NON-WIRES ALTERNATIVES AS A PATH TO LOCAL CLEAN ENERGY: APPENDIX A

Demand Response Field Test Protocol and Results

Center for Energy and Environment

RESEARCH GOAL

This document outlines the most recently proposed protocol and results from dispatching Xcel Energy's AC Rewards and Saver's Switch demand response (DR) assets for residential customers in a localized, non-wires alternative (NWA) area in 2019 and 2020 to assess the impact of demand response assets on the local distribution system for the non-wires alternative pilot. These field tests had the following objectives:

- Assess the value of these assets to distribution system capacity;
- Assess the interaction of these assets with declining community solar garden (CSG) production in the evening; and
- Compare above impacts across system (at the feeder level).

DEMAND RESPONSE DISPATCH FOR PILOT AREA

Communicating a Dispatch

We proposed a dispatch confirmation request be issued by CEE to Xcel Energy operations staff three days prior to an anticipated dispatch. A CEE staff member emailed Xcel Energy operations staff each Monday to indicate if a dispatch confirmation request would be likely in the upcoming week. A final go/no-go dispatch signal was issued one day before the potential dispatch.

Dispatch Events

This protocol was made up of four individual "dispatch events" at the pilot site during the cooling season (largely anticipated in July and August). The three-hour dispatch treatments were scheduled around the peak period for this part of the system and timed to coincide as community solar production was tailing off during the latter part of the evening (5:00 p.m.–8:00 p.m.). As of early 2020, there were 3,833 residential customers enrolled in Saver's Switch and 39 customers enrolled in Residential AC Rewards.

Table 1: Four dispatch events.

Description of Treatment	Duration	Event Length	Total Dispatch Events	Target Criteria (High Temp)	Contingency Criteria (High Temp)
Call single group at 5 p.m.	5–8 p.m. (3 hr)	One day	4	≥ 86 ˚F	≥ 85 ˚F

Dispatch Schedule & Contingency Planning

The field test ran June through September, but dispatch conditions were anticipated to occur July through August given historic temperature trends. It was planned to wait a minimum of one week between dispatch events.

Table 2 shows the anticipated schedule of the treatments by month. If dispatch conditions were not satisfied in the first two weeks of any month with scheduled dispatches (i.e., before the 15th), the contingency values were to be triggered until the required number of dispatches would be achieved for that month. For example, if a one-day weekday period with forecasted peak temperatures exceeding 86°F was not realized through June 1 through July 14, the contingency dispatch criterion would be lessened to 85°F until a one-day dispatch is completed.

Table 2: Treatment schedule

Type	July	August
One day	2	2

TECHNICAL DATA AND BACKGROUND

Dispatch Criteria

Dispatch criteria were based on field test requirements and the likely incidence of these events, a balance between the peak load conditions (due to high outside temperature) and the probability of high outdoor temperature events occurring in the field test period (May–September). Five years of data were analyzed for the field test area to determine the frequency of single-day (one-day) events of peak temperatures. The frequency of peak summer temperatures for the past five years is shown in Table 3. These figures were translated into a probability that such events would occur in Table 4 for one-day events in the 2019 and 2020 field test periods.

Two sets of criteria were developed, a target value and a contingency value. Target values were the highest peak temperatures that would occur with less than 95% confidence. Contingency values were those values which would occur with greater than 95% confidence. The number of events deemed necessary was more than the planned calls to allow for scheduling flexibility and control data (triggering events without resource dispatch).

Table 3: N weekdays with temperature at or exceeding given value

Year	80°F	81°F	82°F	83°F	84°F	85°F	86°F	87°F	88°F	89°F	90°F
2014	44	39	31	20	12	8	4	3	1	1	1
2015	39	35	25	22	13	7	6	4	3	2	2
2016	33	28	26	20	17	14	11	9	7	5	2
2017	36	31	26	20	15	11	10	7	6	4	2
2018	44	39	33	29	22	16	11	10	8	8	7

Table 4: Probability of N weekday events with temperature exceeding given value

Type	80°F	81°F	82°F	83°F	84°F	85°F	86°F	87°F	88°F	89°F	90°F
(6) 1-day events	100%	100%	100%	100%	100%	98%	85%	69%	33%	16%	3%

Table 5: Target and contingency values for triggering dispatch and control events.

Type	Target (°F)	Contingency (°F)
1-day	86	85

Dispatch Schedule

Dispatch calls were scheduled based on their likelihood on a monthly basis during the May through September period as shown in Table 6, which yields the call schedule given in Table 7. The probabilities that the given quantity of dispatch events will occur by reaching the target values and contingency values are shown in Table 8 and Table 9, respectively. Pacing dispatches throughout the summer also enables a more systematic approach to apply contingency plans should target conditions not be reached.

