Appendix A

National Fuel Gas Distribution Corporation

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National Fuel®

CONTENTS

Appendix A: Modeling of Decarbonization Actions

I. Overview

Each decarbonization action model incorporates assumptions that are specific to the individual action and are detailed in this appendix. However, there are certain modeling concepts that apply to all decarbonization actions, and the modeling of each decarbonization action ultimately produces the same outputs. Each decarbonization action requires inputs related to when the decarbonization action begins (i.e., start year) and how quickly it increases over time. The modeling of each decarbonization action produces the same outputs including incremental installation and/or implementation costs, gas usage reductions and associated gas bill savings, electric usage increases and associated electric bill increases, and GHG emission reductions.

II. Global Assumptions

The global assumptions listed in the following tables are inputs that are consistently used throughout the modeling of decarbonization actions (e.g., common conversion rates and inflation rates).

Table A-1

National Fuel System Assumptions

Shrinkage Rate	1.72%
Gas Heating Value (MMBtu/Mcf)	1.033

- Shrinkage refers to the difference between the amount of gas received by National Fuel's distribution system at its citygates and the amount of gas delivered through its customer meters.
- Gas higher heating value refers to the heat content of gas per volume. It allows for converting between volumetric measurements (e.g., Mcf) and heat content measurements (e.g., MMBtu).

Table A-2

Inflation Forecast

Inflation	GDP Chained Price Index (Q3 to Q3) [1]	Inflation Adj Factor (Cumulative since Q3 2022)
2022	7.30%	100.00%
2023	3.30%	103.30%
2024	2.20%	105.57%
2025	2.10%	107.79%
2026	2.10%	110.05%
2027	2.10%	112.36%
2028	2.00%	114.61%
2029	2.00%	116.90%
2030	2.00%	119.24%
2031	2.00%	121.63%
2032	2.00%	124.06%
2033	2.00%	126.54%
2034	2.00%	129.07%
2035	2.00%	131.65%
2036	2.00%	134.29%
2037	2.00%	136.97%
2038	2.00%	139.71%
2039	2.00%	142.51%
2040	2.00%	145.36%
2041	2.00%	148.26%
2042	2.00%	151.23%

(1) Sources: Blue Chip Economic Indicators, GDP Chained Price Index. April 11, 2022, at 5. BCEI Long-Range Consensus US Economic Projections, GDP Chained Price Index. March 11, 2022, at 14.

Table A-3

National Fuel Cost of Capital

	Ratios	Cost Rates	Weighted Rate
Long Term Debt	56.70%	5.62%	3.19%
Short Term Debt	0.00%	0.00%	0.00%
Customer Deposits	0.40%	0.85%	0.00%
Common Equity	42.90%	8.70%	3.73%
	100.00%		**6.92%**

Source: NY PSC Case 16-G-0257, Commission Order, Appendix 2, page 7 of 8

III. Energy Efficiency - Home Energy Reports

A. Methodology

Home Energy Reports ("HER") encourage participants to reduce their usage through personalized letters or emails. Each report contains the participant's energy usage compared to other similar homes in the same neighborhood or geographic area. The HER includes energy-saving tips and goals for the next mailing. The HER program at National Grid's Rhode Island gas utility and other utility HER programs were reviewed to establish assumptions for customer adoption levels, reduction in gas usage, and associated program costs. Customer participation level is defined as a percentage of total residential customers. Using this data, the model estimates total emissions reduction and program costs specific to National Fuel. This data is used to compute a net present value of cost per emission savings ($/CO2e) based on customer participation levels in each scenario.

B. Assumptions, Inputs, Sources

The estimated cost and energy savings per participant are detailed in Table A-4.

Table A-4

Home Energy Report Cost and Saving Assumptions

Home Energy Report Cost ($2021/Customer)(1)	$2.96
Home Energy Report Savings (%/Year)(2)	0.90%

(1) Source: 2021-2023 National Grid Energy Efficiency Program Plan & 2021 Annual Energy Efficiency Program Plan.
(2) Source: "Impact Evaluation: Home Energy Reports Program - National Grid Rhode Island," Cadeo Group, August 28, 2020. Savings as a percentage of energy use.

C. Scenario Inputs

The Home Energy Report assumptions vary by scenario to reflect different customer participation levels. The Supply Constrained Economy ("SCE") Scenario assumes a start year of 2025 with 50% residential customer participation. The Long-Term Plan and Aggressive Scenario start in 2025 and assume a 100% residential customer participation level. Table A-5 presents annual customer participation levels.

Table A-5

Customer Participation by Scenario 2023-2042

Year	Total Residential Customers	SCE Participation (%)	LTP Participation (%)	Aggressive Participation (%)
2023	506,539	0%	0%	0%
2024	508,683	0%	0%	0%
2025	510,682	100%	50%	100%
2026	513,168	100%	50%	100%
2027	514,695	100%	50%	100%
2028	516,228	100%	50%	100%
2029	517,764	100%	50%	100%
2030	519,306	100%	50%	100%
2031	520,852	100%	50%	100%
2032	522,402	100%	50%	100%
2033	523,957	100%	50%	100%
2034	525,517	100%	50%	100%
2035	527,082	100%	50%	100%
2036	528,651	100%	50%	100%
2037	530,224	100%	50%	100%
2038	531,803	100%	50%	100%
2039	533,386	100%	50%	100%
2040	534,974	100%	50%	100%
2041	536,566	100%	50%	100%
2042	538,164	100%	50%	100%

IV. Energy Efficiency – Weatherization

A. Methodology

Residential weatherization involves upgrades to a home's building envelope through various measures. Individual weatherization measures were analyzed to establish assumptions for customer adoption levels, reduction in gas usage, and associated costs. This analysis utilized cost, applicability percentages, and gas savings from a residential weatherization study conducted for National Fuel.[1] Cadmus evaluated the following residential weatherization measures: air leakage sealing, attic insulation, rim and band joist insulation, wall insulation, floor insulation, window upgrades, and duct sealing and insulation. Measure cost and gas savings are differentiated based on income level for low- and moderate-income ("LMI") customers, and standard income customers. The Cadmus Weatherization Study identified total technical potential and maximum achievable potential for residential weatherization programs within National Fuel's customer base.

B. Assumptions, Inputs, Sources

Assumed cost and gas usage reduction for each measure are presented in Table A-6.

Table A-6

Cost and Gas Use Reduction by Weatherization Measure

	Applicability		Gas Savings (Mcf)(3)		
Measure	Standard Income	Low and Moderate Income(2)	Standard Income	Low and Moderate Income1	Installation Cost ($2022/Unit)
Air Leakage Sealing	30%	44%	7.6	7.6	$ 680
Insulation – Attic Insulation	47%	47%	4.5	9.4	$ 2,558
Insulation – Rim and Band Joist Insulation	68%	69%	1.4	1.5	$ 63
Insulation – Wall Insulation	27%	27%	8.3	16.5	$ 1,404
Insulation – Floor Insulation	14%	14%	22.8	11.4	$ 1,423
Window	37%	55%	5.6	18.4	$ 13,753
Duct Sealing and insulation	5%	5%	0.7	0.9	$ 1,442

(1) Source: Cadmus Weatherization Study
(2) Low and Moderate-Income segments presented the same assumed applicability rate and gas savings.
(3) Annual savings assume furnace heating system.

1 Residential Weatherization Potential Study Report," The Cadmus Group, Inc. ("Cadmus"), prepared for National Fuel Gas Distribution Corporation, November 2, 2022. ("Cadmus Weatherization Study", provided as Appendix F).

Table A-7 depicts the breakdown of National Fuel's customer base by income level.

Table A-7

National Fuel Customer Population by Income 2022

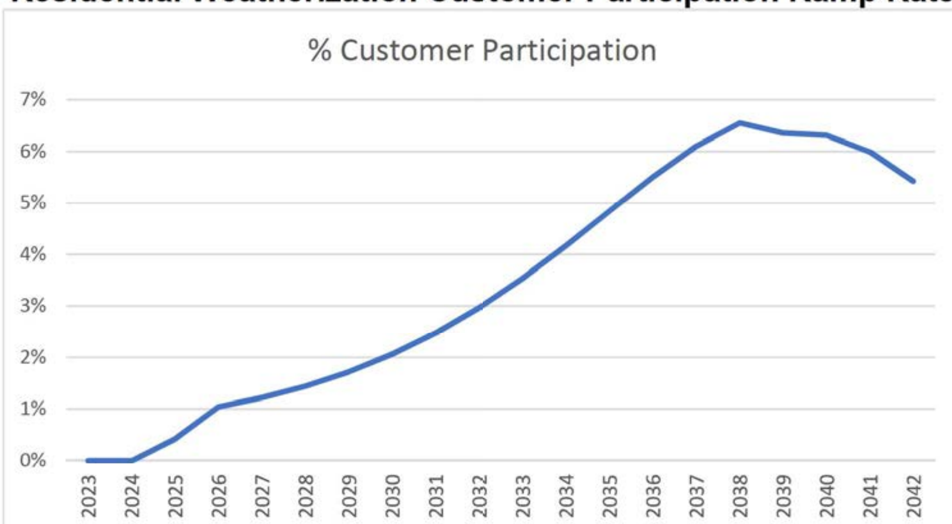
Percentage of Standard Income Participants	53%
Percentage of Low- and Moderate-Income Participants	47%

Source: Cadmus Weatherization Study

Figure A-1 depicts the Cadmus developed ramp rate utilized to determine annual program participation rate. Cost, gas savings, customer breakdown by income, and the participation ramp rate are all sourced from the Cadmus Weatherization Study.

Figure A-1

Residential Weatherization Customer Participation Ramp Rate



Source: Cadmus Weatherization Study. Aggressive ramp rate reduced to 85% of total per Cadmus Weatherization Study and adjusted for a 2025 start year.

C. Scenario Inputs

The residential weatherization scenarios differ with respect to the customer participation level assumptions and the measures that are included in the program. The SCE scenario assumes a start year of 2025 with 75% of the max achievable participation for both LMI and standard income customers. The Long-Term Plan and the Aggressive Scenario start in 2025 but assume 100% of the maximum achievable participation for both LMI and standard income customers. The LTP eliminated windows from the standard income program because it is a more expensive measure, but included all measures in the LMI program. Table A-8 presents weatherization measures included in each scenario.

Table A-8

Residential Weatherization Measures Included by Scenario

Measure	SCE & Aggressive	LTP
Air Leakage Sealing	Both LMI & Standard	Both LMI & Standard
Insulation - Attic	Both LMI & Standard	Both LMI & Standard
Insulation - Rim and Band Joist	Both LMI & Standard	Both LMI & Standard
Insulation - Wall	Both LMI & Standard	Both LMI & Standard
Insulation - Floor	Both LMI & Standard	Both LMI & Standard
Windows	Both LMI & Standard	**LMI Only**
Duct Sealing and Insulation	Both LMI & Standard	Both LMI & Standard

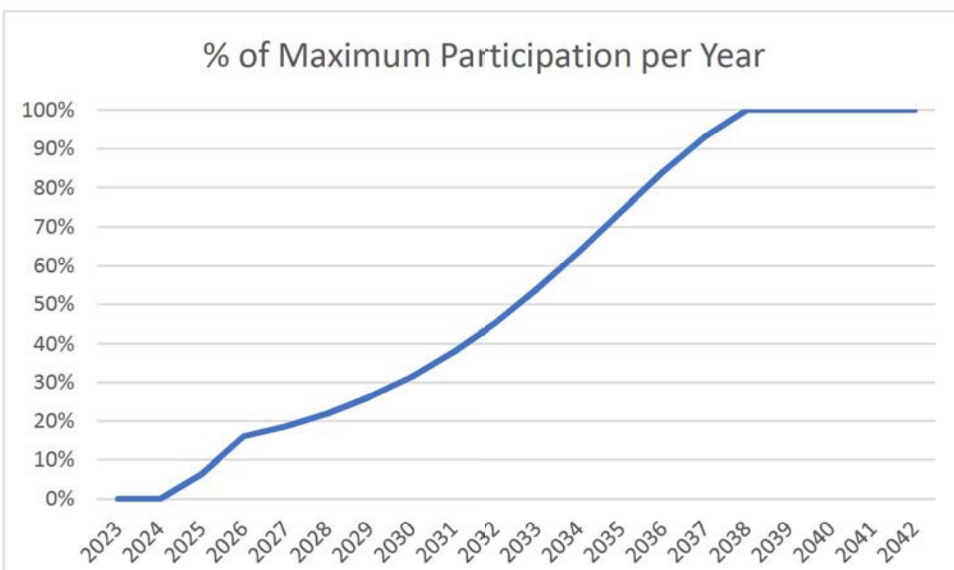
V. Electrification – Generic Assumptions (Applicable to All Classes)

A. Overview

Electrification is the process of replacing gas powered technologies with electric technologies. Electrification options are modeled separately for National Fuel's residential, small commercial, large multi-family (i.e., public authority housing), universities, and industrial customer segments. Conversion options rely on current heat pump technologies including standard air-source heat pumps ("ASHP"), cold climate ASHP ("ccASHP"), and ductless mini-split heat pumps. The model assumes that electrification conversions occur either at the end of equipment life or at the time of new builds. Annual conversion counts by equipment type are calculated for existing appliance stock by applying a ramp rate schedule, shown in Figure A-2, to a specified maximum participation rate, which is multiplied by number of potential conversions of existing equipment at time of equipment retirements in each year. For existing furnace HVAC systems, potential conversions to heat pumps are assumed to occur at either end-of-life of the furnace or end-of-life of the central air conditioning system. For existing equipment stock conversions, the ramp rate from Cadmus' Residential Weatherization Study is relied on with modification in year 2039 and later to hold conversion rate constant at maximum participation rate to produce an increase in the electrification participation rate over time. The ramp rate schedule's gradual increase accounts for the time required to reach full program implementation. New builds are assumed to electrify at double the rate of existing equipment, increasing to 100% participation starting in year 2026 to comply with new legislation.

