Title

Intermittent Renewable Management Pilot Phase 2:

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The authors would like to thank all the participants for their support and continued engagement through the pilot, and the California Independent System Operator and California Public Utilities Commission for their ongoing guidance and support.

Disclaimer

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Abstract

The Intermittent Renewable Management Pilot - Phase 2 (IRM2) was designed to study the feasibility of demand-side resources to participate into the California Independent System Operator (CAISO) wholesale market as proxy demand resources (PDR). The pilot study focused on understanding the issues related with direct participation of third-parties and customers including customer acceptance; market transformation challenges (wholesale market, technology); technical and operational feasibility; and value to the rate payers, DR resource owners and the utility on providing an enabling mechanism for DR resources into the wholesale markets.

The customer had the option of committing to either three contiguous hour blocks for 24 days or six contiguous hours for 12 days a month with day-ahead notification that aligned with the CAISO integrated forward market. As a result of their being available, the customer was paid $10/ kilowatt (kW)-month for capacity in addition to CAISO energy settlements. The participants were limited to no more than a 2 megawatt (MW) capacity with a six-month commitment.

Four participants successfully engaged in the pilot. In this report, we provide the description of the pilot, participant performance results, costs and value to participants as well as outline some of the issues encountered through the pilot.

Results show that participants chose to participate with storage and the value of CAISO settlements were significantly lower than the capacity payments provided by the utility as incentive payments. In addition, this pilot revealed issues both on the participant side and system operations side. These issues are summarized in the report.

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Executive Summary

The Intermittent Renewable Management Pilot - Phase 2 (IRM2) was designed to study the feasibility of demand-side resources to participate into the CAISO wholesale market as proxy demand resources (PDR). The pilot concentrated on understanding the issues related with direct participation of third-parties and customers including customer acceptance; market transformation challenges (wholesale market, technology); technical and operational feasibility; and value to the rate payers, DR resource owners and the utility on providing an enabling mechanism for DR resources into the wholesale markets.

PDR requirements include the resource can be one or more customer locations bid and dispatched as a single resource with a minimum of 100 kW load shed. The participant had to be served by a single Load Serving Entity (LSE) and all of the resources had to be located within a single Sub-Load Aggregation Point (sub-LAP).

The customer had the option to commit to either three contiguous hour blocks for 24 days or six contiguous hours for 12 days a month with day-ahead notification that aligned with the CAISO integrated forward market. As a result of their being available, the customer was paid $10/kW-month for capacity in addition to CAISO energy settlements. The participants were limited to no more than 2MW capacity with a six-month commitment.

Participants bid a quantity (nomination) and a price each month. A maximum capacity value, called the qualified capacity, was identified in a pre-operational test. The pre-operational test was a three or six hour test where the average of load shed delivered during these hours defined the qualified capacity. Subsequent nominations were at or below this qualified capacity value and were commitments to provide energy. Nominations were the basis for retail settlements and CAISO bidding requirements. Within each block, each hour's energy should be at or above the nomination value to fulfill the requirement. Bid price for this pilot was designed at or above the net benefits test with a ceiling also identified at $150/MW. Once a participant bid 30 hours, their obligation to bid ended but participants could bid in addition to these requirements to maximize the value from the pilot. Bids were entered into the Olivine system no later than 8:30 AM day-ahead and award notifications were received by 2 PM day-ahead.

The capacity payments had no penalties and excluded energy payments. They were settled at the enrollment but it was forfeited if bidding requirements were not fulfilled. Wholesale settlements were at the PDR level and participants were paid for over-delivery at the real-time price and charged the replacement cost for under-delivery at the real-time price. All grid management charges were covered by PG&E.

Of the sixteen potential participants, including large individual sites, community choice aggregation entities and demand response providers, with which Olivine had ongoing discussions over several months, there were five participants in the pilot as of October 31, 2014. There were varying reasons some of the sites or entities could not participate in the pilot and these included the following:

- The prospective participant had concerns about the resource not being flexible enough to participate in the program. This prospective participant had a large discrete load which could not accommodate a potential partial award from the market, and there was some concern about the risk associated with over delivery. In addition, dual participation restrictions effectively meant that participating in the

IRM2 would have meant forgoing the capacity payments from other DR programs on a portion of their total load capability.

- The prospective participant could not reach the resource requirements. For example, did not have enough customers from a single LSE within a sub-LAP and did not have time to recruit enough sites to meet these requirements.
- The prospective participant actually had no customers.
- Direct access customers had delays in participation. For all locations, the ISO requires an agreement between the LSE of the customers and the DRP. ESPs must also register for inclusion in the ISOs DRS system to validate their customers. Unless the customer yields significant leverage, certain ESPs are reluctant to take these steps due to uncertainty around the process and potential competitive concerns.

Table ES-1 summarizes the qualified capacity by end uses that deliver these reductions for each participant. We contacted each participant to receive permission to publish their names and only one participant, Site 1, asked to remain anonymous. County of Alameda participated with the Santa Rita Jail, which is a microgrid and has experience in participating in demand response and automated demand response over the years. Google had two sites that provided reductions by rescheduling their electric vehicle charging. NW Natural enrolled in the pilot and got certified but actually did not bid into the market. Their participation strategy involved rescheduling run time of compressors. Stem participated using aggregated distributed storage systems.[1] Of these 5 sites, only three of them actually enrolled, bid into the market, received awards, delivered reductions and received payments for their participation. While Google sites did bid into the market, they did not receive awards and were ultimately removed from market bidding due to challenges with reliably obtaining meter data (detailed discussion is included in the following section). NW Natural did not bid into the market.

Site Name	Qualified Capacity Reduction (kW)	Lighting	HVAC	Other
Site 1	500			x
County of Alameda, SRJ	810	X	X	X
Google	100		X	X
Google	100		X	X
NW Natural	3080 (capped at 2000)			X
Stem	120			X

Table ES- 1 Participants, their qualified capacity and end uses

Each site's participation is summarized below with a section that summarizes the lessons learned from this pilot:

Alameda County:

[1]http://www.greentechmedia.com/articles/read/aggregating-building-batteries-into-grid-resources

- Bid into the market with over 800 hours during their participation. Received awards for 13 hours.
- Participated with demand shed achieved from HVAC and lighting loads as well as utilizing their fuel cell.
- Provided the highest performance with close to 100% adjusted performance each month they participated.
- Received $85,160 from capacity incentives and about $648 from CAISO settlements

Stem:

- Bid into the market with over 500 hours during their participation. Received awards for 16 hours.
- Participated with aggregation of distributed batteries. .
- Provided high performance, on average 95% adjusted performance each month they participated.
- Received $6,550 from capacity incentives and about $16 from CAISO settlements.

Site 1:

- Bid into the market with over 225 hours during their participation. Received awards for 16 hours.
- Participated with stationary battery storage behind the meter of a highly variable and large load.
- Provided low performance at the whole-premises level with an average of 68% adjusted performance each month they participated; however, the performance of the controlled storage asset was closer to 100%.
- Received $6,788 from capacity incentives and no payments from CAISO settlements.

NW Natural never actually bid into the CAISO market and Google had meter issues that prevented them from being reliably bid into the CAISO market.

Lessons Learned

We categorize the lessons learned in this pilot into customer acceptance, market transformation challenges (wholesale market, technology), technical and operational feasibility, and value to participants.

Customer acceptance:

- Prospective participants were mostly highly experienced with DR and baselines.
- Participants with variable loads were concerned about the accuracy of the PDR baseline.
- Participants with controllable loads that were discrete (i.e., all on or off), without flexibility move under the nomination, chose not to participate.
- Where the resource size met the minimum CAISO requirement but the resource was behind large variable loads, while the resource performed as expected, it was not visible from the baseline.
- All participants that received payments, participated in using their storage systems or in deferring vehicle charging.

Market transformation challenges:

- Aggregators approached did not have sites within a sub-LAP or did not have time to recruit and enable enough sites to make up for the resource size within a sub-LAP.

- Most of the sites were semi-automated with manual bid entry and semi-automated response at the sites.

Value to participants:

- ISO settlements were significantly less than the retail capacity incentives and did not result in significant value for the participants.
- With the set up costs (about $25,000) and operating cost ranges ($2,500 -$10,000), and the given $10/kW capacity incentive, a minimum of 12 month participation with a resource size between 460 kW and 1210 kW is required to cover the SC costs.

Operational feasibility

- Problems with CAISO processes, systems and settlement issues were identified and were brought to the CAISO's attention. These problems included
    - Incorrect calculations of Default Load Adjustment,
    - Unobserved minimum run time, which is an operational parameter stored in the resource data template, and
- Delays due to LSE / DRP agreement requirement for direct access customers.
- Problem with the regular retrieval of revenue quality meter data, particularly when site conditions change (e.g., service account changes or meter changeout occurs).
- Training is needed for customers to understand the basic ISO market operations, baselines, determining load shed strategies in response to program requirements, quantifying nominations, qualifying capacity, understanding retail incentives and wholesale settlements.
- Despite consistent efforts to engage conventional aggregators, there was no participation. The pilot could be richer if aggregators made use of the training and had first-hand experience in participating in PDR.

Conclusion and Next Steps

In this pilot, we concentrated on understanding the issues related with direct participation of third-parties and customers in CAISO's PDR model including customer acceptance; market transformation challenges (wholesale market, technology); technical and operational feasibility; and value to the rate payers, DR resource owners and the utility on providing an enabling mechanism for DR resources into the wholesale markets. We summarize lessons learned in these four areas.

As of the writing of this report, the follow on to IRM2 is underway. This new pilot, the Supply Side Pilot (SSP), continues with the objective of engaging participants in a third-party wholesale integrated capacity program. It also moves beyond day-ahead energy provided by C&I customers, enabling:

- Participation by residential customers.
- Participation in real-time energy and non-spinning reserves.
- A simplified program design, particularly around the wholesale market pricing rules.
- A program design that is more closely tied to resource-adequacy must-offer-obligations. For example, this results in a single 4-hour contiguous block instead of the 3 and 6-hour block options in IRM2.

The SSP is scheduled to run through December, 2016.

CHAPTER 1: Introduction

Background

New California policies, establishment of new state's goals and penetration of new end use technologies continuously add complexity to the future grid needs. In addition, California Independent System Operator (CAISO) identified that with the 33% penetration of renewables, net load to be served will have steep ramps during winter and spring with significant changes expected in 2015. These changes in net load, policy and technology require CA to evaluate which resources can address the future grid needs. In this project, demand responsive loads are being considered as one of the many resources that can support economical and reliability needs of the future grid. In addition to traditional DR that addresses summer peak shaving, new DR offerings must be constructed in order to meet future transmission and distribution grid needs.

This is the second phase of the Intermittent Renewable Management project. During the first phase, three facilities, two commercial buildings and one industrial facility, were equipped with automated demand response (AutoDR) and telemetry equipment and were tested for response time, duration and latencies (Kiliccote et al. 2010). As part of their 2012-2014 Demand Response (DR) application, Pacific Gas and Electric Company (PG&E) requested funding to conduct the second phase of the pilot demonstration, which is focused on providing fast responding resources to help renewable integrations, specifically regulation, net load following, and ramping needs. The objective for this pilot is to demonstrate with third-party aggregators and large commercial and industrial customers that DR resources can participate in the CAISO wholesale market and provide flexible resources.

In this second phase, the pilot program was designed so resources could bid into the CAISO wholesale market as proxy demand resources (PDR). The pilot concentrated on understanding the issues related with direct participation of third-parties and customers including the following:

- Customer acceptance;
- Market transformation challenges (wholesale market, technology);
- Technical and operational feasibility; and
- Value to the rate payers, DR resource owners and the utility on providing an enabling mechanism for DR resources into the wholesale markets.

Introduction

At the time this pilot program was designed and operated, PG&E had no demand response programs integrated into the wholesale markets. The last program that PG&E was effectively bidding into the wholesale market as PDR was PeakChoice, which was closed end of 2012.

This pilot was designed to facilitate daily energy bids into the wholesale market in usable blocks with retail capacity incentives provided from the utility so as to understand if:

- DR is able to provide valuable capacity through utility agreements; and

- resources are able to bid directly into the wholesale market providing support for the integration of intermittent renewables into the grid and valued as a supply resource.

This second phase of the pilot program, called IRM2, involved a monthly participation with ISO bidding requirements. The customer had the option of committing to either three contiguous hour blocks for 24 days a month or six contiguous hours for 12 days a month with day-ahead notification that aligned with the CAISO integrated forward market (IFM) market. As a result of their being available, the customer was paid $10/kilowatt (kW)-month for capacity. Olivine, Inc. served as the program administrator and took on scheduling coordination for third party and customer resources. For initial participation, prospective participants were required to commit their resources for six months and the minimum resource size was 100 kW. Figure 1 displays the concept for integration of the retail resources with wholesale PDR model.

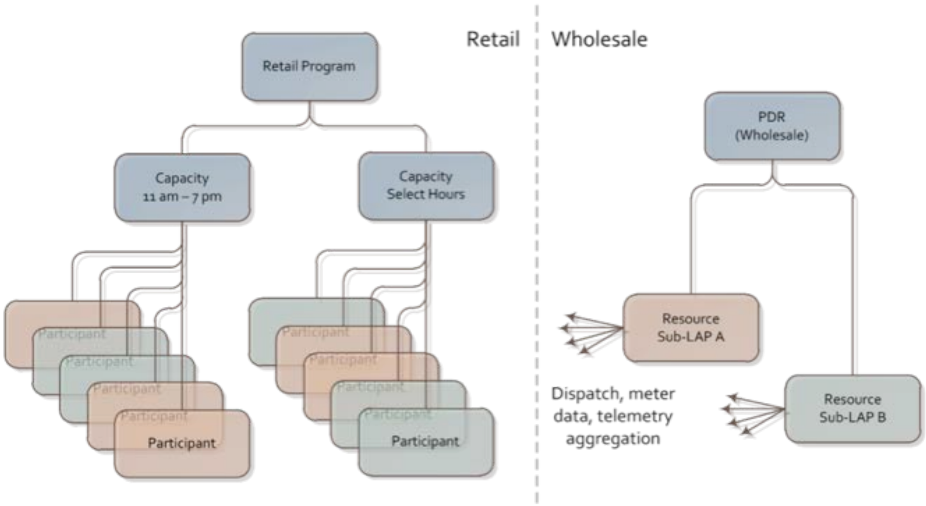


Figure 1. Concept for integration of retail and wholesale DR (Source: Olivine)

The pilot team and roles and responsibilities are identified in their boxes in Figure 2. Large single customers and aggregators both could participate in IRM2. Participants could get assistance in developing DR strategies from Lawrence Berkeley National Laboratory's (LBNL) Demand Response Research Center (DRRC). Olivine acted as a scheduling coordinator (SC) and wholesale market demand response provider (DRP). It provided the sole interface between participant and pilot, including the CAISO market and handled recruitment, enrollment and registration; nominations and bidding; award and dispatch notifications; meter data aggregation and submissions; resource certification; credit and collateral; and settlements and payments. Lawrence Berkeley National Laboratory (LBNL) assisted with recruitment, DR strategy development, surveys and reporting.

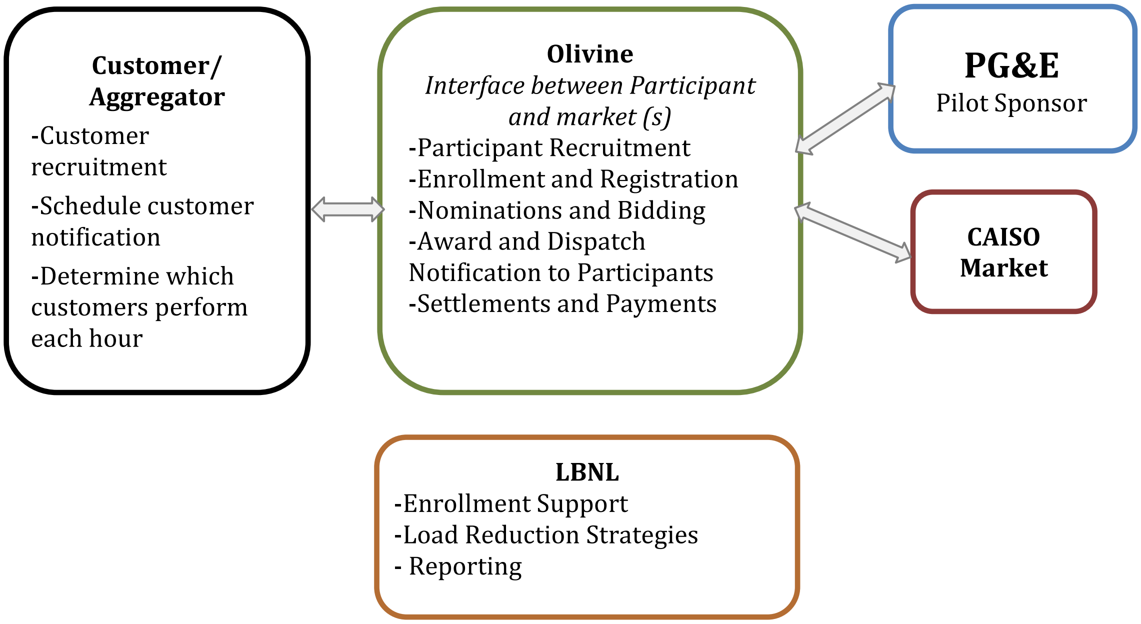


Figure 2. Entities involved in the pilot and their roles

Chapter 2: Methodology

Process Description:

The pilot design modeled the elements of similar must-offer contracts. The participants were limited to no more than 2MW capacity with a six-month commitment and participated in the CAISO's Proxy Demand Response (PDR) model. The initial phase was designed to be day-ahead energy only with second phase expansion envisioned to capture real-time energy and potentially ancillary services. Capacity (retail) payments were provided to each customer as well as wholesale payments/charges for bidding activity. In this pilot, OpenADR implementation was optional. Potential participants filled out a declaration of interest, and provided detailed information on locations, load shed, and meter identification. Once completed, the enrollment was reviewed and approved. Following the enrollment, the participant signed a participation agreement. Each enrollment had a monthly nomination, was bid and dispatched in unison, had a single retail settlement, was subject to a test before becoming operational, and had to adhere to CAISO's PDR requirements.

PDR requirements specified that the resource could be one or more customer locations bid and dispatched as a single resource with a minimum of 100 kW load shed. The participant had to be served by a single Load Serving Entity (LSE) and all of the resources had to be located within a single Sub-Load Aggregation Point (sub-LAP).

Participants made a monthly kilowatt nomination for each enrollment. A maximum capacity value, called the qualified capacity, was identified in a pre-operational test. The pre-operational test was a three or six-hour test and an average of load shed delivered during these hours qualified. Subsequent nominations were at or below this qualified capacity value and were commitments to provide energy. Nominations were the basis for retail settlements and CAISO bidding requirements. Within each block, each hour's energy had to be at or above the nomination value to fulfill the requirement, nothing that participants could bid in addition to these requirements. Bid price for this pilot was designed at or above the net benefits test with a ceiling also identified at $150/MW. Had a participant been awarded for 30 hours, their obligation to bid would end, though this did not occur during the pilot. Bids were entered into the Olivine DER system no later than 8:30 am day-ahead and award notifications were received by 2 pm day-ahead.

The capacity payments had no penalties and excluded energy payments. They were settled at the enrollment but it was forfeited if bidding requirements were not fulfilled. Wholesale settlements were at the PDR level and participants were paid for over-delivery at the real-time price and charged the replacement cost for under-delivery at the real-time price. All grid management charges were covered by PG&E.

Enrollment changes could be made for subsequent months, including adding or dropping locations to the PDR. In addition, qualified capacity could be increased.

Recruitment

The objectives of the recruitment effort were for prospective participants and aggregators to educate as many of them as possible and enroll the first seven resources willing to participate. Olivine had materials developed to educate and enroll the various entities including a summary of the enrollment process with timelines and list of all the required documentation as well as a list of frequently asked questions (http://olivineinc.com/irm2).

Olivine also developed training materials and held training sessions for participants and other interested parties.

Not all resources were eligible to participate in the pilot because the project had a set of well-defined site selection criteria. Participants enrolled one or more customer locations into a single aggregated CAISO demand-response resource. This resource type – called a Proxy Demand Resource (PDR) – had to meet certain requirements. For example, each resource needed to include customers from a single Sub-LAP, be served by a single LSE, and be able to achieve a minimum load shed of 100 kW. Other requirements were defined as follows:

- *Individual CAISO Demand Response resources cannot include customer locations served by different LSEs.* The LSE is the entity responsible for procuring electricity for their customers. For Bundled customers, the LSE was Pacific Gas & Electric. For Direct Access customers, the LSE is an Energy Service Provider (ESP).
- *Participants had to be tested for qualified capacity and make nominations.* All resources were tested outside of the wholesale market to determine their *Qualified Capacity* before becoming operational. To determine this value, the total average energy delivered over the election period was subtracted against the PDR baseline.
- *Bidding requirements:* To fulfill the bidding requirements, participants were required to make bids at or above the nominated value for a minimum of 72 hours out of the month[2]. The participant has the option to elect for either:
    - 3-hour contiguous blocks at least 24 days per month
    - 6-hour contiguous blocks at least 12 days per month
- Each bid quantity had to be greater than or equal to the nomination. Bids were subject to a price ceiling of $150 and a price floor of the current CAISO-specified net benefits test[3] value (See Figure 3). Participants had to meet these requirements to receive a capacity payment.

