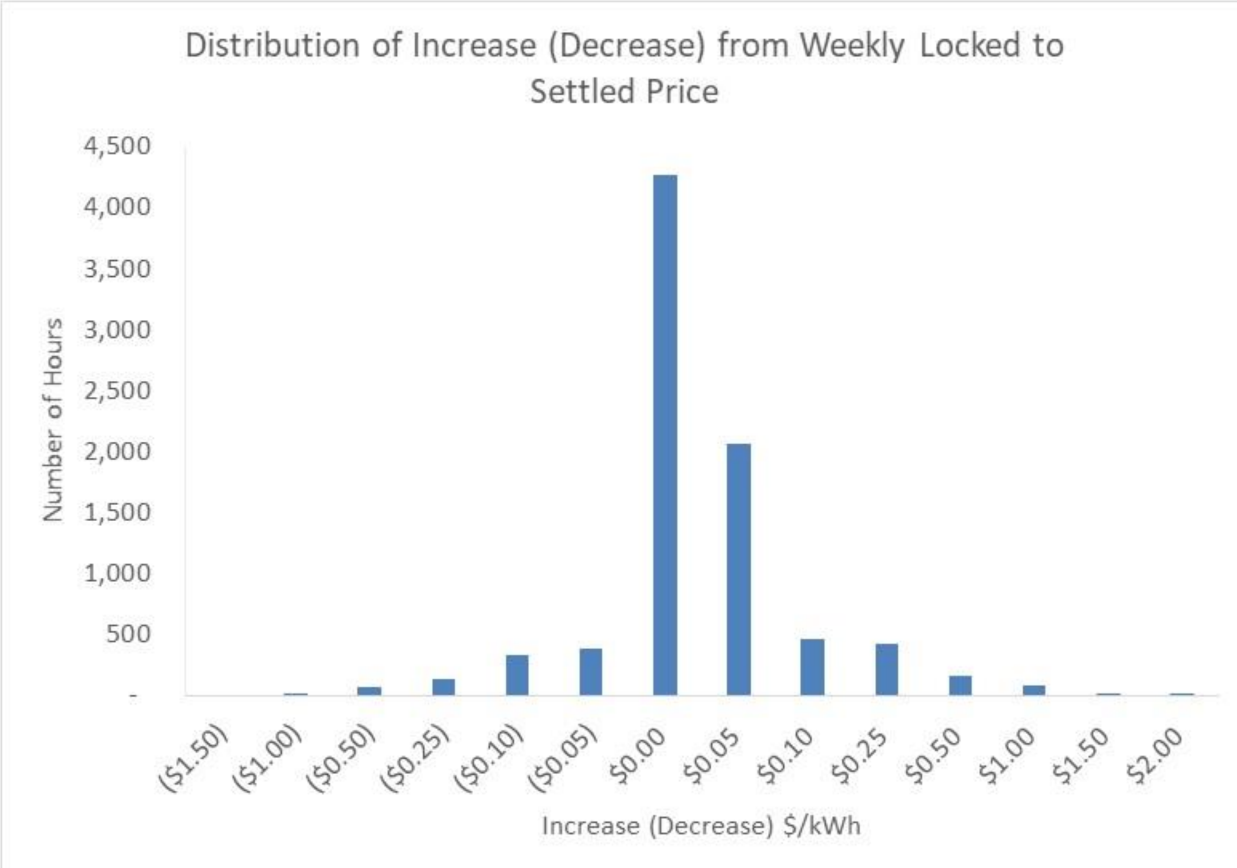
Figure 33: Transactive Energy Pilot Locked vs Settled Rate – Sample Week



Source: Polaris Energy Services.

Analysis of one year of TeMix generated price data shows that the average change from weekly tender to settled price is $0.005/kWh and that the change in price for 80 percent of the hours is $0.05/kWh or less, confirming that the cost of hedging the risk between a weekly and real-time price is negligible, as shown by the histogram in Figure 34.

Figure 34: Transactive Energy Pilot: Distribution of Difference Between Locked and Settled Prices



Source: Polaris Energy Services.

Customer Engagement – what support was provided and required to achieve the pilot results and what are the implications for program and market design?

To bridge the gap between a simulated market in the context of a research project to widescale market adoption, it is necessary to identify factors in the project that contributed to success and need to be replicated or replaced. The researchers identified three success factors that should be accounted for in market and program development:

- Catalyst: the researchers in their ongoing engagement with participants prior to and during the project served as the causal factor in the adoption of automation and adjustment of operational schedules and practices to earn energy incentives. Technology solutions were available and existing TOU rates and programs offered some of the savings opportunities achieved in the pilot but the participants did not take advantage of them. The qualitative research shows that 'build it and they will come' is not a viable strategy for gaining AEU adoption.
- Training and Integration: significant work is required to integrate systems with each AEU's unique operations, address configuration and calibration issues and train all relevant personnel. With the highly variable operations of the agricultural sector, these services need to be provided at the appropriate times in the annual cycle and not necessarily at deployment as is common with other technology projects.

- Customer Success: there was a critical period of one to two months during which each participant required close support and encouragement to fully endorse the technology and the practices that earn energy incentives. This period is crucial as failure to build momentum and address obstacles can lead to reversion to old practices. Leading business-to-business (B2B) technology companies have identified customer success as a practice distinct from and additive to customer support, recognizing that increasing usage of their products and earning enthusiastic references requires more than the absence of product bugs and faults and in fact requires that customers achieve and see quantifiable success by their own metrics. Energy programs in California do not factor in the need for customer success and where it exists, it is usually because a vendor's interests are aligned with ensuring success.

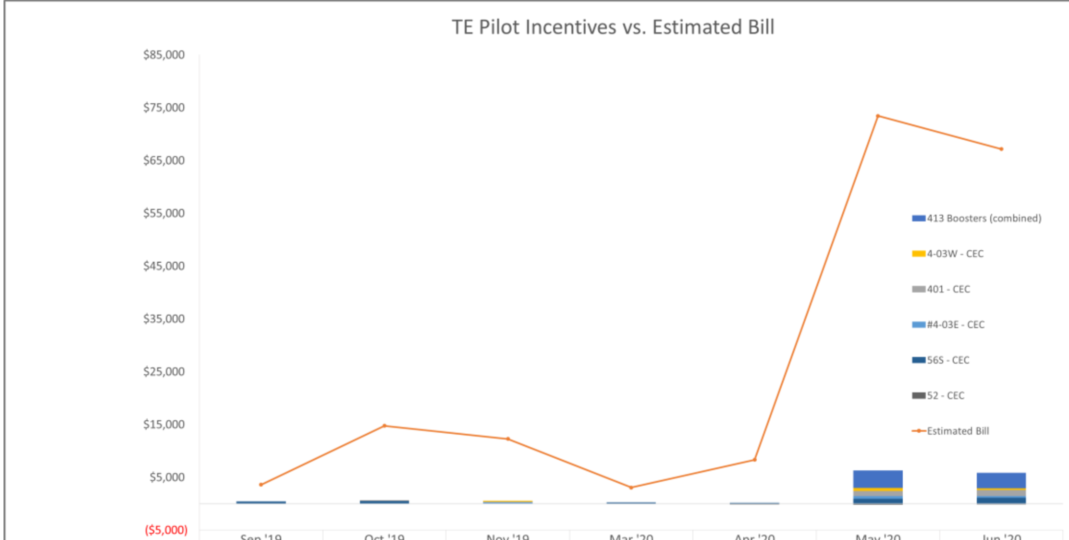
While these factors are critical and require attention and resources, there is an inverse benefit once they have been provided. AEU who adopted technology and money-saving practices were satisfied with them at all levels (management to field labor) and develop habits and practices that themselves become hard to break. This finding has important implications for the structuring of incentives and expectations for the continuation of benefits.

- Simplification of programs and markets as recommended by this report cannot be accompanied by an assumption that energy users will identify, access and implement them without significant support. Policy makers must provide for them and not assume that customers or technology vendors will pick up the slack if third parties are not directly participating as aggregators or program implementers.
- The benefits of these upfront investments will extend longer than typically assumed based on the usable lifetime of technology. Once new practices and habits are embedded in AEU operations, and financial incentives remain strong, they will continue to maintain, repair, renew and upgrade enabling technologies of their own accord; they are unlikely to revert to previous practices. In simple language, habits are hard to create and hard to break.

Participant results – what benefits were derived by participants, at what costs, and what are the implications for widescale adoption of technologies and response to load management signals?

Participants' incentives averaged 9 percent of estimated actual bill costs for the period of the pilot, as shown in Figure 35, which both participants described as highly attractive. This included a learning curve and so for calculating potential returns a 13 percent bill savings is estimated when all potential load is shifted with a 22 percent load factor. Extrapolating savings, net of a recurring subscription, and dividing by system cost provides estimated return on investment (ROI) if operated year-round. System costs vary widely depending on whether pump automation is sufficient or additional controls are needed for valves in the field. In this pilot, the higher cost/lower ROI installations were those that customers agreed to invest in.

Figure 35: Transactive Energy Pilot Participant Incentives vs Estimated Bill



	Sep '19	Oct '19	Nov '19	Mar '20	Apr '20	May '20	Jun '20
413 Boosters (combined)						$3,339.26	$2,938.79
4-03W - CEC		($7.81)	$173.21			$524.17	$359.77
401 - CEC		$212.76	$151.84			$952.80	$1,094.99
#4-03E - CEC		$5.37	$167.33			$543.59	$370.13
56S - CEC	$428.42	$472.23	$82.52	$219.48	$213.36	$942.19	$1,115.01
52 - CEC				($58.18)	($155.91)	($217.67)	($156.21)
Estimated Bill	$3,606	$14,778	$12,276	$3,062	$8,329	$73,433	$67,171
Bill Savings	12%	6%	7%	5%	1%	10%	10%

Source: Polaris Energy Services.

Figure 36: Transactive Energy Pilot Estimated Return on Investment on Automation Investments

Avg. Total Energy Cost ($/kWh)	$0.153
Savings	13%
Load Factor	22%

TE Incentive ROI on Automation Systems

System Cost	Pump(s) Max kW: 75	100	125	150	200	250
$7,500	36%	49%	61%	73%	97%	122%
$15,000	18%	24%	30%	36%	49%	61%
$25,000	11%	15%	18%	22%	29%	36%
$50,000	5%	7%	9%	11%	15%	18%
$75,000	4%	5%	6%	7%	10%	12%
$100,000	3%	4%	5%	5%	7%	9%
$150,000	2%	2%	3%	4%	5%	6%
$200,000	1%	2%	2%	3%	4%	5%

The matrix shows return on investment on automation investments based on pump size and system cost. The cells with the black borders represent the size and investments represented in this pilot.

Source: Polaris Energy Services.

For AEU, energy savings are but one value stream from automation. Growers that operate pumps remotely or automatically enjoy significant labor savings; one of the participants estimated a savings of 30-40 percent during the pilot for the participating sites. The precision and accuracy of schedules is a benefit to crop yield that was cited by a participant but not quantified; in a pre-pilot interview, he said that "I tell them [the irrigators] to put eight hours [on the crop] but when I look at the crop I'd swear they only put six."

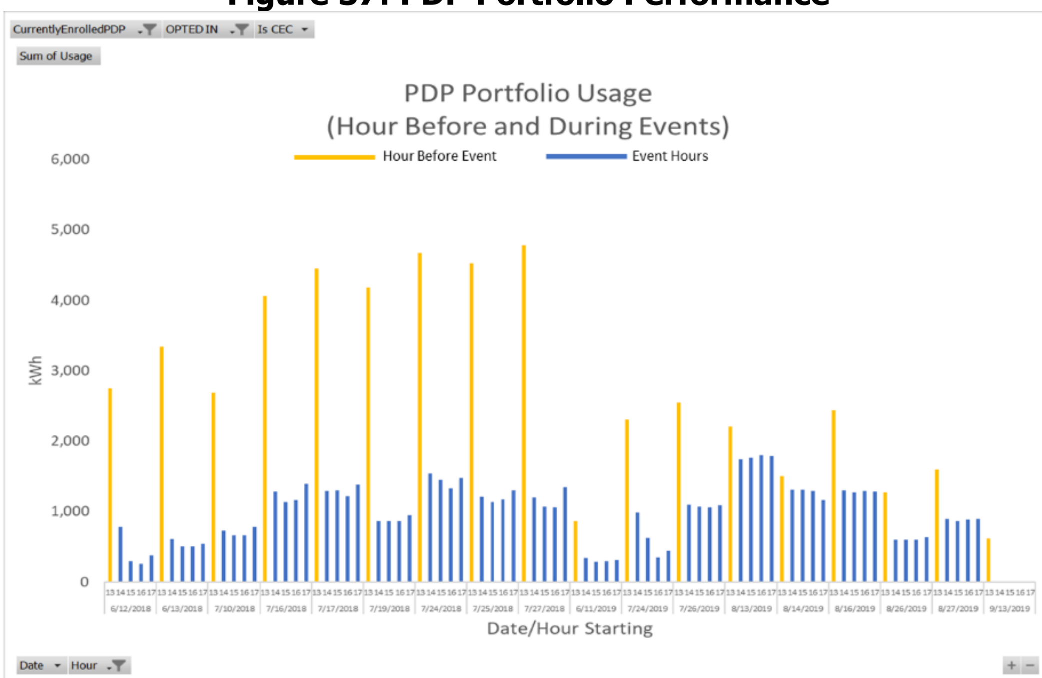
Demand Response Program Participation

Participating pump sites were enrolled in existing DR programs to set a baseline of their ability to reduce or shift load before implementing technology upgrades and new market and program paradigms. Participation continued throughout the project except where program structure conflicted with the TE Pilot.

Peak Day Pricing

The program has been successful for Polaris' customers, performing at 75 percent across the portfolio (67 percent of running load curtailed), Figure 37, and 99 percent for the four service points participating in this project (87 percent of running load curtailed), Figure 38.

Figure 37: PDP Portfolio Performance

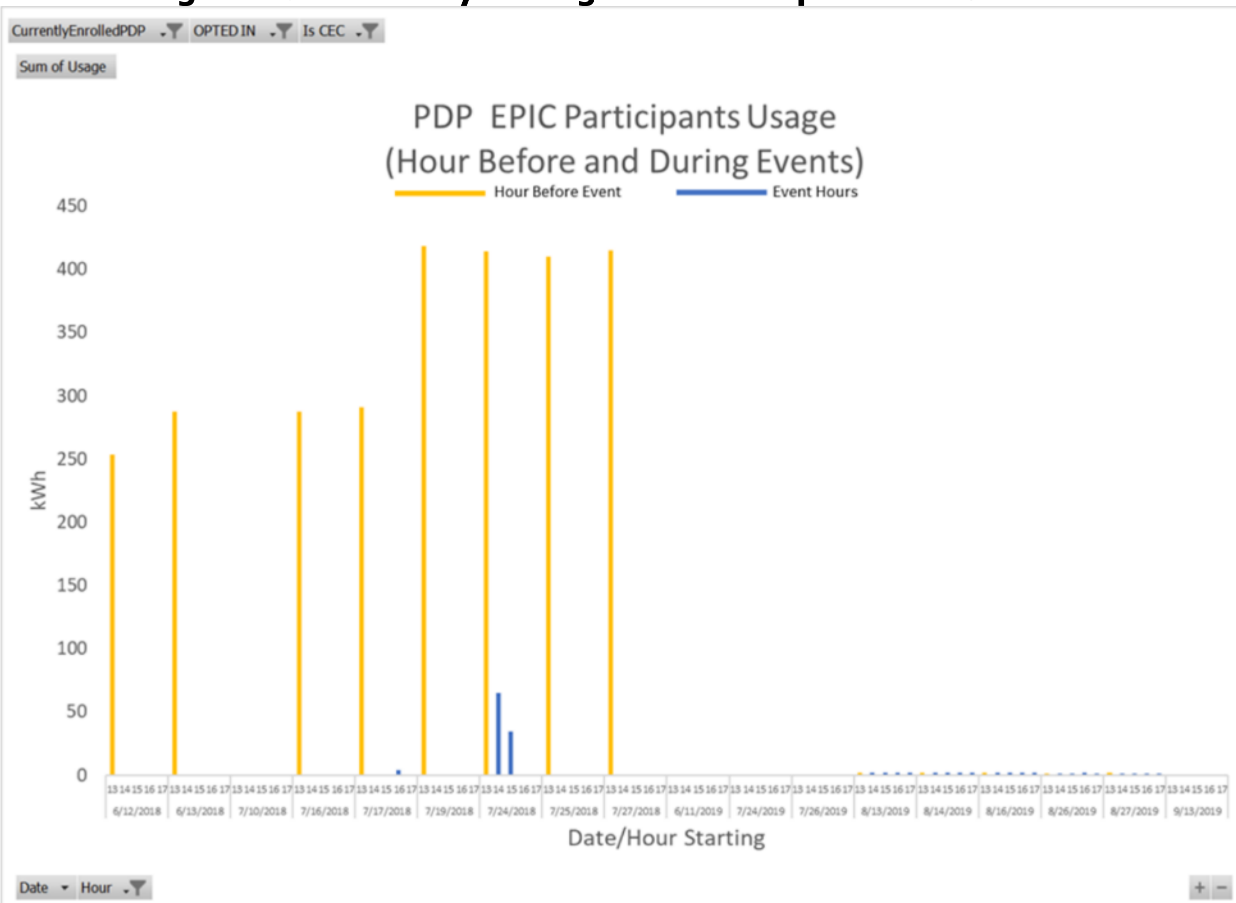


Source: Polaris Energy Services.

Peak day pricing (PDP) has some of the attributes that the research indicates are needed — price based, no nominations, no payment/penalty tiers — so the question is why adoption has been low? One possible answer is the lack of a role for aggregators in recruiting for and managing customer participation in the program. Polaris provides notification and dispatch services for participants as part of an AutoDR project but without that there are no third parties helping customers to enroll and succeed in the program. Until CPUC Decision 18-11-029 on November 29, 2018, customers could participate in both PDP and BIP which provided a pathway to greater participation, starting with relatively infrequently called BIP, through an

AutoDR project to participation in both PDP and BIP. With elimination of that option, customers must choose one program; if they want ADR incentives, aggregators are more likely to steer them to CBP and, if not, to BIP.

Figure 38: Peak-Day Pricing EPIC Participants Performance



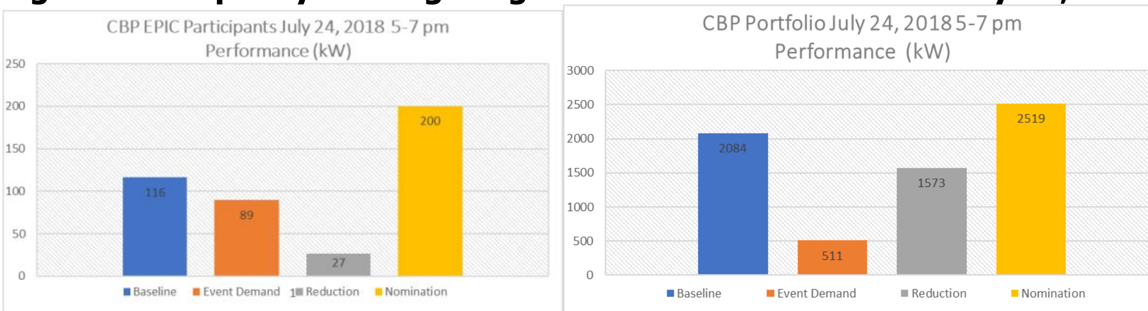
Source: Polaris Energy Services.

Capacity Bidding Program

Nine participating pump sites behind six PG&E meters were enrolled in the capacity bidding program (CBP) for the duration of the project and nominated on a monthly basis depending on their expected operations and baseline. Three events were dispatched during that time and participating sites' performance was in line with the broader portfolio as highlighted in Figure 38, Figure 39, and Figure 40. Participating sites curtailed 76 percent of baseline load compared to 77 percent for the portfolio and 21 percent of nomination compared to 29 percent of nomination for the portfolio as highlighted in Figure 41.

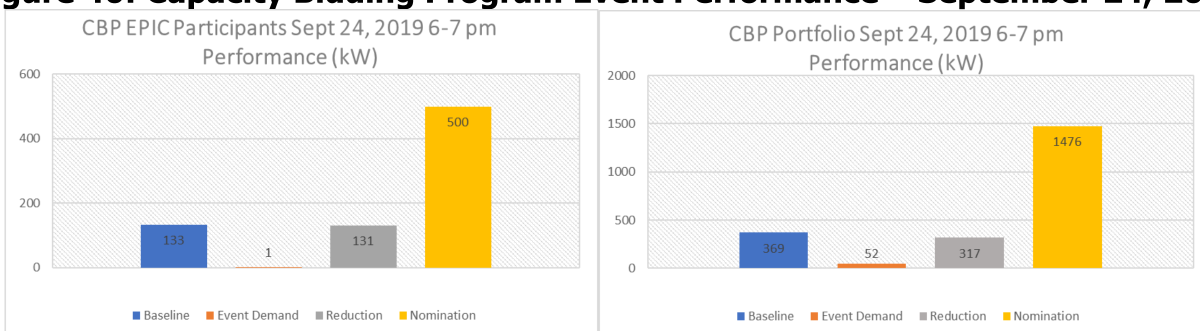
The clear issue with CBP performance is not whether technology or engagement of participating sites has measurable impact but rather the discrepancy between curtailment vs baseline load and curtailment vs nomination. The data in Figure 39, Figure 40, and Figure 41 confirm observations about the program and the challenges with any construct that requires nominations in advance, especially in comparison to a counterfactual baseline. Researchers conclude that the benefits of technology and engagement can only be reaped when suitable program and market designs are in place.

Figure 39: Capacity Bidding Program Event Performance – July 24, 2018



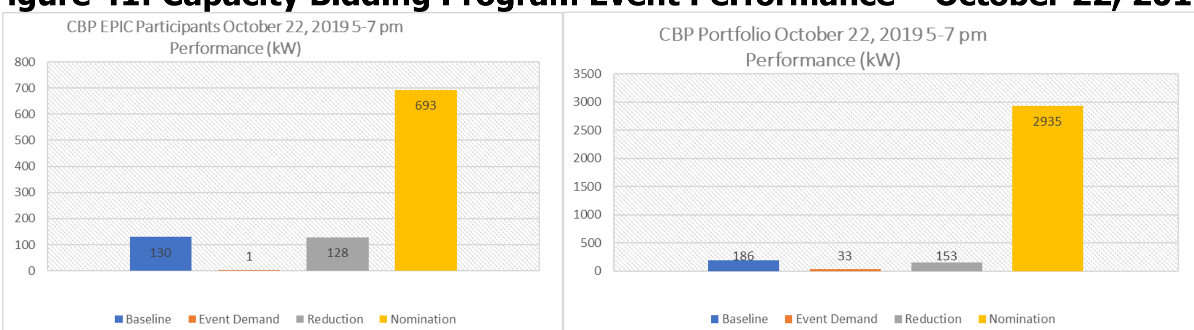
Source: Polaris Energy Services.

