Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Direct Testimony

of the

Future of Heat Panel

Dated: July 31, 2020

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I. Introduction and Qualifications

Q. Please introduce the members of the Future of Heat Panel.

A. The Panel consists of Donald Chahbazpour and Owen Brady-Traczyk.

Q. Mr. Chahbazpour, please state your name and business address.

A. My name is Donald Chahbazpour. My business address is One MetroTech Center, Brooklyn, New York 11201.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid USA Service Company, Inc. ("National Grid Service Company"), a subsidiary of National Grid USA ("National Grid"), and currently hold the position of Director of Gas Utility of the Future. My responsibilities include leading efforts to reduce methane and carbon emissions through policy, strategy, and technology for National Grid's operating companies, including Niagara Mohawk Power Corporation d/b/a National Grid ("Niagara Mohawk" or the "Company"). I am also responsible for engaging stakeholders to raise awareness regarding the potential of renewable natural gas ("RNG").

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Science in Mechanical Engineering from New Jersey Institute of Technology in 1998 and a Master of Public Administration from Columbia University's School of International and Public Affairs in 2000. I joined National Grid in 2004 and have held various positions of increasing responsibility in strategic planning, energy procurement, mergers and acquisitions, gas operations, and regulatory and customer strategy.

Q. Have you previously testified before the New York State Public Service Commission ("Commission")?

A. Yes. I testified on behalf of The Brooklyn Union Gas Company d/b/a National Grid NY ("KEDNY") and KeySpan Gas East Corporation d/b/a National Grid ("KEDLI") in Cases 19-G-0309 and 19-G-0310 (the "2019 KEDNY and KEDLI Rate Cases").

Q. Mr. Brady-Traczyk, please state your name and business address.

A. My name is Owen Brady-Traczyk. My business address is One MetroTech Center, Brooklyn, New York 11201.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid Service Company and currently hold the position of Manager, Future of Heat in the Customer organization. My responsibilities include leading the team responsible for developing the business models, technical design, and business strategy for new product offerings that will meet customers' changing energy needs and will allow the gas business to support and accelerate the transition to a decarbonized energy future.

Q. Please describe your education background and business experience.

A. I received a Bachelor of Science in Mechanical Engineering from the University of Vermont in 2010. Thereafter, I worked for Vermont Gas Systems from 2011 until 2017, where I held positions of increasing responsibility in areas of strategic planning, policy development, and customer-account management. In 2017, I was hired by National Grid as a member of the New Energy Solutions group, where I was responsible for managing demonstration projects and overseeing investment in research and development. In August 2018, I was promoted to Product Management Specialist in the Emerging Product group and in June 2019 was promoted to my current role. I received an MBA from Columbia University and an MBA from the London Business School in February 2020.

Q. Have you previously testified before the Commission?

A. Yes. I testified in the 2019 KEDNY and KEDLI Rate Cases.

II. <u>Purpose of Testimony</u>

Q. What is the purpose of the Panel's testimony?

A. The purpose of the Panel's testimony is to set forth the innovative approaches developed by the Company for its natural gas business to support achievement of the State's ambitious carbon emission reduction goals while meeting the Company's obligations to provide safe, reliable, and affordable gas service to its customers in New York. In addition to its legal obligations, the Company is committed to addressing climate change and advancing clean energy solutions for its customers, including its approximately 600,000 natural gas customers. Today, demand for natural gas remains strong, as customers seek a cost-effective, reliable heating source that generates fewer emissions than alternatives such as heavy oil. In this way, natural gas continues to play a critical role in driving economic opportunity in New York. Yet, with the challenges presented by climate change, the State, the Commission, and the Company recognize that more is needed to meaningfully change the current climate trajectory. In July 2019, Governor Cuomo signed into law the Climate Leadership and Community Protection Act ("CLCPA") that set an economy-wide goal of net-zero carbon emissions by 2050, as well as an aggressive new renewable energy goal that 100 percent of electricity consumed in New York be carbon neutral by 2040. For its part, National Grid launched its "Northeast 80x50 Pathway" (the "80x50 Pathway") complementing New York State's efforts. After the enactment of the CLCPA, the Company explored more ways by which it can support the 2050 net-zero emission goal and 85 percent emission reduction target recognizing that its gas system will play an integral role in meeting these ambitious targets and delivering the low-carbon economy of the future.

As more fully discussed by the Panel, the Company is sponsoring a suite of proposals directed at (i) reducing emissions resulting from customer energy use, (ii) promoting gas demand response and other non-pipes alternatives ("NPAs"); (iii) encouraging the development of sustainable heating options; and (iv) developing new technologies to advance the low carbon heating solutions needed for the future.

These proposals will supplement the Company's programs designed to reduce gas emissions from the gas distribution system and lower gas usage as outlined in the Gas Infrastructure and Operations Panel ("GIOP Panel") and the Customer Energy Panel ("CEP Panel"), respectively, as well its economic development programs discussed in the Shared Services Panel.

Q. Does the Panel sponsor any exhibits as part of its testimony?

A. Yes. The Panel sponsors the following exhibits that were prepared and compiled under our direction and supervision:

(i) Exhibit __ (FOH-1): Projected Labor and Non-Labor Operations and Maintenance Costs and Full Time Equivalent ("FTE") Employees and Capital and Regulatory Asset costs;

(ii) Exhibit __ (FOH-2) Geothermal Demonstration Project Final Report

(iii) Exhibit __ (FOH-3) Description of RNG Interconnection Proposals;

(iv) Exhibit __ (FOH-4) Navigant Business Case; and

(v) Exhibit__ (FOH-5) BCA for Geothermal proposal.

Q. Please describe the Company's vision for the future of the heating sector.

A. National Grid envisions a future where customers have multiple options for accessing low carbon, affordable, reliable and safe heating. The Company recognizes that significant action needs to be taken over the next three decades to achieve the climate targets outlined in the CLCPA, and that particular attention needs to be paid to the heating sector. Emissions from on-site fuel combustion, which provide space heating, process heating, and other applications, contributes approximately 30 percent of New York State's greenhouse gas ("GHG") emissions.[1] The residential sector contributes 50 percent of the emissions from on-site fuel combustion.[2] This means that achieving net zero in New York State by 2050 will require the heating sector to deliver meaningful emission reductions. At the same time, solutions for addressing heating sector emissions must deliver heating that customers can afford and rely upon on the coldest day of the year.

To support this transition, the Company created a team focused on delivering clean energy options to customers, which it terms the "Future of Heat." This team is dedicated to scaling near term solutions that can achieve meaningful emission reductions, such as RNG and geothermal projects, and identifying and developing longer-term solutions needed to fully decarbonize the heating sector. The Company has a four-pronged strategy that establishes the goals, tools and incentives for driving meaningful evolution of the gas industry:

1. Reducing Methane Emissions from the Gas Distribution System 60 percent by 2035: Building on its 80x50 Pathway, National Grid proposes an aggressive goal of reducing total network emissions 60 percent by 2035; continuing its leadership role in national initiatives aimed at reducing emissions; identifying, prioritizing, and repairing

[1] https://www.nyserda.ny.gov/-/media/Files/EDPPP/Energy-Prices/Energy-Statistics/greenhouse-gas-inventory.pdf, page S-13
[2] *Id.*

large-system leaks; and implementing work procedures to further reduce emissions going forward. The Company's strategies to reducing emissions from the gas distribution system are outlined in the GIOP Panel testimony.

2. <u>Empowering and Enabling Customers to Sustainably Meet Their Heating Needs</u>: The Company developed a suite of programs, products, and demonstration projects described by this Panel aimed at empowering and enabling customers to take control of their energy usage, by providing flexibility in choosing the manner by which their energy needs can be met while also achieving their carbon reduction goals.
3. <u>Integrating Renewables into the Gas Network</u>: The Company developed several proposals for integrating RNG into its gas network as described by this Panel. The integration of RNG, including RNG produced from biomass and from renewable electricity, will reduce the carbon footprint of the Company's gas networks and provide sources of local supply.
4. <u>Developing Performance-Based Incentives and Revenue Sharing</u>: To align the Company's incentives with a sustainable vision for the future of the heating sector and overarching energy policy goals, the Company proposes several Earnings Adjustment Mechanisms ("EAMs"), and two Platform Service Revenue ("PSR") opportunities as set forth in the testimony of the CEP Panel.

Q. Please outline why the Company believes it is appropriate for a natural gas utility to be involved in innovating Future of Heat activities.

A. The Company supports New York's climate change policies and is looking for innovative ways to meet the aggressive targets that have been set with a special focus on reducing emissions from its natural gas system such that the CLCPA's 2050 net zero industry-wide GHG emissions target can be met. Achieving these targets will require significant changes in the way energy is produced, distributed, and consumed. The Company sees its role in this transition as two-fold. First, by developing solutions to utilize the existing gas distribution infrastructure to enable a low carbon future. This includes integrating low carbon energy into the gas distribution network. The Company believes that utilizing existing infrastructure can help achieve this critical energy transition at a lower cost than other pathways by minimizing the amount of infrastructure investment required. Second, the Company aims to support the development and market adoption of the solutions needed to achieve decarbonization of the gas network. The Company believes that it is appropriate to support necessary technologies, when those solutions are not expected to reach maturity or achieve the required scale without intervention.

Q. Please describe the anticipated benefits of the Company's strategy for its gas network.

A. The Company's multi-faceted approach empowers customers to make energy choices that further clean energy goals, while also positioning the Company in the central role of supporting its customers' energy transition through development and deployment of innovative Future of Heat solutions. Collectively, the solutions presented here will influence a positive change in how customers meet their energy requirements and have a beneficial impact on the environment due to reduced GHG emissions.

