

**COMMONWEALTH OF MASSACHUSETTS**

**DEPARTMENT OF PUBLIC UTILITIES**

Petition of NSTAR Gas Company d/b/a  
Eversource Energy for Approval of an  
Increase in Base Distribution Rates and  
Performance-Based Regulatory Plan for Gas  
Service Pursuant to General Laws Chapter  
164, §94 and 220 C.M.R. §§ 5.00, *et seq.*

D.P.U. 19-120

**DIRECT TESTIMONY OF**

## WILLIAM J. AKLEY AND DOUGLAS P. HORTON

*Case Overview*  
*Performance-Based Regulatory Plan*

**On behalf of**

**NSTAR Gas Company  
d/b/a Eversource Energy**

November 8, 2019

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**Table of Contents**

I.	INTRODUCTION .....	1
II.	OVERVIEW .....	8
III.	NSTAR GAS ORGANIZATIONAL STRUCTURE .....	17
IV.	OPERATING FOCUS NOW AND IN THE FUTURE .....	21
A.	Investments in People .....	36
B.	Investments in Process .....	55
C.	Investments in Technology .....	59
V.	PROGRESS ON EMISSIONS REDUCTIONS .....	65
A.	Reducing GHG Emissions on the Distribution System .....	66
B.	Renewable Natural Gas.....	70
C.	Environmentally Responsible Gas Supply.....	74
VI.	DESCRIPTION OF THE PROPOSED PBR PLAN .....	79
VII.	SCORECARD METRICS .....	99
A.	Safety and Reliability Metrics .....	104
B.	Emissions Reduction Scorecard Metrics .....	110
VIII.	CONCLUSION.....	113

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**I. INTRODUCTION**

**Q. Mr. Akley, please state your name and business address.**

**A.** My name is William J. Akley. My business address is 247 Station Drive, Westwood, Massachusetts 02090.

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

**A.** I am President of the Eversource Energy gas distribution business, employed by Eversource Energy Service Company (“Eversource Service Company” or “ESC”). The Eversource Energy gas distribution business encompasses NSTAR Gas Company d/b/a Eversource Energy (“NSTAR Gas” or “Eversource” or the “Company”) and Yankee Gas Services Company (“Yankee Gas”). ESC provides financial, administrative and technical support to the direct and indirect subsidiary companies of Eversource Energy. My current duties include oversight of the day-to-day operations of the gas distribution business and other gas-related subsidiaries operating in Connecticut and Massachusetts. My oversight duties include all maintenance, construction and emergency response activities, as well as oversight of the Eversource Energy liquefied

1 natural gas (“LNG”) operations and all customer meter-service activities across the gas  
2 distribution businesses.

3 **Q. Please describe your educational background and professional experience.**

4 A. I earned a Bachelor of Science degree in mechanical and industrial engineering from  
5 Clarkson University in Potsdam, New York in 1983. In 1987, I earned a Master of  
6 Business Administration degree from Adelphi University in Garden City, New York.  
7 I joined the Brooklyn Union Gas Company in 1983 as a management trainee and held  
8 a series of successively responsible positions in the gas business operated by KeySpan  
9 Corporation (“KeySpan”), including project and design engineering, dispatch, field  
10 operations, corrosion engineering, leak survey, budget support and contract  
11 administration. In 2002, I was named Vice President for the KeySpan organization  
12 with responsibility for Real Estate, Property Services and Security. In 2004, I was  
13 named Vice President of Gas Operations - Long Island. In 2007, I was promoted to  
14 Senior Vice President, U.S. Gas Operations and Construction for National Grid USA’s  
15 U.S. gas distribution business, following National Grid’s acquisition of KeySpan. I left  
16 this position in June 2014 and commenced my current position with Eversource Energy  
17 in November 2014.

18 **Q. Have you previously testified before the Massachusetts Department of Public**  
19 **Utilities?**

20 A. Yes. I testified before the Massachusetts Department of Public Utilities (the  
21 “Department”) in NSTAR Gas Company, D.P.U. 14-150 (2015). Prior to that, I

1 testified before the Department on behalf of National Grid in Boston Gas Company,  
2 Colonial Gas Company and Essex Gas Company, D.P.U. 10-55 (2010) regarding  
3 operations and maintenance practices used by National Grid to provide safe and reliable  
4 service to customers. I also testified in Oversight Investigation into the National Grid  
5 and KeySpan Merger, D.P.U. 07-30 (2010), regarding the performance of the gas  
6 distribution business following the KeySpan/National Grid USA transaction.

7 **Q. Mr. Horton, please state your name, position and business address.**

8 A. My name is Douglas P. Horton. I am Vice President, Distribution Rates and Regulatory  
9 Requirements, employed by Eversource Service Company. My business address is 247  
10 Station Drive, Westwood, Massachusetts 02090.

11 **Q. What are your principal responsibilities in this position?**

12 A. As Vice President, Distribution Rates and Regulatory Requirements, I am responsible  
13 for the oversight, coordination and implementation of revenue requirement calculations  
14 and distribution rates for the Eversource Energy operating companies in Massachusetts,  
15 Connecticut and New Hampshire, including NSTAR Gas. In addition, I have the  
16 overall responsibility for regulatory interfaces for all revenue requirement-related  
17 filings before the Department.

18 **Q. Please summarize your professional and education background.**

19 A. I graduated from Bentley College (now Bentley University) in Waltham,  
20 Massachusetts in 2003 with a Bachelor of Science degree. In 2007, I graduated from

1 the Bentley University McCallum Graduate School of Business with a Master of  
2 Business Administration. I joined NSTAR Electric Company as a Senior Financial  
3 Planning Analyst in August 2007 and was promoted to Project Manager, Smart Grid,  
4 in March 2010. Following the merger of NSTAR and Northeast Utilities in 2012, I  
5 was promoted to Manager of Revenue Requirements for Massachusetts. I was then  
6 promoted to Director, Revenue Requirements for Massachusetts, in February 2015. I  
7 assumed my current role as Vice President, Distribution Rates and Regulatory  
8 Requirements in December 2018.

9 **Q. Have you previously testified before the Department?**

10 A. Yes. Most recently, I sponsored testimony in the Department's investigation into the  
11 federal income tax rate change in D.P.U. 18-15. I testified on behalf of NSTAR Electric  
12 d/b/a Eversource Energy ("NSTAR Electric") in its most recent base distribution rate  
13 proceeding in D.P.U. 17-05. I also testified in the petition for approval of a gas service  
14 agreement between NSTAR Gas and Hopkinton LNG Corp. ("HOPCO") in D.P.U. 14-  
15 64, and in support of the HOPCO demand charge in the Company's last base-rate  
16 proceeding in D.P.U. 14-150, among other proceedings.

17 **Q. What is the purpose of your testimony?**

18 A. Our joint testimony is designed to serve three purposes. First, our testimony provides  
19 the Department with an in-depth perspective on the current operating environment for  
20 natural gas local distribution companies and the significant challenges for gas  
21 companies that exist in this environment. These challenges revolve around two

1 dynamics shaping the future of the natural gas industry across the U.S., which are the  
2 urgent need to achieve the utmost level of public safety and reduce methane emissions.

3 In this context, the full attention of management, and its commitment of resources, is  
4 appropriately focused on the Gas Customer. Although customers continue to prefer  
5 gas service where that service is reasonably available, *gas customers do not have to be*  
6 *gas customers*. It is the customer that is connected to the distribution system; it is the  
7 customer who relies on the availability and safety of the gas delivered to their homes;  
8 it is the customer who is able to employ strategies to use gas conservatively; and it is  
9 the customer community that is demanding that the Company work harder to reduce  
10 gas emissions. Therefore, it is the Gas Customer who will ultimately decide whether  
11 the Company is meeting the challenges existing in today's operating environment.  
12 Eversource Energy is acutely aware that, if customer needs and preferences for safe,  
13 reliable, reasonable cost and environmentally responsible gas service cannot be  
14 fulfilled, the Company's business will decline. Therefore, these industry dynamics and  
15 customer trends are the prevailing influence on the Company's proposals in this case.

16 Second, our testimony provides an overview of the principal components of the  
17 Company's filing in this case, which are a requested change in base distribution rates  
18 and the proposed implementation of a performance-based regulatory ("PBR") plan with  
19 a five-year initial term and provision for extension. The PBR Plan is designed to:  
20 (1) advance the customer objectives of safety, reliability, reduced emissions and

1 reasonable cost gas service; (2) provide strong incentives to the Company to control  
2 costs, particularly where efforts to heighten safety and emissions reductions are causing  
3 increased costs; and (3) establish a construct that will enable the Company to focus on  
4 its operations while furthering the safety of the system and the success of the  
5 Commonwealth's energy policies. As part of the PBR Plan, the Company is proposing  
6 that the Department allow recovery of two demonstration projects designed to test the  
7 feasibility of natural gas demand-reduction initiatives and to assess the viability of  
8 geothermal distribution. The Company is also proposing to institute a series of new  
9 gas safety initiatives and related performance metrics that would be reported to  
10 interested stakeholders via an annual scorecard.

11 Lastly, our testimony discusses how the PBR Plan will enable the Company to achieve  
12 its critical public-service obligations over the next five years in the context of industry  
13 dynamics requiring the Company to strive for the utmost level of public safety and  
14 reductions in methane emissions. Almost 300,000 customers in Massachusetts rely on  
15 natural gas service from Eversource Energy to meet the energy needs of their homes  
16 and businesses—and will do so into the future. The Company's obligations to its  
17 customers make it incumbent upon the Company to find a regulatory structure that will  
18 allow it to further intensify its efforts to serve customers with the utmost safety and  
19 environmental responsibility, while maintaining the financial integrity needed to  
20 support this effort. As described in this testimony, NSTAR Gas is presenting the



1 Department with a set of proposals that represent an integrated, regulatory structure to  
2 achieve this critical objective.

3 **Q. Are you presenting any exhibits in addition to your testimony?**

4 A. Yes. We are presenting one exhibit as part of our testimony in this case, which is  
5 Exhibit ES-WJA/DPH-2 (Organizational Chart and Summary of Incremental  
6 Employees).

7 **Q. How is your testimony organized?**

8 A. Our testimony is organized as follows: Section I is the introduction. Section II  
9 provides an overview of the Company's filing and identifies the witnesses that are  
10 supporting the Company's proposals. In Section II, Mr. Akley and Mr. Horton discuss  
11 the reasons that the PBR Plan is the appropriate regulatory structure to allow the  
12 Company to amplify its efforts to serve customers with the utmost safety and  
13 environmental responsibility, while maintaining financial integrity. In Sections III and  
14 IV, Mr. Akley discusses the NSTAR Gas organizational structure and operating focus  
15 now and into the future. In Section V, Mr. Akley discusses the Company's progress  
16 with the emissions reductions and sustainability efforts the Company is working on  
17 with respect to its gas supply resource portfolio. In Section VI, Mr. Horton discusses  
18 the components of the Company's proposed PBR Plan. In Section VII, Mr. Akley and  
19 Mr. Horton discuss the Company's proposed performance metrics. Section VIII is the  
20 conclusion.

1   **II.    OVERVIEW**

2   **Q.    Please describe the primary elements of the Company's filing in this proceeding.**

3   A.    In this proceeding, the Company is requesting a change in its base distribution rates  
4       and implementation of a five-year PBR Plan that would adjust rates annually in  
5       accordance with a revenue per customer cap formula to be approved by the Department.  
6       If approved by the Department, the Company would commit to refrain from requesting  
7       a subsequent change in base rates for a minimum five-year period. The Company has  
8       also incorporated elements into the PBR Plan that may allow it to continue past the  
9       five-year mark, as permitted by Massachusetts law. The Department has implemented  
10      PBR plans or PBR-like mechanisms where it has found that this type of regulatory  
11      method better satisfies public policy goals and statutory obligations. Massachusetts  
12      Electric Company and Nantucket Electric Company, each d/b/a National Grid, D.P.U.  
13      18-150, at 45-74 (2019); NSTAR Electric Company and Western Massachusetts  
14      Electric Company, D.P.U. 17-05, at 370-414 (2017); Boston Gas Co., D.P.U. 96-50  
15      (Phase I), at 261 (1986); Incentive Regulation Investigation, D.P.U. 94-158, at 42-43  
16      (1995); NYNEX Price Cap, D.P.U. 94-50, at 139 (1995).

17      As integral parts of the PBR Plan, the Company is proposing to initiate two clean  
18      energy demonstration projects and to establish reportable scorecard metrics to drive the  
19      targeted achievement of several policy goals important to the Department and the  
20      Commonwealth. The demonstration projects are designed to identify ways to harness  
21      reductions in gas demand and to utilize geothermal resources as a substitute and

1 (potentially) a supplement to the use of natural gas in serving customers. The scorecard  
2 metrics will provide stakeholders with a transparent view of the Company's  
3 performance and assist in demonstrating the customer benefits arising during the term  
4 of the Company's five-year PBR Plan.

5 **Q. What type of scorecard metrics is the Company proposing in this proceeding?**

6 A. As discussed below, the Company is proposing a series of 12 scorecard metrics,  
7 organized by three high-level categories: Safety and Reliability; Customer Satisfaction  
8 and Engagement; and Emission Reductions. The Company's proposed scorecard  
9 metrics are aligned with several of the Department's policy objectives and will allow  
10 the Department and stakeholders to monitor the Company's progress on important  
11 public policy objectives during the term of the PBR Plan. Below, our testimony  
12 provides detail on the Safety and Reliability and Emission Reductions metrics. The  
13 Company's proposed Customer Satisfaction and Engagement metrics are discussed in  
14 the joint testimony of Company Witnesses Conner and Goldman.

15 **Q. Please describe the Company's request for a change in base rates.**

16 A. The Company is requesting that the Department approve new base rates to address a  
17 net revenue deficiency calculated by the Company to be approximately \$38 million.  
18 This represents an increase of approximately 19 percent in total distribution revenue, if  
19 approved without change. This proposed revenue change is based on a test year-ending  
20 December 31, 2018, adjusted for known and measurable changes to test year amounts  
21 for ratemaking purposes. The revenue requirement is based on a total rate base of \$895

1 million and an overall weighted cost of capital of 7.68 percent, reflecting a return on  
2 equity (“ROE”) of 10.45 percent. The total rate base presented in this case incorporates  
3 the addition of nearly \$640 million in gross plant additions plus cost of removal  
4 expenditures, since the Company’s last general base distribution rate case in D.P.U.  
5 14-150.

6 The Company’s current distribution rates are insufficient to recover the cost of  
7 providing safe and reliable service to customers, including a fair return on the assets  
8 devoted to utility service. Accordingly, the Company now finds it necessary to petition  
9 the Department for review and determination of an increase in base distribution  
10 revenues to support utility operations. The Company’s filing includes the results of a  
11 revenue requirement calculation; a lead-lag study; a depreciation study; an allocated  
12 cost of service study; a marginal cost study; and other testimony and exhibits in support  
13 of the Company’s proposals in this case. If the Company’s proposals are approved  
14 without modification, the typical residential heating customer would see a total annual  
15 bill impact of 8.6 percent, which equates to an average monthly increase of \$9.03. For  
16 commercial and industrial (“C&I”) customers, the average impact would range from 1  
17 percent to 8.1 percent, depending on the respective rate class.

18 **Q. Why is the Company’s filing necessitated at this time?**

19 A. The Company’s request for a change in base distribution rates is necessitated by several  
20 factors; but is primarily due to the substantial level of capital investment that the  
21 Company has made since those authorized in D.P.U. 14-150. In addition to the cost of

1 carrying capital investment not yet recovered through rates, the Company continues to  
2 experience upward pressure on operating and maintenance (“O&M”) expense  
3 associated with the cost of labor and materials, driven by accelerated capital  
4 replacement and safety and reliability-related investments, and other products and  
5 services needed to operate and reinforce the system.

6 Another significant factor that is motivating the Company to submit this petition now  
7 is that NSTAR Gas anticipates a step-up in safety requirements imposed through  
8 legislation and regulations as a result of the Merrimack Valley incident and the various  
9 investigations flowing therefrom. NSTAR Gas is filing now so that the undivided  
10 attention of all NSTAR Gas personnel will be focused on embedding new and  
11 continuing safety initiatives into gas operations over the next five years and beyond.  
12 With a 10-month suspension period, the Company work effort associated with a base-  
13 rate petition is in the range of 18-24 months, requiring attention of the resources and  
14 expertise of the entire gas business including the managers of gas operations.  
15 Therefore, NSTAR Gas has made the decision to head off this diversion of resources  
16 over the next five years by making this filing now and requesting that the Department  
17 put in place a multi-year rate plan that will support the Company’s critical efforts to  
18 meet its obligations to public safety and sustainability without undermining the  
19 Company’s financial integrity. Without this multi-year rate plan in place, the  
20 Company’s expectation is that it will need to treat every other year as a test year and to  
21 file base-rate petitions accordingly so that the Company’s allowed cost recovery

1 remains reasonably aligned with investment and operating costs necessary to operate  
2 the system safely.

3 **Q. Why does the Company view a performance-based regulatory plan to be the**  
4 **appropriate regulatory structure in today's operating environment?**

5 A. The Department has found that PBR provides a utility company more flexibility to  
6 address a changing operating environment and higher customer expectations.<sup>1</sup>  
7 Consistent with this philosophy, the Company is seeking to engage in a multi-year,  
8 performance-based rate plan to take a meaningful step forward in addressing the  
9 confluence of factors that are substantially and irrevocably changing the operating  
10 environment for local natural gas distribution companies. The Company has devoted  
11 significant study and analysis to develop a proposed regulatory structure that is  
12 adequate to support utility operations; is administratively efficient; benefits customers  
13 in terms of continuing to promote a high level of safety and service reliability; and  
14 provides strong incentives to the Company to control costs.

15 The Company's proposed PBR Plan would adjust rates annually through a  
16 performance-based ratemaking mechanism ("PBRM") that utilizes a "revenue per  
17 customer cap" formula. The PBRM formula is derived through economic analysis of  
18 utility cost trends as indicated by measures of inflation, input prices and total factor  
19 productivity. The specific revenue per customer cap formula that the Company is

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<sup>1</sup> Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid, D.P.U. 18-150, at 53 (2019).

1 proposing is discussed in the joint testimony of Company Witnesses Julia Frayer and  
2 Marie Fagan. Ms. Frayer and Ms. Fagan have performed the in-depth economic  
3 research and analysis supporting the Company's proposed revenue per customer cap  
4 formula and her testimony details its methodological underpinnings. The revenue per  
5 customer cap formula is designed to parallel, and work in tandem with, the revenue  
6 decoupling mechanism ("RDM") that the Department approved in D.P.U. 14-150.

7 The PBR Plan, with operation of the annual PBRM, is a better fit than the current  
8 ratemaking methodology for the Company in terms of providing the Company with the  
9 revenue support that it needs to address the challenges of today's operating  
10 environment without diverting focus from the operation of the system. As discussed  
11 below, the Company anticipates that the principal cost driver over the next five years  
12 will be the substantial amount of capital investment needed for system upgrades *outside*  
13 *of* the Gas System Enhancement Program ("GSEP"). For example, as discussed below,  
14 if the Department approves the Company's PBR Plan as filed, the Company projects  
15 the annual increases in revenue growth would be in the range of \$8 million; however,  
16 the annual revenue requirement associated with the \$100+ million of *non-GSEP* annual  
17 capital investment planned over the term of the PBR Plan will be in the range of \$13-  
18 15 million, conservatively calculated. Increases in operating costs will also occur,  
19 although the Company will be working diligently to maintain the most efficient cost  
20 platform possible while meeting safety and reliability requirements. Therefore,  
21 implementation of the PBR Plan in conjunction with the GSEP mechanism will require

1 the Company to surrender its right to a base-rate proceeding for at least a five-year term  
2 even though the annual PBR revenue falls short of the annual revenue requirement on  
3 incremental capital investment. This dynamic will create a strong challenge for the  
4 Company in relation to its management of O&M expense and capital expenditures.

5 Thus, the greater incentives for cost control inherent in the PBR framework and the  
6 need for flexibility in relation to O&M and capital cost planning are factors motivating  
7 the Company to request the implementation of the proposed PBR Plan (rather than  
8 capital cost recovery) as the most effective tool to address the drivers of change in the  
9 business and operating environment.

10 **Q. Would you please identify the witnesses presented by the Company in this**  
11 **proceeding?**

12 A. Yes. In addition to this joint testimony, the Company is submitting testimony, analysis  
13 and documentation from the following witnesses in support of its petition:

14       ▪ Penelope M. Conner and Michael R. Goldman: Ms. Conner is the Chief  
15 Customer Officer and Senior Vice President of the Customer Group for  
16 Eversource Service Company. Mr. Goldman is the Director, Regulatory,  
17 Evaluation & Support, Energy Efficiency for Eversource Service Company.  
18 Their joint testimony presents the Company's customer philosophy and  
19 sustainability vision and sets out the details of two proposed demonstration  
20 projects, which are designed to assess the viability of a natural gas demand  
21 reduction program and geothermal distribution.



- 1       ▪ Julia Frayer and Marie Fagan: Julia Frayer is a partner and a Managing Director  
2       of London Economics International LLC (“LEI”). Marie Fagan is a Managing  
3       Consultant and Lead Economist at LEI. Ms. Frayer and Ms. Fagan’s testimony  
4       discusses the methodology and results associated with the Total Factor  
5       Productivity (“TFP”) Study, which is the basis of the Company’s proposed “X  
6       factor” component of the PBRM. Ms. Frayer and Ms. Fagan also presents LEI’s  
7       benchmarking study relating to the Company’s cost performance and respective  
8       ranking within the natural gas utility industry group used for the TFP Study.
  
- 9       ▪ Douglas P. Horton and Ashley N. Botelho: Mr. Horton is the Vice President,  
10      Distribution Rates and Regulatory Requirements. Ms. Botelho is the Manager  
11      of Revenue Requirements, Massachusetts, employed by ESC. Their joint  
12      testimony presents the Company’s revenue requirement analysis and revenue-  
13      deficiency calculation for NSTAR Gas, among other revenue requirement-  
14      related proposals.
  
- 15      ▪ Robert B. Hevert: Mr. Hevert is Managing Partner, ScottMadden, Inc. The  
16      testimony of Mr. Hevert presents the Company’s proposed ROE, cost of capital  
17      and capital-structure analysis.
  
- 18      ▪ Sasha Lazor: Mr. Lazor is Director, Compensation for Eversource Service  
19      Company. The testimony of Mr. Lazor presents the Company’s employee

1 compensation programs, including base and variable pay elements of  
2 compensation.

3       ▪ Michael P. Synan: Mr. Synan is Director, Benefits Strategy for Eversource  
4 Service Company, presenting testimony on the Company's employee benefits  
5 and discussing the underlying rationale and assumptions related to these costs.

6       ▪ John J. Spanos: Mr. Spanos is Senior Vice President, Gannett Fleming  
7 Valuation and Rate Consultants. The testimony of Mr. Spanos presents the  
8 Company's depreciation study in support of the Company's proposed  
9 depreciation rates in this proceeding.

10       ▪ David Heintz: Mr. Heintz is Vice President, Concentric Energy Advisors. The  
11 testimony of Mr. Heintz presents the allocated cost of service study for the basis  
12 of the Company's rate design.

13       ▪ Melissa Bartos: Ms. Bartos is Assistant Vice President, Concentric Energy  
14 Advisors. The testimony of Ms. Bartos presents the NSTAR Gas marginal cost  
15 study, which was prepared in accordance with the Department's directives and  
16 standards related to marginal cost studies.

17       ▪ Richard D. Chin: Mr. Chin is the Manager of Rates for the Eversource Energy  
18 operating affiliates in Massachusetts, including NSTAR Gas. Mr. Chin

1 presents the Company's proposed distribution rates and rate design. His  
2 testimony includes rate design proposals and bill-impact analysis.

3 ■ Richard D. Chin and Lisa Cullen: Ms. Cullen is the Manager of Gas Supply  
4 Operations for NSTAR Gas and Yankee Gas Company. Mr. Chin and Ms.  
5 Cullen's joint testimony presents the Company's proposed changes to its tariffs.