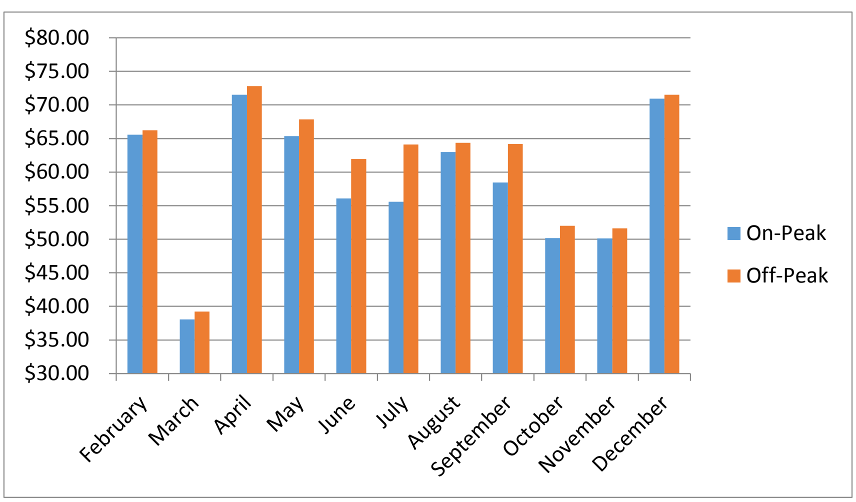


Figure 3 Net benefits test prices during the pilot period

[2] Any additional bids made at a valid quantity and price may be made into the market but are not required.
[3] The NBT is the Net Benefits Test, a price at which DR is determined to be cost effective given the current market conditions identified by the ISO.

Load Impact

CAISO uses 10-10 baseline with up to 20 percent adjustment for settlements[4]. To evaluate loads at each site and identify good candidates, LBNL calculated the hourly variance of loads using the same period of performance from the previous year. If there was no significant load variability of each hour during the period considered, we suggested participation in baseline-based programs like PDR.

Incentives

In addition to the energy settlements in the wholesale market based on the 10-10 baseline with a 20 percent-capped day-of adjustment, the participants received a retail incentive in the form of capacity payments. These capacity incentives were set at $10/kW and capacity payments were the product of monthly performance, nomination amount and the capacity incentive.

Monthly performance

The Qualified Capacity is a tested kilowatt value that has been demonstrated as achievable by the enrolled participant. The *nomination* is a capacity commitment to the program, at or below the Qualified Capacity. *Qualifying bids* are made at or above the given nomination. Once a customer made a qualifying bid and participated in a qualified event, their monthly performance was calculated mapping their raw event performance to adjusted event performance. Table 1 shows the mapping between raw event performance and adjusted event performance.

Table 1. Mapping of raw performance to adjusted performance

RAW PERFORMANCE	ADJUSTED PERFORMANCE
≥ 0.66 and ≤ 1.00	1.00
≥ 0.33 and < 0.66	0.66
< 0.33	0.33

Raw event performance is the average performance over a qualified event, measured against the nomination using the PDR baseline. A*djusted event performance* is calculated using Table 1. *Monthly performance* is the weighted average of each adjusted event performance, with the weights being the per-event awarded kilowatt-hour (kWh). For example, if a site had three awarded qualified hours where the awarded quantities were 100 kWh, 100 kWh, and 150 kWh and the delivered energy was 50 kWh, 75 kWh, and 140 kWh, respectively, the actual monthly performance would be calculated as:

$$\frac{(0.66 \times 100 + 1.00 \times 100 + 1.00 \times 150)}{100 + 100 + 150} = 90\%$$

[4] Demand Response and Proxy Demand Resource – Frequently Asked Questions http://www.caiso.com/Documents/DemandResponseandProxyDemandResourcesFrequentlyAskedQuestions.pdf

Nomination

Participants provide a monthly capacity commitment to the program, at or below the qualified capacity, which is the maximum kilowatt value that can be delivered by an enrollment, as identified in a pre-operational test.

In the above example, given a nomination of 100 kW, the capacity payment, which is a product of monthly performance, nomination amount and capacity incentive would equal $90\% \times 100 \times \$10 = \$900$.

ISO Settlements:

For the purposes of this pilot, grid management charges were covered by PG&E and the customers received payments for awarded energy at the day-ahead price adjusted by their real time performance. It they over-delivered, they received additional payments at the real-time market price. If they under-delivered, they were charged the replacement cost at the real-time market price.

Chapter 3: Results

Site Summary

In this section, we describe the participating sites and summarize their participation.

Of the 16 potential participants with which Olivine had ongoing discussions over several months, five participants were in the pilot as of October 31st. There were varying reasons some of the sites or entities could not participate in the pilot including the following:

- The prospective participant had concerns about the resource not being flexible enough to participate in the program. This prospective participant had a large discrete load which could not accommodate a potential partial award from the market, and there was some concern about the risk associated with over delivery. In addition, dual participation restrictions effectively meant that participating in the IRM2 would have meant forgoing the capacity payments from other DR programs on a portion of their total load capability.
- The prospective participant could not reach the resource requirements. For example, did not have enough customers from a single LSE within a sub-LAP and did not have time to recruit enough sites to meet these requirements.
- The prospective participant actually had no customers.
- Direct access customers had delays in participation. For all locations, the ISO requires an agreement between the LSE of the customers and the DRP. ESPs must also register for inclusion in the ISOs DRS system to validate their customers. Unless the customer yields significant leverage, certain ESPs are reluctant to take these steps due to uncertainty around the process and potential competitive concerns.

Table 2 summarizes the reduction and the qualified capacity by end uses that deliver these reductions by participant. Site 1 asked to remain anonymous. County of Alameda participated with the Santa Rita Jail (SRJ), which is a microgrid and has experience in participating in demand response and automated demand response over the years. Two Google sites provided reductions by rescheduling their electric vehicle charging. NW Natural enrolled in the pilot and became certified but actually did not bid into the market. Its participation strategy involved rescheduling run time of compressors. Stem participated using aggregated distributed storage systems.[5] Of these five sites, only three of them actually enrolled, bid into the market, received awards, delivered reductions and received payments for their participation. While Google sites did bid into the market, they did not receive awards and were ultimately removed from market bidding due to challenges with reliably obtaining meter data (detailed discussion is included in the following section). NW Natural did not bid into the market.

[5]http://www.greentechmedia.com/articles/read/aggregating-building-batteries-into-grid-resources

Table 2. Participants, their qualified capacity and end uses

Site Name	Qualified Capacity Reduction (kW)	Lighting	HVAC	Other
Site 1	500			x
County of Alameda, SRJ	810	X	X	X
Google	100		X	X
Google	100		X	X
NW Natural	3080 (capped at 2000)			X
Stem	120			X

Table 3 provides a summary of total number of days, the total number of hours and average price bid by and awarded to each participant. Alameda County's Santa Rita Jail was the first site that participated in the pilot. Santa Rita Jail participated in their first market transactions starting early February, giving them ample time to bid and gain experience with the market as well as maximize their capacity payments. Although Site 1 and Stem bid fewer days and hours, they were awarded three hours more than Santa Rita Jail. This is due to both differences in the clearing prices based on their locations as well as different bidding strategies employed by the participants. We summarize all three participants' hourly performance in Table 4 and provide details in Appendix A. Alameda County consistently participated and delivered the awarded amount. On average, Stem also performed close to their bids. However, Site 1 had performance issues. It is a large manufacturing site with variable large loads, participating in the pilot with a relatively small battery. Although the battery consistently performed, its performance was not visible from the whole facility meter due to the variability of large loads. If the pilot had allowed for submetering of the participating end-uses, the performance of Site 1 could have been measured more accurately.

As mentioned before, NW Natural did not participate, ultimately due to a lack of a consistent demand profile that would allow them to meet the pilot availability requirements. While Google did participate, their resources were not awarded, and ultimately were suspended in the pilot due to meter issues. The meter issues consisted of service-level changes at the premises which resulted in meter numbers changes, and ultimately issues for PG&E to provide the meter data in a timely fashion for the pilot.

Table 3. Summary of bids and awards

	Bids			Awards		
Site Name	**Total number of days**	**Total number of hours**	**Ave. price ($)**	**Total number of days**	**Total number of hours**	**Ave. price ($)**
Alameda	276	828	0.07	9	13	0.07
NW Natural	0	0	n/a	0	0	n/a
Site 1	61	183	0.06	9	16	0.06
Stem	165	536	0.05	10	16	0.05
Google	72	225	n/a	0	0	n/a

Table 4. Summary of participation

	Month (n=number of hours)	**Average Reduction (kW)**	**Average Bid (kW)**	**Raw Performance**	**Adjusted Performance**
Alameda	February (n=11)	651	450	145%	97%
	April (n=1)	982	800	123%	100%
	July (n=1)	876	810	108%	100%
Stem	June (n=1)	209	120	174%	100%
	July (n=1)	141	120	117%	100%
	September (n=6)	120	120	100%	94%
	October (n=4)	168	120	140%	100%
	November (n=4)	100	120	83%	92%
Site 1	August (n=4)	-362	500	7%	83%
	September (n=12)	-11	500	-2%	52%

Figure 4 displays calculated baseline and the measured load from the Alameda County site on February 5, 2014 with 15 minute data granularity. On this day, the site bid 450 kW for three hours between 7 am and 10 am. The baseline is significantly lower than the measured load. However, the site was able to achieve its target award of 450 kW.

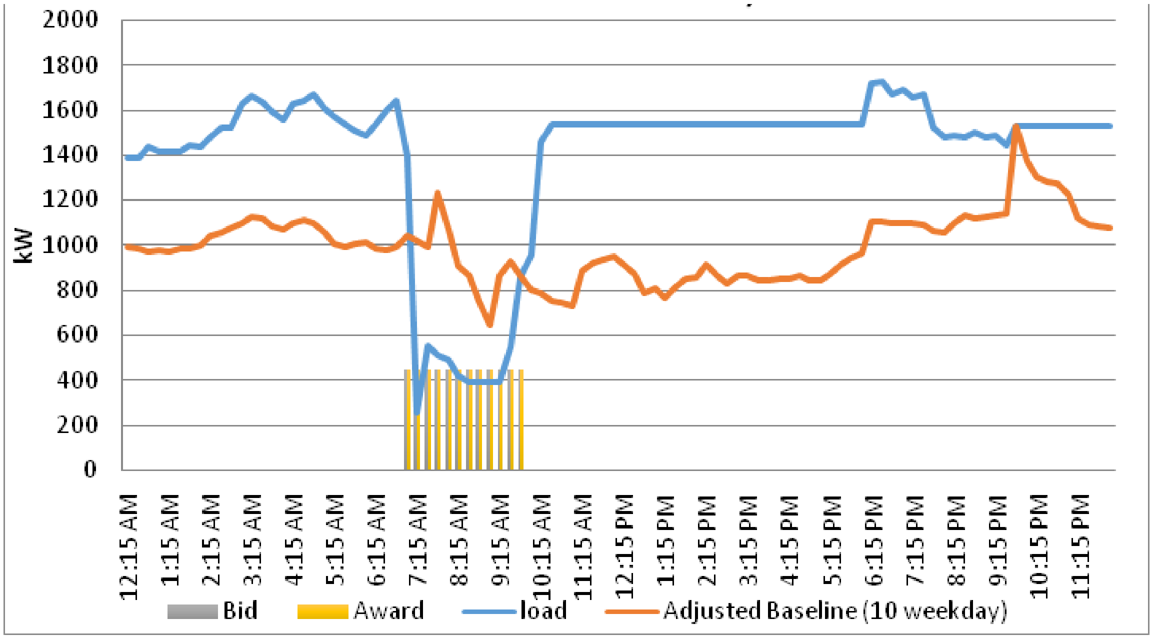


Figure 4 Load and baseline profiles along with bids and awards for Alameda County site on February 5, 2014

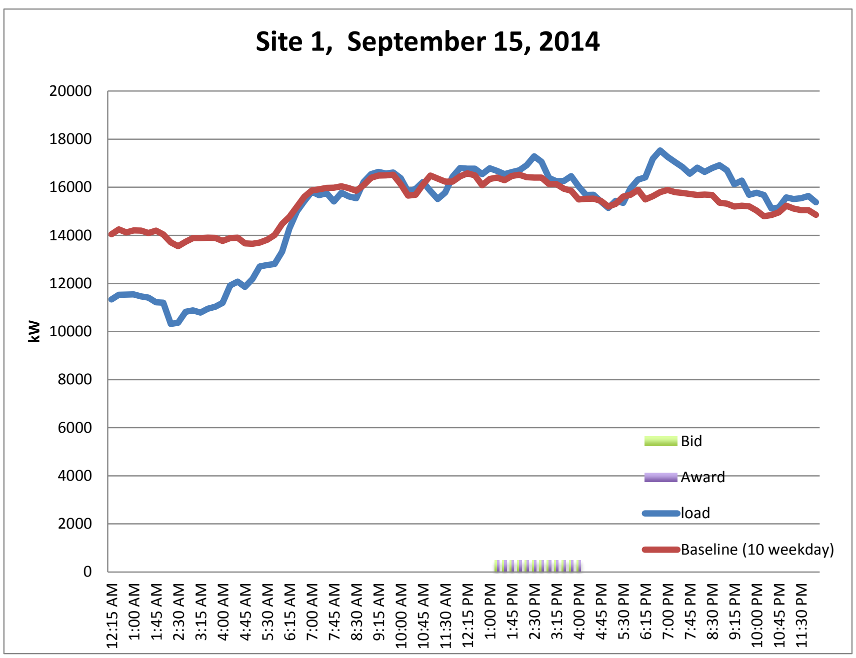


Figure 5. Load and baseline profiles for Site 1 with 500 kW nomination on September 15, 2014.

Figure 5 shows the measured load and calculated baseline along with the three-hour, 500 kW nomination between 1 pm and 4 pm for Site 1. The overall load of the facility was high and variable. Therefore, because of the small size of this resource and the difficulties with baseline methodology to accurately represent the variability, this site had a difficulty capturing the response from the whole facility meter. If the 500 kW had been submetered, the reduction would have been measurable.

The plots for each site and each day they participated in PDR are provided in Appendix B.

Enablement Costs

Enablement of sites took place in stages. In this section, we summarize the enablement issues and costs both from the scheduling coordinator's (SC's) perspective and from the participant's perspective to provide all the enablement issues.

The SC is the only entity that transacts with the CAISO and is the actual market participant. The wholesales demand response provider (DRP) and the SC are separate roles at the CAISO that may or may not be fulfilled by the same entity and services could be contracted. Although they are sometimes referred to interchangeably, a retail aggregator is not necessarily equivalent to a CAISO DRP.

An SC provides credit and collateral, handles CAISO administrative charges and payments and ensures accurate meter data is provided on a timely basis. In this section, we summarize these tasks and outline set up and operating tasks and costs.

Credit and Collateral

Minimum participation requirements are related to the market participant's financial stability. Minimum requirements are for the market participant or its guarantor to have at least: $1 million in tangible net worth or $10 million in total assets or to post financial security of $500,000.

Separately, to address the market participant's forward position, the SC must maintain an aggregated credit deposit sufficient to meet all of its financial obligations. The CAISO will calculate market exposure and require additional credit to ensure the forward position is covered.

CAISO Administrative Charges

Depending upon the reporting requirements, a separate Scheduling Coordinator ID (SCID) ($1,000 per month) may be required for a participant. Charges for operating the grid (Grid Management Charges - GMC) are assessed to each SC based on number of SCID and transaction level.

CAISO Payment

Since payment to the CAISO is required via wire transfer in a timely manner based on a set schedule associated with the transaction date (specifics) the financial transactions can be frequent and costly. Typically a third-party SC would consider this and include this in its pricing model for services but would require the client/participant to pay for the charges to the CAISO prior to the due date so that the funds are available for the SC to transfer to the CAISO. Monies owed the CAISO are due immediately while final settlement for energy payments may not occur until a future settlement calculation, and in fact the SC is financially responsible for market resettlements in perpetuity.

Meter Data Management

The SC is responsible for ensuring that accurate Settlement Quality Meter Data (SQMD) is provided on a timely basis and must resubmit meter data as appropriate to ensure accurate settlement. For PDRs, the SC must create SQMD from Utility Distribution Company (UDC) Revenue Quality Meter Data (RQMD). Generation resources are typically CAISO metered with the CAISO responsible for validation, estimation and editing activity. There is a $1000 per day cost for submittal of meter data past the 48 business day cut-off. Updates in meter data may require processing and adjustment to settlements up to three years from the trade date. SC is also subject to an annual meter audit and sanctions for late or inaccurate meter data.

As described above, becoming an SC is costly requiring 24/7 operations, and capitalization requirements. In addition, typically it takes 120 days from application to certification and carries long term risk.

Costs

Typical setup fees are per resource and can be approximately $25,000. The costs arise from the following SC activities:

- Ensuring that market dispatch communication protocols are in place
- Establishing a resource/registration validation process
- Being available for a 30 day lead for simple (predefined) PDR – 180 days for telemetry (additional tasks and certification).

In addition to the set up costs, there are ongoing monthly operations costs. These prices typically vary depending upon the bidding activity volume and other variables with typical minimum monthly fees around $10,000 due to the infrastructure and support costs. Since there is a lack of third parties bidding demand-side resource into the market, there is a limited frame of reference. Charges are expected to be on a per-resource basis, dependent upon activity and operational risk anticipated with a minimum monthly fee of $2,500 to $10,000. This could vary widely dependent upon the business model and cost of commercial operations. Below is a set of activities that the operations costs cover:

- Maintain bidding platform services (24 x 7)
- Monitor market results/dispatch (24 x 7)
- Settlements and Invoicing Administration (daily/weekly)
- Resource Maintenance (Registrations/RDTs)

In this project, in addition to the costs of bringing the resources to participate in PDR, Olivine had to provide two different types of training. One, which took place on January 16, 2014, was a general training session open to all potential participants. It concentrated on CAISO market basics and introduction to the pilot, the operational details, and settlement and incentive mechanisms. Following this training, for those sites that decided to participate in the pilot, additional hands-on training at their location was provided. On-site training familiarized the participants with the Olivine distributed energy resources (DER) system and allowed them to walk through nomination and bid entry, and prepared them for pre-operational test to qualifying their capacity. These sessions were well received and appreciated by the participants because they allowed them to become comfortable with the systems and the bidding process. Olivine has made the CAISO market training portion of their presentation available on the IRM2 web page at http://olivineinc.com/irm2.

Capacity Testing

Each site had to go through capacity testing to receive the capacity incentives, and the participants all passed. In this section, we summarize the issues that came up during capacity testing.

Site 1 operated a large industrial manufacturing facility with a relatively smaller behind-the-meter stationary storage device. The size of the battery was roughly one-tenth of the whole premise's peak load. Due to fluctuations in the manufacturing processes, the whole premise's load was extremely variable. These factors made the load reduction achieved by the relatively small stationary storage device impossible to measure against the noise created by the calculated baseline. As a result, the performance data calculated from the baseline produced radically differing numbers across different event days (+/- 200 percent). While the resource size meets the pilot minimum requirements, over all load is highly variable and large compared to the resource, which made visibility of the resource from the PDR baseline difficult.

Alameda County has behind-the-meter distributed energy resources and their fuel cell sometimes stops working unexpectedly. When this happens, the baselines no longer represent load and potentially cause issues with the settlements.

NW Natural has large available natural gas turbines, however they are subject to availability limitations because their injectors run intermittently. This creates an extreme amount of variability, with a tendency to drag down the baselines. Ultimately, NW Natural never had enough load to have confidence in the baseline nor to bid the requisite number of days into the pilot.

Google had small resources behind their meter and could benefit from submetering but it is the lack of availability of meter data ultimately led to suspension of bidding.

Stem did not have baseline or sub-metering issues, however Olivine experienced several errors in CAISO baseline calculations.

Value of Participation

Each participant received capacity incentives for each month they nominated resources as well as payments from CAISO for the energy they delivered.

Table 5 summarizes capacity and CAISO settlements received by each individual site based on its participation. As expected, the capacity payments, which is an incentive offered by the pilot, were significantly higher than the CAISO settlements. Alameda Country received the most capacity payments because their capacity was highest and it participated in more months. Because of load size and variability issues at Site 1, its adjusted performance indicated under performance of the resource.

Table 5. Total payments to participants

	Total capacity payment ($)	**Total CAISO settlement ($)**
Alameda	$ 85,160.91	$ 647.80
Stem	$ 6,550.00	$ 15.91
Site 1	$ 6,787.50	$ -

What is important to note is that given SC costs that include set up fees of $25,000 per site and monthly fees between $2,500 and $10,000 (which eventually will have to be covered by the participants), short term participation and CAISO settlements alone are not profitable endeavors for the participants.

Lessons Learned

In this section, we outline the lessons learned throughout the pilot implementation.

Default Load Adjustment calculated incorrectly

The default load adjustment (DLA) is an adjustment made by the CAISO that results in a reduction in the scheduled load of an LSE equal to the amount of energy delivered during a demand response award. Note that the DLA is only intended to be applied to an LSE load schedule in those cases that the demand response energy was paid at below the NBT. While the IRM2 required participants to bid at or above the NBT in all hours, it was still possible for that participant to be paid for energy at below the NBT if they over-delivered energy and the real-time market price during the award period was below the NBT.