Figure 40: Capacity Bidding Program Event Performance – September 24, 2019



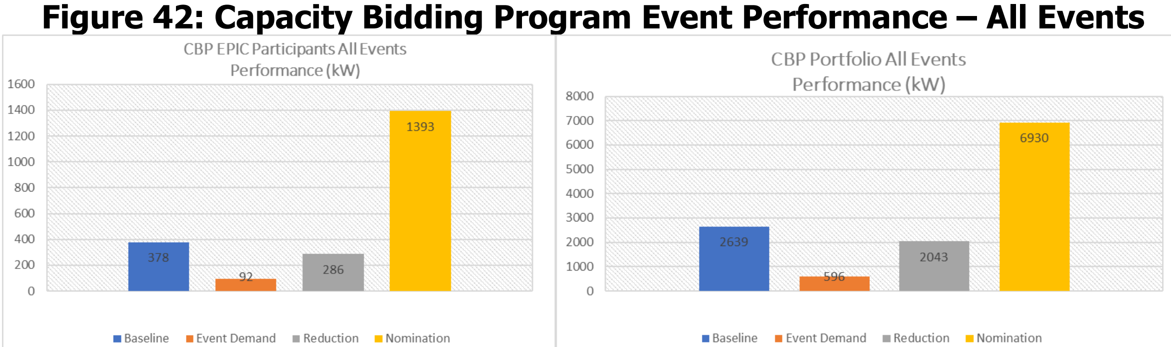
Source: Polaris Energy Services.

Figure 41: Capacity Bidding Program Event Performance – October 22, 2019



Source: Polaris Energy Services.

Figure 42: Capacity Bidding Program Event Performance – All Events

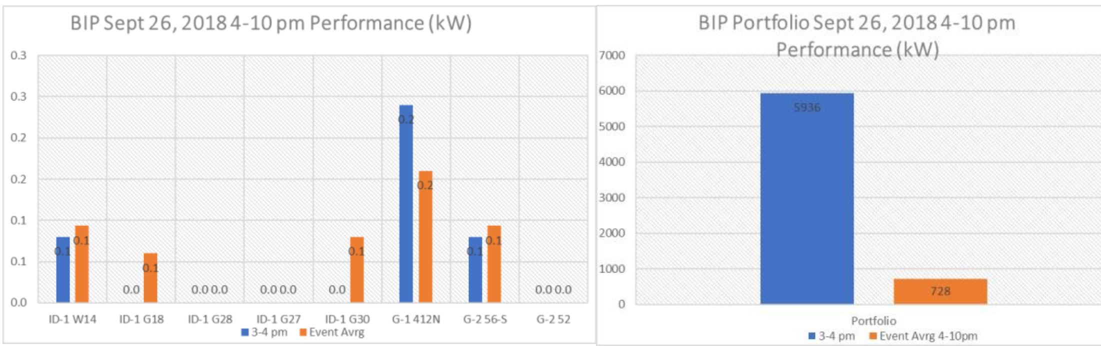


Source: Polaris Energy Services

Baseload Interruptible Program

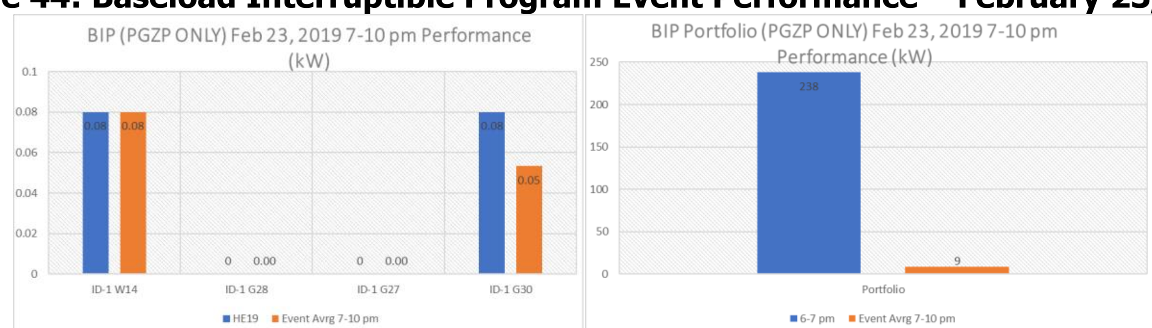
Eight participating pump sites were enrolled in the baseload interruptible program (BIP) for the duration of the research and during the baseline year of 2018 and the testing year of 2019. There were four events dispatched, of which two were zonal dispatches (only service points in certain zones are called). Only one pump was running before one of those events and it was curtailed successfully, 100 percent of load, compared to 88 percent of load reduced across the entire Polaris BIP portfolio in that event and 87 percent across all events during the two years analyzed. The sample is small and there is no indication that participation in the project impacted BIP performance in either direction. Figure 43, Figure 44, Figure 45, and Figure 46 show performance in these events for participants in this project (left) compared to the whole Polaris portfolio (right), illustrating this point.

Figure 43: Baseload Interruptible Program Event Performance – September 26, 2018



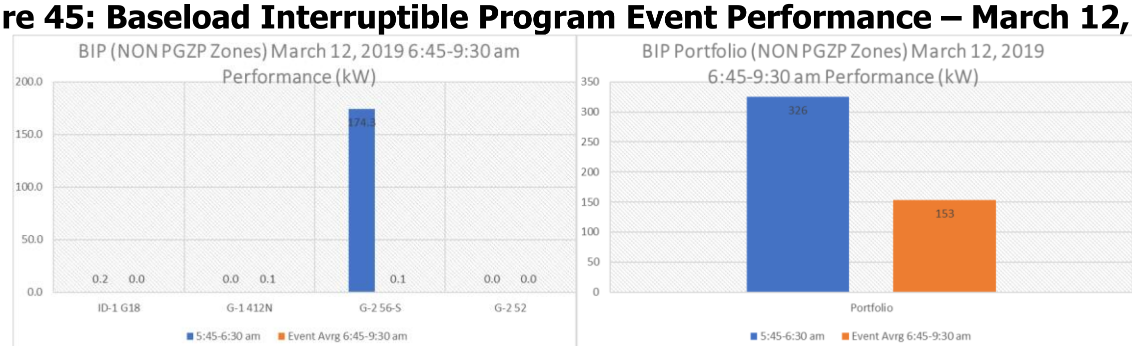
Source: Polaris Energy Services.

Figure 44: Baseload Interruptible Program Event Performance – February 23, 2019



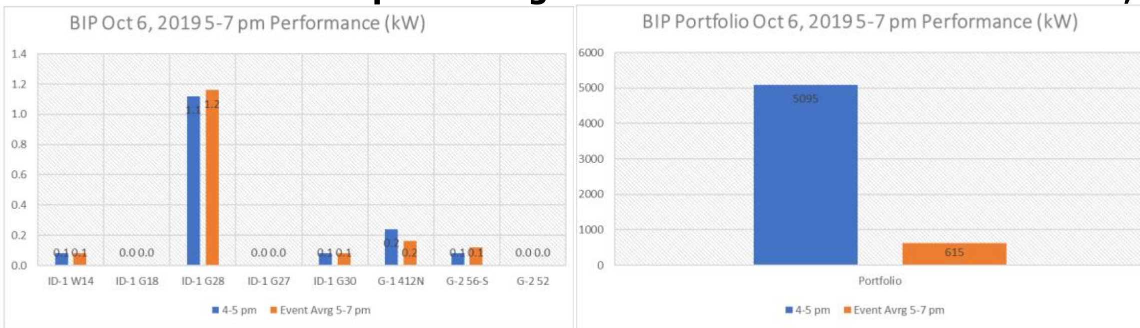
Source: Polaris Energy Services.

Figure 45: Baseload Interruptible Program Event Performance – March 12, 2019



Source: Polaris Energy Services.

Figure 46: Baseload Interruptible Program Event Performance – October 6, 2019

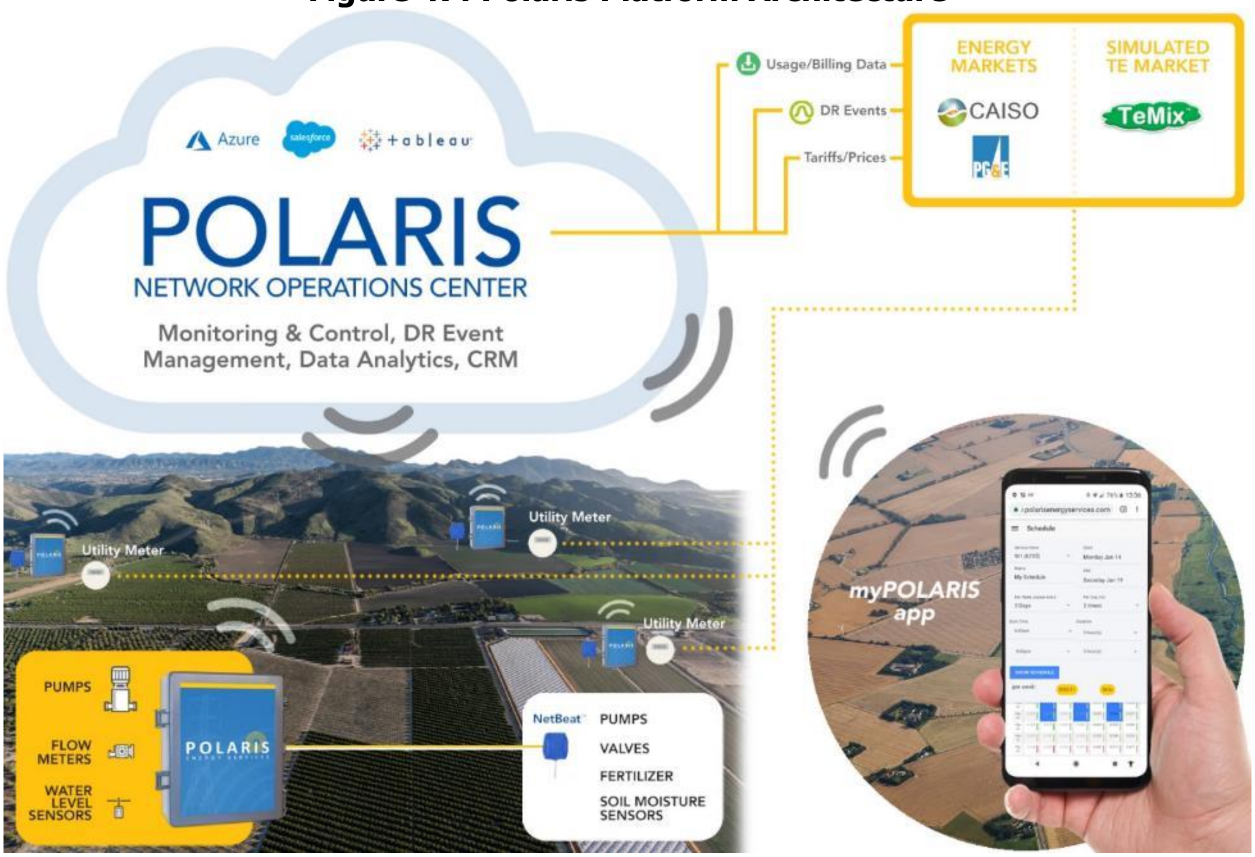


Source: Polaris Energy Services.

Technology Deployment

The project, built upon the core AERO system, has turned into a multi-faceted, powerful platform for agricultural energy management and market integration, shown in Figure 47 that exceeded the initial expectations and proposed scope.

Figure 47: Polaris Platform Architecture



Source: Polaris Energy Services.

Until this project, there were two technologies available for agricultural pumping to automate participation in DR programs in California, including Polaris' Pump Automation Controller (PAC) and Universal Devices' ADR controller. In both cases, DR signals interrupted pump operation for events but usually required manual intervention to resume operation, limiting the frequency of response and precluding participation in more dynamic programs or market structures. They worked independently of or without irrigation management systems; most pumps were controlled manually other than for event curtailment. Technology advances delivered by this project advance the state of the art in three ways:

- Hardware, firmware, and software to operate pumps remotely or automatically with scheduling based on energy market signals, at all times, not just for DR events.
- Integration with an irrigation management system to extend control to 'behind-the-pump' hardware that requires automation in order for growers to respond to dynamic signals.
- Development of a cloud-based version of the OpenADR software that can communicate with a wide range of irrigation controllers via their cloud software with a simple application programming interface (API), eliminating the need for OpenADR hardware in the field. Think, "Energy Hub®" for irrigation management systems.

Each component added to the scope addressed an obstacle that the researchers encountered. The following sub-systems were developed or integrated and, unless noted otherwise, are in full production:

Field Hardware

Field hardware for the project was divided into two deliverables, monitoring and control.

Monitoring

A suite of hardware upgrades for each pump site was included in the initial scope, including a power meter and flow meter for each pump site and depth meters for the grower 1's 413 reservoir and the irrigation district 1's canal. There were three objectives for these deployments:

- To provide the researchers with granular data for analysis of load shift potential and ability.
- To test whether access to real-time and historical usage and water data would increase AEU ability and willingness to shift load.
- To provide an incentive to AEU to participate in the research.

The monitoring provided useful data for the researchers but had less impact on participants' load shift efforts with one notable exception. Key findings from the monitoring efforts:

- Participants expressed enthusiasm in the visibility provided by power and flow metering but did not use it extensively when available. Analytics available with this monitoring such as pump efficiency (power consumption/water volume) or expected vs actual water deliveries to a field or orchard fall in the 'important but not urgent' category and this seems to explain the gap between initial enthusiasm and actual usage of the charts and tables.
- Sustainable Groundwater Management Act (SGMA) compliance is an important issue for growers and irrigation districts that pump water from aquifers and will require detailed water accounting that has not been in place before. AEU expressed interest in 'SGMA-compliant' reporting but it is something they are expecting but not actually doing now.
- Power monitoring is largely redundant when Green Button data is available with a 1-2-day delay, with one exception.

- When two or more pumps or other discrete loads are connected to a single utility meter, power metering is useful for energy analytics.
  - At the meter level, most energy analytics are easily performed with Green Button data.
  - The information that is needed in real-time and before Green Button data is available is primarily whether a pump is running or not and this is provided by the pump status indicator in the Polaris platform.
- While participants did not change their procedures to take advantage of flow metering, reservoir depth monitoring was highly valued and used to manage the filling and use of water at pumping site 413 reservoir (Figure 48).

Figure 48: Reservoir Depth vs Booster Power

Source: Polaris Energy Services.

- Findings from use of this sensor:
  - Calibration is critical and tricky. Placement of the sensor in a standpipe led to drawdown below the reservoir level when the pumps were running at high output and it is possible that placement of the sensor in the main reservoir will provide better results.
  - Raw readings are converted to a depth value and values are assigned to one of several bands so that users can be alerted to changes. To avoid excessive messages when values fluctuate close to change point between one band and another, a "deadband" is introduced within which alerts are not generated. The equations determining the depth from the raw readings were adjusted and, in one case, not communicated to the user who was making mental adjustments to the previous incorrect values.
  - Calibrating the number and type of notifications is non-trivial. Initially, notifications were sent when a band was crossed (low-low, low, high, high-high) and in one case the user lost situational awareness when there had not been a change for two days and the level began increasing quickly in the middle of the

night, causing the reservoir to overflow. The level appeared steady because the reservoir was both filling and being emptied at high rates so that when pumping out of the reservoir was ceased, the level shot up quickly. The researchers worked with the users to add periodic notifications to help maintain situational awareness.

Control of Pump Automation Controller

To facilitate dynamic load shift with greater frequency than typical DR programs require, AEU require the ability to operate pumps remotely. For most existing programs, it was sufficient for the field controllers to shut down or disable pumps during events after which users would restart them. While the Polaris PAC had the ability to control both start and stop operations, upgrades were needed to address the safety and operational requirements of AEU to operate remotely. These upgrades included adding a remote/local switch on the PAC and integrating a pump monitor that shuts down the pump when anomalous operation is detected that might otherwise be observed by the operator when starting the pump. Automation was also required to start the external oiler pump employed in many cases that runs independently of the irrigation pump. The improved Polaris PAC is called the SuperPAC.

Several findings from the control hardware deployments inform future adoption of the technology:

- There is wide variability among the electrical configurations of controlled pumps that limits standardization. During the initial period of usage especially, mistakes in the settings of local switches and controls (Figure 49 and Figure 50) delayed employment of automated scheduled operations. This period is short relative to the lifetime of a system but is critical to gaining buy-in and adoption of new technology, especially in a small pilot deployment. To minimize these occurrences, significant attention is required to training, documentation and ongoing support. To address this, 'pump site instructions' were developed and provided for each individual site.

Figure 49: Local/Remote Switch

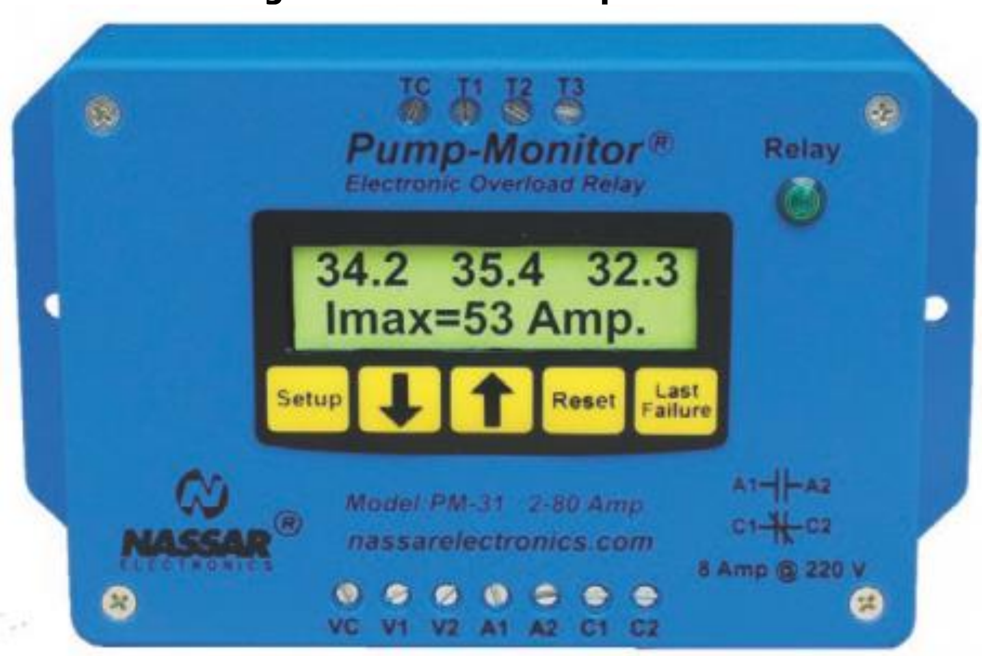
Source: Polaris Energy Services.

Figure 50: Pump Site Instructions

Source: Polaris Energy Services.

- The Nassar PM-32 (an electronic over/under load relay and pump monitor), Figure 51, shut down the Utica North pump several times, which contributed to a loss of confidence in the remote system by the participant. Upon investigation, it was determined that the monitor functioned properly, likely because debris blocked the pump inlet, causing cavitation which led amperage values to reach parameters that led to a shutdown. The settings can be changed but this case demonstrated the difficulty of identifying a level of sensitivity that is neither too high nor too low.

Figure 51: Nassar Pump Monitor



Source: Nassar Electronics.

Figure 52: Automated Oiler

Source: Polaris Energy Services.

Netafim Control

The researchers surveyed what upgrades were needed by participants to achieve remote control capabilities that could enable more load shift. Participants indicated that pump control alone is insufficient where valves in the field or at the pump and/or fertilizer dosing pumps need to be controlled. Valves need to be controlled to direct water to the right blocks in the fields and to run water through the pump to clear out sand before directing it through the pressurized drip irrigation system.

The researchers consulted with the participants and learned that they were considering irrigation management systems and identified Netafim as one of the leading vendors. Meetings among the researchers, participants and Netafim led to proposals for deployments at the Grower 2's 56 and Grower 1's 413 pump sites; 413 represents one utility meter with three booster pumps behind it. The second Grower 2 site required the next generation of controller, NetBeat, which was not available at the time.

Netafim and their distributor/installer, C&F Irrigation, deployed systems for these four pump sites that enable full operational control with the Polaris PAC connected with a dry contact to inhibit operation during DR events.

The 56-pump site installation, Figure 53 and Figure 54, included control valves to irrigate one or both of two fields and to pump water to a ditch for a set period of time, usually 15 minutes, to clear the line of sand before pressurizing the drip lines.

The 413-pump site installation, Figure 55, included 8 control valves for sections of an orchard, charged by three booster pumps drawing from a reservoir.

The ability to control irrigation remotely and on automated schedules was attractive to the participants. Participants contributed 50 percent of the cost to deploy the systems.

Figure 53: Netafim NMC Controller

Source: Polaris Energy Services.

Figure 54: Automated Valve (Netafim)

Source: Polaris Energy Services.

Figure 55: Netafim NetBeat Controller

Source: Polaris Energy Services.

Network Operations Center (NOC) Tools

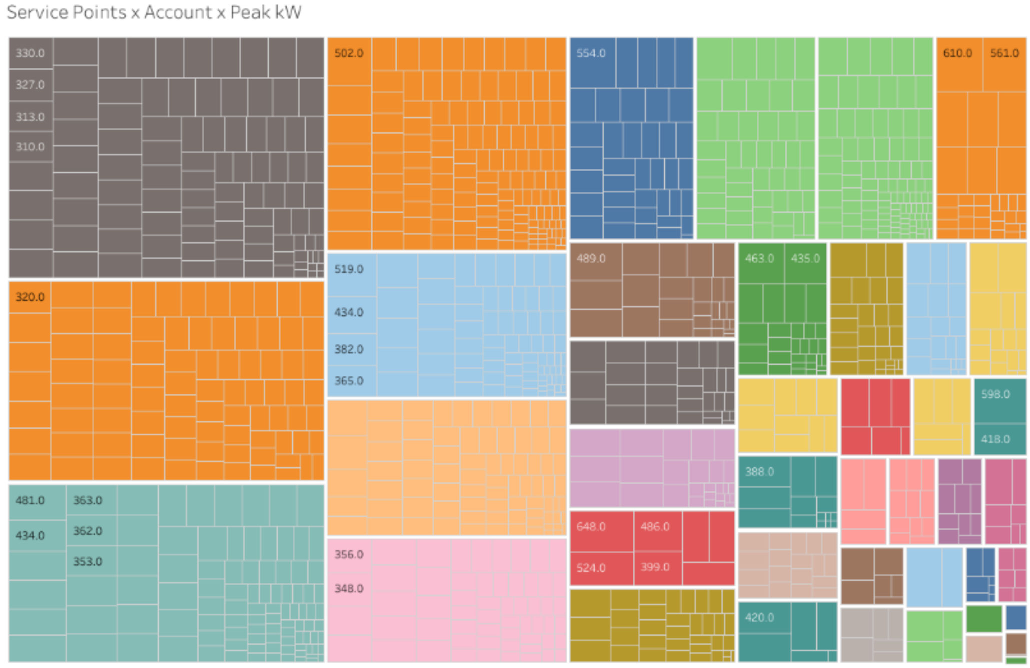
To enable more frequent, larger scale participation in dynamic load shifting, the researchers evaluated the entire value chain and identified the processes that needed to be streamlined and/or automated. The analysis showed that, while Polaris' core NOC functionality for real-time event management was robust, myriad data regarding its portfolio of service points, program enrollments, site readiness and maintenance and payments were all managed in offline tools and processes. This problem in DR management is not unique to Polaris or the agricultural sector but it is amplified by some of the attributes of agricultural DR:

- Customer accounts comprised of many meters – while agricultural customers are large energy users, their usage is spread across many individual meters, each of which requires the same effort for enrollment, billing, tracking, analysis, etc. This is visualized in Figure 56.
- Ag service account ambiguities – unlike other multi-meter accounts such as retail chains, matching utility information with operational is not simple. Locations are not easily identifiable by street address and the meter serving a given operation can change as wells are drilled, used, moved, etc.

