To Have Your Cake and Eat It Too: Mitigate Grid Constraints and Reduce Greenhouse Gases with Demand Response

Vijay Gopalakrishnan, DNV, Middletown, CT
Ignacio Obejero Paz, Eversource, Westwood, MA
Walter Schaefer, DNV, New York, NY

ABSTRACT

Nationwide, regulators and policymakers are sharpening their focus on decarbonization and benchmarking carbon emissions. This focus on carbon accounting is driving utility energy efficiency and grid management programs to use greenhouse gas (GHG)-based metrics in addition to traditional kWh and therm-based metrics. Historically, the objective of demand response (DR) programs has been economic optimization. One program administrator explored stacking a second objective during the winter season, greenhouse gas reduction, to increase the value of DR programs. This endeavor, comprising primary and secondary research, found that in addition to reducing peak loads, DR programs would benefit from exploring DR event triggers and other signals that would shift energy consumption from periods of high carbon generation (i.e., the grid is at its "dirtiest" when oil or coal power is on the margin) to periods of low carbon generation.

This paper explores how DR programs can help achieve GHG targets, by answering the following questions:

- Can DR successfully provide GHG emissions and traditional load management benefits?
- What are the factors that determine when the grid is most "dirty"/carbon-intensive?
- What are the data sources that could be leveraged to obtain necessary information regarding the grid fuel mix and marginal fuel resources?
- What are the strategies for event triggers that could satisfy existing load management goals (peak reduction, reliability, etc.) while adding GHG reductions as an additional goal?
- What DR technologies and strategies are most conducive to reducing GHG emissions?

Introduction

Utilities increasingly use demand response (DR) programs to manage peak electricity demand and potentially mitigate greenhouse gas (GHG) emissions. The extent to which DR contributes to GHG reductions depends significantly on the operational context and the methods used by participants to reduce their loads.

When DR results in simple load shifting—rather than actual load curtailment—and the marginal fuel source remains unchanged over time, the net GHG impact tends to be negligible. Worse, GHG emissions can even increase if participants use on-site generation (OSG) resources with higher carbon intensity than the displaced grid electricity. In contrast, DR strategies that achieve true curtailment, shift load to cleaner marginal generation periods, or avoid dispatching carbon-intensive power plants can result in meaningful emissions reductions.

Eversource, a program administrator (PA) in New England, designed its winter season DR initiative in Massachusetts and Connecticut to achieve GHG reductions. Recognizing that natural gas—while cleaner than coal and oil—is frequently constrained during extreme cold due to heating demand, Eversource sought to target DR events during these extreme, natural gas constrained conditions. On January 29, 2021, such conditions materialized: low temperatures, elevated heating degree days (HDDs), high real-time locational marginal prices (LMPs), and constrained natural gas supplies signaled a likely reliance on more carbon-intensive resources. Accordingly, Eversource called a DR event aimed at curbing load during this peak period. Coal and oil plants, with carbon intensities of 1.45 and 1.49 metric tons CO_2 per megawatthour (MWh), respectively, are significantly more emission-intensive than natural gas (0.43 Mt CO_2/MWh). By avoiding their dispatch during high-demand events, the DR program sought to produce a disproportionately large reduction in emissions. Furthermore, ISO-NE's reserve and contingency requirements sometimes necessitate dispatching these higher-emission resources for grid reliability reasons.

Eversource's approach illustrates how targeted DR—aligned with real-time grid conditions and fuel availability—can significantly enhance the effectiveness of DR programs. By prioritizing emissions outcomes alongside reliability and cost, DR programs can serve as strategic tools in decarbonizing power systems.

Data Sources

Four data sources were used in the primary research portion of the study. These data sources and analyses are described in this section.

Third-Party Modeled Marginal Emissions Rate Data

The study team examined marginal emissions rate (MER) data from a third-party source to determine its usability for quantifying the actual carbon intensity of the ISO-NE grid. This data was available for the three Massachusetts ISO-NE load zones (Western and Central Massachusetts, Northeast Massachusetts and Boston, and Southeastern Massachusetts) and the Connecticut ISO-NE load zone from March 1, 2017, through January 31, 2021. For each load zone, a timeseries of MER values with 5-minute resolution in UTC format was provided, in lbs. of CO_2 per MWh of electricity generated. This data was then converted to prevailing time (Eastern time zone) and rolled up to hourly average MER values for analysis.

