Incentives and Challenges for Agricultural Energy Use and Grid Services

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ABSTRACT

In this paper we analyze the 2018 irrigation season for three different farms using three different demand management options (Baseline, Time of Use, and Demand Response) and compare the profit potential for each management approach. We also identify critical challenges to making irrigated agriculture a resource for demand management and electricity grid and next steps and possible technological developments to improve the economics of agricultural load management.

KEYWORDS: Agricultural energy use; Pumping costs; Energy use efficiency; Solar; Grid services; Demand management; Demand response; Time of use; Transactive energy; Real-time pricing; deficit irrigation; Evapotranspiration

INTRODUCTION

On-farm energy use is an increasingly important cost and variable irrigators must balance against their water availability, yield targets and production schedules. Declining surface water and lower water tables in many western states are increasing the energy intensity and therefore the cost of irrigation. At the same time, due in part to the low cost of land, agricultural areas are emerging as major producers of clean energy. In California, for example, over the last five years solar production has jumped from 5.5 million net MWh to 28.5 million MWh, with the largest volume of solar generated in counties with some of the largest volume of agricultural production.

As the electricity grid evolves to include more distributed sources of energy generation, it needs flexible loads to maintain its stability. Twenty-nine states, Washington, D.C., and three territories have adopted a Renewable Portfolio Standard (RPS). Top irrigated agricultural states are among those with ambitious RPS targets such as California (50% by 2030), Texas (10 GW by 2025), Kansas (20% by 2020), and Montana (15% by 2015). In order to meet those RPS goals, large quantities of solar and wind electricity need to be integrated into the electricity grid.

Unlike conventional thermal power plants (e.g. natural gas and coal), these new generation sources are inherently intermittent and not always available. Until large scale battery storage becomes widely available at a low enough cost, many renewable energy sources are only available during when their energy source is available -- solar generation occurs during daylight hours, wind generation is only available when winds are blowing. This intermittency of renewables, their lack of dispatchability, and currently high cost of energy storage makes planning and managing the electricity grid more difficult.

With intermittent generation sources, managing energy demand is a critical part of maintaining grid stability. Historically, generation would be modulated to match demand, but with intermittent supply from renewables now it’s the other way around. Demand is altered to match generation. Agricultural loads, with their large magnitude and uniformity, have the potential to satisfy a significant portion of that critical resource.

DEMAND MANAGEMENT

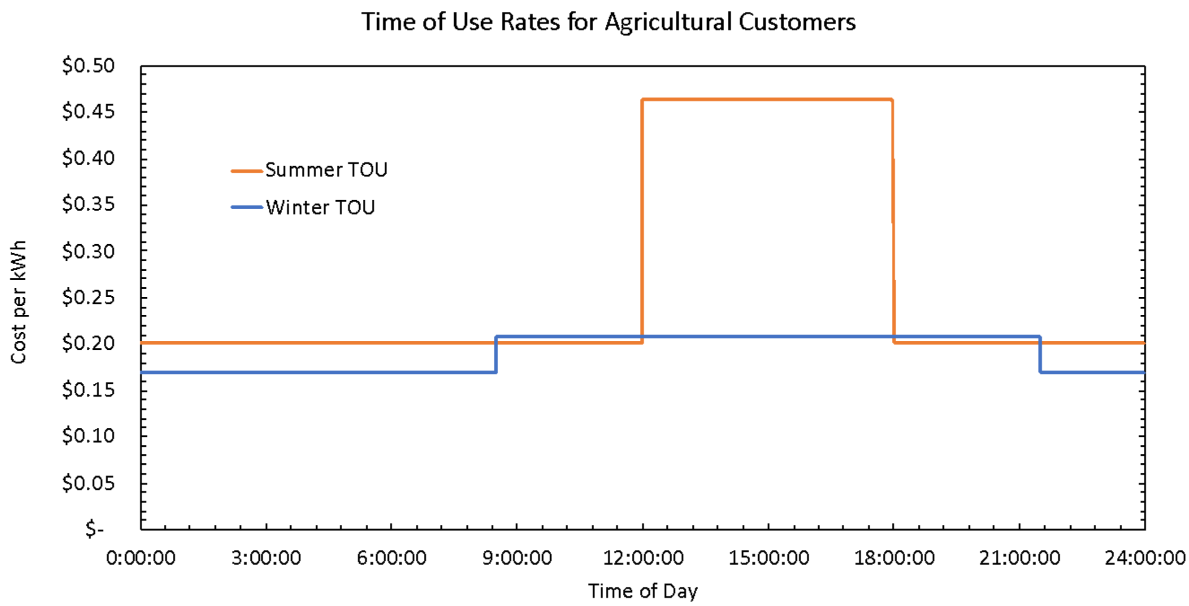
The term demand management encapsulates any mechanism through which and end users’ demand is modified in order to benefit the grid. In return, end users are compensated either through incentives or lower rates. The most common demand management strategies are Time of Use (TOU) pricing and various forms of Demand Response (DR) or Automated Demand Response (ADR). An emerging approach which may be better suited to address the future grid needs is Real-Time Pricing (RTP) through a Transactive Energy (TE) market mechanism.