This did, in fact, happen during the IRM2 pilot and Olivine determined by Olivine that the current DLA calculations are not being performed correctly by the CAISO, resulting in a larger DLA than appropriate.

The calculation appears to be incorrect whenever it is performed; it can be reproduced under the following conditions:

- A PDR is bid into the day-ahead market. Note that it is not necessary that the price be bid at or above the NBT.
- The PDR receives an award at or above the NBT.
- The PDR delivers energy in excess of the award.
- One or more real-time interval prices are below the NBT.

In this case, the DLA should apply to the portion of the energy delivery that is paid below the NBT (i.e., the excess delivery in intervals priced below the NBT, not the amount awarded and priced in the day-ahead market); however, DLA calculations are including the entire delivered energy. For example:

- A PDR is bid into the day-ahead market as 1 megawatt-hour (MWh) at $55 with an NBT of $50.
- The PDR receives an award of 1 MWh at $60.
- The PDR delivers 1.1 MWh during the awarded period.
- The real-time price for that awarded period is $48. Note this is intentionally simplified across the award period.

The DLA in this case should be the excess energy of 0.1 MWh, because the first 1 MWh was paid above the NBT at $55 while the last 0.1 MWh was paid at below the NBT; however, the CAISO would calculate a DLA of 1.1 MWh.

Minimum run time not observed

CAISO resource-specific operational parameters are stored in the resource-data-template (RDT). Minimum run time is one of those parameters which is intended to allow a resource owner to identify that their resource must run for a minimum amount of time once it is started. For example, a minimum run time of 120 minutes should identify that if the CAISO makes an award to such a resource, that award must be at least two hours long. This was experimented with during the pilot and, contrary to CAISO documentation, is not observed for PDR resources.

LSE / DRP agreement requirement for direct access customers

Primarily due to the DLA, the CAISO requires that the DRP have an agreement with the LSE to include the LSE's customers in a proxy demand resource (PDR). The California Public Utilities Commission (CPUC) has ordered a pro forma DRP/LSE agreement for the investor-owned utility LSEs, but has no such jurisdiction over energy service providers (ESPs) who act as the LSE for their direct access customers.

Securing agreements with ESPs is more challenging that one would expect for several reasons. The primary issue is that DRPs generally have no leverage with an ESP to get an agreement (noting that the CPUC ruled that DRPs should not pay LSEs for demand response). After all, placing an ESPs customer into the CAISO energy markets, if anything, can result in a (likely small) default load adjustment which reduces settlement payments by the CAISO to the ESP. An equally important issue is that some ESPs have shown an unwillingness to sign agreements with DRPs because the ESP has an interest in being the DRP to those same customers. While on the IOU side consumers are protected by such a conflict through so-called "firewalls", there is no such protection for direct access customers. The final issue is that, in many cases the LSE itself is unaware of this CAISO agreement requirement and the implications of having such an agreement. As a result, the process has either never been executed by an ESP or not often repeated, resulting in a lack of systemization. As a result, it requires an iterative process of discovering the appropriate contacts and working simultaneously across several distinct departments within the company. The process can be laborious, time-intensive, and political.

In one particularly clear-cut example, a direct access (DA) participant ended up entering the pilot roughly 5-6 months later than intended due to delays arising from this issue, noting that no participants were held out of the pilot due to a lack of cooperation from ESPs.

Assuming an ESP is properly registered as an LSE in the relevant UDC territory, the DRP can proceed with registering a PDR with the LSE's customers. At that point, the LSE is given ten-days during which they may validate the pending PDR registration. If no action is taken, the registration is deemed validated. However, there is no way to guarantee the engagement of the LSE throughout these steps. In the case of DA customers, this translates into additional requirements for a DRP since they must now coordinate the completion of these requirements with an LSE over which they have no legal basis to compel to act.

Easing this requirement by the CAISO and/or standardization of this process by the CAISO and CPUC is vital to unlocking some of the vast integration potential of demand response since non-bundled customers participate disproportionately in utility programs. Specific actions to be taken include the development of LSE/DRP agreements that can be used as templates for future negotiations. As a result of dealing directly with these challenges, Olivine has successfully navigated with several ESPs, and developed several documents of this kind.

Baseline calculations methodologies and resource size

The participants had two major concerns with baselines: (1) when there is large variability in the load, the current 10/10 baseline fails to capture it; and (2) when the resource size is small compared to the loads, the resource contributions are not visible. Lawrence Berkeley National Laboratory addressed the first issue (Coughlin et al. 2007) by suggesting that loads be categorized in terms of their variability and weather sensitivity. When the loads are variable, they are not good candidates for averaging baselines such as the 10/10 baseline being used for PDR. Therefore, these loads should move away from incentive-based programs to price-based programs or tariffs.

The second issue, that is the resource size being too small compared to the load they are bundled with, has to be considered from both the participant's perspective and the system operator's perspective. From the participant's perspective, although they are contributing with a load that is measureable and persistent (e.g., battery storage), they are not able to receive incentives. From a system operator's perspective, if the resource is not visible, both in terms of its magnitude and duration, then it is not valuable. While the system operator's perspective is extremely valuable, there may be a compromise. For new, not widely adopted and therefore expensive technologies, such as battery storage, that deliver dispatchable and reliable DR, the system operators may want to agree to submetering these resources for a pre-specified time period. This, in return, may increase adoption of these technologies by providing additional values to offset the costs and in the long run being valuable resources to the system operators.

Chapter 4: Conclusion and Next Steps

In this pilot project, five resources participated and learned about the process of developing nominations, setting prices for their nominations, and bidding into the wholesale market as PDR. Four of these participants received payments for their participation. In the process, there were lessons learned, both from the participant's perspective, and the SC's perspective. In this section, we summarize the results from each perspective.

Participant

- Participants with variable loads were concerned about the accuracy of the PDR baseline.
- Participants with loads that were all on or off, without flexibility move them under the nomination, chose not to participate.
- Where the resource size met the minimum CAISO requirement but the resource was behind large variable loads, while the resource performed as expected, it was not visible from the baseline.
- All participants that received payments, participated in using their storage systems or deferring vehicle charging.
- The conventional aggregators approached did not have sites within a sub-LAP or did not have time to recruit and enable enough sites to make up for the resource size within a sub-LAP.
- Most of the sites were semi-automated with manual bid entry and semi-automated response at the sites.
- As expected, ISO settlements participants received for the energy they provided were significantly less than the retail capacity incentives and did not add up to a significant value for the participants.

Scheduling Coordinator

- Training is needed for customers to understand the basic ISO market operations, how to calculate baselines, how to determine load shed strategies in response to program requirements, how to quantifying nominations, how to qualifying capacity, retail incentives and wholesale settlements.
- Despite consistent efforts to engage conventional aggregators, there was no participation. The pilot could be richer if aggregators made use of the training and had first-hand experience in participating in PDR.
- Problems with CAISO processes, systems and settlement issues were identified and were brought to the CAISO's attention.

The next phase of this pilot, called the "Supply Side Resource Pilot", is underway and will explore the use of these and additional resources as a supply side resource as it builds from experiences gained from this pilot.

As of the writing of this report, the follow on to IRM2 is underway. This new pilot, the Supply Side Pilot (SSP), continues with the objective of engaging participants in a third-party wholesale integrated capacity program. It also moves beyond day-ahead energy provided by C&I customers, enabling:

- Participation by residential customers.
- Participation in real-time energy and non-spinning reserves.

- A simplified program design, particularly around the wholesale market pricing rules.
- A program design that is more closely tied to resource-adequacy must-offer-obligations. For example, this results in a single 4-hour contiguous block instead of the 3 and 6-hour block options in IRM2.

The SSP is scheduled to run through December, 2016.

References

Kiliccote, Sila, P. Sporborg, I. Sheikh, E. Huffaker, M.A. Piette, Integrating Renewable Resources in California and the Role of Automated Demand Response. LBNL-4189E. November 2010.

Coughlin K, Piette MA, Goldman CA, and Kiliccote S. "Statistical analysis of baseline load models for non-residential buildings." Energy and Buildings 41, no. 4 (2009): 374-381.

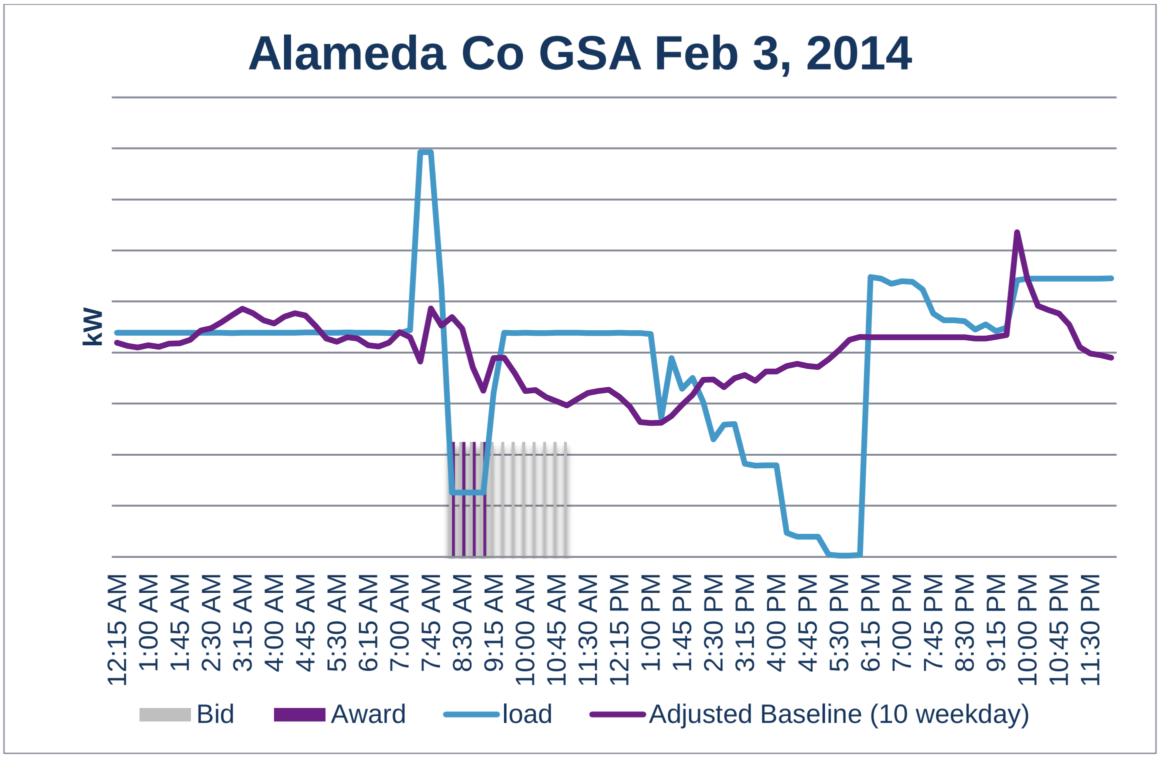
Appendix A – Summary of hourly performance by participant

	End Time	Baseline (kWh)	Metered Energy (kWh)	Reduction (kWh)	Award (kWh)	Raw Performance	Adjusted Performance
Alameda	2/3/2014 9:00	823.6	256.07	567.53	450	126.12%	100.00%
	2/4/2014 9:00	1,007.85	245.23	762.62	450	169.47%	100.00%
	2/4/2014 10:00	914.56	244.46	670.1	450	148.91%	100.00%
	2/4/2014 11:00	775.06	8.68	766.38	450	170.31%	100.00%
	2/5/2014 8:00	1,094.72	465.28	629.44	450	139.87%	100.00%
	2/5/2014 9:00	1,007.85	409.25	598.6	450	133.02%	100.00%
	2/5/2014 10:00	914.56	704.91	209.65	450	46.59%	66.00%
	2/7/2014 8:00	1,097.15	245.6	851.55	450	189.23%	100.00%
	2/7/2014 9:00	1,058.52	399.91	658.61	450	146.36%	100.00%
	2/10/2014 9:00	1,058.52	245.99	812.53	450	180.56%	100.00%
	2/11/2014 9:00	1,058.52	425.56	632.96	450	140.66%	100.00%
	February Averages					144.65%	96.91%
	4/17/2014 11:00	1,343.03	360.86	982.17	800	122.77%	100.00%
	April Average					122.77%	100.00%
	7/14/2014 12:00	1,495.42	619.58	875.84	810	108.13%	100.00%
	July Average					108.13%	100.00%

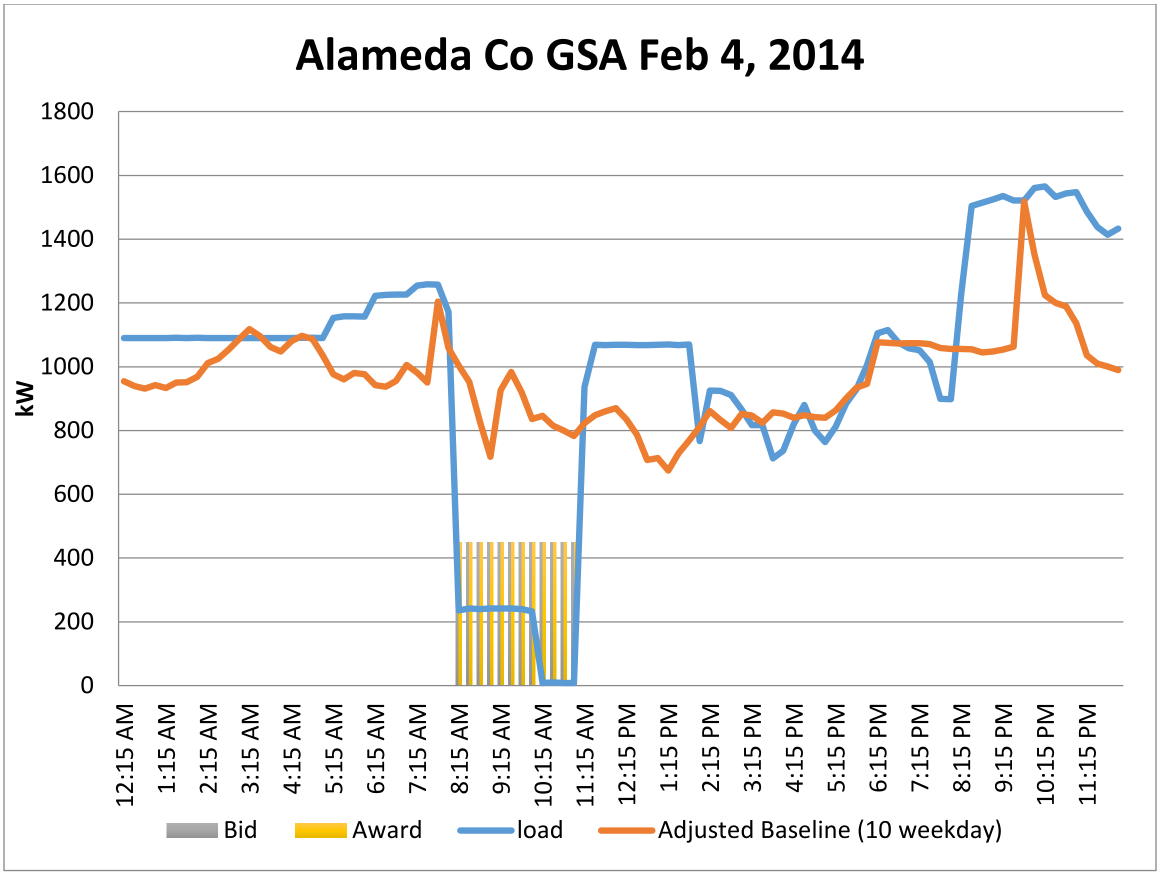
Stem	6/30/2014 19:00	1,562.57	1,353.83	208.74	120	173.95%	100.00%
	June Average					173.95%	100.00%
	7/1/2014 19:00	1,461.62	1,320.80	140.82	120	117.35%	100.00%
	July Average					117.35%	100.00%
	9/11/2014 16:00	1,674.57	1,582.32	92.25	120	76.88%	100.00%
	9/12/2014 16:00	1,659.09	1,551.17	107.92	120	89.93%	100.00%
	9/15/2014 18:00	1,633.26	1,567.39	65.87	120	54.89%	66.00%
	9/16/2014 18:00	1,657.04	1,474.37	182.67	120	152.22%	100.00%
	9/17/2014 18:00	1,696.53	1,515.75	180.78	120	150.65%	100.00%
	9/18/2014 18:00	1,711.49	1,622.36	89.13	120	74.27%	100.00%
	September Average					99.81%	94.33%
	10/7/2014 16:00	1,594.46	1,431.88	162.58	120	135.48%	100.00%
	10/8/2014 16:00	1,653.78	1,464.61	189.17	120	157.64%	100.00%
	10/10/2014 16:00	1,582.70	1,440.43	142.27	120	118.56%	100.00%
	10/13/2014 16:00	1,773.44	1,594.83	178.61	120	148.84%	100.00%
	October Average					140.13%	100.00%
	11/4/2014 16:00	1,488.71	1,372.09	116.62	120	97.19%	100.00%
	11/5/2014 16:00	1,635.41	1,572.34	63.07	120	52.56%	66.00%
	11/18/2014 16:00	1,323.38	1,183.47	139.91	120	116.59%	100.00%
	11/20/2014 10:00	1,513.89	1,433.78	80.11	120	66.76%	100.00%
	November Average					83.28%	91.50%

Site 1	8/1/2014 14:00	13,504.61	13,111.20	393.41	500	78.68%	100.00%
	8/1/2014 15:00	13,489.63	12,970.80	518.83	500	103.77%	100.00%
	8/1/2014 16:00	13,372.13	13,026.00	346.13	500	69.23%	100.00%
	8/2/2014 16:00	9,828.00	10,945.20	-1,117.20	500	-223.44%	33.00%
	August Average					7.06%	83.25%
	9/11/2014 15:00	16,557.01	16,468.80	88.21	500	17.64%	33.00%
	9/11/2014 16:00	16,083.36	15,736.80	346.56	500	69.31%	100.00%
	9/12/2014 15:00	16,755.42	16,600.80	154.62	500	30.92%	33.00%
	9/12/2014 16:00	16,276.09	16,119.60	156.49	500	31.30%	33.00%
	9/13/2014 16:00	13,355.28	14,498.40	-1,143.12	500	-228.62%	33.00%
	9/15/2014 14:00	16,386.41	16,640.40	-253.99	500	-50.80%	33.00%
	9/15/2014 15:00	16,311.77	16,914.00	-602.23	500	-120.45%	33.00%
	9/15/2014 16:00	15,845.13	16,251.60	-406.47	500	-81.29%	33.00%
	9/16/2014 15:00	16,817.12	15,978.00	839.12	500	167.82%	100.00%
	9/16/2014 16:00	16,336.02	16,378.80	-42.78	500	-8.56%	33.00%
	9/17/2014 15:00	16,996.16	16,693.20	302.96	500	60.59%	66.00%
	9/17/2014 16:00	16,509.95	16,080.00	429.95	500	85.99%	100.00%
	September Average					-2.18%	52.50%

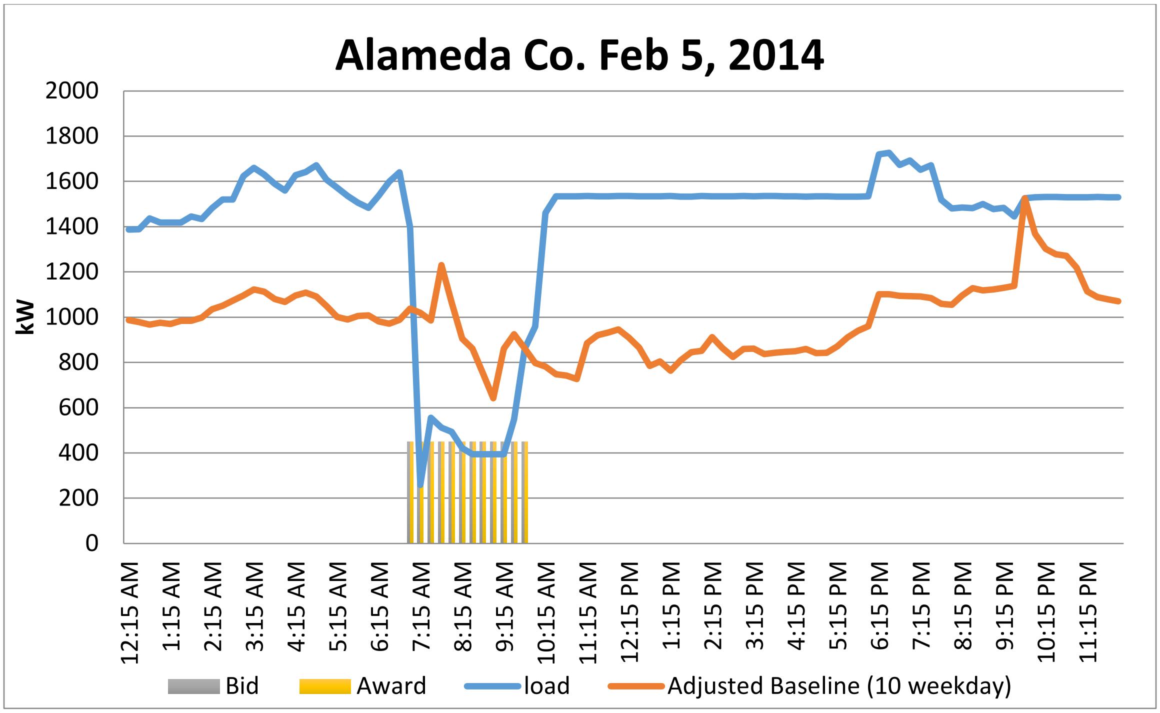
Appendix B - Plots for each site for each day they received awards and dispatches.



