AESC 2021 Supplemental Study

Expansion of natural gas benefits

Prepared for AESC Supplemental Study Group

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TABLE OF CONTENTS

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1. EXECUTIVE SUMMARY

In summer 2021, the Massachusetts natural gas energy efficiency Program Administrators (gas EE PAs) contracted Synapse Energy Economics, Inc. (Synapse) and North Side Energy, LLC (together, the Synapse Team) to provide more detailed information on avoided costs for natural gas EE programs than was provided in the AESC 2021 Study.[1]

The Synapse Team worked with a stakeholder group to conduct analysis across the three topic areas. The stakeholder group, called the AESC Supplemental Study Group, includes the gas EE PAs from Eversource, National Grid, Unitil, Liberty, and Berkshire Gas, along with representatives from Massachusetts state agencies and organizations—including Massachusetts Department of Energy Resources (DOER) and Massachusetts Energy Efficiency Advisory Council (EEAC). The three topic areas were the following:

- **Adapting existing $ per MWh avoided costs from AESC 2021 to different costing periods**: In this task, we have adapted existing $ per MWh electric avoided costs, which are currently provided in AESC 2021 in hourly format or in ISO New England's electric costing periods, into a format that is more aligned with the time periods used to assess natural gas avoided costs. The analysis includes three methodological approaches: weather data and historical load shapes, historical natural gas consumption, and user input. This format summarizes electric avoided costs for (a) design day, (b) next top 10 days, (c) remaining winter, and (d) rest of year. Users may also design a custom period.
- **Expanding cost period of AESC 2021 gas avoided costs**: In this task, we have expanded the existing $ per MMBtu avoided costs provided in AESC 2021 into more detailed costing periods. AESC 2021 currently provides $ per MMBtu avoided costs in six different costing periods based on gas consumption patterns (Baseload, Winter/Shoulder, Winter, Top 90, Top 30, and Top 10). This supplemental study adds a seventh (design day), which may be of interest to PAs exploring peak-day DERs, such as demand response measures. Values are also provided separately for each of the top 10 peak days, allowing users to create custom avoided costs for resources with varied dispatch patterns.
- **Describing a methodology for calculating avoided costs of localized natural gas transmission and distribution infrastructure**: In this task, we have adapted Section 10.4 of the AESC 2021 Study which describes a methodology for calculating avoided costs of localized electric transmission and distribution (T&D) infrastructure to the natural gas sector.

Each of these tasks is described in detail in the following sections.

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[1] The most recent edition of AESC 2021, at the time of this document's writing, was released in May 2021. It is available on the Synapse website at https://www.synapse-energy.com/project/aesc-2021-materials.

2. ADAPTING EXISTING $/MWH AVOIDED COSTS IN AESC 2021

AESC 2021 provides hourly avoided costs for wholesale energy and energy DRIPE. These electric avoided cost streams are summarized according to the four costing periods defined by ISO New England (winter peak, winter off-peak, summer on-peak, and summer off-peak). While these costing periods adhere to the periods conventionally used to test electric efficiency measures for cost-effectiveness, natural gas program administrators expressed a desire for other costing periods that adhere more closely with those used for evaluating gas measures, and costing periods that have been used in past cost-benefit analyses to examine "super-peak" pricing events. Although gas EE measures primarily produce MMBtu benefits, they may also produce MWh benefits, necessitating an estimate of a $/MWh value to apply to these benefits.

The Excel-based user interface accompanying AESC 2021 included a tab titled "VGSCosts" which summarizes hourly energy and energy DRIPE into four costing periods often associated with gas efficiency measures: design day, next 10 peak days, rest-of-winter, and rest-of-year. This worksheet also includes definitions of each of these periods, per an assignment developed by Synapse in conjunction with Vermont Gas (VGS).

In this supplemental study, we describe a methodology for assigning each modeled hour in AESC 2021 to one of these four gas costing periods, or for any user-defined custom periods. In addition, we have updated the AESC 2021 User Interface to allow users to summarize these electric avoided costs for any of the regions modeled in AESC 2021.

2.1. Assigning hours to gas costing periods

Electricity modeling in AESC 2021 was conducted on an hourly basis from January 1, 2021 through December 31, 2035. AESC 2021 used a consistent hourly load shape for each year, based on data publicly posted by ISO New England.[2] Our electric-system model combined this hourly load shape data with annual projections of demand and other inputs relevant to the electricity system (e.g., fuel prices, power plant retirements, renewable policy requirements) and output hourly energy pricing and load data from 2021 through 2035. These results were then reported in the AESC 2021 User Interface as wholesale energy costs. The results were also passed through a set of calculations to derive values for energy DRIPE.[3] These hourly avoided costs were then summarized for each year over the four ISO New

[2] More detail on the load shape used in AESC 2021 can be found in Section 4.3 of the AESC 2021 Study.

[3] More detail on the DRIPE calculations can found in Section 9.2 of the AESC 2021 Study.

England electric costing periods using a weighted average (i.e., costs are weighted by loads).[4] Avoided costs were reported separately for each of the regions modeled in AESC 2021.

In order to summarize hourly energy and energy DRIPE avoided costs into natural gas costing periods, it is necessary to explicitly define which calendar days in each year apply to specific gas costing period category. The gas costing periods are defined as:

- Design day: The day expected to feature the highest level of gas consumption in a single year.
- Next 10 highest days: The 10 days following the design day with the highest levels of gas consumption in a single year.[5]
- Rest of winter: The remaining 140 winter days.[6]
- Rest of year: The remaining 214 days in the year.

Because the "rest of winter" and "rest of year" periods are effectively defined based on the first two category assignments, the problem simplifies to identifying which 11 of the 151-day-long winter season days are expected to have the highest level of gas consumption. This is a non-trivial issue, as prices can vary widely in the AESC 2021 results. For example, we observe that for Massachusetts, in Counterfactual #1, winter energy prices in 2021 ranged from $37 per MWh to $59 per MWh, with an average value of $45 per MWh. By 2035, this spread widens to a range of $14 per MWh to $77 per MWh, with an average value of $59 per MWh.

The following sections describe three methods for defining these periods. The updated version of the AESC 2021 User Interface includes all three methods; users of AESC 2021 should decide which of these approaches are most useful or relevant to the measures they are examining for cost-effectiveness. Approach A is likely most useful to users who wish to identify the days with high gas use and high energy prices as modeled by AESC 2021, regardless of the calendar date of when they are expected to occur.[7] Approach B is likely most useful to users who wish to evaluate energy prices for future programs based on the expectation that they will dispatch on calendar days with historically high gas use. These calendar days may not necessarily line up with the high gas use days or high energy price days modeled in AESC 2021. Approach C is best for users who are seeking the most flexibility for program design.

[4] The four ISO New England electric costing periods are described in detail in Appendix B of the AESC 2021 Study.

[5] Note that the days in the "next 10 highest days" do not overlap with the design day. This is in contrast to the "Top 10 Day" period described in Chapter 3. As described in Section 2.2, users may also define a custom period that covers a top X number of days, including a top-10-day period that aligns with the Top 10 Day period described in Chapter 3.

[6] In AESC 2021, "winter" for gas costing purposes is defined as all days and hours in November through March, inclusive. It is different than the "winter" season defined for electric costing purposes, which includes all days and hours in October through May, inclusive. There are 151 total days in the winter season for gas costing purposes.

[7] Note that the AESC 2021 User Interface also allows users to define a custom period (a top X number of days) in Approach A. See Section 2.2 for more discussion on how to do this.

In most cases, we recommend users rely on Approach A. Approach B or C may be useful in some specific cases, but they may produce avoided costs that are not aligned with the underlying AESC assumptions of peak days.

Approach A: Based on weather data associated with ISO New England electric load shape

Under the first approach, we estimate that the 11 winter days in our hourly electric cost dataset with the greatest amount of gas consumption are likely to be the 11 days representing the design day and next 10 highest days. The premise for this is that days with the greatest amount of gas consumption are also likely to be the days with the coldest temperatures. The load shape published by ISO New England, which was used to model hourly load in AESC 2021 is based on the hourly data from 2002. Using hourly temperature data from the Iowa Environmental Mesonet website, we have identified the heating degree days (HDD) relative to 65 degrees Fahrenheit for each of the New England states.[8] Hourly temperature data was obtained for eight airports throughout New England. Temperatures were calculated for each state by relying on ISO New England's weighting of airport weather data to states.[9] HDD are calculated by subtracting the hourly temperature observation for each hour from 65, summing the total values from each day, and dividing the resulting sum by 24 hours.[10]

Table 1 details the top 11 coldest days, in order from coldest to warmest, for Massachusetts. This table only includes non-holiday weekdays. Table 1 also identifies the HDD for each day, and the calculated energy price for Massachusetts (statewide) in AESC 2021, for the year 2021.[11] Not unexpectedly, these days tend to be among the days with the highest energy prices. Of the 11 days shown, nine are in the top half of daily winter energy prices for Massachusetts in 2021. Three are in the top five days for energy prices. Discrepancies in days with a large number of HDD but a relatively low price may be because of differences in modeling assumptions related to monthly gas prices, hourly renewable capacity factors, annual demand, or power plant availability interacting with the 2002 load shapes.

[8] The Iowa Environmental Mesonet (IEM) is an archive of hourly weather data from around the planet. Data is typically based on automated airport weather observations (often called "ASOS" sensors). Data available at https://mesonet.agron.iastate.edu/request/download.phtml?network=MA_ASOS. Data accessed on July 26, 2021.