In this section we discuss each of these mechanisms and identify some of the benefits and drawbacks of each. This is followed by cost benefit analysis of each demand management approach at a farm setting – and how much things will vary from one farm to another. Three farms, each with different pumping demands and irrigation management constraints, are analyzed for baseline energy use and three demand management scenarios: TOU, DR, and RTP. All data is from the 2018 growing season in California’s San Joaquin Valley.

Time of Use (TOU)

Time of Use pricing aims to re-shape the underlying load profile through long duration price responses that are announced months ahead of time and change seasonally. TOU rates are typically higher during peak hours (hours with highest demand for electricity) and lower during off peak hours. Figure 1 shows an example of TOU rates for agricultural accounts in the Pacific Gas and Electric (PG&E) territory in California.

Figure 1: Time of Use Rates for PG&E Agricultural Customers (Based on AG4A rates per kWh 9/1/18)



TOU has historically been the most cost-effective option for modifying load shapes. A recent study conducted by LBNL for California Public Utilities Commissions (CPUC, 2016) estimates that time of use pricing is particularly cost effective because few site-level technologies are required for enablement. While the load reduction at any given site is typically small, the breadth of participation – possibly for a variety of rates schedules that currently exist – we can see substantial statewide effect/benefit. With 60% of all growers in California taking part in some form of TOU scheduling, this is by far the most widely used demand management program in agriculture. With the goal being to avoid peak energy rates, there are many different approaches.

Pros of TOU:

- Low cost of implementation
- No need for program management, it's completely up to the customer to modify load based on the rate

Cons of TOU:

- Rates need to be constantly updated to reflect the latest grid status
- Requires largest numbers of customers to respond to the rates in order to achieve its goal

- Predictable outcome. In aggregate, result from a TOU rate is predictable

- Irrigation systems during peak season may require schedules shift to irrigate during peak hours.

Demand Response (DR/ADR)

DR and ADR is referred to strategies that encourage end-users of electricity to shed or shift their load for economic or reliability reasons. DR is commonly referred to strategies that are implemented manually, and ADR refers to automatically adjusting loads based on the signals received from the utility or the Independent System Operator (ISO).

DR and ADR programs are often supported by third party aggregators who act as an intermediary between the farm and the utility, vetting the farm's energy use history and setting up the contracts and hardware that might be required to monitor and control pumps and power supplies, enabling the farm to profit from the curtailment calls. Curtailments are typically announced in advance by as much as 24 hours or as little as 30 minutes. With DR, the curtailment call comes to the grower asking if they can shut down their pumps for a set amount of time lasting anywhere between 30 minutes and 4 hours. With and ADR program, unless the grower opts out ahead of time, the pump is controlled automatically.

With most DR and ADR programs, growers sign agreements to take part in a minimum number of curtailments during the season. Failure to fulfill these agreements results in penalties -- penalties vary and are determined in a case by case basis but in general failure to curtail up to 60% of the nominated capacity, will result in penalties as high as 60% of the capacity payment (PG&E, 2013).