Table 6. N weekdays with temperature at or exceeding given value (five years)

Month	80°F	81°F	82°F	83°F	84°F	85°F	86°F	87°F	88°F	89°F	90°F
May	13	12	12	10	9	8	7	6	5	4	4
June	26	22	20	14	8	7	6	6	6	4	3
July	30	29	28	26	20	17	13	9	7	6	4
August	25	24	24	21	18	13	10	7	4	4	2
September	13	12	12	9	7	3	3	3	2	1	0

Table 7: Dispatch schedule, falling short triggers contingency call schedule on a monthly basis

Type	May	June	July	August	Sep	Total
One-day			2	2		4

Table 8: Probability of trigger events by month

P - trigger	May	June	July	August	Sep
One-day — 86°F	47%	75%	86%	61%	32%

Table 9: Probability of contingency events by month

P - contingency	May	June	July	August	Sep
One-day — 85°F	54%	84%	97%	80%	67%

Scheduling

The dispatch schedule was proposed to be organized around the 10-day weather forecast, which was monitored by CEE daily. Potential dispatch conditions were identified at 10-, 5-, and 3-day intervals. The highest peak temperatures were prioritized in any given forecast window. A dispatch request was issued by CEE to Xcel Operations staff three days prior to an anticipated dispatch. A final go/no-go dispatch signal was issued one day before the potential dispatch. If dispatch conditions were not satisfied in the first two weeks of any month with scheduled dispatches (Table 7), the contingency values were triggered until the required number of dispatches were achieved for that month. Signaled dispatch events were scheduled to proceed even in the case forecasted targets were not met (i.e., peak temperatures did not hit forecasted value the day of scheduled dispatch).

RESULTS

Demand Response

Six demand response events were called during the summer of 2019 and 2020. Two of these events were utility-scheduled system tests and four events were explicitly called to evaluate the DR resource in the NWA area. Two events were called in 2019 following the above methodology. The four events in 2020 were called under slightly different conditions — they were focused on conditions where the CSG resource was underperforming. This underperformance happens with overcast skies during evening hours; the overcast skies are critical to lowering the CSG output to less than load at risk prior to 8 p.m. To share coincidence with seasonally high or peak loads, overcast skies must break hot weather, typically in the form of an advancing front or change in weather. The research team was generally successful in achieving these conditions during 2020 DR calls. Each DR call was successfully coordinated with the utility between zero and three days prior to the event. These DR events and their results are summarized in Table 10.

Table 10: Six demand response events during 2019-2020.

Event	Time	Weather	Result
NWA area	07/19/19 17:00–19:00	• Decreasing temperature over event • Low outside air temperature (< 80°F)	• Slight load reduction • No snapback observed
System test	08/20/19 15:00–17:00	• Peak daily temperature • Increasing temperature over event	• Statistically significant load reduction • Snapback observed
NWA area	07/08/20 17:00–20:00	• Storm event • High cloud cover • Decreasing temperature over event	• Flat load • No snapback observed
System test	07/24/20 15:00–19:00	• Peak daily temperature • Storm event • Decreasing temperature over event	• Slight load reduction • Snapback observed • Intermittent CSG output
NWA area	08/11/20 17:00–20:00	• High cloud cover • Low outside air temperature (< 80°F)	• Flat load • Snapback observed
NWA area	08/26/20 17:00–20:00	• High & variable cloud cover • Missed forecast • Low outside air temperature (< 80°F) • Decreasing temperature over event	• Flat load • Intermittent CSG output • No snapback observed

The DR events were compared with three short-term load forecasts obtained by (1) linear interpolation of the load during the event call; (2) regression to outside air temperature for the day of the event; and (3) regression to a lagging outside air temperature. None of the NWA event calls showed a load reduction equivalent exceeding the margin of error of any of the above load forecasts. However, one system test did demonstrate a DR resource that was of similar magnitude to that anticipated as well as beyond the margin of error of the forecasted load.

The inability to observe the DR resource on the grid was attributed to the following circumstances.

- Lower than desired event temperatures — Temperatures during DR event window were typically much less than forecasted daily peak temperatures driving the DR scheduling.
- Outside air temperatures generally decreased during the DR event windows — These temperature declines were more dramatic under conditions of advancing weather fronts necessary for CSG underperformance.
- Variable CSG output — While overcast skies limited CSG output, the amount of CSG output still fluctuated due to changing sky conditions by magnitudes that rivaled the DR signal.
- Time resolution of the CSG and SCADA data — The hourly data was too coarse for the intended application and it was not possible to validate synchronicity between CSG data and SCADA data (CSG data are reported by third-party generators on a monthly basis).