[9] See https://www.iso-ne.com/static-assets/documents/2020/09/ld2021_methodology.pdf, Slide 34. Under this assignment, Vermont is assumed to rely exclusively on Burlington, VT weather data; New Hampshire is assumed to rely exclusively on Concord, NH weather data; Rhode Island is assumed to rely exclusively on Providence, RI weather data and Maine is assumed to rely exclusively on Portland, ME weather data. Weather data for Connecticut and Massachusetts are based on a weighted average of weather from several airports: Bridgeport, CT and Windsor Locks, CT for Connecticut, and Boston, MA, Providence, RI, Windsor Locks, CT, and Worcester, MA, for Massachusetts.

[10] In the winter months of 2002 (January, February, March, November, and December), we observe several hours with missing data in each of the eight locations with surveyed data. These data points were "gap-filled" by calculating the average temperature from the two most-adjacent data points with reported data.

[11] This analysis has not yet been performed for energy DRIPE due to computational complexity. If desired by the Study Group, this analysis could be included in future versions of this document.

Table 1. Top 11 coldest days in 2002 in Massachusetts

Rank by HDD	Date	Number of HDD65 in Massachusetts	2021 Energy Prices for Massachusetts (2021 $/MWh)	Rank by price
1	12/9/2002	46.7	$58.85	4
2	12/3/2002	44.0	$58.92	2
3	12/4/2002	42.6	$54.93	24
4	2/5/2002	41.3	$48.44	33
5	12/5/2002	40.7	$54.70	25
6	12/17/2002	40.2	$58.74	5
7	3/22/2002	40.2	$42.23	93
8	2/14/2002	39.7	$44.39	52
9	3/5/2002	39.6	$42.97	79
10	1/8/2002	38.8	$43.92	57
11	12/6/2002	38.0	$57.97	12

ISO New England (and AESC 2021) rely on load shapes and weather data from 2002, but how similar was this year to other years? To answer this question, we examined hourly weather data for Logan Airport from November 2001 through March 2021.[12] Table 2 displays the share of HDD by month that occurred on average from 2001 to 2021.[13] It also shows the share of HDD by month that occurred in 2001 through 2003 (e.g., the average of two winter seasons, 2001–2002 and 2002–2003). The final row is the share of HDD by month that occurred in 2015 through 2021 (e.g., six winter seasons). The timespan covered by this last row is of interest below in Approach B. According to this analysis, 2002 appears to contain rather representative winter weather, compared to the past 20 years. It has a similar number of HDD to the 20-year average (less than 1 percent different), and these HDD are allocated across the five winter months in a pattern that is very similar to the 20-year average. This monthly distribution of HDD is also shared by the past six winters. However, these winters contain 5 percent fewer HDD, on average, relative to the last 20 years, and relative to 2002. In other words, 2002-based analysis does not underestimate HDD relative to the very recent past, it but may overestimate HDD.

[12] While the actual load shapes created by ISO New England are based on more sites than just Logan Airport, per ISO New England's assumptions, its weather data is the primary source used for Massachusetts (with a 44 percent weighting). We observe that for 2002, the weather at Logan Airport does not differ substantially from other sites throughout New England.

[13] Throughout this long-term weather analysis, we evaluated gas winter seasons. For example, the 2001–2002 winter season encompasses November 2001, December 2001, January 2002, February 2002, and March 2002.

Table 2. Share of HDD by month

	November	December	January	February	March	Average HDD
2001–2021 Average *(20 winters)*	21%	14%	25%	22%	19%	4,277
2001–2003 Average *(2 winters)*	20%	14%	25%	22%	19%	4,267
2015–2021 Average *(6 winters)*	21%	14%	24%	21%	19%	4,095

The AESC 2021 User Interface contains ranked HDD data under Approach A for all six New England states.

Approach B: Based on more recent historical data

In a separate task conducted by Synapse on behalf of Vermont Gas, Synapse examined the gas sendout from the Vermont Gas system in five winters from 2015 through 2020. In each winter, we calculated the 11 calendar days with the highest sendout. These days were indexed to the start of the gas winter season (with November 1 having an index of 1, November 2 having an index of 2, March 31 having an index of 151, and so on). We then calculated the average index for each of the top 11 spots for each of the five winters. With this methodology, we were able to identify the calendar days that have historically been most likely to be in the top 11 days. VGS requested a tab in the AESC 2021 User Interface that would allow it to calculate the energy and energy DRIPE avoided costs during those 11 days.

We repeated this same methodology for data provided by the Study Group sponsors as of July 26, 2021. Data has been provided for National Grid (MA), Unitil (MA), Unitil (NH), Berkshire Gas (MA), and Liberty Gas (MA).[14] Data analyzed only includes sendout data for non-power plant customers. The lines in Figure 1 highlight the days identified as one of the top 11 days for natural gas consumption, not including holidays and weekends (except for the top panel which calculates top days based on temperature). For the data provided by the four different utilities, we find a general clustering of top days between mid-January and mid-February. These days are generally aligned with each other, but not with the days calculated using Approach A.

Table 3 displays the energy prices associated with the identified days for the four Massachusetts utilities who provided data. Unlike in Approach A, the daily prices associated with peak sendout days are not generally among the highest of winter prices.[15] While National Grid (MA) and Berkshire Gas (MA) each

[14] The only utility sponsoring this supplemental study that did not provide data was Eversource (MA).

[15] We note that under Approach B, calculations for National Grid (MA), Unitil (MA), and Berkshire Gas (MA) yield duplicative days. In other words, a simple average of each of the top 11 days over the six years analyzed produces the same day for multiple spots in the ranking. In these situations, we continue our analysis through the 12th and 13th highest days and rely on those dates instead.

have 6 of their top 11 days in the top half of daily winter prices, Unitil (MA) only has 5 of its 11 days in the top half of daily winter prices and Liberty Gas (MA) only has 4 of its 11 days in the top half of daily winter prices. This mismatch is not unexpected—Approach B is indirectly based on weather patterns observed over the past six winters, while the energy prices calculated in AESC are, in part, based on weather patterns observed in 2002.

Figure 1. Top 11 days based on Approach A or sendout data analyzed using Approach B

Table 3. Energy prices and price rankings for top 11 days calculated under Approach B for Massachusetts utilities

Rank by Average Sendout	National Grid (MA)		Unitil (MA)		Berkshire Gas (MA)		Liberty Gas (MA)	
	Energy Price	*Rank in MA Prices*	*Energy Price*	*Rank in MA Prices*	*Energy Price*	*Rank in MA Prices*	*Energy Price*	*Rank in MA Prices*
1	$43.66	60	$42.66	88	$43.92	57	$42.66	88
2	$42.68	87	$39.64	131	$42.41	90	$39.64	131
3	$39.56	132	$42.99	78	$47.05	47	$43.58	63
4	$43.24	71	$39.65	130	$43.58	63	$39.88	128
5	$43.24	71	$43.04	76	$43.04	76	$47.86	36
6	$47.42	43	$41.99	101	$43.24	71	$43.92	57
7	$47.05	47	$44.12	54	$47.20	45	$47.05	47
8	$39.77	129	$43.21	73	$43.58	63	$39.27	134
9	$42.34	91	$43.58	63	$39.64	131	$42.78	84
10	$41.99	101	$43.61	62	$39.37	133	$39.37	133
11	$43.26	69	$44.05	55	$47.86	36	$43.25	70

Note: All data is calculated based on hourly 2021 data for Massachusetts in Counterfactual #1. Prices are described in terms of 2021 $ per MWh. Average sendout ranks are based on six winters' worth of data. Price ranks are based on a single modeled year (2021).

Approach C: Based on user input

Users may also elect to develop their own methodologies for identifying peak days. See the following section for instructions.

2.2. Updates to AESC 2021 User Interface

This supplemental study is accompanied by a new version of the Excel-based User Interface.[16] In this document, users can go to the "GasCostingData" tab and select an approach or view outputs.

- In Section A, users select an approach for assigning daily gas costing periods. Users may select: (1) User Input (Approach C), or (2) a costing period assignment based on Approach A or Approach B for one of several gas utilities.
    - If users select "User Input", they are required to identify the top 11 days for gas consumption. Enter "1" for the top day, "2" for the second-peakiest day, and so on. The #1 day will be marked as the design day and the other 10 days will be marked as the peak period. The User Interface will then automatically categorize all other days accordingly.
    - If users select "User Input" or any of the options that begin with "2002" (which are calculated according to the methodology described in Approach A), users may enter a custom period. Under the custom period, a user can enter a value

[16] The changes discussed in this section have been applied to all AESC 2021 counterfactuals and sensitivities.

for the top X days, and the User Interface will automatically calculate the energy and DRIPE avoided costs over this period. If "User Input" is selected, a user must specify a number of days for this custom period and also identify which days are the peak days (with a 1, 2, 3, and so on). If a "2002" option is selected, a user must enter a top number of days (e.g., "20"). The model will then automatically calculate avoided costs using the weather data analyzed in Approach A, which matches the hourly load shapes in AESC 2021.

  - If users select one of the other options (e.g., "National Grid (MA)"), they are choosing a period assignment based on Approach B. Because of the methodology used in Approach B, users are not able to specify a custom period. Instead, they may use the "User Input" and "Custom Period" selections to create a period that matches their program requirements.

- In Section B, the User Interface undergoes an intermediate step where daily gas period assignments are assigned to each of the 8,760 hours modeled in AESC 2021.

- In Section C, the User Interface calculates the load-weighted energy costs, in-region energy DRIPE values, and rest-of-region energy DRIPE values. Values are calculated for each of the four costing periods over the 15 years modeled in AESC 2021.

- In Section D, the User Interface transposes the energy and energy DRIPE values to the format used in Appendix B and Appendix C of AESC 2021 (with years going down and categories of avoided costs going across). Costs are also extrapolated through 2055 using the extrapolation technique described in Appendix A of the AESC 2021 Study. Costs shown in Section D are wholesale values.