This data is the output of a proprietary data model developed by the third party. The model output is not a report based on actual generation resources for each time period. Instead, it uses historical resource load data, weather data, and a wide array of other inputs, including publicly available grid data from ISO-NE, to predict MERs. The third-party model begin by utilizing raw data on electricity production and emissions, sourced from the U.S. Environmental Protection Agency's Continuous Emissions Monitoring System (CEMS). They then employ regression analysis to determine which power plants adjust their output - either increasing or decreasing - in response to changes in electricity demand at specific times and locations. This approach enables analysts to assess how marginal emissions rates fluctuate across different regions and timeframes.

ISO-NE Fuel Mix Data

The study team queried roughly 5-minute resolution fuel mix data for the entire ISO-NE using the ISO's application programming interface (API). This data set provides a breakdown of the generation, in MW, from each fuel type, as calculated by the ISO's dispatch software on a given operating day. It is the only data set available from the ISO-NE that breaks down total generation by fuel type with a high level of granularity. This data is only available at the level of the entire ISO and is not disaggregated by load zone. It is also not granular beyond individual fuel types, meaning it is not possible to identify the output of an individual power plant using a particular fuel type. The fuel types included in this data set are coal, hydro, landfill gas, natural gas, nuclear, oil, other, refuse, solar, wind, and wood. Data from January 1, 2015, through July 2, 2021, was converted to prevailing time (Eastern time zone) and rolled up to hourly average power levels (MW) by fuel type, or resource, for analysis.

ISO-NE Marginal Resource Data

The study team queried roughly 5-minute resolution marginal resource data for the entire ISO-NE using the ISO's application programming interface (API). This data set indicates which fuel type or fuel types were tagged as marginal in each time step, as calculated by the ISO's dispatch software on a given operating day.

Similar to the fuel mix data, the marginal data is the only data set available from the ISO-NE that identifies marginal resources by fuel type with a high level of granularity. Also, like the fuel mix data, this data is only available at the level of the entire ISO, is not disaggregated by load zone, and does not get more granular than individual fuel types. This means it is not possible to ascertain whether an individual power plant is marginal at a given point in time. The fuel types included in this data set are the same as those included in the fuel mix data set described above. This data was converted to prevailing time (Eastern time zone) and rolled up to hourly average power levels (MW) by fuel type, or resource, for use in this analysis. Data from January 1, 2015, through July 1, 2021, was included in the analysis.

NOAA Weather Data

To support the assessment of the temperature-dependency of the third-party MER data, ISO-NE fuel mix data, and ISO-NE marginal resource data, the study team queried hourly dry-bulb temperature (DBT) data for several Massachusetts and Connecticut weather stations from the National Oceanic and Atmospheric Administration (NOAA) local climatological data database. Data was collected for the period from January 1, 2015, through July 1, 2021. This data contains one or multiple temperature readings per hour. The study team converted the data to prevailing time (Eastern time zone) and aggregated it to develop hourly average temperature readings in Fahrenheit.

Marginal vs. Average Emissions Rates

There are two methods of measuring the grid's GHG emissions: average emissions rates and marginal emissions rates. In this section, we define the two methods and outline the rationale for using marginal emissions rates in this analysis.

Average Emissions Rate

The average GHG emissions rate (or average emissions rate, AER) represents the load-weighted (by MW contribution) average GHG intensity of all grid resources that contribute to the supply stack. Average emissions rates are most often used to measure and compare the carbon intensity of the grid on a monthly, seasonal, or annual basis. It would not be appropriate to use AERs to measure a DR program's GHG emissions impact, since not all grid resources in the supply stack are impacted equally by a targeted reduction in demand. Directly reported marginal emissions rates, discussed below, more accurately capture the real-time emissions impact of load-shifting or load-shedding.

Marginal Emissions

The marginal GHG emissions rate (or marginal emissions rate, MER) represents the load-weighted (by MW contribution) average GHG intensity of all resources that are on the margin at a given point in time. As discussed above, the "marginal resource" is the grid resource (or collection of resources) that would supply the next unit of load to the grid if demand were to increase; conversely, it would also be the next resource to reduce its output if demand were to decrease. Thus, if a targeted DR program successfully reduced load on an event day, the marginal resource would be the only grid resource to reduce demand, and the associated emissions reduction would be based only on the carbon intensity of the marginal resource. For this reason, the evaluators focused on measuring the MER to evaluate the ADR Program's emissions reduction impact.