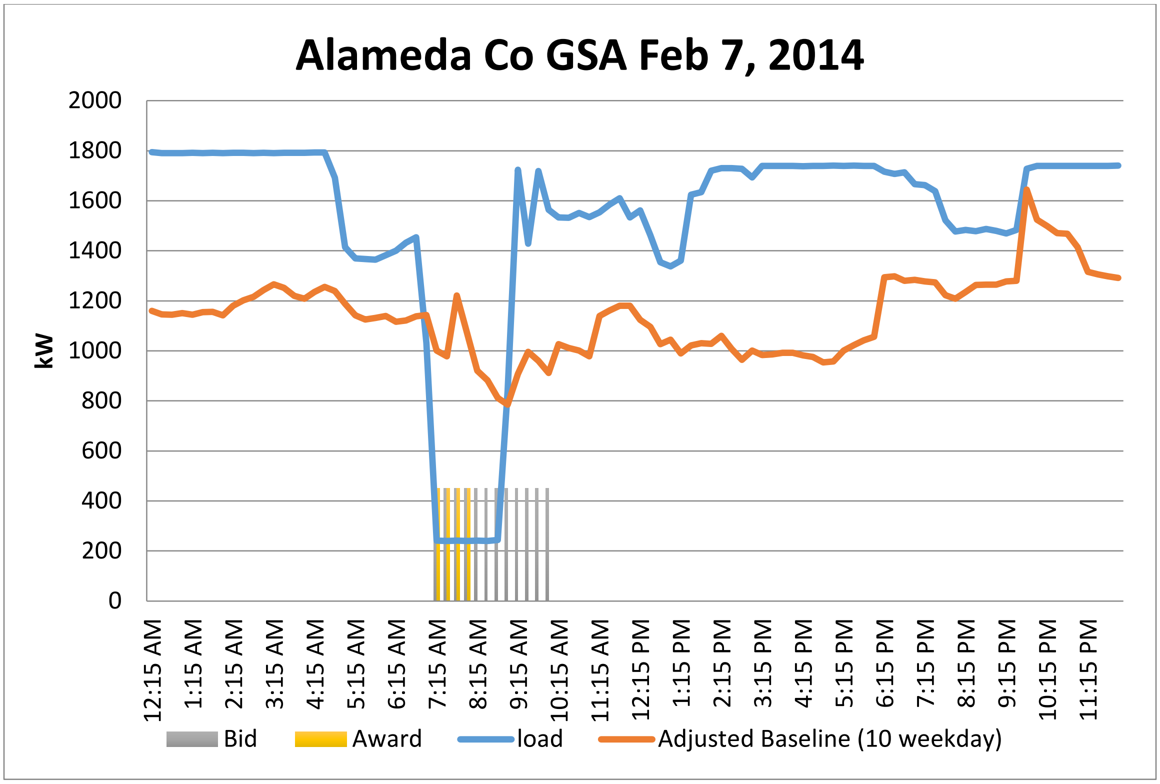
Alameda Co GSA					
2/5/14					
Time	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
8:15 AM	251	938.84	450	450	687.84
8:30 AM	251	893.76	450	450	642.76
8:45 AM	251	741.86	450	450	490.86
9:00 AM	251	650.72	450	450	399.72



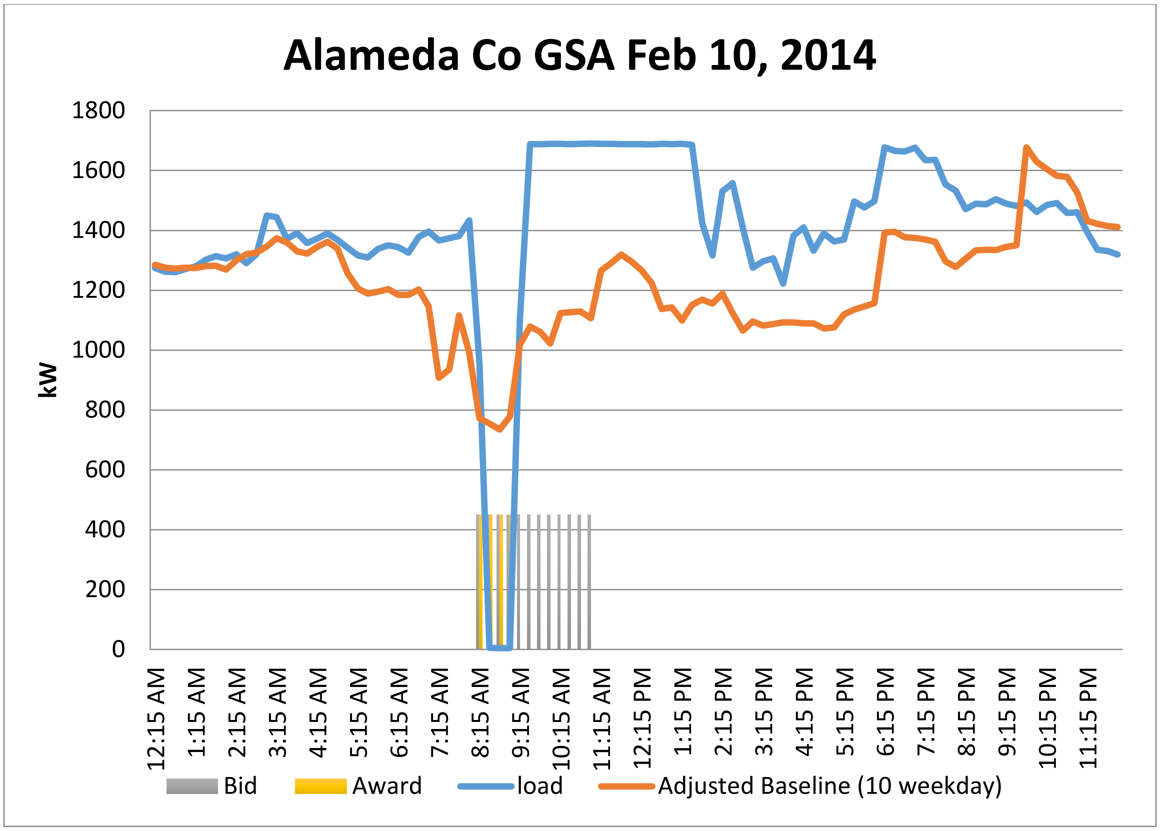
Alameda Co GSA					
2/4/14					
Time	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
8:15 AM	236	1003.2	450	450	767.2
8:30 AM	242	952.8	450	450	710.8
8:45 AM	240	829.2	450	450	589.2
9:00 AM	242	717.6	450	450	475.6
9:15 AM	242	926.4	450	450	684.4
9:30 AM	242	984	450	450	742
9:45 AM	240	919.2	450	450	679.2
10:00 AM	233	836.4	450	450	603.4



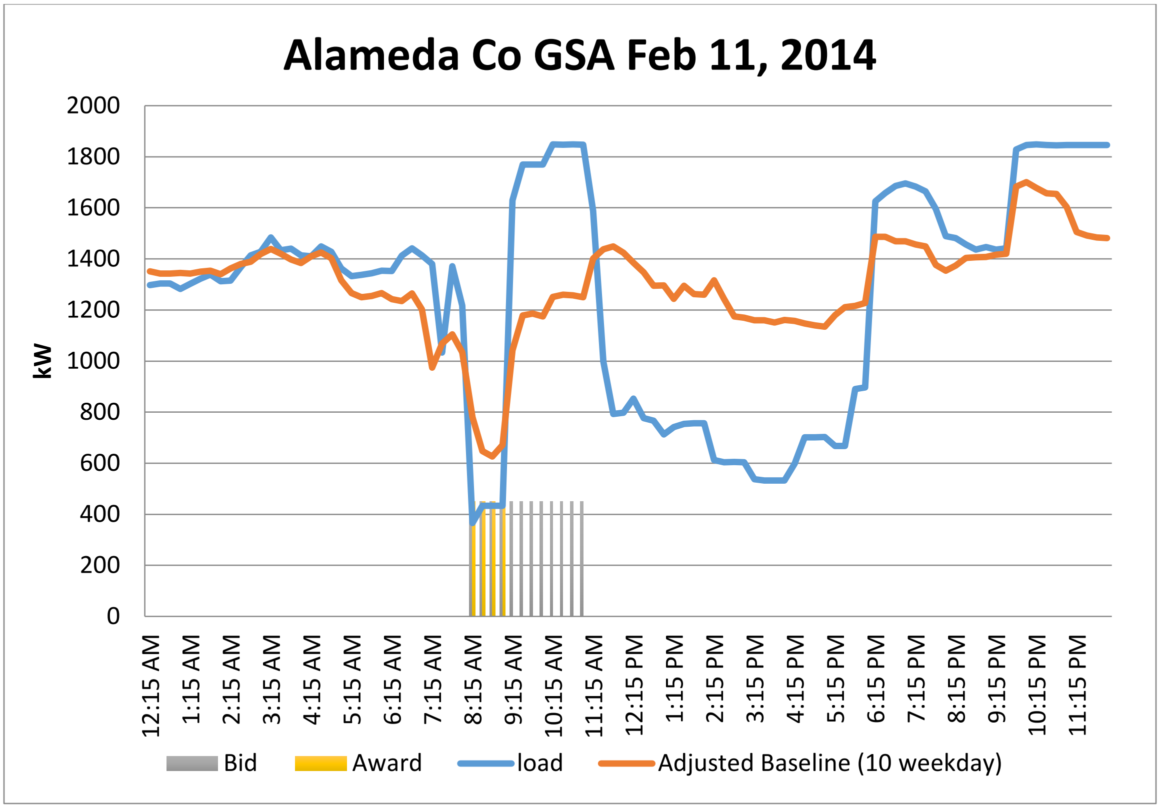
Alameda Co GSA					
2/5/14					
Time	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
7:00 AM	1,397	1038	450	450	-359
7:15 AM	259	1018.8	450	450	759.8
7:30 AM	556	985.2	450	450	429.2
7:45 AM	512	1230	450	450	718
8:00 AM	494	1064.4	450	450	570.4
8:15 AM	421	904.8	450	450	483.8
8:30 AM	394	861.6	450	450	467.6
8:45 AM	394	751.2	450	450	357.2
9:00 AM	394	642	450	450	248
9:15 AM	395	860.4	450	450	465.4
9:30 AM	548	924	450	450	376
9:45 AM	860	862.8	450	450	2.8



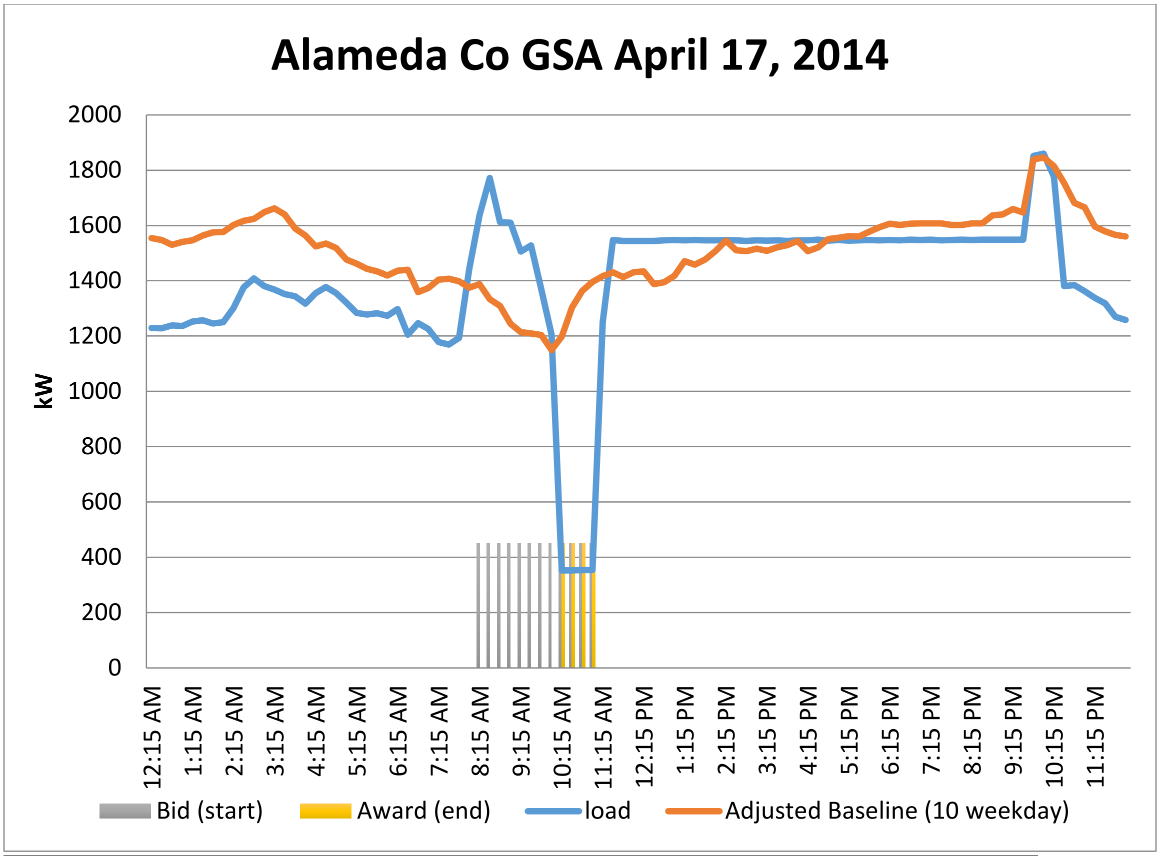
Alameda Co GSA					
2/7/14					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
7:15 AM	241	1000.8	450	450	759.8
7:30 AM	240	978	450	450	738
7:45 AM	241	1221.6	450	450	980.6
8:00 AM	240	1071.6	450	450	831.6



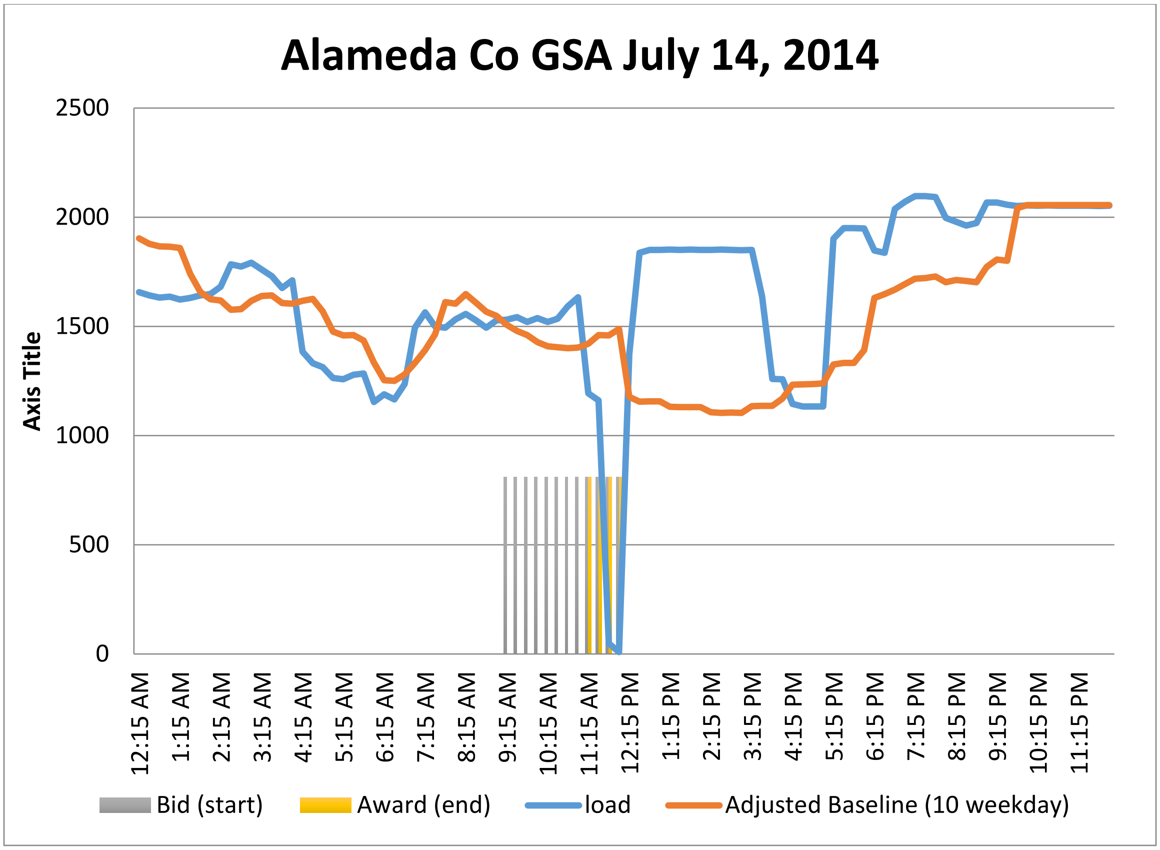
Alameda Co GSA					
2/10/14					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
8:15 AM	952	771.6	450	450	-180.4
8:30 AM	5	754.8	450	450	749.8
8:45 AM	4	734.4	450	450	730.4
9:00 AM	4	778.8	450	450	774.8



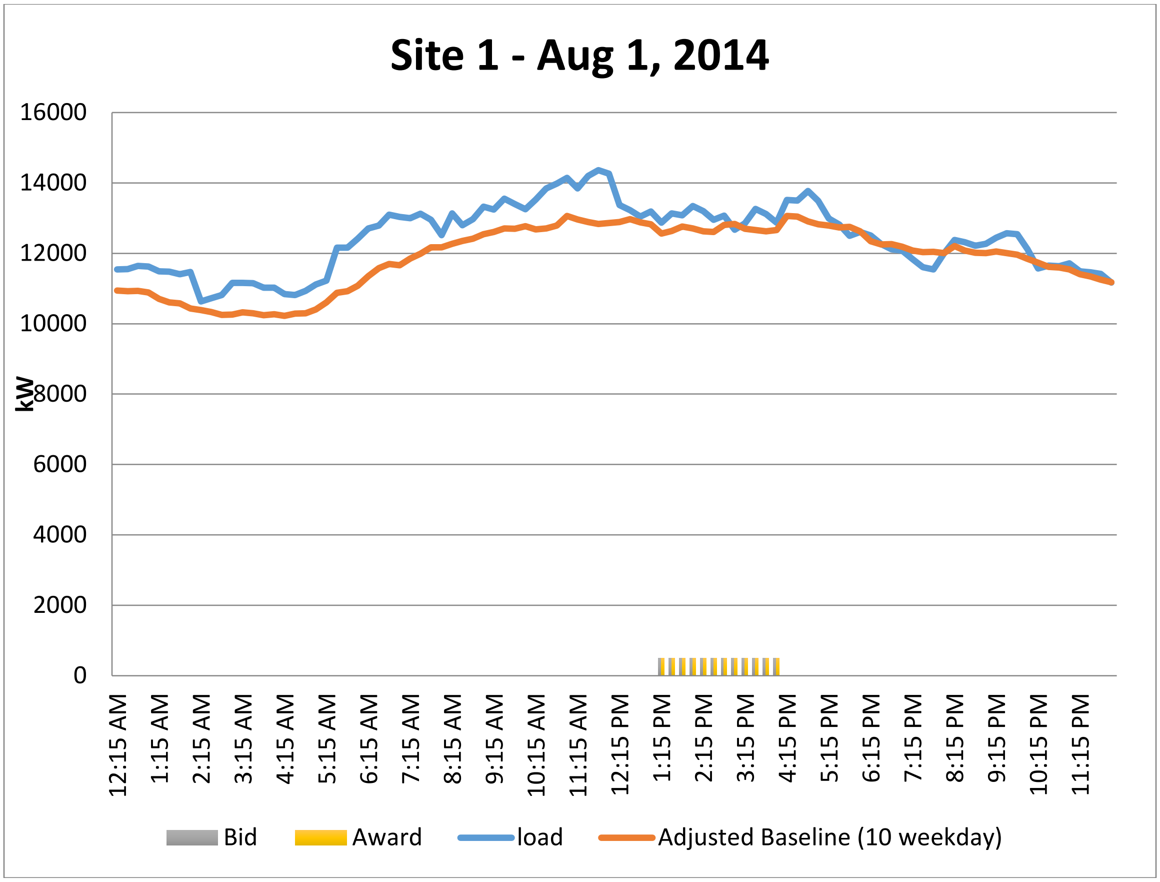
Alameda Co GSA					
2/11/14					
Hours	load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
8:15 AM	366	780	450	450	414
8:30 AM	434	648	450	450	214
8:45 AM	434	626.4	450	450	192.4
9:00 AM	434	672	450	450	238