Q. How has the Company presented its proposed FOH capital investments and operating and maintenance ("O&M") expenses in the case?

A. The Rate Year is the twelve months ending June 30, 2022. Data Year 1 is the twelve months ending June 30, 2023 and Data Year 2 is the twelve months ending June 30, 2024. Data Year 1 and Data Year 2 are collectively referred to as the "Data Years." As the Revenue Requirements Panel explains in its direct testimony, the Company operates on a fiscal year ("FY") that runs from April 1 through March 31, and typically develops its capital and expense budgets on a FY basis. Because of the three-month delay in filing this rate case related to the COVID-19 pandemic, the proposed Rate Year and Data Years do not directly align with the Company's FY. For this reason, the FOH capital investments and program costs described in our testimony are presented on a FY basis.

Q. What is total investment the Company is proposing for its Future of Heat strategy?

A. The capital investment proposed for the Company's Future of Heat strategy is $18.07 million over the fiscal years FY22 – FY25, as set forth in Exhibit__ (FOH-1) Schedule 2. An additional $2.89 million for FY21 – FY25 is proposed for RNG

Interconnection, as presented in the GIOP Panel's Exhibit___(GIOP-1) and Exhibit __ (FOH-1), Schedule 2. The Company also is proposing to invest $12.9M for FY22 – FY25 in geothermal assets that ultimately will be funded by the customers utilizing the geothermal assets. Therefore, the geothermal program costs are not reflected in the Company's capital forecast that will be included in gas plant in service, but instead in the Company's regulatory asset forecast. Altogether, this Panel is proposing investments totaling $33.8 million over FY21 – FY25 in incremental initiatives to reduce carbon emissions on the gas network and empower customers in support of a cleaner, more sustainable energy future. These amounts were provided to the Revenue Requirements Panel to develop the revenue requirements for the Company in the Rate Year and Data Years. The total projected non-labor O&M expense costs and labor costs for FTE employees for the initiatives are set forth in Exhibit__(RRP-3), Schedule 27 to the Revenue Requirement Panel as well as in Exhibit ___(FOH-1), Schedule 1.

Q. Does the Company require additional FTEs to support the proposed Future of Heat initiatives?

A. Yes. The Company is proposing eight incremental FTEs to support Future of Heat initiatives during the Rate Year with an additional incremental FTE requested for the Data Years to support the Carbon Capture and Utilization Storage ("CCUS") project, for a total of nine additional FTEs. The need for these FTEs is discussed below.

III. New Customer Products and Services

Q. What role do customers play in the Company's efforts to reduce carbon emissions?

A. Customers are at the heart of the Company's commitment to adapting the gas system to meet new demands with a variety of cleaner options while continuing to deliver safe, affordable, and reliable service. In practice, this means seamlessly enhancing the customer experience by: (i) advancing new products and services that allow customers to actively participate in achieving clean energy goals; (ii) offering options for demand reduction that provide an incentive for customers to use less natural gas during peak event; and (iii) empowering customers to take control of their energy usage through robust energy efficiency offerings.

Q. What are the Company's proposals for new customer products and services?

A. The Company is committed to empowering and enabling customers to take more control over their energy usage and to proactively embrace products and services that align with the State's clean energy goals and reduce consumption and environmental impact. To that end, the Company is proposing the following products and services as a means of providing customers with new options they can use to optimize energy usage and reduce their environmental impact:

(1) Expanded Gas Demand Response ("DR");

(2) Fuel-Switching Calculator;

(3) CCUS; and

(4) Geothermal Network.

A. Expanded Gas Demand Response

Q. Please describe the Company's propose gas demand response program.

A. The Company is proposing to develop a portfolio of gas DR programs to complement other demand-side management programs in the Company's territory. Specifically, the Company is seeking to mirror the programs that were deployed by National Grid's downstate New York affiliates during the winter of 2019/2020. This includes three programs:

- A behavioral demand response program targeting residential and small and medium business ("SMB") customers;
- A bring-your-own-thermostat ("BYOT") program targeting residential and SMB customers; and
- A commercial and industrial ("C&I") demand response program that produces verifiable peak-day reductions

These programs have proven effective at engaging a wide-variety of customers and at producing meaningful reductions in peak-hour and peak-day demand.

Q. What are the costs of the Company's proposed gas DR program?

A. Two incremental FTEs are needed to deliver the Company's proposed demand response program. The first will be a program manager to manage the development of the program and integration with existing operations as the impact of demand response increases. The second will be an analyst that will support the program manager, providing support with data management for the program, including evaluation of customer performance over the course of the program. Costs of the program also will include incremental non-labor O&M expense of $1.314 million in the Rate Year and Data Year 1 and $2.354 in Data Year 2 for incentives to be paid to participating customers, and capital investments to install metering at participating customer sites. The Company anticipates that gas DR programs will be needed more in the future and will grow over time. The costs for the proposed gas DR program are shown in Exhibit___ (FOH-1), Schedules 1 and 2 and represented in the table below.

Table 1: Expanded DR Program Costs ($000)

	FY22	**FY23**	**FY24**	**FY25**
CapEx	$106.0	$ 10.6	$ 118.6	$ 127.4
	Rate Year	Data Year 1	Data Year 2	
Non-labor Opex	$1,314.4	$1,314.4	$2,353.8	
Labor Opex	$325.6	$331.8	$337.8	

Q. Please describe the benefits associated with Gas Demand Response.

A. Gas DR is a potentially valuable tool in the Company's NPA toolbox to reduce the aggregate load during a DR event. DR supports efficient utilization of the gas system and rewards customers for their flexibility. KEDNY and KEDLI's DR programs already demonstrated the willingness of customers to reduce their gas usage in response to financial incentives, resulting in meaningful decreases in system pressure during peak periods.

Q. What is the Company's experience with DR?

A. The Company has offered DR for its electric customers for many years. This experience and resulting performance data have allowed the Company to incorporate electric demand response programs into its system planning. The Company, and the gas industry at large, does not have as much experience with gas DR. KEDNY and KEDLI were the first gas utilities in the country to pilot an incentivized DR program for firm C&I customers. This pilot was approved in KEDNY and KEDLI's 2016 rate cases (Cases 16-G-0058 and16-G-0059) ("2016 KEDNY and KEDLI Rate Cases") and has provided many of the best practices used in gas DR programs to this day. In 2019, KEDNY and KEDLI successfully expanded its DR programs as a key component of the package of solutions deployed to address peak customer demand in downstate New York, which enabled those companies to lift restrictions on new customer connections.

In its last rate proceeding in 2017 (Case 17-G-0239), the Company proposed a gas DR pilot that was very similar to the one approved in the 2016 KEDNY/KEDLI rate case. This pilot is currently underway and has met all of its operational targets. It is structured to achieve peak-hour reductions from C&I customers and does not require achieving peak-day reductions.

Q. How does design of gas DR programs affect participation rates and quantification of benefits?

A. Gas DR, like all DR programs, provides an incentive for customers to use less of a specific resource (in this case natural gas) during a specified period of time termed the DR event. This reduces the aggregate load during the DR event. There are two ways that participants can reduce their consumption during a DR event. First, they can use an alternative fuel (*i.e*., keep the same area under the load curve but satisfy the need with another source). Second, they can use less total energy (*i.e*.. reduce the area under the load curve). If customers participate using the second option, the customer may have unmet needs, such as their space being colder than desired or a production run that needs to be completed. This can be addressed either by using more energy before the start of the event (*e.g*., pre-heating the facility, completing a production run earlier than planned) or by using additional energy after the event, a usage pattern known as a "snapback" (*e.g.*, heating the facility at the conclusion of the DR event, completing a production run later than planned). In either case, it is likely that the total amount of energy consumed by the facility over a longer time horizon (*e.g*., 24 hours) will not differ significantly from the amount that would have been expected in the absence of a gas DR event. Furthermore, the longer the DR event, the harder it is for customers to reduce the amount of energy that they need. If, on the other hand, a customer participates by using an alternative source of energy (*e.g*., switching to a backup fuel), they have fewer unmet needs and, therefore, are less impacted by long-term and/or frequent DR events and are less likely to require additional consumption pre or post event. It is important to consider the structure of the program to achieve the desired outcomes, measured in terms of reliability of reduction, satisfaction of participants, cost of the program, and overall fuel use.

Q. Will the C&I program have a fixed incentive rate?

A. Yes. Similar to electric DR programs, the Company envisions having a standardized incentive calculation. This rate may be adjusted annually, but it will be published for all customers to review.

Q. Please explain the purpose for the metering to be installed at participating customers' sites.

A. The Company will be installing metering at participating customers' sites to obtain specific usage data needed to evaluate their participation in the program that is not provided by traditional metering. The Company anticipates that the costs for installing meters in the second year of the program (Data Year 1) will be lower than other program years because it expects 90 percent of the participants from Year 1 (Rate Year) will wish to continue their participation in the program, therefore requiring CapEx meter installation costs for only 10 percent to account for new participating customers.

B. Fuel-Switching Calculator

Q. Please describe the Company's proposed fuel-switching calculator.

A. The Company proposes to develop a web-based calculator similar to one developed by Central Hudson Gas and Electric Company. Using current energy costs, incentives, desired heating technology (*e.g.*, natural gas, ground or air sourced heat pumps), and existing equipment, the calculator can provide customers an estimated annual cost, payback period, carbon profile, and net cost for alternative energy options as compared to their current system. The calculator will highlight low-carbon fuel offerings, such as the Company's proposed geothermal services, to allow users further clean-energy comparisons.