6 ■ Leanne M. Landry and Thomas C. Desrosiers: Ms. Landry is the Director,  
7 Budget and Investment Planning for ESC. Mr. Desrosiers is the Manager  
8 Investment Planning for ESC. The joint testimony of Ms. Landry and Mr.  
9 Desrosiers presents project documentation for capital additions made since  
10 D.P.U. 14-150. Their testimony also describes the capital planning and  
11 approval process in place to manage the capital expenditures for NSTAR Gas.

### 12 **III. NSTAR GAS ORGANIZATIONAL STRUCTURE**

13 **Q. Mr. Akley would you please provide a brief description of the Company?**

14 A. NSTAR Gas is a regulated public utility incorporated in Massachusetts in 1851.  
15 NSTAR Gas currently operates as a wholly-owned subsidiary of Yankee Energy  
16 System, Inc. ("Yankee Energy"). NSTAR Gas is engaged in the retail distribution and  
17 sale of natural gas to approximately 296,000 customers in 51 communities in central  
18 and eastern Massachusetts, covering 1,067 square miles. Some of the larger  
19 communities served by NSTAR Gas include Cambridge, New Bedford, Plymouth,  
20 Worcester, Framingham, Dedham and the Hyde Park area of Boston. Natural gas

1 supply services are provided to NSTAR Gas during the winter heating season by  
2 HOPCO, another wholly-owned subsidiary of Yankee Energy.

3 **Q. What is the overall operating philosophy of Eversource Energy in relation to its**  
4 **gas distribution operations?**

5 A. Eversource Energy is a mission-driven organization grounded in the voice of the  
6 customer. Within the organization, there is an embedded cultural philosophy that  
7 values leadership, the provision of safe and reliable service to customers, constant  
8 attention to service-quality, and deep appreciation of employees and the skill and talent  
9 they bring to the mission. Eversource Energy strongly encourages employees to  
10 engage, listen and learn from customers, colleagues and other industry participants; and  
11 to incorporate that learning into everyday work so the customer is served with the  
12 highest expertise and dedication in the industry.

13 Within Gas Operations, there is careful and consistent attention to detail. Gas  
14 Operations relies on standardized construction practices, rigorous protocols for  
15 training, testing and operator qualifications and comprehensive quality assessment and  
16 quality control (“QA/QC”) processes, among other strategies, to assure work is  
17 performed correctly and safely. In particular, the Company’s QA/QC function  
18 introduces a second, intensive level of internal review to assure adherence to applicable  
19 standards and compliance requirements. Fundamentally, experts are in charge, i.e., it  
20 is not enough to lead, but also Eversource leaders must be experts in the work tasks  
21 within their domain. This means that, from top to bottom, a single mindset is in place,

1 focused intently on getting the job done safely, effectively and at a reasonable cost with  
2 minimal environmental impact.

3 **Q. Mr. Akley, please describe the leadership team of the Eversource Energy gas-**  
4 **distribution business.**

5 A. Effective November 10, 2014, I was named President of the Eversource Energy Gas  
6 Distribution group. As shown in the high-level organization chart provided as Exhibit  
7 ES-WJA/DPH-2, on page 1, I have three direct reports: Kevin J. Kelley, Vice President  
8 – Gas Operations; Gregory J. Hill, Vice President – Gas Engineering; and Darrin K.  
9 Wertz, Director Pipeline Safety and Quality.

10 Mr. Kelley has been an Eversource Energy employee for over 29 years and is  
11 responsible for various operational functions including but not limited to Construction,  
12 Maintenance, Meter Services, Project Management and Dispatch/Technical Services.

13 Mr. Hill joined Eversource Energy in 2017. He is responsible for all engineering  
14 matters associated with the Company's gas business; LNG operations and LNG capital  
15 projects involving three operating facilities located in Connecticut and Massachusetts;  
16 gas emergency preparedness; and the gas-control activities for the gas distribution  
17 business.

18 Mr. Wertz has 13 years of utility experience and joined Eversource Energy in 2015.  
19 He is responsible for the Company's Pipeline Safety Management Systems and Quality  
20 Assurance/Quality Control.

1        These three individuals are responsible for functional areas that play vital and  
2        interrelated roles in achieving the central mission of the Company, which is to provide  
3        safe and reliable service to customers at a reasonable cost. This leadership team and  
4        the Company's organizational structure facilitate the Company's ability to meet  
5        growing operating challenges, including increasing compliance requirements geared  
6        toward ensuring continued safe operation of the system and the accelerated replacement  
7        of aging, leak-prone infrastructure.

8        **Q.    How does the Company's organizational structure assist in meeting pipeline safety**  
9        **regulatory requirements?**

10      A.    The Company's Gas Operations Group is responsible for system repair and  
11      maintenance activities, as well as new construction and replacement of leak-prone  
12      mains and services. The Gas Operations Group is also responsible for performing the  
13      work associated with pipeline safety requirements and is organized on a functional  
14      basis centered around: Maintenance, Construction, Meter Services, Project  
15      Management and other compliance activities such as facility mark-outs, corrosion  
16      control and leak management activities, among other functions.

17      The Engineering Group is responsible for gas system operations, Instrumentation and  
18      Regulation ("I&R") and LNG, as well as for defining the compliance activities and  
19      system replacement work needed to be completed in any given calendar year or  
20      regulatory driven timeframe. The Gas Engineering Group is also responsible for

1 ensuring that gas policies, procedures, and standards comply with all state and federal  
2 regulations, as well as gas system operations, I&R and LNG operations.

3 The Pipeline Safety and Quality Group is responsible for implementation of the  
4 Pipeline Safety Management System as well as QA/QC of gas projects.

5 **IV. OPERATING FOCUS NOW AND IN THE FUTURE**

6 **Q. Mr. Akley, what are the Company's most important priorities from an operating**  
7 **perspective?**

8 A. The natural gas business has experienced many changes over the last several years.  
9 However, the guiding principle driving all decision making in the natural gas  
10 distribution business is public safety. This bedrock principle has existed for my entire  
11 career in the gas industry and remains a central focus for NSTAR Gas today and for  
12 the future. At Eversource Energy, our shared commitment to "Safety First and Always"  
13 is a principle and mindset that is weaved into the fabric of every job and every task—  
14 whether in the field or in the office. The gas industry cannot survive without confidence  
15 that the system is safe, and this has always been true. Accordingly, safety is the highest  
16 priority for Eversource Energy.

17 The Company's strong focus on continuing to improve the safety and reliability of the  
18 system requires prioritization of replacement programs for aging infrastructure and  
19 rigorous efforts to maintain full compliance with federal and state pipeline safety  
20 regulations. The Company's efforts in this regard were furthered by the legislature's  
21 initiative in 2014 to put in place An Act Relative to Natural Gas Leaks (the "Gas Leaks

1 Act”), which permitted local distribution companies (“LDCs”) to submit to the  
2 Department annual plans to repair or replace aged natural gas infrastructure. On  
3 October 31, 2014, NSTAR Gas, along with the other LDCs, submitted the first GSEP  
4 filings setting forth plans for replacing leak-prone infrastructure during the 2015  
5 construction year. Pursuant to the Gas Leaks Act, each gas company, including  
6 NSTAR Gas, established a timeline to replace all leak-prone infrastructure on an  
7 accelerated basis, specifying an annual replacement pace and a program end date. On  
8 April 30, 2015, the Department approved each gas company’s GSEP, thereby  
9 commencing accelerated pipeline replacement across the Commonwealth and  
10 corresponding dramatic increases in capital investment and O&M activity.

11 Also, in 2014, Eversource petitioned the Department for approval of a Gas Service  
12 Agreement (“GSA”) between NSTAR Gas and HOPCO that was designed, among  
13 other things, to facilitate a substantial refurbishment of the HOPCO facilities. The  
14 HOPCO facilities represent approximately 40 percent of the Company’s peak day  
15 supply. This asset is particularly critical to the continued safe and reliable operation of  
16 the system and provision of service to customers because there are no significant  
17 pipeline expansions on the planning horizon for the region. Moreover, LDC demand  
18 is highest during the winter-heating season, which leaves limited capacity available in  
19 the secondary market, causing price volatility during cold weather periods as wholesale  
20 entities vie for available gas supplies. As a result, the HOPCO facilities stand as an  
21 important resource for NSTAR Gas customers both in terms of the availability of a safe



1 and reliable supply source, and in terms of being able to mitigate the impacts of price  
2 volatility in the New England.

3 The HOPCO facilities required substantial capital upgrades due to their advancing age.  
4 The nature and scope of these upgrades precluded construction and implementation in  
5 a single year, and instead required a phased project approach over a multi-year period.  
6 In D.P.U. 14-64, the Department concluded that the HOPCO facilities are an important  
7 and necessary component of the Company's resource portfolio and approved the  
8 proposed GSA with modifications. NSTAR Gas Company d/b/a Eversource Energy,  
9 D.P.U. 14-64, at 33, 73-75 (April 29, 2015). The refurbishment continues at both the  
10 Main Facility (Hopkinton) and Acushnet Facility and the component projects are in  
11 various phases of development. These projects include civil and structural  
12 improvements, electrical and control system upgrades, building replacements and other  
13 system improvements. The Company's current assessment of the proposed  
14 refurbishment program's budget and schedule suggests that refurbishment projects are  
15 expected to continue through 2021, subject to permitting and other unforeseen  
16 operational constraints.

17 **Q. What impacts has GSEP had on the Company's business?**

18 A. The GSEP framework established in 2014 has provided a critical pathway to accelerate  
19 the installation of modern, safe, and environmentally sound natural gas distribution  
20 systems in the Commonwealth of Massachusetts. The pace of capital work completed  
21 since 2014 has been unprecedented. In addition to the safety, reliability and

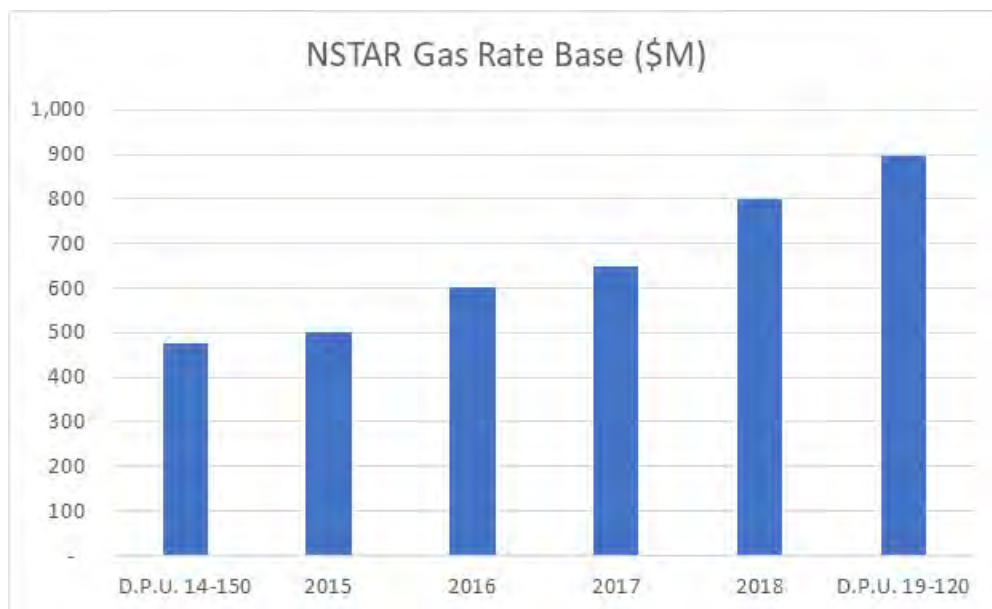
1 environmental benefits associated with NSTAR Gas infrastructure replacement efforts,  
2 GSEP has provided economic benefits to the Commonwealth in the form of additional  
3 jobs created both within the Company, and at the third-party contractors who play a  
4 vital role in performing GSEP work. Since the inception of GSEP on January 1, 2015,  
5 the contractor pool qualified to perform this work has increased to keep pace with the  
6 GSEPs. For example, prior to January 1, 2015, NSTAR Gas relied on approximately  
7 15 contractor crews (4 members per crew) to perform replacement work as part of its  
8 annual capital program. By 2018, NSTAR Gas was relying on approximately 40  
9 contractor crews to perform GSEP work. NSTAR Gas also increased internal staffing  
10 in the areas of engineering and supervision, including nine Supervisors of Field  
11 Operations and 17 Field Operations Inspectors, as well as administrative support to  
12 assure the continued, safe, effective and efficient completion of GSEP work.

13 **Q. Is the Company making other significant capital investments in the distribution**  
14 **system that will continue in the future?**

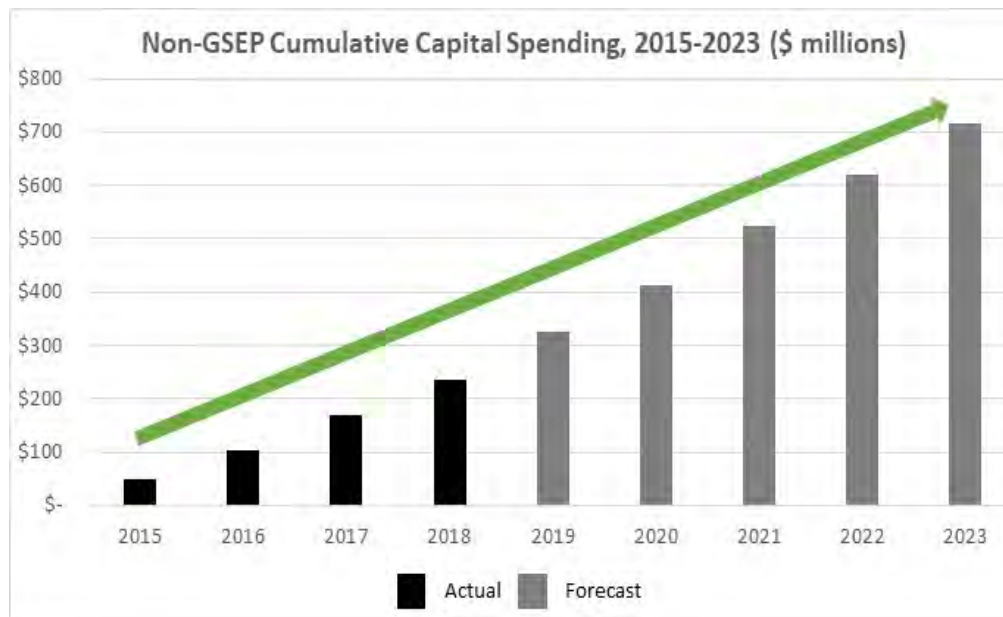
15 A. Yes, in addition to the significant amount of capital work completed since 2015 through  
16 the GSEP (averaging approximately \$72 million per year), the Company is making  
17 substantial investments in other system components for reliability purposes. In fact,  
18 annual non-GSEP distribution investments totaled approximately \$65 million, on  
19 average, over the past five years and annual expenditures on non-GSEP capital projects  
20 are expected to increase over the next five years. A significant amount of attention is  
21 placed on the Company's GSEP work and the associated cost recovery; however, the

1 Company's investments in *non-GSEP* infrastructure are just as vital to the public safety  
2 and emissions reductions objectives that serve the interests of customers. These  
3 investments are a critical impetus of the Company's PBR proposal in this case.

4 In that regard, the dominant cost pressure for the Company is the carrying cost of capital  
5 investment not yet included in base rates or recovered through GSEP. As shown in the  
6 graph below, rate base grew by more than two-thirds between 2014 and 2019, due to  
7 both GSEP and non-GSEP investment. The Company's expectation is that rate base  
8 will continue to increase on a comparable basis over the PBR Plan term creating cost  
9 pressures that have to be addressed for the Company to maintain the financial integrity  
10 needed to support safe and reliable operations.



1 Looking ahead, the Company expects that capital spending over the five-year PBR plan  
2 term, on both GSEP and non-GSEP work, will increase substantially as compared to  
3 spending over the last five years. In particular, non-GSEP spending is forecast to more  
4 than double over the course of the PBR Plan term, as compared to the level of spending  
5 in 2015.



6 The Company's non-GSEP investment is focused in four principal categories,  
7 encompassing the following:

8 ***Pressure Regulation Modernization***

9 Pressure regulation in use currently at city gate and district regulator stations is robust,  
10 simple, safe, reliable and operates even when electric power and communication with  
11 the Gas Control Center is lost. However, there are opportunities for modernizing  
12 pressure regulation, system oversight and control through incremental capital

investment in equipment that is monitored, supervised and controlled by the Gas Control Center. The Company's investment strategy for improvement in these areas is based on a multi-year plan with phased implementation focused on broadest to localized impact; land and use rights; and downstream system pressure classification. The Company has planned specific investments including emergency shut-down devices, remote monitoring and control devices, and telemetry, which will be phased-in as follows:

- Phase 1 involves the installation of Emergency Shutdown Devices at all gate stations (excluding those planned as part of the Gate Station Asset program).
- Phase 2 involves the installation of electric power and communications at targeted district regulator facilities, which includes remote monitoring and control devices, where rights and ownership already exist.
- Phase 3 includes accelerated deployment of pressure telemetry.
- Phase 4 accommodates the timing necessary to establish rights and further the installation of additional monitoring and control.
- Phase 5 involves the installation of targeted Remote-Control Valves in the distribution system.

***Low-Pressure Protection Program***

Eversource has developed preferred district regulator, outlet piping and sensing line designs for all pressure classes. This program uses the risk-assessment regulator model and the risk-assessment sensing light model to develop projects. The goals of this program include:

- Providing for a third level of pressure protection to protect Eversource's low-pressure systems.

- Eliminating single incident failures at all low-pressure district regulators.
- Developing protection measures based on the configuration and condition of district regulators, sensing lines and outlet piping.
- Converting approximately 17 low-pressure district regulators to intermediate pressure by 2024.

The specific pressure-protection measures planned for investment include:

- Installation of strainers and regulators to prevent single incident failures.
- Installation of slam-shut and super-monitor regulators to prevent over/under pressure situations.
- Rebuilding/installing sensing line and outlet piping to match new manifold design.

### ***System Resiliency***

Mitigating energy disruptions is fundamental to infrastructure resilience. Mitigating natural gas disruptions is particularly important because customers rely on natural gas to heat their homes, and more customers depend on it as a source of energy. For example, customer-owned fuels cells powered by natural gas are becoming more prevalent. Although natural gas disruptions are generally less likely than electricity disruptions, it is significantly more difficult to recover from disruptions to these systems than electric systems. Recovery from natural gas disruptions is particularly difficult because of the need to individually visit customers multiple times to fully restore service. To address this area of concern, the Company has planned three pipeline infrastructure projects to mitigate energy disruptions:

- Hopkinton Ashland Transfer Line
- Worcester Feed Replacement
- Plymouth North South Connector

***System Reliability Investments***

Eversource has planned a set of investments and a coordinated work plan to attain safety and reliability goals that meet state and federal pipeline safety requirements. For example, the Company has planned upgrades to several of its gate and regulator stations and projects to maintain minimum system pressures under winter peak conditions, as well as reinforcements for reliability. The Company is also planning investments in leak remediation, corrosion remediation, service valve replacement and system telemetry.

**Q. What are the principal operational areas that the Company is working on to promote the safety of the system?**

A. Over the last several years, the Company has focused on implementing several measures, initiatives and organizational enhancements to improve the safety of operations. The two principal areas of focus are, as follows:

- Gas Control and Dispatch Consolidation. The Gas Control and Dispatch Center is the nerve center of the NSTAR Gas distribution network. In November 2018, Eversource Energy completed the consolidation of its Massachusetts and Connecticut Gas Control operations into a single combined location in Southborough, Massachusetts. This consolidation was undertaken, in part, to better

1 leverage best practices from each Gas Control and Dispatch area. In addition, with  
2 the ability to cross-train employees, the Company will provide more enhanced Gas  
3 Control and Dispatch support during non-routine peak periods.

- 4 • Standardization of Procedures & Construction Standards. Eversource Energy is  
5 working to consolidate and standardize the Massachusetts and Connecticut  
6 procedures and construction standards into a common set of procedures and  
7 construction standards across the entire Eversource Energy gas-service territory.  
8 Having a single set of procedures and construction standards will streamline and  
9 standardize operations, improve the effectiveness of employee training and  
10 augment service quality across the entire business. This effort is nearly complete.  
11 All consolidated procedures, construction standards and work practices are  
12 expected to be published by November 2019. However, standardization is an on-  
13 going process and the Company expects to continually update and refine its  
14 operating procedures over time.

15 **Q. What are the supporting areas of focus that NSTAR Gas is working on to promote**  
16 **safety and service quality on its distribution system?**

17 **A.** In addition to the two primary areas of focus discussed above, the Company has taken  
18 the following actions to reinforce safety:

- 19 • Quality Assurance and Quality Control (“QA/QC”) Program. The Company has  
20 greatly enhanced its QA/QC program. Through quality management, NSTAR Gas  
21 is ensuring that its people, processes, and technology work effectively to achieve



1 excellence in safety, compliance, reliability and productivity. The NSTAR Gas  
2 QA/QC programs perform random, post-construction audits and re-dig inspections  
3 highlighting where risks exist. Objectives include reviewing construction with  
4 respect to federal/state safety codes, Construction Standards, Safety Policies and  
5 Operator Qualifications (“OQ”). QA/QC assists with taking corrective action when  
6 required and helps ensure that focus is re-directed on proper procedures when  
7 necessary. QA/QC also highlights when modifying current procedures/training is  
8 necessary and promotes the addition of new procedures and training, all designed  
9 to further increase safety and efficiency.

- 10 • Improved Safety Performance. Eversource Energy is committed to providing a safe  
11 work environment. Eversource Energy recently hired Ken Bogler as Vice  
12 President, Safety, who is dedicated to overseeing the Company’s culture of “Safety  
13 First and Always.” This principle guides all employees to take personal  
14 responsibility by following required safety practices, acting proactively to prevent  
15 incidents and injuries, communicating potential hazards and being prepared for  
16 emergencies that may occur in the workplace. The Company has improved safety  
17 performance with a “Safety First and Always” culture and it is a key operating focus  
18 for the business. The Company’s goal is a zero-injury environment.

19 For Connecticut and Massachusetts combined, Eversource Energy’s gas operations  
20 have improved safety performance from 29 Days Away, Restricted or Transferred

1 (“DARTs”) in 2014 to 14 DARTs in 2018; and improved safety performance from  
2 17 Preventable Motor Vehicle Accidents (“PMVAs”) in 2014 to eight PMVAs in  
3 2018. For Massachusetts gas operations during this timeframe, DART rates  
4 decreased from 3.33 in 2014 to 1.84 in 2018; and PMVAs decreased from 3.14 in  
5 2014 to 1.17 in 2018.

- 6 • Shift to Eversource Energy Operator Qualification Program. In 2017, the Company  
7 took the initiative to implement an Eversource Energy-specific OQ program, which  
8 includes third-party proctoring of all employee testing. NSTAR Gas is the first  
9 New England company to move its on-line OQ testing to an offsite testing facility.  
10 The benefits of this initiative include:

- 11 ■ Aligning OQ testing with Company standards, which in all cases at least match  
12 the minimum federal requirements, and in many instances exceed the minimum  
13 federal regulations.
- 14 ■ Ensuring employees and contractors are knowledgeable of and trained on those  
15 requirements.
- 16 ■ Providing a secure online testing environment where content is protected (Pro-  
17 metric testing centers are established nationwide as a secure and trusted testing  
18 center used by hundreds of organizations).
- 19 ■ Conducting performance evaluations with an objective third-party vendor  
20 (Lonestar Consulting Services), which is subjected to periodic audits by the  
21 Company’s online database provider, Energy Worldnet.