- In Section E, we translate costs in Section D into retail values. See *Appendix B: Detailed Electric Outputs* in AESC 2021 for more information on the calculations used in this translation.

3. Expanding Detail of AESC 2021 Gas Avoided Costs

This task supplements the AESC 2021 results by providing natural gas avoided costs estimates for the Design Day and the Peak Period, defined as the 10 days with the highest gas use. It builds on the methodology and data used for the AESC 2021 Study. Note that this supplemental study does not update or revise any of the short- or long-term gas price forecasts originally developed in the AESC 2021 Study.

3.1. AESC 2021 methodology: An overview

AESC 2021 developed natural gas avoided costs in two component parts. The first component is the upstream avoided cost, which includes the fixed and variable costs to obtain natural gas and deliver it into the local gas distribution system through local distribution companies (LDC). The second component is the avoidable distribution margin, which is the cost of delivering additional gas from the LDC's connections with upstream pipelines and on-system peaking facilities to the end-use customer.[17]

Upstream avoided costs

The methodology used in AESC 2021 to estimate upstream avoided costs has four steps:

1. First, we identify the resources that New England LDCs commonly use to make additional gas supply available for customers. We rely on publicly available information from LDC gas resource plans and applications for state regulatory approval of new pipeline and gas supply contracts.

2. Second, for each of the representative gas supply resources identified in Step 1, we calculate the annual cost per MMBtu of using that resource to supply gas requirements in each of six costing periods, for all years of the forecast period.

3. Third, we set the avoided costs for each costing period equal to the cost of the resource with lowest discounted cost over the forecast period. The avoided costs by costing period are shown in Tables 161 and 162 of the AESC 2021 Study. We include one table for southern New England and one table for northern New England, to differentiate between the varied gas resources and transportation systems in each region.[18] An abbreviated version of Table 161 is shown below as Table 4.

4. Finally, we calculate the avoided cost for each end-use category as a weighted average over the six costing periods, using weighting factors that reflect the load shape for each end-use. The natural gas avoided cost results without distribution margin are presented in Tables 150 and 152 of the AESC 2021 Study. We include one table for southern New

[17] See Section 2.4 for more detail on the methodology for avoided natural gas avoided costs.

[18] In AESC 2021, natural gas avoided costs are estimated for three regions: (1) southern New England (Connecticut, Rhode Island, and Massachusetts); (2) northern New England (New Hampshire, Maine); and (3) Vermont.

England and one table for northern New England. An abbreviated version of Table 150 is shown below as Table 5.

Table 4. Avoided natural gas costs by costing period – southern New England (2021 $ per MMBtu)

Years	Baseload	Winter/Shoulder	Winter	Top 90	Top 30	Top 10
Days	*365*	*273*	*151*	*90*	*30*	*10*
2021	$4.45	$5.61	$7.69	$8.67	$16.69	$29.84
2022	$4.24	$5.44	$7.69	$10.19	$19.27	$33.14
2023	$4.03	$5.20	$7.41	$10.03	$18.98	$32.63
2024	$4.35	$5.52	$7.73	$10.35	$19.51	$33.20
2025	$4.41	$5.57	$7.76	$10.42	$19.61	$33.22

Note: This is an abbreviated version of Table 161 in the AESC 2021 Study.

Table 5. Avoided cost of gas to retail customers by end-use for southern New England (SNE) assuming no avoidable retail margin (2021 $ per MMBtu)

Year	Residential				Commercial & Industrial			All Retail End-Uses
	Non-Heating	*Hot Water*	*Heating*	*All*	*Non-Heating*	*Heating*	*All*	
2021	4.45	5.21	6.92	6.21	5.29	6.42	5.92	6.07
2022	4.24	5.11	7.08	6.26	5.20	6.50	5.93	6.11
2023	4.03	4.90	6.84	6.03	4.98	6.27	5.71	5.88
2024	4.35	5.22	7.17	6.35	5.30	6.60	6.03	6.20
2025	4.41	5.28	7.22	6.41	5.36	6.65	6.09	6.26

Note: This is an abbreviated version of Table 150 in the AESC 2021 Study.

Avoidable distribution costs

AESC 2021 used recent marginal cost-of-service studies filed with LDC rate case applications to estimate a weighted average avoidable distribution margin for each customer category. These marginal cost studies estimate the capacity-related plant and operating costs that are caused by changes in design day demand and annual gas deliveries. Table 6 shows the updated LDC cost-of-service study results and the weighted average value for each cost driver.

Table 6. LDC marginal distribution cost estimates for design days

Company	Docket Number	Design Day Demand (2021 $/MMBtu)	Delivery Quantity (2021 $/MMBtu)	Annual Use (Bcf)
National Grid (Boston Gas)	21-120	150.86	0.00	95.4
National Grid (Colonial Gas)	21-120	124.09	0.41	23.8
Berkshire Gas	18-40	143.86	0.06	7.6
Bay State Gas	18-45	65.99	0.00	51.8
NSTAR Gas	19-120	193.50	0.00	51.7
EnergyNorth	DG 20-105	344.21	0.00	15.7
Northern - Maine	2019-00092	188.27	0.00	10.8
Weighted Average		153.03	0.04	

3.2. Supplemental study methodology and results

The following sections describe the methodology used in this supplemental study.

Upstream avoided costs

In AESC 2021 we calculated avoided upstream costs for the Highest 10 Day costing period as an intermediate step in the natural gas avoided cost methodology. For this supplemental study, we calculate the Design Day using the same cost inputs as this Highest 10 Day process, but with two adjustments. First, we modify the fixed-cost portion of the total cost to reflect the recovery of these costs over a single day. Second, we substitute a higher peak day gas commodity price for the Highest 10 Day price. The Highest 10 Day gas price used for AESC 2021 was calculated by applying a multiplier to the average gas price for the months of December through February. The Design Day price multiplier is based on the relationship between the highest daily gas price and the average gas price during the top 10 days observed over five winter periods (2014–15 through 2019–20).

Marginal distribution costs

Using available marginal cost-of-service study results described above in Table 6, we derive weighted average marginal costs that are used to calculate avoidable distribution margins for the Design Day and the six costing periods currently in AESC 2021 (Baseload, Winter/Shoulder, Winter, Top 90, Top 30, and Top 10). See Table 7 for a summary of these distribution margins.

Table 7. Distribution margin by costing period (2021 $ per MMBtu)

Costing Period	Number of Days	Distribution Margin
Baseload	365	0.46
Winter/Shoulder	273	0.60
Winter	151	1.05
Top 90	90	1.74
Top 30	30	5.14
Top 10	10	15.34
Design Day	1	153.07

Results

The following tables detail the results of our Design Day and peak period avoided cost analysis. Table 8 and Table 9 display avoided natural gas costs by costing period for southern New England and northern New England, respectively. These tables include results from Table 161 and Table 162 in the AESC 2021 Study, with a new column detailing avoided costs for the design day. Note that the avoided costs for southern New England decline slightly over time because charges for pipeline transportation services are assumed to be level in nominal dollars. This causes the fixed-cost component of the avoided costs to become smaller when converted to 2021 dollars. Because the fixed costs for the marginal resource in northern New England are based on peaking facility costs assumed to increase with inflation, the avoided costs expressed in 2021 dollars are relatively flat. Table 10 and Table 11 show the avoided costs by costing period from Table 8 and Table 9 with the distribution margins from Table 7 included.

The Top 10 Day avoided costs shown in Table 10 and Table 11 measure the benefits of reducing gas use for temperature-sensitive loads during peak winter periods. This type of targeted reduction of gas use could result from a program where gas users curtail gas use or stop using gas entirely when directed by the utility, and these events are expected to occur approximately 10 days each year. A different type of program that reduces gas use by a certain amount each day, where the size of the reduction does not vary by temperature, would have less impact on design day requirements, and would therefore be expected to have a lower benefit per MMBtu of gas use reduction over the same number of days. Avoided cost estimates for this type of program, where the size of the reduction in daily gas use is "level" and is not tied to a temperature-sensitive load shape, are shown in Table 12 through Table 15.[19] Results are shown for reductions in gas use that occur over a period of one day (the design day) to 10 days. For example, a five-day reduction in gas use is assumed to occur on the design day plus the next four highest demand days.

Finally, the avoided cost estimates presented here would also apply to a program that reduces gas use during certain hours of the day if that the program also causes total gas use to be lower on the design

[19] Values are shown for both southern New England and northern New England, both with and without the avoidable distribution margin. These tables are also available in the Appendix C Excel workbook.

day and other peak demand days. Programs that reduce peak hourly gas use and dampen hourly variability in consumption would also be expected to create other operational and system design benefits that are not reflected in these estimates of avoided gas supply resource costs.

Avoided cost examples

The numbers shown in Table 12 through Table 15 measure the annual avoided cost savings per MMBtu from reducing gas consumption only on the days of highest gas use, where the number of days on which gas use is reduced varies from one day (the design day) to ten days. For example, the avoided costs for a utility located in Southern New England, before adding marginal gas distribution system costs, are shown in Table 12. If gas use is reduced by 10 MMBtu per day on the ten highest use days per year, for a total reduction of 100 MMBtu, the savings for 2021 would be 100 MMBtu times $24.77, or $2,477. If the same total reduction in gas use occurred during the four highest use days, the savings would be 100 MMBtu times $44.38, or $4,438.

If the reduction in gas use is closely tied to temperature, so that the change in daily gas use is higher on days that are colder, the avoided cost estimates for this example are shown in Table 8. In this case, the savings for a total reduction in gas use of 100 MMBtu that occurs on the ten highest use days would be 100 MMBtu times $29.84, or $2,984.