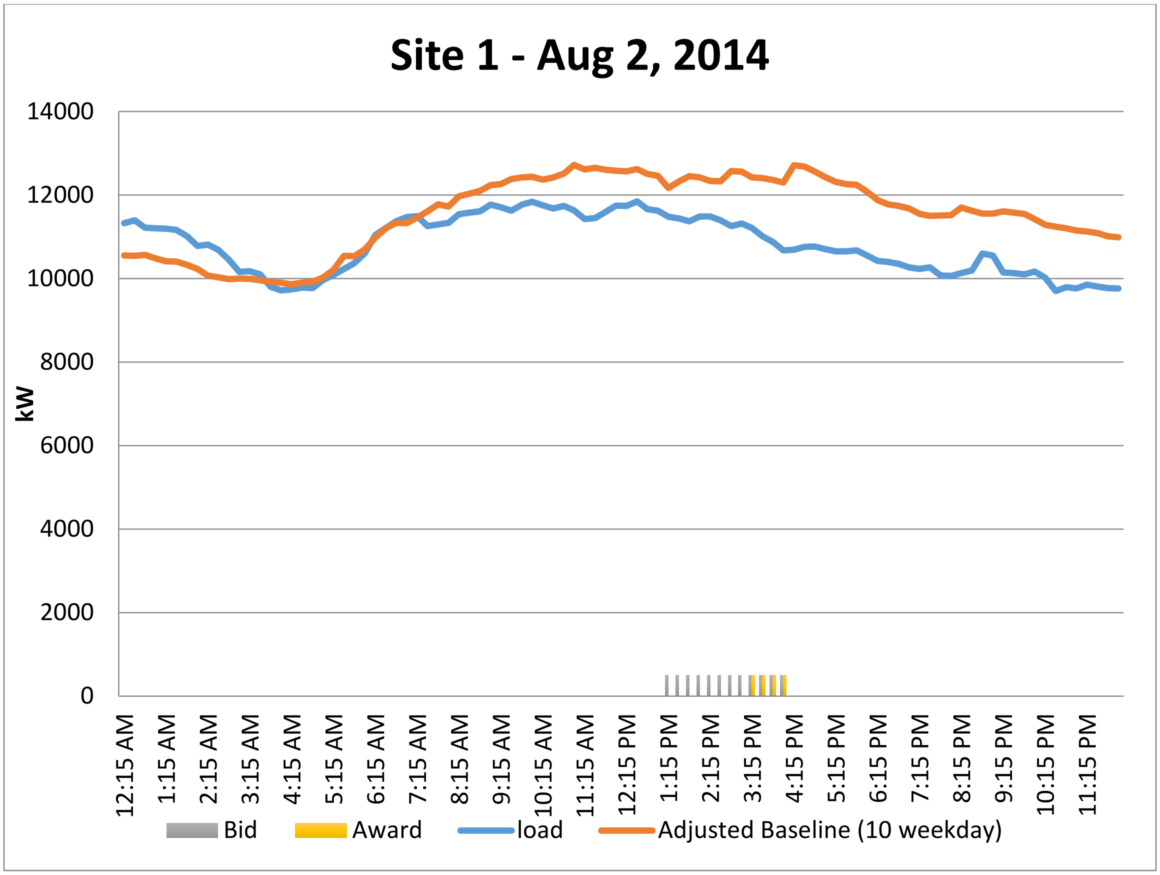
Alameda Co GSA					
4/17/14					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
10:15 AM	353	1197.91	800	800	844.91
10:30 AM	353	1303.64	800	800	950.64
10:45 AM	354	1363.59	800	800	1009.59
11:00 AM	354	1396.29	800	800	1042.29



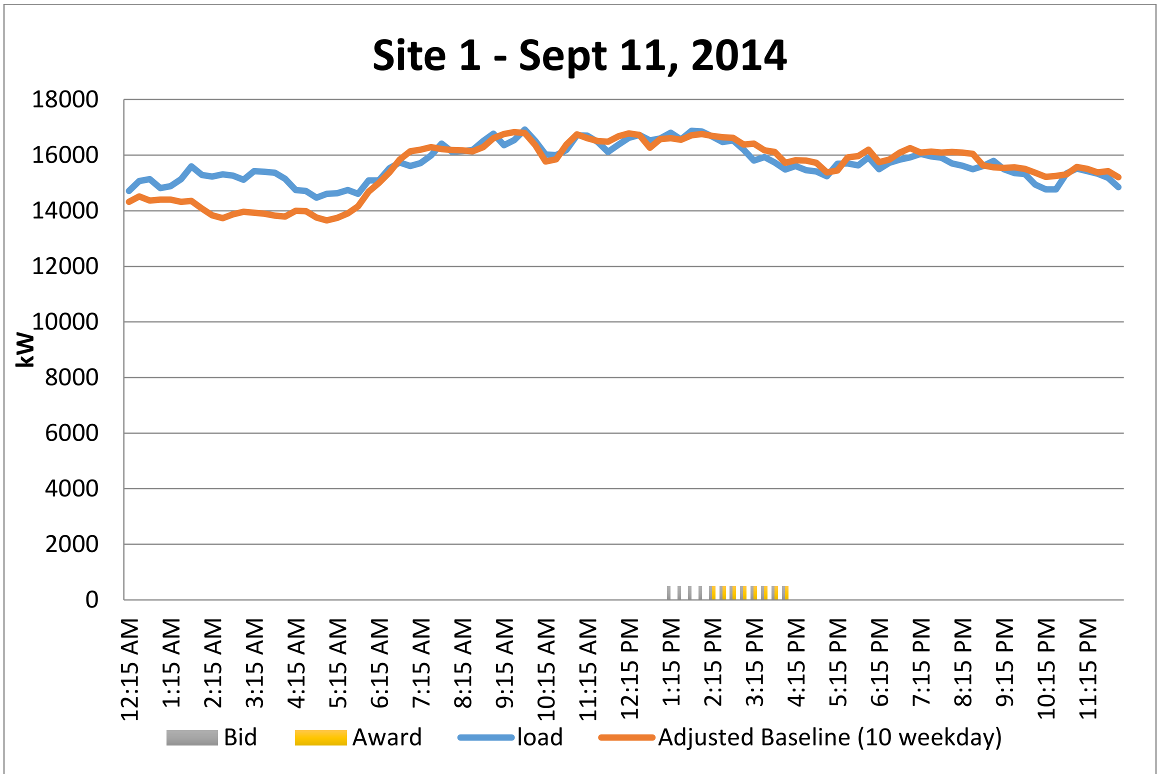
Alameda Co GSA					
7/14/14					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
11:15 AM	1,194	1,421	810	810	227
11:30 AM	1,162	1,460	810	810	298
11:45 AM	49	1,459	810	810	1410
12:00 PM	9	1,489	810	810	1480



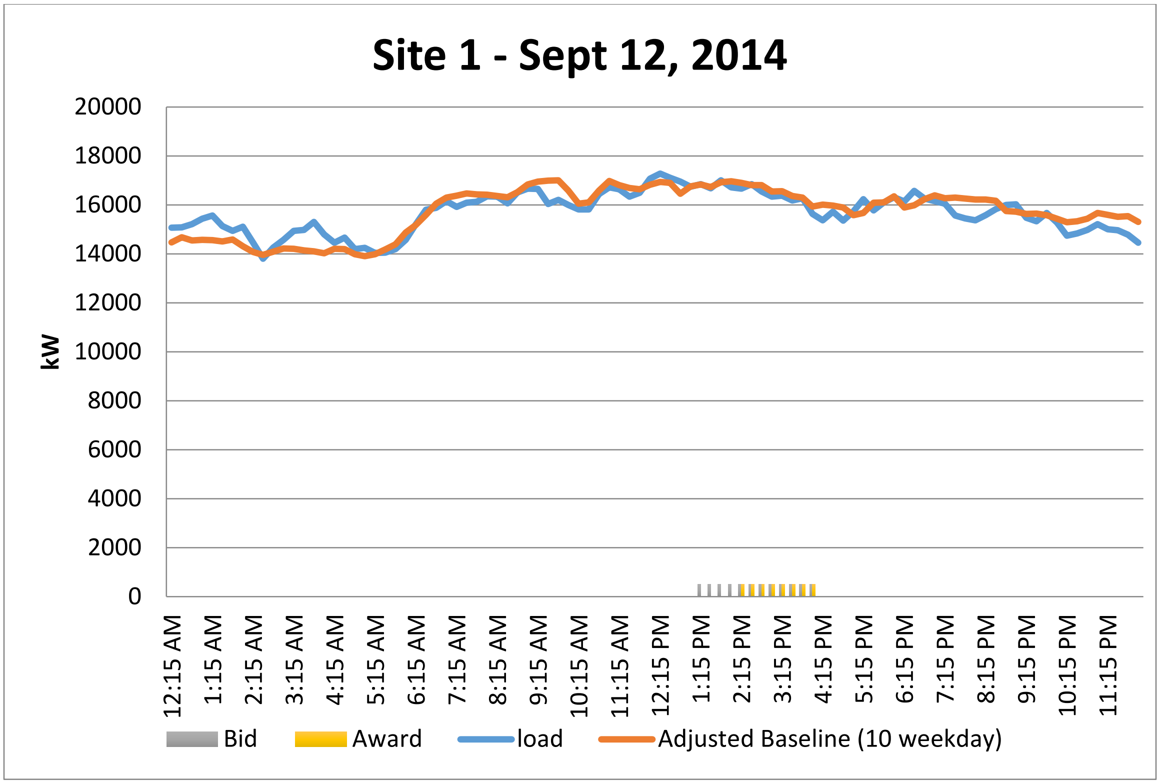
Tesla					
8/1/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
1:15 PM	12,874	12561.6	500	500	-312
1:30 PM	13,138	12636	500	500	-502
1:45 PM	13,085	12762	500	500	-323
2:00 PM	13,349	12711.6	500	500	-637
2:15 PM	13,195	12622.8	500	500	-572
2:30 PM	12,950	12607.2	500	500	-343
2:45 PM	13,070	12810	500	500	-260
3:00 PM	12,667	12835.2	500	500	168
3:15 PM	12,850	12700.8	500	500	-149
3:30 PM	13,267	12660	500	500	-607
3:45 PM	13,114	12627.6	500	500	-486
4:00 PM	12,874	12661.2	500	500	-213



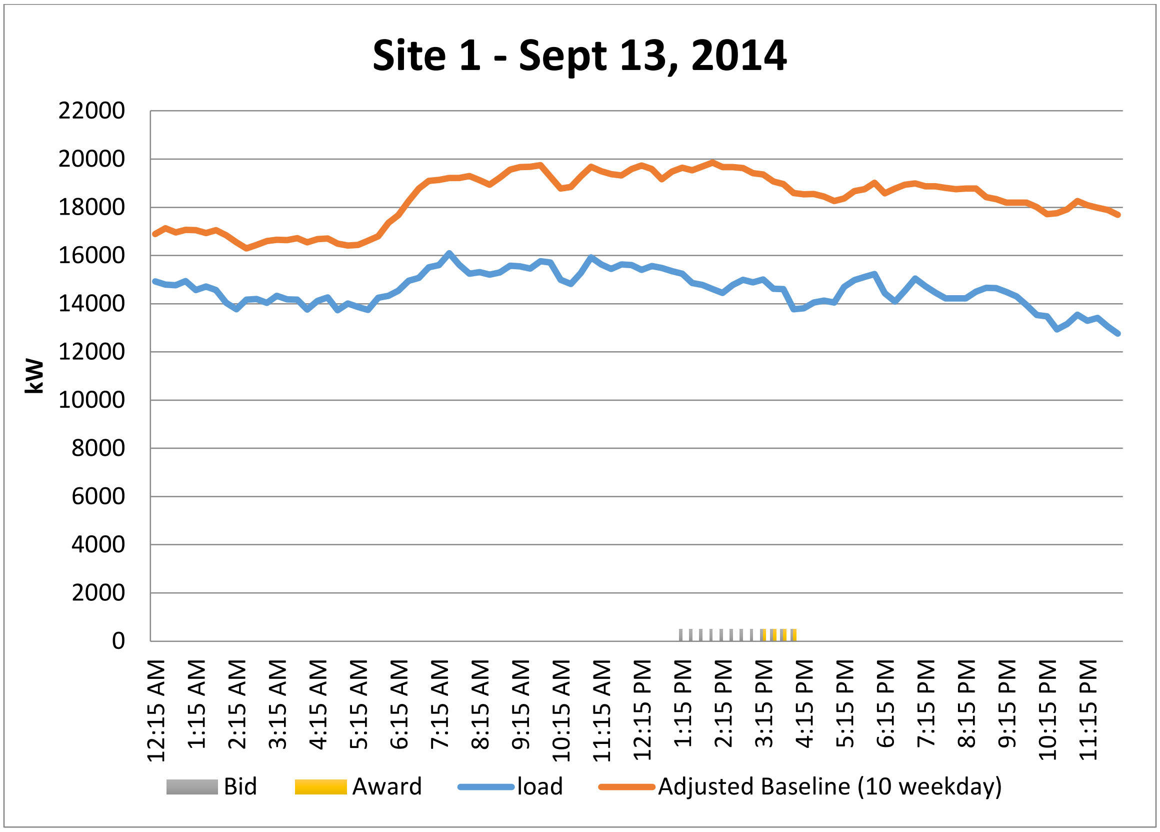
Tesla					
8/2/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
3:15 PM	11,213	12427.2	500	500	1,214
3:30 PM	11,011	12411.6	500	500	1,401
3:45 PM	10,877	12364.8	500	500	1,488
4:00 PM	10,680	12301.2	500	500	1,621



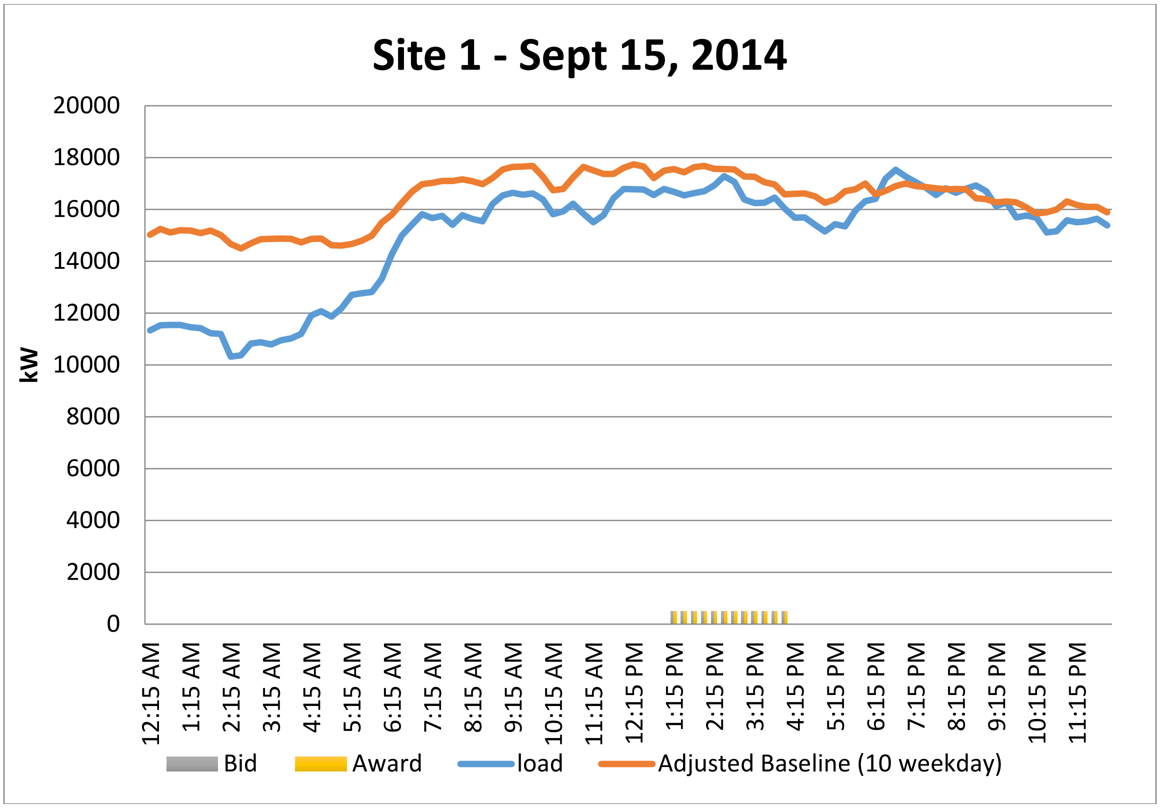
Tesla					
9/11/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
2:15 PM	16,666	16688.22	500	500	22
2:30 PM	16,478	16645.38	500	500	167
2:45 PM	16,531	16621.92	500	500	91
3:00 PM	16,200	16380.18	500	500	180
3:15 PM	15,802	16418.94	500	500	617
3:30 PM	15,931	16174.14	500	500	243
3:45 PM	15,734	16114.98	500	500	381
4:00 PM	15,480	15729.42	500	500	249



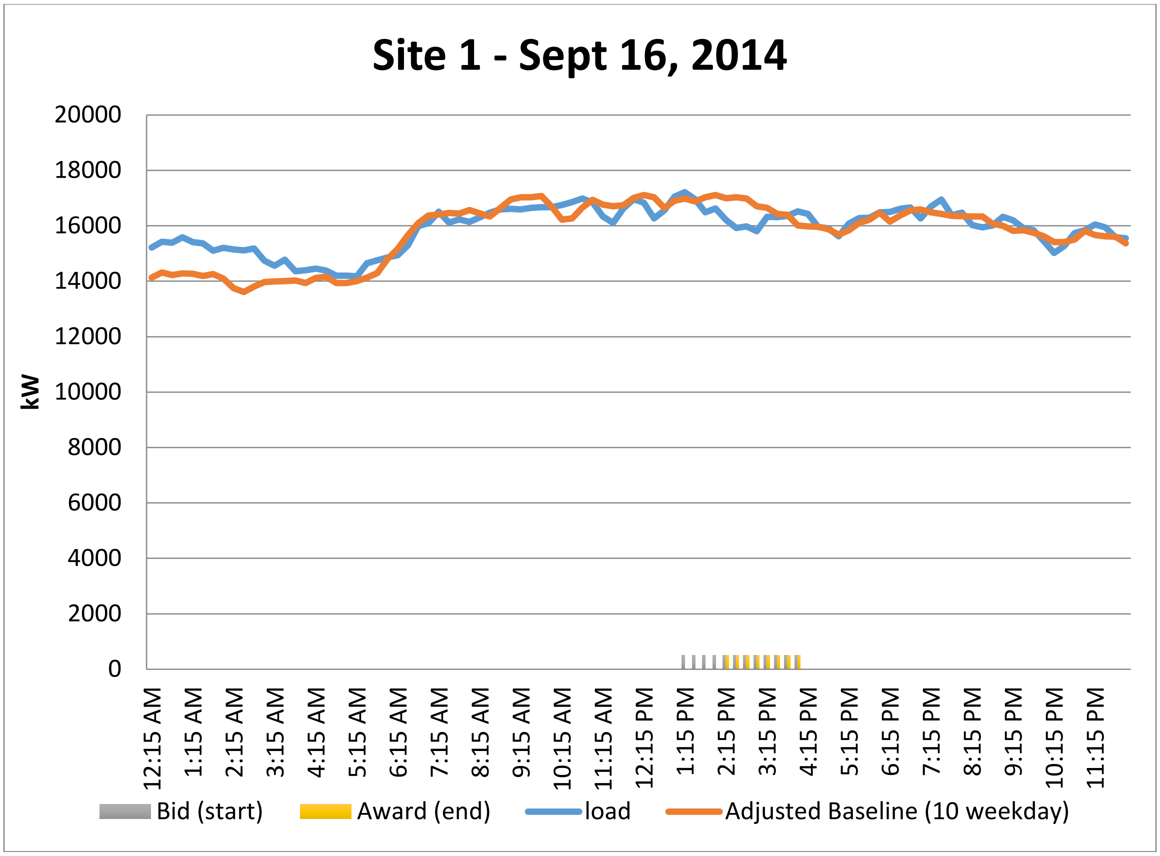
Tesla					
9/12/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
2:15 PM	16,661	16898.18	500	500	237
2:30 PM	16,853	16809.6	500	500	-43
2:45 PM	16,546	16806.51	500	500	261
3:00 PM	16,344	16545.92	500	500	202
3:15 PM	16,378	16562.4	500	500	184
3:30 PM	16,186	16363.61	500	500	178
3:45 PM	16,277	16302.84	500	500	26
4:00 PM	15,638	15941.31	500	500	303