Emissions Impact Factor Calculation

Factors to calculate carbon emissions from generation fuels were calculated from 2019 EIA data[1] for states in ISO-NE. To calculate metric tons of CO_2 per MWh generated by each generation fuel, we aggregated EIA data for both parameters for the six states in New England (CT, MA, ME, NH, RI, VT) and divided them to calculate a fuel type carbon emissions rate. These rates ranged from 0.43 metric tons of CO_2 per MWH MWh generated from natural gas to 1.49 generated from oil. These factors are used with the mix of marginal fuels and hourly reductions during the January 19th event to estimate emissions reductions. Note that the EIA data considers nuclear, hydroelectric, other biomass, pumped storage, solar, wind, and wood generation to have zero emissions.

Table 1. Summary of 2019 CO_2 emissions and generation levels by fuel

Fuel Type	Total 2019 Metric Tons CO_2	Total 2019 MWh Generated	Fuel Type Emissions Rate (CO_2 per MWh)
Coal	1,351,970	934,241	1.45
Natural Gas	42,277,624	98,544,663	0.43
Other	5,424,490	3,761,950	1.44
Petroleum	572,914	385,322	1.49

Findings

This section reviews findings related to a secondary research effort to understand the data sources used to calculate carbon emissions, and concludes with an estimate of the amount of GHG reductions achieved by the program.

Secondary Research

The study team explored two sets of questions with secondary research to supplement the results gathered from our primary research and data analysis. They are:

- What is the carbon impact of the avoided kW achieved by the program? What are the carbon impacts of the different participating technologies?
- What are program design best practices in other jurisdictions offering emissions-based DR programs?

We provide the results of our research for each below, beginning with our examination of the carbon impact of avoided kW and different participating technologies. As part of the secondary research for this study, we reviewed four studies, as summarized below.

Exploring the carbon impacts of DR. A 2015 study[2] examined the carbon impacts of DR using a model based on the EIA National Energy Modeling System. Multiple scenarios were exercised, with varying price-based load shifting and load reduction assumptions developed from a literature review. A key feature of

[1] https://www.eia.gov/electricity/data/state/emission_annual.xls
[2] Alexander M. Smith and Marilyn A. Brown, "Demand response: A carbon-neutral resource?", 2015.

the study was a focus on emissions changes for DR at “highly aggregated levels,” which we interpret to be a fully scaled DR program or portfolio. The paper has two primary conclusions, each resting on the assumption that DR operates only at the top 1% of load hours. The first is that price-based DR can defer large amounts of peak capacity construction. The second is that, in general, neither small nor large levels of load shifting away from the peak 1% appear to significantly change CO_2 emissions. A key observation of the study was that DR during other intermediate periods (outside of the 1%) may increase opportunities to impact CO_2 emissions (positively or negatively). This appears to largely depend on whether there is a “large portion of off-peak, low-carbon, ramping renewable generation in the energy portfolio that can reduce carbon emissions on the margin by dispatching DR.”

Another study from 2016[3] in the United States examined the use of real-time DR triggered at electricity price points to help mitigate risks associated with the variability of renewable generation (such as wind turbines). This study was performed in the context of the Clean Power Plan, and simulated power system and market mechanisms through a two-stage stochastic optimization framework with Monte Carlo modeling covering combinations of wind and load level. The study concluded that a framework such as that in the Clean Power Plan can bring together renewable generation, price-based DR, and changes in the merit order (i.e., natural gas units dispatched before coal-fired) to reduce emissions. The study goes on to suggest that implementing any one of the initiatives on its own does not provide the emissions reductions of the framework as a whole. It specifically cites a concern that wind generation without the use of real-time DR could lead to reliability and cost concerns.

A search for other studies identified no recent studies on the impact of DR on system emissions in the United States, but some that assessed the carbon impact of various DR schemes in other countries, including Korea[4] and Ireland.[5] The study in Korea assessed the effects of DR bidding markets on generation. This study found that “despite its small presence in the wholesale electricity market, demand-resource bidding can bring about marginal environmental improvements of about 2% and 0.3% reductions in CO_2 and PM emissions, respectively.” These findings were modestly statistically significant.

The research in Ireland concluded that “studies based on short-run estimates indicate that demand response can have a negligible effect in certain power systems, and may even increase emissions, e.g., due to efficiency losses in domestic battery systems. By contrast, where long-run structural impacts are accounted for, then demand response can achieve considerable reductions in carbon emissions.” This appears to mean that larger system-level changes such as “changing the dispatch of generation, reducing renewable generation curtailment, but particularly the decommissioning of peaking generation and replacement with (less polluting) base-load generation” needs to accompany DR, or be in place, for DR to have an emission impact.