Figure A-2

Electrification Existing Customer Participation Ramp Rate



Source: Cadmus Weatherization Study

B. Electrification Options Modeled

All modeled options are detailed in Table A-9. The residential electrification model focuses on the electrification of space heating and conversion of gas appliances including cooking ranges, dryers, and water heaters. The residential electrification model differentiates among several residential subgroups including new builds, existing typical homes (less than 80 years old) and older homes (80+ years old), furnace and boiler heating systems, and provides analysis focused on full electrification using ccASHP versus hybrid heating systems that pair efficient gas furnaces with standard air-source heat pumps. Residential electrification options can be specified independently for new homes, existing typical homes or old homes (e.g., gas clothes dryers in typical homes could be converted to electric while clothes dryers in old homes might not be converted). In addition, electrification of each appliance type can be specified independently (e.g., boilers could be kept as gas while furnaces are converted to electric).

Electrification options for small commercial, large multi-family, universities and industrial segments are restricted to full electrification of heating load only. Heating load is separated from processing load for large multi-family, universities and industrial segments based on analysis of National Fuel's EMM Equipment customer database. Heating load associated with equipment that is also used for processing load is excluded from electrification potential.

Table A-9

Electrification Conversion Options

Natural Gas Appliance Type	Residential	Small Commercial, Universities, Large Multi-Family, Industrial
Forced Air Furnace, Heaters[2]	Full electrification w/ ASHP	Full electrification w/ ASHP
	Hybrid gas/electric HVAC System	
Boiler	Full electrification w/mini-splits	Full electrification w/mini-splits
Water Heating w/ Tank	Gas Tankless	
	ASHP w/ tank	
Tankless Water Heater	ASHP w/ tank only for old homes	
Clothes Dryers	Convert to electric	
Gas Range	Convert to electric	

C. Net Installed and Operating Costs

Participant net installed costs are costs to purchase and install new equipment minus replacement cost of retired (or avoided new) equipment compared to baseline equipment included in the Reference Case. Because heat pumps also provide space cooling in addition to heating, the model assumes that participants avoid the cost of replacing their central air

2 Non-residential heaters include space heating furnaces, unit heaters, infra-red heaters, make-up air heaters and rooftop heaters.

conditioning (AC) or window AC units. Participant window ac units are assumed to reach end-of-life concurrent with furnace and/or boiler conversions. For instances where an HVAC system is converted at the end-of-life of the central air conditioning component, 50% of participant furnace units are assumed to reach end-of-life concurrent with the central air component. Similarly, for instances where an HVAC system is converted at the end-of-life of the furnace, 50% of participant central air conditioning units are assumed to reach end-of-life concurrent with the furnace.

Participant net operating costs account for both the increase in participant's electric bill resulting from increased electrical use and reduction in gas bill resulting from decreased gas use due to their electrification conversion. In full electrification cases where gas service is terminated, the gas customer charge is also subtracted from participant's net operating cost. For full electrification of new buildings, the customer's gas meter and service line costs are removed from the Company's capital plan, resulting in a reduction in revenue requirement and associated base distribution rate charged to all customers.

D. Seasonal Electric and Gas Usage

Net changes in annual electric and gas usage due to conversions are allocated to winter, shoulder, and summer seasons. Heating usage is allocated between winter and shoulder seasonal usage based on proportion of total annual normal heating degree days ("HDDs")[3] associated with days with an HDD greater than or less than an assumed 35 HDD setpoint compared. The winter season is assumed to occur during the 76 days in the year with a normal HDD greater than or equal to the assumed 35 HDD setpoint. The shoulder season is assumed to occur during the by proportion of heating days in the year with a daily normal HDD greater than or equal to 247 days in the year with a normal HDD less than the assumed 35 HDD setpoint.

The summer cooling season is assumed to occur during 25 days in the year with a normal cooling degree days ("CDD") greater than 5 CDDs.[4] Net change in summer peak electric kW demand associated with cooling is calculated as (space cooling kWh) / (25 cooling days x 24 hours).

3 HDD is a unit of measure used to relate a day's temperature to the energy consumption associated with space heating. HDD = 65 minus average daily temperature. Days with average daily temperatures above 65 degrees have HDD of 0 (i.e., HDD does not go negative).

4 Source: NOAA 1981-2010 normal Cooling Degree Days, Climate Region: 3009 (NY, Great Lakes). CDD is a unit of measure used to relate a day's temperature to the energy consumption associated with air conditioning. CDD = average daily temperature minus 65 degrees. Days with average daily temperature less than 65 degrees have CDD of 0 (i.e., CDD does not go negative).

Table A-10

Heating and Cooling Seasonal Definitions

Heating/Cooling Season	Load Type	Definition	Normal HDD	% HDDs / CDDs	Number of Days in Normal Year
Winter	Heating	HDD >= 35	3,555	45%	76
Shoulder	Heating	HDD < 35	2,912	55%	247
Total Heating	Heating	HDD>0	6,467	100%	323
Summer	Cooling	CDD > 5	n/a	100%	25

E. Winter and Summer Peak Demand

Net change in winter peak kW demand associated with residential gas furnace heating conversion options is based on CJ Brown's hourly analysis results. Net change in winter peak electric kW demand associated with boiler and non-residential heating conversions is calculated by dividing the heating net kWh by total annual HDDs, multiplying by Design Day HDD and dividing by 24 hours. . Net change in summer peak kW demand is calculated as net change in cooling kWh divided by (25 cooling days x 24 hours). Electric water heaters, dryers, and cooking ranges are assumed to run all-year round with peak winter and summer kW demand contributions equal to their annual kWh usage divided by 8760 hours in the year. Electric fans and pumps are assumed to run at constant level throughout 323 heating and 25 cooling days but assumed to not run on the 17 moderate weather days.

F. Design Day Gas Demand

Net change in residential design day gas demand associated with heating conversions is based on CJ Brown's hourly analysis for each conversion option, with adjustment from historical HDD to Design Day HDD criteria.

Net change in non-residential design day gas demand associated with heating conversions is calculated by dividing the heating net ccf by total annual HDDs and multiplying by Design Day HDD.

VI. Electrification - Residential

A. Methodology

The residential electrification model includes electrification of space heating and conversion of gas appliances including cooking ranges, dryers, and water heaters. This analysis allows for differentiation among several residential subgroups including new buildings, existing typical versus older homes (80+ years old) and furnace versus boiler heating systems. In addition, the analysis provides for analysis of full electrification versus hybrid heating systems.

The residential electrification model starts with the residential customer count forecast. Appliance-specific market saturation percentages and assumed equipment lifespans are applied to estimate potential conversions. An assumed maximum annual participation rate is applied to a ramp rate schedule and annual potential conversions, resulting in number of conversions, before calculating natural gas use and GHG emission reductions.

B. Assumptions, Inputs, Sources

Residential cost and energy use assumptions for each baseline and conversion equipment type are from a residential home energy study performed for National Fuel,[5] which provides cost and energy usage electrification conversion data for a typical western New York home. The CJ Brown Study also includes estimates of the increased costs required to fully electrify an 80+ year-old home due to prevalence of knob-and-tube wiring. The LTP model includes three furnace conversion options for residential homes: (1) full electrification with a ccASHP that relies on electric for heating on all days, (2) hybrid gas/electric heating system that relies on a gas furnace on colder days and a standard 3-ton electric air-source heat pump on less cold hours above 30°F,[6] and (3) hybrid gas/electric heating system that relies on a gas furnace on the coldest hours and a 4-ton ccASHP on hours above 15°F. Input appliance life, cost, and energy use data for residential electrification are provided in the following tables.

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5 Residential Home Energy Calculations," C.J. Brown Energy, prepared for National Fuel Gas Distribution Corp, April 2023. ("CJ Brown Study.") Provided in Appendix G.

6 Assumes a 35 HDD setpoint for switching between gas furnace and ASHP heat source.

Table A-11

Residential Baseline Natural Gas and Air Conditioning Equipment Assumptions

Load Type	Baseline Equipment	Appliance Life Expectancy: Min Life(1)	Max Life(1)	Modeled	Replacement Cost ($2022)(2)	Annual Usage(2): ccf	kWh
Space Heating	Gas Furnace	16	27	22	$5,000	819	
Space Heating	Gas Boiler(3)	20	30	25	$5,800	900	
Space Cooling	Central AC	11	25	18	$3,500		1,341
Space Cooling	Window AC(4)			n/a	$500		1,073
Fans & Pumps	Fans			n/a	Incl above		552
Water Heating	Gas Storage Tank	6	20	13	$2,101	200	
Water Heating	Gas Tankless	6	20	13	$4,000	148	
Cooking	Gas Range	9	15	12	$1,000	35	
Clothes Drying	Gas Dryer	8	18	13	$920	35	

(1) Source: U.S. Energy Information Administration, Assumptions to the Annual Energy Outlook 2022: Residential Demand Module. Table 5. Minimum and maximum life expectancies of equipment in years. March 2022.

(2) Source: CJ Brown Study

(3) Boiler annual ccf/year calculated as Forced Air Furnace ccf/year multiplied by ratio of baseline equipment gas boiler to gas furnace natural gas usage from National Grid 2021 Long-Term Capacity Report Appendices Table A-7. Boiler replacement cost estimate from HomeAdvisor (December 12, 2022) (https://www.homeadvisor.com/cost/heating-and-cooling/gas-boiler-prices/)

(4) Residential Window AC annual kWh assumes 2 window AC units per hours each running at 1.2 KW compared to three-ton central air unit running at 3 kW.

Table A-12

Residential Gas Furnace Conversion: 100% Electrification Cost and Usage

Gas Furnace Conversion Option 1: Cold Climate Air Source Heat Pump				
Load Type	**Conversion Equipment**	**Energy Type**	**First Cost ($2022)**	**Annual Usage (kWh)**
Space Heating	Cold Climate ASHP	Electric	$17,500	10,527
Space Cooling	Cold Climate ASHP	Electric	incl above	969
Fans & Pumps	Fans	Electric	incl above	494
Water Heating	ASHP Storage Tank	Electric	$3,500	1,077
Cooking	Electric Range	Electric	$750	821
Clothes Dryer	Electric Dryer	Electric	$770	821

Source: CJ Brown Study

Table A-13

Residential Gas Furnace Conversion: Hybrid Heating System Cost and Usage

Gas Furnace Conversion Option 2: Hybrid Heating System with 3-ton Standard ASHP for hours warmer than 30°F					
Load Type	**Conversion Equipment**	**Energy Type**	**First Cost ($2022)**	**Annual Usage (ccf)**	**Annual Usage (kwh)**
Space Heating	Furnace	Gas	$5,000	393	
Space Heating	Standard ASHP & Fans	Electric	$6,000		3,988
Space Cooling	Standard ASHP	Electric	incl above		1,341
Water Heating	Tankless	Gas	$4,000	148	
Cooking	Gas Range	Gas	$1,000	35	
Clothes Dryer	Gas Dryer	Gas	$920	35	

Source: CJ Brown Study

Gas Furnace Conversion Option 3: Hybrid Heating System with 4-ton ccASHP for hours warmer than 15°F					
Load Type	Conversion Equipment	Energy Type	First Cost ($2022)	Annual Usage (ccf)	Annual Usage (kwh)
Space Heating	Furnace	Gas	$5,000	101	
Space Heating	ccASHP & Fans	Electric	$17,500		9,232
Space Cooling	ccASHP	Electric	incl above		969
Water Heating	Tankless	Gas	$4,000	148	
Cooking	Gas Range	Gas	$1,000	35	
Clothes Dryer	Gas Dryer	Gas	$920	35	

Table A-14

Residential Boiler Conversion, Typical Home: Ductless Mini-split ASHP

Gas Boiler Conversion Option 1: Cold Climate Mini-Split Air Source Heat Pump				
Load Type	Conversion Equipment	Energy Type	First Cost ($2022)	Annual Usage (kWh)
Space Heating	Ductless Mini-Split ASHP	Electric	$19,000	11,021
Space Cooling	Ductless Mini-Split ASHP	Electric	incl above	1,341
Water Heating	ASHP Storage Tank	Electric	$3,500	1,077
Cooking	Electric Range	Electric	$750	821
Clothes Dryer	Electric Dryer	Electric	$770	821

Source: CJ Brown Study

Table A-15

Cost to Electrify an 80+ Year-Old Home

Category	Item	Cost ($2022)
Electrical Service	Upgraded 200 Amp Service	$4,500
	New Lines Throughout House	$14,000
	Plaster Patching	$1,000
Heating / Cooling	Ductless Mini-splits 4-6 units	$19,000
Water Heating	Heat Pump Water Heater	$3,900
	220 Elec Line from Panel	$300
Cooking	220 Elec Line from Panel	$800
	Electric Range	$750
Clothes Drying	220 Elec Line from Panel	$600
	Electric Dryer	$770

Source: Company Data

Existing market saturation for each baseline gas equipment type is based on a residential market study performed for National Fuel.[7] The residential electrification model assumes that boilers are allocated on equal percentage basis to houses built prior to 1941 versus houses built between 1941 and 1970. Houses built prior to 1941 are assumed to require significant electrical upgrades as shown in Table A-15, above. Allocation of housing stock by age is based on 2014

7 "2021 Residential Market Study: National Fuel," JRB Insights, August 5, 2021. ("JRB Residential Market Study.") Provided in Appendix H.

property tax database for zip codes comprising National Fuel's New York service territory. The model assumes that new gas customers from new construction will use air furnaces and not use boiler systems, which are more expensive than furnace systems and lack air conditioning from a hydronic system.