Q. What is the cost of the fuel-switching calculator?

A. The cost of this proposal will be shared with KEDNY and KEDLI (who proposed a similar project in the 2019 KEDNY and KEDLI Rate Cases) as the same calculator framework will be used in all three territories. If KEDNY and KEDLI's proposal is not approved, the full cost for development of the calculator would be borne by the Company. As shown in Exhibit ___ (FOH-1), Schedule 1, the fuel-switching calculator proposal includes incremental non-labor O&M expense for the development and operation of the calculator based on the specific market conditions for the Company's service territory of $0.194 million in the Rate Year, and $0.100 million in each of the Data Years.

Q. What are the benefits of the proposed fuel-switching calculator?

A. The fuel-switching calculator will empower customers to make more informed energy choices, providing them with information to assess the financial and environmental impacts of alternative energy options. The Company believes that through such energy insights, customers will discover how they can use low-carbon solutions (*e.g.*, RNG, ground or air-sourced heat pumps) at a reasonable cost. This, in turn, may animate the market for low-carbon products and services, leading to increased adoption and lower emissions in support of the State's clean energy goals and the REV objectives.

Q. Is the Company requesting any additional FTEs to support the proposed fuel switching calculator program?

A. Yes. The Company is requesting one additional FTE to support the proposed fuel switching program. This additional FTE will be responsible for ensuring that the calculator program meets the needs of customers and internal partners, that the data in it is up to date and reflective of current market conditions (e.g. incentive rates), and for reporting on the usage statistics for the calculator over the course of the rate case. An incremental FTE is needed because the Fuel-Switching Calculator is a new offering for the Company and its usefulness will be based on the accuracy of its inputs. Without dedicated resources, the calculator may fail to achieve its intended outcome of empowering customers to make informed decisions about their energy use.

C. Customer Carbon Capture Utilization and Storage Demonstration Project

Q. Please describe the Company's proposal for carbon capture.

A. The Company proposes to pilot CCUS at customer sites, which will demonstrate a technological means for reducing GHG emissions from gas heating systems, a solution that has the potential to reduce carbon emissions associated with natural gas service.

Q. Please describe how the CCUS product works.

A. The CCUS product is a unit that is installed at the customer's premises that diverts flue CO_2 gas emissions generated by the gas-heating system, mixes it with potassium hydroxide in a sealed reactor vessel producing potassium carbonate (pearl ash), a fine white powder. The pearl ash can be used to produce other useful materials, such as soaps. The CCUS reaction also generates heat, which can supplement the building's heating system, and could be especially valuable in situations where low-efficiency equipment has not reached the end of its useful life. A unique aspect of this product is the dispersed CCUS concept, meaning that it is sized and designed to be installed at a residential or light commercial customer site, rather than at a centralized location. Capturing emissions at residences provides customers with another option to reduce emissions from their gas use, without the need to replace their appliances or supporting equipment.

The Company is proposing a demonstration project that will include the installation and evaluation of the dispersed CCUS concept, using ten Clean O2 units connected to high-efficiency heating systems in residential or light-commercial buildings. The Company will conduct an evaluation of the demonstration project that determines the efficiency of the Clean O2 units, customer satisfaction with performance, the feasibility of selling the pearl ash by-product, and the break-even carbon price for the Company's service territory.

Q. Does the Company believe that CCUS is a potentially significant component of the strategy to address climate change?

A. Yes. Addressing climate change will require a fundamental transformation of the energy sector, and through the CLCPA, New York is taking the lead on making that transformation a reality. The transition to a low carbon future is already underway, mitigation efforts include scaling and integrating new and existing technologies such as electrification, geothermal, RNG, and hydrogen. However, all of these efforts may not be sufficient to offset ongoing emissions. For natural gas utilities to support the CLCPA's 2050 net zero emission goal, the Company believes that some form of CCUS will be needed. This issue was first raised in the Intergovernmental Panel on Climate Change ("IPCC") Fifth Assessment Report in 2014. In 2018, IPCC released a Special Report (Global Warming 1.5 C), where different mitigation strategies were examined through a pathway modeling effort.[3] The analysis concluded that "all pathways use carbon dioxide removal."[4] The amount of carbon dioxide removal (*i.e.*, CCUS in some form) varied across different pathways, but the IPCC's conclusion was clear: it is likely carbon capture technologies will be needed to meaningfully address climate change. Offering CCUS will benefit customers by providing them with an option to reduce carbon emissions while maintaining their existing natural gas service or converting to natural gas service from delivered fuels.

Q. What additional carbon emission reductions can be achieved if a customer combines CCUS while simultaneously converting from oil to gas heat?

A. Surveys have indicated that oil-to-gas conversions typically are driven by life-cycle cost, convenience, as well as benefits gained in carbon emission reductions. These oil-to-gas conversions result in a greater than 25 percent reduction in carbon emissions, depending on the type and age of the heating system that is replaced. Annually, the Company averages the conversion of approximately 6,000 homes, primarily from heating oil to gas service. If a customer converts from oil to gas and also installs a CCUS product, the oil-to-gas conversion could have the effect of

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[3] "Global warming of 1.5º C An IPCC Special Report on the impacts of global warming of 1.5º C above pre-industrial levels and related global greenhouse gas emission pathways in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty" https://www.ipcc.ch/site/assets/uploads/sites/2/2019/06/SR15_Full_Report_High_Res.pdf

[4] *Id.* at 14.

reducing carbon emissions from that customer's heating system by 60 percent or more depending on the condition of the heating equipment replaced.

Q. Why is it appropriate for this demonstration project to be funded in rates?

A. The Company believes that a small-scale demonstration project can provide significant insight into implementation and deployment of innovative technologies that meaningfully reduce carbon emissions, potentially reducing the cost or barriers to adoption. Given the novel nature of this product, despite the potential for heat recovery and the theoretical marketability of the by-products, the economics of the unit are still challenging. The Company is seeking to understand what factors can be influenced to improve the BCA for the unit to increase customer adoption. For example, if a price on carbon were to be instituted, the BCA for this type of technology would greatly improve.

Q. What benefits are presented by a gas utility's investment in CCUS?

A. In the near term, until such time as options such as RNG and hydrogen are developed to scale, there will be net positive emissions due to the combustion of gas. The Company is committed to creating options for customers to reduce these emissions and believes that CCUS could be a viable option. As noted above, CCUS is viewed as being a critical component of most future scenarios that achieve needed emissions reductions. What is unclear is how that technology can be best deployed to achieve maximum reduction of emissions while minimizing disruption for customers in a manner that is not cost-prohibitive. Utilities, which have insight into the energy usage of entire communities, are well positioned to evaluate whether in-facility CCUS, like the technology proposed in this program, or direct air capture (DAC), a type of CCUS where CO_2 is removed from outdoor air, or potentially a combination of different technologies, will be most effective.

Q. What is timeline for the proposed CCUS demonstration project?

A. The Company proposes a three-year demonstration project with site selection occurring during the Rate Year and installation occurring during Data Year 1 with subsequent years' costs including operation, monitoring, analysis and evaluation of the concept's potential.

Q. What are the costs of the proposed CCUS demonstration?

A. The total procurement and installation cost of all units is not expected to exceed $0.330 million, which will be incurred in Data Year 1. Annual operational costs, including chemical replacement will be limited to $0.100 million annually starting in Data Year 2 as shown in Exhibit __ (FOH-1) Schedule 1.

Q. Is the Company requesting any additional FTEs to support the proposed CCUS demonstration project?

A. Yes. The Company is requesting one additional FTE to support the proposed CCUS project starting in Data Year 1. This additional FTE will be responsible for outreach and site selection, managing the installation of the systems, ongoing data collection and analysis, and all required reporting. They are needed because this is a pilot exploring a new topic and additional value can be extracted from these pilots by having dedicated resources that can notice opportunities and adjust course as needed.

D. Geothermal Network Proposals

1. Background

Q. Please describe the geothermal system that is the focus of the Company's proposals for heating and cooling?

A. Geothermal heating and cooling systems, referred to as ground-source heat pump (GSHP) systems, utilize the ground's stable subsurface temperature to exchange heat to provide space conditioning (heating and cooling) or other thermal processes (*e.g.*, water heating). In its simplest form, (*i.e.*, for residential uses), heat stored in the earth or in groundwater is transferred into a building during the winter to heat the space, and heat is transferred out of the building and back into the ground during the summer to cool the space. Similar to heat exchangers found in air-conditioning systems and furnaces, this energy exchange is achieved using a series of pipes that circulate a fluid medium. In geothermal systems, the pipes are installed in the ground. There are a variety of possible configurations for geothermal ground loops, including closed-loop or open-loop, and vertical or horizontal. The Company is primarily focusing on closed, vertical loop systems due to both their performance and the relatively small surface footprint required for their installation. Ground loops may be constructed to serve a single building or multiple buildings (*e.g.*, a shared loop or network). In shared loops, connected buildings may be able to exchange heat; for example, if one or more buildings generates excess heat (*e.g.*, waste heat from chillers). This load diversity can result in lower overall thermal capacity required and a smaller required geothermal loop. Geothermal heating and cooling is sometimes referred to as "low temperature" geothermal to distinguish from "high temperature" geothermal systems which use naturally-elevated subsurface temperatures to create steam to drive a turbine in an electric generator.

Q. Why is the Company making these proposals in the current rate case when the Commission's January 16, 2020 "Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios through 2025" in Case 18-M-0084 ("NENY Order") provided for funding of geothermal heat pump programs to be paid by electric customers?