Collectively, these studies suggest that DR programs on their own show marginal or no positive net environmental impacts with existing generation resources, although we acknowledge that two of the studies are from abroad with different markets and systems. They provide evidence to suggest that as part of a broader set of system activities aimed at reducing GHG emissions, DR can yield greater reductions than individual activities. Our broad takeaway of these studies is that coordinated efforts among stakeholders and policymakers are likely to have the most success in reducing emissions from the electric grid beyond a singular pursuit of DR.

Technological considerations for a DR program targeting emissions reduction. It is important to consider startup characteristics, and the duration needed to go from cold state to fully operational. Eversource hypothesized that if a DR action can keep an oil or coal plant from coming online on a peak

[3] J. B. Cardella, C. L. Anderson, Targeting Existing Power Plants: EPA Emission Reduction with Wind and Demand Response

[4] Minwoo Hyun and Jiyong Eom, “Assessing the impact of a demand-resource bidding market on an electricity generation portfolio and the environment.” 2020.

[5] McKenna and Darby, How much could domestic demand response technologies reduce CO_2 emissions?, 2017

day, it could have emissions impacts during subsequent non-peak days or weeks if the plant typically commits to longer periods of generation once started. The study team examined elements of this theory as part of its secondary research effort.

Most coal-fired turbines can take more than 12 hours to start up (i.e., become operational from a state of full non-operation).[6] Petroleum-fueled plants can start up much more quickly (within an hour). Most natural gas turbines can reach full operation between 1 to 12 hours. Generator startup times differ across electricity-generating technologies because of the differences in the complexity of the electricity-generating processes themselves. The bullets below provide more detail on generation technologies and start-up times.

- *Relatively quickly:* hydroelectric turbines (turbines spun by flowing water; most take ~10 minutes to start up) and simple cycle combustion turbines (which use a combusted fuel-air mixture to spin a turbine; most take up to an hour to start up).
- *Relatively slowly*: steam turbines (a fuel heats water to form steam, and that steam needs to reach certain temperature, pressure, and moisture content thresholds before it can be directed to a turbine that can spin the electricity generator). All coal and nuclear power plants use steam turbines.

  The majority of natural gas-fueled turbines in the United States are combined-cycle systems. They use natural gas to fire a steam turbine and then use the exhaust gases to generate steam. The steam generation aspect puts them in the "relatively slow" category. Some less efficient but faster starting simple cycle combustion gas turbines are in fleets, typically for short-notice high-cost generation, as are natural gas steam turbine-only systems.[7]

  About 58% of New England's natural gas capacity has dual-fuel capability[8] (i.e., they can switch to other fuels such as petroleum-based fuels). In this region, winter periods of constrained natural gas can force some plants to ratchet down output or shut down. When this happens, dual-fuel units can continue generation on other fuels. This ability has been critical for grid reliability during cold snaps. For example, during the bomb cyclone event (December 28, 2017 – January 8, 2018), several dual-fuel capable generators switched from natural gas to petroleum to continue generating electricity.

Marginal Emissions Research Findings

The study team has access to MER data from a third-party source. We first sought to determine whether this data would serve as an accurate proxy for the marginal GHG intensity of the grid on DR event days, which would allow us to use it directly in our impact evaluation calculations.

The third-party data has the advantages of being direct marginal emissions rate estimates and load zone-specific, as opposed to more general marginal fuel source estimates. However, because it is model-based and not reflective of actual power plant activity on event days, analysts needed to verify the model.

To conduct this verification analysis, the evaluators integrated third-party MER data, ISO-NE fuel mix data, ISO-NE marginal resource data, and NOAA weather data to identify any correlations between MERs, observed grid operations, and temperature.

[6] https://www.eia.gov/todayinenergy/detail.php?id=45956

[7] Nationwide, 58% of natural gas generation capacity is combined cycle, 28% is combustion turbines, and 17% is steam turbines. However, about 90% of generated energy is from combined cycle systems. https://www.eia.gov/todayinenergy/detail.php?id=34172 and https://www.eia.gov/todayinenergy/detail.php?id=39012.

[8] https://www.eia.gov/todayinenergy/detail.php?id=37992.

Findings. The evaluators were unable to identify a relationship between the third-party MER data and the operation of coal and oil resources on the ISO-NE grid. While there was a clear relationship between temperature and the level of generation from coal and oil on the grid—during periods of extreme cold as well as extreme heat—the MER data did not appear to respond to these changing weather and grid conditions. As a result, the evaluators determined that the MER data was not an accurate proxy for actual grid marginal emissions available for the impact evaluation calculations.