- 1 • Refined Emergency Response Plan. Between 2014 and 2019, Eversource Energy  
2 conducted a comprehensive review of its Gas Operations Emergency Response Plans  
3 (“ERPs”) to identify and incorporate best practices and harmonize training, practices,  
4 and procedures across its operating units. This effort was accomplished by a dedicated  
5 Company team managed by Joshua D. White, the recently appointed Manager of Gas  
6 Emergency Preparedness for the Company. Mr. White has a Master of Science in  
7 Emergency and Disaster Management and, prior to his current position with the  
8 Company, had an impressive career building expertise in operational planning and  
9 strategic analysis. Mr. White previously served as the Operations Manager for the  
10 Federal Emergency Management Agency, Region I, where he managed the operational  
11 response of all federal military assets across six states during Superstorm Sandy and  
12 Hurricane Isaac. In this capacity, Mr. White served as the primary safety officer for all  
13 federal military assets deployed within Region I in support of disaster response  
14 operations during three presidential-declared disasters.

15 The ERP is the foundation of a comprehensive emergency management program of  
16 preparedness, mitigation, response, and recovery actions designed to preserve the  
17 public safety and welfare through the delivery of safe, efficient, and reliable gas  
18 service.

- Continued Focus on Seeking to Improve Customer Satisfaction. The joint testimony of Company Witnesses Conner and Goldman discusses the strategies that the Company is employing to improve the satisfaction and experience of its customers.

**Q. What are the factors driving change in the Company's business and operating environment looking forward?**

A. The date of this filing marks just over one-year since the tragic events that took place in the Merrimack Valley. This event has profoundly impacted the natural gas industry and prompted both the industry and its regulators to reevaluate safety standards, practices, protocols, and procedures to enhance the safety and reliability of the natural gas distribution system. The Merrimack Valley incident will catalyze change to the regulation of natural gas and to the Company's business and operating environment into the future.

In fact, this catalyzation has already started to take shape. For example, on December 31, 2018, Massachusetts Governor Charlie Baker signed Chapter 339 of the Acts of 2018, An Act Further Providing for the Safety of the Commonwealth's Natural Gas Infrastructure ("Gas Safety Act"), as emergency legislation requiring a licensed Professional Engineer to approve plans for the construction of natural gas infrastructure. In March 2019, the Department initiated a proceeding to promulgate the regulations necessary to implement the Gas Safety Act.

Most important is that the Merrimack Valley incident has shaken the confidence of the general public, including current and potential customers of NSTAR Gas. Regarding

1 its current customers, NSTAR Gas has experienced negative impacts to its J.D. Power  
2 customer ratings. As discussed in the joint testimony of Company Witnesses Conner  
3 and Goldman, gas customers are seeking reassurance from their utility providers that  
4 the service they are taking is safe. As explained in that joint testimony, the Company  
5 has taken proactive steps to deploy a Public Safety Education Campaign to engage and  
6 educate customers with relevant gas-safety messaging. NSTAR Gas plans to carry this  
7 program forward with refinements in the future.

8 In the wake of the Merrimack Valley incident, the natural gas industry must rebuild the  
9 trust of all stakeholders, including the general public and regulators, and work to restore  
10 their confidence in the safety and reliability of the natural gas system. NSTAR Gas  
11 recognizes that increasing investments and improvements to operating processes are  
12 necessary and plans to work hard over the five-year PBR term to further improve the  
13 safety and reliability of the NSTAR Gas distribution system.

14 **Q. What specific actions are planned by the Company to further improve safety and**  
15 **reliability post-Merrimack Valley?**

16 **A.** On a going forward basis, and as described more fully in the following sections, the  
17 Company is planning strategic investments in people, processes and technology to  
18 further improve safety and reliability in a post-Merrimack Valley operating  
19 environment.

1           **A.       Investments in People**

2       **Q.       You mentioned that the Company is making strategic investments in people,**  
3       **processes, and technology. What is the Company doing in relation to investments**  
4       **in people?**

5       A.       Simply put, the Company's most valuable resource is its workforce. For this reason,  
6               training is the fundamental stepping stone to increase employee engagement and reduce  
7               risks associated with human error. An engaged workforce is critical to Eversource  
8               Energy's mission of delivering safe and reliable energy service and a superior customer  
9               experience.

10           As discussed above, Eversource is engaged in an unprecedented level of capital  
11           deployment driven by the need to replace aging infrastructure and to comply with state  
12           and federal regulatory requirements. At the same time, rates of employee retirements  
13           in the gas industry are accelerating and there is a scarcity of new skilled labor to backfill  
14           those positions. These dynamics pose a challenge for the business. Also, the  
15           demographics in the Company are changing, in that employees who are hired by the  
16           Company in today's environment are technologically savvy and are used to relying on  
17           technology for educational purposes. To meet these challenges, the Company is  
18           continually refining its recruiting strategies to ensure that NSTAR Gas can attract and  
19           retain high-quality talent and improve upon its training practices to make sure these  
20           new employees are productive, responsible and empowered to be successful in the  
21           field.

1   **Q.    What actions is NSTAR Gas taking to improve recruiting and training?**

2    A.    The Company expects to add personnel to assist in efforts to replace aging  
3           infrastructure across its system at an accelerated pace and to comply with the rigorous  
4           state and federal regulatory requirements that will be implemented post Merrimack  
5           Valley. Eversource Energy is offering candidates solid, long-term career jobs with  
6           competitive benefits and, with effective and targeted recruiting strategies, NSTAR Gas  
7           should be able to find the right talent to staff its workforce for the future.

8           With respect to recruiting, Eversource Energy is in the process of creating a program  
9           in Massachusetts similar to what it already has in place in Connecticut. This will be a  
10          tuition-based certification program, with a rigorous selection process that requires  
11          participants to complete a course over several months to learn the gas distribution  
12          business. In Connecticut, the program is conducted in partnership with Middlesex  
13          Community College (“MCC”). The students pay tuition to the college and a portion of  
14          those funds is used to defray Eversource Energy’s costs to conduct the program (e.g.,  
15          drug and alcohol testing, instructor costs, program materials, and personal protective  
16          equipment). The students receive instruction and training at Eversource Energy’s  
17          Berlin campus and MCC conducts the recruiting and marketing for the program.  
18          Participants who successfully complete the program will have the opportunity to  
19          interview for positions within the Eversource Energy organization. The Company’s  
20          first class graduated from the Connecticut program last year, and every one of the  
21          graduates secured employment with Eversource Energy. The Company is in

1 preliminary discussions with a Massachusetts college to act as partner for the program  
2 in the Commonwealth.

3 The Company is also finding success in recruiting former military personnel as those  
4 individuals have the strong leadership and practical know-how that Eversource Energy  
5 is looking for in its employees.

6 With respect to training, it is imperative that new and existing employees receive  
7 extensive hands-on training; have an opportunity to get familiar with the equipment;  
8 gain knowledge of the Company's processes and procedures; and learn to work on the  
9 natural gas distribution system in a safe manner. The importance of hands-on training  
10 cannot be stressed enough—employees needs to be exposed, under controlled  
11 conditions, to what they may encounter in the field, so they are prepared to respond in  
12 the event that unexpected circumstances occur.

13 The Company recently completed a new training facility at Eversource Energy's Berlin  
14 campus, which contains a Natural Gas Training Yard, featuring five main activity areas  
15 that focus on providing safe, hands-on training for natural gas personnel. NSTAR Gas  
16 is creating the same training opportunity in Massachusetts where the Company can  
17 conduct both classroom training and hands-on training to the new hires, veteran  
18 employees, and contractors who work on the Company's natural gas distribution  
19 system. To that end, Eversource Energy is outfitting the Auburn Area Work Center



1 (“Auburn AWC”) to be the flagship location for employee training and fleet  
2 maintenance and the facility features an Outdoor Training Yard, like the Berlin facility.

3 **Q. What are the incremental staffing additions that are now necessary for the**  
4 **NSTAR Gas Operations group?**

5 A. The incremental staffing additions that are now necessary for the Company’s Gas  
6 Operations group are shown in Exhibit ES-WJA/DPH-2, at pages 2 and 5. Specifically,  
7 the Company is increasing staffing within Gas Operations by 32 fulltime equivalents  
8 (“FTEs”) to support the increased amount of field work associated with the Company’s  
9 capital programs, which maintain the safety and integrity of the distribution system.  
10 Additional staffing will be added to the organization overseen by the Vice President of  
11 Gas Operations to further support the Company’s long-term strategic objectives,  
12 including improvements to the Company’s delivery of Project Management, Long-term  
13 Planning, Pipeline Safety Management, and Quality Assurance. The specific FTEs are  
14 described by business unit below.

15 **Maintenance**

16 The Company is hiring 12 FTEs in the Maintenance unit within the Gas Operations  
17 group as follows:

18 *Maintenance Supervisor (1 FTE)* – This FTE will supervise the work performed by the  
19 Company’s internal workforce of mechanics who maintain the gas distribution system.  
20 This incremental position is required to maintain an appropriate span of control over  
21 the work force.

1       *Welder (1 FTE)* – Welders perform welding services on steel pipe required to maintain  
2       the gas distribution system. This incremental position is needed to support increases  
3       in annual work volumes.

4       *Maintenance Mechanics/Technicians (10 FTEs)* – Distribution mechanics repair leaks,  
5       replace and install service lines and perform live gas main connections and  
6       disconnections. These FTEs are needed due to increases in annual work volumes,  
7       which are the result of increases in the miles of main installed and retired under the  
8       Company's GSEP program.

9       **Dispatch & Meter Services**

10       The Company is adding 6 FTEs to the Dispatch and Meter services unit within the Gas  
11       Operations group to support both increases in work volumes and additional  
12       responsibilities, which have been assigned to the Dispatch and Meter group from Gas  
13       Control.

14       *Dispatch Manager (1 FTE)* – This FTE will oversee and manage the Dispatch Center.

15       *Meter Services Supervisor (1 FTE)* – This FTE will supervise the work performed by  
16       the Company's internal workforce of meter-services technicians.

17       *Service Technicians (3 FTEs)* – These FTEs will install, change, remove, inspect and  
18       maintain meter set assemblies; perform meter turn-on and turn-offs; support leak  
19       investigations; and provide emergency response.

1       *Dispatch Clerk (1 FTE)* – This FTE will be responsible for monitoring various aspects  
2       of the Dispatch office, including customer requests, questions, issues and Meter Service  
3       Department workload management. Additional duties will include acting as a  
4       communication liaison for Dispatch/Meter Service and the Call Center.

5       **Construction**

6       The Company is hiring 1 FTE in the Construction unit within the Gas Operations group:

7       *Construction Supervisor (1 FTE)* – Construction supervisors are responsible for the  
8       execution of construction projects to install gas main and services by internal personnel  
9       and external contractors. This FTE is needed to provide oversight to incremental  
10      outside contractor resources required to complete the work associated with the overall  
11      capital plan, which includes five-miles per year increases in the amount of main being  
12      replaced annually under the GSEP program.

13      **Technical Services (Leak Survey and Damage Prevention)**

14      The Company is adding 2 FTEs to the Technical Services unit within the Gas  
15      Operations group:

16      *Corrosion Technician (1 FTE)* – This FTE will perform mandated testing of  
17      cathodically protected steel gas mains and services and manage the work of contractors  
18      engaged by the Company to make required corrosion repairs to its gas distribution  
19      system. Performing this work in-house enhances the Company's ability to perform

1 testing concurrent with corrosion repairs, where in the past, a second visit to the job  
2 site was required to complete testing after a repair was made.

3 *Damage Prevention Supervisor (1 FTE)* – This FTE will be responsible to improve and  
4 manage the Company’s damage-prevention program by working with third-party  
5 excavators and managing internal personnel that perform mark outs of Company gas  
6 facilities in accordance with Dig Safe law.<sup>2</sup> This FTE is needed to maintain an  
7 appropriate span of control over Company resources that execute the work due to  
8 increases in work volumes.

9 **Project Management**

10 The Company is hiring 6 FTEs in the Project Management unit within the Gas  
11 Operations group as follows:

12 *Manager Project Controls (1 FTE)* – This is a new position to oversee the work order  
13 creation process and closeout teams, along with any supporting design estimation  
14 involved in finalizing budgets for capital work.

15 *Supervisors (2 FTEs)* – One supervisor role will support the work-order creation,  
16 approval and close-out processes for capital work. The second Supervisor role will  
17 oversee the estimation and project budget tracking for capital work orders, as well as

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<sup>2</sup> G.L. c. 82, §§ 40 through 40E.

1 any variances and will maintain and apply proper pricing information for project  
2 estimates.

3 *Specialist Contractor Billing (1 FTE)* – This is a new position to support adequate and  
4 timely processing of contractor billing to ensure all costs are accurately reflected on the  
5 corporate books. This FTE will be responsible for validating contractor bills relative  
6 to the work performed along with the contracted rate structure.

7 *Estimators (2 FTEs)* – These FTEs will support annual increases in work volume.  
8 These FTEs are required to adequately support the needs of the operating departments  
9 and are responsible for supporting the work order creation team with timely cost and  
10 material estimates for capital projects.

11 **Planning and Scheduling**

12 The Company is hiring 5 FTEs in the Planning and Scheduling unit within the Gas  
13 Operations group as follows:

14 *Manager of Operations Performance and Long-Term Planning (1 FTE)* – This FTE  
15 will oversee the Operations Performance Analysts and the Long-term planning function  
16 implemented by the Company.

17 *Operations Analyst (1 FTE)* – This new analyst will prepare operational measures and  
18 metric reports that will be used to monitor business performance and provide analytical

1 support to field Operations departments. This FTE is required to adequately support  
2 the needs of the Operations departments.

3 *Gas WAM Administrator (1 FTE)* – This FTE will perform the system maintenance and  
4 updates required to support the Company’s new work and asset management systems  
5 that were implemented in 2019.

6 *Resource Management and Workforce Analyst (1 FTE)* – This is a new position that  
7 will be responsible to maintain integrated one-year, three-year and five-year resource  
8 plans to support the Company’s future operating and capital programs. Development  
9 and maintenance of these staffing models will allow the Company to properly plan for  
10 and execute its hiring needs in the future.

11 *Clerk (1 FTE)* – The Operations clerk will process payroll, apply for permits and dig  
12 safe requests, and perform other administrative duties as assigned in support of day to  
13 day operations. This FTE is required to support increases in the volume of work  
14 associated with corresponding increases in the Company’s capital programs.

15 **Q. What are the incremental staffing additions now necessary for the NSTAR Gas**  
16 **Engineering Division?**

17 A. As shown in Exhibit ES-WJA/DPH-2, on pages 2 and 5, the Company is increasing  
18 staffing within Gas Engineering by 34 FTEs to better position the Company to respond  
19 to increasing regulatory requirements and increasingly formalized coordination and  
20 risk management processes. These positions will also support the Company’s

1 increased and growing capital programs. The FTEs are described by business unit  
2 within the Gas Engineering group below.

3 **Gas System Engineering**

4 The Company is hiring 19 incremental FTEs in the Gas System Engineering unit within  
5 the Gas Engineering group as follows:

6 *System Planning and System Analysis Enhancement (1 Manager, 2 Engineers)* - The  
7 system-planning and system-analysis group oversees the design and planning of the  
8 overall distribution systems. Additional staffing is required to support the formalized  
9 Planned Work Authorization (“PWA”) process. The PWA process is as follows:

- 10       ▪ The PWA process is intended to provide greater visibility into all projects  
11       occurring simultaneously within the system to all the affected groups with the  
12       Eversource Energy gas business.
- 13       ▪ The PWA process is the sequence of steps necessary to accomplish planned  
14       work in the Eversource Energy gas business, beginning with the request to  
15       develop a job-specific procedure or to schedule other planned work, and ending  
16       with the close out of the work authorization by Gas Control.
- 17       ▪ The PWA process integrates all the steps required to submit and authorize work  
18       that can affect the flow of gas or generate alarm conditions in the Control Room.
- 19       ▪ System planning participates in each PWA to perform system analysis for  
20       each job specific procedure, including consideration of other ongoing  
21       and/or simultaneous procedures.
- 22       ▪ System analysis updates the system analysis when a change to a job specific  
23       procedure is made.
- 24       ▪ System analysis is also responsible for coordinating with Field Engineers to  
25       resolve conflicts.

1        *Field Engineers (7 engineers)* – The field engineers focus on a specific geographic area  
2        to increase knowledge and visibility of area-specific issues in the Gas System  
3        Engineering department. These additional engineers are required to support the PWA  
4        process described above and the Field Condition-Based Modification process described  
5        below.<sup>3</sup>

6        *Policy and Compliance Enhancement (1 engineer)* - This group supports the  
7        development and continuous improvement of Eversource Gas Standards, Procedures,  
8        and Work Practices. There are three major new procedures in development as part of  
9        the Company's initiatives post-Merrimack Valley: the PWA process described above,  
10       the Field Condition-based Modification procedure, and the Management of Change  
11       Initiative. Additional staffing is required to ensure that the Field Condition-Based  
12       Modification is implemented effectively, as follows:

- 13        ■ This procedure will validate that any changes made to job-specific procedures  
14        attributable to field conditions are safely and effectively incorporated to new  
15        job-specific procedures, drawings and records. The procedure also ensures that  
16        this process is performed in a way that meets regulatory requirements.
- 17        ■ All stamped drawings used with job-specific procedures will be approved by  
18        Project Engineering and Operations.

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<sup>3</sup> Under Gas Engineering, the Company is currently planning to add professional engineers within the category of Field Engineers (7 FTEs) and Complex Projects PM Enhancement (3 FTEs). All of the ten incremental FTEs planned in these two categories do not need to be professional engineers to meet the Department's pending standard. However, the Company is targeting five positions in Massachusetts. Some of these professional engineers may be hired having passed the exam, but needing work experience to fulfill the entirety of the professional engineer licensing requirements.



- 1           ▪ Drawings will be managed consistently across the Eversource Energy Gas  
2           business. Drawing formats, notes, and symbology should be consistent and  
3           conform to existing Eversource Energy standards.
- 4           ▪ Criteria for what constitutes a drawing change (based on field conditions) will  
5           be defined in a drawing modification work practice.
- 6           ▪ A process will be developed to ensure that drawing modification support is  
7           available whenever field work is taking place that could require a change.
- 8           ▪ Where required by state regulations, Eversource Energy gas business drawings  
9           will be stamped by a licensed Professional Engineer.

10           *Management of Change Coordinator (1 engineer)* – As noted above, there are three  
11           major new procedures in development as part of the Company’s initiatives post-  
12           Merrimack Valley: the PWA process described above, the Field Condition-based  
13           Modification procedure described above, and the Management of Change Initiative. A  
14           Management of Change (“MOC”) Coordinator will be hired to oversee this important  
15           initiative. MOC considerations are as follows:

- 16           ○ Management of Change, or MOC, is a best practice used to ensure that safety,  
17           health and environmental risks are controlled when a company makes changes  
18           in their physical assets, facilities, documentation, personnel, or operations.
- 19           ○ Eversource Energy plans to meet MOC requirement(s) by following the MOC  
20           Guidelines in API-RP-1173 and verify that all other requirements are met by  
21           API-RP-1173.
- 22           ○ The changes that a MOC addresses will include technical, physical, procedural  
23           and organizational.
- 24           ○ For each MOC, the pipeline operator will identify the potential risks associated  
25           with the change and any required approvals prior to the introduction of such  
26           changes.
- 27           ○ This procedure will consider permanent or temporary changes.

- The process will incorporate planning for the effects of the change for each of these situations.

In addition, the MOC Coordinator will:

- Receive, collect, and manage all MOC forms.
- Track the status of all in-progress MOC forms, risk analyses and implementation plans.
- Perform analyses to support the continued improvement of the MOC procedure.
- Propose and implement changes to the MOC procedure and the development of additional procedures to support effective MOC in the Gas Business Unit.
- Aid in the resolution of conflicts discovered during an MOC process.

*Asset Management Enhancement (2 engineers)* - These FTEs will support the gas asset and risk management program, which uses a risk-based approach to asset management and establishes the capital budget based on risk prioritization. The addition of these engineers will also:

- Accelerate the timeline to improve asset and risk management program maturity and achieve ISO 31000 standard, demonstrating the Company's commitment to safety and operational excellence.
- Increase the rigor of engineering assessments, including quantified risk scoring to build a common risk register across asset families.
- Provide the opportunity for increased engagement and follow up with groups outside of engineering to emphasize safety and risk reduction efforts through the gas organization.
- Ensure the timely completion of studies to more proactively identify and mitigate risks.
- Improve the quality of program elements, including: integrity assessments, data collection and analysis, performance tracking, asset replacement reviews, resource planning, records management, and fitness for service reviews.

1        *Complex Projects PM Enhancement (3 engineers)* - These FTEs will manage  
2        engineering, design, construction and project management for all I&R capital and  
3        complex projects: take stations, district regulators, remote control valves, telemeters,  
4        and temporary LNG/CNG facilities in both states. The addition of these engineers will  
5        also:

- 6            ▪ Establish strategy and implement enterprise wide standards for engineering  
7            design to support the consistent, reliable and cost-effective gas delivery.
- 8            ▪ Provide oversight of third-party engineering service providers.
- 9            ▪ Ensure all complex design projects are appropriately assessed, designed,  
10          planned, resourced and scheduled in a timely and cost-effective manner.
- 11          ▪ Complete independent design reviews of complex projects.
- 12          ▪ Assess and implement new technology and techniques that improves safety,  
13          reliability and compliance.
- 14          ▪ Plan, manage, and work with I&R and Asset Family Owners to implement  
15          enhancements to take station and district facilities to maintain a reliable network  
16          and ensure potential hazards are managed safely and effectively.
- 17          ▪ Oversee Management of Change procedures for projects – a design change that  
18          alters the approved design and may result in operation changes of the system  
19          (flows, pressures, temperature, reliability, etc.).
- 20          ▪ Ensure proper communications interface and information flow with Gas  
21          Control and control room management requirements

22        *GIS Techs (2 techs)* - These FTEs will support the use of GIS as the repository of record  
23        for all assets in the Gas Business Unit.

1       **Gas System Operations (Gas Control) (1 Supervisor, 1 Engineer)**

2       The Gas Control organization is the nerve center of the gas distribution system. Gas  
3       Control is responsible for observing and watching over the system using Supervisory  
4       Control and Data Acquisition (“SCADA”). Gas Control responds to alarms through  
5       the SCADA program and interacts with the multitude of crews working on the  
6       distribution system daily to ensure supply of gas is not unintentionally interrupted to  
7       any customers, and to ensure the safety of our employees, customers, and their  
8       property. Additional staffing is required to support the following changes to the Gas  
9       Control system, as follows:

- 10           • Meet increased regulatory requirements related to control room management
- 11           • Oversee additional data and control points on the distribution system
- 12           • Support the Planned Work Authorization process
- 13               ○ Review and approve job-specific procedures.
- 14               ○ Review, approve, and communicate all scheduled work as submitted in
- 15               PWA forms.
- 16               ○ Communicate with and approve or deny supervisors or employees
- 17               requesting authorization for planned work immediately prior to the
- 18               commencement of the work.
- 19               ○ Communicate with supervisors and employees notifying Gas Control
- 20               that the authorized task was completed or that they are leaving the work
- 21               site.

22       **Instrumentation and Regulation (1 Director, 4 Technicians)**

23       The GBU I&R department is responsible for the maintenance and inspection of many  
24       critical components of the Company’s gas distribution system, including gate and

1 pressure regulation stations and large customer meter sets. The team also performs  
2 monthly tests to ensure the gas traveling in the distribution system is properly odorized.  
3 The team monitors and responds to all system alarms, including pressure, temperature,  
4 station intrusion, and odorizer reports from the field.

5 In addition to conducting the inspections required by the Department, the team also  
6 plays a lead role in the prioritization and execution of all gate and regulator station  
7 modifications and replacements, remote control valve installation and maintenance,  
8 large customer set installation, pickling of new steel pipelines and purging (pre-  
9 odorizing pipe) and flaring operations. Additional staffing is required to support  
10 various initiatives related to gate and regulator stations:

11 **Emergency Preparedness (1 ERP Specialist)**

12 The Emergency Preparedness group ensures that the Company is prepared for any type  
13 of emergency event. The group is responsible for maintaining the Incident  
14 Management Team roster, as well as the ERP for Eversource Gas, including acquisition  
15 of outside mutual aid resources, and communication plans to affected areas. Additional  
16 staffing is required to support the continued improvement of the Gas ERP.

