COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 24-25

DIRECT PRE-FILED JOINT TESTIMONY OF

ELIZABETH D. ARANGIO

FAYE BROWN

SAMARA A. JAFFE

MICHAEL J. PINI

AND

DEBORAH M. WHITNEY

ON BEHALF OF
BOSTON GAS COMPANY D/B/A NATIONAL GRID

EXHIBIT NG-AGREEMENT-1

February 9, 2024

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JOINT TESTIMONY OF
ELIZABETH D. ARANGIO, FAYE BROWN, SAMARA JAFFE, MICHAEL J. PINI, AND DEBORAH WHITNEY

I. INTRODUCTION

Q. Ms. Arangio, please state your name and business address.

A. My name is Elizabeth D. Arangio. My business address is 170 Data Drive, Waltham, Massachusetts, 02451.

Q. Please state your business position and responsibilities.

A. I am the Director of Gas Supply Planning for National Grid USA Service Company, Inc. ("NGSC") with responsibility for the resource portfolio of the Massachusetts local gas distribution company that operates as "National Grid," which is Boston Gas Company ("Boston Gas") d/b/a National Grid ("National Grid" or the "Company"). In addition to the Massachusetts portfolio, I am also responsible for gas-supply planning for the resource portfolios of The Brooklyn Union Gas Company, KeySpan Gas East Corporation and Niagara Mohawk Power Company, all located in New York. In this proceeding, I am testifying on behalf of Boston Gas.

Q. Please summarize your educational background and your professional experience.

A. I graduated from the University of Massachusetts in 1991 with a Bachelor of Business Administration. In 1995, I graduated from Bentley College with a Master of Business Administration. From 1991 to 1994, I worked as a Gas Accounting Analyst in the Marketing Operations Department at Algonquin Gas Transmission Company. In 1994, I joined Boston Gas Company as a Gas Supply Analyst. In 1997, I was promoted to Group

Leader Transportation Services, with responsibility for managing all activities associated with the customer-choice program. In 1998, I was promoted to Director of Gas Acquisition and Transportation Services with responsibility for the administration of the Company's gas-resource portfolio and customer-choice program in Massachusetts. In February 2004, I assumed the additional responsibility of gas-supply planning for the former KeySpan Corporation New York and Long Island resource portfolios. Following the acquisition of KeySpan Corporation by National Grid plc, I was named to my current position with the added responsibility for the National Grid gas resource portfolios in upstate New York and in Rhode Island. In August 2018, I assumed the added responsibility for all National Grid's gas Customer Choice programs.

Q. Have you previously testified in regulatory proceedings?

A. Yes. I testified before the Department of Public Utilities (the "Department") in Boston Gas Company d/b/a National Grid, D.P.U. 19-132 (2020) wherein the Department approved the Company's firm transportation agreement with Algonquin Gas Transmission, LLC ("Algonquin" or "AGT") for the firm transportation of gas supplies to the Company's distribution system under the Atlantic Bridge Project. I also testified in Boston Gas Company d/b/a National Grid, D.P.U. 18-104 (2019) wherein the Department approved the Company's gas supply option agreement with Constellation LNG, LLC, as well as in Boston Gas Company d/b/a National Grid, D.P.U. 17-174 (2017) wherein the Department approved the Company's firm transportation agreements with Tennessee Gas Pipeline Company, LLC ("Tennessee" or "TGP") and Portland Natural Gas Transmission Systems. I also testified before the Department in D.P.U. 18-148, D.P.U. 16-181, D.P.U. 15-36, D.P.U. 15-34, D.P.U. 15-129, D.P.U. 15-130, D.P.U. 13-01, and D.P.U. 13-157.

Q. Ms. Brown, please state your name and business address.

A. My name is Faye Brown. My business address is 170 Data Drive, Waltham, MA 02451.

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

A. I am employed by NGSC as Director, Gas Planning and Design Engineering for Massachusetts. My responsibilities include engaging with internal and external stakeholders to identify the needs, develop strategies and plans to deliver the long-term network capacity needs and meet the Company's Clean Energy Vision. In my role, I manage a team of engineers that work collaboratively with other teams to provide support for non-pipeline alternative project pilots, like the Lowell Network Geothermal project, and development of Integrated Energy Planning process.

Q. Please summarize your educational background and professional experience.

A. I graduated from Widener University, located in Chester, Pennsylvania with a Bachelor of Science degree in Electrical Engineering. I joined the Company, then known as KeySpan Energy Delivery New England, in 2002. I advanced to Engineering Manager and Principal Engineer and was promoted to my current role in June 2023. Although most of my time with the Company was in Gas Engineering, from 2008-2011, I was a Lead Resource Planner in Construction. From 1994-2002, prior to joining National Grid, I worked in the telecommunications construction industry in various project management roles.

Q. Have you previously testified before the Department or any other regulatory commissions?

A. Yes, I filed testimony and related exhibits in the Company's calendar year 2024 Gas System Enhancement Plan in docket D.P.U. 23-GSEP-03. I also provided support for the Company's 2020 Long Range Resource and Requirements Plan filing and I have testified

before the Rhode Island Public Utilities Commission on behalf of the Company's former affiliate, The Narragansett Gas and Electric Company.

Q. Ms. Jaffe, please state your name and business address.

A. My name is Samara A. Jaffe. My business address is 100 East Old Country Road, Hicksville, NY 11801.

Q. Please state your business position and responsibilities.

A. I am the Director of Gas Contracting, Compliance and Hedging for NGSC. In this position I am responsible for the acquisition of long-term gas supply and pipeline capacity; gas contract management; intervention in proceedings before the Federal Energy Regulatory Commission ("FERC"); and compliance with FERC regulations in connection with National Grid's gas trading activities for National Grid's gas distribution companies in Massachusetts and New York, including Boston Gas. In this proceeding, I am providing testimony on behalf of Boston Gas.

Q. Please summarize your educational background and your professional experience.

A. I graduated from the State University of New York at Buffalo in 2006 with a Bachelor of Arts degree in Chemistry. In 2012, I graduated from Touro Law Center with a Juris Doctor. In 2016, I graduated from Dowling Institute with a Master of Business Administration. I joined KeySpan Gas East Corporation in 2007 as a Natural Gas Scheduler in KeySpan's Energy Procurement area with responsibility for scheduling natural gas on interstate pipelines utilized by the Company to meet the requirements of its wholesale firm gas customers. After graduating from Touro Law Center in 2012, I accepted a position as

Program Manager for National Grid USA's Energy Procurement Gas Contracting and Compliance group. In April 2021, I was promoted to my current role.

Q. Have you previously testified in regulatory proceedings?

A. Yes. I testified most recently in D.P.U. 19-132 wherein the Department approved the firm transportation agreement with Algonquin for the firm transportation of gas supplies to the Company's distribution system under the Atlantic Bridge Project. I also testified in D.P.U. 19-26 wherein the Department approved an asset management arrangement between the former Colonial Gas Company with Emera Energy Services, Inc. I also testified before the Department in D.P.U. 18-104 wherein the Department approved the Company's long-term supply agreements with Constellation LNG, as well as in D.P.U. 17-174 wherein the Department approved the Company's firm transportation agreements with Tennessee and Portland Natural Gas Transmission Systems.

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

A. My name is Michael J. Pini. My business address is 170 Data Drive, Waltham MA 02451.

Q. Please state your business position and responsibilities.

A. I am the Manager of the Massachusetts Gas Pricing group of the Regulatory and Pricing department for NGSC. Massachusetts Pricing provides rate-related support to the Company. My duties include oversight of the preparation of rate design, tariff development and administration, reconciliations of revenue and costs pursuant to the Company's reconciling mechanisms, and various regulatory filings.

Q. Please summarize your educational background and your professional experience.

A. I earned a B.S. in Economics and Finance from Bentley University in 2010. In 2009, I joined National Grid USA as an intern in the Support Services function within Gas Operations. In 2010, I became an Associate Analyst in the Regulatory Compliance department. In 2011, I joined the New England Electric Pricing group and was promoted to Analyst in 2012. In 2013, my responsibilities changed to supporting Boston Gas, and in 2014, I was promoted to Senior Analyst in the same capacity. In 2017, I was promoted to Lead Program Manager, supporting the Company. In 2021, I was promoted to Manager of the Gas Pricing group.

