STATE OF NEW HAMPSHIRE

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Inter-Department Communication

DATE: March 19, 2019
AT (OFFICE): NHPUC

FROM: Leszek Stachow, Assistant Director, Electric Division
Jim Cunningham, Utility Analyst
Jay Dudley, Utility Analyst
Elizabeth Nixon, Utility Analyst

SUBJECT: DE 17-136 EERS
Staff Recommendation Regarding Demand Response Pilot
Public Service of New Hampshire and Unitil Energy Systems, Inc.

TO: Martin Honigberg, Chairman
Kathryn Bailey, Commissioner
Michael Giaimo, Commissioner
Debra Howland, Executive Director

CC: Tom Frantz, Director, Electric Division
Paul Dexter, Staff Attorney

On January 28, 2019, Public Service of New Hampshire d/b/a Eversource Energy ("Eversource") and Unitil Energy Systems, Inc. ("UES") filed information on their proposed 2019 Commercial and Industrial Demand Reduction Initiative ("DRI") per the Settlement Agreement submitted on December 13, 2018 and Order No. 26,207 and based on similar initiatives in Massachusetts, Connecticut, and Rhode Island. Per the Supplemental Order of Notice issued on February 4, 2019, a duly noticed pre-hearing conference was held on February 27, 2019, which was attended by Eversource, UES, NH Department of Environmental Services, Office of Consumer Advocate, and Commission Staff. No additional parties sought to intervene in this proceeding. Eversource and UES propose to conduct a pilot working with curtailment service providers ("CSPs") to reduce the ISO-NE annual system-wide peak demand by 5 MW and 1.8 MW, respectively, through an active demand reduction approach targeted at large commercial and industrial ("C&I") customers. The utilities will focus on reducing capacity and possibly transmission costs.

Customers may use any technology or approach to reduce demand. Typical technologies or strategies to reduce load include the following: energy management systems, building management systems, software and controls, HVAC controls, lighting with controls (manual, network system, or integrated), process offsets, battery storage, any open automated demand response compliance technology, startup sequencing and other customer facility specific approaches. The utilities anticipate that 10 events will be called lasting about 20-40 hours in total from June 1 through September 30, 2019. The utilities will work in conjunction with the CSPs and their distributed energy resource management system provider to call events.

To determine the amount of demand reduced, the utilities will determine an average baseline load for each participant for 10 non-holiday, weekdays prior to the event. The utilities indicated in responses to data requests,[1] that a participant's baseline will be adjusted upward if the hour preceding an event is greater than the average baseline. The utilities also indicate in their January 28, 2019 filing describing the DRI that "A CSP or C&I customer is restricted from taking any action to create or maintain baseline that exceeds the typical electricity consumption levels that would be expected in the normal course of business for the customer." Staff believes that the baseline calculation should be based on the 10 non-holiday, weekdays prior to the event, without any adjustments. However, since this is a pilot initiative, Staff recommends approval of the utilities proposal to allow for baseline adjustments with the requirement that the utilities provide detailed justifications in their pilot evaluation report for any adjustments made to a participant's baseline. Staff understands that the utilities agree to comply with this recommendation.

After an event, the demand during the event will be subtracted from the baseline load to determine the demand reduced. At the end of the summer, the average demand reduction for all of the events will serve as the basis for the demand reduction payment. Based upon experience in other states, the utilities will pay the CSPs $35/kilowatt (kW) reduced, and the amount paid to the customer is dependent upon the customer agreement with the CSP. Customers that are subject to demand charges and direct capacity charges determined by their installed capacity ("ICAP") tags may see additional benefits from the demand reduction.

The total estimated cost of the DRI is $250,000 for Eversource and $93,765 for UES. The detailed cost estimate for each utility is shown in Table 1. These costs were incorporated into the System Benefit Charge rates approved by the Commission in Order No. 26,207.

Table 1. Detailed Cost Estimate for DRI

Cost Element	Eversource	UES
Internal Administration	$5,000	--
External Administration	$5,000	--
Customer Service/Incentives	200,000	$70,324
Internal Implementation	$20,000	$14,065
Marketing	$7,500	$4,688
Evaluation, Measurement & Verification	$12,500	$4,688
Total	$250,000	$93,765

For the performance incentive ("PI") calculation, the utilities propose to include the costs of the DRI, but not any benefits. This has the effect of increasing the PI collected by the utilities by a small amount (about 6% of the $344,000 budget or $21,000). Staff does not object to this treatment for PI, but reserves the right to propose a more balanced application if the Initiative is extended in time or scope, or is expanded to other utilities. In addition, the utilities do not propose to include any lost revenue from reduced kilowatt-hours or kW from the DRI in the lost base revenue recoveries.

[1] See attached data request Staff 05-011.