Pros of DR/ADR:

- Ensuring grid reliability when demand exceeds generation
- Cost and environmental benefits by avoiding expensive and polluting peaker plants form going online
- If done correctly can result in cost saving for the customer

Cons of DR/ADR:

- Complex utility programs
- DR/ADR and TOU are in conflict (doing TOU lowers DR potential)
- Baselining issues with DR programs. 10-day baseline causes farm to not be compensated based on their actual load shed/shift
- Running DR programs are costly for the utilities
- Grid needs have evolved but the framework of utility DR programs have stayed the same

- Without automation, responding to DR is a huge undertaking, especially in a farm setting
- Short notification periods with penalties to follow if the end user misses the notification
- Long gaps in irrigation for cotton, of ten days or more, create a negative incentive for DR (see graphic)

Real-Time Pricing and Transactive Energy (RTP/TE)

Real-Time Pricing and Transactive Energy are demand management for the "smart grid." Both provide the customer with greater transparency and control over energy pricing opportunities, allowing the user to find energy pricing that more effectively meets their needs. Both rely on "smart metering" and interactive smart grid infrastructure. Both provide the customer with more control. And both avoid the baseline problem of DR. Transactive Energy also provides pricing and control systems for distributed energy resources (DERs), micro-grids, and peer-to-peer exchange. TE is designed for the current trend of increasingly distributed, renewable energy generation, and to provide greater economic and management stability in a future of increasingly dynamic energy markets. RTP tariffs are offered by some utilities. TE provides a platform through which loads and electricity generators can directly communicate. As a market mechanism, TE is still in the demonstration and testing phase.

Pros of RTP/TE:

- No need for program management; similar to TOU everything is left up to the customer
- The rates are much more dynamic and allows the utility to adjust rates in real-time to reflect the status of the grid (allows for pricing of congestion or greater availability, for example)
- TE enables decentralized, local, peer-to-peer, and micro-grid energy exchange

Cons of RTP/TE:

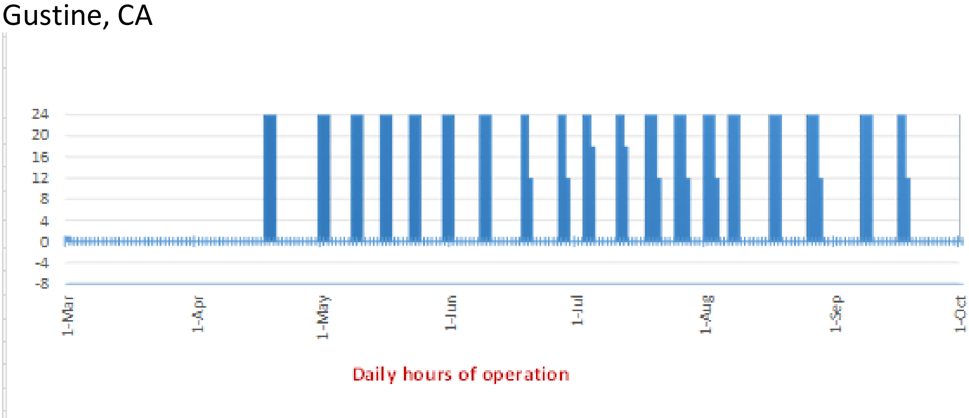
- Requires high level of automation and communication (e.g. Smart grid infrastructure; OpenADR communication protocols)
- Almost all RTP rates offered through utilities are experimental
- TE as a control and pricing mechanism is still in an experimental stage

- Unlike DR, end users can plan ahead of time; or adjust operations in real-time
- Unlike DR, No penalties for participation or opting out
- Unlike DR, there is no program management required
- Avoids the baseline problem of DR
- Low cost (or no cost) to implement (once Smart grid or OpenADR are established)
- If proven successful, TE rates need to be approved by the Public Utilities Commission, which could be a significant hurdle

ANALYSES OF THREE FARMS

We tracked the 2018 irrigation season for three cooperating farms in California's San Joaquin valley, including their energy use requirements, irrigation strategy (irrigation dates, amounts and set times) and the resulting soil moisture profiles, each farm's unique irrigation system, pumping demands (measured as total dynamic head), soil moisture holding capacity, climate and weather, and seasonal crop water demands. Using this information as a baseline, we modeled each site and analyzed three different demand management scenarios (TOU, DR, and RTP), and calculated the irrigation timing strategies necessary to meet each demand management approach, and the cost of energy for each strategy based on the unique constraints of each location.