Q. Have you previously testified in regulatory proceedings?

A. Yes, I have testified before the Department in support of the Company's base distribution rate case in D.P.U. 20-120, its Gas System Enhancement Plan ("GSEP"), and GSEP reconciliation filings, and I have submitted pre-filed testimony in the Company's annual Performance-Based Ratemaking filings, Residential Assistance Adjustment Factors filings, in its Energy Efficiency Plan filing in D.P.U. 15-161, and in its fee-free credit/debit card payment option in D.P.U. 20-91. I have also testified before the Rhode Island Public Utilities Commission on behalf of the Company's former Rhode Island affiliate in support of various regulatory filings.

Q. Ms. Whitney, please state your name and business address.

A. My name is Deborah M. Whitney. My business address is 170 Data Drive, Waltham, Massachusetts, 02451.

Q. Please state your business position and responsibilities.

A. I am a Lead Analyst in the New England Gas Supply Planning Department for NGSC. I am responsible for evaluating whether the capacity and gas-supply resources available to National Grid are sufficient to meet sendout requirements using the SENDOUT® model. The SENDOUT® model is a linear programming optimizations software tool used to assist in evaluating, selecting and explaining National Grid's long-term portfolio strategies. Using the SENDOUT® model, the Company is able to determine the least-cost supply portfolio that will meet the forecasted demand and to test the sensitivity of the portfolio for key inputs and assumptions, including its ability to meet sendout requirements under the Company's planning standards and contingency scenarios. Based on the results of this analysis, the Company is able to make preliminary decisions on the adequacy of its resource portfolio and ability to meet system requirements over the longer term. In this proceeding, I am testifying on behalf of Boston Gas.

Q. Please summarize your educational background and your professional experience.

A. I graduated from Northeastern University 1990 with a Bachelor of Science Degree in Finance and Management. Since 1989 I have held positions in the gas industry related to gas capacity contracts. From 1989 to 1994, I worked at Citizens National Gas Company as a Staff Accountant. From 1994 to 1996, I worked at XENERGY, Inc. as an Account Manager. From 1996 to 2004, I worked at AllEnergy Marketing Co., LLC where I held various positions including Supervisor of Gas Scheduling and Manager of Gas Operations. From 2004 to 2007, I worked for KeySpan Energy Delivery New England (as noted above KeySpan was acquired by National Grid) where I was hired as an analyst in the Customer Choice Department. In 2006, I joined the Gas Supply Planning Department as a Senior

Analyst. In 2007, I was promoted to Lead Analyst with responsibility for evaluating whether the capacity and gas-supply resources available to National Grid's gas distribution companies in New England are sufficient to meet customer requirements using the SENDOUT® model.

Q. Have you previously testified in regulatory proceedings?

A. Yes. I testified most recently in D.P.U. 19-132 wherein the Department approved the Company's firm transportation agreement with Algonquin for the firm transportation of gas supplies to the Company's distribution system under the Atlantic Bridge Project. I also testified in D.P.U. 18-104 wherein the Department approved the Company's gas supply option agreement with Constellation LNG as well as D.P.U. 17-174 wherein the Department approved the Company's firm transportation agreements with Tennessee and PNGTS. I also testified before the Department in D.P.U. 16-181 where the Department approved the Company's forecast and supply plan for the five-year forecast period 2016-2017 through 2020-2021.

Q. What is the purpose of your joint testimony?

A. The purpose of our joint testimony is: (1) to describe the agreement executed by the Company with Constellation LNG, LLC ("Constellation") for the option to purchase gas supplies from Constellation's LNG terminal including the associated operational and reliability benefits; (2) to explain the Company's resource requirements that establish the need for the proposed agreement with Constellation; (3) to review reasonably available alternatives to the agreement, to the extent that such alternatives exist; (4) to describe price and non-price factors considered in the determination that the proposed agreement is the

best alternative for meeting the identified needs of the Company; and (5) describe the estimated bill impacts to customers.

The Company is requesting Department approval of a multi-year agreement with Constellation ("Agreement"). The Agreement is for a six-year term beginning June 1, 2024 and ending May 31, 2030. The Agreement provides for up to 27,000 Dth per day with a seasonal quantity of 500,000 Dth in the first year of service, with increasing quantities over the contract term commensurate with the Company's imported LNG needs. The Agreement will provide seasonal peaking supply in liquid and/or vapor form, backed by imported LNG through Constellation's Everett LNG Facility located in Everett, Massachusetts ("Everett Marine Terminal" or "EMT" or "Facility"). The Agreement is necessary for the Company to reliably serve customers for the next six-year period with an existing resource that cannot be replicated in the time period for which it is needed. Moreover, as described herein, there are no viable alternatives to meet the need by the Agreement that do not require additional natural gas infrastructure to be sited and built. The Agreement is provided in Exhibit NG-Agreement-2 (CONFIDENTIAL).

Q. Please describe how the Company's filing is organized.

A. To support this request for approval of the Agreement, the Company prepared pre-filed testimony and other supporting documentation providing: (1) an introduction to the witnesses and an overview of the Agreement; (2) an overview of the Company's supply portfolio; (3) an overview of the New England gas market; (4) a description of the Agreement; (5) discussion of the need for the Agreement and consistency of that agreement with the portfolio objectives established in the Company's Supply Plan; (6) discussion of the reasonably available project alternatives; (7) price and non-price factors considered by

the Company; and (8) discussion of estimated bill impacts to customers; and (9) a conclusion.

Q. Are you sponsoring any additional exhibits in this proceeding?

A. Yes. We are supporting the following exhibits in addition to our testimony:

- Exhibit NG-Agreement-2 – Agreement (CONFIDENTIAL)
- Exhibit NG-Agreement-3 – Agreement Price Terms (CONFIDENTIAL)
- Exhibit NG-Agreement-4 – Base Contract with Constellation
- Exhibit NG-Agreement-5 – G-Tables
- Exhibit NG-Agreement-6 – Bill Impacts

Q. Please summarize the Company's request for Department approval of this Agreement.

A. The Company's primary objective is to provide safe and reliable service to gas customers, particularly on the coldest days of the year. Due to regional gas supply constraints, this six-year Agreement is critical in allowing the Company to continue to provide gas supply in a safe and reliable manner to customers in the immediate term on peak days through the use of existing gas infrastructure. The Company is fully cognizant of the Department's recent Order in D.P.U. 20-80-B, stating that new gas infrastructure is not preferred, that the gas distribution companies must analyze non-pipeline alternatives prior to making new gas infrastructure investments, and review customer connection policies to dissuade gas growth. Taken together, these policies will ultimately lead to a reduction in gas demand by 2050. Therefore, the Company is pursuing a fixed term agreement that can be available without delay to meet immediate customer and system reliability needs.

Moreover, the Company supports the Commonwealth's plan to meet its 2050 climate goals through multiple initiatives for the electric and gas utilities, all which must align and deliver to achieve these goals. Specifically, the Company is supportive of these efforts to increase energy efficiency and transition the Company's customers to non-gas alternatives. For example, the Company's electric affiliates have filed comprehensive Electric Sector Modernization Plans to chart the future infrastructure required to meet an increase in electrification over the next two decades. Additionally, the Company continues to support customer adoption of energy efficiency and building electrification through its nation-leading energy efficiency programs, filed and approved through statewide Three-Year Energy Efficiency Plans. The impact of these programs remains to drive reductions in gas consumption and peak demand that rival reductions achieved in any other state in the country, through both energy usage reductions as well as through fuel switching away from natural gas to electricity for heating.

The Company is obligated, however, to plan and procure gas commodity to meet the near-term gas supply need to ensure customers are served on the coldest, high demand days for the upcoming winter seasons. This need cannot be filled or eliminated solely by the measures above or with the Company's current supply portfolio. This Agreement is a critical component in the Company's supply portfolio to bridge the current gas customer need with the charted future these initiatives are designed to achieve – a significant reduction in gas demand.