Table A-16

National Fuel Residential Customer Market Saturation by Appliance

Residential	Existing Stock as of 2023	New Construction 2024-2042
Natural Gas Forced Air Furnace	68%	100%
Natural Gas Boiler	23%	0%
Natural Gas Water Heater w/ Tank	69%	89%
Natural Gas Tankless Water Heater	9%	11%
Natural Gas Clothes Dryer	55%	55%
Natural Gas Range	56%	56%

Source: JRB Residential Market Study

Table A-17

Age of Homes Built in 1970 or Earlier (1)

Age of Home	% of Homes
Built prior to 1941 (2)	53%
Built between 1941 and 1970 (3)	47%
Subtotal	100%

(1) Source: 2014 property tax database
(2) Assumes prevalence of knob-and-tube electrical wiring in homes built prior to 1941.
(3) Residential furnace systems became more prevalent than boiler systems starting in the 1970s.

Table A-18

Percentage of Homes with Air Conditioning (1)

Residential	Existing Stock as of 2023	New Construction 2024-2042
% of Accounts heated with gas furnaces with Central Air (Electric)	73%	90%
% of Accounts heated with gas furnaces with Window AC (Electric)	11%	4%
% of Accounts heated with gas boilers with Window AC (Electric)	42%	42%

(1) Source: JRB Residential Market Study

C. Scenario Inputs

The SCE Scenario assumes residential electrification starts in 2025 with a percentage of existing gas furnaces converted to hybrid heating systems and other non-heating gas appliances converted at appliance end-of-life ramping up over time to a maximum rate of 50%. It is assumed that customers in old homes or heating with boilers do not electrify. All new residential customers are assumed to have ccASHP starting in 2026, consistent with new legislation.

The Aggressive Scenario assumes residential electrification starts in 2025 with a percentage of existing gas furnace, boiler converted to full electrification and other non-heating gas appliances converted at appliance end-of-life ramping up over time to maximum rate of 90%. Furnaces are converted to fully electric cold climate ASHPs; boilers are converted to ductless mini-split ASHPs. Old homes are assumed to be electrified. All new residential customers are assumed to have ccASHP starting in 2026, consistent with new legislation.

The LTP assumes residential electrification starts in 2025 with a percentage of existing gas furnaces converted to hybrid heating systems and other non-heating gas appliances converted at appliance end-of-life ramping up over time to maximum rate of 70%. It is assumed that customers in old homes or heating with boilers do not electrify. All new residential customers are assumed to have ccASHP starting in 2026, consistent with new legislation.

The resulting percentage of appliance converted by 2042 is shown in Table A-19.

Table A-19

Percentage of Residential Appliances Converted to Electric by 2042

Baseline Gas Equipment	SCE Scenario	Aggressive Scenario	LTP
Gas Forced Air Furnace (existing)	34% (hybrid)	53% (full electric)	44% (hybrid)
Gas Forced Air Furnace (new)	88% (full electric)	88% (full electric)	88% (full electric)
Gas Boiler	0%	39% (full electric)	0%
Gas Water Heating w/ Tank	37%	64%	51%
Gas Tankless Water Heater	37%	64%	51%
Gas Clothes Dryer	38%	65%	52%
Gas Range	40%	69%	55%

For all three scenarios, 50% of residential customers that electrify their homes are assumed to weatherize their homes at the same time.

VII. Electrification – Small Commercial

A. Methodology

The model includes small commercial electrification options that target conversion of space heating from gas furnace and boilers for National Fuel's SC3 rate class. The small commercial electrification model assumes that baseline small commercial gas furnaces are converted to ASHPs, while gas boilers are replaced with ductless mini-split ASHPs.

Similar to the residential electrification, the small commercial electrification model starts with the SC3 customer count forecast, to which appliance specific market saturation percentages and assumed equipment lifespans are applied to estimate potential conversions. An assumed maximum annual participation rate is applied to a ramp rate schedule and annual potential conversions, resulting in number of conversions, from which net installed cost, natural gas use and GHG emission reductions can be computed.

B. Assumptions, Inputs, Sources

Small commercial furnace and boiler annual gas usage estimates are calculated by scaling the Company's estimates for residential furnace and boiler annual gas usages by ratio of National Fuel's New York average small commercial SC-03 annual normalized heat load to residential SC-01 annual normalized heat load. Similarly, small commercial central air annual kwh usage is calculated by multiplying the Company's residential estimate provided in the CJ Brown Study by the Company's ratio of SC-03 annual normalized heat load to SC-01 annual normalized heat load.

Small commercial annual kWh usages for each baseline and electrification equipment type are calculated by multiplying National Fuel's annual ccf usage estimates discussed above for small commercial furnaces and boilers and applying ratios from National Grid's 2021 Natural Gas Long-Term Capacity Report ("National Grid's LTCR").[8] Therefore, small commercial annual kWh usage estimates for electrification conversion equipment from National Grid's LTCR are calibrated to National Fuel's service territory, accounting for differences in average customer consumption, building size and temperature patterns between the two service territories.

Calibration adjustments made to small commercial equipment annual kwh usage estimates are as follows:

- Small commercial ASHP annual kWh usage is calculated by multiplying National Fuel's annual ccf estimates for a small commercial gas furnace by ratio developed using data of small commercial ASHP annual kWh usage divided by annual ccf usage for gas furnace.
- Similarly, the small commercial ductless mini-split ASHP annual kWh usage is calculated by multiplying National Fuel's annual ccf estimates for a small commercial gas boiler by ratio developed using data from National Grid's LTCR of small commercial ductless mini-split ASHP annual kWh usage divided by annual ccf usage for gas boiler.
- Small commercial room AC annual kWh usage is calculated by multiplying the Company's central air annual kWh usage estimate by ratio of National Grid's small commercial room AC annual kWh usage to National Grid's small commercial ducted AC annual kWh usage as reported in National Grid's LTCR.
- Annual kWh usage for fans associated with baseline gas furnace and boilers are calculated by multiplying National Fuel's annual ccf estimates for a small commercial gas furnace and gas boiler, respectively, by ratio developed using data from National Grid's LTCR of annual kwh divided by annual ccf estimates for each furnace and boiler appliance type.

Small commercial cost assumptions for each baseline and conversion equipment type are sourced from National Grid's LTCR.

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[8] National Grid. *Natural Gas Long-Term Capacity Second Supplemental Report for Brooklyn, Queens, Staten Island and Long Island ("Downstate NY")*, Appendix, June 2021.

Table A-20

Small Commercial Baseline Natural Gas and Air Conditioning Equipment

Baseline	Equipment	Appliance Life Expectancy Min(1)	Max (1)	Modeled	Replacement Cost ($2022)(2)	Annual Usage ccf	kWh
Space Heating	Gas Furnace & Fans	16	27	22	$12,361	3,038	1,961
Space Heating	Gas Boiler & Fans	20	30	25	$18,831	3,338	1,340
Space Cooling	Central AC	11	25	18	$21,197		4,975
Space Cooling	Room AC			n/a	$3,648		6,805

(1) Source: U.S. Energy Information Administration, Assumptions to the Annual Energy Outlook 2022: Residential Demand Module. Table 5. Minimum and maximum life expectancies of equipment in years. March 2022.
(2) Source: National Grid's LTCR, escalated by 7.3% inflation from $2021 to $2022 dollars.

Table A-21

Small Commercial Gas Furnace Conversion: ASHP Cost and Usage

Gas Furnace Conversion Option: Cold Climate Air Source Heat Pump				
Load Type	**Conversion Equipment**	**Energy Type**	**First Cost (1) ($2022)**	**Annual Usage(2) (kWh)**
Space Heating	ASHP	Electric	$41,809	29,263
Space Cooling	ASHP	Electric	incl above	4,975

(1) Source: National Grid's LTCR, escalated by 7.3% inflation from $2021 to $2022 dollars.
(2) ASHP cooling electric load assumed to be same as Baseline central AC.

Table A-22

Small Commercial Boiler Conversion: Ductless Mini-split ASHP Cost and Usage

Gas Boiler Conversion Option: Ductless Mini-Split Cold Climate Air Source Heat Pump				
Load Type	**Conversion Equipment**	**Energy Type**	**First Cost ($2022)**	**Annual Usage (kWh)**
Space Heating	Ductless Mini-Split ASHP	Electric	$68,601	26,801
Space Cooling	Ductless Mini-Split ASHP	Electric	incl above	6,805

(1) Source: National Grid's LTCR, escalated by 7.3% inflation from $2021 to $2022 dollars.
(2) Ductless mini-split ASHP cooling electric load assumed to be same as baseline room AC.

Space heating existing market saturation for National Fuel's small commercial class is assumed to be 64% gas furnace and 36% natural gas boiler.[9] Air conditioning market saturation for National Fuel's small commercial customers is adopted from National Grid's LTCR.

9 NYSERDA Commercial Baseline Study Vol 1. page 16 Table 1. Assumes furnace includes infrared heaters and unit heaters.

Table A-23

Small Commercial National Fuel Market Saturation by Appliance

Appliance	Existing Stock as of 2023	New Construction 2024-2042
Natural Gas Forced Air Furnace	64%	100%
Natural Gas Boiler	36%	0%

Table A-24

Small Commercial Air Conditioning Market Saturation(1)

Assumed % of Businesses with Air Conditioning (Electric)	Existing Stock as of 2023	New Construction 2024-2042
% Businesses heated with gas furnaces / heaters with Central Air(2)	70%	70%
% Businesses heated with gas furnaces / heaters with Room AC	29%	29%
% Businesses heated with gas boilers with Room AC	29%	29%

(1) Source: National Grid's LTCR
(2) Sum of Central A/C and Packaged A/C.

C. Scenario Inputs

The SCE Scenario assumes small commercial electrification starts in 2025 with percentage of existing gas furnaces to ASHP conversions at furnace and central air appliance end-of-life ramping up over time to a maximum participation rate of 50%. All new small commercial customers are assumed install ASHP starting in 2026. These assumptions result in 3% of existing furnaces and 91% of new construction being converted to full electric ASHP by 2042. It is assumed that existing customers heating with boilers do not electrify.

The Aggressive Scenario assumes small commercial electrification starts in 2025 with percentage of existing gas furnace and boiler conversions at appliance (including central air) end-of-life ramping up over time to maximum participation rate of 90%. All new small commercial customers are assumed install ASHP starting in 2026. Furnaces are converted to ASHPs; boilers are converted to ductless mini-split ASHPs. These assumptions result in 52% of existing furnaces, 39% % of existing boilers and 91% of new construction being converted to full electric ASHP by 2042.

The LTP assumes small commercial electrification starts in 2025 with percentage of existing gas furnace to ASHP conversions at furnace and central air appliance end-of-life ramping up over time to maximum participation rate of 70%. All new small commercial customers are assumed install ASHP starting in 2026. These assumptions result in 44% of existing furnaces and 91% of new construction converted to full electric ASHP by 2042. It is assumed that existing customers heating with boilers do not electrify.

VIII. Electrification –Large Multi-Family, Universities, and Industrial

A. Methodology

Electrification options modeled for large multi-family (e.g., public authority housing), universities, and industrial customer segments include full electrification of space heating load associated with gas furnaces, heaters[10] and boilers. This electrification analysis assumes that heating load associated with baseline gas furnaces and heaters is converted to ASHPs, while heating load from boilers are replaced with ductless mini-split ASHPs.