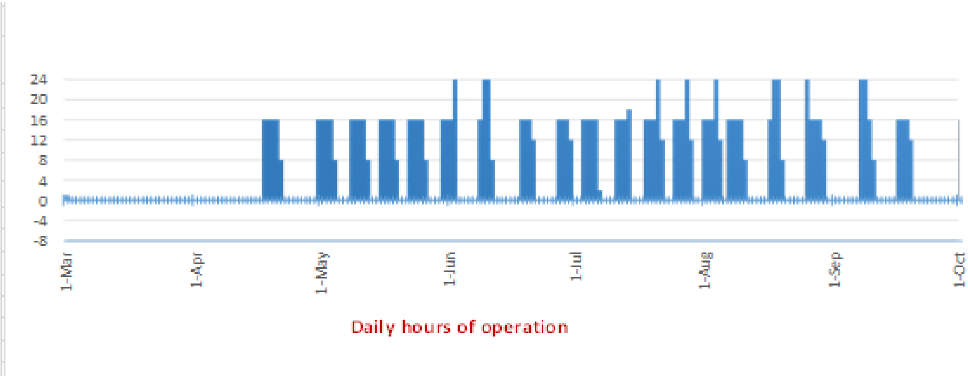
Gustine, CA



TDH	85
Application rate (in/hr)	0.064
Acres	92
Power (kW)	21
Sets	3
Baseline energy cost	$9,020
Revised energy cost	$9,020
Capacity pmt	$0
Energy pmt	$0
Net gain	$0
Net gain per acre	$0

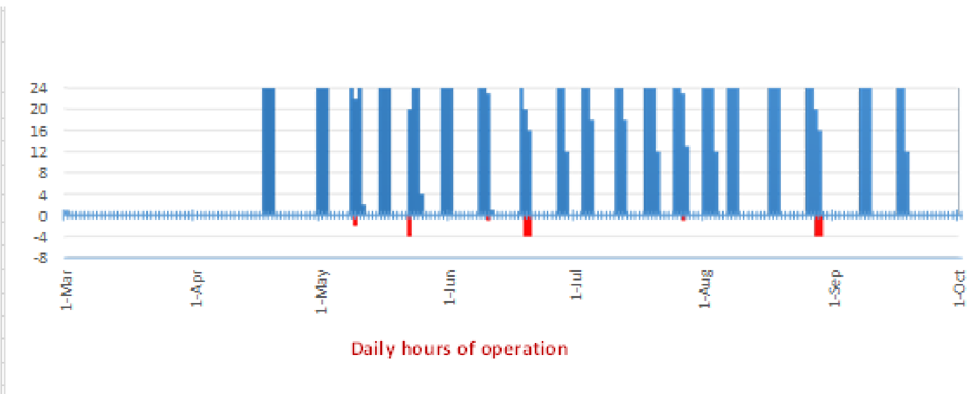
The Gustine site is a small family almond orchard (92 acres) on soils that are two types of sandy loam and a significant amount of river rock. Their pumping lift is minimal (TDH = 85) as their water comes directly from a canal beside the orchard. The blue bars in the graph, above, show the irrigation times and amounts of their 2018 season. Using this as a baseline, the following two graphs show alternative irrigation timing strategies for TOU and DR. Their baseline energy costs is: $9,020, or $98 acre.

The TOU strategy (below) generated for the Gustine site, shifts the start and stop times to avoid peak hours, producing a savings of $2,419, or $26 acre.



TDH	85
Application rate (in/hr)	0.064
Acres	92
Power (kW)	21
Sets	3
Baseline energy cost	$9,020
Revised energy cost	$6,600
Capacity pmt	$0
Energy pmt	$0
Net gain	$2,419
Net gain per acre	$26