Q. Why has the Company concluded that there are no feasible alternatives to this Agreement?

A. As the Company further describes in the present filing, the Company previously pursued potential new pipeline infrastructure into the Northeast which would have eliminated the Company's reliance on imported LNG from Everett. In recent years, proposed expansions such as Tennessee's Northeast Energy Direct and Algonquin's Access Northeast failed to move forward, as regulatory policies and opposition in the Northeast have deterred customer commitments necessary to move projects forward, despite increases in regional customer demand. Recognizing that a new pipeline to the Northeast is not the Commonwealth's or region's preferred pathway, the Company has relied on the Everett Marine Terminal and its existing infrastructure and connection to Boston Gas's system for incremental gas needs. The Company has also explored existing pipeline capacity originating from LNG import terminals to the extent it is available, increased vaporization at existing LNG facilities, use of portable LNG equipment, and major on-system distribution system projects to meet peak demand and system reliability needs; however, all of these discrete projects, even in aggregate, could not provide the volume or reliability benefits EMT provides in the timetable required.

Moreover, these alternatives lack the locational benefits of EMT. In addition to the gas supply, EMT's strategic location within the Company's service territory provides Boston Gas with operational flexibility and hydraulic support which can be used to mitigate disruptions and serve communities in and around the greater Boston area.

Based on the current imbalance between supply and demand and potential alternatives, the Company determined that the Agreement is therefore the most viable option available that is also consistent with the stated policy and objectives of the Commonwealth.

Q. What are the benefits and costs to customers of the Agreement?

A. The primary customer benefit of the Agreement is that it will allow the Company to serve customers on peak days as soon as the winter 2024/2025 season, using existing gas infrastructure, over a six-year term. In terms of costs, the Agreement is projected to result in an average increase on a typical residential heating customer's monthly winter bill of around 1.3 percent for the first year of the contract period. For an average residential heating customer, this translates into an increase of approximately $3.30 on a monthly winter bill. Winter bill increases for years 2 – 6 of the contract period are estimated to be between 0.3 percent and 1 percent year over year, for an average annual increase of less than 1 percent over the contract period. The Agreement is also compliant with the Global Warming Solutions Act ("GWSA"), in that it will not lead to an increase in greenhouse gas emissions, as the Agreement is replacing existing supply from which no additional greenhouse gas emissions will result. To the extent there is any increased gas usage due this Agreement, it will likely be used to serve new customers converting from oil heating to natural gas. Thus, the Company expects that the acquisition of gas supplies under the Agreement will reduce greenhouse gas emissions and contribute toward the GWSA goals.

II. OVERVIEW OF THE SUPPLY PORTFOLIO

Q. Please provide an overview of the Company's Massachusetts supply portfolio.

A. Boston Gas provides natural gas sales and transportation service to approximately 950,000 residential and commercial customers in 144 cities and towns. To meet design-day and design-year sendout requirements, the National Grid resource portfolio is composed of the following categories of available resources: (1) transportation contracts; (2) underground storage contracts; (3) peaking resources; and (4) gas commodity contracts.

National Grid has capacity entitlements on multiple upstream pipelines that allow for the delivery of gas to its citygates in Massachusetts. These contracts provide access to domestic production fields and liquid trading points that afford the Company a level of operational flexibility to ensure least-cost and reliable delivery of gas supplies. In general, the National Grid transportation agreements provide: (a) transportation to the Company's citygates for Gulf Coast, Mid-Continent, Northeast Market Area and Canadian supplies; (b) transportation for underground storage withdrawal and injection; or (c) flexibility to meet balancing and no-notice requirements.

National Grid's pipeline capacity contracts[1] fall into three primary categories:

(1) Long-haul capacity that is used to transport gas from production areas in the Gulf of Mexico, Mid-Continent and the Northeast to underground storage facilities in Maryland, New York, Pennsylvania and West Virginia and to the Company's Massachusetts citygates;

[1] Many of the Company's upstream pipeline capacity contracts are regulated by the FERC. FERC regulates the rates and services for natural gas pipeline transportation and storage facilities, as well as certification of new facilities and abandonment of existing facilities, primarily under the Natural Gas Act. FERC's authority under the Natural Gas Act ensures that the rates, terms and conditions of service by parties subject to its jurisdiction are just and reasonable and not unduly discriminatory or preferential.

(2) Short-haul capacity that is used to transport gas from underground storage fields to National Grid's Massachusetts citygates. These short-haul capacity entitlements are also used to ensure the deliverability of non-storage supplies to the Company's citygates when the capacity is not being used to transport underground storage supplies; and

(3) Short-haul capacity that is used to transport gas sourced in Canada to National Grid's Massachusetts citygates.

The transportation contracts allow for varying degrees of flexibility with respect to such features as no-notice requirements and nomination time changes.

The Company also has contracts for underground storage capacity. The Company's underground storage assets provide the Company with the ability to meet winter-season loads, while avoiding the expense of adding 365-day long-haul transportation capacity. Underground storage supplies also allow the Company to serve peak-period requirements with off-peak priced gas supply. By using long-haul capacity to fill underground storage, the Company is able to use those resources at a higher load factor. Lastly, underground storage greatly enhances the flexibility of the portfolio, allowing the Company to manage major fluctuations in weather from day to day, as well as within the day.

In addition to interstate pipeline and underground storage resources, National Grid utilizes peaking supplies, including city-gate delivered supplies and LNG to meet its design day and design season requirements. Peaking supplies are a critical component of the resource mix in that these supplies provide National Grid with the ability to respond to fluctuations

in weather, economics and other factors driving the Company's sendout requirements. The Company utilizes both on-system and off-system peaking resources to meet system needs.

Q. Please provide an overview of the role imported LNG currently plays in the Company's portfolio.

A. Where the Company's existing resource portfolio is insufficient to meet the Company's forecasted design-year sendout requirements for a given forecast period, the Company must consider incremental resources over and above the available assets in the Company's portfolio. Historically, the Company has been able to satisfy this deficit via citygate delivered supplies, but opportunities to do so are currently limited by a number of factors, including but not limited to: existing market conditions, capacity availability, primary point deliverability and supply availability. Limitations of market conditions, availability, and deliverability are reflective of the lack of infrastructure available in the region able to satisfy the demand for natural gas by both local distribution companies and power generation. Today, New England market area supplies able to satisfy the Company's incremental need are primarily limited to imported LNG that can either be (i) vaporized directly into the Company's distribution system by a third party or (ii) delivered via additional transportation capacity contracts on Tennessee, Algonquin, and Maritimes & Northeast Pipeline, LLC ("Maritimes"). Absent any further gas infrastructure expansions or upgrades, reliance on this additional pipeline capacity is limited in availability as natural gas pipelines are at full capacity for west to east flows into the region during peak periods. Thus, available capacity on pipelines able to serve the Company is limited to capacity that can only be used to transport supplies from east end LNG receipt terminals. Lastly, absent any further on-system gas infrastructure expansions or upgrades, reliance on this additional

pipeline capacity is also limited in that the gas must be able to be delivered to the LDC system at a point where it is needed.

Q. Please explain whether the addition of liquefaction contracts with National Grid LNG and Northeast Energy Center, LLC approved in D.P.U. 15-129 mitigate the Company's exposure to the global LNG market.

A. The agreements approved in D.P.U. 15-129 were part of the Company's long term LNG strategy, entered into at that time as commercial alternatives during the off-peak period where the Company is replenishing its LNG inventory in anticipation of the upcoming heating season. At the time the Company entered into agreements with National Grid LNG and Northeast Energy Center, LLC, EMT served as the only viable option for the Company to meet its LNG refill requirements. Development of liquefaction at these two facilities has enabled the Company to use its pipeline transportation capacity on both Algonquin and Tennessee outside of the peak period to liquefy domestic priced supplies for future consumption during the peak period. However, these liquefaction agreements do not provide incremental deliveries to the Company's citygates. Further, the Company has no firm rights to liquefaction services at either facility during the peak period and would require the Company to encumber its transportation on Algonquin and Tennessee during peak periods if it were to utilize the services during the winter.