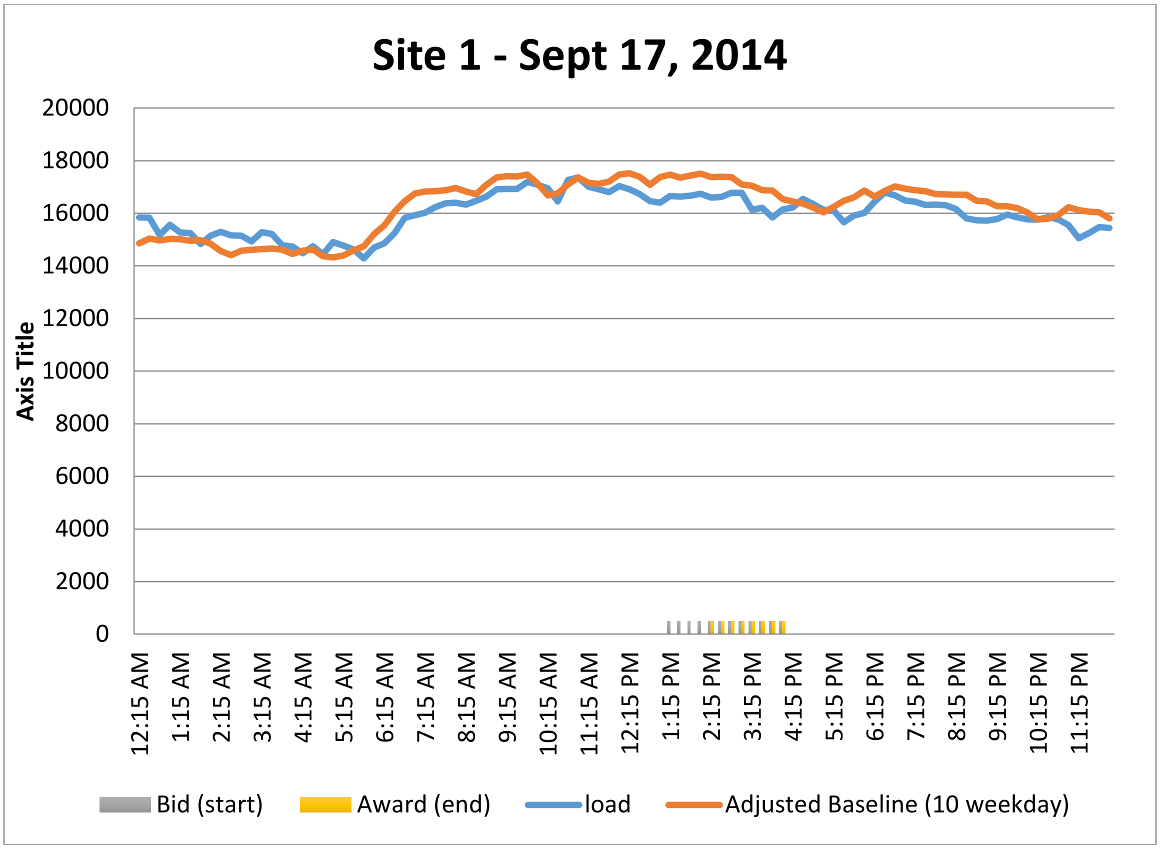
Tesla					
9/13/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
3:15 PM	15,000	19368	500	500	4,368
3:30 PM	14,616	19069.2	500	500	4,453
3:45 PM	14,611	18969.6	500	500	4,359
4:00 PM	13,766	18585.6	500	500	4,820



Tesla					
9/15/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
1:15 PM	17552.28	500	500	872	17552.28
1:30 PM	17436.72	500	500	891	17436.72
1:45 PM	17626.11	500	500	994	17626.11
2:00 PM	17678.54	500	500	975	17678.54
2:15 PM	17570.47	500	500	650	17570.47
2:30 PM	17554.42	500	500	264	17554.42
2:45 PM	17546.93	500	500	488	17546.93
3:00 PM	17266.59	500	500	880	17266.59
3:15 PM	17260.17	500	500	1,007	17260.17
3:30 PM	17053.66	500	500	792	17053.66
3:45 PM	16965.92	500	500	507	16965.92
4:00 PM	16579.65	500	500	548	16579.65

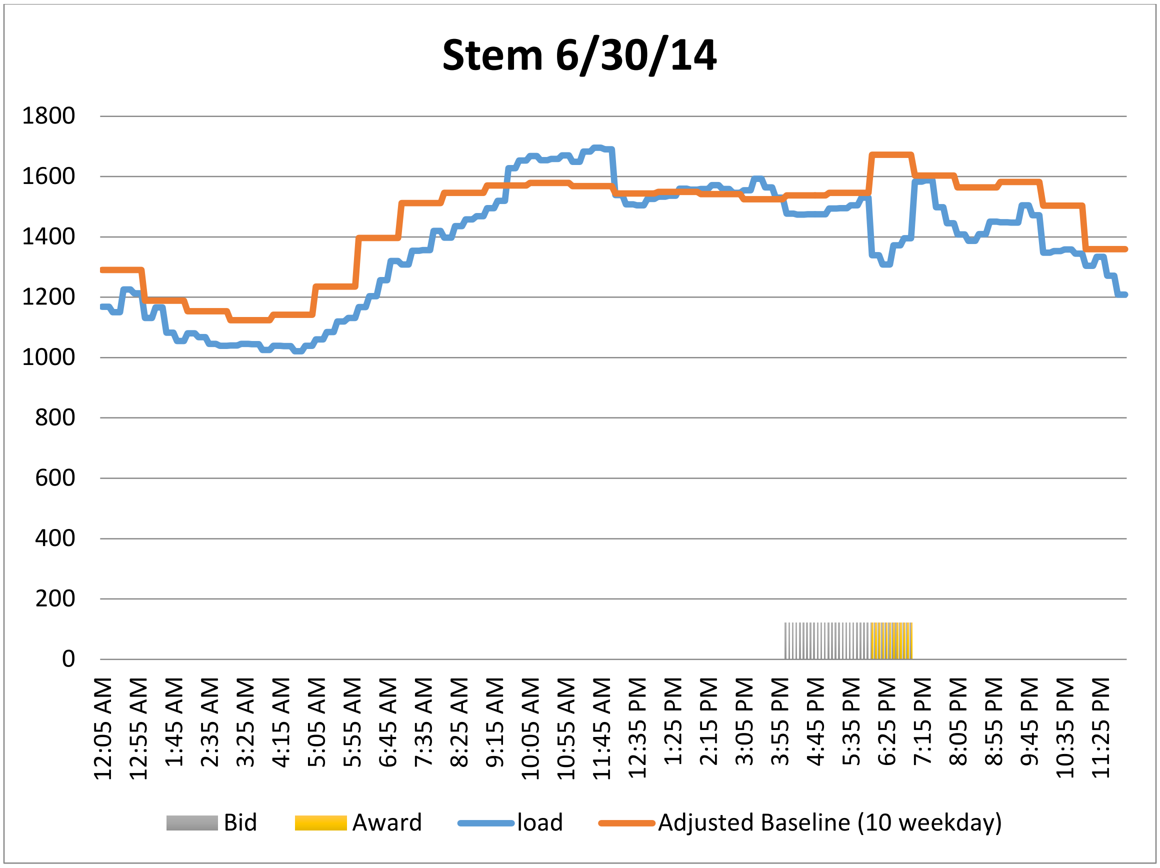


Tesla					
9/16/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
2:15 PM	16,214	16997.06	500	500	783
2:30 PM	15,917	17024.87	500	500	1,108
2:45 PM	15,979	16983.67	500	500	1,005
3:00 PM	15,802	16700.42	500	500	898
3:15 PM	16,325	16643.77	500	500	319
3:30 PM	16,315	16429.53	500	500	115
3:45 PM	16,358	16394.51	500	500	37
4:00 PM	16,517	16015.47	500	500	-502

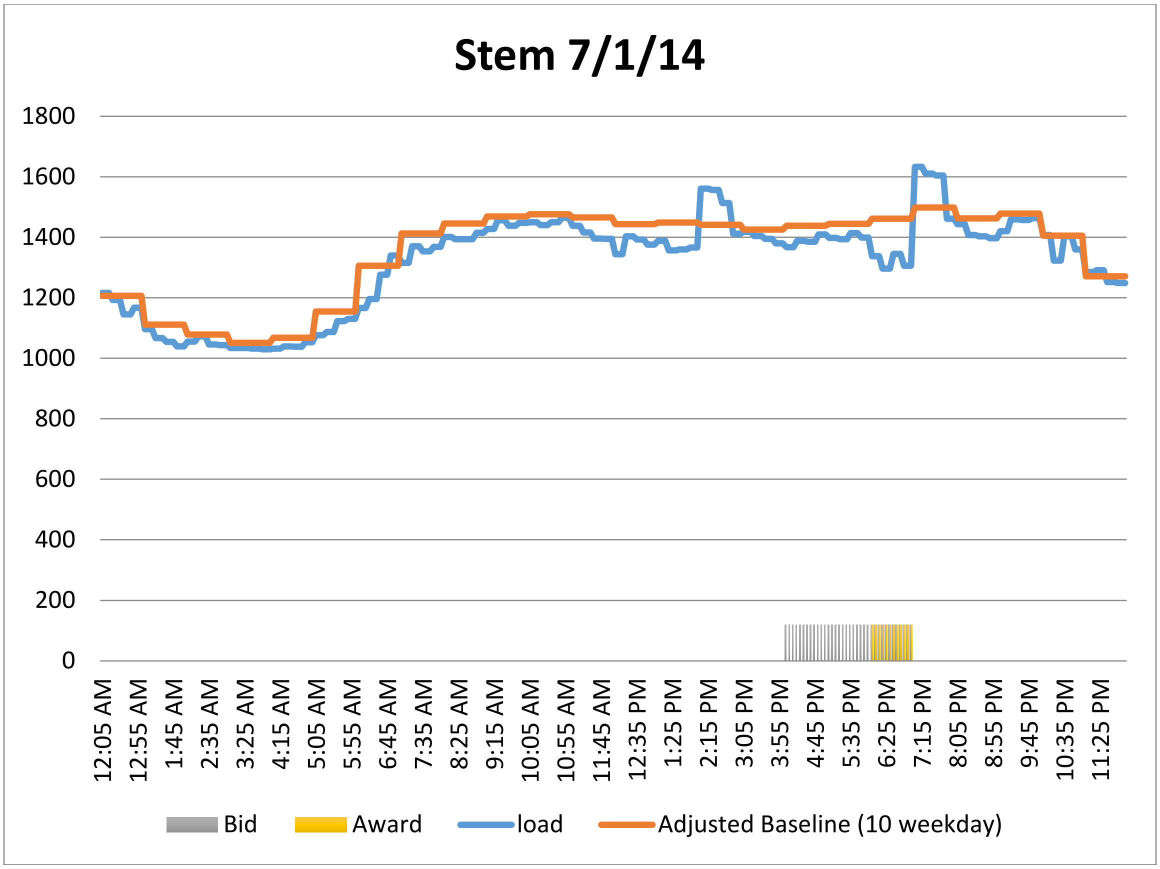


Tesla					
9/17/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
2:15 PM	16,598	17375.4	500	500	777
2:30 PM	16,618	17390.1	500	500	772
2:45 PM	16,781	17377.5	500	500	597
3:00 PM	16,776	17090.85	500	500	315
3:15 PM	16,128	17047.8	500	500	920
3:30 PM	16,205	16870.35	500	500	665
3:45 PM	15,840	16860.9	500	500	1,021
4:00 PM	16,147	16537.5	500	500	391

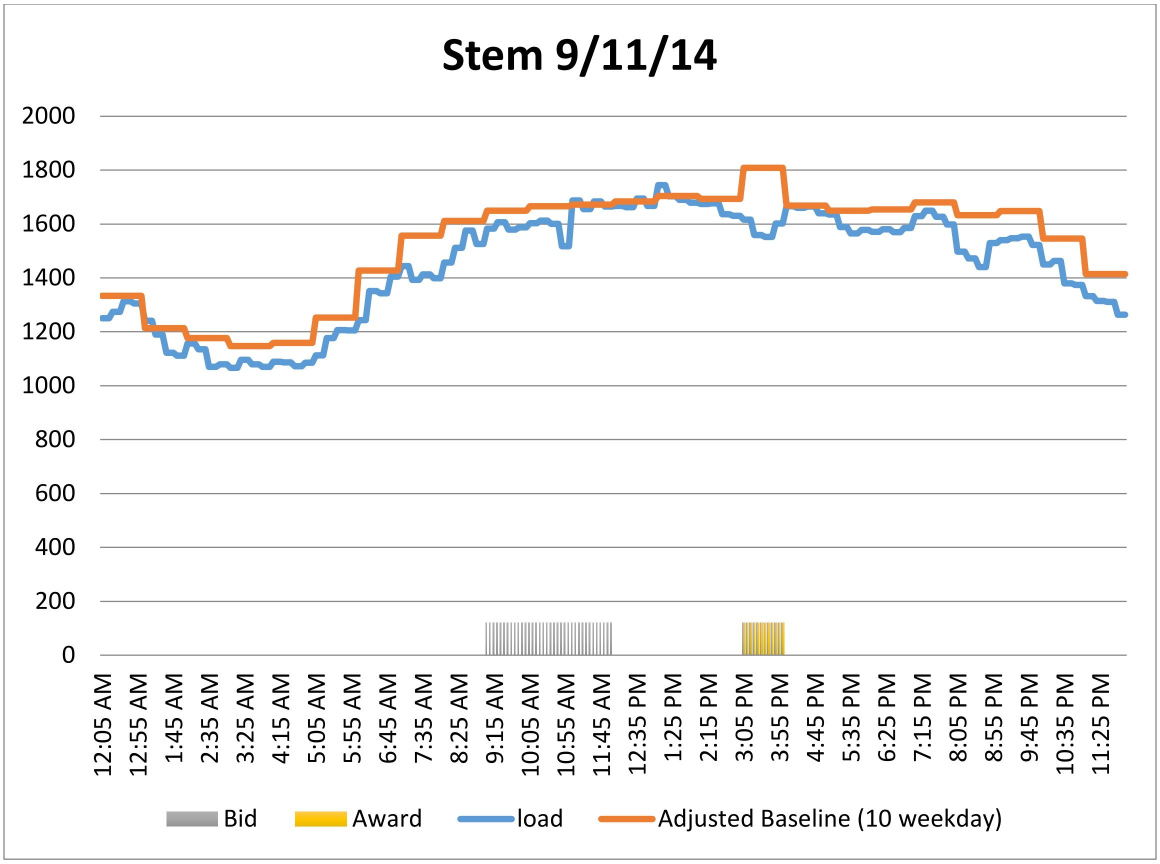
Note: Data for STEM is from Olivine others from Interact. Olivine is "native interval" data, in 5 min increments where Interact reports 15 min. data.



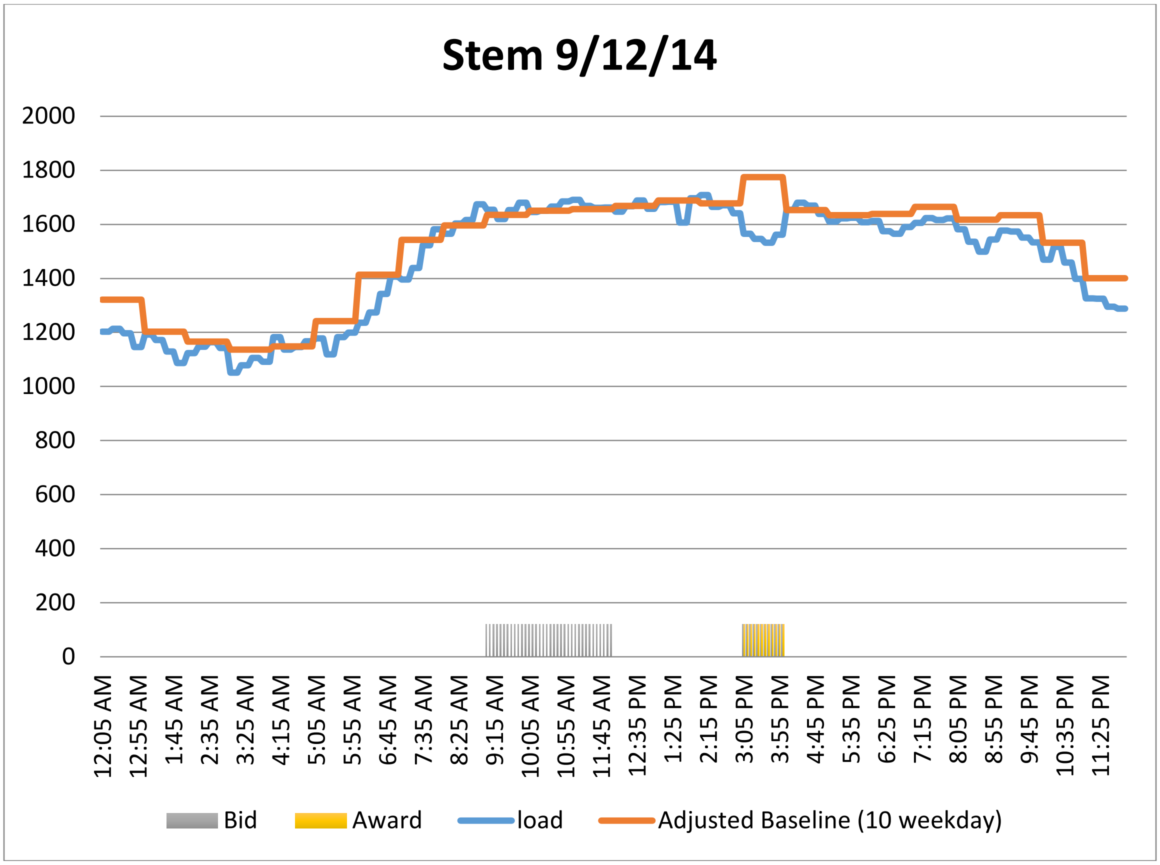
STEM					
6/30/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
6:05 PM	1,339.03	1671.95	120	120	223.54
6:10 PM	1,339.03	1671.95	120	120	223.54
6:15 PM	1,339.03	1671.95	120	120	223.54
6:20 PM	1,308.19	1671.95	120	120	254.38
6:25 PM	1,308.19	1671.95	120	120	254.38
6:30 PM	1,308.19	1671.95	120	120	254.38
6:35 PM	1,372.58	1671.95	120	120	189.99
6:40 PM	1,372.58	1671.95	120	120	189.99
6:45 PM	1,372.58	1671.95	120	120	189.99
6:50 PM	1,395.51	1671.95	120	120	167.06
6:55 PM	1,395.51	1671.95	120	120	167.06
7:00 PM	1,395.51	1671.95	120	120	167.06



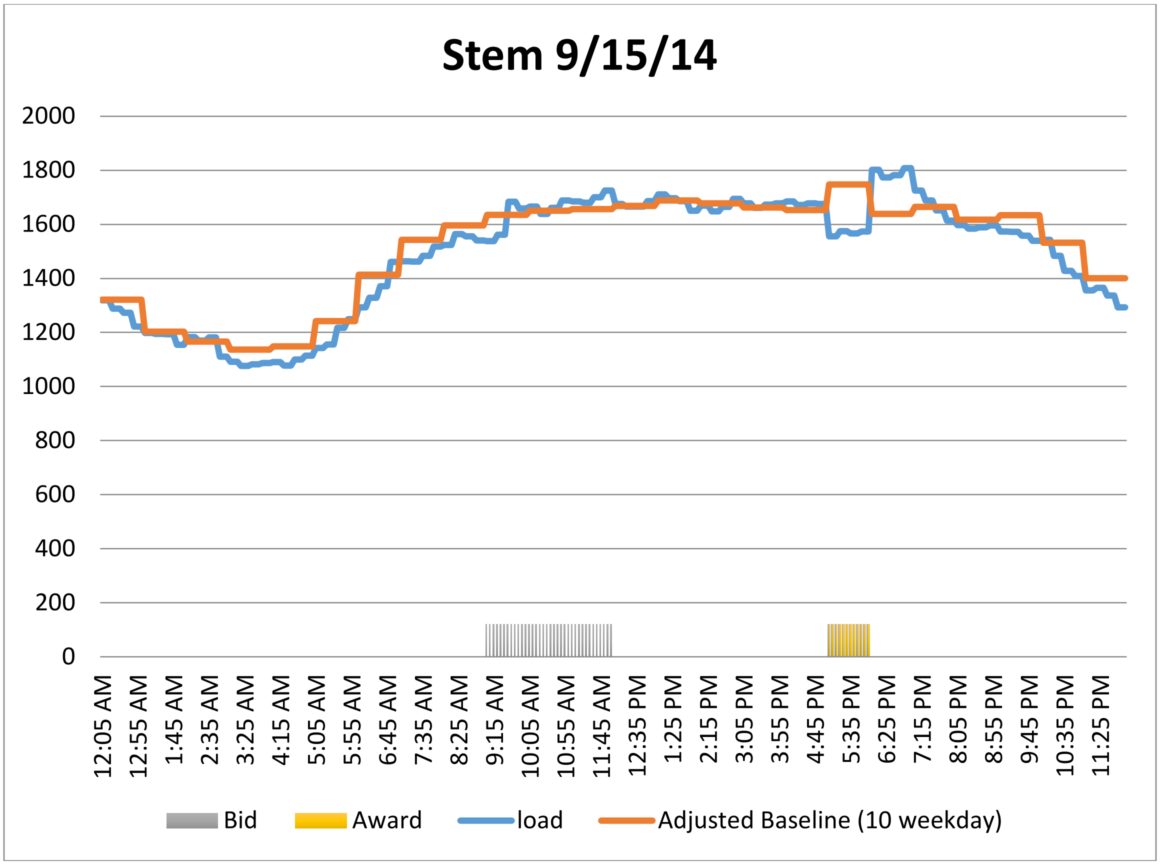
STEM					
7/1/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
6:05 AM	1,165.84	1,305.43	120	120	139.59
6:10 AM	1,165.84	1,305.43	120	120	139.59
6:15 AM	1,165.84	1,305.43	120	120	139.59
6:20 AM	1,195.36	1,305.43	120	120	110.07
6:25 AM	1,195.36	1,305.43	120	120	110.07
6:30 AM	1,195.36	1,305.43	120	120	110.07
6:35 AM	1,276.48	1,305.43	120	120	28.95
6:40 AM	1,276.48	1,305.43	120	120	28.95
6:45 AM	1,276.48	1,305.43	120	120	28.95
6:50 AM	1,339.87	1,305.43	120	120	-34.44
6:55 AM	1,339.87	1,305.43	120	120	-34.44
7:00 AM	1,339.87	1,305.43	120	120	-34.44