Adapting avoided cost estimates from the most recent AESC Study,[2] Eversource and UES estimate that the benefit/cost ratio for the pilot will be 4.93 and 4.73 respectfully assuming that 5 MW and 1.8 MW are reduced at the time of the annual ISO-NE system peak. The utilities note that they believe that avoided costs calculated using an active demand response benefit/cost model should ultimately be used to more accurately estimate the benefits of the DRI. The utilities are working to develop an active demand response benefit/cost model for New Hampshire. The utilities also estimate that if the proposed demand reduction is not fully achieved (e.g., if only about 1 MW for Eversource and 0.36 MW for UES are reduced), then the benefit/cost ratio will decrease to about 0.99 and 0.95.[3] Staff believes that the savings estimates provided are an appropriate representation of the expected benefits for purposes of approving the pilot at this time.

The December 13, 2018 Settlement Agreement provides that Eversource and UES will provide progress reports on the DRI at the EERS quarterly meetings. In addition, in data response Staff 5-022, and at the February 27 technical session, the utilities indicated they will provide a written evaluation of the pilot with (or prior to) their 2019 Quarter 4 EERS report. However, the utilities indicated that they did not intend to include a benefit/cost assessment of the pilot in that written report, but would instead provide an assessment of the actual benefits and costs with the filing of their request for approval of performance incentives, which request would not be made until June, 2020. Staff recommends that the utilities be required to include an assessment of the actual benefits and cost of the pilot in the written evaluation that will be submitted with (or prior to) the 2019 Quarter 4 EERS report. Staff understands that the utilities have agreed to this filing schedule.

Based upon the utilities' proposal, as submitted in their January 28, 2019 filing and detailed further in data responses and as summarized above, Staff recommends approval of the DRI, as discussed above, as soon as possible so that that the CSPs and necessary equipment are in place to allow implementation by June 1, 2019.

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[2] Synapse Energy Economics, Inc., *Avoided Energy Supply Components in New England: 2018 Report*, October 24, 3018. http://www.synapse-energy.com/project/aesc-2018-materials

[3] See attached data request Staff 6-003. Note that the summer coincidence factor was used as a proxy to estimate the benefit/cost ratio in a scenario when the full 5 MW and 1.8 MW are not reduced at the annual system peak. Staff understands that the summer coincidence factor percentages relate to the demand reduction achieved at the annual system peak. For example, the summer coincidence factor of 50% is approximately a 2.5 MW demand reduction for Eversource and 0.9 MW reduction for UES.

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Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 02/05/2019 **Date of Response: 02/15/2019**
Request No. STAFF 5-011
Request from: **New Hampshire Public Utilities Commission Staff**

Witness: **Thomas R. Belair, Michael R. Goldman, Thomas Palma**

Request:
Regarding the incentives offered to achieve demand reductions:
a. What will the specific incentive be (e.g., in $/kW saved)?
b. How will the kW saved be calculated?
c. At what frequency will the incentive be paid (e.g., for each event, once a year, etc.)?
d. How much incentive will go to the customer, and how much to the CSP?
e. Will the customer and the CSP be paid for each called event?

Response:
Eversource and Unitil Response

a. Eversource and Unitil have contracted with CSPs and will pay them $35/kW curtailed during the target hours. The CSPs will use this payment for their costs and to pay customers to reduce their load.

b. Performance Calculation

Baseline:
In order to calculate a customer's performance during a demand response event, it is necessary to calculate what a customer's typical power use is to estimate what the power use would have been if no demand response event was called.
The method we use to calculate a customer's baseline is referred to as a "last 10 of 10 model". ISO-NE uses this same method in their active demand response programs. This method looks at the customer's last 10 similar days. Similar days are weekdays that are not holidays and where no other DR event from either ISO-NE (OP4) or the utility was called. Days where a customer has a scheduled shutdown are not considered similar days. For shutdown days to be excluded from the baseline calculations, customer's or their CSP must inform their PA of the shutdown with a week notice. There is a limit of 10 shutdown days per summer.

Example of baseline set by loads in the 10 similar days before a DR event

Time Interval	10 similar day before event	...	3 similar day before event	holiday	weekend	weekend	Day of another DR event	1 similar day before event	Customer's Baseline
Noon - 1pm	500kW	...	500kW	Not counted in average				500kW	500kW
2pm - 5pm	500kW	...	500kW					500kW	500kW

Baseline Adjustment:
Demand response events are called on hot summer days. The day of the event may be hotter than the last 10 similar days, and the customers load may be higher that day. To account for this, the baseline is adjusted to reflect to customers load during the demand response event day. This is called the baseline adjustment. The baseline adjustment is the difference between the customer's average load in the 2 hours before the event start and the load during the event day.
However, the customers load may be lower during an event day than the last 10 similar days because the customer is responding to the DR event. Therefore, the adjustment can only be positive. It will never penalize the customer.

Example of a same baseline adjustment.

Time Interval	Customer's Baseline	Event Day Load	Baseline Adjustment
Noon – 1pm	500kW	600kW	100kW

Demand Response Performance:
Performance is calculated by subtracting the event day load during the demand response event from the sum of the customer's baseline and baseline adjustment.