Table 8. Avoided natural gas costs by costing period, before distribution costs – southern New England (2021 $ per MMBtu)

Years	Baseload	Winter/Shoulder	Winter	Top 90	Top 30	Top 10	Design Day
Days	*365*	*273*	*151*	*90*	*30*	*10*	*1*
2021	$4.45	$5.61	$7.69	$8.67	$16.69	$29.84	$147.49
2022	$4.24	$5.44	$7.69	$10.19	$19.27	$33.14	$152.40
2023	$4.03	$5.20	$7.41	$10.03	$18.98	$32.63	$150.88
2024	$4.35	$5.52	$7.73	$10.35	$19.51	$33.20	$151.21
2025	$4.41	$5.57	$7.76	$10.42	$19.61	$33.22	$150.62
2026	$4.52	$5.66	$7.84	$10.54	$19.79	$33.33	$150.20
2027	$4.58	$5.71	$7.86	$10.61	$19.89	$33.34	$149.63
2028	$4.72	$5.85	$7.99	$10.76	$20.15	$33.56	$149.41
2029	$4.85	$5.96	$8.09	$10.91	$20.37	$33.75	$149.15
2030	$4.91	$6.01	$8.12	$10.97	$20.47	$33.77	$148.62
2031	$4.92	$6.02	$8.11	$11.00	$20.49	$33.68	$147.93
2032	$4.99	$6.08	$8.15	$11.08	$20.61	$33.73	$147.46
2033	$5.06	$6.13	$8.19	$11.15	$20.72	$33.77	$147.00
2034	$5.08	$6.15	$8.19	$11.18	$20.76	$33.72	$146.39
2035	$5.09	$6.15	$8.17	$11.20	$20.77	$33.63	$145.73
2036	$5.14	$6.18	$8.19	$11.25	$20.83	$33.61	$145.17
2037	$5.18	$6.21	$8.20	$11.30	$20.90	$33.59	$144.63
2038	$5.22	$6.25	$8.22	$11.35	$20.97	$33.58	$144.08
2039	$5.27	$6.28	$8.23	$11.40	$21.04	$33.56	$143.53
2040	$5.31	$6.31	$8.25	$11.45	$21.11	$33.55	$142.99
2041	$5.36	$6.34	$8.26	$11.50	$21.18	$33.53	$142.45
2042	$5.40	$6.38	$8.28	$11.55	$21.25	$33.52	$141.91
2043	$5.45	$6.41	$8.29	$11.60	$21.32	$33.50	$141.37
2044	$5.50	$6.45	$8.31	$11.66	$21.39	$33.48	$140.84
2045	$5.54	$6.48	$8.32	$11.71	$21.46	$33.47	$140.31
2046	$5.59	$6.51	$8.34	$11.76	$21.54	$33.45	$139.78
2047	$5.64	$6.55	$8.35	$11.81	$21.61	$33.44	$139.25
2048	$5.69	$6.58	$8.37	$11.87	$21.68	$33.42	$138.72
2049	$5.73	$6.62	$8.38	$11.92	$21.75	$33.40	$138.20
2050	$5.78	$6.65	$8.40	$11.97	$21.82	$33.39	$137.67
2051	$5.83	$6.69	$8.41	$12.03	$21.89	$33.37	$137.15
2052	$5.88	$6.72	$8.43	$12.08	$21.97	$33.36	$136.63
2053	$5.93	$6.76	$8.45	$12.13	$22.04	$33.34	$136.12
2054	$5.98	$6.79	$8.46	$12.19	$22.11	$33.33	$135.60
2055	$6.03	$6.83	$8.48	$12.24	$22.19	$33.31	$135.09

Note: This table is identical to Table 161 in the AESC 2021 Study, except for the addition of a new "Design Day" column.

Table 9. Avoided natural gas costs by costing period, before distribution costs – northern New England (2021 $ per MMBtu)

Years	Baseload	Winter/Shoulder	Winter	Top 90	Top 30	Top 10	Design Day
Days	*365*	*273*	*151*	*90*	*30*	*10*	*1*
2021	$4.28	$5.33	$7.23	$11.55	$19.19	$50.24	$208.24
2022	$4.07	$5.17	$7.24	$11.65	$21.82	$51.77	$209.77
2023	$3.86	$4.94	$6.96	$11.30	$21.58	$51.63	$209.63
2024	$4.18	$5.26	$7.29	$11.60	$22.15	$51.96	$209.96
2025	$4.25	$5.32	$7.33	$11.60	$22.30	$52.05	$210.05
2026	$4.36	$5.41	$7.41	$11.63	$22.53	$52.18	$210.18
2027	$4.42	$5.47	$7.45	$11.63	$22.67	$52.26	$210.26
2028	$4.56	$5.60	$7.58	$11.71	$22.97	$52.44	$210.44
2029	$4.69	$5.72	$7.69	$11.78	$23.24	$52.59	$210.59
2030	$4.75	$5.78	$7.73	$11.78	$23.38	$52.68	$210.68
2031	$4.77	$5.79	$7.72	$11.73	$23.44	$52.71	$210.71
2032	$4.84	$5.85	$7.77	$11.74	$23.60	$52.80	$210.80
2033	$4.91	$5.91	$7.82	$11.75	$23.75	$52.89	$210.89
2034	$4.94	$5.93	$7.82	$11.71	$23.83	$52.94	$210.94
2035	$4.95	$5.93	$7.81	$11.66	$23.87	$52.96	$210.96
2036	$5.00	$5.97	$7.83	$11.64	$23.98	$53.03	$211.03
2037	$5.04	$6.00	$7.85	$11.63	$24.09	$53.09	$211.09
2038	$5.09	$6.04	$7.88	$11.61	$24.20	$53.15	$211.15
2039	$5.14	$6.08	$7.90	$11.59	$24.31	$53.22	$211.21
2040	$5.18	$6.11	$7.92	$11.57	$24.43	$53.28	$211.28
2041	$5.23	$6.15	$7.94	$11.55	$24.54	$53.34	$211.34
2042	$5.28	$6.19	$7.96	$11.54	$24.65	$53.41	$211.40
2043	$5.33	$6.23	$7.99	$11.52	$24.76	$53.47	$211.47
2044	$5.38	$6.27	$8.01	$11.50	$24.88	$53.53	$211.53
2045	$5.43	$6.30	$8.03	$11.48	$24.99	$53.60	$211.59
2046	$5.48	$6.34	$8.05	$11.46	$25.11	$53.66	$211.66
2047	$5.53	$6.38	$8.08	$11.45	$25.22	$53.72	$211.72
2048	$5.58	$6.42	$8.10	$11.43	$25.34	$53.79	$211.78
2049	$5.63	$6.46	$8.12	$11.41	$25.45	$53.85	$211.85
2050	$5.68	$6.50	$8.14	$11.39	$25.57	$53.92	$211.91
2051	$5.73	$6.54	$8.17	$11.37	$25.69	$53.98	$211.97
2052	$5.79	$6.58	$8.19	$11.36	$25.80	$54.05	$212.04
2053	$5.84	$6.62	$8.21	$11.34	$25.92	$54.11	$212.10
2054	$5.89	$6.66	$8.23	$11.32	$26.04	$54.17	$212.16
2055	$5.95	$6.70	$8.26	$11.30	$26.16	$54.24	$212.22

Note: This table is identical to Table 162 in the AESC 2021 Study, except for revisions to the "Top 10" column and the addition of a new "Design Day" column.

Table 10. Avoided natural gas costs by costing period, with distribution costs – southern New England (2021 $ per MMBtu)

Years	Baseload	Winter/Shoulder	Winter	Top 90	Top 30	Top 10	Design Day
Days	*365*	*273*	*151*	*90*	*30*	*10*	*1*
2021	$4.91	$6.21	$8.74	$10.41	$21.83	$45.18	$300.56
2022	$4.70	$6.04	$8.74	$11.93	$24.41	$48.48	$305.47
2023	$4.49	$5.80	$8.46	$11.77	$24.12	$47.97	$303.95
2024	$4.81	$6.12	$8.78	$12.09	$24.65	$48.54	$304.28
2025	$4.87	$6.17	$8.81	$12.16	$24.75	$48.56	$303.69
2026	$4.98	$6.26	$8.89	$12.28	$24.93	$48.67	$303.27
2027	$5.04	$6.31	$8.91	$12.35	$25.03	$48.68	$302.70
2028	$5.18	$6.45	$9.04	$12.50	$25.29	$48.90	$302.48
2029	$5.31	$6.56	$9.14	$12.65	$25.51	$49.09	$302.22
2030	$5.37	$6.61	$9.17	$12.71	$25.61	$49.11	$301.69
2031	$5.38	$6.62	$9.16	$12.74	$25.63	$49.02	$301.00
2032	$5.45	$6.68	$9.20	$12.82	$25.75	$49.07	$300.53
2033	$5.52	$6.73	$9.24	$12.89	$25.86	$49.11	$300.07
2034	$5.54	$6.75	$9.24	$12.92	$25.90	$49.06	$299.46
2035	$5.55	$6.75	$9.22	$12.94	$25.91	$48.97	$298.80
2036	$5.60	$6.78	$9.24	$12.99	$25.97	$48.95	$298.24
2037	$5.64	$6.81	$9.25	$13.04	$26.04	$48.93	$297.69
2038	$5.68	$6.85	$9.27	$13.09	$26.11	$48.92	$297.14
2039	$5.73	$6.88	$9.28	$13.14	$26.18	$48.90	$296.58
2040	$5.77	$6.91	$9.30	$13.19	$26.25	$48.89	$296.03
2041	$5.82	$6.94	$9.31	$13.24	$26.32	$48.87	$295.48
2042	$5.86	$6.98	$9.33	$13.29	$26.39	$48.86	$294.94
2043	$5.91	$7.01	$9.34	$13.34	$26.46	$48.84	$294.39
2044	$5.95	$7.04	$9.36	$13.39	$26.53	$48.82	$293.84
2045	$6.00	$7.08	$9.37	$13.45	$26.60	$48.81	$293.30
2046	$6.05	$7.11	$9.39	$13.50	$26.67	$48.79	$292.75
2047	$6.09	$7.15	$9.40	$13.55	$26.74	$48.78	$292.21
2048	$6.14	$7.18	$9.42	$13.60	$26.81	$48.76	$291.67
2049	$6.19	$7.22	$9.43	$13.65	$26.88	$48.74	$291.12
2050	$6.24	$7.25	$9.45	$13.71	$26.96	$48.73	$290.58
2051	$6.29	$7.28	$9.46	$13.76	$27.03	$48.71	$290.04
2052	$6.33	$7.32	$9.48	$13.81	$27.10	$48.70	$289.51
2053	$6.38	$7.35	$9.49	$13.87	$27.17	$48.68	$288.97
2054	$6.43	$7.39	$9.51	$13.92	$27.24	$48.67	$288.43
2055	$6.48	$7.43	$9.53	$13.97	$27.31	$48.65	$287.90

Note: This table is identical to Table 161 in the AESC 2021 Study, except for the addition of a new "Design Day" column and the inclusion of impacts from the avoidable distribution margin.