In contrast to the residential and small commercial electrification models, the large multi-family, universities, and industrial electrification models start with total customer segment forecasted throughput, which is then allocated between heating load and process load. Unlike residential and small commercial customers, these larger customers may have multiple heating units which are likely not retired at the same time. Electrification conversions are likely to occur in multiple phases as individual units reach end-of-life.

A. Assumptions, Inputs, Sources

Heating load is separated from processing load for large multi-family, university and industrial segments based on ratios calculated using National Fuel's EMM Equipment customer database. Heating load associated with equipment that is also used for processing load is excluded from electrification potential.

Large multi-family, university and industrial equipment costs and energy usage estimates for both baseline and conversion technologies are scaled from the Company's small commercial estimates while maintaining the small commercial ratio of costs to energy usage. These assumptions are presented in Tables A-25 and A-26.

Table A-25

Heating Load as % of Customer Segment Throughput by Appliance

Baseline Gas Equipment	Large Multi-Family	University	Industrial
Forced Air Furnace and Heaters(1)	22%	3%	4%
Natural Gas Boiler, Ductless	46%	67%	17%

(1) Source: Based on analysis of National Fuel's EMM Equipment customer database.

10 Heaters includes space heating furnaces, unit heaters, infra-red heaters, make-up air heaters, and rooftop heaters.

Table A-26

% of Customer Segment Throughput by Appliance

Baseline Gas Equipment	Large Multi-Family(1)	University(1)	Industrial(2)
% of Furnace and Heater Systems with Central AC(3)	15%	15%	70%
% of Furnace and Heater Systems with Room AC	54%	54%	29%
% of Boiler Systems with Room AC	54%	54%	29%

(1) Source: National Grid's 2021 Natural Gas Long-Term Capacity Report, estimates for Large Multi-Family
(2) Source: National Grid's 2021 Natural Gas Long-Term Capacity Report, estimates for Small Commercial
(3) Sum of Central A/C and Packaged A/C.

B. Scenario Inputs

The SCE Scenario assumes that large multi-family, university and industrial heating load electrification starts in 2025 with the percentage of gas furnaces to ASHP conversions at appliance end-of-life ramping up over time to a maximum participation rate of 50%. It is assumed that customers heating with boilers do not electrify.

The Aggressive Scenario assumes large multi-family, university and industrial heating load electrification starts in 2025 with the percentage of gas furnace and boiler conversions at appliance end-of-life ramping up over time to maximum participation rate of 90%. Furnaces are converted to ASHPs; boilers are converted to ductless mini-split ASHPs.

The LTP assumes large multi-family, university and industrial heating load electrification starts in 2025 with percentage of gas furnace to ASHP conversions at appliance end-of-life ramping up over time to maximum participation rate of 70%. It is assumed that customers heating with boilers do not electrify.

The resulting percentage of appliances converted by 2042 is presented in Table A-27.

Table A-27

Percentage of Appliances Converted by 2042

SCE Scenario

Baseline Gas Equipment	Large Multi-Family	University	Industrial
Natural Gas Forced Air Furnace	24%	24%	24%
Natural Gas Boiler	0%	0%	0%

Aggressive Scenario

Baseline Gas Equipment	Large Multi-Family	University	Industrial
Natural Gas Forced Air Furnace	44%	44%	44%
Natural Gas Boiler	39%	39%	39%

LTP

Baseline Gas Equipment	Large Multi-Family	University	Industrial
Natural Gas Forced Air Furnace	34%	34%	34%
Natural Gas Boiler	0%	0%	0%

IX. Industrial – Process Energy Efficiency

A. Methodology

Industrial energy efficiency includes measures that target process load efficiency. Energy efficiency measures were modeled using customer adoption levels, reduction in gas usage, and associated program costs. This analysis utilized costs from a Guidehouse decarbonization pathways study for National Fuel.[11] These inputs are used to model energy efficiency potential within National Fuel's industrial customers. The model uses customer participation and gas reduction to compute an associated emissions reduction. Finally, the model uses customer participation and cost inputs to calculate a total program cost for industrial energy efficiency.

B. Assumptions, Inputs, Sources

These costs apply only to energy efficiency measures for process load.

Table A-28

Industrial Energy Efficiency Cost 2020-2050

Year	Annual Cost ($/MMBtu)
2020	$ 183
2030	$ 202
2040	$ 223
2050	$ 247

Source: "Meeting the Challenge: Scenarios for Decarbonizing New York's Economy," Guidehouse Inc., February 19, 2021. Provided in Appendix E.

C. Scenario Inputs

The industrial energy efficiency decarbonization scenarios differ with respect to maximum participation rate assumptions. The SCE Scenario assumes a 0.5% participation rate annually starting in 2025 until a maximum of 5% is reached. The Aggressive Scenario and LTP assumes a 0.5% participation rate annually starting in 2025 until a maximum of 9% is reached.

11 "Meeting the Challenge: Scenarios for Decarbonizing New York's Economy," Guidehouse Inc., February 19, 2021. Provided in Appendix E.

X. Thermal Energy Networks

A. Methodology

The modeling focused on geothermal networks, one type of Thermal Energy Network ("TEN"). A geothermal network consists of a system of interconnected pipe that supports the use of ground source heat pumps to heat and cool homes or buildings. They are modeled to estimate potential reduction in gas usage and project cost assuming that each network has 50 customers. While a hypothetical geothermal network project is specified for modeling purposes, it does not fully capture the site-specific nature of these projects. Two types of geothermal network projects are modeled: newly constructed developments and existing neighborhoods. Emissions reduction estimates are based on ground source heat pump electric usage and average home gas consumption. Ground source heat pump and shared loop costs are used to calculate an average cost per home for both project types.

B. Assumptions, Inputs, Sources

A standard new construction project is defined as a 50-home new development comprised of 2,500 square foot homes that would have heated with gas forced air furnaces and cooled with central AC systems. A standard existing home project is defined as a 50-home existing neighborhood with 1,500 square foot homes that all heat with gas forced air furnaces. Table A-29 provides a description of both projects and the cost associated with the geothermal network loop as well as market saturation data for air conditioning and other gas appliances.

Table A-29

New Construction and Existing Home Standard Project Definitions

	New Construction	Existing Home
Number of Homes	50	50
Size (SQFT)	2,500	1,500
Heat Pump Size (ton)	5	3
Cost ($/Home)(1) $2022	$71,626	$54,431
Market Saturation (% of Homes)	**New Construction**	**Existing Home**
Gas Air Furnace	100%	100%
Central Air(2)	100%	50%
Window AC(2)	0%	7%
Gas Water Heater / Tank(2)	100%	69%
Gas Clothes Dryer(2)	55%	55%
Gas Range(2)	56%	56%

(1) Source: "Net Zero Community Study: National Fuel," Cadmus, August 5, 2021. ("Cadmus Geothermal Study.") Provided in Appendix I; Cost per home includes ground loop cost, indoor equipment cost, design cost, and thermal conductivity testing cost.

(2) Source for existing home estimate: JRB Residential Market Study

In calculating net installed costs, the cost of the geothermal loop and equipment are offset by the avoided cost of gas heating and air conditioning equipment. For new construction projects avoided costs include both the avoided gas equipment cost and gas infrastructure cost: main, service line, and meter. New construction projects also reflect a discount on the ground loop installation cost due to savings from working in open ground, unencumbered by other utilities, roads, and landscaping.

For existing neighborhood projects, avoided gas and central air conditioning equipment costs are reduced by 50% to reflect the likelihood that not all homes in an existing neighborhood will have appliances approaching end-of-life at time of heating system conversion to geothermal.

Table A-30

Geothermal Network: Baseline Natural Gas and Air Conditioning Equipment

Natural Gas Mains & Services, Appliances & Air Conditioners	Replacement Cost $2022/Unit		Annual Use per Unit	
	New Construction	Existing Home(1)	New Construction	Existing Home
Main	$2,114	n/a	n/a	n/a
Service	$1,512	n/a	n/a	n/a
Meter	$126	n/a	n/a	n/a
Natural Gas Furnace	$5,000	$2,500	112 Mcf	87 Mcf
Central Air	$3,500	$1,750	1,341 kWh	1,341 kWh
Window AC	n/a	$250	n/a	1,073 kWh
Natural Gas Water Heater w/ Tank	$2,101	$1,051	20 Mcf	20 Mcf
Natural Gas Clothes Dryer	$920	$460	4 Mcf	4 Mcf
Natural Gas Range	$1,000	$500	4 Mcf	4 Mcf

(1) Installed cost reduced by 50%.

Geothermal network installed cost and equipment annual kWh usage assumptions are shown in Table A-31 below. Ground loop costs include drilling piping, right of way, and central pumping station costs. Indoor equipment includes a 5-ton and 3-ton ground source heat pump ("GSHP") for new construction and existing home projects, respectively, and an assumption to reflect the cost of site-specific improvements. Additional costs include thermal conductivity test and design cost from the Cadmus Weatherization Study.

Table A-31

Thermal Energy Network: GSHP Cost Component and Annual Usage

GSHP & Electric Appliances	Cost $2022/Unit		kWh / Unit	
	New Construction	Existing Home	New Construction	Existing Home
Ground Loop Cost(1)	$35,444	$35,698	n/a	n/a
Indoor Equipment(1)	$28,221	$18,133	n/a	n/a
Additional Cost(1)	$600	$600	n/a	n/a
GSHP, Space Heating(1)	incl above	incl above	5,732	3,460
GSHP, Air Cooling(2)	incl above	incl above	555	335
Water Heating w/ Tank(3)	$5,350	$5,350	630	630
Electric Clothes Dryer(4)	$770	$770	821	821
Electric Range(4)	$750	$750	821	821

(1) Source: Values adjusted based on Cadmus Geothermal Study
(2) Cooling kwh estimated by multiplying space heating kwh by ratio developed using estimates from CJ Brown Study estimate for individual geothermal ground sourced heat pump cooling to heating kwh.
(3) Source: CJ Brown Study, Water heating WWHP kWh estimate.
(4) Source: CJ Brown Study

C. Scenario Inputs

The SCE Scenario and LTP assume one existing neighborhood geothermal network project will be placed into service per year beginning in 2027. The Aggressive Scenario assumes two existing neighborhood geothermal network projects will be placed into service per year beginning in 2027.

XI. Renewable Natural Gas

A. Methodology

Renewable Natural Gas ("RNG") is biogas that has been converted to pipeline-quality gas. The RNG model focuses on the anerobic digestion-based production of RNG from animal manure, food waste, landfill gas and wastewater feedstocks within National Fuel's New York service territory and its injection into the Company's distribution system and supplemental anerobic digestion-based production from Pennsylvania and Ohio available through National Fuel's firm capacity on upstream pipelines. The model includes all costs to produce and interconnect RNG to National Fuel's distribution system or upstream transportation pipelines and assumes the RNG is delivered for use by National Fuel customers. The model does not include any revenue from selling the environmental attributes since it is assumed that benefits accrue from capturing GHG emissions that otherwise would have been emitted to the atmosphere. The model allows for specification of different timeline estimates of RNG supply availability and analyzes the resulting production and interconnection cost premium and GHG emission reductions as compared to the natural gas it displaces.

B. Assumptions, Inputs, Sources

Table A-32

RNG Production Cost

Process	Feedstock	Production Cost $2022/ MMBtu(1)
Anaerobic Digestion	Landfill Gas	$11.29
	Animal Manure	$34.56
	Food Waste	$23.86
	Wastewater	$27.68

Source: "Potential of Renewable Natural Gas in New York State prepared for New York State Energy Research and Development Authority", ICF Resources, April 2022. NYSERDA Report Number 21-34, ("ICF NYSERDA RNG Study,") p 44. Production cost adjusted for inflation in modeling.

Emissions impacts related to using RNG sourced both in-state and out-of-state are captured on a life-cycle basis, RNG life cycle CO2e emission rates are estimated based on 100-year GWP CO2e emission rates, which are converted to 20-year GWP rates to allow for comparison with other decarbonization measures included in this LTP and to comply with New York GHG accounting requirements. This conversion process is illustrated Tables A-33 and A-34. RNG sourced from out-of-state is assumed to have higher emissions than RNG sourced from within National Fuel's service territory due to the added use of upstream transportation to deliver the out-of-state RNG. The emissions associated with upstream transportation for out-of-state RNG are also shown in Table A-34.