A. The Company intends for this proposal to complement the NYS Clean Heat program established under the NENY Order. The NYS Clean Heat incentives can offset the costs associated with the above ground heat pump equipment while the Company's Geothermal Network program would finance the high-cost underground loop. As a frame of reference, the geothermal shared ground loop is analogous to the underground infrastructure needed for gas service to a customer, and the incentives offered through NENY are analogous to energy efficiency incentives available for high efficiency equipment installed by the customer. As set forth below, these costs would be fully paid back by geothermal customers, and not gas or electric customers, and will test the efficiencies that could be achieved by shared loop systems. The Company believes that both programs will be needed to fully achieve the ambitious energy reduction and heat pump adoption goals of the NENY order.

Q. How do geothermal heat pump systems differ from air-source heat pumps?

A. In an air-source heat pump ("ASHP) system, thermal energy is exchanged with the outside air as compared with a geothermal or ground-source system, that exchanges thermal energy with the ground. According to an analysis by the New York State Energy Research and Development Authority ("NYSERDA"), a ground source heat pump is 38 percent more efficient in heating mode than an ASHP.[5] Efficiency in heating is especially important in northern states like New York where heating is the dominant energy need. Ground source heating is more efficient because the ground remains at a relatively stable temperature (approximately 50-60F depending on local conditions) throughout the course of the year, compared to outdoor air which could range between 0-100 degrees Fahrenheit. Ground-source systems have more heat available for use during the winter and are able to reject heat more efficiently in the summer than ASHPs. This characteristic allows geothermal systems to more effectively meet customers' year-round energy needs without customers having to rely on a backup heating or cooling system, and results in

[5] See Table 6-1 on page 23 in NYSERDA 18-44 report https://www.nyserda.ny.gov/-/media/Files/Publications/PPSER/NYSERDA/18-44-HeatPump.pdf

geothermal heat pump systems having higher overall system efficiency, reducing energy consumption and associated emissions.

Q. What is the current state of the market for geothermal in New York?

A. As explained below, the most-costly portion of the geothermal system that has inhibited growth in the geothermal market is the ground loop. Geothermal systems are not a new technology and have been installed in New York for decades, in both urban and rural environments. Despite the benefits that they offer in terms of increased efficiency and lower associated GHG emissions, the adoption of the technology has not notably increased over that time, primarily due to the high upfront cost of the system. In addition, due to high upfront costs, the benefits of geothermal have been largely inaccessible to customers with limited incomes. Geothermal vendors have been exploring how to reduce the cost of adoption for consumers through standardization, coordination, and financial innovation. However, the rate of converting buildings to geothermal systems from delivered fuels throughout New York state is currently is low (less than 1,000 per year), which is significantly fewer than will be required to advance the efficiency, heat pump adoption, and carbon reduction goals outlined in the Commission's NENY Order.

Q. What factors are limiting the adoption of geothermal in New York?

A. The factors that have been cited as limiting the adoption of geothermal and challenges to market growth in New York include (1) high upfront costs, (2) long payback periods, (3) poor public awareness, (4) lack of access to financing solutions, and (5) supply chain barriers.[6] Due to the ground loop components and drilling requirements, the installed up-front cost of geothermal tends to be much higher than other heating alternatives. When combined with low gas or oil prices, geothermal has historically delivered inadequate returns on investment for facilities looking to convert, even though it delivers much higher efficiency. Financing mechanisms that consider the long-term value of geothermal ground loop systems (*e.g.*, 60 years or more) for the ground loop, have yet to be developed by the market despite the length of time that geothermal systems have been available.

Q. How can the Company help overcome market barriers for the adoption of geothermal systems in New York?

A. First, as an entity with access to low-cost capital and the ability to recover costs over long periods of time, the Company is well-positioned to invest in long-lived thermal infrastructure. By amortizing the costs of geothermal loops over their useful lives and charging participating customers for access to the loop over time, the Company can make access to this technology more affordable for customers. The Company can also increase equity of access to geothermal by not requiring participating customers to use their personal credit to finance the cost of underground infrastructure, opening up the benefits of geothermal to low and moderate income (LMI) customers. Second, by virtue of its presence and reputation in its service territory, the Company also can effectively advance public awareness

[6] https://www.nyserda.ny.gov/-/media/Files/Publications/PPSER/NYSERDA/RHC-Framework.pdf

of geothermal systems, increase confidence in the technology, and reach a broad set of prospective customers. Finally, the Company can help address supply chain market barriers by creating business opportunities for a range of service providers (drillers, loop installers, heat pump installers, system integrators, etc.) through its program, and by increasing the profile of geothermal technology in a way that benefits the entire industry in the region.

Q. In addition to the reasons set forth above, why is it appropriate for a gas utility to invest in geothermal?

A. The Company is seeking solutions to limit the amount of incremental gas delivery infrastructure required to meet customers' need for heat and also believes that geothermal provides an effective alternative service for customers looking to convert from delivered fuels to natural gas for their heating needs. Geothermal is a lower-emitting alternative that can be offered to those customers. A gas utility also is well-positioned to support construction and oversee long-term operation of the geothermal ground loop infrastructure because gas engineers and construction personnel are already experienced in the design and installation of underground plastic pipe systems.

2. Geothermal Pilot Program Proposals

Q. What is the Company proposing in this rate case in relation to geothermal?

A. The Company is proposing to develop and implement a geothermal shared loop service program enrolling up to 2,600 tons (equivalent to approximately 650 4-ton, single-family home systems) in its gas service territory between 2021 -2025. Under this pilot program, the Company will target customers for installation of geothermal heating and cooling, in partnership with competitive suppliers of geothermal heat pumps, with the Company owning the shared loop infrastructure and supplying thermal energy to connected customers under a long-term contract rate. There are four main elements to this program. First, the Company will solicit a range of customer types, including existing delivered fuels customers who are far away from the Company's gas mains and new construction customers who would otherwise install gas heat supplied by the Company's network. Second, the Company will evaluate the potential for geothermal conversion for existing gas heat customers who are served by a segment of leak-prone pipe, as a way to avoid replacement of the leak-prone pipe and instead remove that segment from service. Third, the Company seeks to account for its investment on a deferred basis to be amortized over fifty years, the estimated life of the shared loop equipment. Finally, the program will include a long-term contract rate through which participating geothermal customers will reimburse the Company for the costs of installation and maintenance of the loop as reflected in Exhibit ___(G-RDP-2). The Company aims to charge fees for this service that will fully recover the investment and avoid any impact to gas rates due to investments in geothermal loop assets.

Q. What approvals is the Company seeking from the Commission for the geothermal shared loop pilot program?

A. The Company is seeking approval for the following:

(1) Regulatory asset treatment for the installation costs of the geothermal assets, amortized over fifty years, the estimated life of the shared loop equipment. The Company is requesting that the geothermal costs be treated as regulatory assets because the Uniform System of Accounts prescribed for Public Utilities under Title 18 of the Code of Federal Regulations does not have capital accounts to which geothermal infrastructure investments can be charged to allow for amortization of those costs over the estimated life of the shared geothermal ground loop. Because the shared geothermal ground loop represents investment in infrastructure that potentially offsets gas infrastructure, it is more appropriate to defer and amortize these costs over the shared loop's estimated life, similar to other capital expenditures, rather than expense the entire costs in the year when the costs are incurred. In addition, it is appropriate to treat these costs as regulatory assets because the shared geothermal ground loops will be acting as an NPA. Finally, it is appropriate to allow regulatory asset treatment for the shared geothermal ground loops because this program will be advancing the climate targets outlined in the CLCPA by providing alternative heating options with lower GHG emissions.

(2) A total of $100,000 in the Rate Year to set up and administrate the program; and

(3) Two additional FTEs to support the proposed geothermal program project as described by the Panel below.

Q. How will the proposed costs for the geothermal proposals impact base rates for the Company's gas customers?

A. Only labor and non-labor O&M expenses for administering the program will be included in gas customers' base rates because the costs of the geothermal assets will be initially recorded as a regulatory asset with the revenue collected from participating customers designed to offset the associated revenue requirement. The geothermal costs are shown in Exhibit___ (FOH-1), Schedule 1 and 2 and represented in the table below:

Table 2: Geothermal Costs ($000)

	FY22	**FY23**	**FY24**	**FY25**
Regulatory Asset	$1,360.0	$ 2,104.3	$ 3,974.4	$ 5,436.2
	Rate Year	Data Year 1	Data Year 2	Program Year 4
Non-Labor OpEx	$100.0	$ 0	$ 0	$ 0
Labor Opex	$325.6	$331.8	$337.8	-

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Q. **Are there any benefits of shared geothermal ground loops compared with ground loops that serve only one building?**

A. Yes. Shared loops can provide efficiencies. For instance, shared loop systems result in mobilization cost savings, which means that installing a loop that serves multiple buildings and is twice the size will not cost twice as much. A shared loop system may also provide operational efficiencies as the separate buildings may not have to draw on the loop at the identical times. In addition, buildings can exchange heat between each other. For example, if one or more buildings is generating heat (*e.g.*

waste heat from chillers) that heat can be drawn by another building that requires heat.

Q. How does this proposal incorporate what the Company learned from the shared loop demonstration conducted by its downstate affiliate?