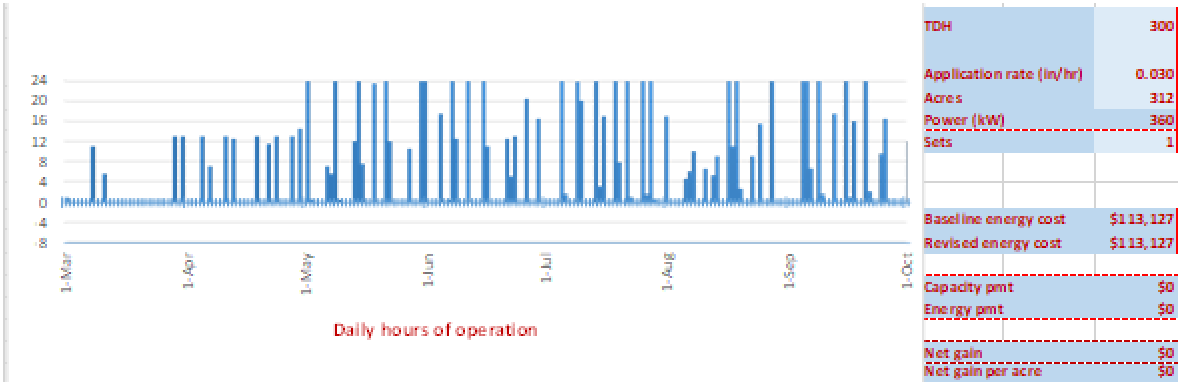
The next graph, below, looks at the economic potential of following their standard schedule while using a DR program at the same site. The red bars below the irrigation times indicate actual DR calls during the 2018 season. Had the irrigator shut down with each DR call, they would have realized a savings of $691, or $8 an acre.



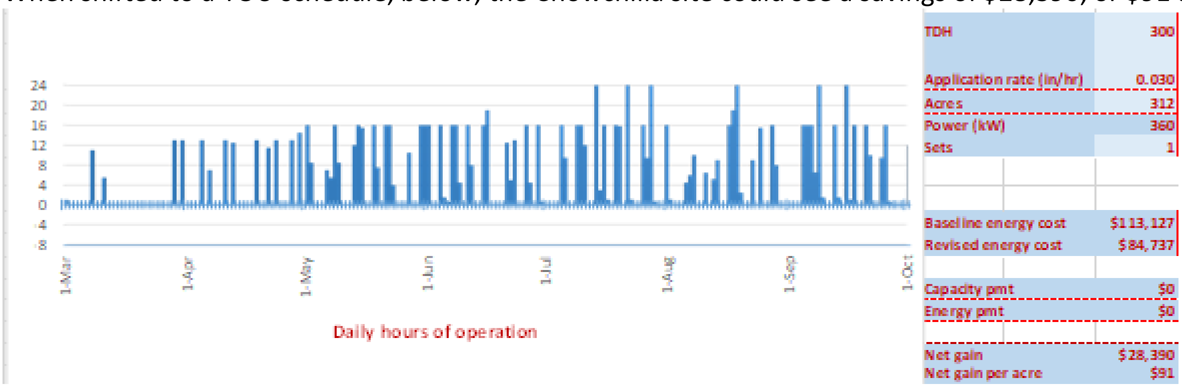
TDH	85
Application rate (in/hr)	0.064
Acres	92
Power (kW)	21
Sets	3
Baseline energy cost	$9,020
Revised energy cost	$9,020
Capacity pmt	$657
Energy pmt	$33
Net gain	$691
Net gain per acre	$8

Chowchilla, CA

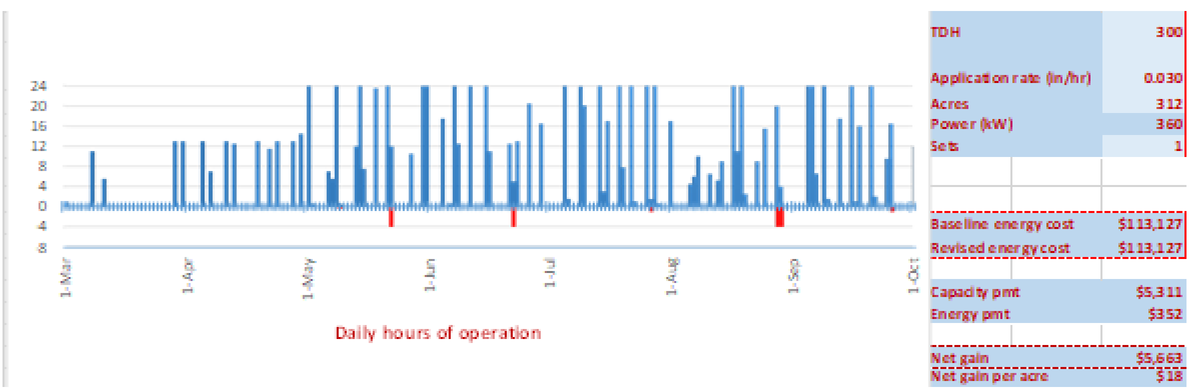
The Chowchilla site is one field (almonds) of a much larger ranch, using deeper wells at a much higher energy cost. There are a range of 10-15 different soils across the ranch. The irrigation system uses fan jets. The graph, below, shows their 2018 season, with a baseline energy cost of $113,127, or $362 per acre.



