N A R U C

National Association of Regulatory Utility Commissioners

Enhancing Grid Reliability through Demand Response

On June 24, 2022, NARUC facilitated a state commission staff "surge" call on enhancing grid reliability through demand response (DR). The North American Electric Reliability Corporation's (NERC) 2022 Summer Reliability Assessment identifies heightened reliability risks for the summer, particularly for the Midcontinental and Western U.S., as the regions are faced with widespread drought, heat, wildfires, and extreme peak demand. In order to avoid capacity shortfalls, grid operators may need to employ mitigating actions such as demand response to reduce or shift consumer electricity usage. This assessment underscores the increasingly important role of demand-side management (DSM) to help ensure grid reliability in a changing climate. During this surge call, commission staff from Maryland, Nevada, and Rhode Island will share their perspectives on the administration of demand response programs in their states, approaches to engaging customers, and lessons learned and opportunities for the future.

View the accompanying presentation slides.

Maryland

Demand response programs began in Maryland in the 1980s in the form of switches on air conditioning unit, but these programs were later discontinued until 2006. In 2006, PJM, the regional grid operator, notified the Public Service Commission (PSC) that the state would start to have rolling blackout and brownouts by 2011 if preventative actions were not taken. The Maryland legislature responded to this issue in 2008 by enacting the Empower Maryland Act which targeted a reduction of 15 percent in per capita electricity consumption by 2015 (using a 2007 baseline). The resulting opt-in DR program allowed participating customers to enable the utility to manage their air conditioning units during high-demand periods. Customers received a $50 sign-up bonus, and most participants agreed to 50% reductions in energy consumption during high-demand periods. To date, approximately 680,000 devices are enrolled across Maryland in DR programs, resulting in 580 MW of load reduction.

As of June 2022, the state has spent approximately $1 billion on its smart thermostat DR program. Due to its location within PJM, the thermostat program is eligible to participate as a capacity resource, and over the years has received $325 million in revenue from PJM to help offset the costs of administering the program.

In addition, Maryland has administered a peak time rebate program since 2015. All major utilities in the state (with one exception) have Advanced Metering Infrastructure (AMI) installed, so the program uses customer meter data to incentivize participants' energy use reductions during peak times. Maryland offers a rebate of $1.25/kWh reduced compared to a baseline calculated from customer use. This program has the capability to produce about 300 MW in savings when needed and is also eligible to sell peak demand reductions to PJM. To date, the peak time rebate program has received $105 million in revenue.

The PSC is currently in stakeholder meetings to determine the future of the Empower Maryland Act. The PSC's recommendation to the Maryland General Assembly is to transition from relieving stress on the grid to a greenhouse gas (GHG) reduction effort.

Nevada

In June 2022, forecasted peak demand in Nevada is approximately 7,600 MW at 5pm. However, the largest potential capacity shortfall is between 7-9pm when solar and battery storage are ramping down. As of

February of 2022, NV Energy had approximately 220 MW of DR capacity installed, which is a 10MW increase over 2021.

The primary DR program in Nevada is operated using smart thermostats. The normal operation periods for controlling smart thermostats occurs on weekdays between 1-7 pm from the summer months of June through September. During this period, NV Energy can call a load management event based on economic or system needs. When this happens, the utility can increase participating customer thermostats by up to 4°F as needed. There is no specific start time for calling an event; it depends on the conditions during an event day. The utility's tariff provides the flexibility to control the DR program as needed to maintain system reliability. A typical load management event lasts about two hours, but there are times when events extend for longer durations (e.g., August 2021 heatwave).

There have been challenges with growing the DR program in Nevada. First, there are concerns that the rebate amount is not commensurate with the value of customers giving up air conditioning. The rebate amount is calculated as kW savings during an event multiplied by the lesser of the system average cost or market price. For perspective, the presenter, who is enrolled in this program, generally receives a $5 – 10 rebate over the course of a year.

Nevada's DR program has experienced difficulty in scaling up as customers are hesitant to invite strangers into their home (especially during the pandemic). In response, NV Energy has created a "bring your own device" program and provides an installation guide. Additionally, the utility has tried to incentivize smart thermostat installations by offering to have staff install energy efficient lightbulbs, check operation of air conditioning systems, check insulation levels, and implement other efficiency measures while in the house for thermostat installations.