17 **New Engineer Cohort Program (6 FTEs)**

18 The Engineer Cohort Program is designed to provide individuals hired into a Gas  
19 Engineering position with an opportunity for career development, training, and varied  
20 work experience. The program provides each individual an opportunity to gain

1 experience working in different engineering areas. This program is based on the  
2 successful Gas Supervisor Cohort Program and, on the electric side, the Eversource  
3 Engineering Professional Development Program.

4 **Director of Clean Gas Technologies (1 FTE)**

5 The Director of Clean Gas Technologies will represent and advance the Gas Business  
6 Unit in areas of clean gas technologies, including RNG, power-to-gas, operational  
7 methane reduction, LNG strategy coordination, and gas efficiencies.

8 **Q. What are the incremental staffing additions now necessary for the Company's**  
9 **Pipeline Safety and QA/QC group?**

10 A. As shown in Exhibit ES-WJA/DPH-2, on pages 4 and 5, the Company is increasing  
11 staffing within Pipeline Safety and QA/QC group by a total of 9 FTEs.

12 As discussed earlier in this testimony, Eversource Energy has adopted and commenced  
13 implementation of QA/QC programs for its gas operations. Also, as discussed later in  
14 this testimony, the Company is implementing a Pipeline Safety Management System  
15 ("PSMS"), in line with the industry standard American Petroleum Institute ("API")  
16 Recommended Practice RP 1173 ("API 1173"). These programs are aimed at assuring  
17 that processes are in place to prevent breakdowns in the controls used by the Company  
18 to maintain compliance, quality, and safety. This is accomplished through proactive  
19 assessment of these controls. The goals of the Eversource PSMS include:

- 20
  - Promoting a proactive safety culture with employees and management;

- Evaluating and assessing PSMS programs on a periodic basis to ensure that structure is aligned with the Company's mission and business objectives;
- Establishing continuous monitoring and improvement programs as appropriate with responsible parties assigned to perform oversight of these programs;
- Coordinating with outside parties (American Gas Association, Northeast Gas Association, other operating companies) to review and identify best practices and processes that enhance the NSTAR Gas PSMS; and
- Measuring the PSMS effectiveness and maturity based on the recommendations per API 1173, Pipeline Safety Management Systems - the industry standard for these programs.

To support the PSMS, QA/QC and the specific goals articulated above, the Company is adding the following nine FTEs to its workforce:

*Director (1 FTE)* – The new Director will oversee this group and the overall PSMS and QA programs.

*Manager (3 FTEs)* – These managers will be responsible for management and oversight of the PSMS and QA programs.

*PSMS Program Administrator (2 FTEs)* – These FTEs will provide support in the execution of the PSMS and QA programs by monitoring and implementing plans within these programs, including gap analyses, fieldwork audits and assessments, and continuous improvement evaluations.

*QA/QC Analyst (1 FTE)* – These analysts will prepare QA/QC measures and metric reports used to monitor quality, compliance, and business performance and provide

1        analytical support to the QA/QC program. These FTEs are required to adequately  
2        support the needs of the PSMS and QA/QC group.

3        *Process Safety Coordinator (1 FTE)* – This FTE will focus on gas-specific process  
4        safety including, but not limited to, performing hazard analysis (core risk-based tasks  
5        and complex projects), leading performance initiatives, and administering the incident  
6        analysis and investigation programs.

7        *Process Analyst (1 FTE)* – This analyst will prepare process measures and metric  
8        reports used to monitor safety performance and provide analytical support to the PSMS  
9        and QA/QC programs. This FTE is required to adequately support the needs of the  
10       PSMS and QA/QC group.

11    **Q.    Is the Company proposing to recover the costs associated with the addition of any**  
12    **incremental post-test year FTEs as part of this proceeding?**

13    A.    Yes. In this proceeding, the Company is proposing to recover the costs of 75  
14    incremental FTEs discussed above in the base revenue requirement approved in this  
15    proceeding, which is 32 FTEs in the Gas Operations group; 34 FTEs in the Gas  
16    Engineering group; and 9 FTEs in the Pipeline Safety and QA/QC group. Exhibit ES-



1 WJA/DPH-2 shows the dispersion of the 75 FTEs that the Company is proposing to  
2 include in the base revenue requirement to support the Company's operating functions.

3 **Q. Why should the Department consider including the cost of 75 incremental FTEs,**  
4 **not hired in the test year in the cost of service in this proceeding?**

5 A. The Company is aware that the Department has denied previous requests to make post-  
6 test year adjustments in base-rate cases to incorporate the cost of employees added after  
7 the test year. The Company is asking the Department to consider including the cost of  
8 incremental FTEs in this case due to the fact that the Company is committing to a five-  
9 year stay-out and will not be in a position to return to the Department in the interim to  
10 include the cost of these incremental employees in the cost of service. It is critical for  
11 the Company to have the flexibility to add these needed positions during the term of  
12 PBR Plan. The Company is committed to hiring these incremental employees and will  
13 report on its progress to fill these positions throughout the course of this proceeding  
14 and beyond if the positions are not filled by the end of the case. The post-test year  
15 adjustment associated with the 75 incremental positions totals \$2.4 million and is  
16 discussed in the joint testimony of Company Witnesses Horton and Botelho regarding  
17 the proposed revenue requirement.

18 **B. Investments in Process**

19 **Q. Please elaborate on what you mean by "process investments."**

20 A. Safety management systems have proven to be useful tools for developing a  
21 comprehensive, process-oriented approach to safety in other industries, such as

1 aviation, nuclear power and chemical manufacturing. The Pipeline Safety  
2 Management System, or PSMS, associated with the American Petroleum Institute  
3 Recommended Practice RP 1173 (“API 1173”) was published in July 2015 and was  
4 developed by the API with input from National Transportation Safety Board (“NTSB”),  
5 the Pipeline and Hazardous Materials Safety Administration (“PHMSA”), states, and  
6 industry representatives. API 1173 is a framework for improving pipeline safety that  
7 includes the identification, prevention and remediation of safety hazards. API 1173  
8 “identif[ies] what is to be done, and leaves the details associated with implementation  
9 and maintenance of the requirements to the individual pipeline operators.”<sup>4</sup>

10 The following eleven principles comprise the basis of the API 1173 PSMS:<sup>5</sup>

- 11       ▪ Commitment, leadership, and oversight from top management are vital to the  
12       overall success of a PSMS.
- 13       ▪ A safety-oriented culture is essential to enable the effective implementation and  
14       continuous improvement of safety management system processes and  
15       procedures.
- 16       ▪ Risk management is an integral part of the design, construction, operation and  
17       maintenance of a pipeline.
- 18       ▪ Pipelines are designed, constructed, operated, and maintained in a manner that  
19       complies with Federal, state, and local regulations.
- 20       ▪ Pipeline operators conform to applicable industry codes and consensus  
21       standards with the goal of reducing risk, preventing releases, and minimizing  
22       the occurrence of abnormal operations.

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<sup>4</sup> ANSI/API Recommended Practice 1173, Pipeline Safety Management Systems at 1, *available at* <https://pipelinesms.org/wp-content/uploads/2018/08/API-RP-1173-Pipeline-Safety-Management-Systems.pdf>.

<sup>5</sup> ANSI/API Recommended Practice 1173, Pipeline Safety Management Systems at vii-viii, *available at* <https://pipelinesms.org/wp-content/uploads/2018/08/API-RP-1173-Pipeline-Safety-Management-Systems.pdf>.

- 1           ▪ Defined operational controls are essential to the safe design, construction,  
2           operation, and maintenance of pipelines.
- 3           ▪ Prompt and effective incident response minimizes the adverse impacts to life,  
4           property, and the environment.
- 5           ▪ The creation of a learning environment for continuous improvement is achieved  
6           by investigating incidents thoroughly, fostering non-punitive reporting systems,  
7           and communicating lessons learned.
- 8           ▪ Periodic evaluation of risk management effectiveness and pipeline safety  
9           performance improvement, including audits, are essential to assure effective  
10          PSMS performance.
- 11          ▪ Pipeline operating personnel throughout the organization must effectively  
12          communicate and collaborate with one another. Further, communicating with  
13          contractors to share information that supports decision making and completing  
14          planned tasks (processes and procedures) is essential.
- 15          ▪ Managing changes that can affect pipeline safety is essential.

16   **Q.    Has the industry, and more specifically the Company, committed to implement a**  
17   **PSMS?**

18   A.    Yes. After the Merrimack Valley incident on September 13, 2018, the Department  
19          requested that all gas companies adopt API 1173 and review their safety protocols,  
20          including an examination of the feasibility of implementing a PSMS. On November  
21          21, 2018, the Baker-Polito Administration announced that the Northeast Gas  
22          Association (“NGA”) committed to adopting API 1173 and same for the  
23          Commonwealth’s gas distribution companies.<sup>6</sup>

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<sup>6</sup> Press Release, Baker-Polito Administration Announces Utilities Will Adopt Comprehensive Pipeline Safety Management Standards (November 21, 2018), *available at* <https://www.mass.gov/news/baker-polito-administration-announces-utilities-will-adopt-comprehensive-pipeline-safety>.

1 NSTAR Gas was one of the first companies to begin piloting API 1173 back in 2016  
2 because it recognized, early on, that it was a rigorous, proactive approach to safe  
3 pipeline operation. In the wake of the Merrimack Valley incident, NSTAR Gas has  
4 committed to accelerate its deployment of a PSMS to augment its existing processes  
5 and procedures, to deal systematically with safe and effective pipeline operation on an  
6 enterprise-wide basis, and to minimize the potential for human-performance errors.

7 **Q. What are some specific examples of enhancements the Company is making as part**  
8 **of the PSMS?**

9 A. One of the key principles of a PSMS is a culture of “Safety First and Always.”  
10 “Leaders, managers, and employees acting to make safety performance and risk  
11 reduction decisions over time will improve pipeline safety, thereby strengthening the  
12 safety culture of an organization.”<sup>7</sup> In this regard, and as discussed above, the  
13 Company has worked diligently to imbue the organization with a “Safety First” culture  
14 by committing to safety at the highest levels of the organization, implementing training  
15 and communication protocols to ensure that all employees understand the  
16 organization’s safety goals and applicable processes and procedures, and considering  
17 risk on a systematic basis. However, it can be difficult to objectively measure the  
18 culture of an organization because it is rooted in shared practices and attitudes that  
19 shape behavior.

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<sup>7</sup> ANSI/API Recommended Practice 1173, Pipeline Safety Management Systems at xi, *available at*  
<https://pipelinesms.org/wp-content/uploads/2018/08/API-RP-1173-Pipeline-Safety-Management-Systems.pdf>.

1 In response to this challenge, the Company has successfully developed several  
2 performance metrics that provide objective indicators of a safety culture and measure  
3 the effectiveness of risk management. As discussed above, the Company measures  
4 DART rates and PMVAs and has already driven significant improvements in these  
5 safety-oriented metrics since its last base distribution rate case in 2014. In this  
6 proceeding, the Company is proposing additional safety-focused performance  
7 metrics—including measurement of API 1173 implementation—which are discussed  
8 in Section VII below.

9 Also, as noted above, one key principal of a PSMS is that risk management must be an  
10 integral part of the design, construction, operation and maintenance of a pipeline.  
11 Accordingly, NSTAR Gas is building controls (checks-and-balances) into how work is  
12 designed, scheduled, managed, and supervised, as well as integrating its ERPs into the  
13 PSMS framework. The Company is also continuing to review and refine its QA/QC  
14 program and implementing processes and procedures to ensure the accuracy and  
15 integrity of its records.

16 **C. Investments in Technology**

17 **Q. Is the Company making investments in technology as part of the PSMS?**

18 A. Yes. In addition to process improvements, the Company is pursuing investments in  
19 technology to improve safety and reliability and that will enhance the PSMS. For  
20 example, the Company has invested in enhancements to its geographic information  
21 system (“GIS”) to make it a central repository for compliance data and asset records.

1 In the past, this information was scattered across several different systems which was  
2 inefficient and time consuming. This effort has been enhanced by the Company's  
3 investments in a new Enterprise Work and Asset Management ("WAM") system and a  
4 ClickSoftware Workforce Management ("Mobile Gas WAM") solution, which is  
5 discussed in more detail below. The Company has also invested in standardizing its  
6 Gas Measurement Instruments, which are used to detect natural gas in the field.

7 On top of the investments described above, the Company is evaluating investments in  
8 integrated field devices and communications infrastructure to more effectively operate  
9 the system, avoid incidents and mitigate the potential for human-error. These types of  
10 modifications could include remote controlled valves, slam-shut valves, and relief  
11 valves. This also includes building in more telemetry so that operators in the Gas  
12 Control Center in Southborough can better monitor pipeline pressures, flow conditions  
13 and operating conditions.

14 **Q. Are there additional technology solutions that the Company may seek to invest in**  
15 **over the five-year PBR term?**

16 A. Yes, there are other new and emerging technologies that may become commercially  
17 viable over the five-year PBR term that the Company could employ to further enhance  
18 safety and reliability. For example, the Company is evaluating residential methane  
19 detectors, which can be deployed to detect natural gas leaks in the Company's territory  
20 and allow the Company to respond quickly to mitigate potential problems. Another  
21 example is evolving meter technology. There are devices under development that have

1 the capability to regulate pressure and flow, and to monitor corrosion and methane  
2 emissions. The Company will continue to track the progress of technologies that could  
3 help enhance safety and reliability, and further the objectives of PSMS, over the course  
4 of the five-year PBR term.

5 **Q. Are there other key technology investments the Company has made that you**  
6 **would like to highlight?**

7 A. Yes, as I noted above, the Company has invested in two significant projects to enhance  
8 the Company's ability to provide safe, reliable, and quality natural gas distribution  
9 service.

10 The first investment is the Gas WAM project. Eversource Energy's work management  
11 systems were dated; at risk of failure due to technical obsolescence; and unable to meet  
12 future business needs. In response to this challenge, Eversource Energy initiated the  
13 WAM project to implement a single, core enterprise asset management solution that  
14 replaces the legacy Northeast Utilities STORMS and legacy NSTAR Passport Work  
15 Management and other associated solutions. The Gas WAM system is implemented at  
16 NSTAR Gas and Yankee Gas and the second phase of the WAM implementation will  
17 cover the Eversource Energy electric operating companies. The NSTAR Gas and  
18 Yankee Gas phase of the WAM project was placed in service in March 2019.

19 The WAM system will enable industry standard, best practices across the Company's  
20 work and asset management processes through a robust application architecture. The  
21 Company anticipates that long-term benefits from the implementation of the WAM

1 system will be experienced in the areas of customer engagement, standardization of  
2 process/metrics, asset management, mobility, and IT:

<b>SUMMARY OF ANTICIPATED BENEFITS</b>	
<b>Customer Engagement</b>	<ul style="list-style-type: none"> <li>• Easy, real-time access to accurate information</li> <li>• Enhanced options for appointment scheduling</li> <li>• Improved service turnaround time (complete the job on or before the promised date)</li> </ul>
<b>Standardization of Processes/Metrics</b>	<ul style="list-style-type: none"> <li>• Implement utility best practice work processes across all Operating Companies</li> <li>• Improves efficiency by standardizing practices, procedures, guidelines, and roles across Design, Scheduling, Construct</li> <li>• Common Performance Metrics</li> </ul>
<b>Asset Management</b>	<ul style="list-style-type: none"> <li>• One single asset repository, fully integrated with WM &amp; GIS</li> <li>• Streamline work processes for maintenance compliance lifecycles</li> <li>• Improved decision-making regarding asset replacements vs. maintenance</li> </ul>
<b>Mobility</b>	<ul style="list-style-type: none"> <li>• Elimination of paper work packages</li> <li>• Improved efficiency via elimination of handoffs / rework / lost paperwork</li> <li>• Near real-time status updates</li> </ul>
<b>IT</b>	<ul style="list-style-type: none"> <li>• Reduced risk of business disruption and mitigation costs</li> <li>• Reduction of application portfolio through retirement of legacy systems</li> </ul>

3 The second investment is the deployment of the Mobile Gas WAM solution, which  
4 complements the Gas WAM system. In the past, Eversource Energy did not employ  
5 an enterprise mobile technology solution for its field operations workforce (i.e., field  
6 supervisors, field workers and contractors). Consequently, job package information  
7 was delivered to the field workforce by way of a paper-based process that was manual  
8 and labor intensive. This “mobility gap” significantly impeded the Company’s ability  
9 to meet or exceed the expectations of customers who have grown accustomed to being



1 served by field mobility solutions as a part of their day-to-day interactions with other  
2 service providers. This work process was highly inefficient and did not provide timely  
3 work status updates to customers or employees.

4 In response to these challenges, the Company invested in the Mobile Gas WAM project  
5 to drive operational efficiencies by significantly improving business processes and  
6 technology used day-to-day by field operations. The Mobile Gas WAM project was  
7 placed in service for the Eversource Energy gas operating companies in August 2019.  
8 Implementation of Mobile WAM for the Eversource Energy electric operating  
9 companies will take place at a later date.

10 The Mobile Gas WAM project provides new capabilities to field workers, which  
11 includes access to GIS, maps, standards, procedures and email/texting to provide them  
12 with more timely, accurate information to perform construction, maintenance,  
13 inspection, compliance and emergency gas work activities required to deliver safe and  
14 reliable energy and a better customer experience. NSTAR Gas has also provided  
15 mobile devices to all its internal field crews, and to external contractors, to give them  
16 real time access to the most up-to-date maps and records.

17 The Company is in the process of adding additional functionality enhancements to the  
18 Gas WAM and Mobile Gas WAM systems to:

- 19       ▪ Provide timely efficient review, approval and processing of Gas contractor  
20       billing and payments.
- 21       ▪ Enhance business processes for leak, corrosion, instrument calibration,

critical valve and regulator management.

- Provide timely, accurate operational and regulatory compliance reporting in conjunction with the corporate data analytics platform being developed.
- Enhance asset data accuracy and reduce cycle times for GIS field data updates.

The Gas WAM and Mobile Gas WAM projects are also discussed in the joint testimony of Company Witnesses Landry and Desrosiers. The Company has incorporated the costs of the Gas WAM system and the Mobile Gas WAM project as post-test year adjustments to the cost of service presented in this proceeding, as described in the joint testimony of Company Witnesses Horton and Botelho.

**Q. Please also describe the Mobile Gas Meter Services project.**

A. As part of the enterprise-wide effort to modernize and streamline its systems to improve operational efficiencies, as well as the customer experience, Eversource Energy is in the process of implementing the Mobile Gas Meter Services (“MGMS”) project. The MGMS project is designed to (1) standardize and streamline the Gas Meter Services dispatch and field execution processes, (2) replace two disparate legacy systems, pCad and Advantex, (3) provide new and improved appointment booking functionality for the Company’s customer service representatives (“CSRs”), as well as for those customers who are utilizing the self-service appointment booking feature, and (4) provide streamlined visibility into all Gas meter services for the Company’s CSRs. This project will also support the Gas Meter Services business, with the following as its key objectives: establish a single unified business process for gas meter services and

1 customer request process for gas meter services work; improve workload and resource  
2 utilization by leveraging automatic scheduling, route optimization, and “Best Fit”  
3 appointment booking; improve customer experience by refining the appointment  
4 process and working towards reducing the customer appointment window; and  
5 providing timely job status information to CSRs and customers. The MGMS project  
6 is currently in the testing phase and, assuming testing is successful, the Company  
7 anticipates that this project will be placed in service by the first quarter of 2020.

8 The MGMS project is also discussed in the joint testimony of Company Witnesses  
9 Landry and Desrosiers. Company Witnesses Horton and Botelho discuss the  
10 Company’s proposal for cost recovery of this investment in the Revenue Requirements  
11 testimony.

12 **V. PROGRESS ON EMISSIONS REDUCTIONS**

13 **Q. Mr. Akley, you have testified that safety is the top priority in the gas industry, are**  
14 **there other overarching priorities that you would like to discuss?**

15 A. Yes. At Eversource Energy, our commitment to environmental sustainability is an  
16 important part of our daily business operations, and a key aspect of our vision to  
17 become the best energy company in the nation. There is an increased urgency to  
18 “decarbonize” energy resources with the ultimate goal of delivering a clean energy  
19 future. And when it comes to natural gas decarbonization, there are several  
20 opportunities to reduce emissions associated with the infrastructure in the ground today  
21 as well as future opportunities around renewable natural gas, natural gas demand

1 reduction, and geothermal distribution. Exploring the potential of a wide variety of  
2 options and solutions is critical as the Commonwealth seeks to reduce greenhouse gas  
3 emissions to meet the goals set forth in the Global Warming Solutions Act.

4 **A. Reducing GHG Emissions on the Distribution System**

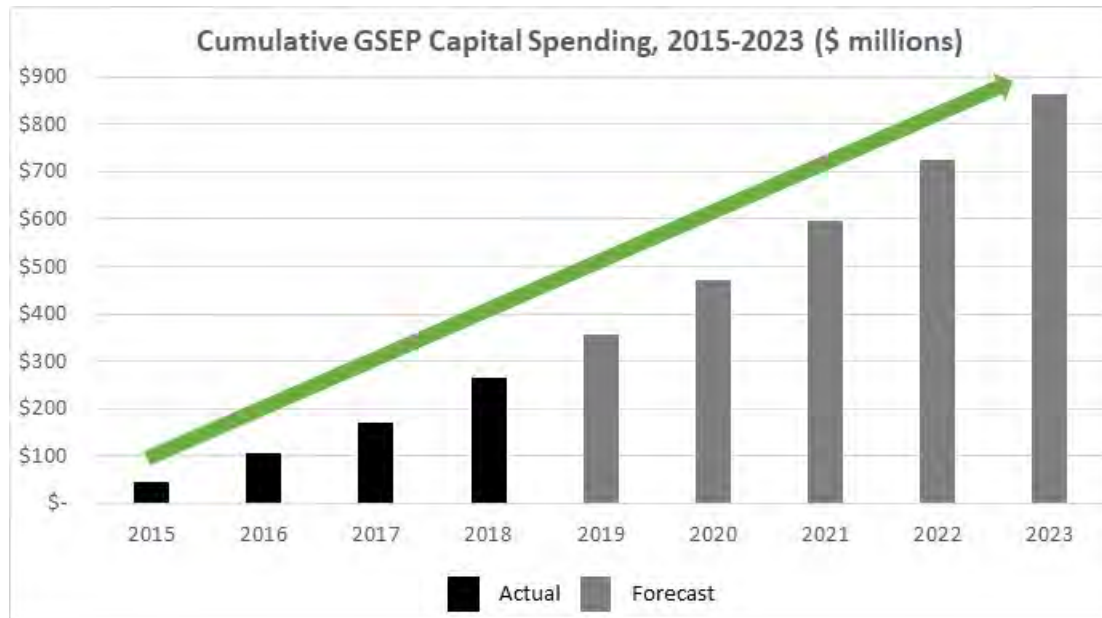
5 **Q. How does the Company work to reduce greenhouse gas emissions as part of its**  
6 **operations?**

7 A. Replacement of aging bare steel, cast-iron and other leak-prone gas infrastructure is a  
8 top priority to minimize the potential for gas leaks and the release of greenhouse gases  
9 into the atmosphere. Since 2012, the Company has replaced 220 miles of leak-prone  
10 gas main resulting in reductions of approximately 226 metric tonnes of methane  
11 annually (5,647 mt CO<sub>2</sub>e). The Company is on track to replace the remainder of its  
12 leak prone facilities within 20 years.<sup>8</sup> As shown in the graph below, capital spending  
13 on GSEP doubled between 2015 and 2019 and it is expected to triple over the course  
14 of the PBR Plan term.<sup>9</sup>

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<sup>8</sup> At the outset of the GSEP, the Department approved a 25-year replacement timeline for the Company with an anticipated replacement rate of 50 miles per year following an initial five-year ramp-up period. In the first four years of the GSEP, the Company has met or exceeded the targeted miles of replacement and expects that the miles of main replaced in 2019 will meet the replacement target approved in D.P.U. 18-GSEP-06.