Analysis of ISO-NE Data to Capture Characteristics of Carbon-intensive Resources

Analysts used ISO-NE grid data with NOAA weather data to understand the use patterns of coal- and oil-fired generators, including assessment of:

- Monthly energy generation trends by resource type over time
- Typical start-up frequency and runtime duration over time
- The impact of temperature on the coal and oil operations

The goal was to project their future use and expected DR GHG impacts. Specifically,

- How likely are coal or oil to be marginal energy sources during future DR events?
- Are they likely to be a source of "bonus" GHG savings outside of DR hours?

Historical analysis of monthly operational data. We first analyzed "runtime" and monthly generation from 2015 through mid-2020 to understand the "typical" behavior of coal and oil over time.

Coal. A review of historical monthly coal generation (MWh) data shows how much energy was generated by the New England coal fleet over time. The historical annual trend indicates that coal generation has reduced significantly over time and the majority of coal generation is during the winter months. The long-term trend of reduced coal generation is supported by the evolving market dynamics in New England and accelerated coal plant retirements and suggests that coal may continue to dwindle in the region; as such, the evaluators suggest that coal may not be an ideal target for carbon-based targeted DR efforts.

Oil. A review of historical oil "runtime" data shows that, as a resource type, oil has historically operated much more intermittently than coal. In nearly 73% of the months from 2015 to 2020, an oil plant was running during fewer than 40% of the hours in a month.[9] Oil has also demonstrated a recent drop-off in utilization, running for fewer hours in both 2019 and 2020[10] than in previous years. This apparent intermittent operation confirms that oil is rarely used as a baseload asset and tends to be called upon when demand is high, supply is constrained, or the grid needs targeted support due to an extreme weather, fuel security, or other contingency event.

Analysis of monthly generation totals, which showed how much energy was generated by the New England oil fleet over time, corroborates this. Aside from extremely high generation totals during polar vortex events in early 2015 and early 2018, oil generated energy sporadically and in relatively low volumes, compared to coal. There was no long-term downward trend in generation to indicate that oil plants were being retired at the same pace as coal plants; however, it would be difficult to draw such a conclusion given oil's low and sporadic generation.

Figure 1 shows the trend of unpredictable annual generation levels for oil on the ISO-NE grid. The two years with the highest generation totals featured polar vortex events. In fact, 61% of all oil-based generation produced in the 72 months between January 2015 and June 2020 was during just three

[9] Here, "runtime" is defined as the percent of hours in the month that the given resource was generating power, i.e., had non-zero generation (MW). Note that this analysis considers only the operation of the New England coal fleet in aggregate, as the data does not provide insight into the operation of discrete power plant operations.

[10] Data was only available for January through June of 2020, so it is possible that this trend reversed itself in the latter half of 2020.

months: February 2015, December 2017, and January 2018. This figure also shows that the majority of oil generated MWh comes during the winter months for each year included in the analysis, with 84% and 89% of annual generation coming during the winter during 2015 and 2018, respectively.

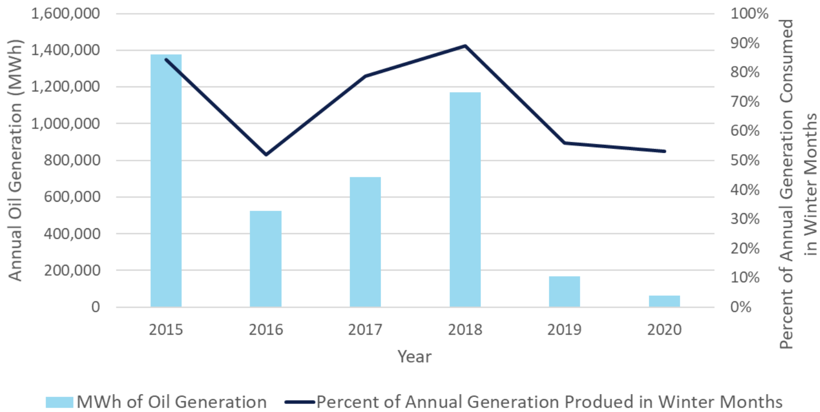

Figure 1. Annual generation levels for oil

The analysis described above suggests that oil is typically used as a responsive resource on the New England grid, called upon during periods of extreme cold, supply constraints, or other contingency conditions. There is also no evident trend of oil plant retirements, suggesting that oil will continue to play a specialized role on the New England grid into the future. Program planners can expect oil to be a common marginal fuel source for the near future.