III. PREVAILING CONDITIONS IN THE NEW ENGLAND GAS MARKET

Q. Please provide an overview of the New England Gas Market, including Everett Marine Terminal and its role in serving Boston Gas.

A. In New England, Tennessee and Algonquin are the only two interstate natural gas pipelines regulated by the FERC that transport natural gas to National Grid for distribution to Boston Gas's customers from highly traded supply points into the Company's service territory;

Maritimes is also directly connected to the Company's distribution system in Haverhill, Massachusetts, however, gas transported on Maritimes is not typically domestically sourced from liquid supply points, but instead is sourced from imported LNG.

In addition to these federally regulated pipelines, the Everett LNG facility has a direct connection with National Grid's distribution system that allows National Grid to access supply from the Everett LNG facility without requiring access to transportation on Tennessee**,** Algonquin, or Maritimes.

Q. What operational benefits does EMT provide Boston Gas?

A. As the Company notes above, the physical location of EMT within the Company's service territory provides for a direct connection into the Company's distribution system that allows National Grid to access supply from the Everett LNG facility without requiring access to transportation on a pipeline system. This physical delivery capability of EMT is therefore unique to the Company based upon the facility's location; deliveries for customers located outside of the Boston Gas distribution system requiring deliveries from EMT would require access to an additional means of transportation in order to move supplies from EMT to their required location for consumption.

Q. In addition to the direct connection at Everett, can EMT support deliveries to other facilities within the Company's service territory?

A. Yes. The Company is aware that Constellation has historically held transportation contracts with both Tennessee and Algonquin that allow it to move supply out of EMT and to various customer citygates off each of these pipelines. Pipeline transportation contracts held by Constellation include delivery capability on Algonquin's highly constrained G-lateral into Cape Cod. As part of the Agreement, the Company is not proposing to contract with

Constellation to receive supply on the G-lateral; the Company will only have the right to take deliveries at EMT through vaporization directly into its distribution system or via truck.

Q. Can other New England LNG providers replicate the same service for the Company as the EMT?

A. No. Although Constellation is not the only entity authorized to import LNG into the New England region, as the owner of EMT, it is the only entity to the Company's knowledge authorized to import and sell natural gas from the terminal. The Company has the ability to purchase LNG from other entities, including both Repsol and Excelerate, however these supplies would require transportation capacity on a pipeline in order to move it from the import terminal to the Company's distribution system.

Q. Why is supply requiring transportation capacity on a pipeline not a comparable alternative to EMT?

A. Supply requiring transportation capacity on a pipeline is not a comparable alternative to EMT because it would require a pipeline transportation agreement and those agreements are limited based on capacity availability and thus cannot transport gas to all the areas served by EMT. As the Company further establishes in its testimony, absent additional pipeline and/or supporting infrastructure, this capacity is limited with respect to the physical locations where it can deliver. The Company currently holds transportation capacity on both Algonquin and Maritimes that has a receipt of Beverly/Dracut, MA which can be filled by Repsol, but this capacity delivers to other parts of the Company's distribution system that do not meet the same locational requirements as the areas served by EMT, which includes the metro Boston region. Similarly, while the Company does not

currently have a transportation agreement that could be fed by the Excelerate terminal on a primary basis, available transportation capacity to do so would also not be able to physically deliver to the areas served by EMT. In addition to EMT's location within the Company's area of need, EMT's location on the extreme east end of the pipeline network provides a supply source downstream of pipeline constraints on the coldest days of the year and serves as a critical backup in the event of a force majeure on one of the pipelines serving Massachusetts. The Company therefore considers these other sources of LNG as complimentary to the Company's portfolio but not a replacement for EMT.

Q. Why is it important the gas supply be delivered to the areas served by EMT?

A. As discussed in greater detail below, the EMT is located at a strategic delivery site. EMT can provide critical hydraulic balancing, inject directly into the Company's distribution system and the constrained areas of Algonquin and Tennessee systems, and can mitigate and prevent disruptions due to upstream pipeline maintenance, failures, or shutdowns. Moreover, from this location, the Company can distribute this gas into the Boston Gas network spanning from Everett, south to Milton, west to Wellesley, and north on the distribution feeder system to supply many communities spanning from Arlington in the west to Lynn in the east. Transportation contracts with delivery points on other parts of the Company's system would not provide these important benefits.

Q. Please explain the Company's understanding of the potential closure of the Everett Marine Terminal.

A. Constellation owns the 1,413-megawatt Mystic natural gas-fired power plant and the LNG import facility at Everett. The Mystic generation facility has supported the operations of and served as the anchor tenant for the import terminal at Everett since the early 2000s.

The Mystic power facility is scheduled to retire after May 2024 and Constellation has indicated it requires long term agreements to maintain the operations of EMT after the retirement of the Mystic power generating facility.

This was reinforced on September 8, 2022, when FERC held a New England Winter Gas-Electric Forum to bring together stakeholders in the region to discuss the challenges faced historically during New England winters and discuss the stakeholders' differing expectations of challenges for future winters. At that meeting, Constellation confirmed publicly that it does not have any commitments to remain open beyond winter 2023/24. Without a commitment from an anchor tenant(s), Constellation noted the possibility of shutting down EMT.

Q. What is the impact to the Company should the Everett Marine Terminal cease to operate?

A. Although production of shale gas in the Marcellus and Utica basins primarily in Pennsylvania and Ohio has continued to grow in recent years, incremental supplies cannot reach the New England market because of pipeline capacity constraints in the region. As a result, local distribution companies, such as National Grid, remain reliant upon LNG imports to meet a portion of peak day and peak season demand. With a limited number of parties able to import LNG into the Boston region, and only the Everett Marine Terminal able to vaporize directly into Boston Gas's distribution system, the potential closure of the EMT threatens Boston Gas's ability to reliably serve its existing firm gas customers on high demand days.

IV. DESCRIPTION OF AGREEMENT

Q. What is the term of the Agreement?

A. As noted above, the term of the Agreement is six years beginning in June 2024 through and including May 2030. The six-year term allows for a transition period during which the Company must continue to reliably meet customer requirements while also planning for the anticipated decrease in customer growth expected by the Commonwealth. Specifics of the term of the Agreement can be found in Section 1(A)(i) of Exhibit NG-Agreement-2 (CONFIDENTIAL).

Q. Please describe Boston Gas's delivery rights under the Agreement.

A. On any day during the months of December through and including March of the term of the Agreement, Boston Gas has the right, but not the obligation, to call on Constellation to deliver supply. Such right is subject to both daily and seasonal limitations. Boston Gas may elect to take 100 percent of its entitlement as vapor supply by having Constellation vaporize such supply directly into its distribution system, or may elect to take a portion of its entitlements as liquid. For supplies nominated as liquid, Boston Gas would be responsible to arrange for the transportation of LNG from EMT to its facilities. The maximum daily quantities ("MDQ") and maximum seasonal quantities ("MSQ") Boston Gas is entitled to nominate are summarized in the table below:

Season	MDQ	MSQ
Winter 24/25	27,000	500,000
Winter 25/26	45,000	950,000
Winter 26/27	59,000	1,450,000
Winter 27/28	66,000	1,705,000
Winter 28/29	73,000	1,925,000
Winter 29/30	78,000	2,100,000

Specifics of Boston Gas's delivery right under the Agreement can be found in Sections 1(A).(ii) and1(B)-(D) of Exhibit NG-Agreement-2 (CONFIDENTIAL).

Q. Is the Company required to purchase its full maximum seasonal quantity under the Agreement?

A. No. The Agreement is structured as a physical option where on any day during the months of December through and including March of the Agreement, the Company has the right, but not the obligation, to call up to the maximum daily quantity for that season, subject to seasonal limitations set forth in the Agreement. Thus, should the Company experience a decrease in the forecasted requirements during the term of the Agreement, the Company would still be obligated to pay the fixed costs for that heating season, and the potential additional costs described herein, but would not be required to purchase the commodity.

Q. What is the significance of the Company's purchase obligation being structured as a call option?

A. As noted above, the Company is aware of and committed to partnering with the Commonwealth to achieve its climate goals. Should the Company's forecasted requirement decrease over the six-year term of the Agreement, the Company is not obligated to purchase the commodity.