When shifted to a TOU schedule, below, the Chowchilla site could see a savings of $28,390, or $91 acre.

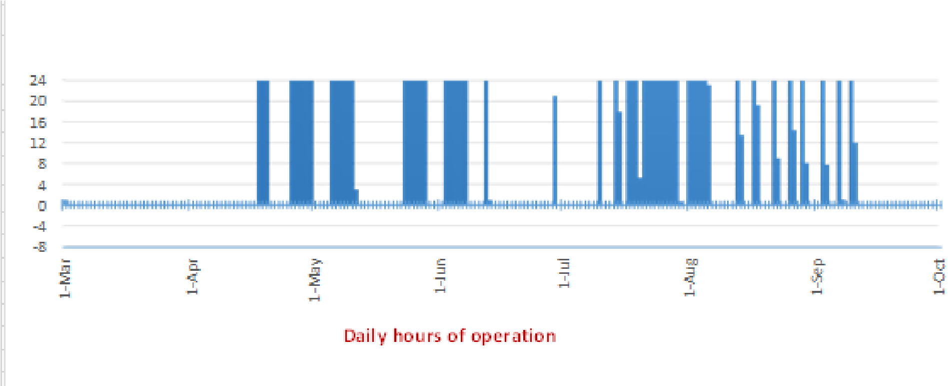


If irrigators at the Chowchilla site had taken advantage of DR events during the 2018 season, below, they would have realized a savings of $5,663, or $18 acre.



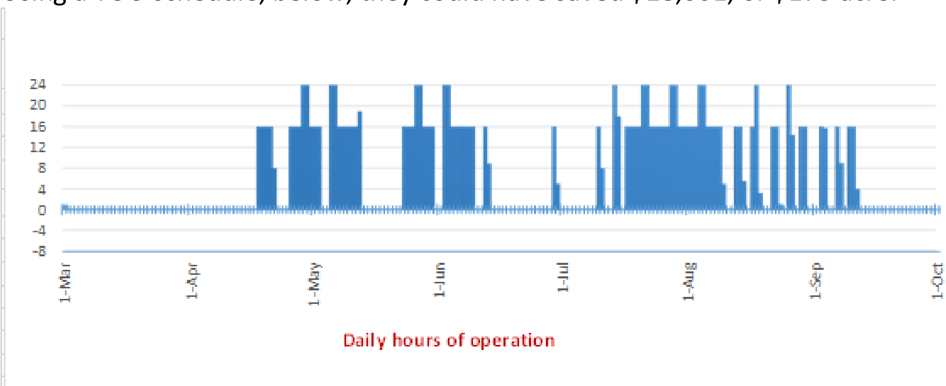
Five Points, CA

This site, below, differs from the other two in a couple significant ways. The soils are heavy loams with much higher holding capacity. The irrigation system is subsurface drip. And the crop is Pima cotton. Their baseline energy cost for 2018 was: $118,743, or $742 acre.