Table 11. Avoided natural gas costs by costing period, with distribution costs – northern New England (2021 $ per MMBtu)

Years	Baseload	Winter/Shoulder	Winter	Top 90	Top 30	Top 10	Design Day
Days	*365*	*273*	*151*	*90*	*30*	*10*	*1*
2021	$4.74	$5.93	$8.28	$13.29	$24.33	$65.58	$361.31
2022	$4.53	$5.77	$8.29	$13.39	$26.96	$67.11	$362.84
2023	$4.32	$5.54	$8.01	$13.04	$26.72	$66.97	$362.70
2024	$4.64	$5.86	$8.34	$13.34	$27.29	$67.30	$363.03
2025	$4.71	$5.92	$8.38	$13.34	$27.44	$67.39	$363.12
2026	$4.82	$6.01	$8.46	$13.37	$27.67	$67.52	$363.25
2027	$4.88	$6.07	$8.50	$13.37	$27.81	$67.60	$363.33
2028	$5.02	$6.20	$8.63	$13.45	$28.11	$67.78	$363.51
2029	$5.15	$6.32	$8.74	$13.52	$28.38	$67.93	$363.66
2030	$5.21	$6.38	$8.78	$13.52	$28.52	$68.02	$363.75
2031	$5.23	$6.39	$8.77	$13.47	$28.58	$68.05	$363.78
2032	$5.30	$6.45	$8.82	$13.48	$28.74	$68.14	$363.87
2033	$5.37	$6.51	$8.87	$13.49	$28.89	$68.23	$363.96
2034	$5.40	$6.53	$8.87	$13.45	$28.97	$68.28	$364.01
2035	$5.41	$6.53	$8.86	$13.40	$29.01	$68.30	$364.03
2036	$5.46	$6.57	$8.88	$13.38	$29.12	$68.37	$364.10
2037	$5.50	$6.60	$8.90	$13.37	$29.23	$68.43	$364.16
2038	$5.55	$6.64	$8.93	$13.35	$29.34	$68.49	$364.22
2039	$5.60	$6.68	$8.95	$13.33	$29.45	$68.56	$364.28
2040	$5.64	$6.71	$8.97	$13.31	$29.56	$68.62	$364.35
2041	$5.69	$6.75	$8.99	$13.29	$29.68	$68.68	$364.41
2042	$5.74	$6.79	$9.01	$13.28	$29.79	$68.75	$364.47
2043	$5.79	$6.83	$9.04	$13.26	$29.90	$68.81	$364.54
2044	$5.84	$6.86	$9.06	$13.24	$30.01	$68.87	$364.60
2045	$5.88	$6.90	$9.08	$13.22	$30.12	$68.94	$364.66
2046	$5.93	$6.94	$9.10	$13.20	$30.24	$69.00	$364.73
2047	$5.98	$6.98	$9.12	$13.19	$30.35	$69.06	$364.79
2048	$6.03	$7.02	$9.15	$13.17	$30.47	$69.13	$364.85
2049	$6.08	$7.06	$9.17	$13.15	$30.58	$69.19	$364.91
2050	$6.14	$7.10	$9.19	$13.13	$30.70	$69.25	$364.98
2051	$6.19	$7.13	$9.21	$13.11	$30.81	$69.32	$365.04
2052	$6.24	$7.17	$9.24	$13.10	$30.93	$69.38	$365.10
2053	$6.29	$7.21	$9.26	$13.08	$31.04	$69.45	$365.17
2054	$6.34	$7.25	$9.28	$13.06	$31.16	$69.51	$365.23
2055	$6.40	$7.29	$9.31	$13.04	$31.28	$69.57	$365.29

Note: This table is identical to Table 162 in the AESC 2021 Study, except for the addition of a new "Design Day" column and the inclusion of impacts from the avoidable distribution margin.

Table 12. Avoided natural gas costs for peak periods with equal reduction in daily use, before distribution costs – southern New England (2021 $ per MMBtu)

Days	10	9	8	7	6	5	4	3	2	1 (Design Day)
2021	$24.77	$25.29	$27.20	$29.65	$32.93	$37.51	$44.38	$55.84	$78.75	$147.49
2022	$28.17	$28.43	$30.37	$32.86	$36.18	$40.83	$47.80	$59.42	$82.67	$152.40
2023	$27.75	$28.02	$29.94	$32.41	$35.70	$40.31	$47.22	$58.74	$81.77	$150.88
2024	$28.42	$28.62	$30.54	$33.00	$36.28	$40.88	$47.78	$59.27	$82.25	$151.21
2025	$28.53	$28.71	$30.62	$33.06	$36.33	$40.90	$47.76	$59.19	$82.05	$150.62
2026	$28.74	$28.88	$30.78	$33.22	$36.47	$41.02	$47.84	$59.21	$81.96	$150.20
2027	$28.84	$28.96	$30.85	$33.27	$36.50	$41.03	$47.81	$59.13	$81.75	$149.63
2028	$29.15	$29.23	$31.11	$33.52	$36.74	$41.25	$48.01	$59.28	$81.81	$149.41
2029	$29.42	$29.46	$31.33	$33.74	$36.94	$41.43	$48.16	$59.38	$81.83	$149.15
2030	$29.53	$29.55	$31.41	$33.80	$36.99	$41.45	$48.15	$59.32	$81.64	$148.62
2031	$29.52	$29.53	$31.38	$33.76	$36.93	$41.37	$48.03	$59.13	$81.33	$147.93
2032	$29.65	$29.64	$31.48	$33.84	$37.00	$41.42	$48.05	$59.09	$81.18	$147.46
2033	$29.78	$29.73	$31.57	$33.92	$37.06	$41.46	$48.06	$59.05	$81.04	$147.00
2034	$29.80	$29.74	$31.56	$33.91	$37.03	$41.41	$47.97	$58.90	$80.78	$146.39
2035	$29.78	$29.71	$31.53	$33.86	$36.96	$41.31	$47.84	$58.72	$80.47	$145.73
2036	$29.85	$29.76	$31.56	$33.88	$36.97	$41.30	$47.79	$58.61	$80.25	$145.17
2037	$29.91	$29.80	$31.60	$33.90	$36.98	$41.28	$47.74	$58.51	$80.04	$144.63
2038	$29.98	$29.85	$31.63	$33.93	$36.98	$41.27	$47.69	$58.40	$79.82	$144.08
2039	$30.04	$29.89	$31.67	$33.95	$36.99	$41.25	$47.64	$58.30	$79.60	$143.53
2040	$30.11	$29.94	$31.70	$33.97	$37.00	$41.24	$47.59	$58.19	$79.39	$142.99
2041	$30.17	$29.98	$31.74	$33.99	$37.01	$41.22	$47.54	$58.09	$79.17	$142.45
2042	$30.24	$30.03	$31.77	$34.02	$37.01	$41.20	$47.50	$57.98	$78.96	$141.91
2043	$30.30	$30.07	$31.81	$34.04	$37.02	$41.19	$47.45	$57.88	$78.75	$141.37
2044	$30.37	$30.12	$31.84	$34.06	$37.03	$41.17	$47.40	$57.77	$78.54	$140.84
2045	$30.43	$30.16	$31.88	$34.09	$37.03	$41.16	$47.35	$57.67	$78.32	$140.31
2046	$30.50	$30.21	$31.91	$34.11	$37.04	$41.14	$47.30	$57.57	$78.11	$139.78
2047	$30.57	$30.25	$31.95	$34.13	$37.05	$41.13	$47.25	$57.46	$77.90	$139.25
2048	$30.63	$30.30	$31.99	$34.16	$37.05	$41.11	$47.20	$57.36	$77.69	$138.72
2049	$30.70	$30.34	$32.02	$34.18	$37.06	$41.10	$47.15	$57.26	$77.48	$138.20
2050	$30.76	$30.39	$32.06	$34.20	$37.07	$41.08	$47.10	$57.16	$77.27	$137.67
2051	$30.83	$30.44	$32.09	$34.23	$37.07	$41.06	$47.06	$57.05	$77.06	$137.15
2052	$30.90	$30.48	$32.13	$34.25	$37.08	$41.05	$47.01	$56.95	$76.86	$136.63
2053	$30.96	$30.53	$32.17	$34.27	$37.09	$41.03	$46.96	$56.85	$76.65	$136.12
2054	$31.03	$30.57	$32.20	$34.30	$37.09	$41.02	$46.91	$56.75	$76.44	$135.60
2055	$31.10	$30.62	$32.24	$34.32	$37.10	$41.00	$46.86	$56.64	$76.24	$135.09