Table A-33

GHG Emission Factor Conversion 100-Year GWP to 20-Year GWP

RNG Feedstock	CO2e Component (100-yr GWP) (lb/MMBtu)			
	Total CO2e(1) lb/MMBtu	Assumed(2) % CO2e from CH4	CO2e from CH4 lb/MMBtu	CO2e from CO2, N2O lb/MMBtu
Landfill Gas	21.0	45%	9.45	11.55
Animal Manure	(124.0)	60%	(74.40)	(49.60)
Food Waste	(9.9)	60%	(5.94)	(3.96)
Wastewater	16.6	60%	9.96	6.64

(1) Based on 100-year GWP. "Meeting the Challenge: Scenarios for Decarbonizing New York's Economy", Guidehouse Inc., February 19, 2021. Table A-1. Estimated RNG Production Potential and Emissions Rates for New York State. Scenarios for Decarbonizing New York's Economy | NFGDC Report | Guidehouse_Provided in Appendix E
(2) Landfill Gas: EPA Landfill Methane Outreach Program
Animal Manure: Michigan State University A Primer on Anerobic Digestion
Food Waste and Wastewater: Environmental and Energy Study Institute Biogas: Converting Waste to Energy

Table A-34

GHG Emission Factor Conversion 100-Year GWP to 20-Year GWP (Continued)

	Emission Rate (lb/Mcf)				Upstream Transportation Adder (lb/Mcf)(1)
RNG Feedstock	CH4	CO2	N2O	20-yr GWP CO2e	20-yr GWP CO2e
Landfill Gas	0.35	11.93	0.00	41.22	25.94
Animal Manure	(2.74)	(51.24)	0.00	(281.80)	
Food Waste	(0.22)	(4.09)	0.00	(22.50)	
Wastewater	0.37	6.86	0.00	37.73	

(1) 2019 NETL Study, Air emissions for processing, transmission stations, storage, transmission pipelines, Exhibit F-31

C. Scenario Inputs

Total RNG technical potential estimates by feedstock within National Fuel's service territory are based on an RNG study prepared for National Fuel.[12]

Annual 2040 RNG production estimates as percentage of total technical potential in New York are calculated from data published in the ICF NYSERDA RNG Study that reflect "achievable deployment" and "optimistic growth" levels. These percentages are then multiplied by the Company's estimated total RNG technical potential within its New York service territory to derive production levels.

The rate of RNG production implementation to reach 2040 achievable deployment and optimistic growth levels is based on information gathered from RNG projects within National Fuel's service territory that are already underway. The resulting 2023-2042 timelines of annual RNG

12 "RNG Potential in NY & NFGDC Territory," National Fuel, April 2020. Provided in Appendix J.

production supply projected to be available within National Fuel's New York service territory are presented in Table A-35 and Figure A-3.

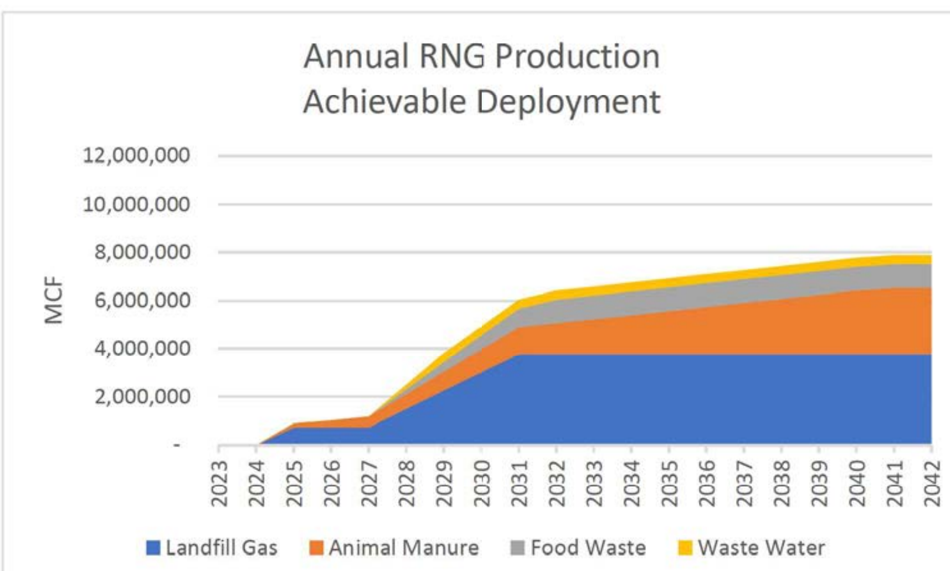
Table A-35

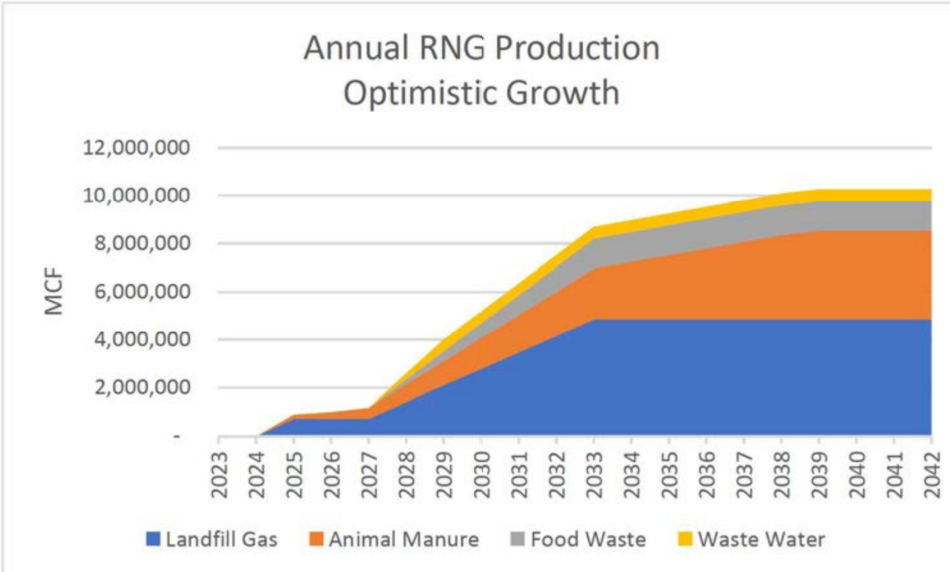
Available RNG Production in National Fuel's New York Service Territory

	Achievable Deployment (Mcf)				Optimistic Growth (Mcf)			
	Landfill Gas	Animal Manure	Food Waste	Waste Water	Landfill Gas	Animal Manure	Food Waste	Waste Water
2023	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-
2025	730,000	170,289	-	-	730,000	169,550	-	-
2026	730,000	283,050	-	-	730,000	280,832	-	-
2027	730,000	452,191	-	-	730,000	447,754	-	-
2028	1,489,569	621,332	196,308	184,563	1,415,356	725,959	206,893	246,085
2029	2,249,139	790,474	392,616	369,127	2,100,713	1,004,163	413,787	492,169
2030	3,008,708	959,615	588,925	369,127	2,786,069	1,282,368	620,680	492,169
2031	3,768,277	1,128,756	785,233	369,127	3,471,426	1,560,572	827,574	492,169
2032	3,768,277	1,297,897	981,541	369,127	4,156,782	1,838,776	1,034,467	492,169
2033	3,768,277	1,467,038	981,541	369,127	4,842,139	2,116,981	1,241,361	492,169
2034	3,768,277	1,636,179	981,541	369,127	4,842,139	2,395,185	1,241,361	492,169
2035	3,768,277	1,805,321	981,541	369,127	4,842,139	2,673,390	1,241,361	492,169
2036	3,768,277	1,974,462	981,541	369,127	4,842,139	2,951,594	1,241,361	492,169
2037	3,768,277	2,143,603	981,541	369,127	4,842,139	3,229,799	1,241,361	492,169
2038	3,768,277	2,312,744	981,541	369,127	4,842,139	3,508,003	1,241,361	492,169
2039	3,768,277	2,481,885	981,541	369,127	4,842,139	3,674,926	1,241,361	492,169
2040	3,768,277	2,651,026	981,541	369,127	4,842,139	3,674,926	1,241,361	492,169
2041	3,768,277	2,763,787	981,541	369,127	4,842,139	3,674,926	1,241,361	492,169
2042	3,768,277	2,763,787	981,541	369,127	4,842,139	3,674,926	1,241,361	492,169

Figure A-3

Available RNG Production in National Fuel's New York Service Territory





The SCE Scenario assumes achievable deployment, while the Aggressive Scenario and LTP assume optimistic growth.

Total RNG technical potential estimates for anaerobic digestion-based feedstocks in Pennsylvania and Ohio are from data published in the 2019 American Gas Foundation Study.[13] Annual 2040 RNG production estimates by feedstock in Pennsylvania and Ohio for ICF's "achievable deployment" and "optimistic growth" scenario levels are calculated as percentage of total technical potential using same ratios developed for New York from data published in the ICF NYSERDA RNG Study.

It is assumed that National Fuel would not be able to purchase all the RNG in Pennsylvania and Ohio because other New York utilities and entities in Pennsylvania and Ohio may also be interested in RNG produced in Pennsylvania and Ohio. The amount of RNG in Pennsylvania that could be available to National Fuel was estimated by calculating National Fuel's percentage of total annual natural gas load in Pennsylvania plus New York (i.e. National Fuel's (New York) load divided by the sum of total gas load in Pennsylvania and total gas load in New York), which is 3.8%. Similarly, the amount of RNG in Ohio that could be available to National Fuel was estimated by calculating National Fuel's percentage of total annual natural gas load in Ohio plus New York (i.e. National Fuel's (New York) load divided by the sum of total gas load in Ohio and total gas load in New York), which is 4.1%.

National Fuel assumes that it would be able to acquire 50% of its pro rata share of RNG in Pennsylvania and Ohio (i.e., 1.9% and 2.05%, respectively) in the SCE Scenario and LTP.

[13] "Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment," American Gas Foundation Study prepared by ICF, Appendix A, December 2019, pg. 64-69.

National Fuel assumes it would be able to acquire its full pro rata share of RNG in Pennsylvania and Ohio (i.e., 3.8% and 4.1%, respectively) in the Aggressive Scenario.

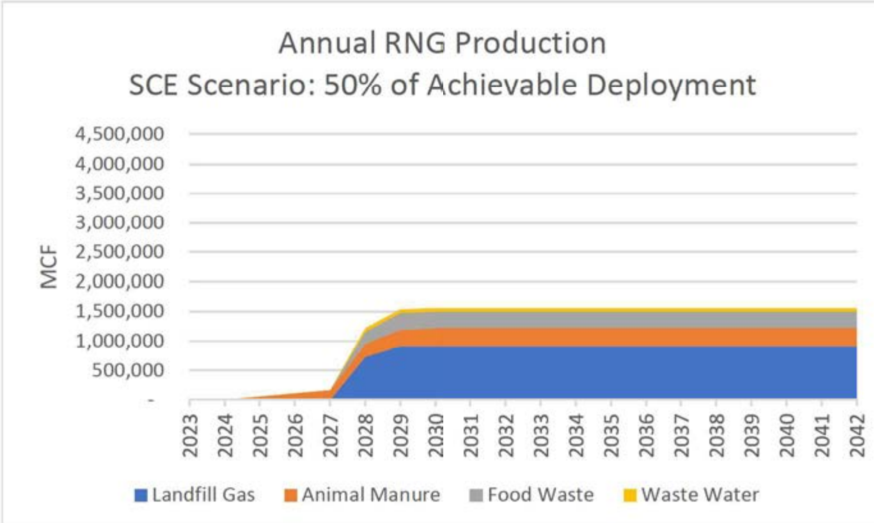
The rate of RNG production implementation to reach 2040 achievable deployment and optimistic growth levels in Pennsylvania and Ohio is based on information gathered from RNG projects within National Fuel's service territory that are already underway. The resulting 2023-2042 timelines of annual RNG production supply projected to be available to NFG from Pennsylvania and Ohio are presented in Table A-36 and Figure A-4.