The team selected a commercially available CRM system, Salesforce.com, that allows extensive customization, to manage and track these myriad data and to integrate with the real-time control system. This CRM system was configured to perform many key DR management tasks in a familiar, intuitive user interface:

- Enrollment
- Nominations
- Event opt-in/opt-out
    - Site readiness and repair ticket management, shown in Figure 57.
- Settlements and payments

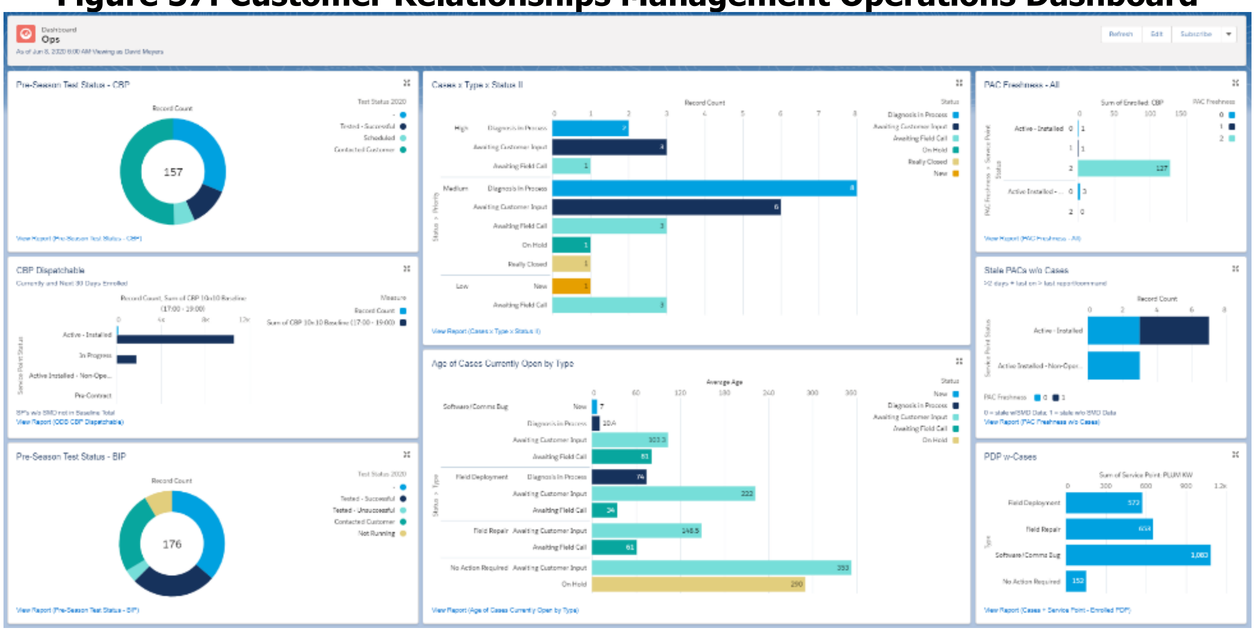
Figure 56: Portfolio Heatmap



In the heatmap, each colored group is a customer account and each rectangle is a pump; the size of the rectangle is proportional to the pump's size.

Source: Polaris Energy Services.

Figure 57: Customer Relationships Management Operations Dashboard



Source: Polaris Energy Services.

Market Integration

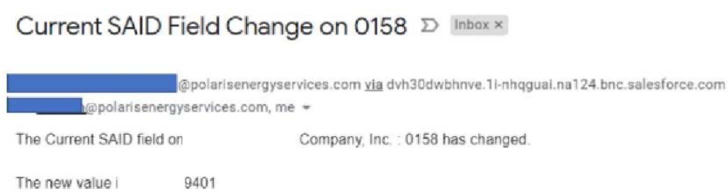
Fundamental to increasing participation in programs and markets is automating integration with markets and minimizing manual processes. The project developed and expanded several integrations for the California market to address current programs and emerging market structures.

Green Button

Utility data is critical for energy transactions, incentives, programs and planning. However, its acquisition and management present significant barriers to effectiveness and efficiency of California's energy system. Siloed, duplicative and at times inaccurate and unsynchronized utility systems hamper use of Green Button implementations like PG&E's Share My Data. For example, changes to service agreements (SAIDs) often leads to inability to access the full billing and usage history of a service point. This limitation has led to the use of only two years of data when determining ADR eligibility and incentives, not because this time frame is representative of any measure of value but because of the availability of data.

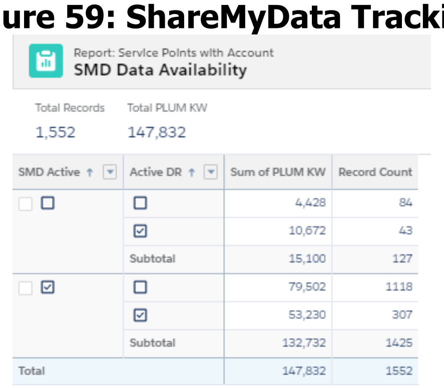
The implementation for this project includes features that synchronize and integrate metadata with the CRM system and use all available online and offline data sources to track changes to service point information. A series of queries and reports identify new service points, metadata changes and when data stops flowing; an example is shown in Figure 58. Customers have provided global account access, so the implementation now tracks 307 service points that are enrolled in DR programs and 1,118 additional service points that are not (Figure 59), which provides a broader data set of 133 MW of peak load for analysis.

Figure 58: Automated Service Point Metadata Updates



Source: Polaris Energy Services.

Figure 59: ShareMyData Tracking



SMD Active	Active DR	Sum of PLUM KW	Record Count
☐	☐	4,428	84
	☑	10,672	43
	Subtotal	15,100	127
☑	☐	79,502	1118
	☑	53,230	307
	Subtotal	132,732	1425
Total		147,832	1552

Source: Polaris Energy Services.

OpenADR

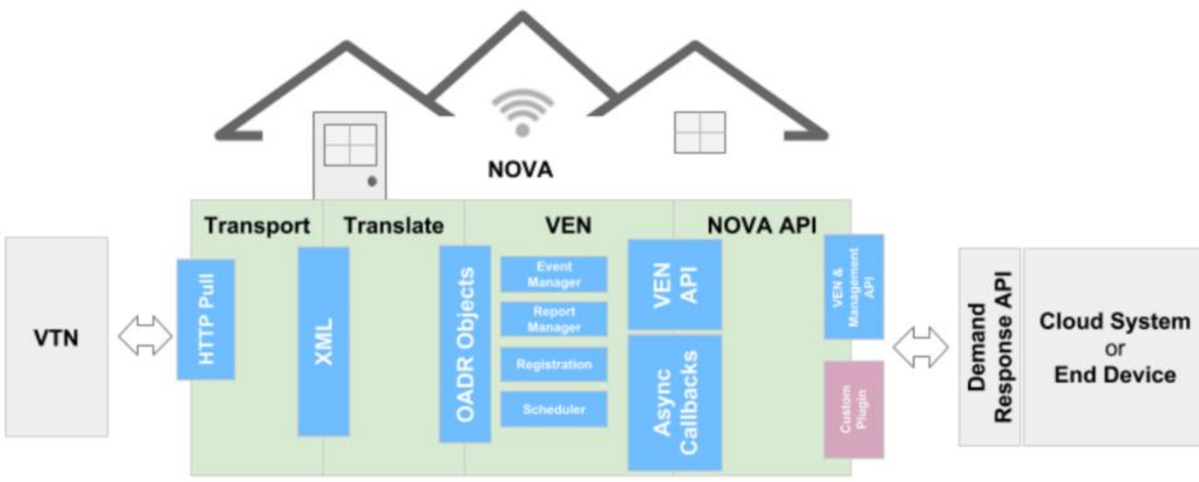
Polaris built much of its DR portfolio with AutoDR projects utilizing the Open ADR board in its PAC. This approach, common in ADR implementations has several limitations and impediments, especially for agricultural sites.

- Opt outs are difficult.
- There is not active management nor regular communications testing for active DR sites.

- The OADR communications protocols are tailored for sites with broadband internet connectivity which are problematic in remote areas.
- Dedicated hardware is required, which adds complexity and reduces the incentives available for automation systems and components that meet users daily operational requirements. This limitation drives the minimum feasible project size for ADR deployments, which has excluded the long tail of irrigation pumping loads.

To address these issues, the researchers implemented a Cloud virtual end node (VEN) which enables a single computer server to receive event notifications for multiple service points and dispatch them through proprietary protocols. A commercially available VEN was deployed and integrated with Polaris' DR management applications. Figure 60 shows how the Cloud VEN receives signaling from the utility's Demand Response Automation Server (DRAS) and manages dispatch of multiple devices through Polaris' cloud system.

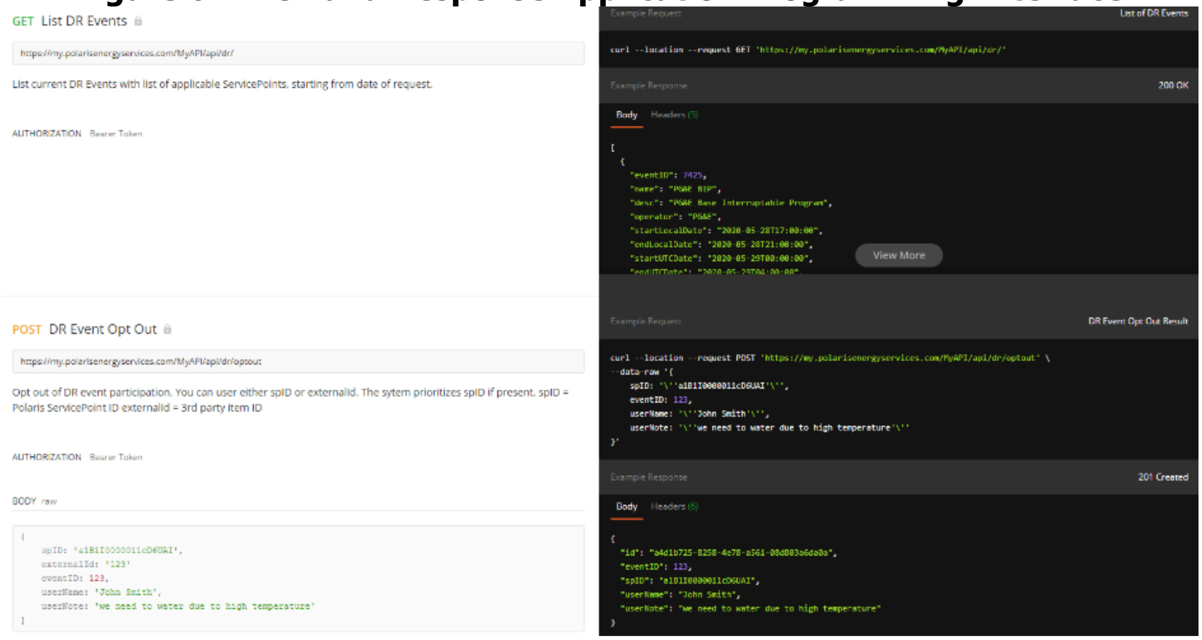
Figure 60: Cloud Virtual End Node Architecture



Source: Grid Fabric.

To enable AEU to participate in AutoDR programs with their choice of irrigation automation systems, a simple DR API was developed to relay event information to their systems using their own identifiers for behind the meter loads while the Polaris platform brokers the interactions with utilities and grid operators as highlighted in Figure 61.

Figure 61: Demand Response Application Programming Interface



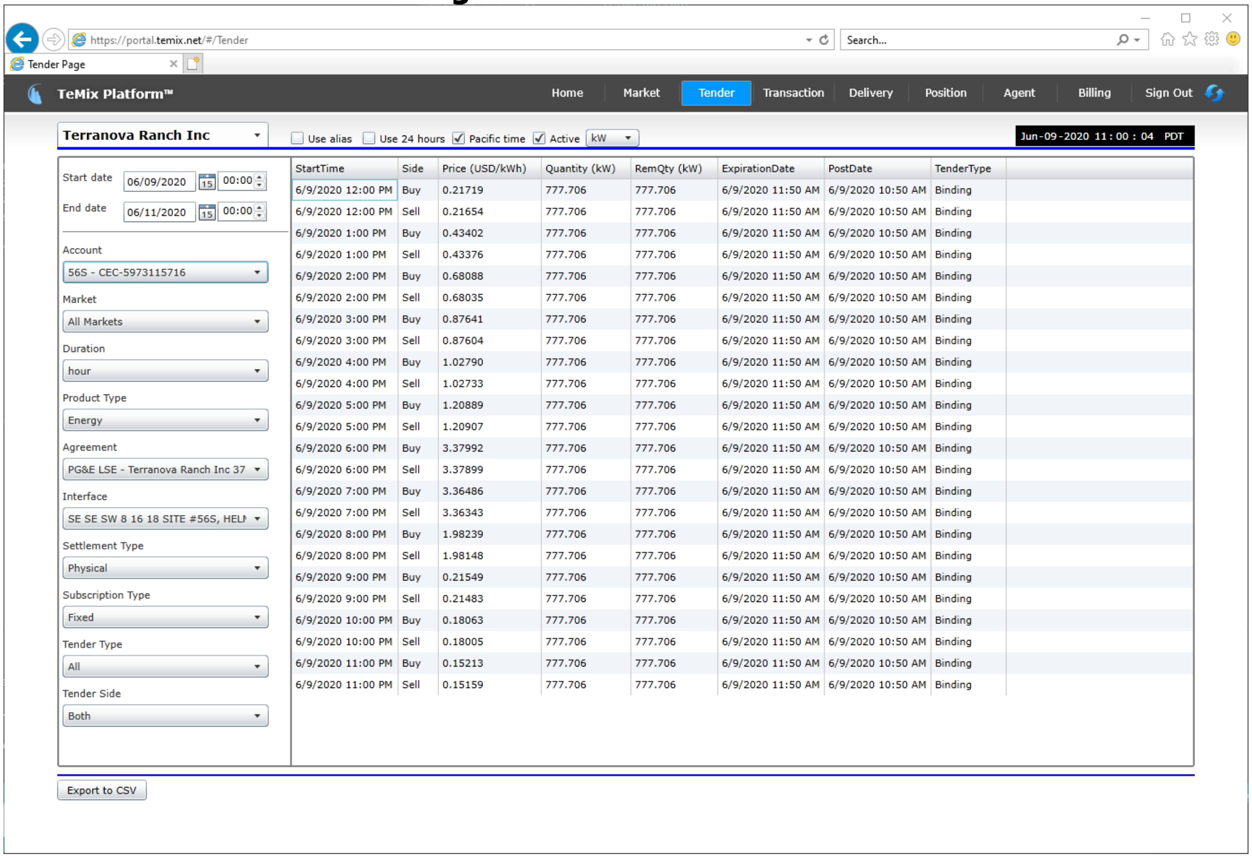
Source: Polaris Energy Services.

TeMix

Results of the TE pilot are described above. The technical integration with the TeMix RATES system provided a template for participation in dynamic and/or real-time markets. The researchers built an application to:

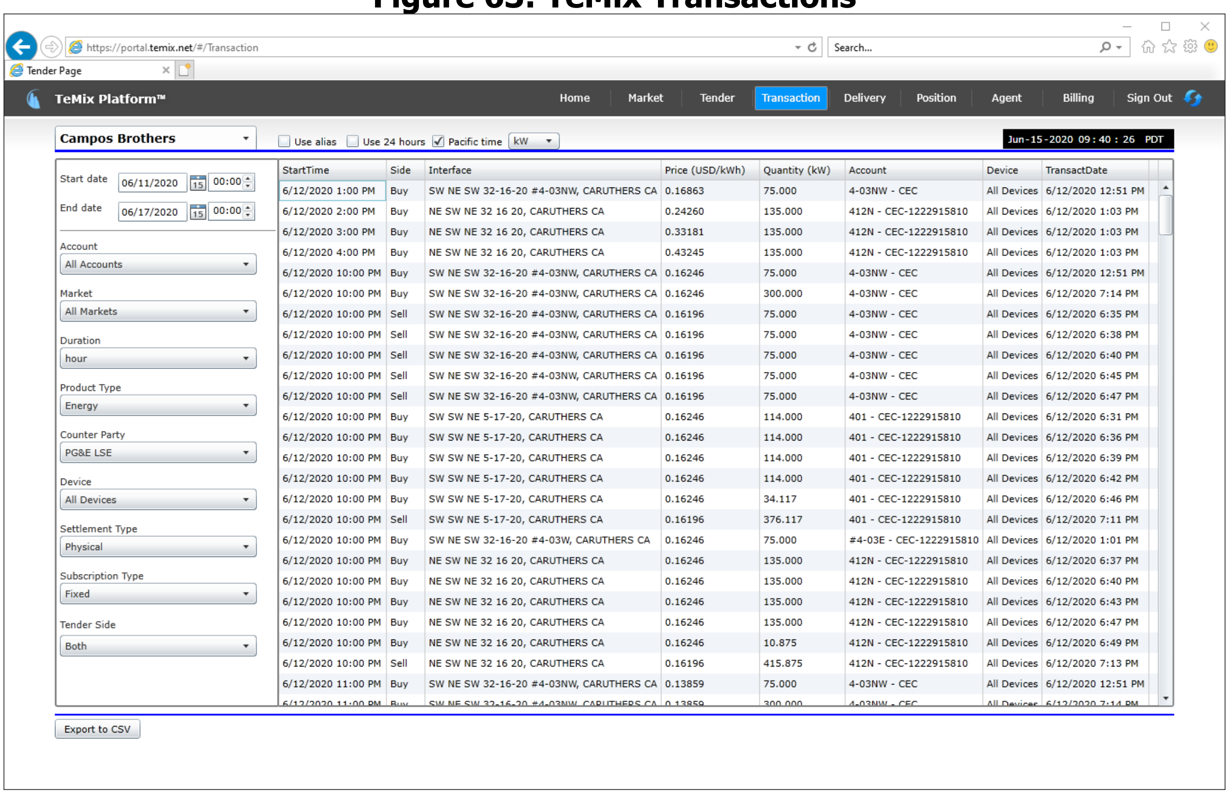
- Retrieve tenders from the TeMix API and store hourly prices for each participating service point, as shown in Figure 62
- Lock hourly prices at a defined time during the week to provide customers with price certainty for one week at a time.
- Convert prices to incentives (positive or negative) and scale them to a desired level of volatility and bill savings.
- Capture scheduling information from the myPOLARIS app chosen by the user based on the incentives offered.
- Execute transactions with the TeMix system, as shown in Figure 63.
- Submit actual usage from Green Button (ShareMyData).
- Retrieve and store settlement data from the TeMix system.

Figure 62: TeMix Tenders



Source: TeMix.

Figure 63: TeMix Transactions



Source: TeMix.

Big Data Storage and Analytics

Prior to this project, the Polaris platform logged and archived PAC data but to make the data useful and accessible, additional capabilities were required.

- Normalization of data to a 15-minute interval time series.
- Processing, consolidating, and storing data from multiple sources.
- Data analysis and visualization.

To store and provide access to large volumes of data while maintaining the high availability/reliability of the real-time control platform, Microsoft's Azure cloud computing service was deployed and integrated with the core platform. The team initially selected Microsoft's PowerBI for business intelligence and after encountering limitations, switched to Tableau for visualization and analytics.

Several tools were built in Tableau both for the research and as production applications in developing and operating DR portfolios. The most impactful tool is the automated statement of financial opportunity (SFO). Applying calibrated filters to usage data shared by customers through the Green Button implementation, the system estimates the AutoDR and DR program incentive opportunities for every customer meter within a few days of customer approval to share the data; an example of the output is shown in Figure 66. This compares with weeks or months to identify meters of interest, provide data to the program implementer and await approvals using paper-based information requests. The models driving the incentive estimation use the distinct calculation methods for AutoDR incentives and DR program incentives. The AutoDR estimation model mimics the process used by PG&E to calculate incentives, Figure 64, which accounts for all program hours equally but weights months according to their event likelihood. The DR program estimation model weights hourly load by event likelihood.

Figure 64: Automated Incentive Estimation

CBP ADR SFO - Interval Data - Table "Customer" (Hrs 11 -19)

Customer Description	Current SAID	PLUM_KW_...	Date June	July	August	September
Grand Total			2,238	2,208	2,143	2,015
	2587	175	58	57	56	57
	4272	489	327	321	325	323
	9810	186	0	0	0	0
	6248	272	182	176	177	175
	3526	31	9	7	9	4
	1726	235	134	136	153	154
	4792	59	46	46	53	42
	4429	169	112	107	116	116
	7992	118	186	186	181	180
	4896	13	7	7	7	4
	8519	31	22	27	21	18
	7720	67	57	49	51	30
	1378	31	6	8	8	4
	6232	40	16	17	17	19
	6604	28	13	14	11	10
	8811	287	197	193	192	187
	9728	74	40	21	24	14
	4577	26	16	21	16	9
	3276	360	94	77	86	61
	1429	10	0	0	0	0
	1491	0	0	0	0	0
	9752	12	9	9	9	6
	5007	56	49	52	18	40
	0431	15	0	0	0	6
	8710	295	308	298	223	176
	5948	352	178	172	177	176
	6793	215	118	138	138	132
	9559	145	55	70	72	72

Average of Usage broken down by Date Month vs. Customer Description, Current SAID and PLUM_KW__c. The data is filtered on Date (MY), Seasonyear 19, Month, Hour and Customer Name. The Date (MY) filter keeps 78 of 78 members. The Seasonyear 19 filter keeps SUMMER 2016, SUMMER 2018, SUMMER 2019 and WINTER 2017/2018. The Month filter keeps 6, 7, 8 and 9. The Hour filter keeps 8 of 24

Source: Polaris Energy Services.

myPOLARIS Web and Mobile Application

The myPOLARIS application is the centerpiece of technology development for this project, centralizing data from all the sources and integrated to provide the user with relevant information to schedule, control and monitor irrigation pumps and their participation in energy markets.