Table 13. Avoided natural gas costs for peak periods with equal reduction in daily use, before distribution costs – northern New England (2021 $ per MMBtu)

Days	10	9	8	7	6	5	4	3	2	1 (Design Day)
2021	$30.24	$31.51	$34.27	$37.82	$42.55	$49.18	$59.12	$75.69	$108.83	$208.24
2022	$31.77	$32.90	$35.66	$39.22	$43.95	$50.59	$60.53	$77.12	$110.28	$209.77
2023	$31.63	$32.77	$35.53	$39.09	$43.82	$50.46	$60.40	$76.99	$110.15	$209.63
2024	$31.96	$33.07	$35.84	$39.39	$44.13	$50.76	$60.71	$77.29	$110.46	$209.96
2025	$32.05	$33.16	$35.92	$39.47	$44.21	$50.85	$60.80	$77.38	$110.55	$210.05
2026	$32.18	$33.27	$36.04	$39.59	$44.33	$50.97	$60.92	$77.50	$110.67	$210.18
2027	$32.26	$33.35	$36.11	$39.67	$44.41	$51.04	$60.99	$77.58	$110.75	$210.26
2028	$32.44	$33.51	$36.27	$39.83	$44.57	$51.20	$61.15	$77.74	$110.91	$210.44
2029	$32.59	$33.65	$36.41	$39.97	$44.71	$51.34	$61.30	$77.89	$111.06	$210.59
2030	$32.68	$33.73	$36.49	$40.05	$44.79	$51.42	$61.37	$77.96	$111.14	$210.68
2031	$32.71	$33.76	$36.52	$40.08	$44.82	$51.45	$61.41	$78.00	$111.18	$210.71
2032	$32.80	$33.84	$36.61	$40.16	$44.90	$51.54	$61.49	$78.08	$111.26	$210.80
2033	$32.89	$33.92	$36.69	$40.24	$44.98	$51.62	$61.57	$78.17	$111.35	$210.89
2034	$32.94	$33.96	$36.73	$40.28	$45.02	$51.66	$61.62	$78.21	$111.39	$210.94
2035	$32.96	$33.99	$36.75	$40.31	$45.05	$51.69	$61.64	$78.23	$111.41	$210.96
2036	$33.03	$34.05	$36.81	$40.37	$45.11	$51.74	$61.70	$78.29	$111.47	$211.03
2037	$33.09	$34.10	$36.87	$40.42	$45.17	$51.80	$61.76	$78.35	$111.53	$211.09
2038	$33.15	$34.16	$36.93	$40.48	$45.22	$51.86	$61.82	$78.41	$111.59	$211.15
2039	$33.22	$34.22	$36.98	$40.54	$45.28	$51.92	$61.87	$78.47	$111.65	$211.21
2040	$33.28	$34.28	$37.04	$40.60	$45.34	$51.98	$61.93	$78.53	$111.71	$211.28
2041	$33.34	$34.34	$37.10	$40.66	$45.40	$52.03	$61.99	$78.59	$111.77	$211.34
2042	$33.41	$34.39	$37.16	$40.71	$45.46	$52.09	$62.05	$78.64	$111.83	$211.40
2043	$33.47	$34.45	$37.22	$40.77	$45.51	$52.15	$62.11	$78.70	$111.89	$211.47
2044	$33.54	$34.51	$37.28	$40.83	$45.57	$52.21	$62.17	$78.76	$111.95	$211.53
2045	$33.60	$34.57	$37.33	$40.89	$45.63	$52.27	$62.23	$78.82	$112.01	$211.59
2046	$33.66	$34.63	$37.39	$40.95	$45.69	$52.33	$62.29	$78.88	$112.07	$211.66
2047	$33.73	$34.69	$37.45	$41.01	$45.75	$52.39	$62.34	$78.94	$112.13	$211.72
2048	$33.79	$34.74	$37.51	$41.07	$45.81	$52.45	$62.40	$79.00	$112.19	$211.78
2049	$33.86	$34.80	$37.57	$41.12	$45.87	$52.50	$62.46	$79.06	$112.26	$211.85
2050	$33.92	$34.86	$37.63	$41.18	$45.92	$52.56	$62.52	$79.12	$112.32	$211.91
2051	$33.99	$34.92	$37.69	$41.24	$45.98	$52.62	$62.58	$79.18	$112.38	$211.97
2052	$34.05	$34.98	$37.75	$41.30	$46.04	$52.68	$62.64	$79.24	$112.44	$212.04
2053	$34.12	$35.04	$37.80	$41.36	$46.10	$52.74	$62.70	$79.30	$112.50	$212.10
2054	$34.18	$35.10	$37.86	$41.42	$46.16	$52.80	$62.76	$79.36	$112.56	$212.16
2055	$34.25	$35.16	$37.92	$41.48	$46.22	$52.86	$62.82	$79.42	$112.62	$212.22

Table 14. Avoided natural gas costs for peak periods with equal reduction in daily use, with distribution costs – southern New England (2021 $ per MMBtu)

Days	10	9	8	7	6	5	4	3	2	1 (Design Day)
2021	$40.11	$42.33	$46.37	$51.56	$58.47	$68.16	$82.68	$106.89	$155.31	$300.56
2022	$43.51	$45.47	$49.53	$54.76	$61.72	$71.47	$86.10	$110.47	$159.22	$305.47
2023	$43.10	$45.07	$49.11	$54.31	$61.25	$70.95	$85.52	$109.79	$158.33	$303.95
2024	$43.76	$45.66	$49.71	$54.90	$61.83	$71.53	$86.07	$110.32	$158.81	$304.28
2025	$43.88	$45.75	$49.78	$54.97	$61.87	$71.55	$86.06	$110.24	$158.60	$303.69
2026	$44.08	$45.93	$49.95	$55.12	$62.01	$71.66	$86.14	$110.26	$158.52	$303.27
2027	$44.18	$46.00	$50.01	$55.17	$62.05	$71.67	$86.11	$110.18	$158.31	$302.70
2028	$44.49	$46.27	$50.28	$55.43	$62.29	$71.90	$86.31	$110.33	$158.37	$302.48
2029	$44.76	$46.51	$50.50	$55.64	$62.49	$72.08	$86.46	$110.43	$158.38	$302.22
2030	$44.87	$46.59	$50.58	$55.70	$62.53	$72.10	$86.45	$110.37	$158.20	$301.69
2031	$44.87	$46.57	$50.55	$55.66	$62.48	$72.02	$86.33	$110.18	$157.88	$301.00
2032	$45.00	$46.68	$50.64	$55.74	$62.54	$72.06	$86.34	$110.14	$157.74	$300.53
2033	$45.12	$46.78	$50.73	$55.82	$62.61	$72.11	$86.35	$110.10	$157.59	$300.07
2034	$45.14	$46.79	$50.73	$55.81	$62.58	$72.05	$86.27	$109.95	$157.33	$299.46
2035	$45.13	$46.76	$50.69	$55.76	$62.51	$71.96	$86.14	$109.77	$157.02	$298.80
2036	$45.19	$46.80	$50.73	$55.78	$62.52	$71.94	$86.09	$109.66	$156.81	$298.24
2037	$45.26	$46.85	$50.76	$55.80	$62.52	$71.93	$86.04	$109.55	$156.59	$297.69
2038	$45.32	$46.89	$50.80	$55.83	$62.53	$71.91	$85.99	$109.45	$156.37	$297.14
2039	$45.38	$46.94	$50.84	$55.85	$62.54	$71.90	$85.94	$109.34	$156.15	$296.58
2040	$45.45	$46.98	$50.87	$55.87	$62.54	$71.88	$85.89	$109.24	$155.94	$296.03
2041	$45.51	$47.02	$50.91	$55.90	$62.55	$71.87	$85.84	$109.13	$155.72	$295.48
2042	$45.58	$47.07	$50.94	$55.92	$62.56	$71.85	$85.79	$109.03	$155.50	$294.94
2043	$45.64	$47.11	$50.98	$55.94	$62.56	$71.83	$85.74	$108.92	$155.29	$294.39
2044	$45.71	$47.16	$51.01	$55.97	$62.57	$71.82	$85.69	$108.82	$155.07	$293.84
2045	$45.77	$47.20	$51.05	$55.99	$62.58	$71.80	$85.64	$108.71	$154.86	$293.30
2046	$45.84	$47.25	$51.08	$56.01	$62.58	$71.79	$85.59	$108.61	$154.64	$292.75
2047	$45.90	$47.29	$51.12	$56.03	$62.59	$71.77	$85.55	$108.50	$154.43	$292.21
2048	$45.97	$47.34	$51.15	$56.06	$62.60	$71.76	$85.50	$108.40	$154.21	$291.67
2049	$46.03	$47.38	$51.19	$56.08	$62.61	$71.74	$85.45	$108.30	$154.00	$291.12
2050	$46.10	$47.43	$51.22	$56.10	$62.61	$71.73	$85.40	$108.19	$153.79	$290.58
2051	$46.17	$47.48	$51.26	$56.13	$62.62	$71.71	$85.35	$108.09	$153.57	$290.04
2052	$46.23	$47.52	$51.30	$56.15	$62.63	$71.69	$85.30	$107.98	$153.36	$289.51
2053	$46.30	$47.57	$51.33	$56.17	$62.63	$71.68	$85.25	$107.88	$153.15	$288.97
2054	$46.36	$47.61	$51.37	$56.20	$62.64	$71.66	$85.20	$107.78	$152.93	$288.43
2055	$46.43	$47.66	$51.40	$56.22	$62.65	$71.65	$85.15	$107.67	$152.72	$287.90