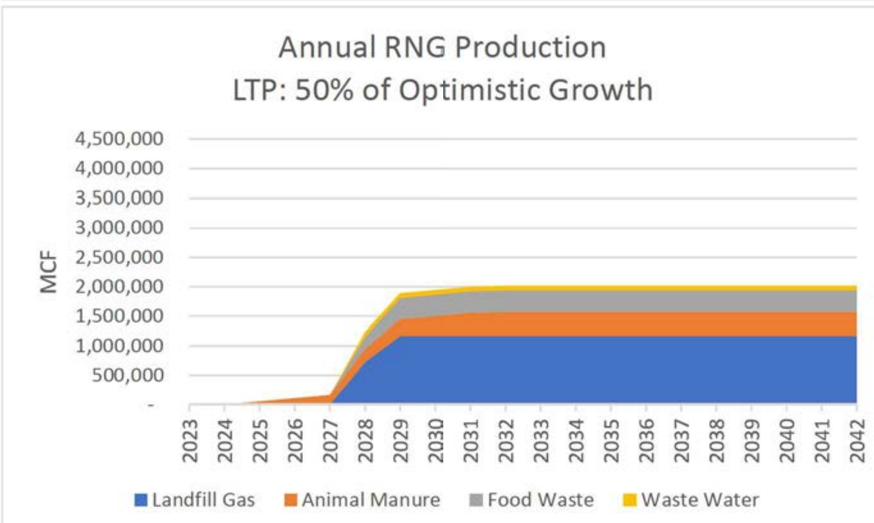
Table A-36

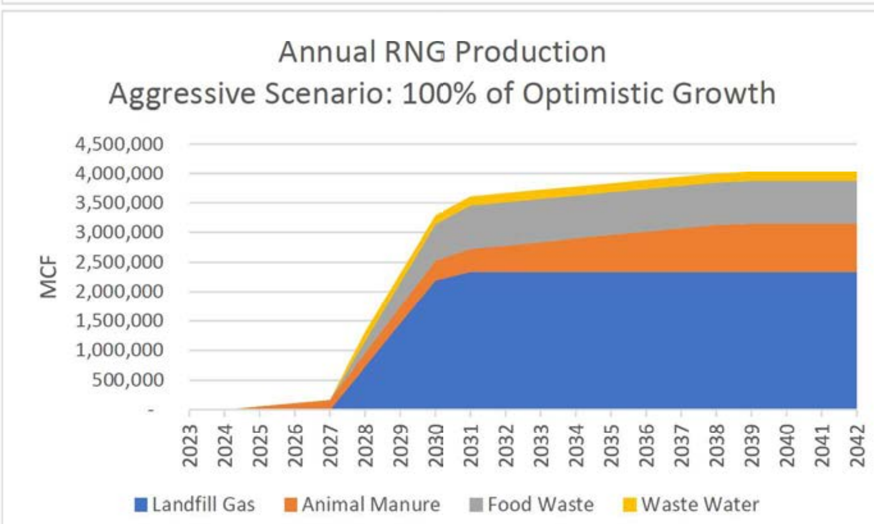
Available RNG Production in Pennsylvania and Ohio

	50% of Achievable Deployment (Mcf)				Optimistic Growth (Mcf)			
	Landfill Gas	Animal Manure	Food Waste	Waste Water	Landfill Gas	Animal Manure	Food Waste	Waste Water
2023	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-
2025	-	56,067	-	-	-	56,067	-	-
2026	-	112,134	-	-	-	112,134	-	-
2027	-	168,201	-	-	-	168,201	-	-
2028	730,000	224,268	203,378	57,454	730,000	224,268	203,378	153,212
2029	909,510	280,334	286,415	57,454	1,460,000	280,334	406,756	153,212
2030	909,510	304,949	286,415	57,454	2,190,000	336,401	610,134	153,212
2031	909,510	304,949	286,415	57,454	2,337,395	392,468	724,461	153,212
2032	909,510	304,949	286,415	57,454	2,337,395	448,535	724,461	153,212
2033	909,510	304,949	286,415	57,454	2,337,395	504,602	724,461	153,212
2034	909,510	304,949	286,415	57,454	2,337,395	560,669	724,461	153,212
2035	909,510	304,949	286,415	57,454	2,337,395	616,736	724,461	153,212
2036	909,510	304,949	286,415	57,454	2,337,395	672,803	724,461	153,212
2037	909,510	304,949	286,415	57,454	2,337,395	728,869	724,461	153,212
2038	909,510	304,949	286,415	57,454	2,337,395	784,936	724,461	153,212
2039	909,510	304,949	286,415	57,454	2,337,395	810,964	724,461	153,212
2040	909,510	304,949	286,415	57,454	2,337,395	810,964	724,461	153,212
2041	909,510	304,949	286,415	57,454	2,337,395	810,964	724,461	153,212
2042	909,510	304,949	286,415	57,454	2,337,395	810,964	724,461	153,212

Figure A-4
Available RNG Production in Pennsylvania and Ohio







XII. Hydrogen

A. Methodology

Blending hydrogen into the natural gas distribution system can reduce emissions by eliminating emissions associated with end-use combustion. This analysis utilized assumptions from pilot programs and independent studies to determine hydrogen cost and safe blending percentages. These assumptions are used to model hydrogen blending potential within National Fuel's distribution system. The model computes costs and GHG emission reductions associated with a specified schedule of annual hydrogen blend as a percent of total Btu throughput.

B. Assumptions, Inputs, Sources

Hydrogen cost data is sourced from ICF's 2021 hydrogen study. Green Hydrogen is assumed to be used in the blending process for all scenarios.

Table A-37

Cost Projection of Green Hydrogen 2023-2043

Year	Green Hydrogen ($2020/MMBtu)
2023	$24.02
2024	$23.26
2025	$22.50
2026	$21.46
2027	$20.42
2028	$19.38
2029	$18.34
2030	$17.30
2031	$16.76
2032	$16.22
2033	$15.68
2034	$15.14
2035	$14.60
2036	$14.18
2037	$13.76
2038	$13.34
2039	$12.92
2040	$12.50
2041	$12.18
2042	$11.86

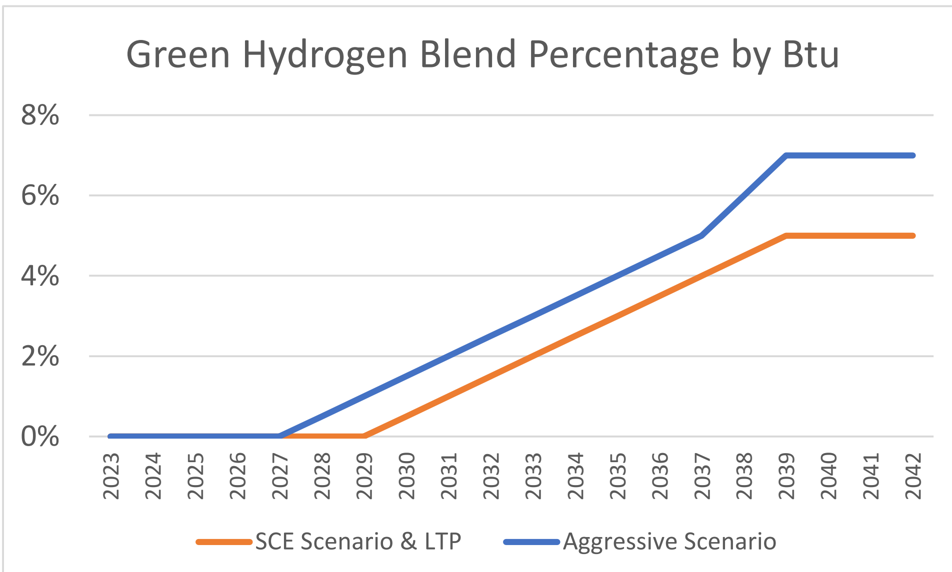
Source: Cost data estimated from graph in "Examining the Current and Future Economics of Hydrogen Energy," ICF, August 13, 2021. Cost adjusted for inflation in modeling to nominal dollars.

C. Scenario Inputs

The SCE and LTP scenarios both assume that the hydrogen blend as percentage of total Btu throughput increases by 0.5% per year starting in 2030 with a max (per Btu) blend percentage of 5%. The Aggressive Scenario increases hydrogen as percentage of total throughput by 0.5% per year starting in 2028, increasing to 1% per year starting in 2038 with a max (per Btu) blend percentage of 7% by 2042. Figure A-5 depicts the start year, total blend percentage, and annual increase by scenario.

Figure A-5

Percent Hydrogen Blend by Scenario 2023-2042



Appendix B

National Fuel Gas Distribution Corporation

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Appendix B: Modeling of Scenarios

I. Modeling of Scenarios

A. Overview

The SCE Scenario, Aggressive Scenario and Long-Term Plan were developed using a bottom-up approach whereby per unit costs (e.g., incremental equipment cost and incremental energy bills per participating customer or incremental cost per unit of RNG or hydrogen) and benefits (e.g., decreased emissions per participating customer, decreased emissions per unit of RNG or hydrogen) were modeled for each decarbonization action on an annual basis over the 20-year planning period. Assumptions specific to each decarbonization action are discussed in Appendix A.

B. Cumulative Impacts

The scenario results incorporate the combined effects of the decarbonization actions included in the scenario. For example, the quantity of hydrogen that is blended into the system in each scenario depends on how much gas throughput remains after energy efficiency and electrification decarbonization actions reduce gas use.

The modeling of each decarbonization action produces the same annual outputs over the 20-year planning period, including the first (or one-time) incremental installation and/or implementation costs, associated gas usage reduction and net change in electric use. While participant installation costs for energy efficiency weatherization and electrification are one time first costs, the net change in gas and electric usage and associated GHG emission reductions occur in the first year and each year following conversion.

The economic impact of reduced gas bills and increased electric bills depends on two major factors: the change in energy usage and the per unit energy price. The total change in gas and electric use is calculated by summing across all decarbonization actions in a scenario. The gas and electric prices used to calculate the economic impact of the change in usage under the scenarios are different from the Reference Case due to the impacts of decarbonization on electric and gas prices. The gas and electric price forecasts used to determine participant net operating costs are discussed in Sections II and III below.

II. Decarbonization Policy Costs

Decarbonization Policy Costs are the non-gas utility costs that are incurred as a result of National Fuel's energy efficiency, electrification, industrial and TENs decarbonization actions. These costs are subject to recovery that will be determined by regulators or legislators. They are comprised of the following three components:

1) **Customer incremental equipment installation costs** are calculated as total cost of installation of new equipment or measures minus replacement cost of baseline retired (or new) equipment, as appropriate. For example, for hybrid electrification example, customer incremental equipment installation costs consist of the cost of the cost to purchase and install an ASHP and efficient gas furnace minus the cost of a baseline gas furnace. It is assumed that 25% of incremental equipment costs will be covered by customer contributions, and the remaining 75% will be covered by some combination of tax credits, rebates, utility program incentives, or other sources.
2) **Participating customer gas cost savings** (i.e., negative costs) resulting from reduced reliance on natural gas for heating and other end-uses. This is calculated as the gas usage after the equipment or measure is installed minus the gas usage before the equipment or measure is installed, times the applicable gas price.
3) **Net change in participants' electric bills** (positive or negative) resulting from changes in the reliance on electricity. This is calculated as the electric usage after the equipment or measure is installed minus the electric usage before the equipment or measure is installed, times the applicable electric price. (Note that this calculation does not account for increases in electric bills associated with higher electric prices applied to typical electric loads (e.g., refrigerators and lights).) For weatherization decarbonization actions, participants electric bills show a net decrease due to building shell improvements reducing cooling needs. For electrification and TENs decarbonization actions, participants bills show a net increase due to electricity required to run heating systems (and other electrified appliances).

III. Gas Prices

The economic benefits of reduced gas usage are determined by multiplying the gas price by the change in gas usage over the 20-year period. The Company's Reference Case cost of gas and base distribution rate forecasts are adjusted separately based on the combined effects of the decarbonization actions on costs and billing determinants (i.e., both the numerator and denominator can be affected by the various decarbonization actions), as discussed in more detail below. The resulting scenario-specific gas prices are used to quantify the economic benefits of reduced gas usage for each scenario.

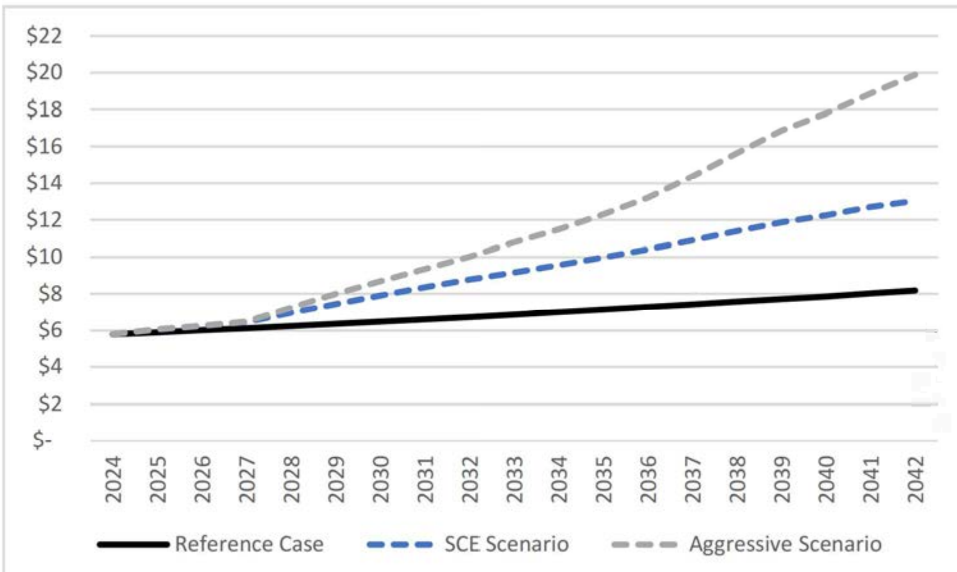
A. Cost of Gas

The cost of gas is comprised of per unit commodity prices and demand charges. The Reference Case cost of gas is adjusted to incorporate the cost premium associated RNG and hydrogen. Since the amount of RNG and hydrogen differs across scenarios, the total effect of these fuels on the cost of gas differs across scenarios. The Reference Case cost of gas is also adjusted to reflect the increased per unit cost of storage and pipeline demand/reservation charges as natural gas demand decreases (i.e., total storage and pipeline demand costs are assumed to remain the same but spread over fewer volumes as gas demand decreases).