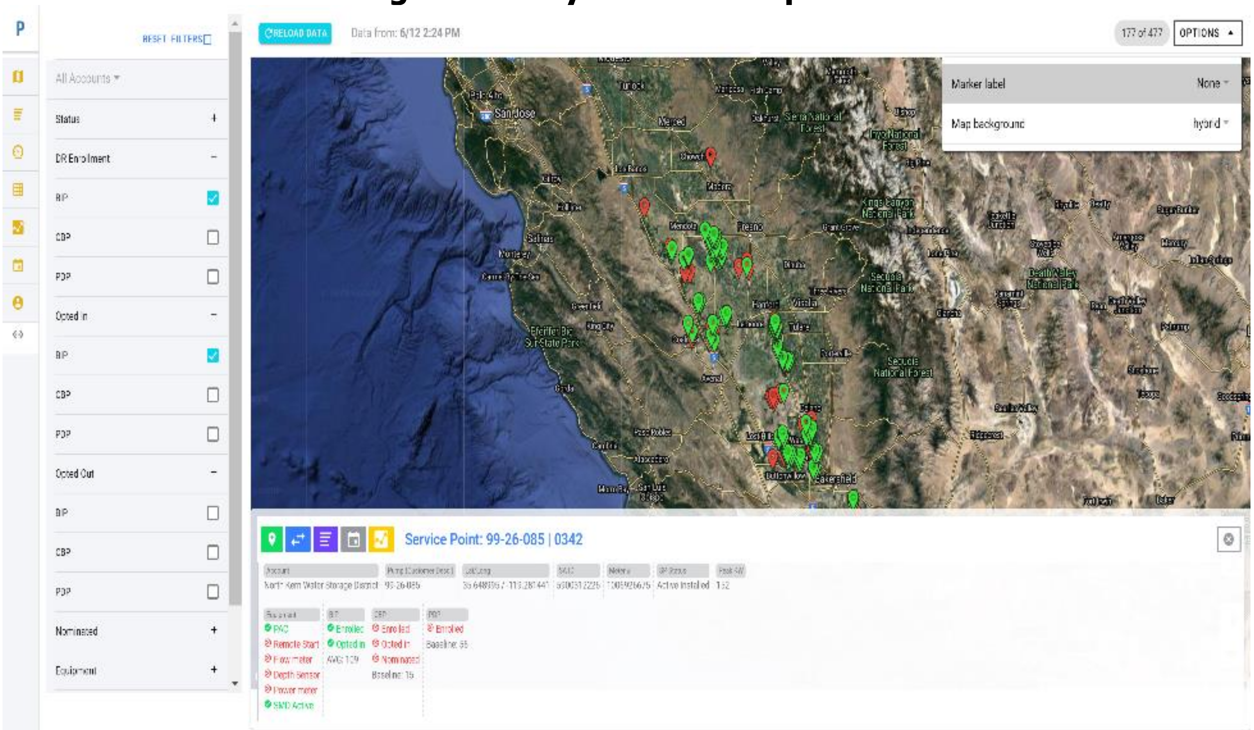
The application also incorporates tools for Polaris' internal users to manage a large portfolio of customer sites on an ongoing basis and during DR events. The application adapts automatically for computer, tablet and mobile screens.

myPOLARIS includes the following features:

Map View With Filters

The map view (Figure 65) enables users to quickly visualize a portfolio of pump sites, filtered by relevant attributes, the ability to focus on key real-time and metadata for a single service point and to launch other features for that service point.

Figure 65: myPOLARIS Map View

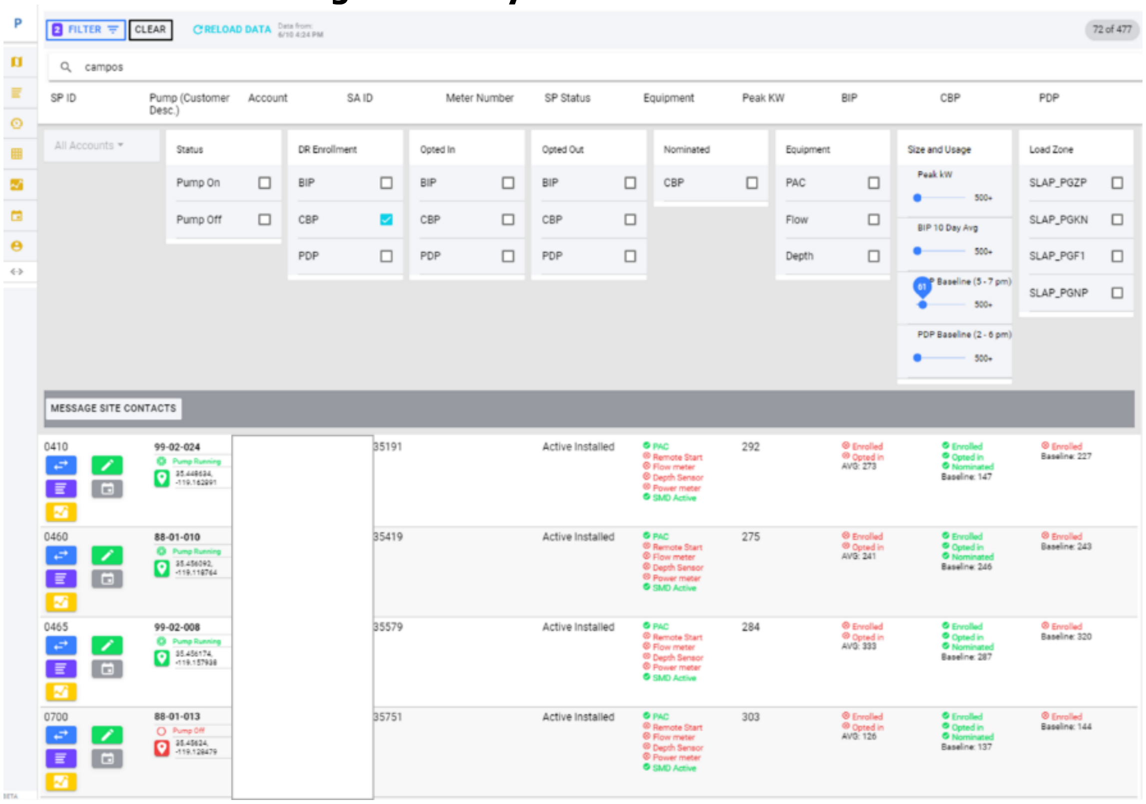


Source: Polaris Energy Services.

Sites List With Filters

The sites list (Figure 66) enables the user to quickly filter and sort relevant groups of service points to prioritize action. For example, the day of a DR event, a user would select service points in a given load zone and program and then by status (running or not) and baseline.

Figure 66: myPOLARIS Sites View



Source: Polaris Energy Services.

Pump Control

The pump control screen provides simple start/stop remote control and granular control down to the relays for normal and DR event control.

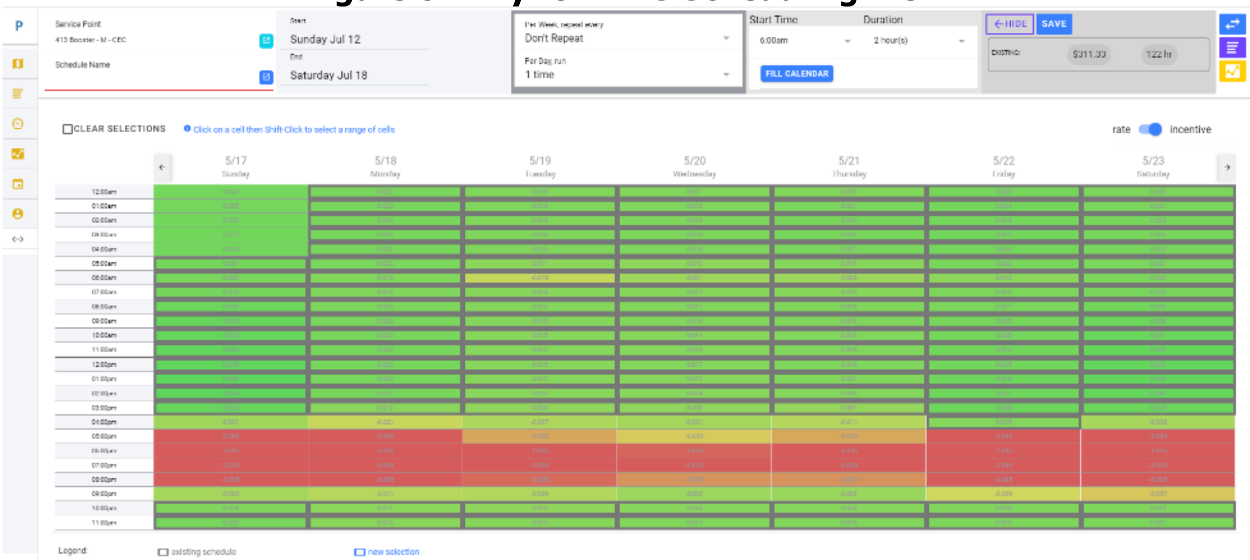
PAC Reports

While the 'Charts' screen displays intuitive, graphic representation of PAC and other data, reports enable users to drill down to the raw reports for troubleshooting and granular investigation.

Pump Scheduling

The scheduling screen (Figure 67) enables the user to evaluate scheduling options with graphical and numerical display of operating hours and costs based on any source of pricing data, tariff or market-based. The user can create and save schedules, without implementing them, to use later; for example, 'alternate days/avoid peak.' The schedule is implemented in one or both of two independent processes. 'Schedule Enabled' means that the system will execute the market transactions required to purchase the energy needed at the prices offered. 'Send Schedule to PAC' triggers steps that load the schedule on the PAC where it is executed without depending on additional communications over the network. These functions are separated so that users can execute transactions in the myPOLARIS system regardless of whether they implement them on a Polaris PAC. For example, in the TE pilot, some sites were controlled by the Netafim system but scheduled transactions in the myPOLARIS application.

Figure 67: myPOLARIS Scheduling View



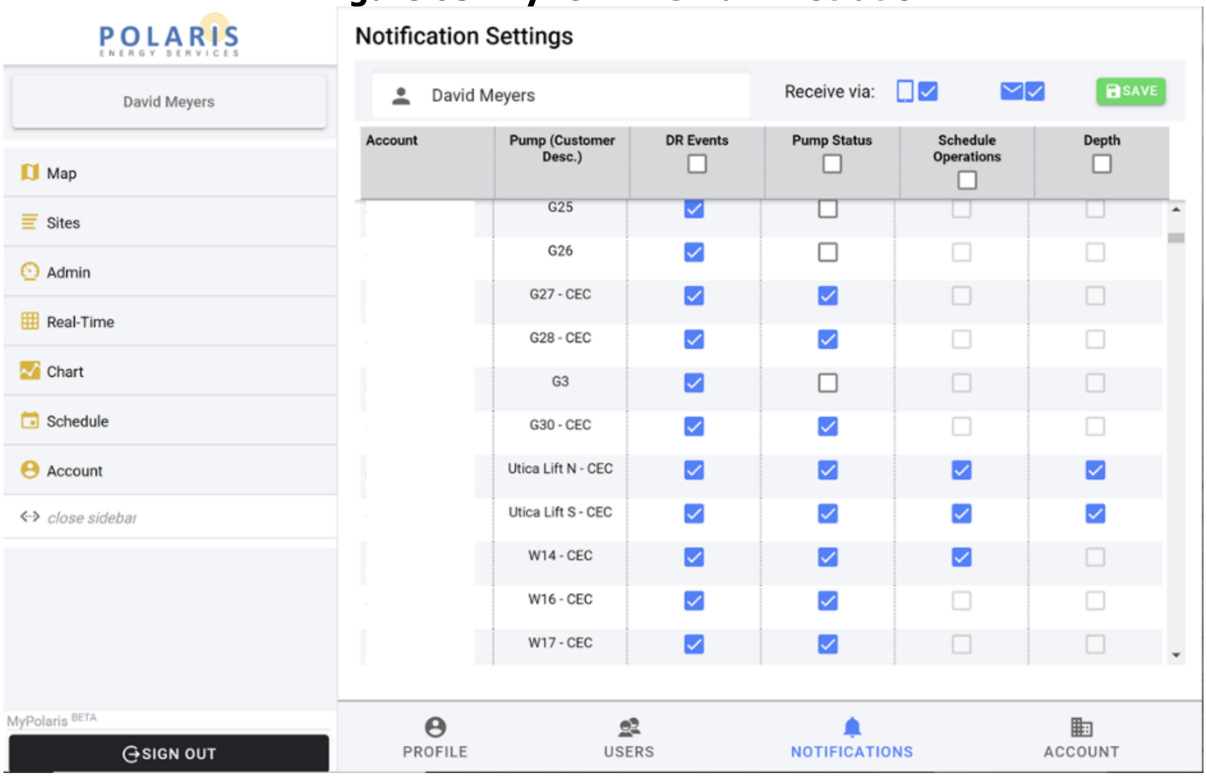
Charts

The charts screen provides a profile view to visualize one or more pump site's data for any sensor and time series data available. For comparison, the profile indicates when a pump is scheduled to run and a 'compare to past' feature to see how usage varies year-to-year. The totals view provides aggregated data in three ways: charts, table and a csv download, enabling users to export to any system and, especially, to provide Sustainable Groundwater Management Act (SGMA) reporting.

Administration

- User Management – tracking and managing users at agricultural operations can be more difficult and complicated than in other industries with personnel working across multiple entities (accounts). To address this, a flexible user management structure was implemented in which access to any account or group of accounts can be provided to any user.
- Notification Management and Access Control (Figure 68) – because of the safety and operational concerns of remote pump operation, authorization to operate pumps is controlled by Polaris and verified by customer permission. Notifications are flexible and can be customized for each user.

Figure 68: myPOLARIS Administration



Source: Polaris Energy Services.

Partner Integrations

A key deliverable of the project was to open the Polaris platform to more easily integrate with external systems. This goal is strengthened by the finding that broad adoption of the capabilities that the team aimed to provide depends on making them accessible through a wide array of systems used by AEU as opposed to gaining adoption only by marketing the system developed by the project.

This project was able to successfully integrate with Netafim's NetBeat system at the cloud to cloud level and tested in a software development environment. Integration efforts will continue under the BIRD grant that the companies were awarded. This project, through pilot efforts, was also able to successfully integrate with hardware (Netafim controller) in the field so that the Polaris system can now pause an irrigation program (a scheduled sequence of operations on the components of an irrigation system).

Program Analysis

The researchers reviewed all the DR programs available to AEU in the PG&E service territory to identify opportunities and obstacles to increasing sector participation as well as the AutoDR incentive program for technologies that automate DR. There are common themes that are relevant to several programs that should be addressed holistically in improving or replacing them.

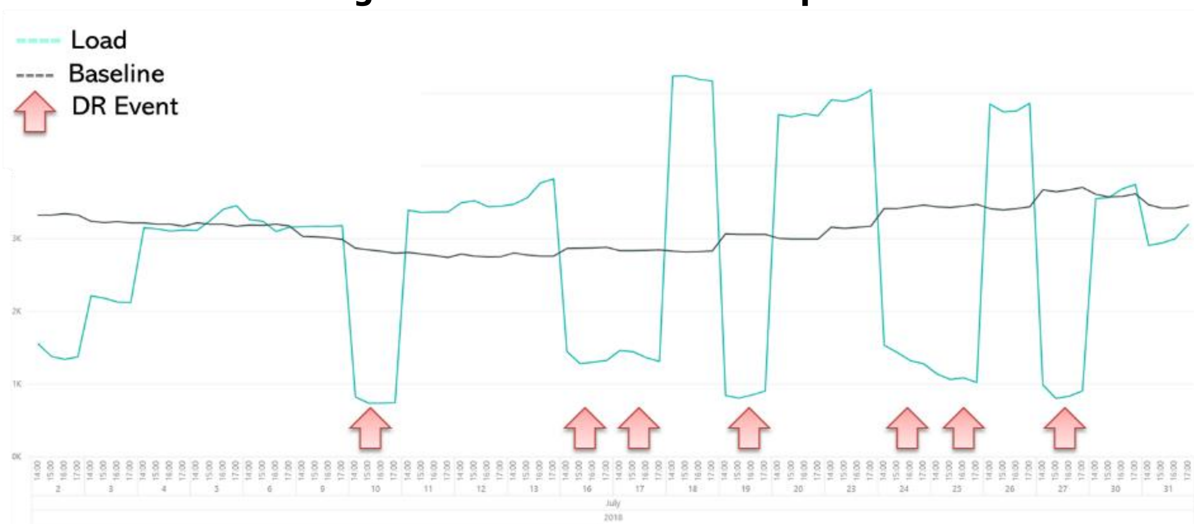
Baselines

Baselines are the oft-debated, never-solved Achilles' heel of DR; the unachievable goal of crafting the "right" baseline sucks up effort and energy that could best be directed to increasing participation. California has settled on a "ten-in-ten" counterfactual baseline to measure many DR programs and, importantly, integration of DR in the wholesale market. This baseline is problematic for many sectors and a particularly bad fit for agricultural pumping, where load is binary (on or off) and may be present during the hours before an event or during the same hours the day before, as shown in Figure 69. However, AEU are only credited with the shed compared to the previous ten days. With a binary load, load at the time an event starts will always be above or below the baseline unless the load was present for 100 percent or 0 percent of the measurement period.

In general, firm service level (FSL) baselines are a better fit for AEU, as the load that will remain on the meter can always be predicted and is usually zero, while the load shed compared to some moving average cannot.

Other options have been evaluated by the Baseline Accuracy Work Group, including Control Group and Weather Matching baselines, none of which are intended for or apply to agricultural pumping.

Figure 69: 10n10 Baseline Impact



Source: Polaris Energy Services.

Nominations

As a method for determining credit, baselines themselves are not the problem; a 100 kW pump that ran for half of the 10n10 days would have a baseline of 50 kW and if load is curtailed would receive credit for those 50 kW (and not the 100 kW actually curtailed). This is a reasonable measurement for the available load prior to the event. What is problematic in many programs though, is the requirement to nominate the load in advance. In that case, the target curtailment for an event can be less than zero kilowatts and therefore unachievable. While this project has delivered significant advances in visualizing current and historical load to help predict future load and guide nominations, actual operations are determined by discrete events that are often unknown at the nomination deadline. These include precipitation, timing of certain on-farm operations like spraying and harvest, delivery timing of produce dictated by buyers and, especially, the availability and timing of surface water deliveries.

Payment Bands

Nominations compound the problems of ill-fitting baselines and payment bands compound the problems of nominations. Before factoring in any inability to perform in an event or potential technical failures, the requirement to submit an achievable nomination leads to significant derating of capacity to reduce risk. Austere payment bands increase that risk, leading to further derates. While it may seem prudent to only nominate with high confidence, the result is that the achievable revenue in a program with a counter-factual baseline, advance nominations and stepped payment bands is too small as a percent of bill costs to be attractive to the AEU.

Programs

Baseload Interruptible Program

BIP has been an exceedingly successful program for AEU with an appropriate FSL baseline and credits based on measured usage, not nominations. High penalties and infrequent events drive high performance of 90 percent+ over time. The short notification time, 30 minutes, and 24x7 availability require automation, which is not available through ADR, but the attractive payments provide sufficient incentive to aggregators to install automation for which costs can be recouped from future revenue streams.

The program does not, however, help the grid in meeting any of its non-reliability challenges and is expensive compared to other resources. PG&E has sought to make changes to the program that would virtually eliminate AEU participation and Polaris submitted a protest and worked with PG&E to gain additional time to develop an alternative program. The full response is included as Appendix B.

Capacity Bidding Program

CBP is one of three programs that meet the DR program participation requirement for receiving automation incentives under the AutoDR program, along with DRAM and PDP. CBP's incentive structure aligns well with the typical irrigation season but other attributes of the program are problematic for AEU and inhibit participation growth. Where growth has been achieved, it is with questionable contribution to the goal of renewables integration.

The program employs the 10n10 baseline and has the compounding problems, described above of the baseline, nominations and payment bands. In addition, the program hours set up a conflict between success in the program and response to TOU rates. If an AEU cannot completely avoid peak and enrolls in the program, they are discouraged form reducing peak consumption because it reduces the baseline, incurring the risk of penalties. This problem is exacerbated by the payment bands (Table 5) that impose regressive penalties on performance below 75 percent of nomination. Because AEU curtailment plan is to drop load to zero, they have no way to achieve the required load drop if their baseline is less than the nomination.

Table 5: Capacity Bidding Program Payment Tiers

Performance Range	Payment Terms
75-105%	Proportional
60-75%	50%
<60%	0%

Source: PG&E.

In efforts to improve wholesale market integration of the CBP program, PG&E has sought to gain better, earlier visibility into available capacity. To do this, the nomination deadline was moved from one week before the month to more than three weeks before. For the reasons described above, this introduced greater uncertainty about load for each program month, led to greater derates of nominations and customer frustration given the additional uncertainty into having to look even further into the future.

On the positive side of the ledger, introduction of bids for strike price in addition to capacity level, have enabled participants to trade event frequency for revenue according to their operational flexibility.

CBP also enables aggregation which provides some portfolio effect to balance under and over-performance but this is limited by the fact that, unlike other sectors, there is never additional load to drop so the benefit comes only incidentally from having a baseline that is greater than the nomination on an event day. Aggregation at the sub Load Aggregation Point (sublap) level also limits the portfolio effect.

Peak Day Pricing

PDP presents an important case for the catalysts needed to increase participation in programs. On its face, the program design incorporates many of the attributes that the researchers recommend: it is price base, lucrative, backward-looking (no nominations), does not have a baseline and is tariff-based. Yet, adoption by the agriculture sector has been tepid – why? The program operates during hours when farm personnel are typically available to stop and restart pumps. Event frequency is a commonly cited concern, at nine to fifteen 4-hour events per season but the research has shown much greater load shift potential. The price disincentives to consume power are high, at $1,000/MWh but only one sixth of those in BIP. A customer can perform in as few as half of the event hours before the cost of non-performance is greater than the program credit.

One significant flaw of PDP is that service points on solar (NEM-A) tariffs cannot participate. Not only is this unnecessarily restrictive but AEU change their NEM-A enrollments to match solar production with varying usage across their meters so there is a never-ending effort to keep service points enrolled in eligible programs.