Q. What are the fixed costs of the Agreement?

A. Under the Agreement, the Company will be responsible for a portion of the fixed costs associated with operation and maintenance of the Everett Marine Terminal to support sales to the Company ("Non-Commodity Demand Charge") and reservation of LNG for the Company ("Commodity Demand Charge"). Application of these fixed costs will be based on the maximum seasonal quantity the Company is allowed to call upon during a given

contract season of the term of the Agreement. The fixed costs under the Agreement are summarized in Exhibit NG-Agreement-3 (CONFIDENTIAL) and can be found in Section 1I of Exhibit NG-Agreement-2 (CONFIDENTIAL).

Q. What are the variable costs of the Agreement?

A. For each day the Company exercises its right to call on supply under the Agreement, the gas will be priced based off a widely published index for the delivery of natural gas. Variable costs under the Agreement can be found in Section 1.E of Exhibit NG-Agreement-2 (CONFIDENTIAL).

Q. Are there any additional costs for which the Company may be responsible under the Agreement?

A. Yes. The Agreement contains a provision whereby Constellation may pass through certain compliance costs associated with changes in law to its customers, including the Company, including compliance with methane regulations. The Agreement contains a capping mechanism for compliance costs that can be recovered by Constellation from the Company, and an obligation of Constellation to pay compliance costs up to a certain amount should costs exceed the customer cap. Should Constellation's compliance costs exceed this aggregate amount, they may seek reimbursement from forward sales customers and reserve the right to terminate the Agreement if they are denied recovery. This is addressed in Special Provision G of Exhibit NG-Agreement-2 (CONFIDENTIAL).

Q. Does the Agreement offer protections to the Company in the event Constellation fails to satisfy its delivery obligations under the Agreement?

A. Yes. The Agreement provides the Company with a crediting mechanism in the event Constellation is unable to satisfy its delivery obligations both during an event of Force

Majeure and for unexcused non-deliveries. If during the winter delivery period Constellation is unable to deliver as a result of a Force Majeure, then (i) after five (5) days Boston Gas shall be credited its Non-Commodity Demand Charge for the remainder of the outage, and (ii) a commodity demand charge based upon the number of days in the winter delivery period. For failure to deliver for reasons not excused by Force Majeure, the Company is entitled to relief in the form of pro-rated demand charges for the undelivered volume, plus cover damages associated with its replacement supply. This is addressed in Special Provision A of Exhibit NG-Agreement-2 (CONFIDENTIAL).

Q. Does the Agreement contain a Most Favored Nations provision?

A. Yes. The Agreement contains a most favored nations provision. This is addressed in Section I(E) of Exhibit NG-Agreement-2 (CONFIDENTIAL).

Q. Are there conditions precedent that must be satisfied before the Agreement becomes effective?

A. Yes. The Agreement contains several conditions precedent for both Constellation and the Company before either parties' obligations under the Agreement, including payment, will become effective. For the Company to be bound by the Agreement, the Company must receive an order from the Department approving its entry into the Agreement by May 1, 2024. Constellation requests that the Department complete its review of contracts for supply from the Everett Marine Terminal by May 1, 2024 to assure ongoing commercial operation of the facility after expiration of the Mystic Cost of Service Agreement with ISO-New England on May 31, 2024. Currently, Constellation does not have contracts that would support its continued operations post-Cost of Service. Constellation has represented to Boston Gas that without approval of this Agreement and the others referenced in it, the

Everett Marine Terminal will retire. Additional conditions precedent include Constellation having a right to terminate the Agreement by a date certain if it has not received an aggregate binding commitments from customers sufficient to support LNG Cargo procurement for the Contract Term. A comprehensive listing of all conditions precedent applicable to Constellation and the Company can be found in Special Provisions D and E respectively of Exhibit NG-Agreement-2 (CONFIDENTIAL).

V. NEED FOR THE AGREEMENT

Q. What factors are driving the need for the Agreement?

A. The need for the Agreement is driven by two factors: (1) a deficit in the Company's available peak day and peak season assets as compared to forecasted customer requirements; and (2) gas system reliability.

Q. What forecast of customer requirements was utilized to determine the need for the Agreement?

A. The need for the Agreement is founded on the Company's 2023 annual demand forecast which was prepared using the methodologies approved in its then most-recent biannual Long-Range Forecast and Supply Plan ("F&SP"), D.P.U. 20-132, as discussed in the pre-filed testimony of Shira Horowitz and Theodore Poe, Jr. ("Forecast Testimony"), Exhibit NG-Forecast-1. The forecast of peak day and peak season customer requirements was then modeled using the Company's SENDOUT® model.

Q. How does the Company use the SENDOUT® model?

A. The Company evaluates whether the capacity and gas-supply resources available to the Company are sufficient to meet sendout requirements using the SENDOUT® model. The SENDOUT® model is a linear programming optimization software tool used to assist in

evaluating, selecting and explaining long-term portfolio strategies. Using the SENDOUT® model, the Company is able to determine the least-cost portfolio that will meet the forecasted demand and to test the sensitivity of the portfolio to key inputs and assumptions, including its ability to meet sendout requirements under the Company's planning standards and contingency scenarios. Based on the results of this analysis, the Company is able to make preliminary decisions on the adequacy of the resource portfolio and its ability to meet system requirements over the longer term.

Q. Does the Company have a deficit in available peak day assets? If so, please explain.

A. The Company previously participated in Kinder Morgan's Northeast Energy Direct project ("NED"), which was approved by the Department in D.P.U. 15-134. Together with the in-service of the liquefaction projects, NED would have made the Company independent of imported LNG based on the Company's then-effective forecast of customer requirements. In 2016, Kinder Morgan provided the Company notice of termination of the NED precedent agreement. Since the suspension of NED, the Company has successfully met a portion of its forecasted need by acquiring small amounts of capacity on each of Tennessee, Algonquin, and Maritimes; however, as the Company discusses in the instant filing, availability of capacity on these interstate pipelines is limited and exposes the Company further to requiring imported LNG. Since the suspension of the NED project, the Company has also seen an increase in its forecasted requirements on both the peak day and peak season.

In addition to the Company's daily and seasonal deficit, the Company also experiences a peak hour deficit behind several of its take stations[2]. Historically, the Company has had operational flexibility across its take stations on Algonquin and Tennessee, within the limits of its total contracted capacity on each pipeline. In recent years, as pipelines serving the Northeast become more heavily utilized by both local distribution companies and power generators, the Company has experienced restrictions on this flexibility and in some cases warnings by the pipeline(s) that it may issue operational flow orders under its tariff for customers to limit their hourly takes to calculated hourly flow limits at each take station. The Company has therefore begun to make certain planning decisions to prepare for the potential interruption of operational flexibility at an hourly level (i.e., deployment of portable LNG operations on Cape Cod).

Q. How did the Company analyze the need for imported LNG for incremental design day and design season resources?

A. The Company ran the SENDOUT® model using the customer requirements forecast with updated pricing, trends and anticipated changes to the portfolio. The Company then analyzed the forecasted design-season and design-day requirements served by domestically sourced pipeline transportation (including upstream LNG delivered via pipeline transportation), underground storage, and on-system LNG available to the Company. Based on this analysis, the Company identified: (1) the total design day need for imported LNG of 41 MDth in 2024/25, growing to 145 MDth in 2029/30; and (2) the total design season need for imported LNG of 684 MDth in 2024/25, growing to 3,869 MDth in 2029/30. These results are presented in Exhibit NG-Agreement-5, page 1 of 8, Table G23-

[2] The design hour represents five percent of the design day.

D, labeled "DESIGN PEAK DAY (Without Constellation)" and Exhibit NG-Agreement-5, page 2 of 8, Table G23-D, labeled "HEATING SEASON (NOV-MAR) (Without Constellation)." See the table below for a summary of total design day and design season need for imported LNG.