<sup>9</sup> During the first five years of the GSEP, the Company has gained significant experience in managing the program and secured the necessary resources, both internal and external, to safely and efficiently implement a program of this importance and magnitude. Thus, the Company anticipates reaching a run rate of 60 miles of main replacement per year within the next two years. The Company anticipates that this ramp-up could reduce the overall GSEP replacement timeline to less than 25 years, subject to unforeseen circumstances.



1        In March 2016, Eversource Energy, along with almost 40 other American Gas  
2        Association members, became a founding member of the U.S. Environmental  
3        Protection Agency’s Natural Gas STAR Methane Challenge Program, in which natural  
4        gas utilities are working to reduce greenhouse gas emissions. The companies, which  
5        together serve 66 percent of natural gas customers in the United States, are making and  
6        tracking commitments to reduce emissions; showcase efforts to improve air quality;  
7        and reduce the remaining inventory of bare steel and cast-iron mains.

8        **Q.    Has the Company worked with external stakeholders to target the reduction of**  
9        **greenhouse gas emissions as part of its operations?**

10      A.    In 2016, as part of *An Act to Promote Energy Diversity* (“Energy Diversity Act”),  
11      Massachusetts required utilities to repair Grade 3 leaks with a “significant  
12      environmental impact.” St. 2016 c. 188, § 11. However, because gas companies had

1        been mandated in the past to focus on impacts to life and property and not emissions,  
2        the industry needed to develop new methods to identify leaks with a significant  
3        environmental impact. NSTAR Gas has worked collaboratively with the Home Energy  
4        Efficiency Team (“HEET”), Gas Safety Inc., Mothers Out Front and the other  
5        Massachusetts LDCs to field-test multiple methods to identify leaks with a significant  
6        environmental impact.

7        NSTAR Gas developed a measurement tool for this purpose, referred to as a FLUXbar  
8        method, which compares and confirms the emissions of leaks through a proxy measure  
9        of flux. The FLUXbar method is a relatively straightforward approach to confirm leaks  
10       with a significant environmental impact and meets the Company’s existing protocols.  
11       Specifically, a FLUXbar is a bar-hole purge tool modified to gently vacuum air through  
12       a drill-hole located over a leak while a combustible gas indicator (“CGI”) measures the  
13       percent of gas in that airflow. 220 CMR 114.07(2). The FLUXbar method, which  
14       measures the steady-state flow rate of a leak, is an accurate method of measuring the  
15       size of a leak and allows for comparison and ranking of leaks by size. The Department,  
16       the Company and other Massachusetts LDCs, as well as other stakeholders will be  
17       better able to judge the accuracy and viability of the leak-extent method as a means of  
18       identifying and classifying Grade Three leaks with a significant environmental impact  
19       using the additional information available from the FLUXbar measurements. D.P.U.  
20       16-31-C, at 20 (2019); 220 CMR 114.07(3).

1   **Q.   What other strategies is the Company employing to reduce emissions on the**  
2   **system?**

3   A.   One of the methods the Company is employing to reduce emissions is to prevent  
4       incidents causing damages to the system that can result in releases of natural gas into  
5       the atmosphere. As discussed above, the Company is implementing a comprehensive  
6       PSMS, part of which includes high-standards for marking the distribution system prior  
7       to excavation, as well as training locators, and educating third-party excavators. The  
8       Company is proposing to track damages as a PBR scorecard metric as part of this  
9       proceeding. Also, the Company is planning to hire a new Director of Clean Gas  
10      Technologies who will be tasked with ensuring that all the Company's processes and  
11      procedures are developed in a manner that minimizes adverse impacts to the  
12      environment.

13   **Q.   Is the Company exploring other potential solutions to reduce greenhouse gas**  
14   **emissions?**

15   A.   Yes. The Company is in the process of looking at other aspects of its operating  
16      practices, such as venting and blow-downs, to determine if those practices may be  
17      safely modified or refined to further mitigate emissions. For example, the Company is  
18      looking at the feasibility of using draw-down compressors to recover all, or a portion,  
19      of vented gas back into the gas distribution system.

20      Also, the Company is proposing two demonstration projects in this proceeding that  
21      could further reduce greenhouse gas emissions. The first proposal is designed to  
22      examine whether a natural gas demand program can mitigate natural gas demand spikes

1 and infrastructure constraints. The second proposal is designed to deploy geothermal  
2 distribution in order to test the viability of a geothermal business model, and to provide  
3 the Company and stakeholders with real-world experience on such applications. These  
4 two demonstration projects are discussed in the joint testimony of Company Witnesses  
5 Conner and Goldman. In addition to these two demonstration projects, the Company  
6 is looking into cleaner energy supply options, such as Renewable Natural Gas and  
7 environmentally responsible natural gas supply, which is discussed in the next section.

8 **B. Renewable Natural Gas**

9 **Q. Please summarize the opportunities the Company is exploring to reduce the**  
10 **environmental impact and enhance the sustainability of natural gas supply for its**  
11 **customers.**

12 A. The Company has been actively exploring opportunities to improve the sustainability  
13 of the natural gas it supplies to its Default Service customers. The Company is seeking  
14 opportunities to add renewable natural gas to its resource portfolio, while at the same  
15 time pursuing available means of minimizing the emissions and environmental impact  
16 of conventional natural gas supply.

17 **Q. What is “Renewable Natural Gas”?**

18 A. Renewable Natural Gas (“RNG”) is gas that is recovered from a waste stream; is  
19 refined to a pipeline-quality standard; and is introduced into a gas pipeline and  
20 ultimately delivered to customers. The gas, if not refined and distributed to customers  
21 as natural gas supply, would be emitted to the atmosphere as methane or flared and  
22 emitted as carbon dioxide. Therefore, RNG represents a low-carbon source of gas



1 supply that can serve the natural gas needs of the Company's customers and contribute  
2 to the state's emission reduction targets.

3 **Q. Is RNG used in natural gas systems today?**

4 A. Yes. Examples of RNG use in local distribution gas systems have existed for several  
5 years and it is a growing source of natural gas supply in several regions. Commercially  
6 usable methane has been recovered from landfills for many years. There are several  
7 examples where landfill gas is being processed and injected into natural gas distribution  
8 systems, as well as other examples of landfill gas being used directly for power  
9 generation.<sup>10</sup> One specific example is the Fresh Kills landfill in Staten Island, New  
10 York, which has been operating for almost 30 years and provides 1.8 billion cubic feet  
11 (Bcf) of pipeline quality gas annually.<sup>11</sup> Additional sources of renewable natural gas  
12 are now being developed or evaluated as demand for low and zero-emission fuel  
13 sources increases.

14 **Q. In addition to the capture of methane, are there any other benefits to using RNG?**

15 A. Yes. RNG can be readily produced locally from available waste streams, with the  
16 impact of increasing available natural gas supply. Locally produced RNG may also  
17 provide additional revenue streams for publicly owned and financially challenged

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<sup>10</sup> See United States Environmental Protection Agency, Landfill Methane Outreach Program (LMOP), Landfill Gas Energy Project Data, <https://www.epa.gov/lmop/landfill-gas-energy-project-data>.

<sup>11</sup> <https://roguevalleycleancities.org/renewable-natural-gas-converting-waste-gasses-to-usable-energy/>

1 facilities, such as waste recycling operations, wastewater treatment plants and retired  
2 landfills.

3 **Q. How is RNG delivered to a gas distribution system for use?**

4 A. To be used in a gas distribution system, RNG must first be processed to a pipeline  
5 standard. Natural gas is mostly methane (CH<sub>4</sub>). Waste gas from wastewater treatment  
6 plants, landfills or dairy farms contain only 40-60 percent methane, the rest is CO<sub>2</sub>,  
7 moisture and other contaminants. The waste gas is passed through various filters to  
8 remove impurities and is then piped or injected into the local distribution system.

9 **Q. What systems and infrastructure are required to use RNG?**

10 A. Processing equipment is required to successfully recover waste gas and process it to  
11 pipeline standards as described above. In addition, infrastructure may be required to  
12 enable its consumption. Additional infrastructure requirements may be limited when  
13 RNG supply is located in areas with a large gas load or is proximate to an interstate  
14 pipeline. However, if the RNG supply must be transported to a point of consumption,  
15 then main extensions or expansions may be required. In some cases, the trucking of  
16 RNG to injection points on the distribution system may be the more cost-effective  
17 option.

18 **Q. What quantity of RNG natural gas is the Company anticipating would be added**  
19 **to the resource portfolio while minimizing cost impacts?**

20 A. The Company anticipates that RNG supplies will come at a higher cost than traditional  
21 supplies due to the necessary integration of capital requirements to prepare the gas for

1 injection into the distribution system and, therefore, any project in the future will likely  
2 require a multi-year contract commitment, subject to approval by the Department. As  
3 a result, at this time the Company is not requesting or estimating an annual supply  
4 percentage associated with RNG. That will be determined on a case-by-case basis as  
5 opportunities arise and are reviewed and approved by the Department.

6 **Q. What is the Company proposing in this case in relation to addition of RNG to the**  
7 **NSTAR Gas resource portfolio?**

8 A. The Company is not requesting that the Department take specific action in this case.  
9 The Company has not yet identified a specific opportunity to procure RNG as part of  
10 its supply portfolio for Basic Service gas customers. As yet, few supplies are available  
11 on terms that align with the Company's existing procurement practices for gas supply.  
12 However, the Company views the use of RNG as an important piece of the overall  
13 strategy for serving gas customers in the future and a statement by the Department that  
14 gas companies should be pursuing this strategy will help to develop market  
15 opportunities.

16 As with other market transformation initiatives, RNG will need to be evaluated  
17 differently due to the fact that it creates substantial environmental benefit but will  
18 require a level of capital investment not typical for gas-supply contracts. This will  
19 mean that long-term contracts will be necessary to support the development of these  
20 types of resources similar to the experience with wind power and other renewable  
21 resources. The RNG market is evolving and growing, and the Company is hopeful

1 opportunities will emerge at reasonable cost to customers. The Company will continue  
2 to monitor RNG market development for procurement opportunities and will conduct  
3 competitive requests for proposals if it finds RNG quantities may be procured at a cost  
4 warranted by the environmental and other non-price benefits. The Company  
5 anticipates that, ultimately, it may be possible to factor in proceeds from renewable gas  
6 attributes or other offsetting revenues that may lower the ultimate cost to customers.  
7 In any event, any contract that the Company may decide to enter into will require the  
8 Department's pre-approval with consideration of the environmental benefits that are  
9 attendant to the agreement.

10 **C. Environmentally Responsible Gas Supply**

11 **Q. Are there any steps that the Company can take to address the environmental**  
12 **impact of its conventional natural gas supply?**

13 A. Yes. Conventionally sourced natural gas will remain essential to meeting the thermal  
14 energy requirements of NSTAR Gas customers. However, the Company is exploring  
15 opportunities to meet the needs of customers in the most environmentally responsible  
16 manner it can through the purchase of gas supply sourced from producers meeting  
17 certain requirements for the use of clean technology in the production process.

18 **Q. What is "environmentally responsible natural gas"?**

19 A. "Environmentally responsible natural gas" is natural gas that is produced from high  
20 integrity wells leveraging new technology that has less impact on the environment than  
21 traditional technologies. Environmentally responsible gas supply is evaluated and

1 certified by a third party as meeting certain criteria and qualifications for  
2 environmentally sound production.

3 Third-party ratings include evaluation of techniques such as risk management, wellbore  
4 integrity, subsurface integrity monitoring, environmental programs, spill prevention,  
5 operator process and procedures. Additionally, ratings are based on how well the  
6 producer has designed well-completions and production to minimize the loss of  
7 methane by approaches including: use of vapor recovery units, electric driven pumps,  
8 automatic facility shut down upon emission control malfunction, use of solar powered  
9 controllers, and the installation of methane sensors that will automatically shut when  
10 methane is detected.

11 **Q. What third-party rating programs exist for environmentally responsible natural**  
12 **gas?**

13 A. Independent Energy Standards Corporation (IES) launched the Trustwell™ ratings  
14 system in 2018 and the first recorded purchase transaction was executed by New Jersey  
15 Natural Gas in the same year. The Trustwell™ ratings system is intended to target the  
16 top producers and companies that employ many best practices across a range of risks  
17 and impacts. Ratings are segmented into Silver, Gold and Platinum levels. A  
18 Trustwell™ Gold Rating is intended to target the top 25 percent of producers. The  
19 program has scaled rapidly since launch and included 2,500 wells from 10 suppliers as  
20 of April 2019.

1    **Q.    What are the benefits of sourcing environmentally responsible natural gas?**

2    A.    There are a range of benefits associated with sourcing environmentally responsible  
3    natural gas supply. The purchase of environmentally responsible natural gas supply  
4    results in quantifiable greenhouse gas reductions because the supplies produced for  
5    consumption have lower methane intensity (based on loss rates) than other sources.  
6    Environmentally responsible natural gas supplies are also verified to have lower water  
7    and community impacts. Perhaps the most important benefit of procuring  
8    environmentally responsible natural gas supply is the encouragement of business  
9    practices within the natural gas sector that reduce environmental impact substantially.  
10    By procuring environmentally responsible natural gas supply, the Company and its  
11    customers will drive change in the production of natural gas supply, encouraging more  
12    producers to adopt rigorous environmental protections and controls in their operations.

13   **Q.    Is there a higher cost associated with environmentally responsible natural gas**  
14   **supply?**

15   A.    Yes. Due to the investment that is needed to produce natural gas at a lower  
16   environmental impact, environmentally responsible natural gas supplies come at a  
17   slightly higher cost. Based on discussions with suppliers, the Company anticipates that  
18   environmentally responsible natural gas supply could be procured at a cost that is no  
19   more than 5 to 10 percent higher than the commodity cost of traditional sources of  
20   natural gas. Given the benefits that are inherent in the use of gas resources that are  
21   produced at a lower environmental impact, this cost difference is reasonable and will

1 support the growth of this market segment without placing significant rate impacts on  
2 customers.

3 **Q. How does the Company propose to procure environmentally responsible natural**  
4 **gas supply?**

5 A. Each year, the Company conducts a process to procure the gas supplies necessary to  
6 meet sendout requirements on a peak day and peak season basis over an annual period.  
7 These procurements are short-term arrangements for supply resources and do not  
8 represent long-term capacity arrangements that are otherwise part of the Company's  
9 resource portfolio. In this case, the Company is requesting that the Department  
10 authorize the Company to procure environmentally responsible natural gas supply  
11 through its normal, annual competitive solicitations and to enter into arrangements to  
12 purchase environmentally responsible natural gas supply for terms of no more than one  
13 year in duration. Any eligible supplies of environmentally responsible natural gas will  
14 require third party-certification. The competitive procurement of supply for terms of  
15 one year or less is consistent with the Company's current procurement practices for  
16 Basic Service.

17 **Q. What quantity of environmentally responsible natural gas is the Company**  
18 **anticipating would be utilized within an annual period?**

19 A. The Company anticipates that it would be possible to balance rate-impact  
20 considerations by limiting the portion of supply procured in the initial phases.  
21 Depending on how circumstances evolve in the marketplace, the Company anticipates  
22 gradually expanding the portion of supply procured from environmentally responsible

1 producers based on the reasonableness of the cost differential as compared to  
2 conventional natural gas supply. The Company anticipates that it could source up to  
3 three percent of its supply from environmentally responsible natural gas sources based  
4 on availability without significant rate impacts and would seek to increase that by up  
5 to one percent per year if achievable while maintaining modest rate impacts.

6 **Q. How does the Company propose to recover the costs of environmentally**  
7 **responsible natural gas supply if procured as part of the annual process?**

8 A. The cost of environmentally sourced natural gas supply would be recoverable through  
9 the Cost of Gas Adjustment Clause ("CGAC"), just as the costs of other gas supply  
10 resources are recovered. Currently, the Company conducts annual requests for  
11 proposals to procure gas supply for each winter heating season. The resulting purchase  
12 contracts are for less than one year in duration and do not require the Department's pre-  
13 approval. If approved by the Department in this case, the Company would be pre-  
14 authorized to purchase environmentally responsible gas supplies even if those supplies  
15 came in at a slightly higher cost not to exceed 10 percent of the regular gas supply  
16 resource available through the solicitation. As it currently stands, the Company would  
17 not be in a position to purchase those supplies because the supplies are not likely to be  
18 the least-cost resource available through the solicitation. If approved by the  
19 Department, the net increase in gas costs would be less than one percent and other  
20 components of gas-supply cost would remain unchanged relative to traditional  
21 procurement practices. Of course, the Company would produce all necessary



1 documentation to the Department at the time that the CGAC is approved to document  
2 that the procurement was in line with the Department's authorization.

3 **VI. DESCRIPTION OF THE PROPOSED PBR PLAN**

4 **Q. Mr. Horton, would you please review the mechanics of the Company's proposed**  
5 **PBR framework?**

6 A. Yes. As noted in the introduction to this testimony, the Company's proposed PBR Plan  
7 encompasses: (1) implementation of a PBRM with a five-year initial term and provision  
8 for extension; and (2) recovery of two, clean energy demonstration projects that are  
9 designed to test the feasibility of a natural gas demand response program and to assess  
10 the viability of geothermal distribution.

11 The PBRM is designed as a "revenue per customer cap" formula that would be used to  
12 adjust rates on an annual basis. The PBRM formula is derived through economic  
13 analysis of utility cost trends as indicated by measures of inflation, input prices and  
14 total factor productivity. The specific revenue per customer cap formula proposed by  
15 the Company is further discussed in the joint testimony of Company Witnesses Julia  
16 Frayer and Marie Fagan.

17 The revenue per customer cap formula is designed to work in tandem with the RDM  
18 that will continue for NSTAR Gas in this proceeding as described further below. The  
19 proposed PBR Plan tariff is presented in Exhibit ES-RDC/LMC-2, accompanying the  
20 joint testimony of Richard D. Chin and Lisa Cullen and is designated as M.D.P.U. No.  
21 411. The first rate change pursuant to the PBRM would not occur until November 1,

1           2021, and would occur annually each year thereafter.

2   **Q.    Mr. Horton, please list the elements of the Company's proposed PBRM.**

3   A.    The Company's proposed PBRM is comprised of five elements:

- 4           1. An inflation index;
- 5           2. A "productivity offset," or X factor;
- 6           3. A "Z" factor for exogenous costs;
- 7           4. A "Y" factor for the recovery of incremental costs associated with the
- 8                 Company's two clean energy demonstration projects; and
- 9           5. An earning-sharing mechanism ("ESM").

10       The Company is also proposing to make annual compliance filings to implement the

11       rate changes in accordance with the PBR Plan. In the annual PBR Plan compliance

12       filings, the Company would report on its progress towards the (1) performance

13       scorecard targets; and (2) the two proposed demonstration projects.

14   **Q.    Please describe how the PBRM would interact with the Company's RDM.**

15   A.    The Company's current RDM is based on a revenue per customer cap formula using a

16       Benchmark Base Revenue per Customer or "BRPC," reflecting the base revenue

17       authorized by the Department in the most recent rate case or other proceeding that

18       results in an adjustment to base rates. Revenue Decoupling Adjustment Mechanism,

19       M.D.P.U. No. 409C, page 3. The Company's proposed PBRM will determine the

20       Benchmark Base Revenue per Customer to be used in the RDM each year. Rather than

1 remaining fixed as a result of the Department's authorization of a base revenue  
2 requirement in a general rate proceeding, the BRPC will be adjusted annually pursuant  
3 to the terms of the PBR Plan in accordance with the PBRM indexing formula described  
4 in the joint testimony of Company Witnesses Julia Frayer and Marie Fagan. This  
5 adjustment will reflect the application of the inflation factor, X factor, Z factor (if  
6 applicable), the ESM (if applicable), and the Y factor, all of which are described in  
7 more detail below.

8 **Q. What is the revenue per customer cap formula supported by the economic analysis**  
9 **performed by Ms. Frayer and Ms. Fagan?**

10 A. The joint testimony of Company Witnesses Julia Frayer and Marie Fagan details the  
11 economic analysis supporting the revenue-per-customer cap formula under an "I-X"  
12 rate adjustment mechanism. The "I-X" formula would serve as the basis for an annual  
13 adjustment to rates with "I" representing a measure of economy-wide output inflation,  
14 i.e., the Gross Domestic Product-Price Index ("GDP-PI"), as measured by the U.S.  
15 Commerce Department, and "X" representing a measure of expected productivity  
16 growth. The X factor is based on the differences in productivity and input price growth  
17 between the gas distribution industry and the overall economy. Combined with the "I"  
18 factor, "I-X" represents the expected unit cost performance of an average performing  
19 company in the industry.

1 **Q. Mr. Horton, please describe the inflation index that will be used in the PBRM**  
2 **formula.**

3 A. The Department has found that GDP-PI is the most accurate and relevant measure of  
4 output price changes for the bundle of goods and services whose total factor  
5 productivity (“TFP”) growth is measured by the U.S. Department of Commerce Bureau  
6 of Labor Statistics (“BLS”) and is: (1) readily available; (2) more stable than other  
7 inflation measures; and (3) maintained on a timely basis. D.P.U. 17-05, at 393.  
8 Therefore, the Company is proposing that inflation be determined each year of the  
9 PBRM using the GDP-PI, as published by the BLS. Consistent with the Department’s  
10 prior rulings on the GDP-PI, the inflation index would be calculated as the percentage  
11 change between the current year’s GDP-PI and the prior year’s GDP-PI. For each year,  
12 the GDP-PI would be calculated as the average of the most recent four quarterly  
13 measures of GDP-PI as of the second quarter of the year to align with the Company’s  
14 annual PBR filing schedule.

15 **Q. Please describe the “X” factor.**

16 A. The Company’s “X” factor, or productivity offset, was determined by Ms. Frayer and  
17 Ms. Fagan’s TFP study of the trends of gas industry participants in the Northeast  
18 Region of the U.S., as defined by BLS. The X factor is based on the differences in  
19 productivity and input price growth between the natural gas distribution industry in the  
20 Northeast and the overall economy. As detailed in Ms. Frayer and Ms. Fagan’s joint  
21 testimony, the Company’s X factor is negative 1.3 percent.

1 **Q. Is the Company proposing any adjustment to the traditional PBR Plan structure**  
2 **to account for the existence of the GSEP mechanism?**

3 A. No. In preparing its proposals for this proceeding, the Company worked closely with  
4 LEI to assess whether there was a conceptual, methodological or economic principle  
5 indicating that there would be overlap that would occur if the PBR Plan were  
6 implemented in conjunction with the GSEP mechanism applying under Massachusetts  
7 law. As explained in the joint testimony of Company Witnesses Julia Frayer and Marie  
8 Fagan, there is no overlap between these two mechanisms. Therefore, in the opinion  
9 of Ms. Frayer and Ms. Fagan, no adjustment is needed to the X-factor to account for  
10 the legislated GSEP program in Massachusetts. The basis for her opinion is explained  
11 in her testimony and the Company agrees with her assessment.

12 **Q. What is your understanding as to the theoretical basis for a consumer**  
13 **dividend/stretch factor deducted from the X factor?**

14 A. As described in the joint testimony of Ms. Frayer and Ms. Fagan, under the revenue-  
15 per-customer cap construct, the Department would be setting a trajectory for future  
16 rates over the term of the PBR Plan. The theoretical basis of the consumer dividend is  
17 the expectation that, over the term of the PBR Plan, the Company should be able to  
18 achieve efficiency improvements not embedded in the “cast-off” rates that will take  
19 effect as a result of this rate proceeding, as a product of the PBR Plan.