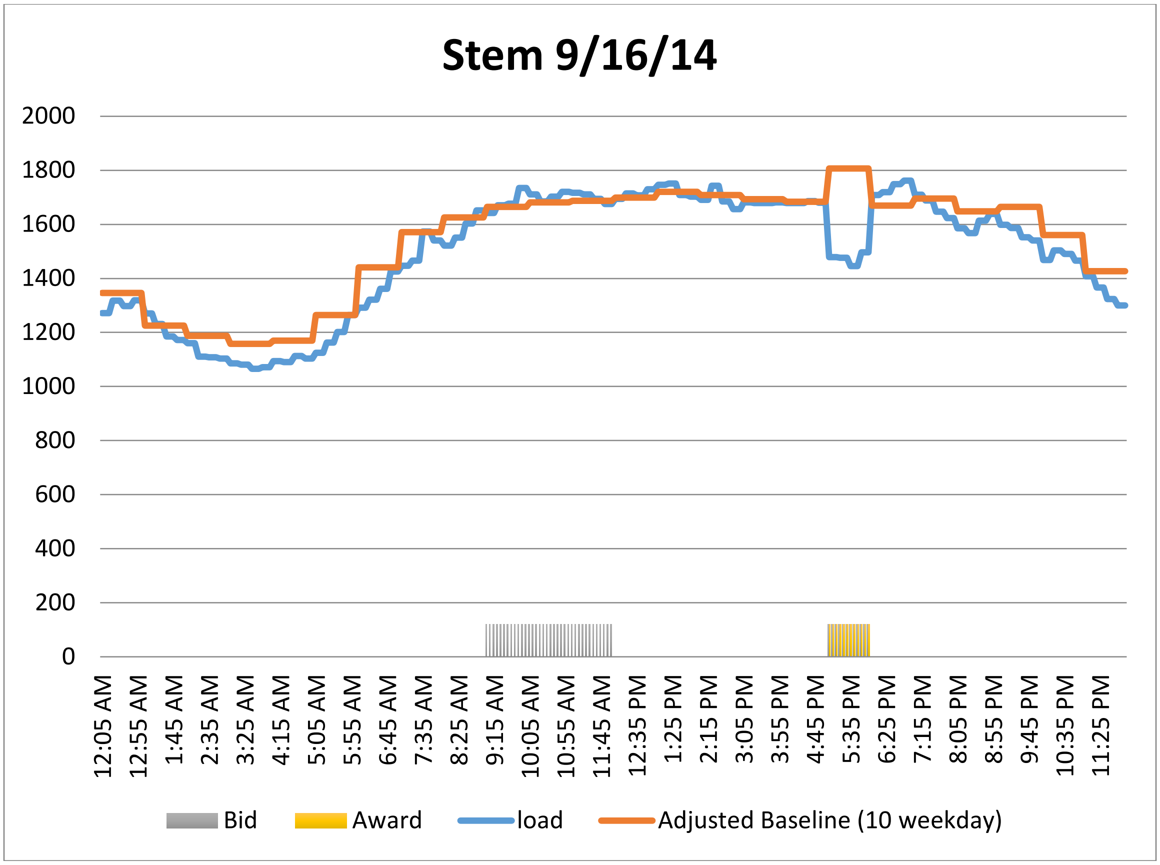
STEM					
9/11/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
3:05 PM	1616.18	1808.536	120	120	58.39
3:10 PM	1616.18	1808.536	120	120	58.39
3:15 PM	1616.18	1808.536	120	120	58.39
3:20 PM	1559.57	1808.536	120	120	115
3:25 PM	1559.57	1808.536	120	120	115
3:30 PM	1559.57	1808.536	120	120	115
3:35 PM	1552.14	1808.536	120	120	122.43
3:40 PM	1552.14	1808.536	120	120	122.43
3:45 PM	1552.14	1808.536	120	120	122.43
3:50 PM	1601.37	1808.536	120	120	73.2
3:55 PM	1601.37	1808.536	120	120	73.2
4:00 PM	1601.37	1808.536	120	120	73.2



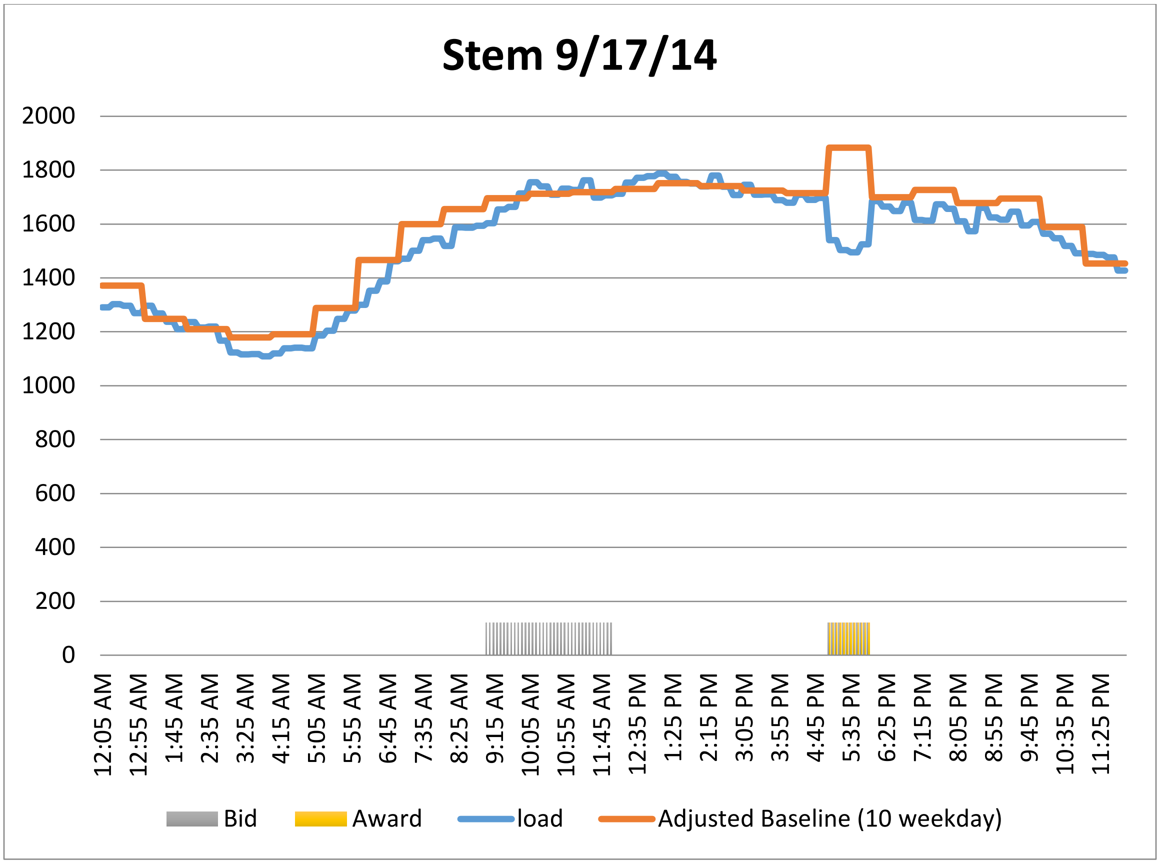
STEM					
9/12/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
3:05 PM	1565.09	1775.226	120	120	94
3:10 PM	1565.09	1775.226	120	120	94
3:15 PM	1565.09	1775.226	120	120	94
3:20 PM	1546.31	1775.226	120	120	112.78
3:25 PM	1546.31	1775.226	120	120	112.78
3:30 PM	1546.31	1775.226	120	120	112.78
3:35 PM	1531.69	1775.226	120	120	127.4
3:40 PM	1531.69	1775.226	120	120	127.4
3:45 PM	1531.69	1775.226	120	120	127.4
3:50 PM	1561.59	1775.226	120	120	97.5
3:55 PM	1561.59	1775.226	120	120	97.5
4:00 PM	1561.59	1775.226	120	120	97.5



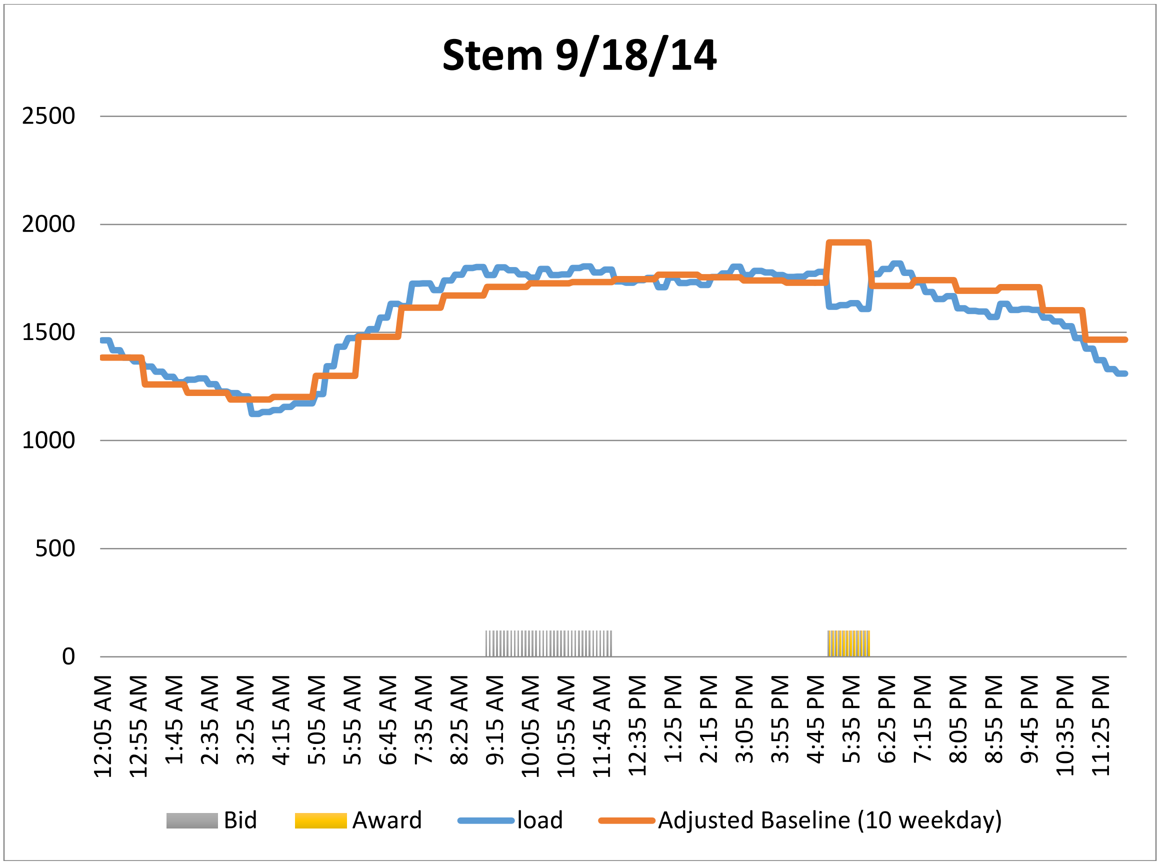
STEM					
9/15/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
5:05 PM	1,555.55	1747.588	120	120	77.71
5:10 PM	1,555.55	1747.588	120	120	77.71
5:15 PM	1,555.55	1747.588	120	120	77.71
5:20 PM	1,574.40	1747.588	120	120	58.86
5:25 PM	1,574.40	1747.588	120	120	58.86
5:30 PM	1,574.40	1747.588	120	120	58.86
5:35 PM	1,566.59	1747.588	120	120	66.67
5:40 PM	1,566.59	1747.588	120	120	66.67
5:45 PM	1,566.59	1747.588	120	120	66.67
5:50 PM	1,573.01	1747.588	120	120	60.25
5:55 PM	1,573.01	1747.588	120	120	60.25
6:00 PM	1,573.01	1747.588	120	120	60.25



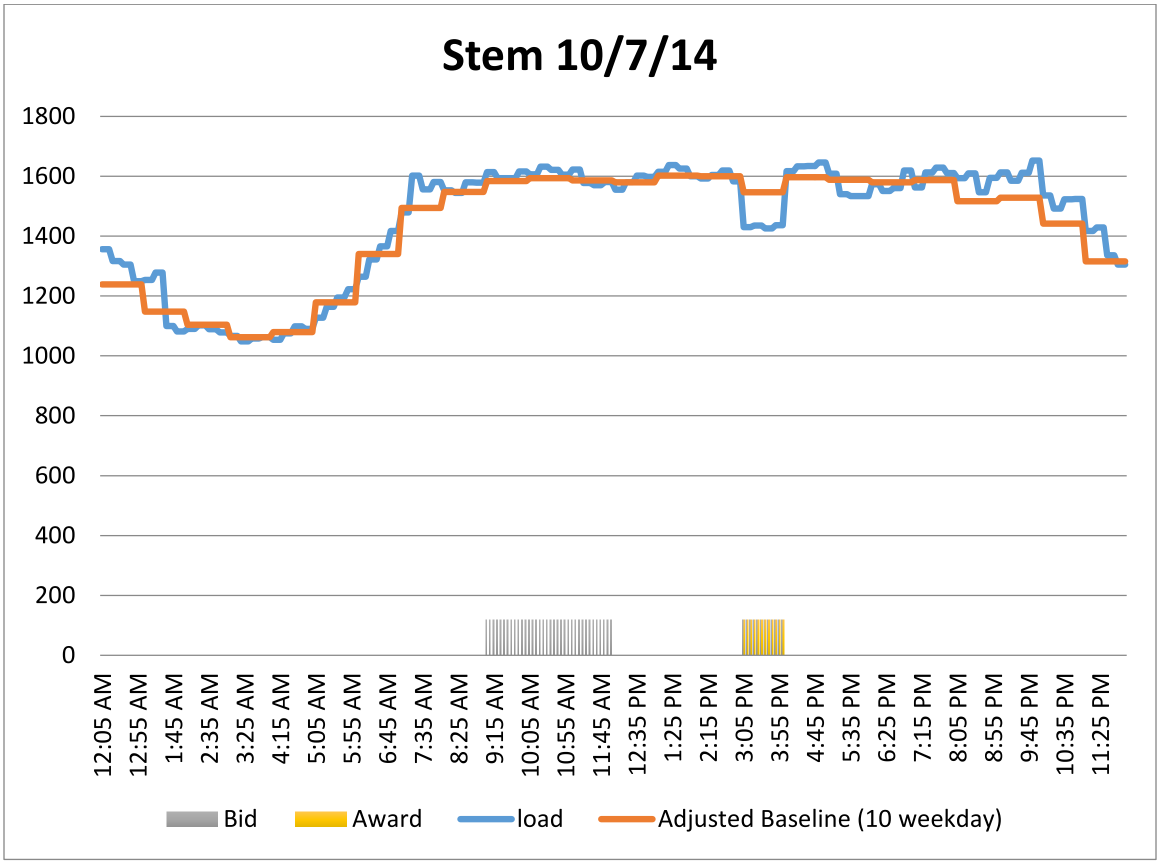
STEM					
9/16/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
5:05 PM	1,478.73	1806.174	120	120	178.31
5:10 PM	1,478.73	1806.174	120	120	178.31
5:15 PM	1,476.17	1806.174	120	120	180.87
5:20 PM	1,476.17	1806.174	120	120	180.87
5:25 PM	1,476.17	1806.174	120	120	180.87
5:30 PM	1,446.17	1806.174	120	120	210.87
5:35 PM	1,446.17	1806.174	120	120	210.87
5:40 PM	1,446.17	1806.174	120	120	210.87
5:45 PM	1,496.40	1806.174	120	120	160.64
5:50 PM	1,496.40	1806.174	120	120	160.64
5:55 PM	1,496.40	1806.174	120	120	160.64
6:00 PM	1,478.73	1806.174	120	120	178.31



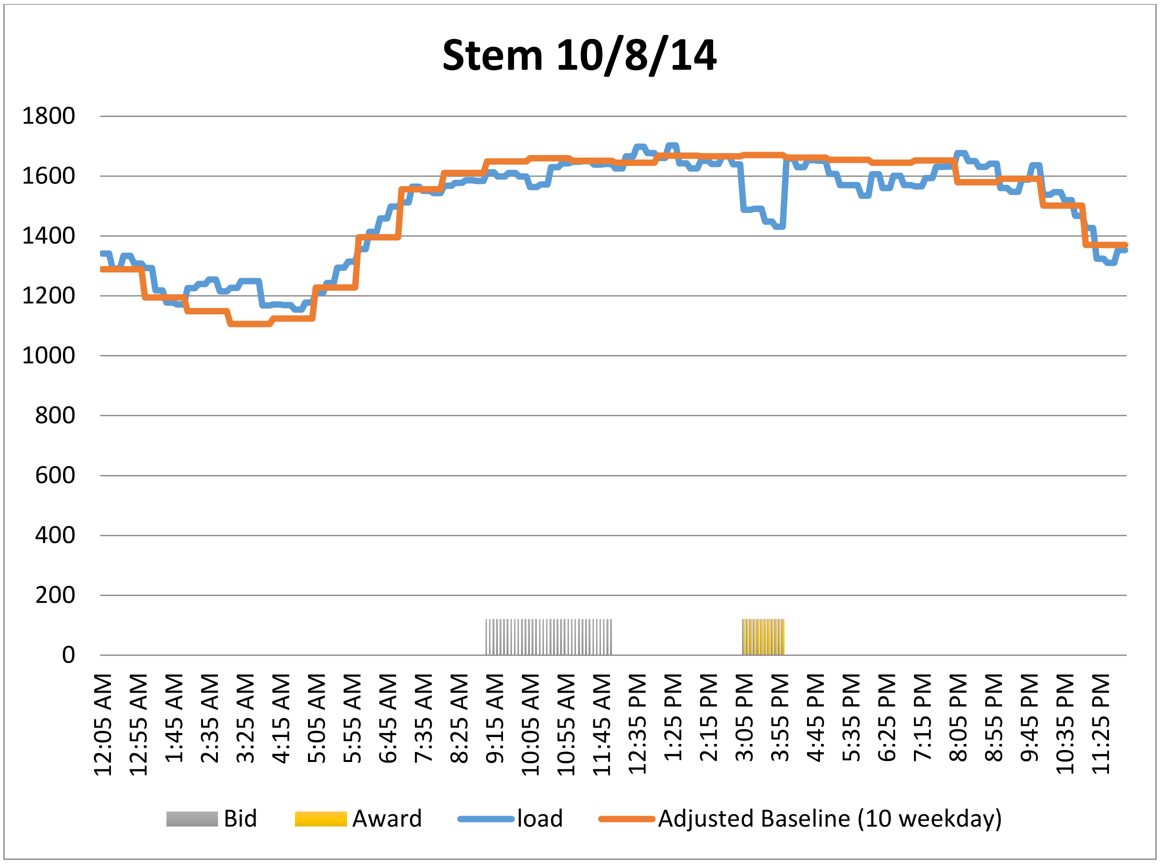
STEM					
9/17/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
5:05 PM	1,539.64	1883.148	120	120	156.89
5:10 PM	1,539.64	1883.148	120	120	156.89
5:15 PM	1,539.64	1883.148	120	120	156.89
5:20 PM	1,503.88	1883.148	120	120	192.65
5:25 PM	1,503.88	1883.148	120	120	192.65
5:30 PM	1,503.88	1883.148	120	120	192.65
5:35 PM	1,494.46	1883.148	120	120	202.07
5:40 PM	1,494.46	1883.148	120	120	202.07
5:45 PM	1,494.46	1883.148	120	120	202.07
5:50 PM	1,525.02	1883.148	120	120	171.51
5:55 PM	1,525.02	1883.148	120	120	171.51
6:00 PM	1,525.02	1883.148	120	120	171.51