Table 1

	Design Day Imported LNG Need Without Constellation bBtu	**Design Day Imported LNG Need Including Constellation bBtu**	**Design Season Imported LNG Need Without Constellation bBtu**	**Design Season Imported LNG Need Including Constellation BBtu**
2024/25	41	14	684	184
2025/26	76	31	1,616	666
2026/27	107	48	2,582	1,133
2027/28	121	55	3,120	1,415
2028/29	136	63	3,542	1,617
2029/30	145	67	3,869	1,769

Q. How do the design day and design season imported LNG needs compare to the volumes in the Agreement?

A. The volumes in the Agreement include half of the design day and design season imported LNG needs as well as the small volume of winter liquid needed to backfill the Company's LNG facilities during the winter season and supply portable LNG operations. As demonstrated by the table above, the Agreement is needed to help to meet the Company's design season and design day requirements. In addition, the Agreement decreases current peak hour deficits at certain of the Company's take stations which feed the system also served by EMT.

Q. Is the need consistent with the trend identified in the Company's D.P.U. 22-149 long-range forecast and supply plan?

A. Yes. In the Company's D.P.U. 22-149 F&SP, the Company identified a net need as forecasted customer requirements exceeded resources available in the Company's supply portfolio. As discussed in the Forecast Testimony, Exhibit NG-Forecast-1, the Company's forecast of customer requirements has decreased compared to those included in D.P.U. 22-149 F&SP. This decrease in customer requirements has reduced the total net need for incremental resources, more specifically imported LNG.

Q. Please explain the need from a gas system reliability perspective.

A. The Everett Marine Terminal is in a unique position to support gas system reliability due to both its location and significant sendout capability. The EMT is located at a strategic delivery site for both National Grid and other customers (e.g., other local distribution companies, power plants, industrial customers) of the Algonquin and Tennessee pipelines in areas north and west of Boston. Constellation can provide critical hydraulic balancing on the Algonquin, Tennessee, and National Grid systems in eastern Massachusetts through direct connection to each of the respective facilities. Everett is a hub with significant pipeline infrastructure that allows for injections of gas supply directly into National Grid's feeder systems, and constrained areas on the Algonquin and Tennessee systems. Gas supplies at Everett can mitigate and prevent disruptions on the Company's distribution system that may otherwise be experienced resulting from upstream pipeline maintenance, compressor failures, or on-system LNG plant shut-downs, or on-system feeder or distribution piping isolations/shutdowns at any time of year.

National Grid can accept gas supply from Constellation in Everett and distribute this gas into the Boston gas network spanning from Everett, south to Milton, west to Wellesley, and north on the distribution feeder system to supply many communities spanning from Arlington in the west to Lynn in the east. Further, Constellation has the capability to inject into the end of the Algonquin and Tennessee systems in Everett and bolster pressures on these constrained portions of the pipelines systems that in turn supply approximately half of the Company's take stations in Massachusetts. These injections are critical to ensure adequate pressures are maintained to these National Grid take stations and to provide for uninterrupted deliveries to the Company's customers. The Company's contractual pipeline deliveries alone may not be adequate to maintain system pressures to these stations. As the upstream pipelines serving the Company's distribution system continue to become more constrained, the operational flexibilities which they have historically provided will continue to diminish.

Q. In addition to the gas system reliability benefits discussed above, are there additional operational benefits to the Company as a result of entering into the Agreement?

A. Yes. Each of the gas system reliability benefits the Company discusses in its testimony are also operational benefits of the Agreement. Further, takeaway at this site under design day conditions can meet approximately fifteen percent of total design hour requirements and supply approximately 95,000 customers in the communities of Belmont, Boston, including the neighborhoods of Charlestown, East Boston, Jamaica Plain, Roxbury and South Boston, Brookline, Chelsea, Everett, Newton, Somerville, Watertown, and Winthrop. Under non-peak conditions, Everett is capable of supplying over fifty percent of National Grid's total sendout in Massachusetts, approximately 350,000 customers, with distribution

system capacity to reach the communities of Arlington, Belmont, Boston, including the neighborhoods of Brighton, Charlestown, East Boston, Jamaica Plain, Roxbury and South Boston, Brookline, Chelsea, Everett, Lexington, Lynn, Malden, Medford, Melrose, Newton, Revere, Saugus, Somerville, Stoneham, Wakefield, Watertown, Winchester and Winthrop.

Q. If the Department approves the Agreement, will the Company have incremental exposure to the global LNG market?

A. Yes. As noted above, the volumes in the Agreement include half of the total design day and design season imported LNG needs. The Company currently holds transportation capacity that is supplied by imported LNG to deliver supplies to the Company's citygates when needed to meet customer requirements. Through the Agreement, the Company is not proposing to fill that transportation capacity. If this transportation capacity needed to meet additional customer requirements above and beyond the needs served by the Agreement, an incremental purchase of imported LNG or procurement from another supply source may be required and need not be limited to supply from Constellation.

VI. EVALUATION OF ALTERNATIVES

Q. Did the Company issue a Request for Proposals ("RFP") to identify solutions to meet the forecasted deficit?

A. Yes. On October 15, 2021, the Company issued an RFP to gas marketers, producers, portable project operators and pipeline developers, to solicit proposals so that it may continue to safely and reliably meet a portion of its peak day requirements beginning with the winter of 2024/25. As part of the RFP, the Company advised the market that it was familiar with supply resources that may be available to meet forecasted peak day

requirements including (i) biomethane facilities that can interconnect directly to the Company's distribution system; (ii) distributed natural gas storage and vaporization, including compressed natural gas ("CNG") and LNG; and (iii) interstate pipeline transportation.

While proposals for service were requested to be available to commence as early as winter 2024/25, the Company considered the pursuit of multiple proposals that could be phased in over several heating seasons. The Company did not expect that a single proposal may be able to satisfy the gas supply requirements identified. Respondents were required to demonstrate they have primary firm capacity to each of the Company's delivery points for which they submitted an offer and/or an explanation of the priority of service to be used in meeting the Company's gas supply requirements if selected.

Q. Is the Agreement the direct result of the RFP?

A. No. In response to the RFP, the Company received several proposals, including an offer from Constellation. Since the issuance of the RFP, the Company has invested significant time and efforts into evaluation of potential solutions to continue to meet its obligations and during that time has seen a shift in the global LNG market. Additionally, the potential closure of Everett has also received the attention of FERC, with multiple commissioner-led forums having been convened to discuss possible solutions to the challenges faced in New England.

Q. Did the Company pursue supply-side alternatives?

A. Yes. Since the RFP, the Company has continued to evaluate various supply-side solutions that could meet the near-term deficit in the portfolio. Supply-side and on-system solutions

include a combination of: (1) existing pipeline capacity originating from LNG import terminals; (2) incremental pipeline capacity from an upstream pipeline expansion project; (3) increased vaporization at existing LNG facilities; (4) portable LNG; and (5) major on-system pipeline system projects to transport volumes from where they are available to where they are needed. A number of these projects are currently included in the Company's 10-year capital investment plan and others are under further consideration and/or extend beyond the 10-year planning timeframe. Additionally, the Company has contracted for capacity originating from LNG import terminals which can be used to meet a portion of its volumetric deficit, but cannot provide the same locational benefits as Everett. Although the Company continues to evaluate the role incremental LNG vaporization or expansion of its portable footprint may hold in meeting supply requirements, these are small discreet projects that even in aggregate could not meet the Company's forecasted deficit. A larger-scale expansion, even if successfully permitted and constructed, could not be available in the timeline required by the Company to meet firm forecasted requirements served by the Agreement.

Q. Has the Company identified any supply-side alternatives that could offer the same operational benefits as the Agreement?

A. No. Many of the supply-side projects, even in aggregate, if implemented, could not meet the needs served by the Agreement in the required timeline. Further, to leverage any additional existing interstate pipeline capacity as a substitute for EMT, the Company would require major new on-system infrastructure to increase system utilization into this same area of Boston. In evaluating this possibility, the Company must consider the maximum allowable operating pressure of the area being served by the facilities, and the length of

pipeline and constructability to move gas supply into where it is needed on the distribution system. The Company is pursuing permanently increasing LNG vaporization capacity at several of its existing LNG facilities and implementing portable injection sites. However, although incremental LNG plant volumes supplement the overall supply portfolio and address peak hour imbalances, they generally do not benefit or support the imbalance which exists in areas fed or supplied from Everett. Finally, increased vaporization at existing facilities without an expansion of storage will not address any seasonal shortfall in the portfolio and will increase the Company's reliance on transportation of LNG via trucks into the Company's facilities throughout the winter months.