1 **Q. What is the method that may be used to assess the efficiency improvement possible**  
2 **as a result of implementing performance-based ratemaking?**

3 A. As discussed in the joint testimony of Company Witnesses Julia Frayer and Marie  
4 Fagan, cost benchmarking provides empirical evidence on the relative efficiency of a  
5 given utility to its peers. Examination of the utility's relative efficiency to its peers  
6 provides an indication of the margin of opportunity that the utility has to identify and  
7 achieve cost savings that are over and above existing cost levels. The underlying  
8 assumption is that the more efficient a utility is relative to its peers, the less opportunity  
9 the utility has to achieve cost savings in its operations. A consumer dividend or "stretch  
10 factor" is designed to motivate a relatively inefficient utility to catch up to the cost  
11 performance of its peers. For the relatively efficient company, the inclusion of a stretch  
12 factor fails to create the desired incentive because the increment of improved cost  
13 performance represented by the factor essentially constitutes a futile exercise, i.e., no  
14 incentive is created where the achievement of the requisite cost savings is a virtual  
15 impossibility.

16 **Q. Is the Company proposing a consumer dividend or other stretch factor as part of**  
17 **the PBRM?**

18 A. No, as discussed in the joint testimony of Ms. Frayer and Ms. Fagan, the results of the  
19 TFP benchmarking study show that NSTAR Gas is relatively efficient as compared to  
20 its peers. Therefore, a stretch factor is not appropriate for inclusion as part of the  
21 PBRM.

1   **Q.     Please describe the “Z” factor.**

2   A.     The “Z” factor accounts for operating cost changes that arise from factors beyond the  
3           control of the Company. The Z factor is necessary because the Company is committing  
4           to refrain from filing a petition for a change in base distribution rates during the five-  
5           year term of the PBR Plan. Therefore, the revenue-per-customer cap needs to be  
6           adjusted to address costs changes arising due to events specific to the gas distribution  
7           industry that occur beyond the control of the Company. Exogenous events cause  
8           positive or negative cost changes that are not reflected in the GDP-PI. Examples of  
9           exogenous events with cost implications include, but are not limited to, incremental  
10          costs resulting from: (a) changes in tax laws that uniquely affect the natural gas  
11          distribution industry; (b) accounting changes unique to the natural gas distribution  
12          industry; and (c) regulatory, judicial, or legislative changes that uniquely affect the  
13          natural gas distribution industry.<sup>12</sup>

14   **Q.     What is the Company’s proposal with respect to exogenous costs?**

15   A.     In this case, the Company is proposing a two-part exogenous cost mechanism, which  
16           is necessary to allow the Company to commit to a five-year stay-out in the very  
17           uncertain circumstances that exist in today’s operating environment. The “two-part”  
18           exogenous event framework would be comprised of: (1) the traditional exogenous  
19           event cost adjustment subject to the Department’s established criteria; and (2) a

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<sup>12</sup> D.P.U. 17-05, at 396.

1 targeted exogenous event cost adjustment arising due to pipeline safety requirements  
2 imposed after November 8, 2019, with demonstrated cost impacts on or after the start  
3 date of the PBRM, or November 1, 2020.<sup>13</sup>

4 **Q. Would you please explain each of these two parts in greater detail?**

5 A. Yes. First, the Department has consistently established an exogenous cost provision  
6 within the performance-based ratemaking plans that it has approved in the past, which  
7 allows for cost adjustments in three instances, which are to address: (a) changes in tax  
8 laws that uniquely affect the natural gas distribution industry; (b) accounting changes  
9 unique to the natural gas distribution industry; and (c) regulatory, judicial, or legislative  
10 changes that uniquely affect the natural gas distribution industry. The Company is  
11 proposing to incorporate this traditional exogenous cost adjustment factor, subject to a  
12 significance threshold of \$700,000.<sup>14</sup> The traditional exogenous factor would be  
13 triggered only if the cost in question fits into the foregoing criteria and exceeds the  
14 significance threshold of \$700,000, in relation to O&M cost changes experienced in a  
15 single year. If meeting the threshold of \$700,000, the cost change would constitute a  
16 significant cost change outside the control of the Company, warranting exogenous cost

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<sup>13</sup> Although the effective date of new rates will be October 1, 2020, the Company is proposing to have new rates, including the GSEAF, take effect for billing purposes on November 1, 2020 to achieve alignment with other rate changes that customers will experience on November 1, 2020.

<sup>14</sup> The Department has previously applied a significance threshold to determine if cost changes are eligible for treatment as an exogenous event by multiplying total operating revenues by 0.001253. NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy, D.P.U. 17-05, at 397 (2017). For NSTAR Gas, the calculation produces a significance threshold of \$626,369 (\$499,895,237 \* 0.001253).



1 recovery. Each year after commencement of the PBR Plan, the significance threshold  
2 would be subject to annual adjustments based on changes in GDP-PI.

3 A second set of criteria for exogenous cost changes would apply to address significant  
4 cost changes arising as a result of new or modified pipeline safety requirements  
5 imposed after the start date of the PBRM. Under this second set of criteria, an  
6 exogenous event would occur where a significant cost change is caused by mandated  
7 changes in law, regulations, requirements, standards or practices relating to gas-safety  
8 directives arising from investigations conducted by the NTSB, PHMSA, the  
9 Department or any investigation conducted on behalf of the Department by an outside  
10 consultant or expert. This exogenous mechanism would also have a significance  
11 threshold of \$700,000 for an annual cost impact; however, the mechanism would allow  
12 for recovery of both capital and expense type cost changes, with the \$700,000 threshold  
13 representing the annual impact in either or both categories, individually (i.e., the  
14 \$700,000 threshold would apply separately to O&M and capital). Each year after  
15 commencement of the PBR Plan, the significance threshold would be subject to annual  
16 adjustments based on changes in GDP-PI.

17 **Q. Why is it necessary to establish a two-part exogenous cost mechanism?**

18 A. The Company is petitioning the Department for review and implementation of the PBR  
19 Plan at a time of great uncertainty for the gas industry in Massachusetts. As the  
20 Company's expert witness Julia Frayer has indicated, the PBR framework is a  
21 framework that is effective in a "status quo" environment, i.e., where economic

1 circumstances in the past are a reasonably sound indicator of the future. Where  
2 economic circumstances in the past are not indicative of the future, risk is created that  
3 has the potential to draw the PBR Plan out of alignment. In this case, it is clear that the  
4 business environment for natural gas companies in New England (and beyond) is  
5 changing in numerous ways due to environmental policy, infrastructure constraints and  
6 ever-increasing public-safety considerations. However, these dynamics would not  
7 necessarily drive the need to establish a two-part exogenous cost mechanism in  
8 isolation — meaning that the Company accepts the responsibility of addressing these  
9 changing dynamics during the PBR Plan term within the confines of the annual PBR  
10 adjustment.

11 Instead, the deep concern that the Company has in commencing a PBR Plan at this  
12 time, with a five-year stay-out commitment, is that in Massachusetts there are  
13 particular, unique circumstances occurring that have the potential to be substantially  
14 disruptive to the PBR Plan. For example, it is possible that discrete directives for gas  
15 companies will come out of the NTSB or Dynamic Risk investigations into the  
16 Merrimack Valley event or that new legislation, regulations or standards and practices  
17 will follow that are not known or anticipated at this date. Directives for gas companies  
18 arising from these investigations have the potential to require significant changes to the  
19 Company's operating processes and associated staffing levels, or perhaps will require  
20 the installation of infrastructure that is not currently anticipated by the Company.  
21 Therefore, the Company is requesting that the Department consider these unique

1 circumstances and establish the two-part exogenous cost provision allowing the  
2 Company to petition the Department for recovery of costs arising from pipeline safety  
3 directives following from the Merrimack Valley event.

4 Accordingly, the second part of the exogenous cost factor is designed to address the  
5 uncertainty associated with the imposition of specific directives affecting operating  
6 processes and associated staffing levels or infrastructure installations. To qualify for a  
7 pipeline safety-related exogenous cost, the Company will need to trace the cost change  
8 to a specific directive or set of directives. Over the next five years, it is possible that  
9 increasing requirements for public safety, emissions reductions and other industry  
10 dynamics will not arise so discretely as to allow unexpected, unusual cost changes to  
11 be addressed by the traditional criteria for an exogenous cost change. Therefore, the  
12 second set of criteria is designed to allow for consideration of cost changes that are  
13 more organic, yet still directly related to changes in operating practices required by  
14 pipeline safety oversight entities.

15 **Q. Please describe the “Y” factor.**

16 A. As described in the joint testimony of Company Witnesses Conner and Goldman, the  
17 Company is proposing two demonstration projects that will move the Commonwealth  
18 forward on clean energy innovation, reduce greenhouse gas emissions, and proactively  
19 test the abilities and potential benefits of new technologies and innovative business  
20 models. These two demonstration projects are the following, as described in the  
21 testimony of Ms. Conner and Mr. Goldman:

- 1           • **Gas Demand Response:** The Company is proposing a gas demand response  
2           demonstration project that would have a duration of three years. The  
3           demonstration project is designed to test whether a gas demand-response  
4           program is effective in shaving peak demand; alleviating temporary physical  
5           pipeline constraints; reducing the amount of pipeline capacity needed to meet  
6           sendout requirements; and reducing greenhouse gas emissions through  
7           reductions in overall gas consumption.
- 8           • **Geothermal Distribution:** The Company is proposing a geothermal  
9           distribution demonstration project to test the viability of a non-gas thermal  
10          distribution model; assess the enabling technology; and evaluate the costs and  
11          benefits.

12          The “Y” factor will allow for the recovery of costs associated with the implementation  
13          of these two demonstration projects. The Company is proposing to amortize the costs  
14          of the demonstration projects over the five-year term of the PBR plan, as actual costs  
15          are incurred for the programs. The Company will update this factor to be included in  
16          the PBRM formula as part of its annual compliance filing to be submitted on September  
17          15th of each year. Within that filing, the Company will submit documentation in  
18          support of the costs incurred for the demonstrations and report on the progress towards  
19          the identified objectives described further below. The Company will file reports  
20          annually on the progress of the demonstration projects and any stakeholder feedback  
21          received upon authorization from the Department to proceed with the execution of the  
22          demonstration projects in this proceeding.

1    **Q.     Please describe the Company's proposed ESM.**

2    A.     The Company is proposing to adopt the ESM that the Department approved for NSTAR  
3           Electric, with certain modifications. In this case, the Company is proposing an ESM  
4           with a 100 basis-point deadband above and below the allowed ROE to preserve the  
5           incentives for the PBR plan and to assure that the PBR Plan does not fall out of  
6           alignment with actual cost circumstances. The Company proposes to share  
7           excess/deficient earnings with customers outside of this deadband on a 75  
8           (customers)/25 (shareholders) basis, whether the ROE is 100 basis points above or  
9           below the authorized ROE. Accordingly, the Company's proposed ESM is designed  
10          to provide customers with a near-term benefit of productivity gains, if gains are  
11          produced above a deadband level, but also to allow the Company an adjustment if the  
12          PBRM is falling out of alignment with the Company's actual cost obligations.

13   **Q.     Why is the Company requesting that the Department establish a symmetrical**  
14   **ESM structure in this PBR Plan, with a narrower deadband than would typically**  
15   **apply?**

16   A.     As we stated above, the Company is coming to the Department for review and  
17          implementation of the PBR Plan at a time of great uncertainty for the gas industry in  
18          Massachusetts. The concern that the Company has in commencing a PBR Plan at this  
19          time, with a five-year stay-out commitment is that in Massachusetts there are particular,  
20          unique circumstances occurring that have the potential to be substantially disruptive to  
21          the PBR Plan. A symmetrical ESM will assure that unexpected or unusual cost changes  
22          that are not addressed by the PBRM will not have a tendency to cause such substantial

1 earnings attrition that the five-year term becomes overly detrimental to the Company.  
2 The Company is committing to a five-year term in a time of substantial uncertainty and  
3 the Company has concerns that circumstances may overtake the PBRM given its  
4 reliance on an X factor that is specified based on historical data not indicative of current  
5 circumstances.

6 **Q. How does the Company propose to compute the ROE to be used in the earnings-**  
7 **sharing mechanism?**

8 A. Earnings Sharing provides an important protection for customers in the event that  
9 expenses increase at a rate lower than the revenue increases generated by the PBRM.  
10 For earning-sharing purposes, the ROE would be calculated as Total Net Utility  
11 Income, less other amounts as described in the testimony, divided by Average Common  
12 Equity.<sup>15</sup> ROE would be computed to exclude Department-approved incentive  
13 payments, such as energy efficiency incentives, and would also exclude service-quality  
14 penalties (if any), as well as any amounts recognized in the current period resulting  
15 from regulatory or court settlements or decisions related to prior periods (if any). ROE  
16 would be calculated using the earnings available for common equity and the capital  
17 structure approved by the Department in this proceeding. Any adjustment would be  
18 subject to investigation and a full adjudicatory hearing before the Department.

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<sup>15</sup> Common Equity = (Total Company capitalization (including long term debt, preferred stock, and common equity, all per the DPU Annual Return) multiplied by the percentage Common Equity approved in D.P.U. 19-120.

1 In the event that the Company's actual Distribution ROE exceeds or falls below the  
2 earnings sharing threshold, the difference between actual earnings and earnings  
3 calculated at the authorized ROE shall be shared 25 percent to the Company and 75  
4 percent to Customers. The Company's ROE used as the basis for evaluating earnings  
5 sharing will be the ROE filed annually with the Department based on calendar year  
6 activity. Because new base rates will go into effect as a result of this proceeding in  
7 October 2020, calendar year 2021 will be the first year for which the Company will  
8 evaluate whether an earnings sharing adjustment is appropriate. For example, if  
9 applicable, the first ESM adjustment will be included in the PBRM adjustment effective  
10 on November 1, 2022 for calendar year 2021.

11 **Q. Mr. Horton, please describe the basis for the five-year plan term.**

12 A. One of the benefits of implementing a PBR plan is the reduced regulatory burden and  
13 the associated costs to customers due to the increased time between rate cases.  
14 Massachusetts Electric Company and Nantucket Electric Company, each d/b/a  
15 National Grid, D.P.U. 18-150, at 53 (2019) (accepting that a five-year stay out  
16 provision will generate diminished administrative burden and will result in  
17 efficiencies). In fact, without PBR, the Company expects that every other year would  
18 become a test year and an associated base-rate case would need to be filed to realign  
19 costs with customer rates. The Company's proposed five-year stay out means that the  
20 PBR Plan is avoiding at least two rate cases.

1 A defined PBR plan term, accompanied by a “stay-out” provision during which time  
2 the Company cannot file a rate case, creates the appropriate incentives for the PBR Plan  
3 to be successful and provides the Department and other stakeholders the assurance of  
4 a reduced regulatory burden. For these reasons, the Company is volunteering to  
5 commit to a five-year stay-out for the PBR Plan. The Department approved the same  
6 term for NSTAR Electric in D.P.U. 17-05.

7 With a five-year term, the PBR plan would commence on November 1, 2020 and expire  
8 on October 31, 2025. Within the five-year term, there would be four annual PBRM  
9 adjustments taking effect beginning November 1, 2021 through November 1, 2024.  
10 The Company would be eligible to file rate schedules to put new distribution rates into  
11 effect no earlier than November 1, 2025, in keeping with the minimum five-year  
12 commitment to stay out.

13 **Q. Is it possible that the Company would stay out longer than five years?**

14 A. Yes. In Massachusetts, there is no requirement for gas companies to submit rate  
15 schedules in five-year increments, as there is for electric companies. Instead, gas  
16 companies are required to submit rate schedules on a schedule of no more than 10 years.  
17 Within the Company’s proposed PBR Plan, there are five elements that are critical to  
18 enable the Company to stay out longer than five years: (1) the two-part exogenous cost  
19 mechanism, discussed in this testimony; (2) the proposed symmetrical ESM with the  
20 narrower, 100 basis point deadband, discussed in this testimony; (3) approval of the  
21 Company’s proposed cost of capital (ROE and capital structure), discussed in the



1 testimony of Company Witness Hevert; (4) approval of the Company's proposal to  
2 incorporate capital additions completed in 2019 and 2020 into rate base through a  
3 sequential process, discussed in the testimony of Company Witnesses Horton and  
4 Botelho; and (5) a provision that would allow the Company to incorporate capital  
5 additions completed through December 31, 2024 into rate base in Year 5 for rates  
6 effective November 1, 2025, which is discussed in this testimony, below.

7 **Q. Please explain the Company's perspective on the necessity of allowing the**  
8 **opportunity to roll-in capital to rate base to support the ongoing application of the**  
9 **PBR.**

10 A. The single-most debilitating cost burden that utilities face is carrying the cost of capital  
11 investment not included in rate base. Given that the Company expects to sustain non-  
12 GSEP capital expenditures in the range of \$85-\$100 million annually over the five-year  
13 term, the Company would expect to be carrying more than \$400 million of non-GSEP  
14 capital investment by the fifth year of the PBR (not incorporated to rate base), assuming  
15 the Department incorporates capital additions completed in 2019 and 2020 at the outset  
16 of the PBR Plan. If the Department approves the Company's PBR Plan, as filed, the  
17 Company projects that the annual increases in revenue growth would be in the range of  
18 \$8 million (plus or minus); however, the annual revenue requirement associated with  
19 \$100+ million of capital investment is in the range of \$13-15 million on a conservative  
20 basis. Increases in operating costs will also occur, although the Company will be  
21 working diligently to maintain the most efficient cost platform possible while meeting  
22 safety and reliability requirements.

1 The theory of the PBR Plan is that it should provide adequate revenues for the Company  
2 to maintain financial integrity as it works to address public safety and emissions  
3 reductions imperatives, but at the same time should impose (through the stay-out) the  
4 strongest possible incentive for the Company to be highly cost-efficient in those  
5 endeavors. However, given the growing capital requirements associated with non-  
6 GSEP investment on the gas system, the annual PBR adjustments will not be sufficient  
7 to keep the Company's cost structure aligned with anticipated cost pressures over the  
8 five-year initial term, even if the I-X formula underlying the PBRM is perfectly  
9 calibrated. Accordingly, it is highly unlikely – despite any and all efficiency gains –  
10 that the PBR Plan will have the impact of eliminating the need for a base-rate  
11 proceeding in Year 5, due simply to the need to incorporate capital costs into rate base  
12 for rate recovery.

13 If the Department were to allow the Company to request to incorporate capital additions  
14 completed in the years 2021 through 2024 in Year 5, rather than submitting a full rate  
15 case, it might be possible for the Company to make a commitment for a stay-out  
16 extended up to five additional years. The Company will have to evaluate circumstances  
17 and the operation of the PBR Plan in Year 4 to determine whether such a commitment  
18 could be made. However, the opportunity to opt for a roll-in of capital additions made  
19 since the last rate case would be an important component for a prolonged stay-out  
20 favoring efficiencies in relation to O&M expenses.

1 **Q. Why is it necessary for the Department to authorize a rate adjustment for base-**  
2 **rate additions in this case?**

3 A. As noted above, with a five-year stay-out, the Company would be authorized to submit  
4 a base-rate filing prior to November 1, 2025 to request a change in base rates as of  
5 November 1, 2025 under G.L. c. 164, § 94. The Company is not surrendering its  
6 statutory right to file a base-rate petition to put new base rates into effect on November  
7 1, 2025 in this proceeding because there is substantial uncertainty surrounding the  
8 operating environment for gas companies at this juncture. However, the Company  
9 intends to work hard to be in a position to extend the duration of the PBR Plan approved  
10 in this proceeding for an additional five-year term. However, the opportunity to  
11 incorporate incremental capital additions made on and after January 1, 2021 to rate base  
12 may be necessary to enable extension of the term. If so, the Company will need to  
13 submit project documentation to the Department in advance of the date of the rate  
14 change to incorporate the investment associated with those projects into rate base. The  
15 Company's proposal in this case is intended to establish the path for that type of  
16 adjustment. Upon the expiration of the initial five-year term, it may also make sense  
17 to update the TFP study to demonstrates whether continuation of the X factor approved  
18 in this case is reasonable and appropriate.

19 **Q. Is the Company's commitment to a five-year stay-out contingent upon the**  
20 **Department's approval of the Company's proposed PBRM adjustment formula?**

21 A. Yes. The Company has devoted considerable time, effort and resources to the  
22 development of a PBR Plan and PBRM adjustment that will provide sufficient support

1 to the Company's operations over a five-year term in highly challenging, unique  
2 circumstances. If the Department materially modifies the PBRM and/or changes the  
3 PBRM without a valid methodological basis, the Company may not be in a position to  
4 commit to a rate-case stay-out over a five-year PBR plan term. Under these  
5 circumstances, the Company would have to re-evaluate whether it could commit to  
6 implement the PBR plan in conjunction with a five-year stay-out. If the PBR Plan (and  
7 PBRM) are not devised appropriately to allow a stay-out commitment, the Company  
8 will need to maintain its statutory discretion to file for base-rate relief. The Company  
9 would likely need to pursue such relief on a nearly biannual basis given the magnitude  
10 of cost changes anticipated over the next five years.

11 **Q. Mr. Horton, what is the Company's proposed schedule for annual PBR plan**  
12 **filings during each year of the five-year PBR plan term?**

13 A. The Company is proposing to make an annual filing on September 15th of each year,  
14 detailing the PBRM adjustments to be effective as of November 1st each year. This  
15 filing will detail the figures associated with each PBRM element listed above; and  
16 calculate the PBRM percentage and dollar adjustment to the BRPC and base  
17 distribution rates. The first annual compliance filing would occur on September 15,  
18 2021, for effect November 1, 2021, and would include only the PBRM adjustment and  
19 the roll-in of plant investment through 2020. The reporting of performance on  
20 scorecard metrics (discussed below), and the evaluation of earnings sharing (discussed  
21 above) would begin in the September 2022 PBR Plan compliance filing.

1 **Q. If the Department were to structure the PBR Plan to allow for a roll-in of capital**  
2 **additions in Year 5, how would that schedule work?**

3 A. If the Department were to decide that it makes sense to provide for an extension of the  
4 PBR beyond five years, the sequence should be the following:

- 5 • First annual PBR Adjustment, November 1, 2021.
- 6 • Base rates eligible for adjustment as of November 1, 2025 (annual PBR  
7 adjustments on November 1 of 2021, 2022, 2023, 2024).
- 8 • With the annual filing of 4<sup>th</sup> Annual PBR Adjustment Filing (made September  
9 15, 2024 for effect November 1, 2024), NSTAR Gas would be required to  
10 indicate whether it has opted to stay out with a roll-in of capital additions rather  
11 than filing a rate case or other proposal for effect November 1, 2025.
- 12 • If NSTAR Gas opts for the roll in of capital additions, it would be required to  
13 present capital projects documentation through December 31, 2024 to the  
14 Department on or before April 1, 2025 for review and roll-in as of November  
15 1, 2025.
- 16 • Then the PBR Plan would proceed as is from there.

17 If the Department preferred, the Company could make a preliminary filing of project  
18 documentation through December 31, 2023 with the annual filing submitted September  
19 15, 2024, which would then be updated to include documentation for the final eligible  
20 year (2024) in April 2025.

21 **VII. SCORECARD METRICS**

22 **Q. What is the purpose and objective of the Company's proposed scorecard metrics?**

23 A. Eversource Energy employs a team of more than 8,000 dedicated staff with a strong  
24 commitment to providing safe, reliable and sustainable electric, gas and water service.  
25 Eversource Energy is proud of its ongoing, rigorous efforts to ensure the safe and

1 reliable delivery of natural gas in the Commonwealth and it will continue those efforts  
2 over the term of the PBR Plan and beyond. The implementation of the PBR Plan is  
3 designed to allow the Company and its employees to focus intently on serving the needs  
4 of the Gas Customer, rather than on the cyclical filing of base-rate cases to support  
5 operations. In this paradigm, the Company recognizes that there should be tangible  
6 improvements in the aspects of utility operations that are important to customers and  
7 most directly influence the customer's confidence and satisfaction with gas service.  
8 Therefore, the Company's performance management group has worked for several  
9 months with Gas Operations and the Customer Group to create a set of 12 metrics that  
10 will demonstrate tangible performance improvements for customers over the five-year  
11 term of the PBR Plan, if implemented by the Department in this proceeding.