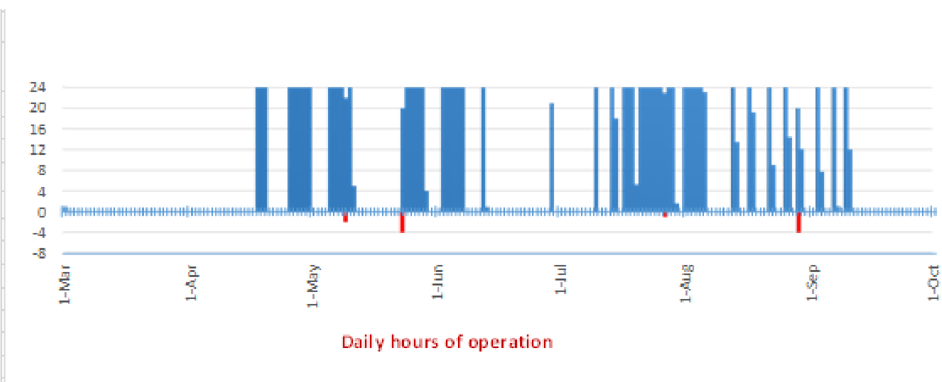
TDH	1000
Application rate (in/hr)	0.042
Acres	160
Power (kW)	287
Sets	3
Baseline energy cost	$118,743
Revised energy cost	$118,743
Capacity pmt	$0
Energy pmt	$0
Net gain	$0
Net gain per acre	$0

Using a TOU schedule, below, they could have saved $28,061, or $175 acre.



TDH	1000
Application rate (in/hr)	0.042
Acres	160
Power (kW)	287
Sets	3
Baseline energy cost	$118,743
Revised energy cost	$90,682
Capacity pmt	$0
Energy pmt	$0
Net gain	$28,061
Net gain per acre	$175

The analysis for a DR strategy for this site produced an interesting finding. Guided by the soil moisture conditions and crop stress, the irrigator was able to pause between irrigations for more than ten days. As a result, when the second DR event was called, under the 10-day baseline rules of the DR program, they would incur a financial penalty had they chose to respond to the DR curtailment request. As a result, their savings using DR would have been, $10,484, or $66 acre.



TDH	1000
Application rate (in/hr)	0.042
Acres	160
Power (kW)	287
Sets	3
Baseline energy cost	$118,743
Revised energy cost	$118,743
Capacity pmt	$10,272
Energy pmt	$213
Net gain	$10,484
Net gain per acre	$66

SUMMARY OF THREE FARMS

This analysis suggests that TOU strategies for demand management are more profitable for irrigated agriculture than DR programs. This also supports the larger trend in irrigated agriculture towards adoption of TOU demand management programs and suggests why DR programs have seen less adoption. This analysis is based on the soils, seasonal weather, age of the orchard and irrigation system constraints at this site. While each farm represents a different irrigation and energy use management challenge, there are some clear benefits for irrigators using TOU strategies. DR is more complicated, less profitable, and costlier to implement and manage than TOU.

CHALLENGES

For irrigated agriculture to successfully participate in these programs and provide value both to the grid (as change in demand) and the farm (as financial incentives), several barriers need to be addressed: (i) Automation; (ii) Irrigation timing and system constraints; (iii) DR programs are complex and poorly aligned for agriculture.

Automation

If irrigated agriculture is to work seamlessly with energy markets, agriculture needs to be integrated with the smart grid in ways and with technologies unique to agriculture. Many irrigation systems still require someone to visit the pump and manually turn it on or off. In many cases data about the field -- flow meter and pressure data -- are also collected manually. To make irrigated agriculture a more flexible, adaptable and profitable participant in energy markets, irrigated fields need to communicate directly with the grid.

From the utility side, connecting agriculture to the smart grid means pumps equipped with smart meters and automated start and stop controls to enable the pump to shut down quickly. But for an irrigator, a market signal to the smart meter on the pump is only a small piece in a chain of evaluations, decisions and actions that must be made about the irrigation system (valves, gates, filters) and crop health (soil moisture profile, stem water potential, crop stress, weather forecasts). For irrigated agriculture to optimize the economics of their energy use and work profitably with the grid, automation solutions should go beyond the smart meter to include remote control of valves, gates, and filter stations, as well as the automated transmission of field data (flow meter and pressure, soil moisture, climate, weather, crop stress), and software to track, interpret and generate decisions based on this data. The smart meter for an irrigation pump should connect to a smart meter for the crop and irrigation system.

Irrigation Timing and Irrigation System Constraints

Crop yields are directly proportional to the amount of water a crop receives and uses over the season. The standard measurement of this relationship between water and yield is evapotranspiration (ET). How easily an irrigator can participate in a demand management program, such as TOU or DR, depends on the limits of the irrigation system and the irrigators ability to keep up with ET. Because many irrigation systems are designed to meet ET during peak season, the opportunity to stop irrigations during the hottest times of the year is limited, but not impossible.