A. Under the REV framework, the Company's downstate New York affiliates received approval from the Commission in the 2016 KEDNY and KEDLI Rate Cases to do a technology demonstration for a shared geothermal system, which would explore how this technology could be deployed as a complement to or replacement for gas infrastructure. The Company tested two geothermal well systems to begin the evaluation of their effectiveness as a cost-effective clean heating and cooling system. The first project was a shared geothermal well system serving ten homes in a residential community and the second project was a single geothermal well system for a residential facility. The criteria for Project eligibility were homes that are located more than 1,000 feet from an existing gas main using fuel oil or kerosene as the primary heating fuel. The demonstration found that shared-loop geothermal can be more cost-effective and produces lower carbon emissions than delivered fuels. Project participants in the shared loop experienced fuel savings ranging from 33 percent to 67 percent compared with their previous heating systems. In the shared loop system, the average peak loads of all ten units during the two years showed significant load diversity (approximately 80 percent), pointing to the potential for smaller, lower-cost shared loops. In addition, the systems installed through this project were specifically designed to meet the peak heating and cooling loads of each house to mitigate the potential need for a backup system or reliance on electric resistance heating during peak winter conditions. Participants in the shared loop system were able to retire their traditional heating and cooling systems completely. Additionally, the demo results suggest that shared-loop geothermal can provide a cost-effective and lower carbon alternative to extending gas service in certain instances. Analysis for the demo area showed the customer contribution in aid of construction ("CIAC") begins at $10,000 for those who are 200 feet or more away from the gas network. The cost of the underground heat exchanger begins to achieve cost parity with the connection cost to the gas network at approximately 225 feet. With available state incentives, the total system cost for off-network systems using geothermal becomes comparable to the cost of extending gas service. See Exhibit ___ (FOH-2) for the Geothermal Gas REV Demonstration Project Final Report.

Q. Why is the Company proposing a program for shared loop underground systems, rather than for single-customer loops?

A. The Company is proposing to develop shared loops for a several reasons. First, as a utility, the Company has core competencies relating to installing and managing shared assets that cross property boundaries. Second, the Company is unlikely to be able to install a system at a single property to serve a single customer at a cost that is lower than the private market. Furthermore, an asset that serves a single customer is inconsistent with the business model of a utility. There are vendors, including those mentioned above, that are serving this market today and the

Company does not wish to stifle their growth. The Company will consider ways to collaborate with those vendors that serve the single user market to drive down overall system costs and to ensure a consistent, high-quality experience for all geothermal customers in New York. Finally, the Company has a macro view of energy consumption, which should allow it to proactively connect customers with diverse load profiles, reducing the peak system needs and allowing for a dynamic of exchange of energy across the geothermal loop. This has the potential to reduce the total amount of capital that would be required to serve a given set of customers. The proposed shared loop program would proceed in parallel with other efforts by the Company to support the single-customer geothermal market, principally the administration of geothermal heat pump incentives in its energy efficiency programs.

Q. How will the shared loop program enable the market for third-party, competitive geothermal vendors?

A. Many geothermal vendors are exclusively focused on the design and installation of the geothermal system. In such cases, the financing for the ground loop is typically managed by a financial third-party. Because the Company's proposal is limited to owning, operating, and maintaining the geothermal ground loop, there would not be any conflict with most existing geothermal vendors. After the Company secures interest from a new geothermal customer, an existing vendor could install the ground loop, which would be owned by the Company. This is analogous to how gas piping is installed in parts of the Company's territory today. The Company would pay the vendor for the service upon completion of the work, which would mean the vendor would not need to collect revenue over the lifetime of the asset. The vendor would continue to contract directly with the customer for the installation and maintenance of the above-ground heat pump equipment. The vendor's marketing spending may also be reduced and they would be able to make investments in additional resources (e.g., drill rigs, staff) based on the predictable future demand resulting from a utility geothermal program.

Q. How will geothermal customers be charged?

A. Geothermal customers will be charged a flat, monthly fee based on their peak heating needs, described in tons of heat pump capacity for as long as they utilize the geothermal system. This will allocate loop costs according to the portion of loop capacity that is utilized by the customer and is designed to simplify billing for customers. A fixed price per ton will be developed for the Company's proposals and customers will be charged a multiple of that rate based on their connected system size. This price per ton will incorporate all of the proposed installations planned by the Company and will be standard for all customers. In this way, it will be a weighted average cost per ton ("WACOT"). This rate will be reviewed going forward to ensure they are accurate based on the average cost to deliver a geothermal project for customers. Based on conversations with stakeholders in the geothermal space, the Company believes that the cost to install geothermal systems will decrease in the future, at which time the WACOT would be revised downward.

Q. What initial WACOT is the Company proposing?

A. Based on the proposed project, the WACOT will be \$22.69/ton/month. The minimum charge for access to the system will be equal to the cost for a 3-ton system, namely 3 x WACOT = \$68.07/month.

Q. Will gas customers be subsidizing geothermal customers?

A. No. The Company's proposal entails collecting sufficient annual revenue from geothermal customers to offset the incremental annual revenue requirement that will result from installing geothermal assets. Due to the small relative size of the geothermal program, the program administration costs (*e.g.*, labor and non-labor O&M expenses) will be included in the revenue requirement for the Company's gas operations. As the number of geothermal customers and the program administration needs increase, the Company envisions that these costs will eventually be recovered from geothermal customers.

Q. What are the benefits of a gas utility investing in a technology that primarily is powered by electricity?

A. There are three main benefits for a gas utility investing in geothermal assets. First, gas utilities have core competencies relating to purchasing, installing, owning, and maintaining underground plastic pipe assets. Second, geothermal systems are more expensive than air-source systems but they may be less expensive than a gas pipeline alternative. Being able to invest in geothermal projects would encourage gas utilities to consider this for NPAs, reducing the net gas capital investments to meet customer needs, avoiding gas demand growth and limiting the need for incremental investment in delivery infrastructure. Finally, gas utilities should be encouraged to pursue investments that support a highly-efficient, decarbonized future, given the potential for geothermal customers to avoid any GHG emissions in a fully decarbonized electric generation sector. Being able to invest in geothermal pipe assets means that capital can be allocated to the type of assets that best meet the long-term needs and preferences of customers.

Q. Does the Company's proposal have the potential to displace or defer traditional gas infrastructure?

A. Yes. The proposed shared loop geothermal program has the potential to displace or defer gas infrastructure investment in three ways. First, it may displace certain gas main extension projects by providing an alternative to gas service to delivered fuels for customers in the Company's gas service territory who are located at significant distance from the mains. Second, it may displace certain gas service connections to new or existing customers located closer to mains, thereby also displacing or deferring capacity expansion of pipeline upstream of those service connections. Finally, the proposal may displace certain leak-prone pipe ("LPP") replacement projects for segments of the Company's gas network by terminating these customers' gas service and taking the segment of the network out of service.

Q. Why should the Commission approve the Company's shared loop ownership proposal in this rate case?

A. There are several reasons. First, there is an urgency to develop low-emission alternatives to gas heating, including geothermal, to advance the CLCPA goals. The Company has developed a proposal for this rate case building on the demonstration by its downstate affiliate to test the potential of a geothermal service model to enable and accelerate the market for third-party service providers. This proposal would generate additional experience at a larger scale for the Company, stakeholders, and the Commission to inform any future regulatory action to enable low-carbon, renewable heating and cooling.

Second, the Company's proposal will test whether utility ownership of the shared loop can help lower the up-front costs of geothermal systems for customers and overcome a critical market barrier for the technology. Third, the Company's proposal tests the efficiency and potential of a dedicated geothermal customer class. Currently, geothermal incentives in the energy efficiency programs are funded by participating and non-participating electric customers. Our proposal is testing a mechanism that would result in participating geothermal customers funding the geothermal shared loop systems.

Finally, the development of geothermal networks will facilitate the distribution of natural gas to existing gas customers by conserving the supply of natural gas and also managing any capacity constraints. The Company believes that this is consistent with the Commission's authority to "encourage all persons and corporations subject to its jurisdiction to formulate and carry out long range programs… for the performance of their public service responsibilities with economy, efficiency and care for the public safety, the preservation of environmental values and the conservation of natural resources"[7] as the reduction of the consumption of natural gas enabled by an increase in geothermal heat pump penetration also furthers the State's GHG emission reduction goals.

Q. Is the Company requesting any additional FTEs to support the proposed geothermal program?

A. Yes. The Company is requesting two additional FTEs to support the proposed geothermal program project. The incremental FTEs requested for the geothermal program will be responsible for customer outreach, coordinating with the geothermal vendors that will be performing installations of ground loops and converting in-home appliances, commissioning system installation, managing billing system changes, monitoring and reporting on performance data, and assessing and reporting changes to the WACOT. The additional FTEs are needed because geothermal is a nascent area for the Company and there are not currently any dedicated resources allocated to running a larger geothermal program.

Q. Did the Company perform a BCA for the proposed geothermal program?

A Yes. The Company calculated the BCA for the geothermal proposal as shown in Exhibit___(FOH-5). The BCA calculation for the geothermal program at 4.46 has a positive benefit to cost ratio.

[7] See PSL § 5(2)

IV. Integrating Renewables into the Gas Network

Q. Please explain why integrating renewable supply into the gas network is an important component of the Company's Future of Heat strategy.

A. The Company believes a holistic approach that includes supply-side and demand-side solutions is necessary to drive meaningful change toward a low-carbon future. Low-carbon supply-side solutions can deliver carbon reductions, while leveraging existing infrastructure and avoiding the need for deep retrofits or lifestyle changes at the customer site. Moreover, including supply-side initiatives allows the Company and local communities to beneficially use biogas produced from local dairy farms, wastewater, and food waste, to provide local supplies of energy while also mitigating some of the environmental impacts of these waste streams.