Demand Response Auction Mechanism

At the outset of the project the researchers expected to enroll participating sites in the Demand Response Auction Mechanism (DRAM) and/or Supply Side Pilot/Excess Supply Pilot (SSP/XSP) to test agricultural customers' ability to participate in these programs that were the contemporary efforts to engage demand to contribute to addressing grid needs, especially the duck curve. Analysis of the DRAM program indicated a number of hurdles that inhibit widescale sector participation:

- Use of the 10n10 baseline, the drawbacks of which are discussed above.
- Portfolio commitments ahead of the season. Unlike C&I aggregation where the ability to 'fill buckets of megawatts' is largely a question of sales effectiveness, for the agricultural sector curtailable load varies widely from year to year with precipitation and water allocations.
- Frequent and advanced nomination requirements.
- Aggregator participation is arduous and requires significant financial sureties. With no advance visibility into award prices, it is difficult to assess the value of participation.

Polaris explored participation as a DRAM aggregator for purposes of the project, but no additional auctions were held. So, Polaris engaged with an 'aggregator of aggregators' and received a price proposal for capacity in the program. The pricing offered — lower, of course then if Polaris registered directly as an aggregator in the program — was less than earned in CBP but spread across the entire year which shifts value to seasons when there is less agricultural pumping, reducing the overall revenue opportunity.

Supply Side Pilot/Excess Supply Pilot

If ever there was a Rube Goldberg machine of DR programs, it is these pilots. Designed to mimic generators, they are cumbersome and complex for participants (Figure 70). Polaris attempted to enroll customers in these pilots but found that it was impossible to get clear qualification criteria (a meter could be submitted for evaluation but received only a yes/no answer). The pilots closed before this project could participate.

Figure 70: Supply Side Pilot/Excess Supply Pilot Bidding Requirements

Bidding Requirements (Summary)

PG&E olivine

Bid Blocks	Total Bid Hours	Unique Days	Dispatchable at least	Capacity Payment
4-hour contiguous bid blocks	72	18	24 hours per month	$10 kW-month

Source: Olivine, Supply-side Pilot Introduction, July 2016

AutoDR Program

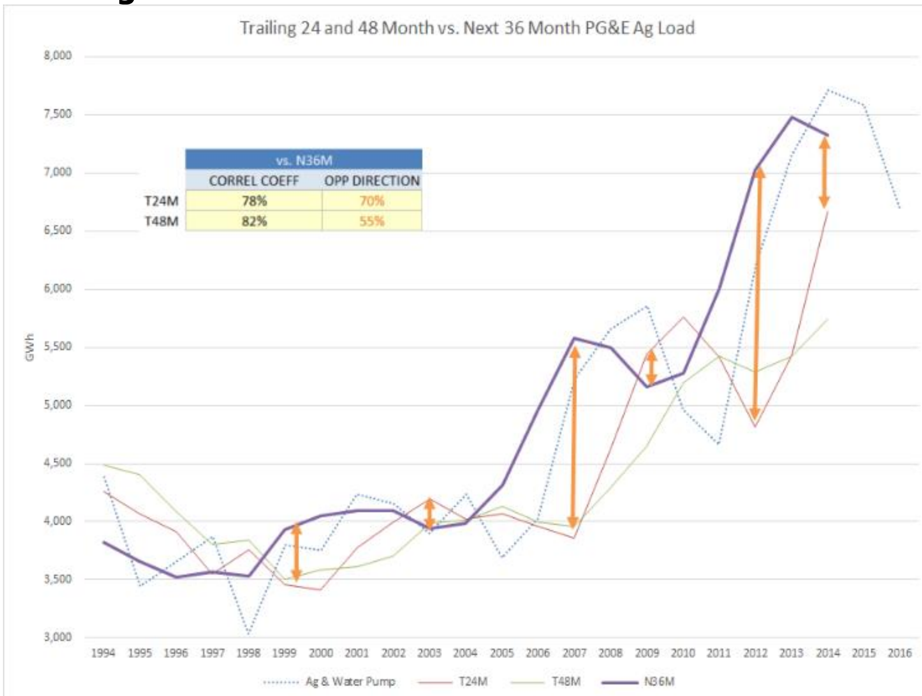
The AutoDR program (ADR) facilitates participation in DR by providing incentives for enabling automation and communication technologies using the OpenADR protocol. AutoDR has played a central role in the growth of the agricultural sector being able to participate over the last decade for several reasons:

- Curtailment of irrigation pumps at remote locations within the specific time frames required by DR programs is prohibitively difficult without automation.
- Automation incentives are attractive to farmers who can apply them to dual use equipment (for DR and daily operations) like sensors and controls.
- The ADR program has attracted technology vendors and integrators who, to develop markets for their systems, have become aggregators and subject matter experts and evangelists for DR in the sector.
- The ability to develop projects across multiple meters enables customers to subsidize the cost of smaller loads with the incentives from larger ones.
- The discretion afforded to the program implementer has enabled them to adjust processes to address discrepancies between irrigation pump sites and typical commercial & industrial participants.

The researchers developed analyses as part of this project to support recommendations that address gaps and shortfalls in the current program, detailed in Appendix A.

- Two years of interval data are used to determine incentive levels and the research demonstrated that this approach is not only inaccurate but tends to lead to the program 'chasing its tail' (Figure 71). After a drought when usage is high, incentives increase which can lead to seemingly poor DR performance if the following years are average or wet. After a wet year, incentives decrease which prevents new projects from being deployed that could be available when usage increases in the next dry year. In all cases, there is a lack of predictability and stability for customers and project sponsors that makes it difficult to maintain momentum, increases the soft costs of adding new capacity and makes the program less successful. The main reason for the two-year standard is data availability and the software developed for the project demonstrated how that can be addressed. The program implementer accepted the analysis and presented to PG&E but informed Polaris two years later that they would not apply the revised analysis period of three years.
- The requirement to calculate incentives for each meter based on historical usage has led to lengthy gaps between customers' applications and project approval which increases cost and dampens enthusiasm for the program. The project addressed this in part by developing software to estimate incentives in a few days using online Share My Data authorizations and Tableau analytics. Recently, the CPUC has instructed the IOU to identify a deemed incentive approach that will eliminate the need for these analyses and the researchers provided data and input in support of this process authorized under a joint advice letter (SDG&E AL 3427-E; PG&E AL 5629-E; and SCE AL 4069-E).

Figure 71: Historical vs Future Load Correlation



Source: Polaris Energy Services analysis of CEC load data.

- The OpenADR standard is tailored for installations with reliable broadband access and is less reliable in remote environments like agricultural pump sites. The software and processes for customers are cumbersome and faulty. Polaris' customers have succeeded in these programs because of a parallel dispatch system that Polaris operates to manage their participation. The cost of dedicated hardware also limits the ability of customers to acquire their preferred technology under the program, especially for sites with smaller loads, which represent a 'long tail' of load that does not participate.

  The AutoDR program allows for a Cloud VEN option which addresses these issues and implementation of one was included in the scope of the project. Before development began, Polaris had to lobby PG&E to allow agricultural customers to take advantage of this provision of the program rules. Though the rules do not exclude agricultural customers, they were interpreted as so. After negotiation, PG&E allowed use of a Cloud VEN for pump sites up to 200 kW (though the rules allow it up to 499 kW).

  Implementation of the Cloud VEN enables receipt of OADR messages in the Polaris cloud and dispatch and management of participating sites using Polaris' ag-optimized technology. In addition to more reliable dispatch, this system provides ongoing monitoring and fault detection to ensure maximum reliability in DR. It also enables dispatch of control technologies that are not OADR-compliant through cloud-to-cloud integrations. This development holds great promise for greater sector participation as it adopts automation from a wide variety of vendors and can use utility incentives and Polaris' Cloud VEN to help them implement greater control while providing valuable resources to the grid.

- The program does not provide a method for participants to opt out of events without emailing or calling the program administrator, negating the benefits of a supposedly fully automated program.
- Measurement and Verification (M&V) for the program which determines whether and how much of 40 percent of the total incentive will be paid employs the CBP baseline, even if the customer is enrolled in PDP. It seems logical and fair that customers would be evaluated on the criteria of the qualifying program in which they enrolled. Figure 72 shows the difference in incentives using the CBP baseline compared to PDP program rules.

Figure 72: Automated Demand Response Incentives for Peak-Day Pricing using Capacity Bidding Program Baseline

	Average of PDP Perf							Average of 10n10 Perf							Total Average of PDP Perf	Total Average of 10n10 Perf	ADR KW	PDP %	10n10 %
Day	10	16	17	19	24	25	27	10	16	17	19	24	25	27					
G1 – P1	119	119	119	119	119	119	119	8	8	16	16	16	16	16	119	14	119	100%	11%
G1 – P2	23	51	51	51	51	51	51	-23	8	8	8	8	8	4	47	3	51	92%	6%
G1 – P3	26	26	26	26	26	26	26	11	15	14	10	10	10	0	26	10	26	100%	39%
G1 – P4	17	-14	-36	17	17	17	17	3	-19	-38	22	23	23	23	5	5	17	29%	31%
G1 – P5	-7	-7	-7	29	29	29	29	-17	-18	-18	36	29	28	21	14	9	29	47%	30%
G1 – P6	-15	-12	-15	27	-57	-55	-56	-8	-6	-8	42	-34	-32	-33	-26	-11	27	-97%	-42%
G1 – P7	49	49	49	49	0	-57	49	32	47	42	50	-2	-59	47	27	23	50	53%	45%
Total	**212**	**212**	**187**	**317**	**184**	**129**	**234**	**6**	**35**	**15**	**184**	**50**	**-6**	**78**	**211**	**52**	**319**	**66%**	**16%**

Source: Polaris Energy Services.

- Paradoxically, AutoDR incentives are available for programs that are dispatched on a day-ahead basis but not for the one program that is dispatched on the day of an event with just thirty minutes notification, BIP. BIP also does not employ or offer dispatch using the OpenADR protocol, even if customers or aggregators are willing to deploy it at their cost. Instead, an insecure, unreliable email dispatch system is employed.
- More germane to renewables integration goals, AutoDR is available for programs that incentivize infrequent load shed or shift in peak hours against the highest possible baseline usage during those hours. It is not, however, available for response to TOU rates nor any other load shift construct. The genesis of this policy is understandable given the change in goals over time, but its persistence is a relic that incentivizes behavior that goes against that which stakeholders claim to value. A 100 kW load that runs during all peak hours is eligible for $20,000 of automation incentives to curtail as few as three times over three years, while the same load that can be shifted off peak on 50 percent of the days is eligible for half the incentive and will face significant performance risk because of the baseline.

Process Analysis

Gaps in technology and program/market design alone do not explain the shortfalls in ag sector participation in DR and addressing them will not ipso facto increase enrollment. There is significant friction in the lifecycle of program participation from enrollment through settlement. The costs of that friction are borne in varying degrees by customers, aggregators and program implementers but, no matter how they are allocated, they raise the threshold of benefits that need to be available.

From customer interviews and analysis of Polaris' processes and interactions, several specific issues are identified but it is questionable whether there is a path to incremental improvement when the trend is toward greater friction. Alternatively, can the paradigm of load management be changed to eliminate as many of these frictions as possible rather than exacerbate them? The team provides recommendations to improve the process in chapter 5; this section addresses the engagement and process issues.

Utility Relationship

Before focusing on DR participation, it is important to describe the relationship between AEU and the utilities (PG&E in our analysis) holistically. Compared to commercial, industrial and institutional energy users, AEU electrical service is more complex to manage than similarly sized utility customers:

- Large number of meters and high energy usage and peak demand – for comparison, participant Irrigation District 1 has 37 meters, 6 MW of peak load and eight employees, none of whom are experts in energy management. By comparison, there are ~270 Target stores in California supported by a 30-person energy team at corporate headquarters (proportionally, five of those people would support the California stores).
- Multiple tariffs – with pumps of different sizes and highly variable operating profiles, AEU service points are on multiple utility tariffs and change them frequently when operations change.
- Physical ambiguity and changes – because pumps are in fields off of designated roadways, just tracking service agreements and bills can be a challenge. Additional challenges include services being frequently discontinued as wells are added and replaced.

The impact of these attributes is that even when AEU expend significant effort managing their energy usage and even with dedicated, effective account executives, most of their attention is focused on just keeping power served where it is needed on the appropriate tariff. The attention available for cost savings through demand side management (DSM) programs is severely limited.

In isolation, these issues seem more appropriate to address in daily interactions with utilities and program implementers than as work product from a three-year research study, and they are addressed in that way. The salient point for the research is the accumulation of small obstacles, frictions and costs that in aggregate impede widescale participation in DR and load management programs by AEU or, metaphorically, death by a thousand cuts.

Program Changes

Program rules and parameters have a variety of flaws that can be mitigated as discussed in the DR programs section. Here, the friction and disincentives to participation inherent in the fact of change itself are addressed. For any given set of rules and processes, customers and vendors adjust and target the subset of customers and service points that fit in the 'box' created by them. When the rules change frequently, however, the market enters a constant state of reevaluation and reconfiguration that threatens the return on investments that were made previously and raises the perceived cost of developing new projects and enrolling new customers. Examples of changes that the market had to adjust to over the course of this project:

- The November 2018 CPUC decision disallowing dual participation in DR programs.

- Service points that were able to dual participate in BIP and PDP are no longer allowed, reducing the incentive that customers had expected.
- Since PDP doesn't allow solar rates, any time a customer switches a rate (to solar or other), they get automatically de-enrolled from PDP. If these sites are Auto DR sites, they need to be enrolled in an "ADR approved program" which is PDP or CBP. Since they were originally dual participating with BIP, they could not leave the BIP portfolio until November in order to be eligible for the CBP program (and CBP season ends in October) so effectively they miss an entire DR season!
- Solar service points enrollments -- the rules on how solar sites (on NEM-A rates) performance is calculated were unclear. Once solar sites were enrolled, the actual BIP incentive was not calculated properly and required months of negotiation and review with PG&E to secure correct payments for customers.

Program Enrollment and Nominations

DR enrollment is far more difficult and complex than it needs to be.

- PDP
  - There is no visibility into where in the program enrollment process the customer is and no confirmation of enrollment unless specifically requested. The current solution is to request an update from PG&E about every 3 months and only then can we see if service points were de-enrolled, which is slow and inefficient. Notably, Share My Data provides this information for a 'Rule 24' deployment but not for a standard deployment.
  - Service points are mysteriously de-enrolled without notifying Polaris or customers.
- CBP
  - Change in nomination deadlines (shifting to 1st week of the month vs last week) is making the load projections difficult as AEU do not have enough visibility into their operational needs (which change based on weather, crop maturity, etc). If the proposed change to comply with supply plan goes forward and the nominations would be required 2 months prior to the beginning of each month, AEU might choose to leave the program. These changes disrupt any routines that have been established to calculate and refine nominations.
  - CBP enrollments are slow if any sites were previously enrolled in other programs. PG&E's demand response management system also automatically rejects enrollees due to participation in another program even though that may no longer be the case. This requires following up several times with PG&E to fix the enrollment issues leading to sites missing out on participating.
- BIP
  - Enrollments take too long -- see issues below re: slow response for FSL submissions.
  - The BIP enrollment change to lottery and only once a year entry is not favorable to agricultural customers at all, making it difficult to maintain a consistent recruitment effort.

Utility Information Systems

Multiple systems provide different views of the same data, are often not updated at the same time and conflict with each other.

- APX vs PG&E provided portfolio files
  - The team has seen multiple discrepancies between information that's available in APX and information that's published on a weekly basis by PG&E. Technically, all info in APX should be updated and correct, however, since at this point it's a manual process, this system is not always updated with the latest information.
  - Service Account ID (SAID) changes are not reflected on a timely basis and even data availability is not complete in the APX system (for example, service points are occasionally completely absent from portfolio reports that it provides).
  - Enrollment requirements such as FSL are not updated in a timely manner by PG&E which causes repeated submission of the same information and causes substantial delays in customer site enrollments.
- SAID changes in general are causing a lot of issues - reconciling sites enrolled initially vs sites enrolled after SAID changes (not all old SAIDs are updated in PG&E's spreadsheet).
  - Energy Solutions uses SAIDs that were submitted during the enrollment process and it causes extra work to reconcile these same sites later (for performance reports) as SAIDs change every time any term on the sites changes (billing cycle is an example in BIP enrollment). Suggestion -- use universally unique identifier (UUID) as the site identifier instead.
- Entity name changes should not cause as much hassle as they do -- if all that changes is entity name to reflect a new configuration of various ranges, a customer should be allowed to stay in the portfolio.
- Share My Data
  - Does not provide critical info that is available in other systems such as:
    - Customer site name
    - DR program enrollment status
  - Missing service points – even with account level authorizations
  - When new service points are added, the customer must resubmit the account level authorization

In aggregate, these process issues serve to make DR participation the province of the 'rich', or many large loads because the relatively fixed effort is not warranted by the incentives and payments available for smaller loads and portfolios. Much like any citizen can take advantage of the US tax code, but only wealthy individuals can hire the accountants and lawyers needed to navigate it. It is difficult to assign specific costs to each activity, but Polaris estimates that one-quarter to one-third of DR revenue is spent on these administrative tasks with an average peak load of 150 kW per service point. This implies that it would be cost prohibitive to serve service points of 75 kW or less, regardless of technology, because of administrative overhead. This is the long tail of agricultural load that is unaddressed today by DR programs.

Customer Engagement

To increase sector participation in programs and markets, it is important to characterize the agricultural sector, compare it to others and identify where current engagement models can be improved. For purposes of this report, 'engagement' is interpreted broadly to include how utility and energy markets interact with the people and operations in the sector.

The participants in this project represent three common types of operations that employ electrical water pumps in California's Central Valley

- Irrigation Districts – cooperatives that deliver water from California's water system and well pumps to members via canals.
- Tree Crops – grow nuts and/or fruit in permanent orchards.
- Row Crops – grow fruits and vegetables in fields that can be changed each year.

There is a wide variety of agricultural operations in every part of California, but these are representative of the lion's share of electrical usage and are the focus of this project. Salient attributes that impact how AEU consume information and respond to signals from the electrical grid:

- Annual Variation – because of climate and business decisions, operations vary greatly from year to year, especially at the level of the individual meter.
    - Crop rotation - in the case of row crops, the irrigation pattern can change significantly from year to year as each crop requires a different quantity of water at different times. Trees produce fruit or nuts for multiple seasons, but orchards too are removed and replanted over multiyear cycles.
    - Local precipitation – the timing and amount of rainfall determines how much water needs to be provided by irrigation.
    - Surface water – the timing and amount of snowfall in the Sierra Nevada mountains drives the allocation of water from snow melt. This water is conveyed by pumps and by gravity and requires less energy than water that is pumped from deep wells.
    - Climate change – growing seasons including the timing of planting and harvest are shifting as climate changes.
    - Market factors – within certain windows, harvest of crops can take place earlier or later depending on pricing and buyer requirements, changing the irrigation season.
- Seasonality – within a given year, growers' operational activities are driven by the season with greatly varying focus and energy usage. Clearly load variability impacts participation in markets and programs but the ability to consider new programs, evaluate and deploy technology and seek operational improvement vary throughout the year.
- Personnel – one of the perceived obstacles to engaging the agricultural sector is the skills and disposition of farmers to technology. There are differences compared to other non-residential sectors but many of the perceptions are based on stereotypes or outdated observations. It is important to differentiate between real and imagined.

- Farms do not have dedicated energy managers. The decision-makers for energy usage are responsible for the key operational decisions as well and typically have a farming background, not engineering. Field personnel who operate irrigation systems typically have informal training and sometimes have limited fluency in English.
- While adoption of information technology in agriculture lags other sectors, this is changing and often computer literacy of the personnel exceeds the use of IT and IoT in the field. The sector commonly uses IT in other aspects of the business, such as agronomy, where implementation has lagged for controls due to technical and cost barriers. There is a clear delineation between older and 'old school' farmers and the generation that is taking on leadership roles today. The latter is not predisposed against adopting new technology but does need to see a strong business case and will stick to traditional approaches until the replacement technology provides a clear advantage.

There is strong risk aversion to energy decisions that have even a small chance of impacting core operations, particularly crop yields, or causing large one-time expenses like replacing a motor. That said, risk aversion among farmers is not qualitatively different from factory managers or building engineers who approach demand management cautiously out of deference to core responsibilities to deliver product or maintain a comfortable building.

CHAPTER 4: Technology/Knowledge/Market Transfer Activities

The research team shared project findings such as policy and marketing recommendations with key stakeholders including regulatory bodies to help increase market adoption of the technology.

Product Launch

Polaris targeted several avenues to bring the results of the project to the agricultural sector in California.

The company launched a digital marketing effort through media outlets, such as Pacific Nut Provider, AgAlert, Google Ad Words, and WaterWrights, used and trusted by California farmers.

Polaris established commercial partnerships with Netafim, Wiseconn and CalWest Rain and continues to seek additional partnerships with vendors and distributors of irrigation technology to include Polaris' energy management capabilities in their products and/or commercial offerings. Implementation of the Cloud VEN within the Polaris platform allows system vendors to execute DR through their hardware making it eligible for AutoDR incentives and providing better total economics to end users because they don't have to pay for dedicated DR hardware. To date, outreach has been through existing networks, taking advantage of vendor relationships that participating customers have, and at events like the Ag Expo in Tulare.

Policy Engagement

Polaris engaged with CPUC and CEC throughout the project on an informal basis and through participation in workshops and submittal of comments on relevant dockets. Polaris continues to engage in these and other forums that may emerge to apply the findings of the project and implement the technologies developed to increase agricultural sector participation in DR and load shifting. Analysis from the project that was shared includes:

- Quantitative and qualitative analysis of existing DR program structures and rules.
- Analysis of agricultural pumping load over time and availability against different baseline and program/market structures.
- Analysis of agricultural DR program performance.
- Analysis of load shift requirement vs cost savings using California ISO market pricing.
- Analysis of load shift under the Transactive Energy pilot.

Polaris provided responses to proposed rules and processes under existing policy frameworks, provided input and response to specific rulemaking proceedings and participated in policy forums that are developing the frameworks for future programs and rules. These include the CPUC Workshop: San Diego Gas & Electric (SDG&E) Dynamic Pricing on October 15, 2019, CEC Commissioner Workshop on Scope of Load Management Rulemaking (19-OIR-01) on January 14, 2020; a comprehensive list is included in Appendix D.

Utility Partnerships and Proposals

Polaris responded to and successfully moved to the next stage of a PG&E RFI for Agricultural Control technologies to be sold in collaboration with their account executives responsible for agricultural customers. The RFI was completed in April 2019 and publication of the subsequent RFP has been delayed several times since then. When the RFP is published, Polaris will respond and expects to enter into a channel sales agreement with PG&E.

Polaris collaborated on two proposals to SCE to deploy the technology in pilots with their agricultural customers, one with Irrigation For the Future (IFF), LBNL and TeMix and the second with program implementer Energy Solutions. As of writing this report, SCE has elected not to move forward with these pilots.