Typical startup frequency and duration. We then analyzed the ISO-NE fuel mix data to assess how frequently oil resources, in aggregate, "startup"—i.e., switch from a non-generating state to a generating state (going from 0 MW to positive generation)—and how long startups tended to last, in hours. This analysis was geared toward understanding whether there are any technical aspects of the two fuel types that might keep them online once they started up and whether discrete startups tended to be longer during cold weather.

Our analysis of oil operational data included all data from January 2015 through July 2020. This analysis showed that, aside from three 385+ hour-long runs (at least 16 days each), the vast majority (96%) of oil "runs" are less than 24 hours in duration.

There were over 2,100 unique oil startups in this roughly 5.5-year period, with an average run duration of 7.5 hours. Over half of the start-up events had a duration of three hours or less and 96% of them were 24 hours or less. Looking only at the winter months (November, December, January, and February), there were a total of 622 unique oil startups averaging 9.3 hours in duration. Again, over half of the events were three hours or less, and 95% of these start-ups lasted less than 24 hours. Figure 2 illustrates this.

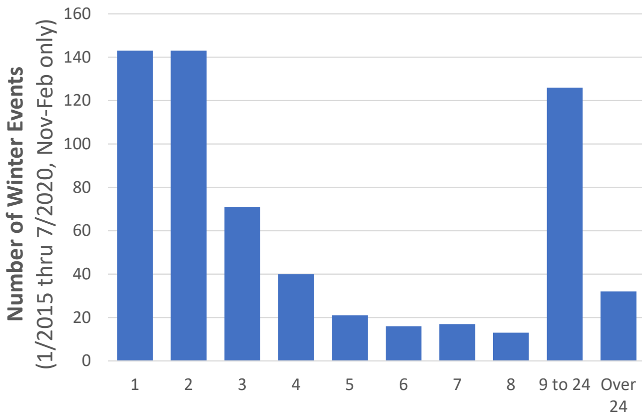

Figure 2. Duration of oil-fired events

This analysis confirms that the oil fleet, in aggregate, is frequently called upon to provide power on an as-needed basis, with oil plants rarely being dispatched for long periods. There is no indication that any technical aspect of oil-generating technology requires an oil plant to stay "on" for an extended period once dispatched by ISO-NE.

Relationship between startup duration and temperature. In the next phase of our analysis, we analyzed ISO-NE fuel mix data to assess how the duration of an oil "start-up event" depends on temperature in the winter months of November, December, January, and February. This analysis was intended to identify any relationship between cold temperatures and how long oil plants run when dispatched, which would allow the study team to assess the feasibility of predicting when dirty plants would come online and subsequently optimize the calling of DR events to maximize emissions reduction impacts. After these results, we reviewed the number of days with oil generation that also had temperatures below various thresholds (0°, 5°, and 10°F).

Oil. Our analysis of oil operational data included all data from January 2015 through July 2020. To visually identify the relationship between temperature and the number of hours oil stayed online when dispatched. Note that only winter oil startups (November, December, January, and February) are included in this analysis.

Although there is not a strong correlation between temperature oil and run times overall, we do see an increased connection between extremely cold temperatures and duration of oil dispatches. This becomes noticeable when temperatures fall below about 20°F and very clear when they fall below 10°F. A closer look at the numbers reveals this finding:

- There are 119 oil startups that include a minimum measured temperature at or below 20°F. The average run time of these startups was 26.2 hours with 13 of them (11%) lasting more than 50 hours.
- There are 29 oil startups that include a minimum measured temperature at or below 10^{o} F. The average run time of these startups was 72.6 hours with 10 of them (34%) lasting more than 50 hours.
- There are 8 oil startups that include minimum measured temperatures below 0°F. Of these, 5 (63%) lasted at least 50 hours, with an average duration of 155.8 hours, or just shy of a week.

It is clear from the data that the two longest oil startups—each at least 16 days long—occurred when temperatures fell to -8°Fand -9°F. Extremely cold temperatures can result in longer oil runs. Thus, Eversource may be able to use these findings to justify calling more winter DR events, particularly when temperatures are forecasted to go negative, as there is a reasonable likelihood that oil will be online during those periods and may remain online for some time, offering the potential to extend the program's impacts beyond the day-of event if DR participation can keep an oil plant offline that would otherwise be dispatched.

Analysis of Marginal Resource Data

This section summarizes the analysis of marginal resource data published by ISO-NE, and the effect of temperature on marginal resources over time.

Analysis. For this analysis, the study team consolidated the ISO-NE marginal resource data and compared it to dry bulb temperature data to assess the marginality of different grid resources by time of day and temperature. We followed the following process for this analysis:

- Iteratively segmented and filtered the data by temperature bin, focusing on cold weather periods; the successive bins included all data below 30°F, 25°F, 20°F, 15°F, 10°F, 5°F, and 0°F, respectively (e.g., only data that occurred at or below a temperature of 15°F was included in the 15°F bin).
- Developed heat maps that visually convey the percentage of hours that each resource was classified as marginal in each temperature bin.