Q. Would a large-scale expansion of an interstate pipeline obviate the need for the Agreement?

A. As explained above, the Company is uniquely served by EMT as a result of the facility's physical location within the Company's service territory and its ability to vaporize directly into the Company's distribution system. An expansion project within this same geographic area could potentially obviate the need for the Agreement; however, such a project could not be constructed absent receipt of any required local, state, and federal permits. Even if such a project were to be permitted, it is unlikely that the construction could be completed by December 1, 2024 when the Company could begin taking delivery of supply from Constellation.

Q. In addition to supply-side solutions, did the Company explore demand-side solutions?

A. Yes. In addition to supply-side resources, the Company has and continues to explore incremental demand-side resources, including targeted outreach efforts and localized enhanced incentives for gas energy efficiency and gas to electric conversions of customer

space and water heating loads, and the launch of gas demand response programs. In light of the demand side contributions already being made through the Company's existing, approved energy efficiency and electrification programs, the potential impact of these incremental demand-side resources is likely to be small as compared to the scale of the need that would be created should Everett cease operations (or the opportunities afforded by the supply-side strategies identified above).

Additionally, policy questions remain regarding the incremental cost of these solutions, the impact of any locally enhanced incentives on the Company's ability to deliver on existing statewide energy efficiency and electrification targets, the cost effectiveness of these potential offerings under the current energy efficiency avoided cost framework, and the scope of potential solutions (including incentivizing customer fuel switching from natural gas to deliverable fuels during peak periods) that would be appropriate for inclusion in any portfolio of demand response offerings. The Company anticipates continuing to explore these questions, and, to the extent that a determination is made to pursue any incremental demand-side resources as a component of a portfolio of solutions, the Company would likely do so either through a mid-term modification proposal under the current Three Year Energy Efficiency plan framework, or as a component of the 2025-2027 Three Year Energy Efficiency Plan, to be filed with the Department in October 2024.

Q. Are there demand-side alternatives to the Agreement?

A. The Company is actively working to transition away from fossil gas as part of the Company's Clean Energy Vision and continuing to explore and execute on a variety of both supply- and demand-side solutions. However, the potential impact of these incremental

demand side resources is likely to be small as compared to the scale of the need that can be fulfilled by the Agreement beginning with the next 2024/2025 heating season. Thus, demand side resources alone will not be a complete substitute for the Agreement. Demand-side solutions are a key pillar of this vision and the Company will continue to rely on the Company's nation leading energy efficiency programs, as filed with and approved by the Department, in order to develop and provide programs for customers to accelerate energy efficiency improvements to buildings. These efforts include traditional energy efficiency measures that reduce peak gas demand, deep energy retrofits, and both full and partial displacement of gas end uses with high efficiency electric equipment. The Company also remains supportive of and is active in advocating for more rigorous appliance standards and building codes for new buildings and major renovations.

In addition to customer efforts as delivered through energy efficiency programs, the Company is also exploring new levers to reduce gas demand outside of energy efficiency programming, including networked geothermal. The Company is currently working to develop the capability to identify and evaluate non-pipeline alternatives ("NPAs"), such as electrification to avoid capacity or supply constraints or in lieu of leak prone pipe replacement, and intends to discuss a NPA framework with stakeholders, as required by D.P.U. 20-80-B. Electrification solutions could include air-source heat pumps, ground-source heat pumps, or networked geothermal. Scaling networked geothermal via utility-owned thermal energy networks is another potential lever for reducing demand. National Grid recently broke ground on the Company's first networked geothermal pilot in Lowell, MA, where it will install and operate geothermal networks at up to four separate locations,

serving a group of customers with diversity in size and use. The Company also recently announced its second networked geothermal site at Franklin Fields in Boston, working with the Boston Housing Authority. Scaling up networked geothermal will require new regulatory and policy enablers.

Demand-side levers to mitigate gas growth will also be necessary alongside solutions to reduce demand, which could involve changes to energy efficiency and/or hybrid electrification at the point of connection, alternatives to gas connections, or a gas moratorium for new customers. National Grid also supports building codes and policies to mitigate gas growth from new construction, including the new stretch energy code and municipal opt-in code finalized by the Department of Energy Resources and implemented in 2023.

Q. Did the Company consider energy efficiency as a supply option in lieu of pipeline capacity?

A. While energy efficiency is not a supply option, the Company has energy efficiency built into its customer demand estimate. Energy efficiency is embedded into the Company's demand forecast as per the Company's approved F&SP methodology. The Company's current Three-Year Energy Efficiency plan includes an average of approximately 16 million therms of annual savings per year. These robust offerings are delivered in a cost-effective manner and are expected to achieve all available cost-effective energy efficiency as mandated by the Green Communities Act. While some degree of incremental energy savings could be theoretically achievable through energy efficiency, the scale of the aggregate achievable opportunity is insufficient to obviate the need for requested supply investments and could not be done cost effectively.

Q. Are there any viable alternatives to the Agreement?

A. No, there are no viable alternatives currently available in the marketplace that offer the services that could be provided to the Company by the EMT during the term of the Agreement. The Company would need a combination of on-system and upstream projects to replace the services provided by Everett. These projects would vary in scope, size, and cost. Further, the scalability of such alternatives would be a challenge, as would the constructability and permitting of such projects.

Q. Is the Agreement compliant with the Global Warming Solutions Act?

A. Yes, the Agreement is compliant with the GWSA. The Agreement will not lead to an increase in greenhouse gas emissions. The Agreement is necessary for the Company to supply the current gas demand of its current customers. Therefore, the Company is replacing existing supply from which no additional greenhouse gas emissions will result. To the extent there is any increased gas usage due this Agreement, it will likely be used to serve new customers converting from oil heating to natural gas. On this basis, the Company expects that the acquisition of gas supplies under the Agreement will reduce greenhouse gas emissions and contribute toward the GWSA goals.

Q. Please discuss the Department's recent D.P.U. 20-80-B Order and how it relates to the Agreement.

A. On December 6, 2023, the Department issued an Order on Regulatory Principles and Framework, D.P.U. 20-80-B, in an investigation into the role of LDCs as the Commonwealth achieves its target 2050 climate goals ("Order"). The Order confirms rate recovery of existing gas system investment and the LDCs' obligation to provide safe and reliable service, including compliance with state and federal mandates. D.P.U. 20-80-B at

14, 97. It also charts a new "lens" to be applied to future gas infrastructure investments, including NPAs, and other policies geared towards minimizing additional investment in pipeline and distribution mains, discouraging further expansion of the natural gas distribution system, achieving decarbonization in customer sectors, and exploring opportunities for strategic and targeted decommissioning portions of the LDCs' service territories through electrification and thermal network technologies. Id. at 14-15.

The Company welcomes the Department's guidance on this complicated target to meet the 2050 climate goals, noting the substantial additional work required to implement the Department's vision in D.P.U. 20-80-B, which will take years to fully embed in the Company's processes and see meaningful results. This work includes creating Climate Compliance Plans, coordination with the electric distribution companies on integrated energy planning, development of NPA processes for investment decisions, creation of demonstration programs, and customer education and outreach.

The Order outlines the Department's long-term vision for the gas system aimed at decreasing the Commonwealth's reliance on and need for natural gas to contribute to emissions reductions. However, the Company has an obligation to supply the needs of current customers and their associated gas demand, at present and in the immediate future, for which this Agreement is required.

Q. Given the Department's D.P.U. 20-80-B Order contemplates a reduction in gas demand in the future, how will the Company address a decrease in its forecast during the term of the Agreement?

A. The Agreement is required for the Company to meet current customer gas demands and the forecasted need in the next six years. If the Company experiences a decrease in the

forecast during the Agreement term (before March 31, 2030), the Agreement's design provides the Company sufficient flexibility to adapt accordingly.