Third Party Integrations

Even with expansion of marketing efforts of Polaris' technology, the goal of the project would not be fully met by capturing a slice of the irrigation controls market in California. Rather, the products developed by this project enable access to market signals using Polaris' control hardware and by any control technology via API.

Polaris API: enables any technology provider to receive DR event notifications (and price signals from the utilities or energy market in the future) that are mapped to loads in their systems using their own data structures, which differ from the customer/meter paradigm used in the energy domain. With Cloud VEN, these providers can also access AutoDR incentives to help customers pay for their systems. This approach enables adoption of load management programs and strategies by farmers and their preferred technology vendors, while minimizing the investment that they need to make in dedicated grid communications and energy management technology.

The API developed under the project for dispatching DR events received by the Cloud VEN to any generic control system was provided to Wiseconn, who implemented and tested it in their system. The implementation enables Wiseconn to access AutoDR incentives for their customers' automation projects and for the customers to participate in DR programs.

Netafim: taking the concept one step further, Polaris partnered with one of the largest irrigation system vendors to develop a fully integrated application that places energy management and load scheduling directly in the farmer's work flow to reduce the effort required to respond to grid signals and thereby increase adoption. Polaris and Netafim applied for and won a grant from the BIRD Foundation. This work is expected to be completed by 2021.

Industry Engagement

The greatest opportunity to stimulate the growth in the market is for California regulators to incorporate key findings from the research in program and market designs. The research demonstrated that clear, simple price signals, adequate automation, and demonstrable and attractive customer benefits can drive significant load shift. Conversely, rate design and program rules and procedures that create great friction and often work to contravening ends present high barriers and challenges for commercialization.

The Technical Advisory Committee (TAC), including customers, industry players and utility representatives, provided significant input to the product development and some assistance in getting the word out. This includes:

- PG&E account representatives invited Polaris to present at customer-facing forums, including the annual water conference and in their booth at the annual Ag Expo, both in Tulare.
- PG&E account representatives provided internal feedback to proposed program changes that were antithetical to the goals of the project, influenced by anecdotal and analytical evidence provided by Polaris.
- Wiseconn, a technology provider for efficient water management, is now promoting DR capabilities developed under the project to customers.

BIRD Foundation Grant

Polaris and Netafim submitted a proposal and won a grant for a $1.6M project from BIRD Energy (the implementation of a cooperation agreement between the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE), the Israel Ministry of Energy jointly with the Israel Innovation Authority, and the BIRD Foundation. This cooperation is based on the Energy Independence and Security Act of 2007, which includes cooperation between the U.S. and Israel on renewable energy and energy efficiency industrial research and development. The grant builds on technological advances from this project.

Netafim USA was a partner on this project, identified by customers as a vendor that provides control technologies that extend further into agricultural operations than Polaris' pump control hardware and software. In this project, the systems were deployed side by side such that participating growers used Polaris' application to select schedules based on energy costs and incentives and then executed the schedules in the Netafim irrigation management system. This approach sufficed for customers in a pilot environment, but it quickly became apparent that customers want — and significant market adoptions requires — that they be able to work in one system that presents all of the inputs and options.

Building on this project, the BIRD grant will embed energy management capabilities including DR event dispatch, energy cost-aware scheduling, and pump cost efficiency analysis in the NetBeat application, powered via API by the Polaris platform. The project extends Polaris' capabilities to other markets and energy pricing structures. Netafim will leverage its size and global reach to commercialize the product, NetBeat Energy.

CHAPTER 5: Conclusions and Recommendations

Terabytes of time series data, months of simulated market participation and hours of conversations with AEU lead to the optimistic and categorical conclusion that agricultural water pumping in California can contribute significantly to decarbonization.

Most of this potential can be realized without large capital investments in physical assets like pumps and reservoirs but does require investments in controls and information technology and in engagement with the agricultural sector.

Critically, to realize this potential, an overhaul is required of the ways in which AEU are engaged, incentivized, and measured by the energy system including by utilities, markets and regulators. This project has demonstrated that AEU will respond to the grid to meet policy objectives when three prerequisites are in place:

- Unambiguous price signals that deliver attractive financial benefits with minimal administrative overhead and friction
- Enabling control technology that delivers operational benefits
- Catalyzing engagement and sufficient support to drive adoption and transition to new operating paradigms

The word "overhaul" is used cautiously but is necessary because the current slate of tariffs, markets and programs is not achieving the state's goals that put DR at the top of the loading order. A patchwork of programs that were designed to meet objectives of a bygone era, which they did with limited success, they are unsuited to meet the state's current goals and challenges. Within that ecosystem, the agricultural pumping sector is lumped with other non-residential load and is often unable to contribute proportionally because the assumptions behind programs and rules do not fit its energy usage patterns. The Mid-August 2020 Heat Storm demonstrated these shortcomings at the system level, indicated in the Preliminary Root Cause Analysis, prepared by the CPUC, CEC and California ISO, and in Polaris' data, showing how much load was on the sidelines for the reasons indicated in this report.

The agricultural sector is at a particularly good juncture for this transition. In California, adoption of automation technology is low but accelerating, cost pressures on AEU are enormous and significant change is needed to meet water and labor challenges. If energy regulators meet the challenge, the first generation of irrigation automation in California will be integrated with and responsive to the electrical grid. Leveraging and building upon investments that AEU are making, such as done in this project, will be key moving forward. This stands in contrast to the first decade of AutoDR investment in agriculture where deployments usually served DR alone.

Further research can help to refine market structures, technologies, and programs but it is more important to begin deployment at scale using what has already been developed and learned. California's investments in smart meters, Open ADR and Green Button were sold to ratepayers with the promise that they would help match consumption to cleaner and ultimately less expensive energy. Instead of leveraging these investments, new options are under consideration for providing price signals, including a new system that would take years to develop and cost $10-15 Million per year to send price signals over FM radio.[9]

By the same token, regulatory and utility efforts often focus on minimizing the cost of and avoiding over-incentivizing small portfolios over growing large flexible resources. Fortunately, California has a successful model for driving adoption of new energy technology to scale and reducing its cost: solar generation (since adopted for energy storage).

Solar adoption has been enormously successful in California and has driven costs below alternatives here and for the rest of the world using a model that should be adopted for flexible load:

- Provide simple, attractive financial incentives.
- Promulgate regulations that ensure financial and operational visibility and predictability over an extended period.
- Decrease incentives over time to encourage early adoption and weed out less cost-effective technologies and vendors.

An example is the declining scale long-term automation incentive:

- Offer current $200/kW ADR incentive based on peak demand, which will effectively increase the value of the incentive because availability discounts would be eliminated.
- Apply an adder to any TOU or dynamic rate that the customer chooses for the most expensive hours that pays back the incentive if the customer does not respond to pricing signals. This can be calibrated for average usage to pay back the investment over the lifetime of the investment.
    - Incentivizing TOU and dynamic rate response greatly increases the value provided to the grid compared to existing DR programs.
- Extend the evaluation period to fifteen years. Technology may need to be replaced during this time, but the investment is in behavioral change which, as demonstrated in this project, tends to persist once achieved. To maintain their benefits, customers will need to maintain and update technology when it fails or is obsolete. Looking at this extended period will make the economics work and provide stability for companies that serve the market.
- Reduce the incentive in steps over ten years to $100/kW. This incentivizes early adoption, which has been successful in the Self-Generation Incentive Program (SGIP) and returns costs to their current level over time.

Potential Contribution of Dynamic Load Management

LBNL identified agriculture as the second largest pool of load shift potential in California after office space and tied with retail, both of which are poised to decline following the COVID-19 pandemic. The cost of agricultural load shift was assessed to be the lowest of 11 types analyzed with the vast majority less expensive than battery storage. This project assessed the load potential using bottom-up modeling and arrived at an estimate within 20 percent of

[9] Herter, 14.

LBNL’s. The customer research and six-month pilot demonstrated that this potential can be realized with the technology developed by this project.

Barriers to Realizing Load Management Potential

The biggest barriers to widescale participation by AEU in load management are misaligned incentives and convoluted business processes. This report enumerated multiple barriers in existing program structures and processes which, as a system, does not provide a clear, cohesive offering to AEU (or other energy users) that makes it easy and attractive to respond to the requirements of the grid.

The ‘long tail’ of small loads is a stubborn structural obstacle. Technology investments and soft costs do not, for the most part, scale down when addressing smaller loads but benefits to the grid and energy savings to the AEU do. This is the same problem inherent in engaging the small business segment and some of the same approaches emerging there can be applied to small agricultural loads integrating with their preferred control systems in the cloud.

Seasonal variability of load in the agricultural sector within and across years is cautiously listed here as an obstacle. In fact, it is an obstacle only when ill-fitting paradigms from other non-residential sectors are applied to agriculture. The fact that there are ‘wet’ years, when pumping load is significantly lower than average, is a risk factor for AEU and third parties when determining incentives and measuring ‘performance’ in programs. Most instances of non-performance among agricultural loads are lack of load during baseline measurement periods, not actual failure to shift or curtail load. The simple reality is that absence of load to shift does not present a problem to the grid during emergencies like the Mid-August 2020 Heat Storm; it just means that value needs to be measured differently than other loads. What is not captured in program analyses, is that managing the risks that current approaches impose for AEU and third parties increases the cost of procuring and managing shiftable load and reduce the quantity available. There is also a dampening effect on recruitment efforts when incentive projections are not consistent throughout the sales process.

It is a common refrain, including among those serving the sector, that ‘ag is different’ and so cannot conform to the paradigms of non-residential energy management. Irrigation load comprises 7 percent of the state’s load, is concentrated in proximity to large concentrations of distributed generation and is inherently flexible. The deployments of a single agricultural project sponsor (Polaris) comprised approximately 60 percent of ADR megawatts enabled since 2016; ensuring that program design options are tailored for the agriculture sector can yield significant benefits.

Policy Recommendations

The researchers recommend development of a new paradigm for agricultural load management that can serve as a template for other sectors. During the three years of this project, much of the researchers’ policy work consisted of responding to proposals and decisions that shared the common attribute of making it more difficult or less attractive for agricultural load to participate in programs or excluded it altogether, with the notable exception of enabling agricultural customers to take advantage of the AutoDR Cloud VEN option.

It is incumbent on regulators to dictate policies that are not only tied to the state's legislated goals but remove the impediments that hamper progress at scale. Key recommendations for agricultural load management:

- Employ clear hourly price signals as the first priority for load management.
  - Allow a sliding scale or at least several options for the time frame in which prices are set. For agriculture, weekly pricing is most appropriate to match operational planning time frames.
  - Roll demand charges into hourly prices to gain the most leverage possible on the price signal without increasing or decreasing average unit prices.
  - TE is a good approach to do this and has been proven in other EPIC projects such as RATES but it is not the only method and does not have to be implemented fully to reap most of the benefits.
- Offer automation incentives to respond to TOU and dynamic pricing, not just DR programs. The policy imperative for load shift exists for most days of the year and incentives should reflect that policy (now, automation incentives *require* consuming load during the most problematic hours only to occasionally curtail it).
  - Ensure that the ratepayer's investment is recouped using a price mechanism that dovetails with the TOU or dynamic pricing structure in place.
  - Require inclusion of the mechanism (for example, an adder during certain hours) until a specified quantity of electricity is consumed. That way, if expensive hours are avoided, the customer reaps savings and, if not, pays a penalty that offsets the incentive received. If there is no usage, there is no gain and no penalty, but the customer is subject to the adder for a longer time. The commitment to the adder remains with the service point in case of transfer or sale.
- Develop a simple DR program tailored for the agriculture sector to address the occasional reliability or economic requirements that cannot be met with strong price signals. Polaris has proposed such a program to PG&E to replace BIP for the ag sector.
  - Eliminate artifacts that are incompatible with agricultural operations, including counterfactual baselines and nominations.
  - Measure actual available load and load shed during events and compensate on those. Only penalize for failure to curtail, not failure to run.
  - Create options within the program to match grid requirements (e.g. notification time, event duration).
- Select a single technology and approach to communication between the market and energy users and apply it to all DR and price signals. Given the investment in OpenADR, this would seem the most logical choice.

Recommendations for Further Research

The researchers emphatically believe that load management needs to move rapidly from pilots to deployment at scale, learn and adjust. Investment should shift from researching agricultural load management to implementing agricultural load management. With that said, there are several open questions that can and should be addressed on the way to and during implementation of new approaches:

- Addition of multi-year, year-round load shift data – by necessity, the project collected data from six months across a wet and a dry year. The researchers believe that extrapolation of these results based on historical data is sound but actual results would complete the picture.
- Expansion of the research to address the 'long tail.' This project focused on large AEU in the Central Valley but, as discussed, there is a long tail of smaller loads dispersed around the state that can contribute to load management, including in utility service territories not addressed by this project. Research to implement strategies and technologies at these sites can temporarily relieve the size constraints faced by vendors and aggregators in existing programs to help develop economic solutions for them.
- Development of an AutoDR option that provides incentives to respond to TOU rates and, at a minimum, a pilot program. This research should address costs and benefits of frequent load shift, measurement mechanisms, interaction with DR programs and issues of free ridership.

CHAPTER 6: Benefits to Ratepayers

This project provides enabling technology and a policy roadmap to unlock a large resource to contribute to reshaping California's electrical load profile to meet its policy goals at a lower cost than known alternatives. Greater automation, monitoring and data analytics for irrigation pumping also helps in the state's efforts to manage scarce water resources while maintaining the strength of its agricultural industry.

Decarbonization

Thirty-two percent of carbon emissions from electrical generation in California are in the top five hours[10] of the day and results of this research demonstrate that, with the technologies developed by the project, 80 percent can be shifted so 25.6 percent of carbon attributable to agricultural water pumping can be avoided. If irrigation pumping represents 7 percent of the state's electrical load, then 1.8 percent of total carbon emissions from power generation can be eliminated. That reduction can be achieved at lower cost than load shift from any other sector and at lower cost than battery energy storage.

Water Management

Energy and water management are interwoven in the agriculture sector and technology applied to reduce energy costs and help the grid will also provide valuable water management benefits. Automation of irrigation helps to ensure that crops receive the right amount — and only the right amount — of water. It enables monitoring of water use for fields, reservoir levels and well depths to enhance water management.

Economic Viability for the Agriculture Sector

The agricultural sector represents ~2 percent of California's economy and employs 2.5 percent of workers. The sector faces challenges from climate change, labor scarcity, water scarcity and trade policy so any reduction in key costs is important. The technology developed by this project enabled participants to use labor more efficiently, reducing the direct and indirect costs of irrigation.

[10] California Air Resources Board.

GLOSSARY AND LIST OF ACRONYMS

Term	Definition
ADR	Automated Demand Response
AERO	Agricultural Energy Rewards and Opportunities; prior branding of the Polaris platform
Ag	Agriculture or agricultural
AEU	Agricultural Energy User
API	Application Programming Interface
BIP	Baseload Interruptible Program
BIRD	Israel-United States Binational Industrial Research and Development Foundation was established in 1977 by the United States and Israel governments to promote mutually beneficial industrial research and development
BMS	Building Management System
California ISO	California Independent System Operator
CBP	Capacity Bidding Program
CEC	California Energy Commission
CEDMC	California Efficiency and Demand Management Council trade group
CI&I	Commercial, Industrial, and Institutional
Cloud VEN	A VEN implemented on a cloud server that relays OpenADR signals using proprietary protocols and/or APIs
CPUC	California Public Utility Commission
CRM	Customer Relationship Management software system
DER	Distributed Energy Resources
DR	Demand Response
DRAM	Demand Response Auction Mechanism program
EPIC	Energy Program Investment Charge
Green Button	Standard for customer access to utility usage and billing data
GWh	Gigawatt-Hour
IFF	Irrigation For the Future EPIC grantee
IoT	Internet of Things - inclusive term for any Internet-connected physical device

Term	Definition
LBNL	Lawrence Berkeley National Labs
LMP	Locational Marginal Pricing
M&V	Measurement and Verification
OpenADR	Open Automated Demand Response standard
PAC	Pump Automation Controller
PDP	Peak Day Pricing DR program; also Critical Peak Pricing (CPP)
PDR	Proxy Demand Response bid directly to the California ISO
PG&E	Pacific Gas and Electric
RATES	Retail Automated Transactive Energy System developed by TeMix
RDR	Reliability Demand Response bid directly to the California ISO
RFI	Request For Information
SAID	Service Agreement ID is a non-permanent identifier for a utility service point
SCADA	Supervisory Control And Data Acquisition
SCE	Southern California Edison
SGMA	Sustainable Groundwater Management Act
Share My Data	PG&E's implementation of the Green Button standard
SSP	Supply Side Pilot DR program
SubLAP	SubLAPs are “sub-Load Aggregation Points” that are defined by the California Independent System Operator based on (relatively) continuous geographic areas that do not include significant transmission constraints within the area. ... The details on this update are documented on the California ISO website
SuperPAC	PAC with full remote control and scheduling
TE	Transactive Energy
TOU	Time of Use pricing in electricity tariffs
UUID	Universally unique identifier is a permanent identifier for a service point
VEN	Virtual End Node - the receiver of OpenADR curtailment signals
XSP	Excess Supply Pilot DR program
ZNE	Zero Net Energy company

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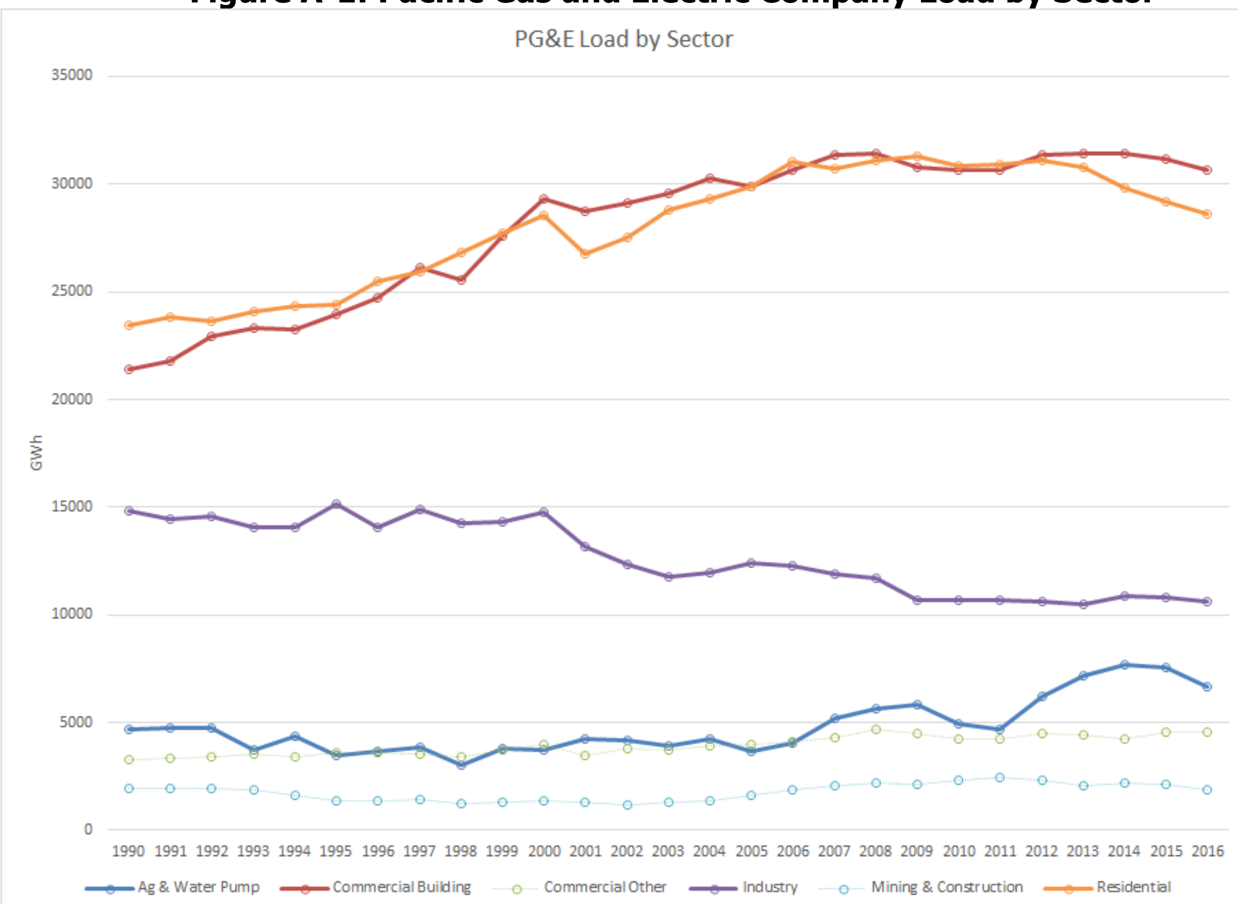
APPENDIX A:
ADR QUALIFICATION PROPOSAL

Why Treat the Agricultural Sector Differently?

Ag load in the PG&E service territory was compared to other sectors as tracked by the CEC to validate the hypothesis that climate-driven fluctuations make the use of 2-year interval data inappropriate. Sectors with significant DR participation are shown in bold lines (residential, commercial building, industrial and ag) while sectors with lower DR penetration (other commercial and mining and construction) are show with thin lines.