For irrigators to work with demand management with irrigation systems at full capacity during peak season requires the ability to predict how each irrigation will shape the of soil moisture profile going forward to meet crop water demand and crop stress. This level of precision makes it possible to do two things: (i) identify irrigation strategies below full ET --deficit irrigation; and (ii) estimate the impact, positive or negative, of different irrigation timing strategies -- including deficit irrigation -- on crop stress and yield outcomes. This will enable the irrigator to more easily see the potential to get behind in ET and the risks to the crop of reducing an irrigation, running different combinations of irrigation intervals (for TOU), or moving an irrigation to a different time to profit from demand peaks (for DR and TE).

Risk to Pumps and Demand Charges

This analysis did not look at the risk to pumps or the potential for demand charges that might be encountered by following DR or TOU programs.

Deep groundwater wells in particular can be very expensive, and thought to have a limited number of starts/stops before damage or failure. If the expected value of the well's damage (failure cost * failure probability) is higher than the incentives to participate, then participation is financially unwise. Even moderate or shallower wells can incur some damage from increased start/stops, and so can the pumps, unless they have soft start/stop capabilities (Olsen, et. al., 2015).

DR Programs are Complex and Poorly Aligned with Agriculture

Currently a suite of DR incentive programs are offered through the utilities and third-party aggregators. However, they are not well suited for adoption by irrigated agriculture for two reasons. First, they are complex to set up, manage and verify. And second, they are poorly aligned with actual farm practices.

Mechanisms through which a farm can be approved for DR, participate in DR events, and receive compensation are complex. Most farms lack the in-house expertise for going through the entire process without the help of external consultants or DR aggregators.

In addition to DR program complexities, DR programs are poorly aligned with actual farm practices. Stringent baseline energy use requirements put in place by the utilities deter, and even disincentivize, agricultural customers from participating. Specifically, the use of a 10 day baseline in order to determine incentive payments, based on the past 10 days of the the participant's energy use. If there is no energy used for the 10 days prior to the DR event, the DR incentives will be significantly reduced, and the participant will not be appropriately compensated for the load shed provided.

CONCLUSION

- TOU demand management programs offer the most profit to the irrigator, with the least amount of complexity; but calculating, planning and implementing full season TOU strategies comes with technical challenges, including irrigation system limitations and the ability to identify timing strategies that meet crop water requirements mid-season.
- DR program complexity and incentives are poorly aligned with the needs of irrigated agriculture, in some cases incentivizing growers to avoid providing loads even when they can, due to the 10 day baseline requirement.
- Demand management programs, in general, present technical challenges for the irrigator because many irrigation systems are designed to meet crop water demands at peak ET without regard for shutdowns.
- To engage with the dynamic, variable market signals RTP and TE make possible, irrigators participating in demand management need ways to precisely calculate how each irrigation will shape their soil moisture status so that they can (i) plan a season using the most cost effective energy timing schedule; and (ii) quickly evaluate how a change in their irrigation schedule presents a risk to the crop and the best way to rebalance their irrigation times to profit from market signals. This sort of crop water status monitoring and forecasting tool would benefit TOU and DR programs as well.
- Real time Pricing and Transactive Energy markets suggest even greater profit potential for irrigators, but demonstrations of TE markets working with irrigated agriculture are needed.

- TOU offers a no cost approach in reshaping load shapes. Historically, TOU has observed the highest level of participation by end users. However, TOU rates are not dynamic and they only change seasonally. Existing TOU rates, put in place by California utilities over a decade ago, define the hours of noon to 6pm, as peak periods. Those hours are now the same hours with highest level of solar generation, which is why utilities have proposed adjusting TOU periods to later in the day (4pm-9pm) to mitigate the steep ramps in demand during the evening hours.
- Dedicated tools, such as a decision support system (DSS), for monitoring the status of crop could enable irrigated agriculture to more profitably and effectively support demand management and
- ADR/DR may not be as profitable as TE/TOU
- The infrastructure needed for a full TE implementation will directly benefit DR.

NEXT STEPS

- Developing DSS to coordinate management calculations
- Evaluate the benefits of automated data / better field monitoring
- Evaluating incentives of TE for farm energy management

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