12 **Q. Is the Company already subject to service-quality metrics?**

13 A. Yes, Company is subject to the Department's Service Quality Guidelines ("SQ  
14 Guidelines"), which include penalty metrics for performance falling below the  
15 requirement benchmarks. Pursuant to G.L. c. 164, §§ 1E and 1I, all LDCs must file  
16 annual service-quality reports with the Department on or before March 1st. Each report  
17 compares annual performance by the respective LDC with the Department's service-  
18 quality metrics established in Order Adopting Revised Service Quality Standards,  
19 D.P.U. 12-120-D (2015) and D.P.U. 12-120-D, Attachment A (2015). The SQ  
20 Guidelines establish three penalty measures for natural gas LDCs: (1) Class I and Class

1 II Odor Call Response; (2) Service Appointments Kept as Scheduled; and (3) Customer  
2 Complaints and Customer Credit Cases.

3 Under the first measure, the Company must respond to 97 percent of all Class I and  
4 Class II Odor Calls in 60 minutes and the Company is subject to a fixed revenue penalty  
5 formula if the metric is not met. SQ Guidelines at Sections IV.B.1, V.B.2. The second  
6 metric measures the percentage of scheduled Service Appointments met by Company  
7 personnel on the same day requested. SQ Guidelines at Section II.A. The Company is  
8 subject to a revenue penalty for this metric if performance is below the Company's  
9 average performance. SQ Guidelines at Section V.B.3. The third metric measures  
10 residential customer contact with the Department, which is categorized by the  
11 Department as a residential Customer Complaint relating to payment and arrearage  
12 management plans, inability to pay, shut-off notices, and terminations. SQ Guidelines  
13 at Section II.B.2. The Company is subject to a revenue penalty for this metric if  
14 performance is below the Company's average performance. SQ Guidelines at Section  
15 V.B.3.

16 **Q. What is the purpose of scorecard metrics and why would the metrics be helpful to**  
17 **the Department and to the Company's customers?**

18 A. The Company's proposed scorecard metrics are aligned with several of the  
19 Department's policy objectives and will allow the Department and stakeholders to  
20 monitor the Company's progress during the term of the PBR plan.

- 1 **Q. Please describe the scorecard metrics that the Company is proposing in this**  
2 **proceeding.**
- 3 **A.** The Company is proposing a series of 12 scorecard metrics, organized by three high-  
4 level categories summarized in the tables below.

<b>SAFETY AND RELIABILITY</b>	
<b>Scorecard Metric</b>	<b>High-Level Summary Description</b>
<b>Emergency Response Rate Within 45 Minutes</b>	The metric will measure the elapsed time from when a report of a gas odor call is received and when a Company representative arrives at the scene. The Company is committing to a target of a 95-percent response within 45 minutes, which <b>exceeds</b> the Department's current requirement.
<b>Total Damages Per 1,000 Tickets</b>	This metric will measure the ratio of the number of times the Company's gas distribution facilities are damaged per 1,000 tickets. The Company is committing to a 10-percent improvement over the baseline by Year Five.
<b>DART Rate</b>	This metric will measure the number of cases resulting in Days Away from Work, Restricted Work Activity, and/or Job Transfer expressed as the number of events per 200,000 hours worked. The Company is committing to a 10-percent improvement over the baseline by Year Five.
<b>Total Grade 2 Leaks Older than 9 Months</b>	This metric will measure the number of Open Grade 2 Leaks older than nine months recorded at the end of the calendar year. The Company is committing to completing 75 percent of Grade 2 leaks in 9 months or less (which is three months faster than statutory requirement).
<b>PSMS Implementation</b>	This metric evaluates the annual implementation of the Pipeline Safety Management System (PSMS), as measured by a third-party assessment.



<b>CUSTOMER SATISFACTION &amp; ENGAGEMENT</b>	
<b>Scorecard Metric</b>	<b>High-Level Summary Description</b>
<b>J.D. Power Survey (Safety &amp; Reliability Factor)</b>	This metric will measure in the Safety & Reliability factor as measured by J.D. Power. The Company is committing to a 23-point improvement in its Safety & Reliability score by Year Five.
<b>Web Satisfaction Survey</b>	This metric will measure improvement in customer satisfaction with on-line tools. The Company is committing to increase this rating to 8.15 out of 10.
<b>Digital Engagement</b>	This metric will measure digital engagement with customers via self-service and alert notifications. The Company is committing to increase the ratio of digital transactions to total transactions to 85 percent.
<b>Gas Emergency Calls - Average Speed of Answer</b>	This metric will measure improvement in the average speed of answer of Gas Emergency Calls. The Company is committing to maintain 10 seconds as the average speed of answer for gas emergency calls.
<b>New Customer Connect Gas</b>	This metric will measure customer satisfaction with respect to the new gas customer interconnection process based on customer survey data. The Company is committing to maintain a satisfaction rating of 9.23 out of 10.

<b>EMISSION REDUCTIONS</b>	
<b>Scorecard Metric</b>	<b>High-Level Summary Description</b>
<b>Methane Emissions</b>	This metric will measure progress in emission reductions, in metric tons, associated with replacement of aged distribution infrastructure through the GSEP program. The Company is committing to reduce methane emissions by 39 percent from the baseline by Year Five of the PBR plan.
<b>Grade 3 Environmentally Significant Leaks</b>	This metric will measure the repair of environmentally significant Grade 3 leaks within 12 months of designation. The Company is committing to repair all non-GSEP environmentally significant Grade 3 leaks within 12 months of designation, which <b>exceeds</b> the Department's regulations.

- 1 The Company proposes to report on these scorecard metrics results as part of the annual
- 2 PBR Plan compliance filings made each year from 2021 to 2025, and at the end of the
- 3 PBR Plan in 2025.

1   **Q.    Is the Company proposing any incentives or penalties with respect to the**  
2   **scorecard metrics it is proposing in this case?**

3    A.    No, the Company is not proposing any incentives or penalties with respect to the  
4           scorecard metrics it is proposing in this case. The Company is already subject to the  
5           Department's rigorous SQ Guidelines, which include penalty metrics. The SQ  
6           Guidelines will continue to apply by operation of law during the period of the PBRM.

7   **Q.    Which scorecard metrics will you be discussing as part of your testimony?**

8    A.    We will be discussing the proposed safety and reliability and emissions reduction  
9           scorecard metrics as part of our testimony. Company Witness Conner will be  
10          discussing the customer engagement and satisfaction metrics as part of her joint  
11          testimony with Mr. Goldman.

12       **A.     Safety and Reliability Metrics**

13   **Q.    What are the proposed scorecard metrics focused on safety and reliability?**

14    A.    The Company is proposing five scorecard metrics in the area of safety and reliability,  
15           which are: (1) a metric that measures the Company's emergency response rate; (2) a  
16           metric that measures damage to the Company's distribution system; (3) a DART rate  
17           metric; (4) a measure of Grade 2 leaks older than 9 months; and (5) a metric to measure  
18           the implementation of the PSMS.

1   **Q.    Please describe the scorecard metric that is designed to measure the Company's**  
2   **Emergency Response Rate.**

3    A.    The Department requires gas companies to respond to 97 percent of Class I and Class  
4           II Odor Calls within 60 minutes. Service Quality Investigation, D.P.U. 16-80 through  
5           D.P.U. 16-90, at Attachment A page 14 (January 18, 2017). The Company is proposing  
6           a scorecard metric that will set a performance target that exceeds the Department's  
7           current requirements associated with the SQ Guidelines. More specifically, the  
8           Company is proposing to respond to 95 percent of Class I and Class II Odor Calls  
9           within 45 minutes.

10   **Q.    How does the Company propose to measure the Emergency Response Rate**  
11   **metric?**

12   A.    The gas emergency response time metric measures the elapsed time between the time  
13           the utility was first notified of the emergency (i.e., from the time the emergency call  
14           was answered) and the time that a Company employee who is qualified to decide upon  
15           the appropriate action to take is on site. Consistent with current practice under the  
16           Department's SQ guidelines, only the first call reporting an individual odor-related  
17           condition shall be counted for the purpose of calculating performance under this metric.

18   **Q.    How did the Company establish the baseline measure for the Emergency**  
19   **Response Rate metric and what is the Company proposing for a performance**  
20   **target?**

21   A.    The Company's baseline, average performance in the three-year period, 2016 to 2018  
22           was 96.11 percent of calls responded to within 45 minutes. For the PBR Plan, the  
23           Company proposes to set a performance target of 95 percent within 45 minutes as its

1 minimum target over the five-year PBR term, which is a performance level that exceeds  
2 the Department's current SQ requirement.

3 **Q. Please describe the scorecard metric that is designed to measure total damages**  
4 **per 1,000 tickets.**

5 A. Excavation damage is a leading cause of natural gas distribution pipeline incidents and  
6 the number of excavation damage occurrences per 1,000 "dig location" tickets is an  
7 established benchmark within the damage prevention industry and an important  
8 indicator of the effectiveness of the Company's damage-prevention program.  
9 Accordingly, the Company is proposing a metric to measure the number of excavation  
10 damage occurrences per 1,000 dig safe tickets.

11 **Q. How does the Company propose to measure total damages per 1,000 tickets?**

12 A. The Company tracks the number of dig safe tickets generated to mark-out the  
13 Company's distribution infrastructure and also tracks all reported damage to its system  
14 caused by Company personnel, Company contractors, or other third-parties (e.g., a  
15 municipal water and sewer department). Using this data, this metric is calculated as  
16 the ratio of reported damages to the Company's gas system per 1,000 dig safe tickets.  
17 This metric is unique because not only is the Company holding itself accountable for  
18 the actions of its employees but also for the actions of third-parties that work in and  
19 around the Company's natural gas distribution infrastructure.

1 **Q. How did the Company establish the baseline measure for the total damages per**  
2 **1,000 tickets metric; what is the Company proposing for a performance target;**  
3 **and what steps will it take to achieve this target?**

4 A. The Company's baseline for this metric is 2.41 damages per 1,000 tickets based on a  
5 three-year average (2016 to 2018). The Company proposes a target of 2.17 damages  
6 per 1,000 tickets (a ten percent improvement) by the end of the five-year PBR Plan  
7 term. The Company plans to achieve this target by taking a holistic approach to educate  
8 and inform excavators, homeowners, and municipalities about the dig safe law and  
9 working safely around utility distribution infrastructure.

10 **Q. Please describe the scorecard metric that is designed to measure DART rate.**

11 A. DART rate is a lagging indicator that is used to measure workplace injuries that result  
12 in days away from work, restricted work activity, and/or job transfer. As discussed  
13 above, the Company has invested a significant amount of time and effort to protect the  
14 safety of its employees and it is very proud of the progress it has made thus far. The  
15 DART rate scorecard metric is important because it provides transparency to the  
16 Department, to Company employees, and other interested stakeholders and makes the  
17 Company accountable for a high-level of performance in this important safety area.  
18 Moreover, both the Company and its employees have invested considerable time in  
19 training to ensure that only highly-qualified professionals are performing work on  
20 behalf of the Company for the benefit of customers. It is in everyone's best interest to  
21 keep these seasoned professionals on the job where they can deliver value for  
22 customers.

1    **Q.    How does the Company propose to measure DART rate?**

2    A.    The Company's Safety Incident Management System ("SIMS") collects data about all  
3    workplace incidents and the Company's payroll system records all hours worked by  
4    employees. Using these two sets of data the Company calculates a DART rate, which  
5    is expressed as the number of events per 200,000 hours worked.<sup>16</sup>

6    **Q.    How did the Company establish the baseline measure for the DART Rate metric?**

7    A.    The baseline DART figure of 2.4 events per 200,000 hours worked is based on the  
8    Company's average performance over the last three years (2016 to 2018).

9    **Q.    What target does the Company propose for the DART rate metric and what steps**  
10   **will it take to achieve that target?**

11   A.    The Company proposes a performance target of 2.2 events per 200,000 hours work (a  
12   ten percent improvement) by year five of the PBR Plan term. As discussed above, the  
13   Company has worked diligently to imbue the organization with a "Safety First and  
14   Always" culture by committing to safety at the highest levels of the organization,  
15   implementing training and communication protocols to ensure that all employees  
16   understand the organization's safety goals and applicable processes and procedures,  
17   and considering risk on a systematic basis. The Company plans to achieve its DART  
18   target by continuing its organizational commitment to "Safety First" and maintaining a  
19   focus on training and communications that is focused on workplace safety.

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<sup>16</sup> Calculated based on 100 FTEs working 40 hours per week, 50 weeks per year.

1   **Q.     Please describe the scorecard metric that is designed to measure the Company's**  
2   **Grade 2 leak metric.**

3   A.     By law, Massachusetts gas companies must repair Grade 2 leaks within 12 months from  
4           the date the leak was classified.<sup>17</sup> The Company is proposing a scorecard metric that  
5           will set a performance target exceeding the current statutory requirement. Specifically,  
6           the Company is proposing to complete 75% of Grade 2 leaks **within 9 months or less**  
7           (which is three months faster than code requirement), with zero exceeding the 12-  
8           month statutory requirement.

9   **Q.     How does the Company propose to measure the Grade 2 leak metric?**

10  A.     The Company plans to track gas leak data through the newly implemented WAM  
11           system.

12  **Q.     Please describe the scorecard metric that is designed to measure implementation**  
13  **of the PSMS.**

14  A.     As explained above, NSTAR Gas is committed to accelerate the deployment of a PSMS  
15           to augment its existing processes and procedures, to deal systematically with safe and  
16           effective pipeline operation on an enterprise-wide basis, and to minimize the potential  
17           for human-performance errors. The Company is currently working to stand-up an API-  
18           administered audit program that will yield an objective evaluation and score across the  
19           program elements. Specifically, the Company has engaged The Blacksmith Group, to  
20           develop an independent third-party evaluation process to develop specific means to

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<sup>17</sup> G.L. c. 164, § 144(c).

1       measure the Company's adoption and maturity level (1-5 scale) per API's framework.  
2       The Company's anticipated approach is to utilize a third party to validate an internal  
3       assessment conducted by the Company to achieve Level 3 (implemented) across all  
4       elements over three years, and then sustain or improve those scores over years 4 and 5  
5       of the PBR plan term.

6       **B.       Emissions Reduction Scorecard Metrics**

7       **Q.       What are the scorecard metrics the Company is proposing in the area of emissions**  
8       **reductions?**

9       A.       As discussed above, Eversource Energy's commitment to environmental sustainability  
10       is an important part of daily business operations, and a key aspect of Eversource  
11       Energy's vision to become the best energy company in the nation. In this regard, the  
12       Company is proposing two emissions reduction scorecard metrics: (1) a metric that  
13       measures methane emissions reductions; and (2) a metric that targets the repair of  
14       environmentally significant Grade 3 leaks within 12 months of designation.

15       **Q.       Please describe the scorecard metric the Company is proposing in the area of**  
16       **methane emissions reduction?**

17       A.       As discussed above, the GSEP framework established in 2014 has provided a critical  
18       pathway to accelerate the installation of modern, safe, and environmentally sound  
19       natural gas distribution systems in the Commonwealth. The Company proposes to  
20       track methane emissions reduction as a result of the GSEP program as part of its PBR  
21       plan and to commit to a 39 percent reduction from the 2018 emission figure.



1    **Q.     How does the Company propose to measure the emissions reduction metric?**

2    A.     The Company is proposing to report methane emissions reductions consistent with the  
3           current Massachusetts Department of Environmental Protection’s (“MassDEP”)  
4           reporting requirements under 310 CMR 7.73. Emissions calculations use the MassDEP  
5           emissions factors, which are based on the Washington State Study, to estimate total  
6           emissions from the distribution system pipe inventory at year end. Total emissions are  
7           reported to the MassDEP on an annual basis. The calculated emissions reduction  
8           associated with retired leak prone pipe will be used to determine the total annual  
9           reduction as a result of the GSEP program.

10   **Q.     How did the Company establish the baseline measure for the emissions reduction**  
11       **metric and what is it proposing as a performance target?**

12   A.     The baseline of 28,767 metric tons of methane emissions is based on the 2018 natural  
13           gas system emissions measured on the Company’s distribution system pursuant to  
14           MassDEP regulations. The Company is proposing to reduce methane emissions by 39  
15           percent (to 17,424 metric tons) by the end of the five-year PBR Plan term.

16   **Q.     Please describe the scorecard metric the Company is proposing in the area of**  
17       **Grade 3 leaks.**

18   A.     Section 13 of the Energy Diversity Act required the Department to open an  
19           investigation to establish specific criteria to identify Grade 3 gas leaks (classified  
20           pursuant to Section 144) that have significant environmental impact, and to establish a  
21           plan to repair leaks that are determined to have a significant environmental impact. St.  
22           2016, c. 188, § 13. On March 8, 2019, the Department issued an order which, among

1 other things, established repair timeframes for environmentally significant Grade 3  
2 leaks. Specifically, the Department adopted the following timeframes for eliminating  
3 leak-extent designated Grade 3 leaks:

- 4 • Leaks with a leak footprint greater than 10,000 square feet shall be repaired within  
5 twelve months of designation; if the leak is on a facility scheduled for  
6 replacement within three years under the GSEP, then the leak shall be repaired or  
7 eliminated within two years of designation, provided that in either instance such  
8 repair or elimination does not compromise public safety;
- 9 • Leaks with a leak footprint between 2,000 and 10,000 square feet shall be repaired  
10 within two years of designation; if the leak is on a facility scheduled for  
11 replacement within five years under the GSEP, then the leak shall be repaired or  
12 eliminated within three years, provided that in either instance such repair or  
13 elimination does not compromise public safety.

14 D.P.U. 16-31-C, at 24-25 (March 8, 2019).

15 In an effort to further reduce the environmental impact of Grade 3 leaks, the Company  
16 propose to extend an accelerated repair timeframe to non-GSEP environmentally  
17 significant Grade 3 leaks.

18 **Q. What target does the Company propose for the Grade 3 leak metric?**

19 A. The Company is targeting the repair of all non-GSEP environmentally significant  
20 Grade 3 leaks within twelve months of designation.<sup>18</sup>

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<sup>18</sup> The 12-month timeframe would be subject to exceptions for environmentally significant Grade 3 leaks that are inaccessible, challenging to repair, or in a street under a paving moratorium, similar to 220 CMR 114.07(2)(a).

1 **VIII. CONCLUSION**

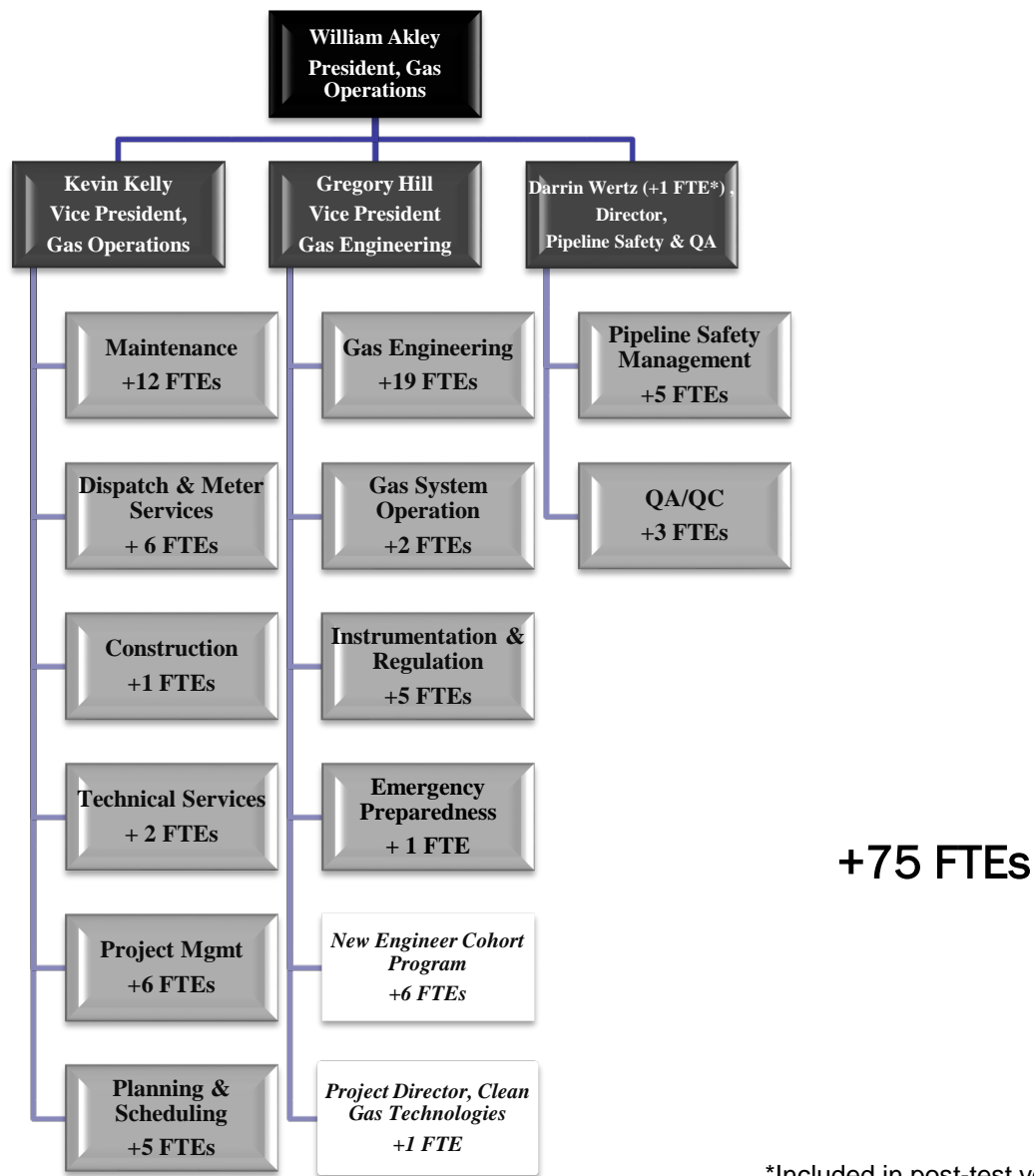
2 **Q. Do you have any summary comments regarding the Company's proposals in this**  
3 **proceeding?**

4 A. The Company appreciates this opportunity to provide the Department with a  
5 comprehensive rate-case filing designed to meet the needs of customers and necessary  
6 revenue support for the Company, and to further the Department's energy and  
7 environmental policy goals. The Company has devoted significant time and effort to  
8 developing and proposing this rate filing and proposed PBR Plan. The PBR Plan is  
9 designed to address the changes in the Company's operating environment that are  
10 discussed herein. In particular, the Company's PBRM will advance the Department's  
11 goals of safe, reliable, and least-cost energy service; further incentivize the Company  
12 to control costs; promote the Commonwealth's energy policies and statutory  
13 obligations; and reduce administrative burden in regulation.

14 **Q. Does this conclude your testimony?**

15 A. Yes. On behalf of NSTAR Gas, we appreciate the Department's consideration of the  
16 Company's proposals in this case.