Table 15. Avoided natural gas costs for peak periods with equal reduction in daily use, with distribution costs – northern New England (2021 $ per MMBtu)

Days	10	9	8	7	6	5	4	3	2	1 (Design Day)
2021	$45.58	$48.55	$53.44	$59.72	$68.10	$79.82	$97.42	$126.74	$185.38	$361.31
2022	$47.11	$49.94	$54.83	$61.12	$69.50	$81.23	$98.83	$128.17	$186.83	$362.84
2023	$46.97	$49.81	$54.70	$60.99	$69.37	$81.10	$98.70	$128.04	$186.70	$362.70
2024	$47.30	$50.12	$55.01	$61.29	$69.67	$81.41	$99.01	$128.34	$187.02	$363.03
2025	$47.39	$50.20	$55.09	$61.38	$69.76	$81.49	$99.09	$128.43	$187.10	$363.12
2026	$47.52	$50.32	$55.21	$61.49	$69.88	$81.61	$99.21	$128.55	$187.23	$363.25
2027	$47.61	$50.39	$55.28	$61.57	$69.95	$81.69	$99.29	$128.63	$187.30	$363.33
2028	$47.78	$50.55	$55.44	$61.73	$70.11	$81.85	$99.45	$128.79	$187.47	$363.51
2029	$47.93	$50.69	$55.58	$61.87	$70.25	$81.99	$99.59	$128.94	$187.62	$363.66
2030	$48.02	$50.77	$55.66	$61.95	$70.33	$82.07	$99.67	$129.01	$187.70	$363.75
2031	$48.05	$50.80	$55.69	$61.98	$70.36	$82.10	$99.71	$129.05	$187.73	$363.78
2032	$48.15	$50.89	$55.78	$62.06	$70.45	$82.18	$99.79	$129.13	$187.82	$363.87
2033	$48.23	$50.97	$55.86	$62.14	$70.53	$82.27	$99.87	$129.22	$187.90	$363.96
2034	$48.28	$51.01	$55.90	$62.19	$70.57	$82.31	$99.91	$129.26	$187.94	$364.01
2035	$48.31	$51.03	$55.92	$62.21	$70.59	$82.33	$99.94	$129.28	$187.97	$364.03
2036	$48.37	$51.09	$55.98	$62.27	$70.65	$82.39	$100.00	$129.34	$188.03	$364.10
2037	$48.43	$51.15	$56.04	$62.33	$70.71	$82.45	$100.05	$129.40	$188.09	$364.16
2038	$48.50	$51.20	$56.10	$62.38	$70.77	$82.51	$100.11	$129.46	$188.15	$364.22
2039	$48.56	$51.26	$56.15	$62.44	$70.83	$82.56	$100.17	$129.52	$188.21	$364.28
2040	$48.62	$51.32	$56.21	$62.50	$70.88	$82.62	$100.23	$129.58	$188.27	$364.35
2041	$48.69	$51.38	$56.27	$62.56	$70.94	$82.68	$100.29	$129.63	$188.33	$364.41
2042	$48.75	$51.44	$56.33	$62.61	$71.00	$82.74	$100.35	$129.69	$188.39	$364.47
2043	$48.81	$51.49	$56.38	$62.67	$71.06	$82.80	$100.41	$129.75	$188.45	$364.54
2044	$48.88	$51.55	$56.44	$62.73	$71.12	$82.85	$100.46	$129.81	$188.51	$364.60
2045	$48.94	$51.61	$56.50	$62.79	$71.17	$82.91	$100.52	$129.87	$188.57	$364.66
2046	$49.00	$51.67	$56.56	$62.85	$71.23	$82.97	$100.58	$129.93	$188.63	$364.73
2047	$49.07	$51.73	$56.62	$62.91	$71.29	$83.03	$100.64	$129.99	$188.69	$364.79
2048	$49.13	$51.78	$56.67	$62.96	$71.35	$83.09	$100.70	$130.05	$188.75	$364.85
2049	$49.20	$51.84	$56.73	$63.02	$71.41	$83.15	$100.76	$130.11	$188.81	$364.91
2050	$49.26	$51.90	$56.79	$63.08	$71.47	$83.21	$100.82	$130.17	$188.87	$364.98
2051	$49.33	$51.96	$56.85	$63.14	$71.52	$83.26	$100.87	$130.23	$188.93	$365.04
2052	$49.39	$52.02	$56.91	$63.20	$71.58	$83.32	$100.93	$130.28	$188.99	$365.10
2053	$49.45	$52.08	$56.97	$63.26	$71.64	$83.38	$100.99	$130.34	$189.05	$365.17
2054	$49.52	$52.13	$57.03	$63.31	$71.70	$83.44	$101.05	$130.40	$189.11	$365.23
2055	$49.58	$52.19	$57.08	$63.37	$71.76	$83.50	$101.11	$130.46	$189.17	$365.29

4. Methodology for Avoided Costs of Localized Gas T&D Infrastructure

Section 10.4 of the AESC 2021 Study documents how program administrators can develop and rely on localized electric T&D values to estimate the value that DERs—specifically energy efficiency and demand response—provide to localized T&D systems.[20] It describes a three-step process for calculating localized electric T&D values and documents current practices that participating utilities follow when evaluating non-wires alternatives. In this supplemental study, we expand and adjust the methodology included in AESC 2021 for developing localized T&D values to reflect considerations for natural gas local distribution companies.

When referring to localized T&D values, we refer to local gas demand driving the need for T&D infrastructure in the same region as the demand. This may include infrastructure such as: interconnections, distribution gates, distribution mains, transmission pipelines, and compressor stations, as well as utility contracts and agreements. While the methodology described in this study would likely be comparable for local gas demand driving the need for T&D infrastructure that is *not* in the same general region as the demand, the development of that methodology would require additional considerations. We therefore recommend it be explored in greater depth in future studies.

Program administrators may use the methodology described in this study in a variety of contexts. For example, it is likely necessary to estimate the value of gas demand-side measures in a location-specific context during an evaluation of a non-pipeline alternative (NPA) or during long-term resource planning processes. By developing localized values of avoided or deferred gas T&D resources, program administrators can identify local demand-side measures that are cost-efficient relative to traditional engineering solutions.[21]

We expect that such evaluations for gas infrastructure will be needed less frequently than those for the electric sector T&D infrastructure. While evaluations of localized electric T&D values may need to be conducted regularly in areas with expected electric load growth (due to electrification of the building and transportation sectors, for instance), evaluations of localized gas T&D values may be conducted less frequently in areas within which gas demand is expected to stagnate or decline (for example, due to the aforementioned electrification of the building and transportation sectors). At the same time, we note that while overall system demand growth may be flat or declining for a given utility, there may still be

[20] See Section 10.4 in AESC 2021 at https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf.

[21] Demand-side measures that may be compared against localized values of avoided or deferred gas T&D include: targeted demand response, targeted energy efficiency, heat pumps, thermal storage, and other electrification and fuel switching. See ICF's *What can we learn from New York's non-pipeline solutions ruling*? Available here: https://www.icf.com/insights/energy/non-pipeline-solutions.

areas within a utility's service territory that are experiencing demand growth. These areas would benefit from the development and application of localized gas T&D values.

Finally, we note that this methodology can be applied to both (a) deferring and (b) avoiding localized T&D systems. Deferring localized infrastructure offers the value of time to determine if infrastructure is ultimately needed in an area, as well as the type and amount of infrastructure needed. In other words, deferral offers time for program administrators to determine whether an investment is needed at all.

4.1. Summary of approach to localized gas T&D value

The key aspects of the methodology for calculating localized values of gas T&D are:

1. Identification of target areas and required demand reduction
2. Determination of benefits of targeted demand reductions by identified target area
3. Calculation of avoided costs ($ per dekatherm per day) based on the present value of avoided or deferred expenditures and the required demand reduction

The following sections detail the three-step process for determining localized T&D values. These three steps will require program administrators to obtain information from their respective planning groups.

Step 1: Identify target areas and required demand reduction

The localized T&D value requires the identification of (a) target projects and (b) required demand reduction and duration to calculate the avoided or deferred cost. This first step of identifying target projects should, to the extent possible, rely on a utility's existing planning processes.

Build on existing T&D planning

Program administrators may rely on peak demand forecasts, five-year plans, resource plans, or other planning processes and documents to identify potential future resource options needed to meet Normal Year, Design Year, and Design Day deficiencies. The peak demand forecasts should be conducted in accordance with the utility's T&D planning practices and regulatory requirements. This process may involve the development of resource-specific forecasts. Stakeholders may consider evaluating peak demand forecasts to include any state, local, and regional electrification goals mandated by current policy, as well as "future of natural gas" policies and plans, even if not required by statute.

After estimating peak demand levels, the next step is to establish the system planning criteria and performance objectives. The system planning criteria should be based on the utility's local T&D system planning guidelines and regulatory obligations. This would involve designing the system in accordance with relevant standards and/or design practices, including local standards if they exist. An example of system planning criteria would involve establishing the supplies needed to meet design day demand, as well as winter, shoulder, and summer demand. Such criteria would include the consideration of scenarios with system contingencies.

As part of the planning process, the planning group can run gas networks or gas pipeline simulations to identify the system contingencies and violations under varying system configurations. This may include understanding and applying the specific contingency standards that define the minimum infrastructure necessary to maintain security standards, depending on the needs of the specific region. The analysis should also estimate the required demand reduction to mitigate the contingency. In addition, the analysis should include a process to identify potential areas where there may be reliability concerns that could be mitigated through NPA solutions or solutions that avoid other traditional engineering solutions.[22]

Considerations

To prioritize areas for targeted NPAs, utilities may currently consider various additional factors before assessing the potential for an NPA option. For example, utilities may establish minimum threshold criteria to meet when addressing a system contingency or considering an NPA as a resource option. Utilities may also consider the timeline required for building the NPA and whether this can be done in time to avoid the identified contingency or violation that it is meant to address based on local conditions. There are issues that may not be considered imminent or immediate concerns (e.g., issues that may have been accepted for many years) and should also be addressed accordingly. For example, contingencies that have sufficient lead time could be considered for NPA solutions whereas projects with imminent needs may not be suitable for NPAs.