One concern that Nevada's DR program faces is the potential for a "snap back" effect if all the thermostats enrolled in the program switch back to normal operations at the same time. In response to this issue, NV Energy has been working to optimize a strategy for staggering DR in phases to reduce sudden increases in demand.

NV Energy is also piloting a program to control electric water heaters to offer additional DR capacity and partnering with hotels and other larger commercial customers to explore what types of dedicated resources commercial customers might be willing to incorporate in a DR program. Nevada offers an interruptible water irrigation service; during events, this provides 14 MW of DR capacity. This program runs from March to October and allows customers to receive a lower rate in return for the utility being able to interrupt pumping loads when capacity is needed.[1] This program is expected to provide a significant discount to enrollees.

Finally, during extreme peak demand events over the past two summers, the utility has put out three public requests for energy conservation. Results have been promising. For example, during an August 2021 event, the public request for conservation reduced demand by somewhere between 111 and 328 MW (the large estimate range is due to complications from accounting for other potential variability factors).[2] Even

[1] Information on the irrigation pumping pilot program is available on p. 261 of Nevada Energy's 2021 IRP https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/recent-regulatory-filings/nve/irp/2021-irp-filings/NVE-21-06-IRP-VOL5.pdf

[2] Potential variables include: weather, people conservation plans prior to the call for conservation, etc.

without a clear estimate of the reduction, public requests for conservation can have a substantial impact as a DR tool when utilized infrequently.

Rhode Island

Rhode Island's DR programs are collectively called ConnectedSolutions, and they are administered by the state's sole distribution utility, National Grid. Rhode Island's DR programs falls under the broader umbrella of energy efficiency (EE) planning. National Grid, as a combined gas and electric utility, plans and delivers the state's EE programs for electric and gas.

The state has DR programs for both residential and commercial and industrial (C&I) customers. The residential program is a "bring your own device" model that allows customers to connect batteries, thermostats, and pool pumps. There are different incentive configurations such as: performance payments ($/kW incentives), and annual enrollment or participation payments (generally between $15 – 20 annually). The residential program is responsible for a little less than 5 MW of demand reduction annually. The C&I program has an annual budget of about $5 million and is responsible for almost 30 MW of demand reduction. There are two subcategories for participation for the C&I sector: a daily dispatch program where participants are called on for 40 to 60 events per summer and a more targeted program where participants have between 1 and 10 events per year. Program participation varies based on load flexibility and customer preference.

The combined budgets for both programs in 2021 was about $6 million, while the total energy efficiency budget is $150 million, so DR makes up a small portion of the EE budget. In 2022, there were 5,000 participants (both residential and C&I) out of about 500,000 electric accounts. The Rhode Island distribution system peaked at 1900 MW, so securing 30 MW of demand reduction is a relatively small portion of the overall load. The PUC hopes to grow DR capabilities in the future.

Program design and cost effectiveness is an area of interest for the PUC. EE and DR programs in Rhode Island are required to be both cost-effective and less than the cost of additional supply. Rhode Island has an Avoided Energy Cost Study (AECS) that is updated every three years which quantifies avoided energy components. The result of the AECS is a list of all the avoided cost quantifications that are used to design and justify EE and DR investments.

A natural assumption of how EE and DR investment planning work is that the utility would consider which avoided costs are most valuable and design a plan to maximize those values. What PUC staff have heard from the utility is that avoided costs are exogenous to programs. So, the utility designs programs based on vendor availability, staffing constraints, and customer interest and then, justifies the programs based on the AECS report post-facto. Learning about this was concerning for the PUC: Rhode Island's local and regional power system is changing incredibly fast, as are avoided costs, so learning that these avoided costs were not the basis for planning demand response was an issue that the commission is considering how to address further.

The ConnectedSolutions offerings are designed to reduce demand coincident with regional system peak in ISO New England. In avoiding that peak, the intention is to avoid energy, capacity, and transmission costs allocated to the state. Those values are going down precipitously over time, and the only cost category that the PUC is seeing increase is distribution value. Currently, the DR programs are not helping to alleviate distribution constraints. In the past, that was not as much of an issue, but as distributed generation grows, Rhode Island is seeing more instances where constraints at the bulks system are asynchronous with constraints at the local system. ConnectedSolutions is not designed to address that issue. The incentives for ConnectedSolutions are not locationally specific, so participants could be on a heavily loaded feeder and receiving the same incentive as someone on a far less loaded feeder. The natural question is: what would be the value of having a locationally specific dynamic built into these programs?