Findings. Through this analytical approach, the evaluators were able to develop insights into how the five grid resources that are most frequently on the margin behave as temperature changes, both in relative and absolute terms. Figure 3 highlights these findings for five fuel types: coal, oil, natural gas, wind, and hydro. One of these five resources (natural gas) was on the margin at least 96% of the time from 2015–2020, and it is rare for another fuel type (coal) to be classified as marginal in ISO-NE territory. In this figure, red cells indicate a higher marginal prevalence, and green cells indicate that the given fuel type was on the margin less frequently at that hour and in the respective temperature bin.

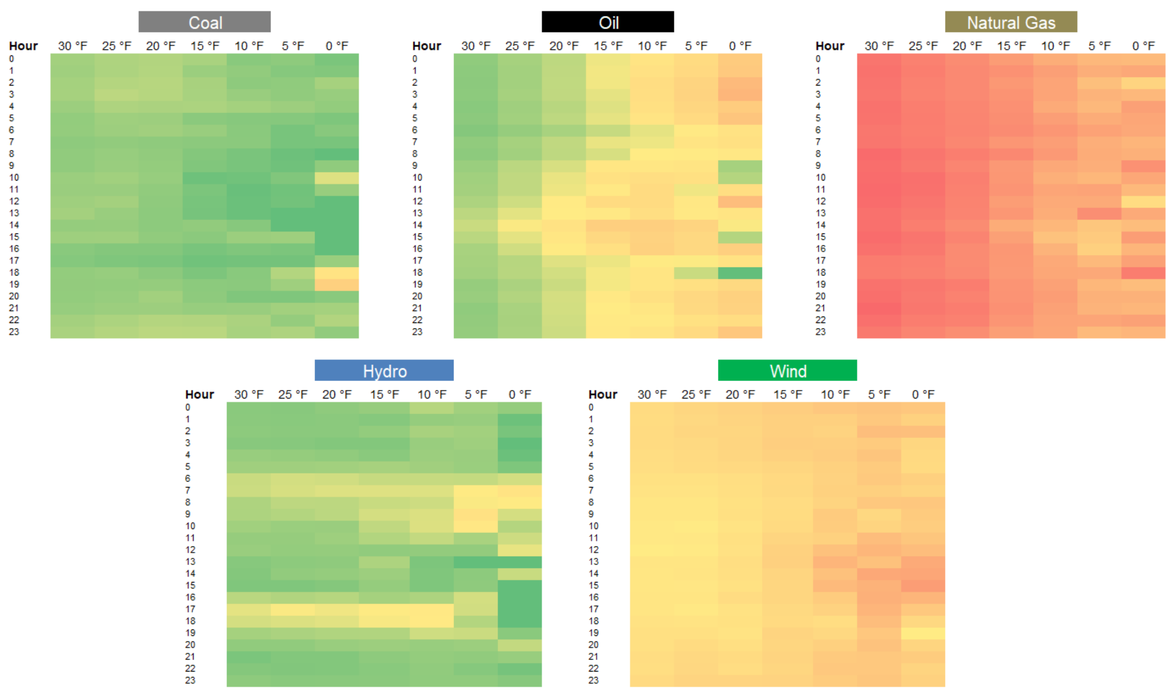

Figure 3. Findings for five fuel types

We can draw several conclusions from these heat maps about the marginal behavior of the included fuel types.

- Natural gas is on the margin significantly more often than any other fuel type.

    - It is marginal about 64% of the time when temperatures are below 30°F, but only 39% of the time when temperatures are below 0°F.
- Coal is on the margin the least often of all fuel types, as it is considered marginal during roughly 5% of hours, regardless of the temperature outside.
- Several resources' marginal behavior appears to be impacted by temperature:
    - As temperatures drop, natural gas is marginal less of the time.
    - As temperatures drop, both oil and wind tend to be marginal more of the time.
    - Oil is on the margin during 21% of hours when temperatures are below 0°F but only 5% of the time when temperatures are below 30°F.
    - Wind is on the margin during 29% of hours when temperatures are below 0°F and 21% of the time when temperatures are below 30°F.
- It is not the case that wind delivers more marginal energy generation than oil; wind resources frequently set local marginal prices (and are thus classified as marginal) in remote parts of New England but are unable to export their power to the rest of the ISO-NE. This could indicate that oil is more marginal in the Eversource territory covered in this study than indicated in the figure above.
- Coal, already the least marginal resource, is considered marginal slightly less often when temperatures drop.
- Hydro power is also frequently considered marginal. It does not exhibit strong temperature dependence. Rather, hydro is most often on the margin from 6–10 a.m. and from 5–7 p.m.; these windows may coincide with periods in which pumped hydro is discharged to address predictable morning and early evening load ramps.