A. Renewable Natural Gas

Q. What is "Renewable Natural Gas"?

A. Renewable Natural Gas ("RNG") is pipeline-compatible gaseous fuel derived from biogenic or other renewable sources that has lower lifecycle carbon dioxide equivalent emissions than geological natural gas. RNG feedstocks include manure, food waste, wastewater treatment plants, or other biomass sources, often processed using an anaerobic digester. With recent advancements to lower the cost of gasification technology, feedstocks with lower moisture content can also be used to produce RNG (*e.g.*, municipal solid waste or agricultural residues). Furthermore, with new technological innovations, production of RNG is moving beyond biomass sources to include using renewable electricity to produce hydrogen, often referred to as power-to-gas ("P2G"). This concept introduces RNG into the gas system by either adding hydrogen to the existing gas system (*i.e.*, hydrogen blending) or producing synthetic methane by combining hydrogen and carbon dioxide. Collectively, RNG offers new ways to decarbonize the natural gas network by reducing the network's carbon footprint. The Company's RNG proposals included below aim to encourage the development of biomass-based RNG facilities within the Company's service territory and to lay the groundwork for other potential RNG technologies through the demonstration of P2G.

Q. Does the Company believe that enabling additional RNG projects to connect to the system will provide a benefit for natural gas customers?

A. Yes. Enabling RNG projects in the Company's gas territory not only will result in lowering GHG emissions but also has the potential to alleviate distribution system constraints by acting as a local source of supply, thereby increasing reliability to gas customers.

Q. Please describe how enabling RNG projects lowers carbon emissions from the gas network while also improving reliability for the Company's gas customers.

A. The production and use of RNG provides two GHG reduction benefits. Not only does it replace geologic natural gas, it also captures methane from naturally occurring waste that may otherwise be released into the environment. This captured gas can be directed towards sectors of the economy that are challenging to decarbonize, such as heat or heavy-duty transportation. Since RNG is compatible with both existing pipelines and gas equipment, it allows natural gas customers to reduce their environmental impact without the need to replace existing natural gas equipment or install additional distribution infrastructure. When RNG is produced and/or injected downstream of the city gate (the portion of the natural gas system where an interstate pipeline interconnects with the Company's local gas distribution network) the need for the Company to purchase geologic natural gas from suppliers is reduced. An added benefit would be that injection of RNG directly into the Company's distribution network will enable the Company to reinforce pressure levels in its gas network independent of the natural gas transmission supply available. Consequently, locally produced RNG may improve reliability and decrease city gate constraints. This way, RNG has the potential to provide both operational and emissions reduction benefits. Utilizing local waste streams as feedstocks for RNG provides additional economic benefits to local in-state RNG developers because it provides new revenue streams for farmers, wastewater treatment plants and landfills while also enabling the waste recycling in the waste collection and management industry.

Q. How does the Company propose to support the development and interconnection of RNG?

A. The Company's three RNG proposals aim to mitigate the challenges facing RNG developers today to encourage local development and deliver local benefits. The proposals are designed to shorten the interconnection process, reduce associated interconnection costs, and provide offtake certainty for RNG developers. The first proposal is to establish a Local RNG Procurement Program, which would authorize the Company to contract and purchase RNG from facilities in the Company's service territory. The second proposal involves an RNG Direct Interconnection Program to make it more cost-effective for RNG project developers to interconnect directly into the existing natural gas distribution network. Finally, the Company is proposing to develop a Centralized RNG Interconnection Facility to receive trucked RNG from sites that are unable to directly connect to the gas network.

1. <u>RNG Procurement</u>

Q. What is the Company proposing regarding RNG procurement?

A. The Company is proposing to contract for and purchase RNG from facilities within the Company's service territory. This proposal is focused on capturing the operational benefits provided by procuring local (*i.e.*, downstream of city gate) supplies, which reduces city gate constraints. Specifically, the Company proposes a program where it will be able to enter into long-term (up to 15 years) purchase contracts with RNG producers that are able to produce local RNG. Long-term contracts are important for RNG developers because will allow the developers to secure financing for projects. The Company is requesting the Commission's support for procuring RNG at potentially higher prices than traditional pipeline gas to reflect the environmental benefits and operational value that is created by the supply being local.

Q. How will these costs be tracked?

A. RNG will be part of the gas supply portfolio and costs will be combined with all other gas supplies when creating a weighted average cost of gas ("WACOG") for the Company. WACOG is an average unit cost of a supply of natural gas. The Company will recover the costs of purchased RNG through its Monthly Cost of Gas ("MCG") rate, consistent with the treatment of other gas commodity costs.

Q. Will the long-term purchase agreements described above involve purchasing the title to the environmental attributes for the RNG, if applicable?

A. No. The agreements above will support RNG projects and will result in additional RNG being injected into the natural gas network. However, the contracted price for the Company to procure the RNG will reflect the value the RNG provides to the local distribution system rather than any associated environmental attributes. Under this proposal the developer will retain title to the environmental attributes and will be able to monetize or retire them as they see fit.

Q. Why does the RNG procurement structure set forth above not include the purchase of environmental attributes?

A. Environmental attributes for renewable natural gas are currently supported by policy frameworks in the transportation sector, and as a result, are valued due to their applicability for renewable identification number (RIN) programs governed by the Environmental Protection Agency's (EPA) renewable fuels standard (RFS) program and the low carbon fuel standard (LCFS) program in California. This means that it is relatively expensive to purchase both the commodity and title to the environmental attribute.

Q. Is the Company requesting any additional FTEs to support the proposed RNG Procurement Program?

A. Yes. As shown in Exhibit __ (FOH-1), Schedule 1, the Company is requesting one additional FTE to support the proposed RNG Procurement Program. The incremental FTE requested will be responsible for establishing and maintaining contacts with RNG suppliers and administering the program and is needed because this is a nascent program and currently there are no dedicated resources allocated to running RNG procurement.

2. <u>RNG Interconnection Proposals</u>

Q. In addition to the RNG Procurement Proposal, why is the Company proposing interconnection programs?

A. Like other renewable energy projects, the high upfront capital costs of RNG projects have impeded development of this local energy resource. A portion of the upfront capital needed for RNG projects is attributable to engineering and equipment requirements established by the Company to ensure safe interconnections. The Company is proposing to engineer, install and own certain portions of RNG interconnections (e.g., meters, odorizors and spectrometers) in order to remove a portion of this upfront barrier and encourage RNG development in Upstate New York. The Company is proposing two interconnection programs, one focused on interconnecting individual RNG facilities that are able to directly connect to the natural gas network as described in this section. The second proposal is described below and focuses on providing a centralized interconnection point for multiple RNG facilities that are unable to connect to the natural gas network directly because they are either too far from the network or too small to connect on their own. The Company believes that these two interconnection programs complement the Company's development of a standard RNG project interconnection guide[8] by further encouraging local RNG development. See Exhibit ___ (FOH-3) for a detailed summary of the Company's RNG Interconnection Proposals.

Q. What experience does the Company have with integrating RNG into its gas network?

A. The Company has over 30 years of experience integrating RNG into the gas distribution network, starting with the Staten Island Landfill project. The Staten Island project – the oldest operating RNG facility in the U.S., has been operating since 1982 and continues to contribute RNG to National Grid's distribution network. In addition, National Grid has partnered with the New York City Department of Environmental Protection ("NYC DEP") to deliver RNG from Newtown Creek, the City's largest wastewater treatment plant. In doing so, National Grid and the NYC DEP are seeking to animate the RNG market and highlight opportunities for expanded use of this valuable energy resource.

[8] https://www.northeastgas.org/pdf/nga_gti_interconnect_0919.pdf

Q. What systems and infrastructure are required to integrate RNG into the distribution gas network?

A. RNG requires much of the same natural gas infrastructure as existing natural gas supplies including metering, odorization, gas quality monitoring, and pipeline main extensions.

<u>Direct RNG Interconnection Program</u>

Q. Please describe the Direct RNG Interconnection Program.

A. The Company proposes to install and maintain some of the necessary interconnection equipment at individual RNG facilities, such as meters, analyzers, and odorization equipment. Although this equipment is required by the Company for interconnection, it is currently the sole financial and operational responsibility of project developers. Based on feedback from RNG developers, the Company believes that lowering interconnection costs will encourage the development of third-party RNG projects in the Company's service territory.

Q. How many individual RNG projects does the Company anticipate interconnecting directly into its gas distribution network annually?

A. Based on the number of inquiries National Grid received from RNG project developers over the past several years and RNG projects currently under development, the Company forecasts approximately one project to mature to the interconnection phase each year starting in 2021 and two in the final year of the rate plan. The proposed capital budget for this program is slightly less than $0.50

million per interconnection project based on the cost of meters, analyzers, and odorization equipment. The table below provides the anticipated annual capital budget included in the GIOP's forecast and the program's non-labor operating O&M expenses both shown in Exhibit __ (FOH-1) Schedules 1 and 2.

<u>Table 3</u>: RNG Direct Interconnection Program Costs

	Rate Year	**Data Year 1**	**Data Year 2**	**Program Year 4**
Non-Labor OpEx	$165,000*	$165,000*	$470,000*	$580,000*
	FY 22	FY23	FY24	FY25
CapEx	$468,000	$ 478,000	$ 487,000	$ 994,000

* Non-labor costs provided in this table also include a portion of costs also supported by the GIOP panel

<u>Centralized RNG Interconnection Facility</u>

Q. Why is the Company also proposing a Centralized RNG Interconnection Facility?

A. The Company is proposing to develop a Centralized RNG Interconnection Facility for potential RNG producers that would be unable to directly connect to the gas network. New York is the third largest dairy state in the US, presenting a significant feedstock source for RNG. However, the cost to directly interconnect individual dairies directly to the gas system has proved cost prohibitive thus far, in part due to additional pipeline costs. Centralizing an interconnection facility is ideal for dairy RNG projects that are plentiful but either too far away from the natural gas network or too small to allow for direct interconnection. Centralizing an interconnection facility also enables the Company to select injection sites based on their potential to provide gas network benefits, *e.g.*, portions of the gas network that are constrained and would benefit from additional local supply.

Q. Please describe the process and timeline the Company envisions for developing the Centralized RNG Interconnection Facility.