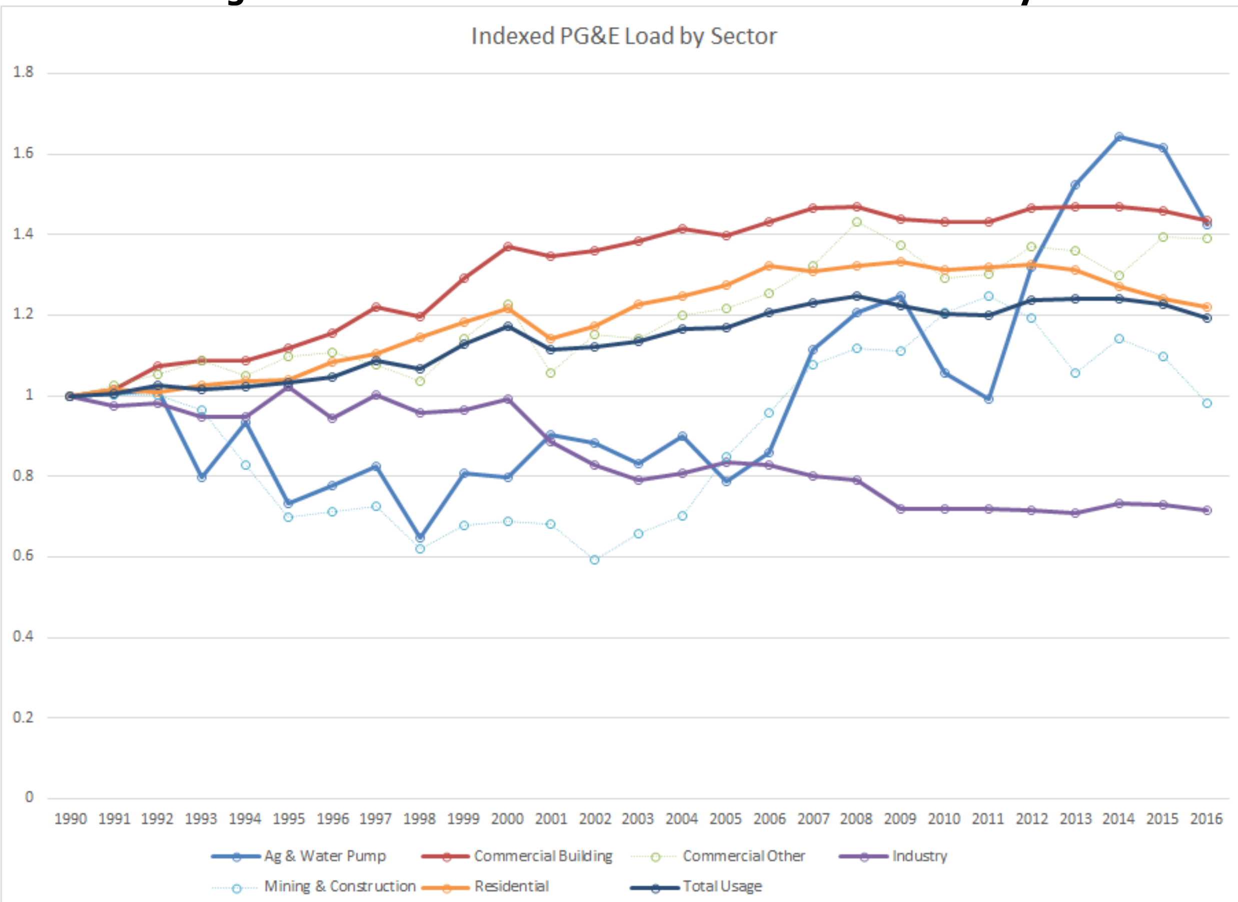
Figure A-1: Pacific Gas and Electric Company Load by Sector



Source: CEC Consumption Database.

When shown relative to an index, it is clear that Ag and Mining & Construction exhibit much greater volatility than the other sectors.

Figure A-2: Indexed Pacific Gas and Electric Load by Sector

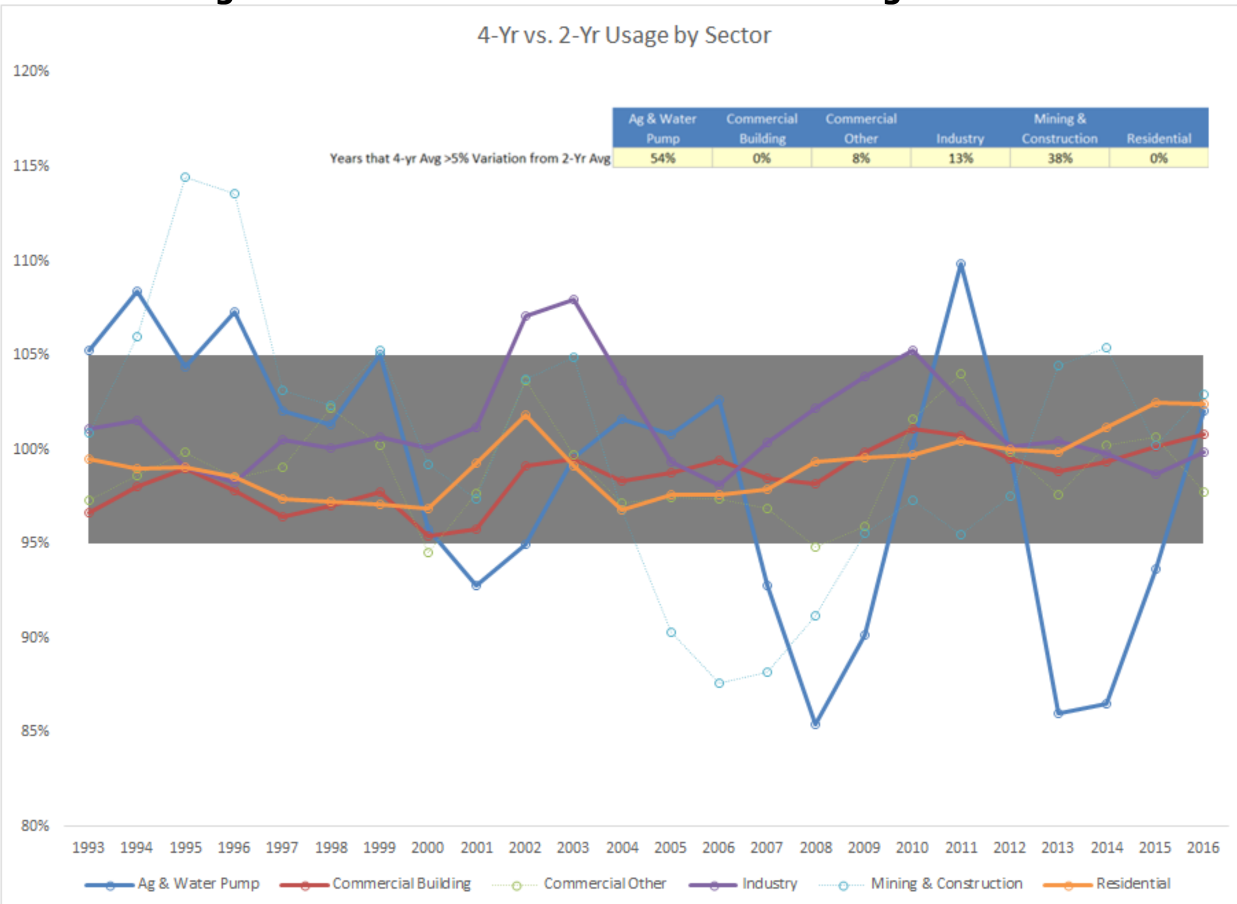


Source: Polaris Energy Services analysis of CEC Consumption Database.

What is the Impact of the 2-Year Average?

For *other* key DR sectors, using two years of data is not highly consequential, as measured by the frequency with which the 4-year data deviates by more than 5 percent from the 2-year average. For Ag, the fact that the 2-year and 4-year averages vary significantly more than half the time implies that 2-year averages may be mischaracterizing the load that participates in DR programs. In doing so, incentives provided can diverge from value delivered.

Figure A-3: Four-Year versus Two-Year Usage x Sector



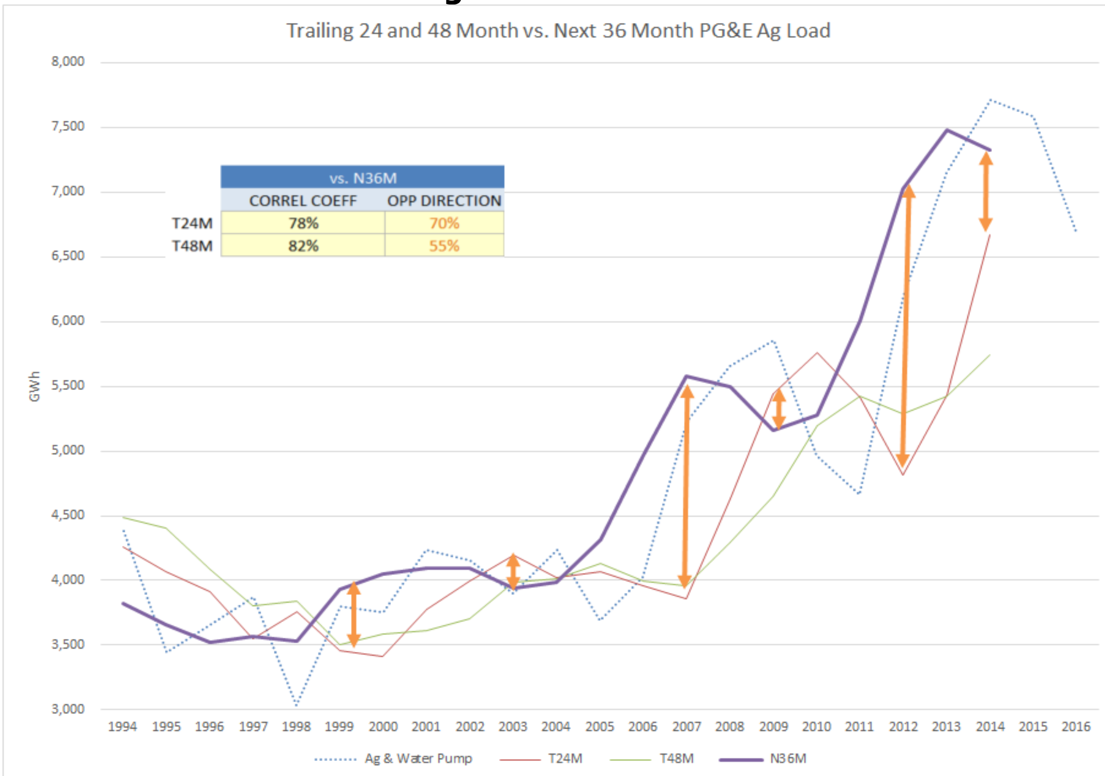
Source: Polaris Energy Services analysis of CEC Consumption Database.

Is a 4-Year Average a Better Predictor?

In addition to the difference in average load, it is important to look at how the averages relate to the period during which load is required to participate in DR programs. To analyze this and determine whether a 4-year average is more predictive, the researchers compare trailing 24-month (T24M) and trailing 48-month (T48M) load with the next 36-month (N36M). This exactly mirrors the situation where a customers' load history is evaluated, a project is deployed, and the customer remains enrolled for three years.

At first glance, both averages are highly correlated with the next 3 years with 4-year data providing a better predictor at 82 percent vs. 78 percent correlation coefficient. But, on closer inspection, it can be seen that the trailing averages are not predictive of the direction (increase or decrease) of load for the next 3 years. The 4-year data is going in the wrong direction about half the time (55 percent) but the 2-year data is directionally incorrect **70 percent of the time.** From a programmatic perspective, this means that incentives are paid that are too high when load has been high, not 'foreseeing' the impending decline and paying incentives that are too low when load has been low, not 'foreseeing' the next increase in load. Extending this view, if a customer waits to get two good years of data, the system will miss out on high load years and then pay a high incentive for participation when there is less load.

Figure A-4: Trailing 24 and 48-Month vs. Next 36-Month Pacific Gas and Electric Agricultural Load



Source: Polaris Energy Services analysis of CEC Consumption Database.

Can Mixed 4-Year Billing and 2-Year Interval Data Serve as a Proxy?

Having shown that 4-year data is a better predictor of DR performance, the data scarcity needs to be addressed. In the first scenario analyzed, the researchers analyzed whether 4-year bill data combined with 2-year interval data at the meter level can provide an accurate proxy. With the 12 meters analyzed, this combination provides highly accurate prediction of even hour demand.

Figure A-5: Predicted Event Hour Demand w/2-Year Interval + 4-Year Usage Data

Predicted Event Hour Demand w/2-Yr Interval + 4-Yr Usage Data										
	Predicted Event Hour Avg Demand				*Actual Event Hour Avg. Demand*				*Avg. Predicted & Actual*	
SP_ID	**J-14**	**A-14**	**J-15**	**A-15**	**J-16**	**A-16**	**J-17**	**A-17**	**AVG**	**Calc Total**
	152	138	148	135	110	114	0	0	100	798
	162	140	160	147	140	147	0	0	112	894
	126	115	98	66	83	91	0	0	72	578
	114	111	111	105	105	98	0	0	80	644
	174	159	168	158	163	148	0	0	121	969
	175	153	174	161	153	161	0	0	122	977
	132	123	76	0	80	103	0	0	64	515
	124	113	118	108	112	110	0	0	86	685
	133	117	129	114	95	108	0	0	87	697
	122	106	121	110	106	105	0	0	84	670
	170	167	184	173	159	180	0	0	129	1033
	169	147	167	94	128	164	0	0	109	871

	Predicted vs. Actual Event Hour Avg Demand								
SP_ID	**J-14**	**A-14**	**J-15**	**A-15**	**J-16**	**A-16**	**J-17**	**A-17**	**AVG**
	4.47%	-4.62%	4.47%	-4.62%					-0.07%
	4.43%	-4.66%	4.43%	-4.66%					-0.11%
	4.37%	-4.71%	4.37%	-4.71%					-0.17%
	4.69%	-4.41%	4.69%	-4.41%					0.14%
	4.78%	-4.33%	4.78%	-4.33%					0.22%
	4.42%	-4.66%	4.42%	-4.66%					-0.12%
	3.97%	-5.07%	3.97%	0.00%					0.72%
	4.60%	-4.50%	4.60%	-4.50%					0.05%
	4.25%	-4.81%	4.25%	-4.81%					-0.28%
	4.56%	-4.53%	4.56%	-4.53%					0.02%
	4.25%	-4.82%	4.25%	-4.82%					-0.28%
	3.97%	-5.07%	3.97%	-5.07%					-0.55%
Average	4.40%	-4.68%	4.40%	-4.26%					-0.04%

Source: Polaris Energy Services analysis of CEC Consumption Database.

Can 2-Year Interval Data Serve as a Proxy With Global 4-Year Averages?

Sometimes. In the situation where 4-year billing data is not available, the researchers look at whether the average distribution of load from a relevant sample can be applied to two years of interval data to predict two prior years. With this limited sample, the average prediction is within 1 percent of actual demand (details of the calculation in the accompanying spreadsheet). This methodology holds up for pumps with similar operating profiles but the research team has not found a model that applies more broadly.

Figure A-6: Predicted Event Demand w/2-Yr Interval and Comparable 4-Yr Data

Predicted Event Hour Deemand w/2-Yr Interval Data Using *Comparable* 4-Yr Data										
	Predicted Event Hour Avg Demand				*Actual Event Hour Avg. Demand*				*Avg. Predicted & Actual*	
SP_ID	**J-14**	**A-14**	**J-15**	**A-15**	**J-16**	**A-16**	**J-17**	**A-17**	**AVG**	**Calc Total**
1596375503	129	128	119	105	110	114	0	0	88	705
2445417703	166	165	153	134	140	147	0	0	113	904
2449625058	100	100	92	81	83	91	0	0	68	547
2703748526	117	117	108	95	105	98	0	0	80	640
4385345455	179	178	165	145	163	148	0	0	122	978
8528972038	181	180	167	147	153	161	0	0	123	987
8814432205	106	105	97	86	80	103	0	0	72	577
8814435305	128	127	118	104	112	110	0	0	87	698
8814461405	118	117	108	95	95	108	0	0	80	641
8814466605	121	121	112	98	106	105	0	0	83	663
8814468705	196	194	180	159	159	180	0	0	134	1068
9941552749	169	168	156	137	128	164	0	0	115	922

	Predicted vs. Actual Event Hour Avg Demand								
SP_ID	**J-14**	**A-14**	**J-15**	**A-15**	**J-16**	**A-16**	**J-17**	**A-17**	**AVG**
1596375503	-11.26%	-11.57%	-16.13%	-25.99%					-16.24%
2445417703	7.20%	12.48%	-0.11%	-12.78%					1.70%
2449625058	-16.94%	-17.59%	-1.49%	17.87%					-4.54%
2703748526	7.90%	0.75%	1.73%	-13.45%					-0.77%
4385345455	7.91%	7.36%	3.17%	-11.80%					1.66%
8528972038	7.75%	12.15%	-0.15%	-13.42%					1.58%
8814432205	-16.79%	-19.08%	33.39%	0.00%					-0.62%
8814435305	7.80%	7.34%	4.60%	-8.75%					2.75%
8814461405	-7.98%	-5.27%	-12.83%	-20.32%					-11.60%
8814466605	4.05%	9.12%	-3.70%	-14.76%					-1.32%
8814468705	20.22%	11.03%	2.11%	-12.63%					5.18%
9941552749	3.76%	8.23%	-3.26%	37.59%					11.58%
Average	1.14%	1.25%	0.61%	-6.54%					**-0.89%**

Source: Polaris Energy Services analysis of CEC Consumption Database.

Other factors and considerations

- This multi-tiered approach to calculating 4-year average demand can yield a result that is too high if there is not a low-usage year so the average should be compared to and capped at a percentage of peak load, for example, 80 percent. Also, ensure that no year's estimated average is higher than the max kW for the service point.
- The model should mirror DR program incentives so as not to disqualify load that can contribute to programs.
    - The 10-in-10 baseline is used in CBP but not PDP, the program more often used by ag customers to earn their incentives. Qualification for ag pumps should use the average load in all even hours.
    - The 70 percent threshold should be removed because (a) it does not reflect DR program structures, (b) is part of the problem that the solution above seeks to address, and (c) does not work with a calculated average as suggested above.
- To ensure that the investment in incentives is recouped while adapting to the cyclical nature of ag irrigation and water conveyance load, the researchers recommend the following:

- When using proxy service points, verify with customers that they serve the same purpose and similar operational profile to the calculated service points.
- Extend the M&V period - rather than capping at one-year M&V and 3-years enrollment, require participation until the service point has delivered the event kW expected of it. This reflects the PDP program structure; there is no penalty for not having load but if you don't have load, it takes longer to earn $X.

APPENDIX B:
Baseload Interruptible Program Alternative for Agricultural Pumping Loads

Background

PG&E submitted Advice Letter 5799-E for its Mid-Cycle Review Compliance Submittal for its 2018-2022 Demand Response funding Application. In that AL, it proposed changes to BIP eligibility criteria that would eliminate participation by current and future agricultural pumping loads. Formal and informal protests were made by customers, agricultural industry groups and Polaris and account representatives who work with these customers provided input on the impact to customers. PG&E has expressed interest in developing an alternative version of the program for this customer segment that will enable them to earn incentives for their flexibility while addressing the issues that led to the proposal.

Problem

According to PG&E's filing and subsequent discussions, the following issues should be addressed in devising a solution:

- Reliable load shed when called, defined as both having load to drop when an event is dispatched <u>and</u> successfully executing the curtailment.
- Predictability of available capacity to support market integration requirements.
- Cost effectiveness as defined by the payment for available capacity and energy delivered. This was not specifically analyzed in the letter but has been raised as a concern.
- While BIP is an emergency program, the addition of a price trigger adds it to the resource stack for addressing non-reliability requirements--economic and renewable standards--and PG&E is interested in program designs that meet multiple needs.

Analysis

As detailed in the protest submitted by Polaris to the AL, the definitions of reliability are conflated and the data show that agricultural pumping load reliably curtails when called upon according to the BIP program design. That said, an improved program design will better align the program with available load across seasonal and hourly dimensions.

To meet the need for measurable load *shed* (not just absence of load), the design should provide a mechanism to measure performance that is absent in BIP, while avoiding the 10-in-10 baseline that does not accurately measure the curtailment actions for agricultural pumping loads. To improve cost effectiveness and usefulness of the resource, a portion of the budget should be shifted to a performance payment measured by actual load shed.

The program should align with and encourage efforts to shape PG&E's load profile to accelerate renewable integration such as the new TOU rates. Customers should be rewarded for responding to price signals and offering curtailable load when they have it, rather than pitting one incentive against the other. Finally, while curtailment of agricultural pumps in Polaris' portfolio has been reliable (90 percent+), the program should require end-to-end automation that aligns with PG&E and California's approach to automated demand response. Requiring OpenADR communications will not only enhance the reliability of this program but put in place the enabling technology for future load shift programs like dynamic pricing.

Solution

Based on these goals and analysis, the proposed program is as follows:

- Eligibility: Service accounts on agricultural pumping rates with enrollment between January 1 and April 30.
- Season: March - October.
    - Benefit: eliminates the months with the least curtailable load and least demand on the grid (lower load and solar production).
- Hours: 24x7 during the program season.
    - *Benefit: ag pumping load is relatively flat and provides a good resource for hours when other loads may be reduced.*
- Dispatch Parameters (notification, number of events, length): Same as BIP.
- Automation Requirements: Dispatchable by the PG&E DRAS using the OpenADR standard. Cloud VEN option for service accounts to 200 kW according to the rules put forward by PG&E for agricultural AutoDR projects. Provide a transition period to implement ADR projects for current program participants.
- Aggregation: Optional.
- Payment Structure:
    - Capacity: $9/kW/month for measured average usage 24x7 during the program month.
        - *Benefits:*
            - Total annual capacity payment is two thirds of the current rate and measurement across 24 hours aligns capacity payment with load available.
            - *Don't pay for peak loads when events are dispatched at any time. Polaris' portfolio curtailments were 72 percent of average usage for the same months because of the difference between the hours used to calculate monthly incentive payments and hours during which events were dispatched.*
    - Performance: $1.00/kWh for actual load curtailed during events (or market price).
        - *Benefit: cost increases above $72/kW/year capacity only as the program is dispatched more.*
    - Performance M&V: the difference between load during the hour before notification and the Firm Service Level (FSL) for each event hour.

        - *Benefit: mirrors PG&E's analysis of actual load shed and is the truest indication of performance for this customer segment using a counterfactual baseline.*
    - Penalty: $1.00/kWh for load not curtailed during events (or market price), using the same M&V.
        - *Benefit: maintains a strong disincentive to opt out of events.*
- Forecasting: Polaris Energy Services will provide an annual load forecast in advance of the season and update it monthly throughout the season based on load analysis, surface water allocations, customer interviews, climate and weather conditions. The forecasts may be based on Polaris' customer load data alone or, with appropriate privacy measures, data provided by PG&E for all participating service accounts. Commercial terms to be determined.

In this proposal the researchers endeavor to balance the need to make changes to address the immediate issues with hewing closely enough to the existing program to make it a viable alternative. We are eager to engage more expansively on program and rate design for agricultural loads based on the findings of our EPIC work. For example, the program proposed here could easily include a 'ramp up' option to address overgeneration during the 'belly' hours, with minimal modifications.

The Polaris team appreciates the opportunity to work with PG&E to develop a reliable and valuable alternative to the BIP DR program for agricultural pumping customers.

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APPENDIX C: Response of Polaris Energy Services on Pacific Gas and Electric Company's Mid-Cycle Review Compliance Submittal for its 2018-2022 Demand Response Funding Application Submitted as Advice 5799-E

Introduction

Polaris Energy Services (Polaris) respectfully submits comments on the April 1, 2020 PG&E's Mid-Cycle Review Compliance Submittal for its 2018-2022 Demand Response funding Application.

Background

Polaris Energy Services, Inc. is a hardware and software technology development, Demand Response (DR) aggregator, energy project development, and service provider focused on helping agriculture energy users--primarily those operating irrigation pumps--to lower costs and improve operational control by participating in energy markets and programs. The Company's proven hardware technology is installed at irrigation and water conveyance sites and controlled by software tailored for the physical and operational requirements of the ag sector.