Takeaways. This analysis yielded several key takeaways.

- Coal is rarely a marginal resource and has not historically shifted to the margin during cold snaps. Combined with its historical decline in use, there is little value in explicitly trying to call winter DR events to target coal as a marginal resource.
- Oil shows a strong shift to marginality as temperatures drop, reflecting its position as a quick-response contingency resource on the New England grid. This temperature dependence makes oil a good target for winter DR events, especially when called during periods of extreme cold.
- While natural gas is marginal less frequently as temperatures drop, it is still marginal for roughly 39% of hours in the coldest temperature bin. Thus, even if oil is not on the margin when a winter DR event is called, there is a relatively high likelihood that natural gas will be on the margin and DR resources with a lower carbon intensity than natural gas will still deliver GHG emissions reductions if they participate.

2020/2021 Season Carbon Impact

During the three-hour event on January 29, 2021, the following fuel resources were on the margin for ISO NE. The percentage of each resource on the margin in each hour has been weighted by the MW load that each would contribute to the grid, if needed. The bottom row shows the CO_2 emissions rate. The rightmost column shows the marginal emissions rate for each hour using the percentage of each fuel resource and its associated emissions rate.

Table 2. Summary of marginal fuels and event hour emissions rates

Hour ending	Hydro	Natural Gas	Wind	Oil	Wood	Marginal Emissions Rate (MER) MT CO_2/MWh
17	0%	87%	10%	2%	2%	0.4008

18	14%	70%	16%	0%	0%	0.2996
19	3%	86%	10%	0%	0%	0.3711
Fuel Emissions rates (MT CO_2/MWh)	0.0	0.43	0.0	1.49	0.0	N/A

While battery and interruptible technologies reduce grid demand and accompanying emissions during the event hours, participants that operate diesel generators as part of their interruptible strategy have emissions associated with their operation that must be accounted for in the net emissions change. This is shown in the three columns under generators, which list the grid emissions reduction, diesel generator operation increase, and net combined impact. We used an average generator efficiency of 40%[11] and standard assumptions and conversion factors[12] to calculate carbon emissions for these generators of 0.65 metric tons/MWh. Despite this negative impact, we estimate that the total carbon reduction of all combined technologies is 15.75 tons of carbon.

It is important to note that Eversource no longer allows the participation of generators in its DR program, thereby minimizing the risk of negative GHG impacts.

Table 3. Tons of carbon impacts by DR technology and overall

Hour ending	Battery Reduction	Interruptible Reduction	Interruptible - Generators			Total
			Reduction	Increase	Net	
17	0.55	6.25	0.84	-1.23	-0.39	6.40
18	0.48	4.87	0.64	-1.25	-0.61	4.74
19	0.58	4.47	0.78	-1.23	-0.45	4.61
Total	1.61	15.59	2.25	-3.71	-1.45	15.75

Conclusion

This paper discusses a study in New England that examined the use of data such as outdoor air temperature, marginal fuel resource data, wholesale prices, natural gas pipeline, and gas compressor utilization as possible inputs that could predict when an event would be most beneficial for load reduction and GHG reductions. The authors reviewed modeled grid carbon intensity data from a third-party data provider, analyzed carbon intensity and resource operation data in relation to weather data, reviewed ISO-NE market operation documentation, and estimated the DR initiative's net GHG impact.

The paper provides results detailing the marginality of various fuels, including but not limited to natural gas, oil, and coal, and identifies how each fuel's behavior on the grid impacts its value as a target for DR events. The study also offers insights into the most appropriate datasets to help predict grid dirtiness during extreme weather conditions.

The study highlighted that battery storage and curtailment participants can indeed reduce grid demand and GHG emissions. However, participants using diesel generators in their reduction strategies could actually increase emissions. This suggests that careful consideration of reduction strategies is crucial for achieving GHG reduction goals alongside traditional load management objectives. All results for this study are complete and publicly available.

[11] https://energyeducation.ca/encyclopedia/Diesel_generator
[12] Kg CO_2 / MMBTU (75.83), kg of CO_2 / MWH (0.29307)

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