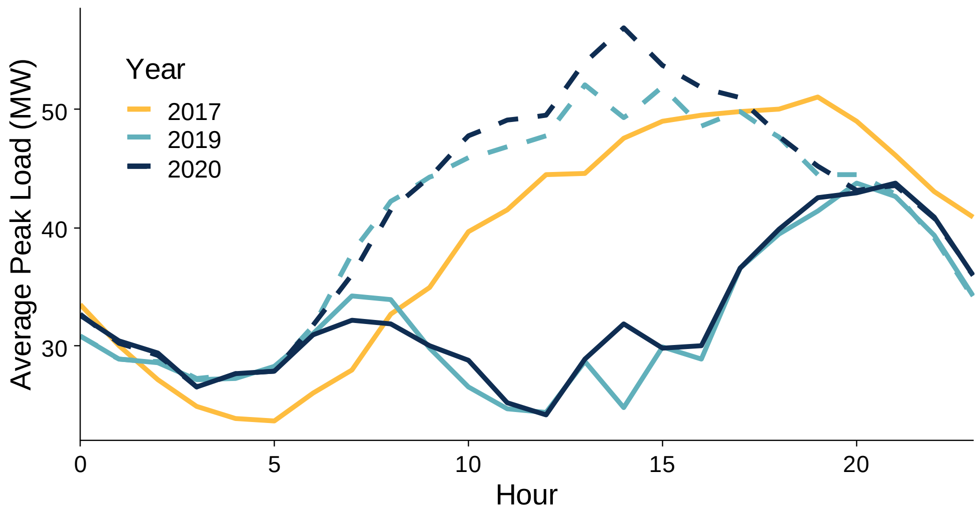
Consequently, we were unable to show the DR signal at the system level in five of six events. The only event that showed a significant load reduction occurred in the 2019 system test. That test occurred earlier in the day as temperatures were still increasing. In all other events, temperatures decreased substantially from peak temperature forecasts triggering the event. During the 2019 system test event, temperatures increased, which lead all three load forecast techniques to project an increasing load.

In conclusion, it is anticipated higher time resolution data and better short-term data modeling would reduce this uncertainty and enable stronger conclusions. Despite the lack of statistical confidence in these findings, demand response technologies should continue to be explored for its potential to extend the duration of risk mitigation for this system as well as and other systems to be used in concert with CSG resources to mitigate load at risk. Furthermore, modern demand response technologies (e.g., smart thermostats) provide feedback allowing load reductions to be validated through feedback rather than inferred from system-level observations. These events also demonstrated reliability in forecasting the conditions that would lead to high system loads during underperforming CSG output and successfully coordinated short-notice, NWA demand response calls with the utility.

Community Solar Garden Interactions

While the project site was initially selected in part due to the absence of planned community solar gardens, their arrival proved inevitable due to the popularity of the CSG program. Over the project timeframe, 32 projects were interconnected across four feeders in this system adding a peak output of 31 MW by summer of 2020. The output from these projects is about 40% of the non-coincident peak loads on the system, substantially changing the peaking characteristics on this system. The scale of solar output is even larger compared to the 1.6 MW load at risk. Over two years of production, data between June and August (2019–2020), solar output exceeded the load at risk prior to 7:00 p.m. in all instances except for two hours corresponding to non-peaking storm events. In other words, the solar output from these plants consistently shifted the daily peak load into the 5:00 p.m.–8:00 p.m. window, which reinforced the peak profile targeted by this project as seen in Figure 1 below. The solid lines are representative of average peak loads for 2017 (without CSG) and 2019–2020 (with CSG). The dashed lines for 2019 and 2020 represent the system loads without the CSG resources. These solar plants may now be viewed as a substantial component of the solution to mitigate load at risk — they virtually eliminate the possibility of peak loads occurring prior to 7:00 p.m.

Figure 1. CSG shifts the daily peak into the 8:00 p.m. hour



These dynamics shift the frame for considering demand response and energy efficiency pilot activities. With solar production on the distribution system, daily peak loads are consistently in the 7:00 p.m. to 8:00 p.m. timeframe. Daily peak loads can occur in the preceding one or two hours under a unique set of conditions. These conditions were observed in 2019 as storm fronts that break hot and humid weather. Overcast skies obscure the solar resource prior to the weather's impact on cooling loads and the diminished solar output creates an earlier peak. This observation lead the 2020 demand response tests to focus on this time period. The goal of the 2020 tests was to see whether the demand response resource could be activated to overcome diminished solar capacity and allow time for cooling loads to catch up to the weather, thereby mitigate the peak on the system.