Example of an event day performance:

Time Interval	Customer's Baseline	Event Day Load	Baseline Adjustment	Event Day Performance
Noon – 1pm	500kW	600kW	100kW	Performance = Baseline + Adjustment – Event Day
2pm – 5pm	500kW	400kW		500kW + 100kW – 400kW = 200kW

The "Average Curtailment over Season" is the average performance of all demand response events for that season.

Performance for an individual demand response event is calculated by subtracting the customer's adjusted baseline power from average power (kW) use during the demand response event.
For example:

Time	Customer's Adjusted Baseline	Customer's Power Use During DR Event	Performance
2pm to 3pm	500kW	400kW	100kW
3pm to 4pm	500kW	400kW	100kW
5pm to 6pm	500kW	400kW	100kW
		Average Performance for Event	100kW

c. Incentives will be paid in the fall after the ISO-NE Summer peak has been certified by ISO-NE

d. How the incentive will be split between the CSP and the customer will be the responsibility of CSP and the customer. Some customers may require more help in developing and executing load shedding plans than others, so the level of effort by the CSP will also fluctuate as will the split of incentive. Additional benefits to the customer beyond the incentive provided by the utility may also play a role in the size of the incentive that the customer needs in order to engage with the initiative.

e. Each called event will be used in the calculation, but the payment will be made in the fall and each customer's payment will be based on their average reduction over all events.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 02/28/2019 **Date of Response: 03/08/2019**
Request No. STAFF 6-003
Request from: **New Hampshire Public Utilities Commission Staff**

Witness: **Katherine W. Peters, Thomas R. Belair**

Request:
Reference Attachment Staff 5-003 b and c: Please provide an estimated Benefit /Cost ratio for the DRI for 2019: Please identify the source of any data used in the calculation. Please explain any assumptions used in the calculation.

Response:
Eversource and Unitil Response

Please see Attachment STAFF 6-003 for the details of the Benefits in the Total Resource Cost Test for this Demand Reduction Initiative. The Benefit / Cost value was developed using the same Benefit / Cost model that was used for the 2019 Energy Efficiency Programs. The assumptions used are as follows:

	Eversource	Unitil
Program Costs	$250,000	$93,765
Total kW Reduction	5,000	1,800
Annual kWh Hours	0	0

New C&I DR Measure Assumptions		
Winter On Peak kWh %	0%	0%
Winter Off Peak kWh %	0%	0%
Summer On Peak kWh %	100%	100%
Summer Off Peak kWh %	0%	0%
Summer Coincidence Factor	100%	100%
Winter Coincidence Factor	0%	0%
Benefit / Cost Value	4.93	4.73

Precise modeling of the B/C ratio for a demand program requires creation of a specific active demand benefit-cost model, which the utilities have not yet done. To inform the bounds of B/C ratios likely to be seen for a DR program, , Eversource and Unitil used the existing B/C model and performed a basic sensitivity analysis wherein they varied the Summer Coincidence Factor, which resulted in the following B/C values:

Benefit / Cost Value	Eversource	Unitil
Summer CF at 100%	4.93	4.73
Summer CF at 80%	3.94	3.78
Summer CF at 50%	2.46	2.36
Summer CF at 20%	0.99	0.95

Eversource NH 5 MW

	Sum CF =	100%
DR Resource - Load Curtailment	**5,000**	kW
Annual kWh Savings	**0**	kWh
Benefits	**$/Unit**	**Benefit Value**
Elec Energy ($/kWH)	$0.00	$0
DRIPE ($/kWh)	$0.00	$0
Sum Gen ($/kW)	$54.24	$271,207
Win Gen ($/kW)	$0.00	$0
Electric Capacity DRIPE ($/kW)	$17.86	$89,320
Transmission ($/kW)	$0.00	$0
Dist Benefits ($/kW)	$81.82	$409,114
PTF Benefits ($/kW)	$92.40	$462,011
Reliability ($/kW)	$0.00	$0
Total Benefits		**$1,231,652**
Cost to Deliver		**$250,000**
TRC (Benefit / Cost)		**4.93**

Unitil NH 1.8 MW

	Sum CF =	100%
DR Resource - Load Curtailment	**1,800**	kW
Annual kWH Savings	**0**	kWh
Benefits	**$/Unit**	**Benefit Value**
Elec Energy ($/kWH)	$0.00	$0
DRIPE ($/kWh)	$0.00	$0
Sum Gen ($/kW)	$54.24	$97,635
Win Gen ($/kW)	$0.00	$0
Electric Capacity DRIPE ($/kW)	$17.86	$32,155
Transmission ($/kW)	$0.00	$0
Dist Benefits ($/kW)	$81.82	$147,281
PTF Benefits ($/kW)	$92.40	$166,324
Reliability ($/kW)	$0.00	$0
Total Benefits		**$443,395**
Cost to Deliver		**$93,765**
TRC (Benefit / Cost)		**4.73**