A. Through this proposal, the Company aims to develop of one or more Centralized RNG Interconnection Facilities that will aggregate and inject RNG into portions of the gas network that would benefit from local gas supply. First, the Company will identify a suitable site to pilot a Centralized RNG Interconnection Facility in the service territory. Then, the Company will establish an ownership and cost recovery framework for the project. The Company anticipates that site selection and framework development will take place over FY21-FY22 and that the facility will be completed by FY24. Currently three locations are under consideration by the Company and are being evaluated based on the design of the area's gas network and the number of local dairies that could provide RNG. Final site selection and framework development will aim to provide economic, environmental, and gas network benefits. Additional anticipated benefits include, access to new revenue-streams for farmers, and reduced methane emissions from agriculture as a result of incentivizing manure collection and processing. Exhibit ___ (GCP-3) provides a map depicting the location of the proposed Centralized RNG Interconnection Facility and further description of the project.

Q. What portion of the Centralized RNG Interconnection Facility is the Company proposing to own?

A. The Company proposes to own and operate all facilities downstream of the biogas conditioning and upgrading equipment, including pipeline lateral and compression, interconnection equipment and any pipeline extension. These facilities align with utility competencies and provide a benefit to the gas network by connecting incremental supply. The Company envisions that the upstream portion of the facility including digesters, biogas collection lines and biogas treatment or conditioning equipment will be owned by a third-party or multiple third parties. Once a suitable interconnection site has been identified, the Company will issue an RFP to select a vendor or vendors to manage and own the upstream portion of the project. Several bids may be selected to meet the full capacity of the Centralized Interconnection Facility. The Company envisions that potential third parties could be farm co-ops or independent RNG developers. The Company will explore opportunities to offer economic development assistance, clean energy incentives and will explore partnerships with NYSERDA and the New York State Department of Agriculture and Markets to lower the cost of the facilities owned by third parties. For instance, the Company will explore opportunities to leverage NYSERDA's Program Opportunity Notice (PON) 3739, through which NYSERDA is seeking to identify and demonstrate new business models for a self-sustaining anaerobic digester technology market.

Q. What is the anticipated cost for the proposed Centralized RNG Interconnection Facility?

A. Final costs for this project will depend on the site selected and the specific makeup of the system. National Grid is already working with RNG stakeholders to evaluate possible locations in upstate New York, but it is expected that it will take a few years to develop the project. The estimated costs for the portion of the Centralized RNG Interconnection Facility to be owned by the Company are shown below in the year during which it is expected that the system will become used and useful.

Table 4: Costs for Centralized RNG Interconnection Facility

	FY22	FY23	FY24	FY25
CapEx	$ -	$ 1,500,000	$7,500,000	$ -

Q. What are the expected line-item costs for the portion of the Centralized Interconnection Facility that will be owned by the Company?

A. Actual costs of the Centralized Interconnection Facility will vary based on the site selected and the final project design. The table below sets forth the estimated range of costs for the facility that the Company used to develop the costs for the portion it will own as set forth in Table 4 above

Table 5: Estimated Low and High Range of Costs of Centralized Interconnection Facility

	Estimated Cost	
	Low	**High**
Real Estate and Permitting (highly variable and site specific)	$200,000	$1,500,000
Civil and Pipeline	$2,000,000	$3,000,000
Decompression and Metering (assuming 4-6 trailer hookups)	$2,000,000	$3,000,000
Analyzers and Buildings	$1,500,000	$2,000,000
Installation and Startup	$500,000	$500,000
Total Estimated Cost	$6,200,000	$10,000,000

B. Hydrogen Proposals

Q. Please describe the current state of hydrogen production and use.

A. Hydrogen has been produced at scale and used in a variety of applications for more than a century. Hydrogen gas has not been widely adopted as a heating fuel, partially due to the fact that it is not commonly naturally occurring, thus it must be manufactured. Hydrogen typically is produced from the electrolysis of water with electricity, or from the thermal reformation of a variety of hydrocarbon fuels, usually natural gas. Generally, the hydrogen produced from these two processes is more expensive than natural gas, which has contributed to its limited use as a source of heating. However, it is anticipated that the cost of producing hydrogen will decline over time as technology improves and as renewables scale.[9] Due to the maturity of the hydrogen industry, and the potential for cost effective hydrogen production via electrolysis, hydrogen has the potential to be both a heating fuel and

[9] https://iea.blob.core.windows.net/assets/8ab96d80-f2a5-4714-8eb5-7d3c157599a4/English-Future-Hydrogen-ES.pdf

a safe and effective medium to transport and store the renewable energy from multiple sources, including those planned to be produced in New York State in the coming decades such as offshore wind.

Q. Why is the Company proposing to develop technologies and programs that utilize hydrogen for use in its gas business?

A. The Company supports the goals of the CLCPA, and like other utilities around the world has concluded that hydrogen, due to its flexibility of use, zero carbon content, and ability to be produced from renewable electricity sources, has the potential to be one of several effective tools available to meet these goals in a manner that is beneficial for gas customers as well. The CLCPA was devised to enable several agencies and utilities to *"implement easily-replicated renewable energy projects."* Hydrogen can provide replicable renewable energy projects that can provide carbon-free fuel for use in difficult to electrify sectors, notably medium and heavy-duty transportation, industrial applications, and space heating. Additionally, hydrogen presents a solution for the intermittency of renewable electricity generation by leveraging the existing natural gas network as a storage medium.

The development of flexible solutions, specifically for energy storage, was also envisioned in the Commission's *Order Establishing Energy Storage Goal and Deployment Policy*, Case 18-E-0130 dated December 13, 2018 ("Energy Storage Order"). A qualified energy storage system under PSL §74(1) includes: "commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy using mechanical, chemical, or thermal processes to store energy that was generated at one time for use at a later time." (emphasis added). The Energy Storage Order highlights the critical role energy storage will play in enabling renewables to provide what is needed to reduce GHG emissions economy-wide to satisfy the State Energy Plan's targets.[10] Hydrogen storage is an energy storage system that can be used to reduce GHG emissions "economy-wide" as contemplated by the Energy Storage Order.

Q. What are the elements of an effective hydrogen development initiative?

A. An effective hydrogen development initiative has to both enable new technologies or new applications of technologies for gas distribution service and validate their environmental and economic value in a fully developed market. Hydrogen has strong potential for providing environmental and economic value, and, consequently, is being developed across Europe. In an October 2019 transatlantic power to gas conference at which several European developers from the United Kingdom and Germany participated, the assessment that *"*Hydrogen can develop from a niche to a multi-purpose solution", and "hence the need for storage/sector coupling.*"* See Exhibit__ (FOH-4). Likewise, based on its assessment of current market conditions, the Company believes there are four relevant functions where New York gas utilities can support decarbonization by integrating hydrogen in the following ways: (1) enabling production by zero or negative carbon means; (2) ensuring efficient, in-region energy transportation using the gas network (3)

[10] Energy Storage Order, p.4.

providing a clean, reliable RNG solution for customers, and (4) providing an effective non-degradable energy storage (*i.e.*, inter-seasonal storage).

Q. What are the Company's set of proposed hydrogen initiatives?

A. The Company proposes two demonstration projects, which, if successful, will create access to hydrogen for customers and the development or expansion of new business in New York State, all while accelerating decarbonization. The proposed projects are as follows:

- Multi-Use Hydrogen Production and Utilization Facility, and
- Power to Gas Collaboration

Q. Has the Company distributed hydrogen blends in the past?

A. Yes. The Company has historically distributed mixtures of gas that include hydrogen. For example,[11] in 1974 Brooklyn Union Gas Company supplemented its natural gas supply with Substitute Natural Gas (SNG) that is typically about 10 percent hydrogen[12] by volume.

1. <u>Multi-use Hydrogen Production and Utilization Facility</u>

Q. Please provide an overview of the Company's Multi-use Hydrogen Production and Utilization Facility proposal.

[11] Murphy, Robert E "Brooklyn Union: A Centennial History", Brooklyn Union Gas Co., 1995
[12] Gas Engineer's Handbook Table 2-25

A. The proposed Multi-use Hydrogen Production and Utilization Facility will be developed and operated under contract between the Company and Standard Hydrogen Corporation of Ithaca, NY ("Standard Hydrogen"). It will be the first demonstration anywhere in the United States of a system that will include the production of hydrogen by zero or negative carbon means for storage and for P2G. The RNG produced will be injected into the Company's gas distribution system. Any excess hydrogen will be available for a number of energy services as described below to generate revenue. The revenue generated will offset the costs of the facility and 80% of any net revenues after all facility costs have been offset will be returned to customers. This project directly supports the evaluation of alternative business models for energy storage discussed in the Energy Storage Order. The multi-use hydrogen production and utilization facility will be a single permanent facility to be located at an industrial or commercial site in the Capital region.

Q. Why was Standard Hydrogen selected for this project?

A. Standard Hydrogen participated in an Innovation Sprint sponsored by the REV Connect program and National Grid in May, 2018 and proposed to partner with National Grid to evaluate the concept of a multi-use hydrogen utilization facility it calls an "Energy Transfer Station" (ETS). In accordance with the established REV Connect process, National Grid expressed interest in the concept. Navigant Consulting was then selected to develop a conceptual Business Case in October of 2018 entitled "*Versatile, Clean, Distributed Hydrogen For Multiple Markets" and a "Value Assessment"* included as Exhibit __ (FOH-4) that defines the potential products and the per unit and gross revenue potential for each product in the National Gris service area and across New York State.