In addition, the severity and nature of the contingency are a consideration for the NPA process. The conditions under which the constraint or planning violation has been identified should be factored into the analysis. This might include examining the degree to which the constraint is present in normal conditions or extreme conditions (such as cold weather). Utilities also consider the nature of the contingencies in terms of whether they are suitable applications for an NPA. In identifying target areas where there are concerns about backing up critical demand, these areas should not be automatically disqualified from NPA consideration—instead, hybrid solutions between the NPA and a traditional engineering solution could also be considered and evaluated by the planning group.

DSM planning and implementation

On the demand side, there is a need to factor in the lead time for marketing, implementation, and verification of DSM under an NPA solution. This is because current NPA evaluation processes require a window of time prior to the need to start construction on T&D infrastructure. In their DSM planning processes, program administrators should also factor the amount of DSM that could be based on potential annual demand reduction (percent) by class and projected overload. Conversely, a traditional engineering solution will also take time, especially if it requires separate regulatory approval and other siting review processes.

[22] Throughout this section, we use NPA as a shorthand to mean alternative solutions to avoid a range of traditional engineering solutions encompassing but expanding beyond pipelines. This includes interconnections, distribution mains, and more.

Identifying expenditures avoidable by demand reductions

In identifying the expenditures avoidable by demand reductions, it is first necessary to identify the magnitude, duration, and coincidence of the demand reduction compared to the location and the timing of the traditional utility solution that would solve any system contingencies. Any constraints identified should be listed as such based on the first year that the constraint is identified. As discussed above, this can be identified through a gas networks or gas pipeline simulation analysis. At minimum, most utilities consider demand growth and reliability as the expenditures that can be avoided by NPAs.[23] However, other projects may also have some suitability in replacing a pipeline solution.

If a project addresses both NPA-eligible constraints as well as non-NPA-eligible constraints, the costs for such projects should be broken down between those that are NPA-eligible and non-NPA-eligible in estimating the avoided cost expenditures. The utility should clearly identify which investments are considered as avoidable or deferrable through an NPA and the expenditures identified should be estimated in accordance with the utility capital investment planning guidelines. The expenditures should include operating expenses, capital investments, and O&M associated with new facilities, net of any savings from retiring old equipment.

Utilities may establish a traditional engineering solution cost threshold before considering NPA solutions. Small projects that can be solved through traditional utility options (such as gas main replacements) may be less costly than procuring an NPA solution. Alternatively, longer-term projects that do not have an imminent need and are above an established cost threshold may be more suitable projects for NPA consideration.

Identify type and period of required reduction

After identifying the expenditures that are avoidable by targeted demand reductions, it is critical to identify the time at which the required demand reduction is needed. This will aid in identifying the types of demand-side measures that could be included in an NPA solution. This exercise involves answering questions such as:

- Does the demand reduction need to occur in a specific season (e.g., winter)?
- Does the demand reduction need to occur in specific hours of the day?
- Over how many hours or days must the demand reduction occur?

In addition, it is important to identify the number of years in which the reduction must occur. For example, if the goal is to defer an expenditure for three years, and the demand is expected to exceed the system's capability for all three of those years, then an effective NPA solution requires its demand reduction to sustain for three years. Program administrators will need to coordinate with the utility's

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[23] Even in scenarios in which overall system demand growth is flat or declining for a given utility, there still may be areas within a utility's service territory that are experiencing demand growth.

planning group to ensure that localized demand reduction programs will meet the planning criteria as an appropriate solution.

Step 2: Determine benefits of targeted demand reductions by identified target area

When calculating the avoided T&D costs, users should quantify the reduced present value of the expenditures. The annualized present value should reflect the utility's cost of capital, income taxes, property taxes, and insurance over the life of the equipment. To do so, one must first calculate the real carrying charge (RCC) that is expressed as a percentage. In general, the RCC equals the weighted average cost of capital (WACC), plus income tax, property tax, associated insurance, and O&M:

$$RCC \; = WACC + Income\,Tax + Property\,Tax + Insurance + O\&M$$

The RCC should then be used to calculate the reduced present value of the avoided expenditures. For example, if the utility's RCC is 15 percent, then a $10 million investment would have an annualized expenditure of $1.5 million per year ($10 million x 15 percent).

There may be situations where a demand reduction defers a specific project by some period of time. For those situations and for the purposes of simplifying a more complex process, we recommend that the deferral value represents the traditional engineering expenditure reduced by the RCC and then discounted by the real discount rate.[24] In our illustrative example, if the RCC is 15 percent and the real discount rate is 3.37 percent, a 1-year deferral would have an avoided cost value of 85.5 percent (0.855 = 1 – [0.15 * (1 – 0.0337)]).

Step 3: Calculate avoided or deferred cost ($ per dekatherm per day)

The next step is to calculate the avoided (or deferred) cost in terms of dollar per dekatherm (Dth) per day for each identified target area. To do so, program administrators must first compile:

1. The present value of the benefits from the deferral or avoidance of demand-related expenditures identified in Step 2, above; and
2. The required demand reduction, in Dth per day, required to achieve the deferral or avoidance of said expenditures.

Next, program administrators should divide the present value of the benefits from deferral or avoidance by the required demand reduction to arrive at a localized avoided T&D value in dollars per Dth per day, by target area.

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[24] For the purposes of this methodology, we do not address any probabilistic planning issues that may arise from the continued deferral or acceleration of specific distribution projects due to changes in localized demand. A more detailed analysis would require the re-running of gas networks or gas pipeline simulations based on changed demand that may result in the determination of a different engineering solution,

Using localized avoided T&D values

PAs who are considering cost-effectiveness thresholds for demand reduction strategies may find the following text helpful for evaluating the likely success or cost-effectiveness of a program or DSM portfolio. We acknowledge that there are many ways that PAs can use the localized avoided T&D values. Therefore, the following text is not meant to be prescriptive.

A localized avoided T&D value can serve as the conceptual average value for which to evaluate the cost-effectiveness of demand reduction resources and technologies between the planning and DSM groups. In other words, the average cost of the demand reduction strategies included in an NPA solution to achieve deferral or avoidance should be less than the calculated localized avoided T&D value, which is the value of the traditional engineering solution. If the average cost per Dth per day is greater than the localized avoided T&D value, then the avoidance or deferral portfolio costs more than the demand-related expenditures that are targeted for deferral or avoidance. In these cases, alternative portfolios should be evaluated. If none are found to be cost-effective relative to the traditional engineering solution, it may be reasonable to pursue the traditional engineering solution. However, there may be non-financial considerations and policy goals that would continue to support the development of an alternative portfolio that is not cost-effective relative to a traditional engineering solution.

Conceptually, it may also be helpful to use the localized avoided T&D values as guidelines when compiling a portfolio to achieve the required demand reduction. To the extent possible, program administrators should concentrate on achieving the required demand reduction at lower costs per Dth per day than the avoided costs. However, specific resources may be less than or even greater than the average avoided cost, as long as the total portfolio cost is less than the localized avoided cost T&D value. This is demonstrated in the illustrative example below.

Units

The engineering side of gas system planning typically relies on Mcf per hour as the unit. This is because flow models are based on physical units rather than the heat content of the gas, and because engineers must design for peak requirements during the day rather than the average gas use over the day. While hourly units are becoming more common in the context of gas pipeline services, gas supply planning outside the engineering sphere is still generally conducted using daily values.

In general, for the purposes of developing localized values of avoided gas T&D infrastructure, we recommend using dollars per Dth per day or dollars MMBtu per day when comparing the costs of the supply-side T&D resource to the costs of the portfolio of demand-side measures that would be used to avoid the supply-side resource. While the cost of the supply-side resource is generally expressed in dollars per year, the cost should be converted to its annualized present value (as described in Step 2 of Section 4.1) before it is converted to the dollars per Dth per day value of the resource.

4.2. Illustrative Example

As a brief example with illustrative numbers, assume that the engineering solution for a demand-related T&D pipeline project is estimated to cost $10 million,[25] and a 1,000 Dth per day reduction is required to defer or avoid the project. Using the methodology described above, the localized avoided T&D value is: $10 million / 1,000 Dth per day = $10,000 per Dth per day.

Expanding on this same example, the program administrator has also identified a portfolio of demand-side resources that will cost $6 million[26] and achieve a demand reduction of 800 Dth per day reduction. On a dollar per Dth per day basis, the partial, preliminary portfolio costs $6 million / 800 Dth per day = $7,500 per Dth per day. This is $2,500 per Dth per day less than the localized avoided T&D value of $10,000 per Dth per day, and it means that the program administrator could spend up to $500,000[27] on resources that achieve the remaining 200 Dth per day of demand reduction required to defer or avoid the original $10 million in demand-related expenditures. Said another way, the program administrator could procure additional demand-side resources with costs of $500,000 / 200 Dth per day = $2,500 per Dth per day before the NPA solution costs exceed the traditional engineering cost.

[25] This is the annualized present value of the T&D project, including upfront capital costs, expected lifetime operations and maintenance costs, expected lifetime carrying costs, and expected lifetime fuel costs. See Step 2 of Section 4.1 for more information on how to calculate the annualized present value of a T&D project.

[26] This is the annualized present value of the portfolio.

[27] This is the annualized present value of the remaining resources.