The cost of gas in the Aggressive Scenario is higher than the cost of gas in the SCE scenario because: (1) the Aggressive Scenario includes more RNG and hydrogen than the SCE scenario, and (2) the Aggressive Scenario has lower billing determinants than the SCE Scenario. The Reference Case, SCE Scenario and Aggressive Scenario cost of gas is illustrated in Figure B-1.

Figure B-1

Annual Cost of Gas by Scenario ($/MCF)



Seasonal gas prices are required to estimate the economics of decarbonization actions that have different impacts throughout the year (e.g., electrification, weatherization). For each scenario, the average monthly gas commodity prices are weighted by HDDs and CDDs using the same winter, shoulder and summer seasonal definitions discussed in Appendix A, Table A-10 to develop seasonal prices. These seasonal prices are then applied to the change in seasonal gas use for each decarbonization action included in the scenario.

B. Gas Base Distribution Rates

National Fuel developed a 20-year Reference Case base distribution revenue requirement forecast for its New York division, applying existing revenue requirements policies. For each scenario, the annual Home Energy Report Program costs are added to the Company's Reference Case revenue requirement.

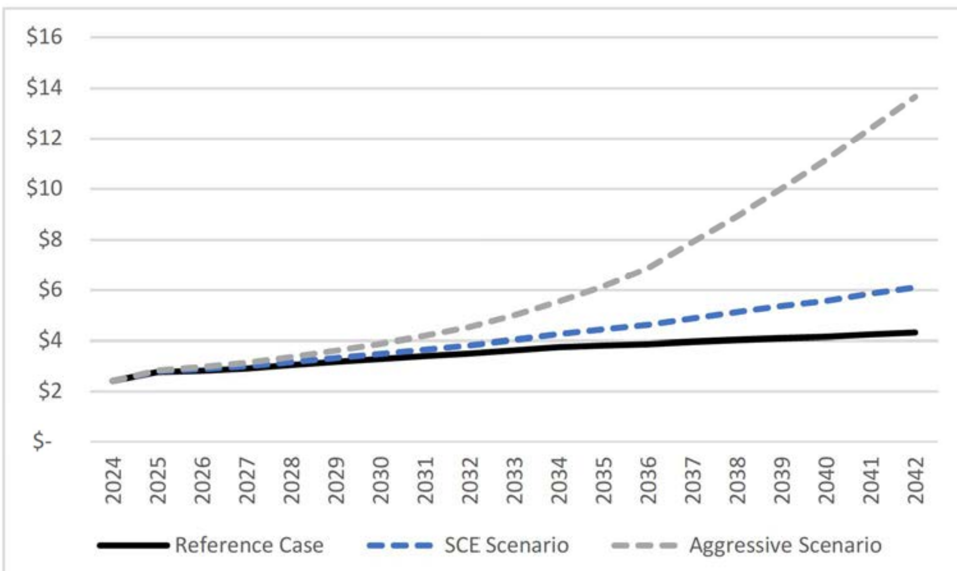
Illustrative gas base distribution non-gas costs are calculated for each rate class (i.e., SC1, SC3, TC1.1, TC2.0, TC3.0, TC4.0, TC4.1) using the Company's adjusted revenue requirement forecast and previously proposed class level revenues as approved in National Fuel's last rate case. For each forecasted year, the model calculates the cumulative percentage change in National Fuel's forecasted revenue requirement from its last approved revenue requirement of $272,375,000 in NYPSC Case 16-G-0257. These cumulative percentage changes are then applied to the base distribution revenues for each rate class as was approved in NYPSC Case 16-G-0257.

Customer charge revenues are assumed to increase at 2% from the Reference Case, reduced for any reduction in customers resulting from full electrification or TENs. The resulting customer charge revenues are netted from base distribution revenues to calculate volumetric revenues. Volumetric revenues are divided by National Fuel's Reference Case throughput, adjusted by the reduction in throughput resulting from the decarbonization actions included in the scenario to derive a $/MCF base distribution volumetric rate.

Average gas base distribution costs are then calculated for each customer segment (i.e., residential, small commercial, industrial, large multi-family, and universities). The Reference Case, SCE Scenario and Aggressive Scenario base distribution rate for residential customers is illustrated in Figure B-2.

Figure B-2

Annual Residential Base Gas Distribution Rate by Scenario ($/MCF)



C. Typical Residential Nonparticipant Gas Bill Impact Calculation

Typical residential nonparticipant gas bill impacts are calculated for each year of the analysis. The analysis assumes typical use remains constant at 106 Mcf per year. Gas bill increases reflect incremental utility program costs and supply cost premiums for RNG and hydrogen, and the impact of reduced throughput resulting from the decarbonization actions.

IV. Electric Prices

The electric price forecast is multiplied by the net change in electric usage under the scenarios to determine the economic impact of the change in electric usage over the 20-year analysis period.

A. Electric Price Base Forecast

At a high level, the Reference Case electric price forecast was developed by calculating weighted average electric rates for the three electric utilities in National Fuel's service territory for 2021 and forecasting these rates using a forecast for Upstate New York electric prices from the U.S. Energy Information Administration ("EIA"). Details regarding these calculations are provided below.

National Fuel's service territory overlaps with three electric utilities: New York State Energy & Gas ("NYSEG"), Rochester Gas & Electric ("RG&E") and National Grid Niagara Mohawk ("NIMO"). Bundled all-in electric prices[1] are calculated for National Fuel's New York residential, commercial, and industrial segments by first calculating 2021 average $/kWh volumetric residential, commercial, and industrial rates for NYSEG, RG&E, and NIMO by dividing 2021 retail electric revenues by electric volumes for each customer segment as reported by S&P Capital IQ. For each of the three electric utilities, average volumetric $/kWh rates are calculated by removing customer charge revenues.

A population-weighted average 2021 $/kWh volumetric bundled all-in rate was calculated for residential, commercial, and industrial segments specific to National Fuel's New York service territory by weighting the volumetric rates calculated for NYSEG, RG&E and NIMO by 2020 zip code-level population census data. NYSEG represents 35% of National Fuel's service territory, NIMO represents 61%, and RG&E represents 4%. The resulting weighted average 2021 volumetric $/kWh bundled all-in rates for residential, commercial, and industrial segments are than escalated by the EIA in its 2022 Annual Energy Outlook ("AEO") year-to-year forecasted change in its end-use Upstate New York $2021/kWh electric price. The resulting annual average $2021 real prices were then inflated to nominal dollars using inflation values shown in Appendix A, Table A-2.

Seasonal average all-in electric prices are calculated by adjusting the supply portion of the forecasted all-in electric prices based on monthly price differentials forecasted by the New York Independent System Operator ("NYISO") in its Base Case 2021-2040 System Resource Outlook for the West Zone A. Specifically, monthly average forecasted LBMPs as a ratio of annual average LBMP for NYISO Zone A are weighted by HDDs and CDDs using the same winter, shoulder and summer seasonal definitions discussed in Appendix A, Table A-10 to develop seasonal average LBMPs. This approach is consistent with stakeholder recommendations.

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1 Bundled all-in electric rates that include generation, transmission, and distribution charges

The allocation between the generation supply portion and delivery portion (i.e., transmission and distribution) of bundled all-in electric prices is estimated for residential, commercial and industrial segments using percentages calculated based on NIMO typical bill impacts provided in Case 20-E-0380 & 20-G-0381.

B. Electric Price Adjustment for Electrification

The Reference Case electricity prices are adjusted to reflect the estimated costs associated with electrification of loads. Distinct adjustments to the Reference Case electric price forecast are made for electric company distribution rates (which include state-jurisdictional transmission) and for generation costs, which are summed together to estimate an all-in electricity price.

1. Electric Distribution Rates

As noted above NIMO represents 61% of National Fuel's service area based on population and NIMO-specific data was used as the basis for electric distribution price changes over time. More specifically, growth in electric distribution rates are forecast based on an analysis of NIMO's 2023 Capital Investment Plan and the revenue requirements methodology as documented in NIMO's 20-E-0380 rate case order. The rate case order presents electric rates for the 2022-2024 rate years (12-months ending June 30th); the 2023 Capital Investment Plan[2] presents a detailed forecast of capital expenditures for the 2024-2028 fiscal years (12-months ending March 31st). A line-by-line forecast of revenue requirements was developed by applying certain assumptions for the 2025-2028 period. The most significant assumptions are (1) that approximately 80% of NIMO's capital forecast will be allowed into rates (mirroring the treatment in the rate case settlement), and (2) that O&M expenses will increase at 1.67% (the increase in rate years 2 and 3 of the NIMO rate case settlement). The average depreciation rate and the rate of return reflect the settlement agreement.

As described in the NIMO Capital Investment Plan, capital expenses are projected to increase substantially beginning in 2023 in order to accommodate a future transition that relies on electrification of building end-uses and electric vehicle charging that involves distribution company investments. The resulting nominal compounded annual growth rate in electric distribution price forecasted for the 2024-2028 period is 5.87%, reflecting a 0.40 percent per year increase in load and a 1.67% annual growth in O&M expenses. Adjusting to remove NIMO's assumed inflation results in a real annual growth rate of 4.13%, which is applied to the delivery component of the Reference Case electric price nominal forecast in the LTP and SCE Scenario.

The NIMO Capital Investment Plan reported the following with respect to anticipated load growth, an appropriate offset to revenue requirements in the calculation of distribution rates:

> Over the next ten (10) years, load growth is expected to increase on an average of 0.40 percent per year after weather normalization to the 90/10 forecast. The forecast incorporates anticipated effects on demand due to solar, battery energy

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[2] NIMO Capital Investment Plan, Case 20-E-0380, February 1, 2023

storage systems, electric vehicles, electric heat pumps, and energy efficiency investments. Incremental funding particularly in the latter part of the plan is driven by capacity needs of electrification (i.e., EVs and electric heat pumps).[3]

An examination of NIMO's approved capital in the rate case and in the Capital Investment Plan reveals that the capital forecast is driven by a need to invest in replacement, upgrades, and modernization of existing infrastructure in order to reliably support an electrified service area.

In response to stakeholder requests, National Fuel performed a "check" on validity of applying the NIMO estimate to National Fuel's customers, rather than using a weighted average of NIMO and NYSEG estimates, because NYSEG represents 35% of National Fuel's service area. NYSEG filed its five-year capital plan on June 30, 2023.[4] NYSEG's distribution capital forecast increases by an average of 33.2% per year over the five-year period, significantly higher than NIMO's 18.9% average increase. In addition, the average 3-year distribution rate increase in NYSEG's recently filed rate case joint proposal is 14.7%, which is also significantly higher than the distribution rate increase in NIMO's rate case settlement, which is approximately 5.4%.[5] Therefore, incorporating data from NYSEG would further increase the electric price forecast. National Fuel relied on the lower electric price forecast based on NIMO's capital plan for this LTP but will consider incorporating data from NYSEG in future LTPs.

2. Generation Supply Prices

The forecast of growth in electric generation supply prices is based on a forecast prepared by the National Renewable Energy Laboratory ("NREL"). NREL projects that by 2035 the U.S. average $/MWh generation system cost for its Accelerated Demand Electrification ("ADE") case will be 6% greater than the EIA AEO 2021 reference case.[6] NREL projects this increase to occur after four years, which is equivalent to a 1.5% compound annual growth rate. Therefore, a compound annual growth rate of 1.5% is applied to the supply portion of the nominal electric price forecast to reflect projected increases in electric generation capacity required to meet additional demand requirements resulting from electrification in the LTP and SCE Scenario.

It is likely that the Aggressive Scenario would be accompanied by higher electricity prices than either the SCE Scenario or the LTP due to additional electric capacity needs from full electrification for residential customers (as opposed to hybrid heating) and overall higher electrification levels. The electric prices used in the Aggressive Scenario assume a 20% increase in annual growth rates for both the distribution and supply components of the base electric forecast. Figure B-3 shows the nominal residential Reference Case electric prices as well as the residential electric prices used for the two scenarios and LTP.

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3 NIMO Capital Investment Plan, Case 20-E-0380, February 1, 2023, page 126.

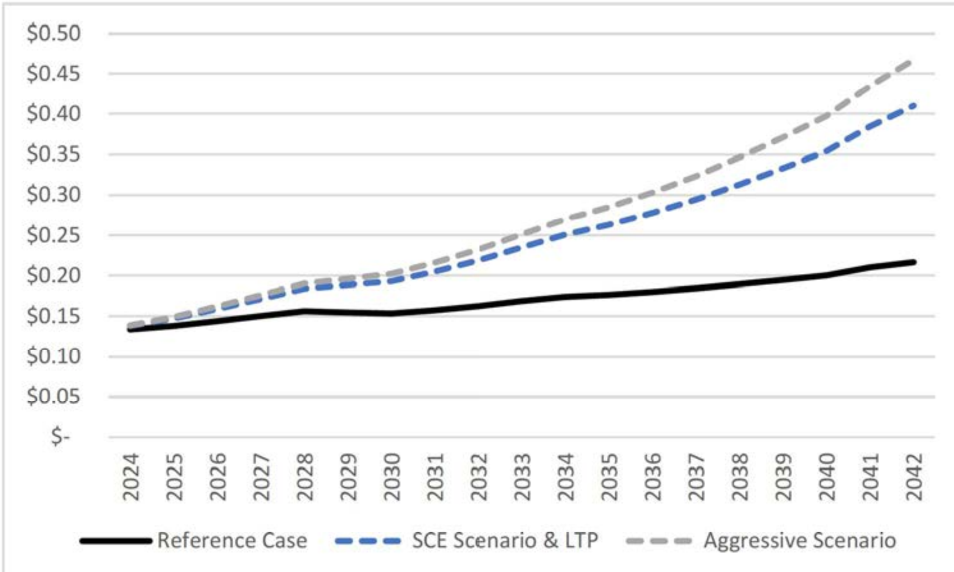
4 NYSEG and RGE Five-Year Capital Investment Plan, June 30, 2023, Case 19-E-0378.