Q. Please describe the proposed ETS facility.

A. The proposed facility is developed around a nominal 1 MW electrolyzer that produces hydrogen from purchased renewable electricity. That hydrogen is used immediately or compressed and stored on site. Hydrogen can be used as a non-pipeline alternative by blending into the natural gas system, or used to produce substitute methane through P2G. Potentially, the ETS can provide commercial gas supply. Excess hydrogen not utilized in the gas network can also provide electricity to the host site as back-up and can be a source of revenue by providing demand or capacity to the electric grid or for Level 3 charging to electric vehicles without using grid capacity. The compressed hydrogen can also be dispensed into the growing population of hydrogen fuel cell electric vehicles in New York, such as the Toyota Mirai, Honda Clarity or range extending electric trucks. Initial engineering design has been completed and the duration of project activities including site identification, permitting, construction, commissioning, operations and data collection, and reporting have been estimated at a high level. The ETS Facility will include the components itemized in Table 6 below and duration of project activities are estimated in Table 7 below.

<u>Table 6</u>: ETS Facility Components

Component	Size*	Description
Electrolyzer	Up to 1.0 MW Input	Up to 32 kg/hr Hydrogen at 430 psig
Compressed Hydrogen Storage	Up to 1,000 kg @ up to 5,000 psig	ASME-Approved Storage
Fuel Cell	Up to 1MW Output	PEM or PAFC fuel cell as determined by location
Hydrogen Vehicle Dispenser	2 - hose dispenser w/VIT	8 kg in 5 Mins.
EVSE	Up to 4DC Fast Chargers	80% vehicle charge in 30 mins
Natural Gas blending	<10% of available gas main	Mixing valve with telemetry

*Final Component size based on final location and corresponding use case

Table 7: ETS Facility Milestones

Action Items	Duration* (Weeks)	Responsible Party
Site identification	8	National Grid and SHC
Final Cost proposal	16	National Grid and SHC
Contracting		National Grid and SHC
SHC	8	National Grid
Customer	12	National Grid and SHC
- Construction	12	SHC
- Renewable Electric Supply	12	SHC &Renewable Energy Supplier
- Elec. Demand Relief	12	National Grid & DR Provider
- Gas Demand Relief	12	National Grid & DR Provider
Interface design		National Grid and SHC
- Electric	20	National Grid and SHC
- Gas	20	SHC and Customer
- Other (water, comms etc.)	20	SHC
Permitting	35	SHC and Customer
Construction	60	SHC
Commissioning	8	National Grid and SHC
Operations	104	SHC
Data Collection/ Reporting	104	SHC and National Grid
FINAL REPORT	8	SHC and National Grid

*****Estimated duration dependent on final location and corresponding use case.

Q. What are the costs of the multi-use hydrogen production and utilization facility?

A. The costs of the project are shown in Exhibit __ (FOH-1) Schedules 1 and 2 and Table 8 below. Costs are based on a project with a total duration of five years with the ETS operational by FY23 and continuing indefinitely beyond the demonstration project. The Company and SHC are each seeking external funding, including potential NYSERDA funding, for the early phases of the demonstration project, and any such awards that may result will be fully deducted from the capital cost. The total cost of the project over 5 years, net of sales, is estimated at $8.2 Million. This is based on reasonable increases in Electrolyzer utilization during the five-year project as follows: (i) Year 2- 5%, (ii)Year 3 -20%, (iii) Year 4 -40% and (iv) Year 5 90%. The actual level of utilization cannot be known at present and the effective net cost will be higher if capacity is not sold or will be lower if utilization increases at a faster rate. The facility will not offer any product for sale unless the incremental cost of providing that product exceeds the revenue generated by that product sale. As shown in exhibit (FOH-7) the ETS has the potential to generate in excess of $0.8 Million in net revenue for each year of operation after the project is completed to the direct benefit of customers.

Table 8: Costs for ETS Facility ($000)

($000)	Rate Year	Data Year 1	Data Year 2
Non-Labor OpEx	$100.0	$391.5	$ 492.0
	FY22	FY23	FY24
CapEx	$ 4,354.9	$ 4,354.9	$ 0

Q. How does ETS advance the goals of the CLCPA?

A. One of the key objectives of the CLCPA and related policies is “the transition of the state workforce and the rapidly emerging clean energy industry.” Rapid development requires flexibility to adjust to emerging markets and market responsiveness. Hydrogen is inherently flexible and the ETS is the most flexible use of hydrogen possible. The ETS, like any clean energy asset, is a capital intensive. Thus, its economic performance is primarily dependent on the level of utilization of the primary assets. The flexibility in the ETS concept will allow a single facility to alternatively provide multiple services responsive to market demand for each service. The plan will be to provide the most value added clean-energy services first, most likely back-up power for the host, and lesser value services thereafter as long as incremental costs are covered, with the goal to maximize the utilization of the common components of the ETS, such as the electrolyzer

Q. What is the timeline for the proposed multi-use hydrogen production and utilization facility?

A. A preliminary project plan and budget has been developed by the Company and SHC. This plan is based on this being a first-of-its kind project and is not representative of what costs or timelines for future project development durations or installations costs may be. As the site, has not yet been secured, the cost is subject to future adjustment up or down based on local conditions. Due to the benefits to the host (*e.g.*, back-up power), costs associated with renting or leasing space is not included. The entire project is based on four phases implemented over a four year time frame from the project approval with one year prior for implementation planning, up to one year for permitting and installation, and two years of monitored operations, revenue sharing and reporting.

Q. Is the Company requesting any additional FTEs to support the proposed multi-use hydrogen program?

A. Yes. The Company is requesting one additional FTE to support the proposed Multi-use Hydrogen Program. The incremental FTE requested will be focused in two areas. First, mechanical operation of the system. Resources will be required to ensure that the system is operating smoothly and that there are no issues with any of the components that might reduce functionality. This is similar to CNG stations that the Company has operated but with added complexity due to new equipment types. Second, interfacing with Standard Hydrogen on the distribution of hydrogen to the various end uses. This will require monitoring of various markets, engaging with customers (*e.g.*, fuel cell electric vehicle fleets, gas DR programs), evaluating the business models, and reviewing financial performance with Standard Hydrogen. An additional FTE is required because this is an expansion of National Grid's experience with hydrogen. It is critical to maintain system function so that an appropriate evaluation of the underlying thesis can be completed.

Q. To what extent will the investment in the ETS be recovered and returned to the Company's customers?

A. This first-of-its kind facility will operate in existing and evolving competitive energy service markets. The sales of products will generate revenues for National Grid that will be used to pay Standard Hydrogen for capital recovery, purchased renewable electricity, SHCs facility operations and funding for anticipated refurbishment of major components, such as the electrolyzer. The ETS has the potential to generate revenues in excess of costs for capital and operations over its operational life. If this project is successful, it is expected that there will be sufficient net revenue generated to fund all the costs for the ETS. The Company proposes to return all net revenue available from this facility to customers until the capital costs of the facility are fully recovered. Thereafter, the Company proposes to split retained net revenue with 80 percent returned to customers and 20 percent retained and shared between SHC and National Grid SHC will also have the option to buy out the investment in the facility and operate it independently together with what it hopes will be a series of similar facilities in the future if this project is successful. No one can know with certainty the market prices of each of the energy product or services over the life of this demonstration or the demand for the products or services or the proportion of each product or service actually sold. However, under reasonable assumptions of production by the ETS it is clear that the proposed revenue sharing with customers could lead to the customers' cost being largely or entirely recouped over the lifetime of the demonstration ETS.

2. <u>Power-to-Gas</u>

Q. Please describe what is meant by the term Power-to-Gas.

A. Power-to-Gas or P2G refers to the technical and economic potential process of converting excess renewable electricity to hydrogen or synthetic methane (*i.e.*, RNG) and utilizing the existing natural gas network to deliver the gas produced using these renewable resources. Indeed. P2G also can provide low- or zero-carbon RNG when renewable electricity is utilized as the feedstock. RNG produced via P2G can serve as a form of large-scale, long-duration energy storage when used to convert excess renewable electricity that would otherwise be curtailed to RNG. P2G can also provide low- or zero-carbon RNG, depending on the feedstocks used for production. The technology holds considerable promise for addressing clean-energy goals, as it has the potential to support deep decarbonization of the transportation and heating sector, which are two sectors of the economy that have proven challenging to decarbonize.

Q. Please describe the proposed Power to Gas Collaboration.

A. The P2G collaboration involves the development of a P2G design that combines existing hydrogen production technology (*i.e.*, an electrolyzer) and cutting-edge methanation technology (*i.e.*, a bioreactor) to produce pipeline-quality RNG capable of meeting gas system requirements in partnership with federal and local governments, as well as industry collaborators, such as Electochaea GmbH, an innovative technology provider that develops bioreactors, to design and engineer the P2G Project. The Company's affiliates in downstate New York have proposed this collaboration in the 2019 KEDNY and KEDLI Rate Cases.

Q. What amount is included in the revenue requirement for the proposed P2G Collaboration?

A. If the P2G Collaboration is approved in the 2019 KEDNY/KEDLI rate case, the Company is proposing to share the costs of the P2G Collaboration with KEDNY and KEDLI. The P2G costs are shown in Exhibit __ (FOH-1) Schedule 1. The

Company believes it is reasonable to share the costs of the Collaboration KEDNY and KEDLI if it is approved, because many of the elements of design that will be developed as part of this proposal will be non-location specific. Because the Company is exploring the potential of deploying P2G across its gas service territory in the future, it makes sense for all customers to share the benefits and costs of proposal development. If the P2G Collaboration is not approved in the 2019 KEDNY/KEDLI rate case, the Company will not pursue this P2G Collaboration.

V. Conclusion

Q. Does that conclude the Panel's testimony.

A. Yes.