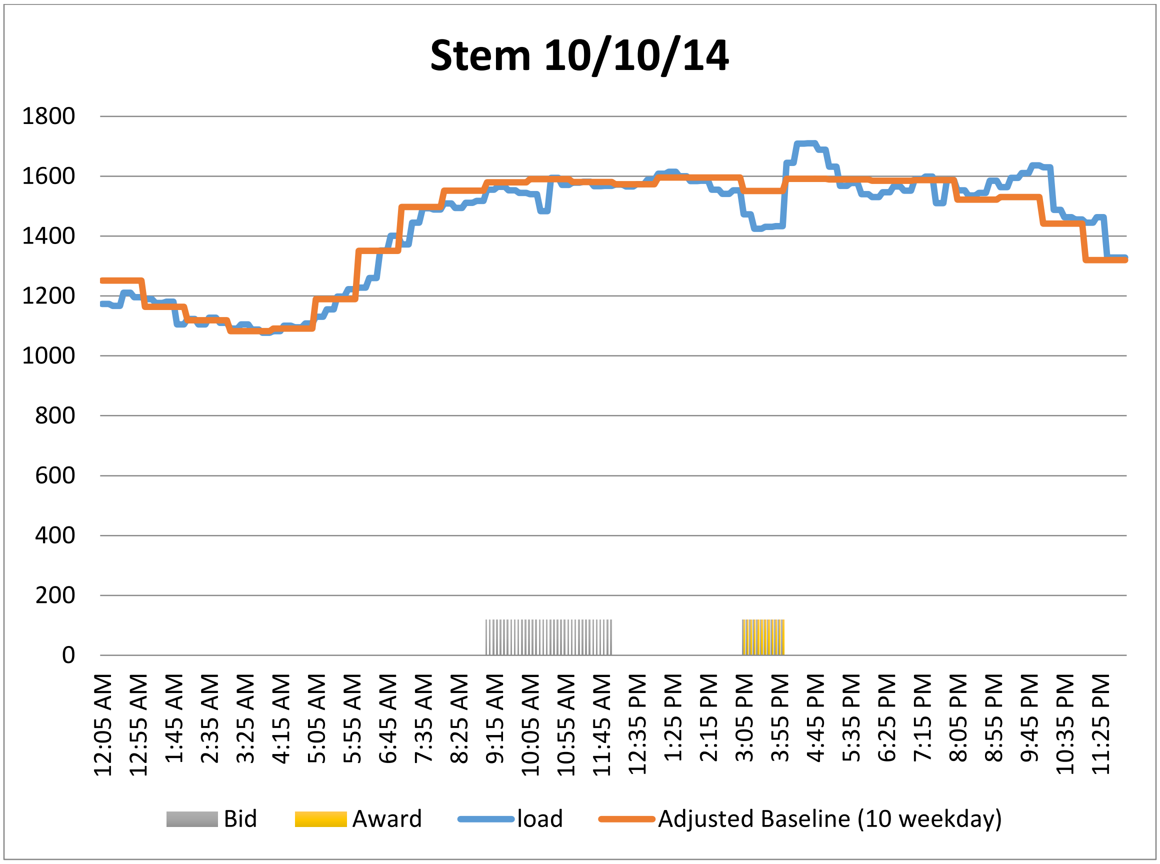
STEM					
9/18/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
5:05 PM	1619.75	1916.869	120	120	91.74
5:10 PM	1619.75	1916.869	120	120	91.74
5:15 PM	1619.75	1916.869	120	120	91.74
5:20 PM	1626.17	1916.869	120	120	85.32
5:25 PM	1626.17	1916.869	120	120	85.32
5:30 PM	1626.17	1916.869	120	120	85.32
5:35 PM	1635.55	1916.869	120	120	75.94
5:40 PM	1635.55	1916.869	120	120	75.94
5:45 PM	1635.55	1916.869	120	120	75.94
5:50 PM	1607.99	1916.869	120	120	103.5
5:55 PM	1607.99	1916.869	120	120	103.5
6:00 PM	1607.99	1916.869	120	120	103.5



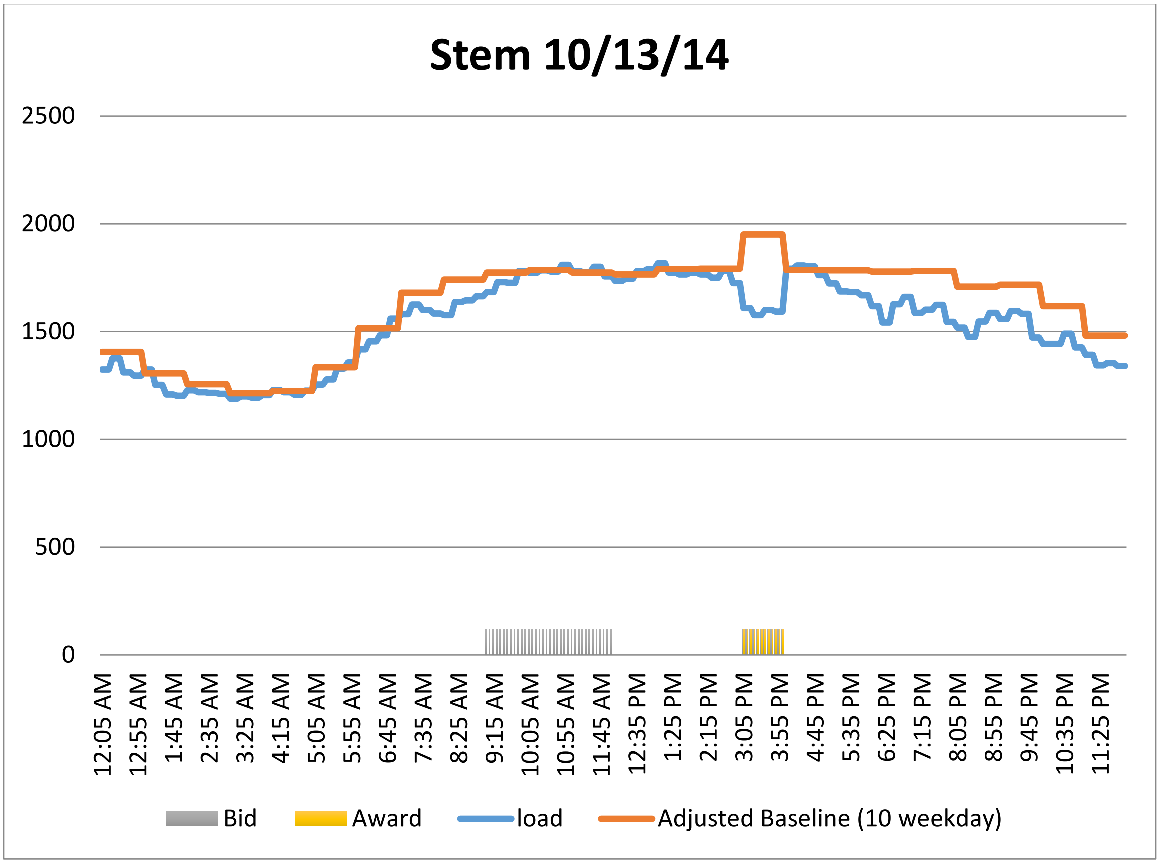
STEM					
10/7/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
3:05 PM	1430.01	1546.626	120	120	164.45
3:10 PM	1430.01	1546.626	120	120	164.45
3:15 PM	1430.01	1546.626	120	120	164.45
3:20 PM	1435.4	1546.626	120	120	159.06
3:25 PM	1435.4	1546.626	120	120	159.06
3:30 PM	1435.4	1546.626	120	120	159.06
3:35 PM	1425.95	1546.626	120	120	168.51
3:40 PM	1425.95	1546.626	120	120	168.51
3:45 PM	1425.95	1546.626	120	120	168.51
3:50 PM	1436.17	1546.626	120	120	158.29
3:55 PM	1436.17	1546.626	120	120	158.29
4:00 PM	1436.17	1546.626	120	120	158.29



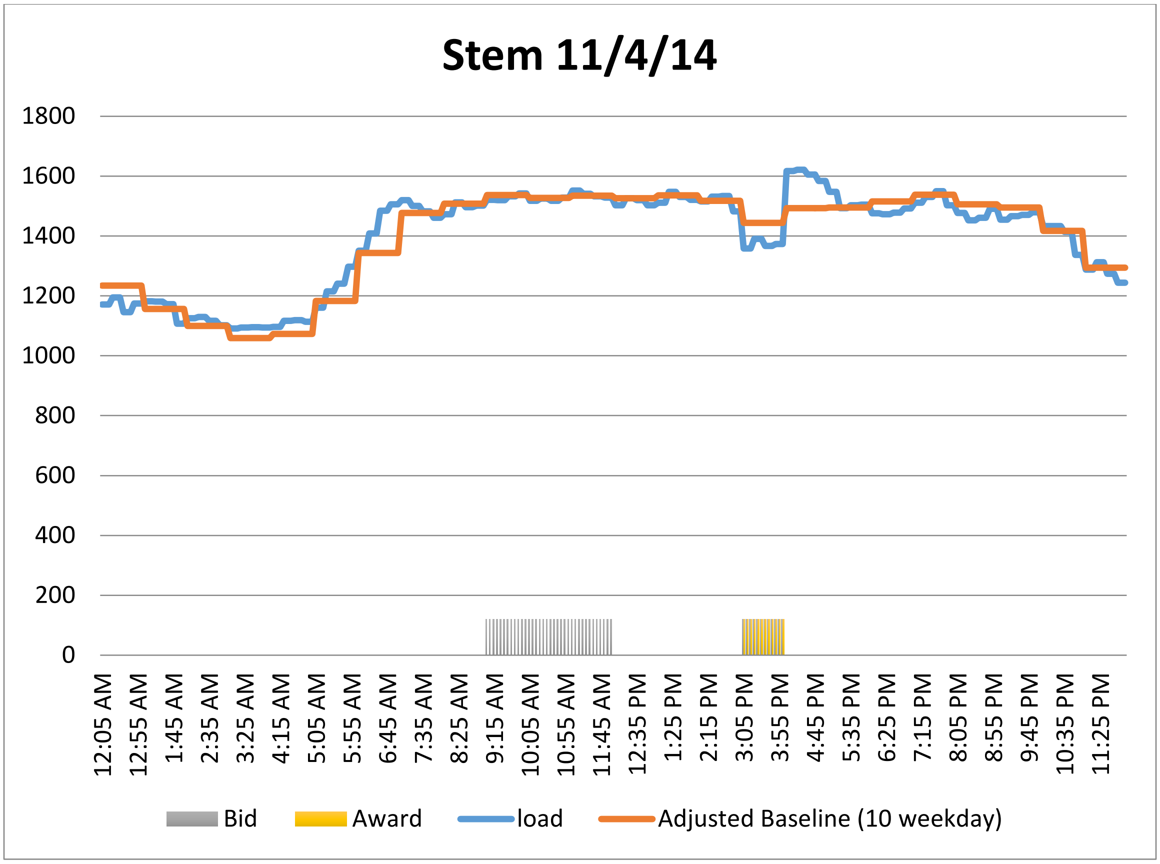
STEM					
10/8/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
3:05 PM	1,487.80	1670.318	120	120	165.98
3:10 PM	1,487.80	1670.318	120	120	165.98
3:15 PM	1,487.80	1670.318	120	120	165.98
3:20 PM	1,491.33	1670.318	120	120	162.45
3:25 PM	1,491.33	1670.318	120	120	162.45
3:30 PM	1,491.33	1670.318	120	120	162.45
3:35 PM	1,448.18	1670.318	120	120	205.6
3:40 PM	1,448.18	1670.318	120	120	205.6
3:45 PM	1,448.18	1670.318	120	120	205.6
3:50 PM	1,431.14	1670.318	120	120	222.64
3:55 PM	1,431.14	1670.318	120	120	222.64
4:00 PM	1,431.14	1670.318	120	120	222.64



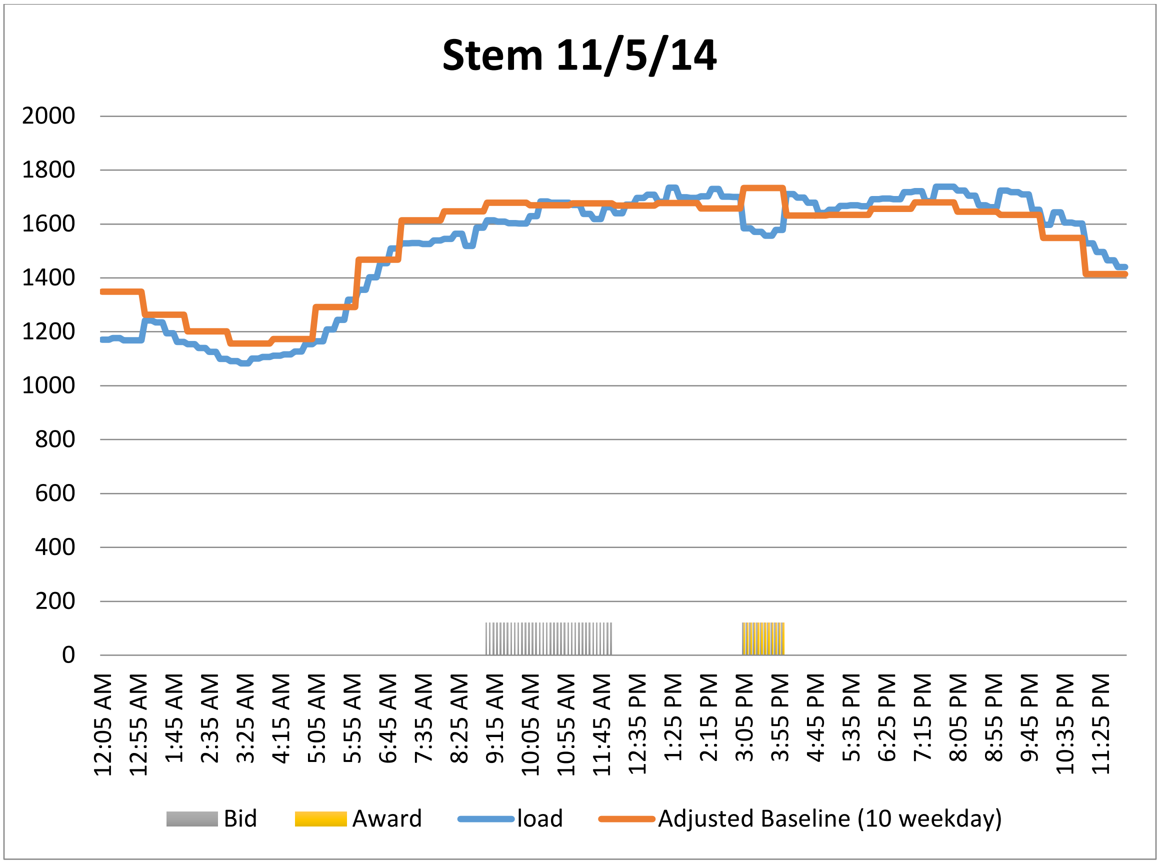
STEM					
10/10/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
3:05 PM	1,472.94	1551.046	120	120	109.76
3:10 PM	1,472.94	1551.046	120	120	109.76
3:15 PM	1,472.94	1551.046	120	120	109.76
3:20 PM	1,424.24	1551.046	120	120	158.46
3:25 PM	1,424.24	1551.046	120	120	158.46
3:30 PM	1,424.24	1551.046	120	120	158.46
3:35 PM	1,431.37	1551.046	120	120	151.33
3:40 PM	1,431.37	1551.046	120	120	151.33
3:45 PM	1,431.37	1551.046	120	120	151.33
3:50 PM	1,433.16	1551.046	120	120	149.54
3:55 PM	1,433.16	1551.046	120	120	149.54
4:00 PM	1,433.16	1551.046	120	120	149.54



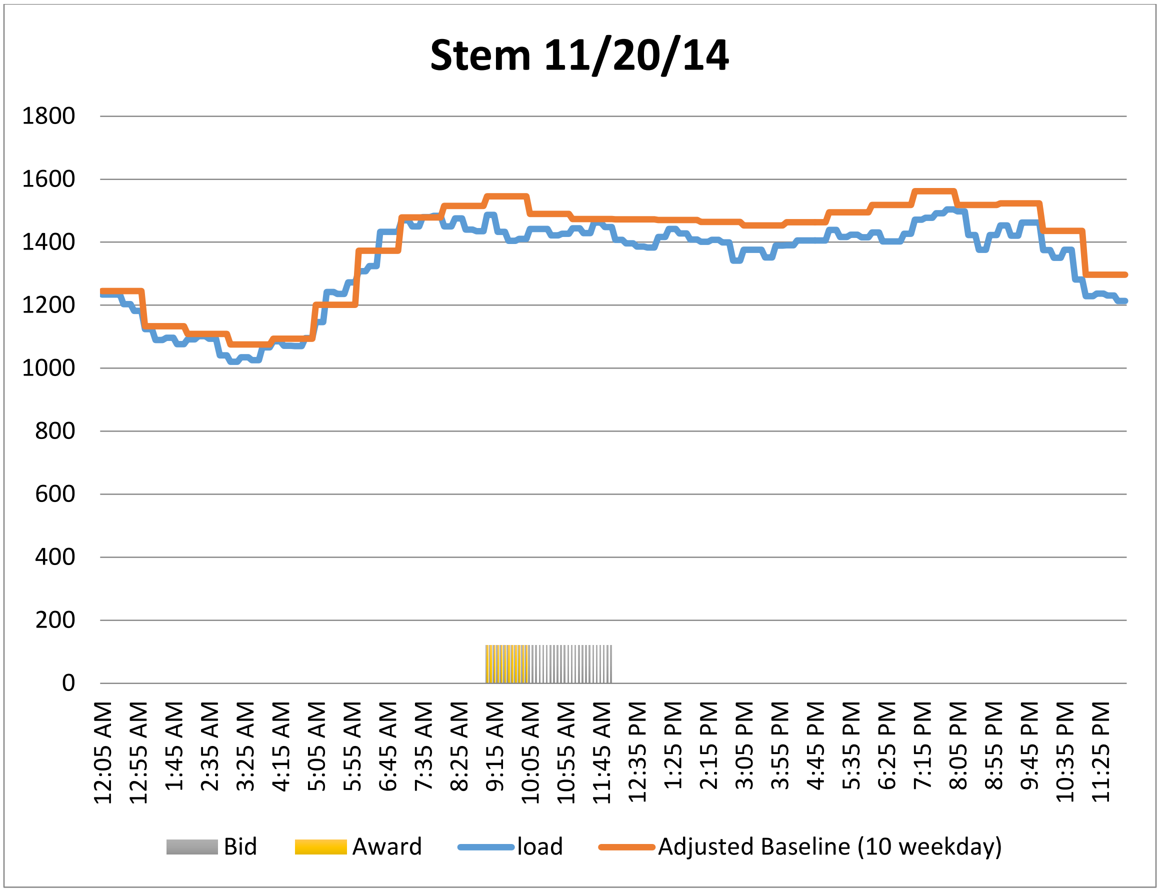
STEM					
10/13/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
3:05 PM	1609.34	1950.784	120	120	164.1
3:10 PM	1609.34	1950.784	120	120	164.1
3:15 PM	1609.34	1950.784	120	120	164.1
3:20 PM	1577.05	1950.784	120	120	196.39
3:25 PM	1577.05	1950.784	120	120	196.39
3:30 PM	1577.05	1950.784	120	120	196.39
3:35 PM	1599.77	1950.784	120	120	173.67
3:40 PM	1599.77	1950.784	120	120	173.67
3:45 PM	1599.77	1950.784	120	120	173.67
3:50 PM	1593.17	1950.784	120	120	180.27
3:55 PM	1593.17	1950.784	120	120	180.27
4:00 PM	1593.17	1950.784	120	120	180.27



STEM					
11/4/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
3:05 PM	1358.01	1444.049	120	120	1358.01
3:10 PM	1358.01	1444.049	120	120	1358.01
3:15 PM	1358.01	1444.049	120	120	1358.01
3:20 PM	1390.71	1444.049	120	120	1390.71
3:25 PM	1390.71	1444.049	120	120	1390.71
3:30 PM	1390.71	1444.049	120	120	1390.71
3:35 PM	1366.48	1444.049	120	120	1366.48
3:40 PM	1366.48	1444.049	120	120	1366.48
3:45 PM	1366.48	1444.049	120	120	1366.48
3:50 PM	1373.14	1444.049	120	120	1373.14
3:55 PM	1373.14	1444.049	120	120	1373.14
4:00 PM	1373.14	1444.049	120	120	1373.14



STEM					
11/5/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
3:05 PM	130.7	1584.2	1733.535	120	120
3:10 PM	130.7	1584.2	1733.535	120	120
3:15 PM	130.7	1584.2	1733.535	120	120
3:20 PM	98	1570.43	1733.535	120	120
3:25 PM	98	1570.43	1733.535	120	120
3:30 PM	98	1570.43	1733.535	120	120
3:35 PM	122.23	1556.19	1733.535	120	120
3:40 PM	122.23	1556.19	1733.535	120	120
3:45 PM	122.23	1556.19	1733.535	120	120
3:50 PM	115.57	1578.54	1733.535	120	120
3:55 PM	115.57	1578.54	1733.535	120	120
4:00 PM	115.57	1578.54	1733.535	120	120



STEM					
11/20/2014					
Hours	Load	Adjusted Baseline (10 weekday)	Bid	Award	Load Reduction
9:05 AM	1,486.96	1545.677	120	120	28.41
9:10 AM	1,486.96	1545.677	120	120	28.41
9:15 AM	1,486.96	1545.677	120	120	28.41
9:20 AM	1,433.00	1545.677	120	120	82.37
9:25 AM	1,433.00	1545.677	120	120	82.37
9:30 AM	1,433.00	1545.677	120	120	82.37
9:35 AM	1,404.36	1545.677	120	120	111.01
9:40 AM	1,404.36	1545.677	120	120	111.01
9:45 AM	1,404.36	1545.677	120	120	111.01
9:50 AM	1,410.79	1545.677	120	120	104.58
9:55 AM	1,410.79	1545.677	120	120	104.58
10:00 AM	1,410.79	1545.677	120	120	104.58