5 Case 22-E-0317, et. al., Appendix A, page 1, line 10.

6 Denholm, Paul, Patrick Brown, Wesley Cole, et al. 2022. *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-81644. https://www.nrel.gov/docs/fy22osti/81644.pdf

Figure B-3

Annual Residential Electric Price ($/kWh)



V. $/MT CO2e Reduction

Comparison of the net present value ("NPV") $/MT CO2e metric across the scenarios as well as across the various individual decarbonization actions allows for a quantitative assessment of the trade-off between reductions in GHG emissions and cost impacts. To calculate this metric for a specific decarbonization action, the NPV of the projected annual costs and NPV of the projected CO2e emission reductions are calculated for the decarbonization action.[7] The NPV $/MT CO2e metric is then calculated by dividing the NPV of costs by the NPV of the CO2e emission reductions for the decarbonization action. To calculate this metric for a scenario, the NPVs of costs and CO2e reductions are summed across all decarbonization actions that comprise the scenario. The NPV $/MT CO2e metric is then calculated by dividing the NPV of costs by the NPV of the CO2e emission reductions for the scenario in total.

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7 All NPV calculations use National Fuel's weighted average cost of capital of 6.92% as approved by Commission in Docket C-16-G-0257.

Appendix C

National Fuel Gas Distribution Corporation

July 17, 2023

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Appendix C: Benefit Cost Analysis

I. The Societal Cost Test ("SCT")

The Commission's Gas Planning Order[1] directs LDCs to apply benefit-cost analyses ("BCA") to long-term plans, adopting the methodology established in the BCA Framework Order.[2]

The BCA Framework Order provides guidance most directly applicable to electric utilities. LDCs have yet to develop a consistent BCA framework for gas utilities, and National Fuel, specifically, has not yet developed a BCA Handbook for Non-Pipeline Alternatives. In the absence of a consistent BCA framework for gas utilities, this analysis follows guidance previously provided in the BCA Framework Order and industry best practices. Care was taken to avoid double counting of monetized benefits or costs by defining each benefit and cost, following the cost and benefit streams resulting from multiple elements of each decarbonization action, and allowing for consideration of how the interconnected components interact.

The BCA Framework Order designated the SCT as the primary BCA method. By utilizing the SCT, National Fuel assesses the impact of its LTP from a holistic perspective that recognizes customer, utility, and societal impacts. The SCT attempts to identify, evaluate, and compare the net present value of all benefits and costs. A Benefit Cost Ratio greater than 1.0 is considered "passing".

The SCT was applied to National Fuel's LTP at the portfolio level (rather than evaluating individual decarbonization actions in isolation), allowing for a comprehensive view, balancing of potential synergies and economies across the LTP and allowing the use of broader assumptions when more granular data is not readily available or quantifiable.

This Appendix contains a description of the LTP's benefit and cost streams included in the BCA and identifies the sources of values used to monetize them over the LTP's 20-year planning horizon.

II. LTP Benefit and Cost Categories

A. Definitions of Benefit Categories

The following categories of benefits are quantified and included in the SCT for the LTP:

- **Fixed and Variable Avoided Upstream Supply:** includes the commodity component associated with physical molecules of natural gas that are delivered to city-gate by pipeline and storage capacity. Avoided commodity costs are the result of displaced

[1] May 12, 2022 Order Adopting Gas System Planning Process.

[2] Case 14-M-0101, Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016).

natural gas supply by RNG and hydrogen or reduced throughput resulting from demand related decarbonization actions.

- **Avoided Distribution Capital Costs**: includes reduction in Company's revenue requirement associated with avoided mains, services and meters from full electrification of new residential and small commercial customers and thermal energy systems in new housing developments.
- **Avoided Electric Costs:** includes reduced electric costs due to lower air conditioning loads resulting from weatherization.
- **Avoided Emissions:** accounts for reduced CO2, CH4 and N20 emissions from reduced gas use.
- **Avoided Electric Generation Capital**: accounts for reduced generation installed capacity costs ("ICAP") due to lower air conditioning loads resulting from weatherization.

B. Definitions of Cost Categories

The following categories of costs are quantified and included in the SCT for the LTP:

- **Program Administration:** includes program administration costs for residential Home Energy Reports.
- **Incremental Electric Generation Capital Costs:** includes incremental installed capacity costs ("ICAP") required to incent the construction of generation capacity required to meet increase in electric demand resulting from electrification.
- **Incremental Participant Electricity Costs:** includes incremental participant electric costs for net increased electric use resulting from electrification decarbonization measures and thermal energy systems.
- **Incremental O&M Expense:** includes incremental supply cost of RNG and hydrogen.
- **Participant Costs:** includes energy efficiency and electrification net installed costs behind the meter. Installed costs are net of avoided replacement cost of retired (or new) appliance. Incentives are assumed to cover 75% of incremental installed costs, with individual customers contributing the remaining 25%.
- **Increased GHG Emissions:** accounts for CO2, CH4, and N2O emissions from increased electricity use resulting from electrification and thermal energy systems. This includes emissions that occur during combustion at fossil plants and transportation of natural gas through pipelines to location of combustion.

III. Avoided and Incremental Cost Values for Monetizing Costs and Benefits

Avoided and Incremental cost values are used to monetize some of the benefits and costs listed above. For example, the social cost of carbon is an avoided cost, which, when multiplied by the amount of CO_2 avoided by a decarbonization measure, provides a dollar value for the societal benefit of reduced CO_2 for that measure. These avoided and incremental costs and associated assumptions are listed in Tables C-1, C-2 and C-3 below.

Table C-1

BCA Global Modeling Assumptions for LTP

Input	Description	Source	Value
Analysis Period	20-years (2023-2042)	Same as LTP	n/a
Inflation Rate	Inflation rate applied if forecasted data is not available.	Blue Chip Economic Indications ("BCEI"), GDP Chained Price Index, April 11, 2022 at 5 and BCEI Long-Range Consensus US Economic Projections at, GDP Chained Price Index, March 11, 2022 at 14.	2022: 7.3% 2023: 3.3% 2024: 2.2% 2025/27: 2.1% 2028/42: 2.0%
Company-retained gas	Gas lost between send-out and point of consumption; includes lost and unaccounted for gas (LAUF) and shrinkage.	NFG's 20-Year Reference Case	1.72%
Electric loss rate	Electricity lost between wholesale and retail	NYSEG and RG&E Secondary Voltage, Energy/UFE Loss Factor in Case 08-E-0751; Niagara Mohawk Power Corporation, Electric Service Tariff, PSC No. 220 Electricity, Leaf 216, Revision 2. Initial Effective Date: February 1, 2011. Weighted average loss factor calculated for NFG service territory using 2020 Census Population data by zip code.	7.95%
Discount Rate	National Fuel's Weighted Average Cost of Capital (WAAC)	As approved by Commission in Docket C-16-G-0257.	6.92%

Table C-2

Avoided Gas Supply and Capacity Benefits for LTP

Input	Description	Source
Gas Rate	Gas rate used to monetize reduced gas use resulting from decarbonization actions.	See Appendix B
Social Cost of Carbon (SCC)	Social cost of CO_2 used to monetize gas and electric GHG emissions ($/MT)	NY DEC Social Cost of CO_2 at 3% discount rate.[3]
Social Cost of Methane and Nitrous Oxide	Social cost of CH_4 and N20 used to monetize avoid gas GHG emissions ($/MT)	NY DEC Social Cost of CO_2 at 3% discount rate.[4]

3 New York State Department of Conservation's report, "Establishing a Value of Carbon. Guidelines for use by State Agencies," May 2022. Available online at https://www.dec.ny.gov/docs/administration_pdf/vocapp22.pdf

4 Ibid.

Table C-3
Increased Electric Supply and Capacity Costs

Input	Description	Source
Electric All-In Rate	Avoided or increased electricity costs	See Appendix B. Excludes electric generation supply cost adjustment for electrification discussed in Appendix B, to avoid double counting of avoided cost of generating capacity which is monetized using ICAP payments.
Incremental cost of generating capacity	Incremental cost of capacity associated with generation	ICAP spreadsheet from DPS Staff published in 14-M-00581/14-M-0101.
Incremental cost of transmission	Incremental cost of electric transmission	Included in electric bundled full rate.
Incremental cost of distribution	Incremental cost of electric distribution	Included in electric bundled full rate.
Electric cost of carbon	Social cost of CO2 used to monetize increased electric GHG emissions ($/MT)	NY DEC Social Cost of CO2 at 3% discount rate[5] net of RGGI credit,[6] escalated by inflation forecast, multiplied by assumed electric emissions rate. Forecasted electric generation emission rates are provided in Appendix D, Table D-22. These emission rates are based on EPA's eGrid data[7] by fuel stock applied to EIA's 2022 AEO reference case forecasted generation mix.
Social Cost of Methane and Nitrous Oxide	Social cost of CH4 and N20 used to monetize avoid gas GHG emissions ($/MT)	NY DEC Social Cost of CO2 at 3% discount rate.

[5] Ibid.

[6] Most recent RGGI Auction 58 (12/7/2022) Clearing Price is $12.99 per Short Ton CO2 (Source: https://www.rggi.org/auctions/auction-results) The cost of CO2 collected through RGGI is already reflected in New York LBMPs component of forecasted fully bundled electric rates. The cost of CO2 collected via RGGI credits are subtracted from the social cost of carbon to avoid double counting.

[7] United States Environmental Protection Agency. *Emissions & Generation Resource Integrated Database (eGrid), NPCC Upstate NY subregion year 2020 data (SRL20),* January 27, 2022.

IV. BCA Results for SCE and Aggressive Scenarios

As requested by stakeholders, the BCA results for the SCE and Aggressive Scenarios are presented in Table C-4.

Figure C-4
SCE and Aggressive Scenario BCA Results

	SCE	AGG
Benefit Cost Analysis **Societal Cost Test**	**Discount Rate** 6.92% **NPV**	**Discount Rate** 6.92% **NPV**
Benefit: Avoided Electrical Costs ($)	$ (31,184,617)	$ (45,268,051)
Benefit: Avoided Gas Costs ($)	$ (1,289,623,841)	$ (3,388,731,792)
Benefit: Avoided Gas Appliances ($)	$ (2,154,160)	$ (4,300,622)
Benefit: Avoided Services and Meters Revenue Requirer	$ (25,271,513)	$ (25,271,513)
Benefit: Avoided Emissions, Societal Cost ($)	$ (986,577,645)	$ (1,693,017,737)
Benefit: Avoided ICAP for Peak kW, Summer ($)	$ (9,758,960)	$ (5,073,917)
Total Benefit ($)	$ (2,344,570,735)	$ (5,161,663,633)
Cost: Incremental Electricity Cost ($)	$ 1,053,219,414	$ 3,273,478,326
Cost: HER Program ($)	$ 9,109,527	$ 18,219,053
Cost: Weatherization Cost ($)	$ 1,046,375,505	$ 1,408,548,734
Cost: Weatherization Cost ($) - Incentive	$ 784,781,629	$ 1,056,411,551
Cost: Weatherization Cost ($) - Non-Incentive	$ 261,593,876	$ 352,137,184
Cost: Net Installed Cost ($)	$ 758,807,376	$ 2,643,723,920
Cost: Net Installed Cost ($) - Incentive	$ 569,105,532	$ 1,982,792,940
Cost: Net Installed Cost ($) - Non-Incentive	$ 189,701,844	$ 660,930,980
Cost: Hydrogen Cost ($)	$ 326,422,531	$ 427,504,283
Cost: RNG Production Cost ($)	$ 1,388,644,320	$ 2,008,650,036
Cost: Implementation Costs ($)	$ 3,529,359,258	$ 6,506,646,026
Cost: Increased Emissions, Societal Cost ($)	$ 29,258,520	$ 81,922,502
Cost: Incremental ICAP for Peak kW, Winter ($)	$ 34,202,366	$ 200,940,169
Cost: Incremental ICAP for Peak kW, Summer ($)	$ 8,242,647	$ 8,641,013
Cost: Incremental ICAP($)	$ 42,445,013	$ 209,581,182
Total Cost($)	**$ 4,654,282,206**	**$ 10,071,628,036**
Benefit/Cost Ratio	0.50	0.51