Polaris manages a network of 340+ irrigation and water conveyance pumps, connected in the field to Polaris Pump Automation Controllers ("PAC") gateways that represent 90 megawatts ("MW") of peak demand, including 46+ MW across 168 service accounts enrolled in PG&E's Baseload Interruptible Program (BIP). Polaris has developed projects enabling customers to access 15 MW of AutoDR incentives to control 50+ MW of curtailable load. The company believes that these numbers represent the large majority of agricultural pumping load participating in programs in the PG&E territory.

Polaris was founded in 2014 and is a small business comprised of leaders in DR and agricultural energy management for the past 10+ years. The company was tapped by the California Energy Commission (CEC) in 2017 to develop technologies and programs to increase agricultural sector participation in DR and load shifting programs.

Discussion

Our comments here relate to the proposal to modify the eligibility requirements of BIP. Polaris manages a portfolio of agricultural irrigation pumps belonging to farmers and irrigation districts comprising 168 meters with 46+ MW of peak load. All of these loads are outfitted with Polaris Pump Automation Controllers (PACs) and monitored 365x24x7 by the Polaris Network Operations Center (NOC) for high availability and reliability. We protest this proposal on a number of grounds but are eager to work with PG&E and the CPUC to find solutions to the real issues that it seeks to address, without collateral damage to customers, vendors and common demand management goals.

- BIP delivers value according to its program design but that does not align with how it is measured under market integration.
- The proposal targets agricultural pumping customers directly and eliminates all participation in the program, hurting the sector and vendors that serve it at a particularly vulnerable time.
- The proposal does not provide an alternative to retain this load in other programs and unnecessarily accelerates a major program change to a MCR when they could be made for the next program cycle after consideration of recommendations to be delivered this year from a three-year EPIC project to increase agricultural sector participation in DR and load management. Key findings from that research include
  - Exploiting the inherent operational flexibility inherent in agricultural usage requires baselines or other incentive schemes that do not penalize customers for <u>not</u> pumping water at certain times. Solutions may include expanding the use of 'drop-to' baselines or employing price signals, but the current trajectory of reliance on counterfactual baselines and advanced bidding of load will exclude agricultural pumping from significantly contributing to achieving goals for the grid.
  - Agricultural operations vary seasonally and annually, as dictated by climate, agronomy and markets, and the sector is among the last to adopt digital technologies and business processes. Efforts to integrate pumping load in energy initiatives must look at data across sufficient time frames and provide sufficient consistency of programs to recruit, deploy, enable, train and engage customers and still provide a reasonable return to customers and third parties.
- PG&E's process leading to the proposal included consultations with representatives of other customer segments but not of agriculture, leading to lack of consideration of alternatives or adjustments to the proposal.

Program Value and Cost Effectiveness

The ostensible reason for changing the eligibility criteria for BIP from 100 kW peak demand in the last 12 months to 100 kW average peak demand in each of the last 12 months is that loads do not perform during events that can be dispatched on any date and at any time and are not cost effective. Under this rule, <u>all</u> agricultural pumps would be eliminated from the program because there are a number of months each year when pumps do not run or run very little. This logic does not hold up for a number of reasons.

- The program design uses a 'Firm Service Level (FSL)' baseline which is a 'drop-to' approach based on the idea that during a grid emergency what matters for reliability purposes is whether load is present, not what it was doing before the event. By this metric, agricultural pumps <u>do</u> perform well - in recent events dropping 91 percent of load that was present in the hour before the event.
- PG&E's proposal says that "While this change would likely result in a decline in enrolled BIP capacity, the capacity that qualifies will be more reliable."   It explains that

reliability means having load available to drop but reliability for this program means achieving the Firm Service Level (FSL) so it is inappropriate to characterize agricultural customers as "unreliable" for not having load to drop. When required, they reach their FSL at a higher rate than the portfolio.

  - In seeking to separate the less reliable load from the program, PG&E did <u>not</u> address the issue of automation, which is bewildering given that BIP is an emergency program with 30-minute notification. California policy based on years of research holds that automated demand response is more reliable than manually activated demand response. All agricultural pumping load in the program aggregated by Polaris is automated and actively monitored and managed to maintain the highest degree of reliability.

- From a cost effectiveness perspective, it is incorrect to say that loads that are not present year-round are being paid for value that they do not deliver. For events in months without load (or with little load), customers are not compensated. If there is an event and meters are at their FSL before the event, they do not get paid for more than the average peak load for the month.
- The inherent problem is that PG&E is bidding these loads against a 10-in-10 baseline in the wholesale market. Removing the valuable load and suggesting that it participate in programs with that problematic baseline shifts the problem to customers rather than addressing it head on.
- The proposal also indicates the need for load that is available 24 hours per day. While agricultural load is seasonal and therefore 'problematic' per the filing, the same is not true for the daily profile when pumps are running; their load profiles are relatively flat throughout the day. The difference between compensation (based on Monthly Average Potential Reduction (MAPR)) and the load available during the hour before an event is due to the fact that compensation is calculated on peak (summer)/part-peak (winter) load and 43 percent of the event hours since 2017 have been during off-peak hours. For agricultural pumps aggregated by Polaris, the load availability one hour prior to events averaged 72 percent of MAPR.
- It is important to consider the scenario that will play out with this proposal. It is correct that recent events and tests were dispatched when there was not a lot of pumping load, due to seasonality or annual climate variability (in wet years with plentiful snowfall, less water is pumped from deep wells). But, when there are events in drought years (like this one and increasing due to climate change) during the irrigation season, these loads will be present in full force, creating greater operational challenges for operators during grid emergencies.

Figure C-1: Baseload Interruptible Program Performance Data

BIP Performance Data

Event Date	Sublap	Event	Event Duration (Hrs)	Peak Hours	BIP Max kW	Monthly Average potential reduction kW	kW demand 1 hr prior to event	Total Penalty kWh	Hourly avrg penalty kWh	MAPR vs BIP Max	Performance vs. 1 hr prior	kW 1hr prior vs. MAPR kW
5/3/2017	All	8:15 pm - 9:30 pm	1.25	-	11,349	1,414	1,117	177	142	12%	87%	79%
9/26/2018	All	4 - 10 pm	6.00	2	36,881	8,765	5,600	2,587	431	24%	92%	64%
2/23/2019	PGZP	7 - 10 pm	3.00	3	17,394	619	462	0	0	4%	100%	75%
3/12/2019	PGF1, PGKN, PGNP	6:30 - 9:30 am	3.00	1	20,481	1,487	343	340	113	7%	67%	23%
10/6/2019	All	5 - 7 pm	2.00	1	38,981	5,665	5,483	1,036	518	15%	91%	97%
Totals			**15.25**	**6.50**	**125,086**	**17,950**	**13,005**	**4,140**	**1,204**	**14%**	**91%**	**72%**

Source: Polaris Energy Services analysis.

Customer and Market Impact

According to LBNL, agricultural pumping represents a 1,150 MW opportunity in California but was only 15 percent penetrated as of 2015. Most of that capacity is in SCE's AP-I and PG&E's BIP programs, with growing capacity in PG&E's CBP program. The proposal would eliminate all agricultural pumping participation in BIP which includes 168 customer meters and 46+ MW of curtailable load aggregated by Polaris. This result would have a severe impact on ag customers and efforts to realize the DR and load shift potential in California's irrigation pumps.

- PG&E agricultural customers rely on compensation for their participation in the BIP program to offset energy costs that are set to increase with new TOU rates at a time that water scarcity, labor cost and, now, the impact of Covid-19 are taking a toll on the agricultural sector and its employees in the Central Valley.
- The new TOU rates that are optional for customers this year will be mandatory for agricultural energy users within one month of the date that they will be expelled from BIP. With no automation incentives to respond to the price signals sent by the new tariffs, this hits customers as a lot of change at one time, none of which is good for customers. For a customer segment that is already somewhat jaded about their utility and regulators, this does not bode well for cooperation with other existing and future demand side management efforts.
- With that, where there is a fit, BIP has been a gateway to participation in additional programs. In particular, customers have added a second program (PDP) when it was allowed or switched to CBP in order to access AutoDR incentives even when the programs themselves are less lucrative. They have also started with BIP and then enrolled service points that were a good fit in CBP. They will not do so where the incentives are not worth it to them and/or because increased effort and hassle reduces their interest and willingness to participate in utility programs and increases their adversarial view of PG&E and the CPUC.
- The potential transfer to other programs is problematic not only because of incentive levels and baselines. The requirement to bid load in advance when customers do not know if they will have load leads to inability to participate.
    - To meet the needs of wholesale market integration, the nomination window has shifted earlier, from five days before the month in question (requiring predictions 1-5 weeks in advance) to thirty-five days before the month (requiring predictions 3-7 weeks in advance). In that time frame, agricultural energy users have

minimal visibility into pumping schedules. In addition to weather, which DR forecasters are familiar with, there are external factors that drive binary decisions (run/not run) such as whether a grower will receive surface water at that time (and not run his/her pumps) and when a buyer will schedule shipment of a crop, which determines when irrigation will cease for harvest. Unlike weather impacts on DR that are common for commercial and residential loads, these are not questions of percentage points of variability (cooling load vs. outside temperature), they are questions of whether the entire load behind a meter will be there 24x7 or there will be no load at all. Nominating in CBP or similarly structured programs amounts to throwing a dart at the range of probabilities and hoping for the best, which leads to severely derated nominations and associated benefit relative to customer effort.

Lack of Transition Plan

PG&E's proposal limits discussion of a transition plan to:

> "Further, while some participants with peaky load will no longer qualify for BIP, these participants could find the CBP to be a better fit due to its flexible nature and the ability to choose the price at which resources are dispatched. PG&E recognizes that if the proposal is adopted by the CPUC that it would impact certain participants. Therefore, PG&E proposes conducting outreach upon CPUC's approval to inform impacted participants of their options."

- In reaching these conclusions, PG&E did not, to our knowledge, reach out to Ag customers nor to Polaris, the aggregator for most or all ag pumping load to find out if participants "could" find CBP or any other program to be a fit.
- The conclusion that these customers might find CBP a better fit ignores, without investigation, the research indicating the many ways in which CBP is not a good fit for ag pumping load.
  - It is not clear what the meaning of "flexible nature" is but bidding 7 weeks ahead of operations that have not been scheduled yet is not perceived as 'flexible' by energy users. And, "conducting outreach to inform" is not a transition plan; it is a notification plan.

Timing and Process

Polaris understands that there are issues to address with longstanding DR programs and their cost and effectiveness in meeting current and future grid challenges. As a company, we not only stand ready to help manage these necessary transitions for agricultural energy users but are actively engaged in research and development to make this happen. That transition requires, however, development of options and communication with stakeholders before pulling the plug on programs that customers and partners rely on.

- The five-year cycle was implemented, at least in part, to provide continuity and consistency to energy users and third parties in planning for and adapting to changes to programs and markets. This proposal, shortly after the market had to adapt to changes mandated by the 2018 decision, more than dilutes the value of putting that cycle in place.

- BIP eligibility requirements were not among the items to be addressed in the MCR and there is no pressing reason to propose changes mid-cycle. The program has room under the megawatt cap so no 'better' capacity is excluded and the program is spending less than authorized so there is not a compelling financial reason to change it now.
- To our knowledge, PG&E met with CLECA representing industrial energy users but not with agricultural customers nor their representatives and so the proposal was developed without this important input.
- PG&E has subsequently indicated interest in working with us to develop alternative programs but this is unlikely to be accomplished before customers are eliminated from their current program. PG&E has also indicated willingness to hear our concerns about this proposal and modify it based on comments received in this process. Ipso facto, that requires rejection of the proposal.
- Most significantly, ratepayers have invested $2.8M to develop technology and recommend program and market changes to increase agricultural sector participation in Demand Response and load management, with another $650K invested by Polaris. The results of that study, CEC's EPC-16-045, will be delivered this year, in time to holistically address the full range of challenges and opportunities for ag sector participation in meeting the needs of California's grid. It is a waste to risk the participation of the sector and threaten the viability of the company delivering this progress--or at least forcing it to hastily reorganize its operations--to save the portion of what amounted to $492K of payments in 2019 that is deemed to be unreliable or not delivering value.

Conclusion

Polaris Energy Services respectfully requests that the Commission reject PG&E's proposal to modify the eligibility requirements of BIP starting in April, 2021, and instruct it to work with stakeholders from the agricultural sector to develop reasonable alternatives for the next program cycle.

APPENDIX D: Technology/Knowledge Transfer Plan

Knowledge gained from the project will be made available through several efforts and channels and is also being disseminated as developed to influence regulatory and commercial developments. The timing and nature of the efforts varies by audience.

- Targeted market sector: Polaris is developing several avenues to bring the results of the project to the agricultural sector in California. The benefits available in advance of regulatory changes are greater success in existing DR programs and taking advantage of new TOU rates and these are the focus of outreach within the sector. To that end, we have established commercial partnerships and will seek additional partnerships with vendors and distributors of irrigation technology to include Polaris' energy management capabilities in their products and/or commercial offerings. In particular, implementation of the Cloud VEN within the Polaris platform allows system vendors to execute DR through their hardware making it eligible for AutoDR incentives and providing better total economics to end users. To date outreach has been direct through existing networks, taking advantage of vendor relationships that participating customers have, and at events like the Ag Expo in Tulare.
- Two of these have led to development projects, one of which led to the award of an additional development grant.
    - Polaris and Netafim submitted a proposal and won a $800,000 grant, representing 50 percent of the total project scope, from BIRD Energy (the implementation of a cooperation agreement between the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE), the Israel Ministry of Energy jointly with the Israel Innovation Authority, and the BIRD Foundation This cooperation is based on the Energy Independence and Security Act of 2007, which includes cooperation between the U.S. and Israel on renewable energy and energy efficiency industrial research and development). The grant builds on technological advances from this project and the winning proposal relied heavily on confidence that CEC placed in Polaris when it awarded this EPIC grant and on Polaris' successful execution of the project and achievement of the milestones defined in the scope.
    - Netafim USA was a partner in this EPIC scope, identified by customers as a vendor that provided control technologies that extend further into agricultural operations than Polaris' pump control hardware and software. In this project, the systems were deployed side by side such that participating growers used Polaris' application to select schedules based on energy costs and incentives and then executed the schedules in the Netafim irrigation management system. This approach sufficed for customers in a pilot environment but it quickly became apparent that customers want — and significant market adoptions requires — that they be able to work in one system that presents all of the inputs and options and captures their selections.

- The development project will embed energy management capabilities including DR event dispatch, energy cost-aware scheduling, and pump cost efficiency analysis in the NetBeat application, powered via API by the Polaris platform. The project extends Polaris' capabilities to other markets and energy pricing structures. Netafim will leverage its size and global reach to commercialize the product, NetBeat Energy. The product is forecast to deliver $3M of DR payments, $2.5 of AutoDR incentives and $0.6M of software subscription revenue in California in the first three years of commercialization, $6.1M out of a total $7.7M of forecasted revenue. In subsequent years, California's share of product revenue will decline as adoption grows in other markets.
    - The API developed under the project for dispatching DR events received by the CloudVEN to any generic control system with was provided to WiseConn, who implemented and tested it in their system. The implementation will enable WiseConn to access AutoDR incentives for their customers' automation projects and for the customers to participate in DR programs. With testing completed, WiseConn will begin commercialization as of May 2020.
- End users: outreach to end users will be expanded from the current direct outreach to encompass online marketing tools in order to generate interest in the technology developed by the project. Specific channels are under evaluation for cost effectiveness and efficacy in reaching a target market that is a late adopter of technology. In addition, Polaris responded to and successfully moved to the next stage of a PG&E RFI for Agricultural Control technologies to be sold in collaboration with their Account Executives responsible for agricultural customers. The RFI was completed in April 2019 and publication of the subsequent RFP has been delayed several times since then. When the RFP is published, Polaris will respond and expects to enter into a channel sales agreement with PG&E. Even with expansion of direct and channel marketing efforts of Polaris' technology, the goal of the project would not be fully met by capturing a slice of the irrigation controls market. To enable widespread access to DR and market pricing signals, Polaris is engaged in two efforts:
    - Polaris API: enables any technology provider to receive DR event notifications (and price signals in the future) that are mapped to loads in their systems using their own data structures, which differ from the customer/meter paradigm that is used in the energy domain. With CloudVEN, these providers can also access AutoDR incentives to help customers pay for their systems. This approach enables adoption of load management programs and strategies by farmers and their preferred technology vendors, while minimizing the investment that they need to make in dedicated grid communications and energy management technology.
    - NetBeat Energy: taking the concept one step further, Polaris has partnered with one of the largest irrigation system vendors to develop a fully integrated application that places energy management and load scheduling directly in the farmer's work flow to reduce the effort required to respond to grid signals and thereby increase adoption. Polaris and Netafim applied for and won a grant from the BIRD Foundation for development of this application, described above. Development is scheduled to be completed at the end of 2021 when the full

product will be released and 'soft launches' of some functionality are expected earlier in the development process but their dates have not been set.

- Forums in which technology was presented to potential end users:
    - SCE+PGE Water Conference 2017 – keynote address.
    - World Ag Expo, Tulare, CA 2018 – exhibit in PG&E booth.
    - SCE+PGE Water Conference 2018 – breakout session.
    - World Ag Expo, Tulare, CA 2019 – exhibit in PG&E booth.
    - SCE+PGE Water Conference 2019 – technology forum.
    - World Ag Expo, Tulare, CA 2020 – exhibit in PG&E booth.
- Utilities: throughout the project, Polaris has initiated contact with PG&E and SCE and its program implementers (Energy Solutions in particular) to share insights without waiting for delivery of the report, to expand the scope of the project within the utilities, and to develop pilots that apply the knowledge gained in this project to policies and programs.
    - PG&E Agricultural Account Rep Meeting, December 11, 2017.
    - ADR Qualification Proposal presentation and document for evaluation for agricultural sites to Energy Solutions on April 10, 2018. This proposal led to an adjustment to the incentive kW calculation.
    - Proposed 'PG&E Retail Automated Transactive Energy System (RATES , The PG&E Transactive Energy Platform', submitted July 30, 2018, with TeMix and Zero Net Energy Alliance. PG&E has not responded to this proposal.
    - Proposed 'Agricultural Transactive Energy Proposal' on December 4, 2018, with LBNL, Irrigation For the Future and TeMix. SCE has not responded to this proposal.
    - AutoDR: Polaris Strategy Meeting with PG&E Agricultural Account Reps on February 21, 2019.
    - Base Interruptible Program (BIP) Event Dispatch Notification Discussion with PG&E Program Manager and IT team to improve reliability and security of BIP event notifications. PG&E made some changes to the email format but did not accept Polaris' recommendation to employ OpenADR.
    - ADR Ag Cloud VEN eligibility and approval; discussion with PG&E and Energy Solutions on March 19, 2019 and associated emails. This meeting and presentation of written information led to the approval for use of CloudVEN technology for agricultural ADR projects up to 200 kW.
    - California Joint Investor-Owned Utilities Automated Demand Response Program Non-Residential Incentive Structure Project. G&E AL 5629-E. Consultant in the process of developing recommendations.
        - Comments and written response to ADR Non-Residential Incentive Research Project – Webinar on January 29, 2020.
        - Interview by Energy Solutions project manager and written recommendations on April 10, 2020.

- Proposed conceptual outline of agricultural pilot to SCE with Energy Solutions. The most recent memo, dated April 23, 2020, is included with this documentation.
    - Proposed to PG&E enabling vendors to receive DR enrollment information from ShareMyData. This was only allowed for demand response auction mechanism (DRAM) under Rule 24.
    - Enrollment and nomination rules and procedures for existing programs to PG&E program teams on an ongoing basis.
        - Capacity Bidding Program (CBP) nomination timeline. This effort led to informal extension of window to revise monthly nominations for May 2020 and going forward.
        - Eligibility and settlement for solar NEM meters. This effort led to retroactive compensation for meters on NEM tariffs that showed incorrect usage for BIP incentives.
- Regulatory agencies: Polaris has engaged with CPUC and CEC throughout the project on an informal basis and through participation in workshops and submittal of comments on relevant dockets. Polaris will continue to engage in these and other forums that may emerge to apply the findings of the project and implement the technologies developed to increase ag sector participation in DR and load shifting. Analysis from the project that has been presented includes:
    - Quantitative and qualitative analysis of existing program structures and rules.
    - Analysis of agricultural pumping load over time and availability against different baseline and program/market structures.
    - Analysis of agricultural DR program performance.
    - Analysis of load shift requirement vs. cost savings using California ISO market pricing.
    - Analysis of load shift under the Transactive Energy pilot (ongoing).
- Polaris has responded to proposed rules and processes under existing policy frameworks, provided input and response to specific rulemaking proceedings and participated in policy forums that are developing the frameworks for future programs and rules. To date these include:
    - California Efficiency and Demand Management Council (CEDMC) comments to Application of Pacific Gas and Electric Company (U39E) for Approval of Demand Response Programs, Pilots and Budgets for Program Years 2018-2022, Application 17-01-012. 2018 decision (regarding dual participation and BIP enrollment timing).
    - Ag DR Overview for CEC Commissioner McAllister on May 31, 2019.
    - Presentation to CPUC DR Team on TE Pilot on October 8, 2019.
    - CPUC Workshop: San Diego Gas & Electric (SDG&E) Dynamic Pricing on October 15, 2019.
    - CEC Commissioner Workshop on Scope of Load Management Rulemaking (19-OIR-01) on January 14, 2020.

    - Comments on Load Management Rulemaking (19-OIR-01) on January 24, 2020.
    - Polaris Energy Services Protest to PG&E ADVICE 5799-E 20200504 changing BIP enrollment criteria on May 4, 2020.
- Other Stakeholders:
    - Presentation at LBNL: ETA Seminar: Putting the Response in Agricultural Demand Response on August 21, 2018.
    - Presentation to CEDMC Symposium: There's No Such Thing As An Energy User on October 23, 2019.
    - Presentation to California ISO: Agricultural DR Overview for California ISO on April 29, 2020.

Publications

- The project was cited in Utility Dive among several CEC grantees: https://www.utilitydive.com/news/what-happened-to-agricultural-demand-response/550829/
- Microsoft Customer Story: Polaris Energy Services transforms agriculture energy use with Azure (https://customers.microsoft.com/en-us/story/730511-polaris-energy-services-azure).
- Microsoft Industry Blog: How Polaris Energy Services is transforming the agriculture industry in the cloud (https://cloudblogs.microsoft.com/industry-blog/microsoft-in-business/energy/2019/05/15/how-polaris-energy-services-is-transforming-the-agriculture-industry-in-the-cloud/).

Website Downloads

To date project results have not been made available for download on the company website and there have been no public requests for project results. The project report will be published on the website when submitted to the CEC and approved.