As stated above, the Company currently holds transportation capacity that requires use of imported LNG to deliver supplies to the Company's citygates. Through this Agreement, the Company is not proposing to fill that transportation capacity. Thus, if the Company experiences a decrease in its forecast during the term of the Agreement, the Company does not need to take further procurement action and will not make any incremental purchases of imported LNG.

Additionally, many of the transportation contracts in the Company's portfolio are outside of their primary term and currently subject to renewal terms triggered by notice provisions of five years or less; this provides the Company with ample opportunities to continuously evaluate contracts within the portfolio should a sustained decrease in customer requirements materialize. The Company further notes for the Department that the Agreement expires as of March 31, 2030 with no option to extend. Thus, any long-term agreement between Constellation and the Company or another service provider beyond the term of this Agreement would require additional approval by the Department.

VII. PRICE AND NON-PRICE CONSIDERATIONS

Q. Please explain price considerations of the Agreement.

A. In 2007, Constellation filed an application under Section 3 and Section 7 of the Natural Gas Act to obtain authorization to abandon services pursuant to its tariff and to cancel its tariff. FERC approved this request in July 2008 and, as a result, the facility was no longer subject to regulation of rates, rate caps for service offerings, and abandonment protection.

The Company recognizes that the price charged under the Agreement is a market-based rate for the services and supply being offered.

Q. Please explain the rationale for the cost components of the Agreement.

A. As explained above, the Company will be responsible for a portion of the fixed costs associated with operation and maintenance of the Everett Marine Terminal to support sales to the Company and reservation of LNG for the Company. Today the Company reimburses pipeline transportation providers with costs associated with its service through rates paid under its transportation contracts. Application of these fixed costs will be based on the maximum seasonal quantity the Company is allowed to call upon during a given contract season of the term of the Agreement.

Q. What are the implications of not receiving approval of the Agreement?

A. If the Company does not receive approval of the Agreement, the Everett facility will likely close. There are no viable alternatives in the marketplace that offer the services provided by Everett to the Company. If Everett were to close, it would significantly and adversely impact the Company's ability to reliably serve its customers over the next several winters. With few suppliers able to import LNG into New England and a lack of new gas pipeline infrastructure into New England limiting access to low-cost domestic supplies, continued reliance on the delivery of imported LNG supplies to satisfy existing and forecasted requirements exposes customers to price volatility and supply reliability risk. Should Constellation cease operation of the Everett LNG facility, the region will be solely reliant on the willingness of other LNG importers to New England to supply LNG into the region. Even if other LNG suppliers will sell such supplies to the Company, incremental pipeline

transportation capacity on Algonquin, Tennessee, and Maritimes will be necessary to deliver such supplies to LDC consumers and could not meet the same locational needs as Everett does today in the Company's portfolio absent incremental infrastructure. Given the density of the areas served by EMT, the impact of this type of situation from a risk and cost perspective is expected to be significant and will be difficult to quantify.

Q. Did the Company analyze non-price factors associated with the Agreement?

A. Yes. With respect to non-price factors, the Company evaluated the reliability, flexibility, and diversity that a new resource would add to the overall resource portfolio. The Company used several criteria to assess each of these non-price factors on a qualitative basis, as follows:

(1) "Reliability" refers to the ability of the Company to obtain and dispatch a portfolio of resources sufficient to meet the needs of its customers when called upon;

(2) "Flexibility" refers to the Company's ability to manage resources in response to daily, monthly and seasonal fluctuations in demand and supply so that reliability is maintained, and cost is minimized; and

(3) "Diversity" refers to the extent to which the portfolio design minimizes risk by allocating the risk of non-delivery over numerous supply resources with diverse characteristics. In addition, diversity of supplies is important in providing a level of flexibility to the management of the portfolio.

As indicated by these factors, the Company's examination of non-price factors does not focus exclusively on the characteristics of the specific resource option under consideration

by the Company. Instead, this analysis also focuses on the benefits that a particular option presents in the context of the Company's existing portfolio. For example, although a given resource may possess flexible attributes (for example, affording deliverability to either Tennessee or Algonquin), the resource may be duplicative of other resources in the portfolio that offer the same flexibility, and therefore, the resource provides no greater level of flexibility to the overall management of the portfolio. Conversely, a resource that possesses no inherent flexibility (e.g., alternative delivery points) may provide the overall portfolio a level of flexibility when it is used in combination with other resources in the portfolio.

As part of the Agreement, the Company maintains the right to dispatch supplies purchased on a non-ratable basis, meaning it can utilize the flexibility of the terminal to manage fluctuating temperatures across holidays and weekends. Details of the flexibility offered by the Agreement can be found at Section 1(B)-(D) and Special Provision B of Exhibit NG-Agreement-2 (CONFIDENTIAL).

Additionally, the Agreement offers the opportunity for the Company to purchase a portion of its volume in liquid form. Historically, the Company has purchased approximately 300,000 Dths of LNG during the winter months to replenish boil off in its existing storage facilities and support operations at its portable sites. As previously explained, while liquefaction is now available to the Company during the refill season, liquefaction is not available to the Company on a firm basis during the winter months.

Q. What reliability benefits does the Agreement provide?

A. The most significant benefit that the Agreement will provide is reliability. As discussed at length above, the Company has identified a need for incremental supplies that continues to grow year after year. Deliveries out of EMT enable the Company to vaporize this gas supply directly into its distribution system, avoiding the need to transport supplies on pipeline capacity. EMT's location on the extreme east end of the pipeline network provides a supply source downstream of pipeline constraints on the coldest days of the year and serves as a critical backup in the event of a force majeure on one of the pipelines serving Massachusetts. The Agreement will assist the Company in filling a portion of this need, in the near term, to ensure reliable service for its customers by providing incremental deliveries to the Company's distribution system.

Q. What flexibility does the Agreement provide?

A. The Agreement provides incremental flexibility to the overall portfolio. The Agreement delivers incremental supply into the Company's distribution system on a primary firm priority, with the flexibility to dispatch these supplies on a non-ratable basis across holidays and weekends. Further, the Company has the ability to take a portion of the total volume each season as vapor or liquid.

Q. What diversity does the Agreement provide?

A. The Agreement provides diversity to the overall portfolio by ensuring that the Company's customers have access to natural gas supplies not only via pipeline transportation, but also directly out of EMT.

Q. Does the Agreement provide for benefits to customers besides the Company?

A. The Company is unaware of other customers besides the Company that have entered into long term agreements with Constellation during the term covered by the Agreement. Based on the Company's knowledge of the integrated gas network, EMT's physical location can facilitate a bolstering of pipeline pressures on Algonquin and Tennessee in periods of peak demand and/or pipeline interruptions.

Q. Did the Company consider regional benefits as part of its non-price considerations?

A. No. In negotiating the Agreement and its terms and conditions, the Company's priority was and remains its ability to reliably serve its customers. As the Company has established in its testimony, the physical location of EMT within the Company's service territory and the facility's ability to vaporize directly into a critical part of the Company's distribution system cannot be replicated by any other existing asset during the term of the Agreement. Further, the Company's volumetric requirements under the Agreement are based on forecasted requirements, including its ability to serve existing customers.

VIII. BILL IMPACTS

Q. Did the Company analyze the bill impacts to customers as a result of the Agreement?

A. Yes. The Agreement is projected to result in an average increase on a typical residential heating customer's monthly winter bill of around 1.3 percent for the first year of the contract period. For an average residential heating customer, this translates into an increase of approximately $3.30 on a monthly winter bill. Winter bill increases for years 2 – 6 of the contract period are estimated to be between 0.3 percent and 1 percent year over year. The illustrative bill impacts for all rate classes are provided in Exhibit NG-Agreement-6

and include results for all six years of the contract term, measured on a year-over-year basis, and are based on current rates and prices.

IX. CONCLUSION

Q. Based on the factors you describe above, is it your opinion that the incremental supply resource is needed to ensure the reliability and deliverability of the natural gas needed to meet the sendout requirements of customers?

A. Yes. It is our opinion that the Company will need the Constellation resource contract to meet both near-term and longer-term sendout requirements of the Company's customers on a reliable basis.

Q. Does this conclude your pre-filed joint testimony?

A. Yes, it does.