Another challenge that Rhode Island is facing is how to encourage utilities to deliver the most valuable DR configurations based on real marginal costs. Rhode Island addresses this issue in part with a targeted performance incentive mechanism (PIM). In a 2018 rate case, part of the settlement included a "system efficiency" PIM. This established an earnings opportunity based on a certain amount of coincident peak demand reduction delivered each year. The targets were established in a roundabout process where stakeholders determined the amount of incentive they would be willing to pay, and then "backed" into a target based on the incentive amount agreed upon. So, targets were not established based on technical feasibility. The final target established was a maximum incentive level of $1 million offered for meeting 24 MW of DR. The utility has had a huge incentive to provide the amount of DR specified in the incentive that they easily meet with the ConnectedSolutions program, but nothing additional.

Staff are curious to know if the capability to provide more DR is there, but the incentive is wrong, or if there are other variables impacting this issue. The demand reduction PIM is expiring soon, and staff are working to incorporate this PIM into a larger system efficiency PIM. It is worth noting that Rhode Island's energy efficiency PIM does not pay utilities for societal benefits, only power system and resource benefits.

Discussion

There was interest in Maryland's rebate program for households that use less than a baseline amount of energy and how the baseline was calculated. Maryland's program has a very customer-specific baseline. The utility creates a baseline using AMI data by finding the highest four peak hours over the past 30 days, and then compares the event day to that average. So, if the customer is below the average, they will receive $1.25/kWh below that average. This program appears to be popular with customers as there is only benefit and customers are not penalized for using additional energy.

One participant wanted to know if states thought there should be some type of penalty for customers who opt out of every DR event. There have been no repercussions for opting out of events with NV Energy. It is worth noting that if an air conditioner is running at 80°F and an event is called where the temperature increases to 84°F, it will take 4 hours to restore the temperature to 80°F after the event. Customers have to decide if that DR measure is worth the incentive offered, or if it is better to just opt out. In Maryland, customers are allowed to opt out three times during the summer, but only when it is an economic event. Participating customers are not allowed to opt out of emergency events, but an emergency hasn't been called by PJM in nine years.

The Rhode Island attendee wants to see how much latitude there is on program pricing signals: how much do customers need to be offered in order to change their behaviors? Can the costs be more effectively allocated at a lower price point? What have other states seen in terms of cost trajectories over time with incentive offerings? Nevada has not seen changes in incentives over time, and staff think that the DR program terms are not appealing enough to encourage customers to participate in the program. Maryland has not changed incentive levels since the programs were established. Maryland has had $50, $75, or $100/season incentives based on cycling level since 2008. For peak time rebates, the utility ran pilots on

DR in 2012, and $1.25 for customers is commensurate to $1.25 peak pricing, so the PSC hasn't made any additional changes.

One participant noted that customers have become accustomed to subscription models in the past decade. National Grid says they need to re-connect with customers after every cycle of demand reduction, and staff think this re-connecting model may no longer be necessary for customers as they are now used to being program subscribers, and don't need this re-engagement. Utilities are making these assumptions based on one-year customer commitments, but there is greater value to be had if utilities can plan for these savings over longer time horizons. Maryland does send out program reminders at the beginning of each season so that customers are aware and ready for curtailment efforts if needed. In Nevada, staff assume customer participation for the life of the asset (in this case, a smart thermostat) which is about three years.

Call participants were interested in how customer opt-out behaviors have changed over time and think this information might be helpful when designing demand response programs. Nevada said they could be better about communicating these events to customers. Nevada utilities acknowledge the need for improved customer communication but are concerned that they will have higher participation if customers don't know about events in advanced to opt-out.

Rhode Island does not have AMI, but the PUC is expecting to receive a new grid modernization proposal that will likely include AMI and wanted to know if states with AMI in place have recommendations for questions for regulators to ask utilities with AMI proposals that will help to ensure AMI is deployed and subsequent data is used effectively. Maryland is using AMI data to calculate baseline usage for their peak time rebate program. All of the distributed generation programs that Nevada has enacted have added functionality to the AMI that has allowed access to data and helped other programs. An upcoming NARUC Summer Policy Summit panel will discuss how to utilize AMI data, and there may be additional opportunities to do a future NARUC panel or surge call on data access and AMI.

This call was made possible by the U.S. Department of Energy under cooperative agreement DE-OE0000925. Please address questions to Kathryn Kline, Technical Advisor, at kkline@naruc.org.