# Gas Business Organization – Post-Test Year FTEs



# Gas Operations (32 Total FTEs)

**William Akley**  
President, Gas  
Operations

**Kevin Kelly**  
Vice President,  
Gas Operations

**Maintenance**  
+12 FTEs

**Dispatch & Meter  
Services**  
+ 6 FTEs

**Construction**  
+1 FTEs

**Technical Services**  
+ 2 FTEs

**Project Mgmt**  
+6 FTEs

**Planning &  
Scheduling**  
+5 FTEs

## INCREMENTAL FTE DETAIL

- Supervisor (1 FTE)
- 12004 Welder (1 FTE)
- 12004 Technicians (10 FTEs)

- Dispatch Manager (1 FTE)
- Meter Service Supervisor (1 FTE)
- 12004 Service Technicians (3 FTEs)
- Dispatch Clerk (1 FTE)

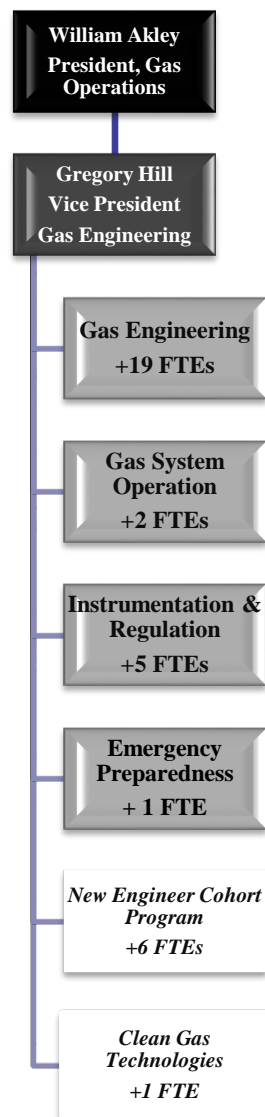
- Construction Supervisor (1 FTE)

- Corrosion Technician (1 FTE)
- Damage Prevention Supervisor (1 FTE)

- Manager, Project Controls (1 FTE)
- Supervisors (2 FTEs)
- Specialist Contractor Billing (1 FTE)
- Estimators (2 FTEs)

- Manager, Ops Performance and Long-Term Planning (1 FTE)
- Operations Analyst (1 FTE)
- WAM Administrator (1 FTE)
- Resource Management & Workforce Analyst (1 FTE)
- Clerk (1 FTE)

# Gas Engineering (34 Total FTEs)



## INCREMENTAL FTE DETAIL

- Manager System Planning (1 FTE)
- Engineer - System Analysis (2 FTEs)
- Field Engineers (7 FTEs)
- Engineer – Policy and Compliance (1 FTE)
- Management of Change Coordinator (1 FTE)
- Asset Mgmt Enhancement (2 FTEs)
- Complex Projects PM Enhancement (3 FTEs)
- GIS Techs (2 FTEs)

- Senior Supervisor Gas Control (1 FTE)
- SCADA Engineer (1 FTE)

- Director (1 FTE)
- Instrumentation Technicians (4 FTEs)

- ERP Specialist (1 FTE)

- New Engineer Cohort Program (6 FTEs)

- Project Director (1 FTE)

## Pipeline Safety & QA (9 Total FTEs)

**William Akley**  
President, Gas Operations

**Darrin Wertz (+1 FTE)\*,**  
Director,  
Pipeline Safety & QA

**Pipeline Safety  
Management  
+5 FTEs**

**QA/QC  
+3 FTEs**

### INCREMENTAL FTE DETAIL

- Director (1 FTE)

- Managers (3 FTEs)
- PSMS Program Administrators (2 FTEs)

- QA/QC Analyst (1 FTE)
- Process Safety Coordinator (1 FTE)
- Process Analyst (1 FTE)

**NSTAR Gas Company  
d/b/a Eversource Energy  
Additional FTEs Post Test Year**

	Service Co	NSTAR Gas	Total
<b>Gas Operations</b>			
<b>Maintenance</b>			
- Supervisor	-	1	1
- 12004 Welder	-	1	1
- 12004 Technicians	-	10	10
<b>Dispatch &amp; Meter Services</b>			
- Dispatch Manager	1	-	1
- Meter Service Supervisor	-	1	1
- 12004 Service Technicians	-	3	3
- Dispatch Clerk	-	1	1
<b>Construction Gas Business Unit</b>			
- Construction Supervisor	-	1	1
<b>Technical Services (Leak Svy Corrosion + Damage Prevention)</b>			
- Corrosion Technician	-	1	1
- Damage Prevention Supervisor	-	1	1
<b>Project Management</b>			
- Manager Project Controls	1	-	1
- Supervisors	-	2	2
- Specialist Contractor Billing	-	1	1
- Estimators	-	2	2
<b>Planning &amp; Scheduling</b>			
- Manager of Ops Performance & Long term Planning	1	-	1
- Operations Analyst	1	-	1
- WAM Administrator	1	-	1
- Resource Mgmt & Workforce Analyst	1	-	1
- Clerk	-	1	1
<b>Total Gas Operations</b>	<b>6</b>	<b>26</b>	<b>32</b>
<b>Gas Engineering</b>			
<b>Gas System Engineering</b>			
- Manager System Planning	1	-	1
- Field Engineers	7	-	7
- Engineer - System Analysis	2	-	2
- Engineer - Policy and Compliance	1	-	1
- Asset Management Enhancement	2	-	2
- Complex Projects PM Enhancement	3	-	3
- GIS Techs (NSTAR)	-	2	2
- Management of Change ("MOC") Coordinator	1	-	1
<b>Gas System Operations</b>			
- Senior Supervisor Gas Control	1	-	1
- SCADA Engineer	1	-	1
<b>Instrumentation and Regulation ("I&amp;R")</b>			
- Director	1	-	1
- Manager (Changed from Service to NSTAR)	(1)	1	-
- Instrument Techs (NSTAR)	-	4	4
<b>Gas ERP</b>			
- ERP Specialist	1	-	1
<b>New Engineer Cohort Program</b>			
- New Engineer Cohort Program	6	-	6
<b>Project Director, Clean Gas Technologies</b>			
- Project Director, Clean Gas Technologies	1	-	1
<b>Total Engineering</b>	<b>27</b>	<b>7</b>	<b>34</b>
<b>Pipeline Safety Management &amp; Quality Assurance</b>			
- Director	1	-	1
- Manager	3	-	3
- PSMS Program Administrator	2	-	2
- QAQC Analyst	1	-	1
- Process Safety Coordinator - MA	1	-	1
- Process Analyst	1	-	1
<b>Total Pipeline Safety Management &amp; QA</b>	<b>9</b>	<b>-</b>	<b>9</b>
<b>Total Gas Business</b>	<b>42</b>	<b>33</b>	<b>75</b>



**COMMONWEALTH OF MASSACHUSETTS**  
**DEPARTMENT OF PUBLIC UTILITIES**

_____	)	
Petition of NSTAR Gas Company d/b/a	)	
Eversource Energy for Approval of an	)	
Increase in Base Distribution Rates and	)	D.P.U. 19-120
Performance-Based Regulatory Plan for Gas	)	
Service Pursuant to General Laws Chapter	)	
164, §94 and 220 C.M.R. §§ 5.00 <i>et seq.</i>	)	
_____	)	

**DIRECT TESTIMONY OF**  
**PENELOPE MCLEAN CONNER AND MICHAEL R. GOLDMAN**

*Customer Service and Sustainability Vision*  
*Clean Energy Demonstration Projects*

**On behalf of**

**NSTAR Gas Company**  
**d/b/a Eversource Energy**

**November 8, 2019**

**COMMONWEALTH OF MASSACHUSETTS**

**DEPARTMENT OF PUBLIC UTILITIES**

**DIRECT TESTIMONY OF**

**PENELOPE MCLEAN CONNER AND MICHAEL R. GOLDMAN**

**Table of Contents**

I.	INTRODUCTION .....	1
II.	CHANGING EXPECTATIONS OF THE CUSTOMER BASE.....	7
III.	MEETING THE EXPECTATIONS OF TODAY’S CUSTOMER.....	11
A.	Initiatives to Improve the Customer Experience and Meet Customer Expectations .....	11
B.	Public Safety Education Campaign .....	19
IV.	EVERSOURCE ENERGY SUSTAINABILITY VISION.....	21
A.	Overview of Proposed Demonstration Projects .....	25
B.	Gas Demand Response Demonstration Project .....	28
C.	Geothermal Network Demonstration Project.....	43
V.	SCORECARD METRICS .....	60
VI.	CONCLUSION.....	71

1 **COMMONWEALTH OF MASSACHUSETTS**

2 **DEPARTMENT OF PUBLIC UTILITIES**

3  
4 **DIRECT TESTIMONY OF**

5 **PENELOPE MCLEAN CONNER AND MICHAEL GOLDMAN**

6 **I. INTRODUCTION**

7 **Q. Ms. Conner, please state your name, position and business address.**

8 A. My name is Penelope McLean Conner. My business address is 247 Station Drive,  
9 Westwood, Massachusetts 02090. I am Chief Customer Officer and Senior Vice  
10 President of the Customer Group for Eversource Energy. I am employed by the  
11 Eversource Energy Service Company (“Eversource Service Company” or “ESC”).

12 **Q. What are your principal responsibilities in this position?**

13 A. As Chief Customer Officer and Senior Vice President for ESC, I am responsible for  
14 overseeing all aspects of customer service, including planning and directing all  
15 activities related to the processes of customer inquiries, billing, credit and collections  
16 and field operations. I am also responsible for delivering a cost-effective portfolio of  
17 energy-efficiency programs to customers of the Eversource Energy operating  
18 companies, including NSTAR Gas Company d/b/a Eversource Energy (“NSTAR Gas”  
19 or “Eversource” the “Company”). I lead a team of 1,400 employees and manage a  
20 \$120 million annual budget in this role.

1   **Q.    Please describe your educational background and professional experience.**

2    A.    I earned a Bachelor of Science degree in industrial engineering from North Carolina  
3           State University and I am a registered Professional Engineer. From 1986 through 1998,  
4           I worked for Duke Power Company in Charlotte, North Carolina. I served in a variety  
5           of roles starting in engineering and progressing to management of dispatch and  
6           customer-service functions and assistant to the president of Duke Power, culminating  
7           in a position as General Manager for Process Integration. From 1998 through 2002, I  
8           worked for Tampa Electric Company in Tampa, Florida, as a Director of Customer  
9           Service. I directed the customer service team of 350 employees with a \$21 million  
10          annual budget.

11          In the four years that I was with Tampa Electric Company, I improved customer  
12          satisfaction while reducing overall customer service costs. For the years 1998 through  
13          2001, I increased Tampa Electric Company's J.D. Power billing and payment rankings  
14          from 11th to 5th in the nation, and customer service rank from 20th to 1st nationally,  
15          while reducing bad-debt write-offs by 20 percent. In 2002, I was hired by NSTAR  
16          Electric and NSTAR Gas (together "NSTAR") as Vice President of Customer Care,  
17          where I assured quality customer service for NSTAR's 1.3 million electric and gas  
18          customers. I was named Senior Vice President and Chief Customer Officer in 2012  
19          following the NSTAR/Northeast Utilities merger.

20          For over a decade, I have served as a columnist for Electric Power and Light Magazine.

21          I am the author of three books, *Customer Service: Utility Style*; *Energy Efficiency*:

1 *Principles and Practices; and Profiles in Excellence: Utility Chief Customer Officers.*  
2 I am a member of the Edison Electric Institute Retail Services Committee; Chair of the  
3 Customer Service Week Board of Directors; and Chair of the American Council for an  
4 Energy Efficient Economy. I also serve on the City of Boston's Green Ribbon  
5 Commission, among other charitable and public-service organizations. I am also the  
6 chair of the Board of the United Way of Massachusetts Bay and Merrimack Valley.

7 **Q. Have you previously testified in formal hearings before the Massachusetts**  
8 **Department of Public Utilities?**

9 A. Yes. I have sponsored testimony in several proceedings before the Massachusetts  
10 Department of Public Utilities (the "Department"), including: NSTAR Electric  
11 Company, D.T.E. 07-64 (2007) (NSTAR Green); Low Income Consumer Protection &  
12 Assistance, D.T.E. 08-4 (2008) (on behalf of NSTAR Electric); Three Year Energy  
13 Efficiency Plans, D.P.U. 09-120 (2010) (on behalf of NSTAR Electric); NSTAR  
14 Electric Company, D.P.U. 10-06 (2010) (revised energy efficiency surcharge tariffs);  
15 NSTAR Electric Company, D.P.U. 11-85-B/11-119-B (2012) (storm investigation);  
16 Electric Grid Modification, D.P.U. 12-76 (2014) (grid modernization); Service Quality  
17 Guidelines, D.P.U. 12-120 (2012) (on behalf of NSTAR Electric and WMECO);  
18 NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a  
19 Eversource Energy, D.P.U. 15-122/123 (Grid Modernization Plan); and NSTAR  
20 Electric Company and Western Massachusetts Electric Company each d/b/a  
21 Eversource Energy, D.P.U. 17-05 (2017 NSTAR Electric rate case).

1   **Q.    Mr. Goldman, please state your name, position and business address.**

2    A.    My name is Michael R. Goldman. My business address is 247 Station Drive,  
3       Westwood, Massachusetts. I am the Director, Regulatory, Evaluation & Support,  
4       Energy Efficiency for the operating companies of Eversource Energy.

5   **Q.    What are your principal responsibilities in this position?**

6    A.    My principal responsibilities in this position are to oversee the development and  
7       evaluation of cost-effective customer-facing program offerings. My team is  
8       responsible for overseeing evaluation activities related to the delivery of the  
9       Company's energy efficiency programs and determining the savings values associated  
10      with the individual measures and overall programs. Additionally, my team is  
11      responsible for developing the energy efficiency plans and subsequent annual and term  
12      reports for those programs in each of the Eversource operating jurisdictions. My team  
13      maintains and runs the benefit-cost ratio model, which helps determine the cost  
14      effectiveness of individual measures and overall programs. Lastly, I am responsible  
15      for developing innovative offerings for Eversource Energy customers that take  
16      advantage of new technologies or strategies.

17   **Q.    Please summarize your professional and educational background.**

18   A.    I earned a Bachelor of Arts degree from the University of Wisconsin-Madison and a  
19      Master of Arts degree from the Johns Hopkins University with specializations in  
20      international finance and energy policy. From 2008-2010, I was an Energy Business  
21      Analyst at the consulting firm of PowerAdvocate focusing on large capital-intensive

1 utility construction projects. From 2010-2012, I was a strategy and operations  
2 consultant within Deloitte Consulting's Energy and Resources practice area, focusing  
3 on energy issues for federal clients. I joined NSTAR in 2012, where I have served in  
4 roles of increasing responsibility, including Senior Analyst, Supervisor, Manager, and  
5 now Director. Within my roles at Eversource Energy, I have been responsible for  
6 energy efficiency planning and evaluation matters across Eversource Energy's three-  
7 state footprint. I have also been responsible for designing and setting the strategic  
8 direction for innovative programs that impact multiple parts of the Company, such as  
9 demand response initiatives. I have produced over 30 publications and have been  
10 featured as a panelist at conferences in the areas of energy efficiency, demand response,  
11 distributed energy resources and innovative energy technologies.

12 **Q. Have you previously testified before the Department or other regulatory agencies?**

13 A. Yes, I have testified in several proceedings before the Department including: NSTAR  
14 Electric, D.P.U. 18-50 (PBR Performance Metrics); Three Year Energy Efficiency  
15 Plans, D.P.U. 18-115 and D.P.U. 18-119; D.P.U. 17-84 (on behalf of NSTAR Electric  
16 and NSTAR Gas); NSTAR Electric Company and Western Massachusetts Electric  
17 Company, D.P.U. 16-178 (Demand Reduction Demonstration Offerings); Three Year  
18 Energy Efficiency Plans, D.P.U. 15-164 and D.P.U. 15-169 (on behalf of NSTAR  
19 Electric and NSTAR Gas). I have also testified before the New Hampshire Public  
20 Utilities Commission in New Hampshire Statewide Energy Efficiency Plan, DE 17-136  
21 (on behalf of Public Service Company of New Hampshire).

1   **Q.    What is the purpose of your testimony?**

2    A.    This joint testimony is designed to serve three important purposes regarding the  
3           Company's customer service and sustainability vision. Specifically, this testimony  
4           discusses the changes that the Company is experiencing in customer perceptions  
5           regarding utility providers, as well as evolving customer expectations about the way  
6           that utility service is provided and the growing demand for cleaner energy solutions.

7           Second, as part of the performance-based regulatory ("PBR") plan proposed by the  
8           Company in this proceeding, the Company is proposing 12 performance metrics within  
9           three categories that will allow the Department and other stakeholders to gauge the  
10          Company's progress on key performance indicators over the five-year term of the PBR  
11          Plan. These three performance categories are: Safety and Reliability; Customer  
12          Satisfaction and Engagement; and Emission Reductions. Our testimony discusses the  
13          metrics comprising the Customer Satisfaction and Engagement category, which are  
14          designed to drive benefits for customers in close alignment with the Department's  
15          regulatory objectives. Metrics comprising the other two categories of performance are  
16          discussed in the testimony of Company Witnesses Akley and Horton.

17          Our testimony also discusses the Company's proposal for two, clean energy  
18          demonstration projects. These projects are designed to produce gains in knowledge  
19          and experience and help inform future development of the industry in relation to gas  
20          demand-response programs and geothermal distribution networks.



1    **Q.    Are you presenting any exhibits in addition to your testimony?**

2    A.    Yes. We are presenting the following exhibits as part of our testimony in this case:

Exhibit	Purpose
Exhibit ES-PMC/MRG-2	Illustrative Gantt chart showing anticipated timing of each aspect of geothermal project
Exhibit ES-PMC/MRG-3	Detailed cost estimates for the geothermal network project, broken down by scenario and cost component

3    **Q.    How is your testimony organized?**

4    A.    This joint testimony is organized as follows: Section I is an introductory section. In  
5    Section II, Ms. Conner presents the Company's customer philosophy and discusses  
6    changes in customer perceptions and evolving expectations about utility service. In  
7    Section III, Ms. Conner discusses Eversource Energy's sustainability vision. In Section  
8    IV, Ms. Conner and Mr. Goldman jointly present the Company's two proposed  
9    demonstration projects. Ms. Conner discusses the Company's proposed scorecard  
10    metrics for Customer Satisfaction and Engagement in Section V. Section VI is the  
11    conclusion.

12    **II.    CHANGING EXPECTATIONS OF THE CUSTOMER BASE**

13    **Q.    Ms. Conner, what is Eversource Energy's overall philosophy for customer**  
14    **service?**

15    A.    Eversource Energy is the largest energy provider in New England and it is committed  
16    to safety, reliability, environmental leadership and expanding energy options for  
17    approximately 4 million electric, natural gas and water customers. Eversource Energy

1 has set an aggressive goal—to be the best energy company in the nation. This goal is  
2 built upon several pillars—two of which are: (1) achieving operational excellence; and  
3 (2) delivering a superior customer experience. Eversource Energy’s commitment to  
4 operational excellence is discussed in the joint testimony of William J. Akley, President  
5 of the Eversource Energy gas distribution business, and Douglas P. Horton, Vice  
6 President, Distribution Rates and Regulatory Requirements. With respect to delivering  
7 a superior customer experience, Eversource Energy is pursuing a multiplicity of  
8 solutions to enhance the ways in which customers interact with Eversource Energy and  
9 that make doing business with the company quick and easy.

10 **Q. How does Eversource Energy gather information and data about customer**  
11 **preferences and expectations?**

12 A. At Eversource Energy, the voice of the customer is extremely important and the  
13 Company works proactively to gather data about customer expectations and  
14 preferences and then adapts its business to those expectations and preferences.  
15 Eversource Energy gathers customer information and research data using multiple tools  
16 and from multiple sources. For example, enhanced analytics on Eversource.com  
17 provide insight into how customers use Eversource Energy’s website and help identify  
18 any pain-points within their online journey. Transactional surveys are used to solicit  
19 feedback on specific interactions as well as a user’s entire online experience.  
20 Eversource Energy has also introduced an online community made up of about 4,000  
21 residential and commercial customers, which allows Eversource Energy to test  
22 messaging, website design, and other new customer service offerings.

1 Eversource Energy reviews national customer trends through information provided by  
2 national trade associations, such as the American Gas Association and the Edison  
3 Electric Institute. Eversource Energy also subscribes to external customer research  
4 through J.D. Power and Escalent (formerly Market Strategies International), which  
5 provide insights on customer perceptions regarding Eversource Energy and on  
6 performance of other utility providers across the country. Eversource Energy also  
7 conducts its own customer perception surveys, which provide insight into customers'  
8 overall perception of Eversource Energy.

9 Eversource Energy has also implemented a voice of the customer dashboard that  
10 provides management with near real-time insights on customer feedback and  
11 perceptions. The dashboard is updated as customer feedback is received and  
12 augmented with internal metrics that can help in understanding the actual results. For  
13 example, in customer service, data is provided on call handling performance, which  
14 has a direct impact on the customer's experience.

15 Lastly, Eversource Energy has created a platform for customers to rate their experience  
16 with customer service representatives ("CSRs")—much like the rating system for Uber  
17 drivers where customer feedback is an integral part of the experience. As soon as the  
18 interaction between the customer and the CSR ends, a survey email is sent to the  
19 customer, and the response rate has been about 80 percent. CSRs can see their rating,  
20 and if it was not positive, the call may be reviewed and CSRs can work with supervisors  
21 to identify areas for improvement going forward.

1    **Q.    What is the data indicating to the Company about its customers?**

2    A.    The customer survey data gathered by Eversource Energy shows that customers  
3           increasingly expect to be served in a digital fashion, using the channel of their choice,  
4           and they expect a variety of choices. The data also shows that, in addition to safe,  
5           reliable and low-cost energy service, customers are increasingly interested in clean  
6           energy solutions. Recently, Eversource Energy surveyed customers in its online  
7           community and more than 50 percent responded that Eversource Energy plays a  
8           leadership role in providing clean energy and 88 percent felt clean energy was strongly  
9           linked to Eversource Energy's efforts to care for the environment. Simply put, clean  
10          energy and sustainability are important to Eversource Energy's customers.

11   **Q.    Ms. Conner, are changes in customer demographics, and changes in the culture**  
12   **more generally, reshaping customer expectations?**

13   A.    Yes, according to data from the U.S. Census Bureau, Millennials are beginning to  
14          surpass Baby Boomers as the nation's largest living adult generation.<sup>1</sup>  
15          Correspondingly, Eversource Energy's customer base increasingly will be comprised  
16          of Millennials who are beginning to overtake Boomers as the largest group of utility  
17          customers.

18          This is an important fact because Millennials and younger generations expect fast and  
19          accessible customer service; they expect multiple channels for service; and they expect

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<sup>1</sup>    Pew Research Center, Millennials projected to overtake Baby Boomers as America's largest generation,  
<https://www.pewresearch.org/fact-tank/2018/03/01/millennials-overtake-baby-boomers/> (March 1, 2018).

1 to be served by digital channels. Also, unlike previous generations, Millennials tend  
2 to be more engaged with respect to sharing their customer service experiences, good  
3 and bad, and rating the products and services they use as consumers. Accordingly,  
4 Eversource Energy is investing in technology and building-out digital channels to serve  
5 the growing demographic of Millennials and younger generations. However, I must  
6 emphasize that Eversource Energy never loses sight of the fact that its customer base  
7 is diverse and Eversource Energy is committed to providing high-quality customer  
8 service for all of its customers, who span multiple generations. For that reason,  
9 Eversource Energy's customer service channels are as diverse as its customer base. For  
10 example, many customers still prefer to use the telephone to interact with the Company  
11 and that option remains available to all customers.

12 **III. MEETING THE EXPECTATIONS OF TODAY'S CUSTOMER**

13 **A. Initiatives to Improve the Customer Experience and Meet Customer**  
14 **Expectations**

15 **Q. Ms. Conner, please discuss some of the specific steps Eversource Energy is**  
16 **pursuing to achieve its customer-service vision and meet the expectation of today's**  
17 **customers.**

18 **A.** A primary interface between Eversource Energy and its customers is billing and  
19 payment—it is a key touch point that occurs on a monthly basis. In fact, over 90 percent  
20 of the visits to Eversource Energy's website are to view and pay utility bills.  
21 Accordingly, Eversource Energy has made several key investments to make the billing  
22 and payment experience better for customers. For example, in 2016, Eversource  
23 Energy implemented a new full-color bill (designed with direct customer feedback),

1 which makes information easy to find and provides a clear view of energy use and  
2 charges to help customers better understand and manage their energy costs.

3 Eversource Energy has also partnered with KUBRA, an industry leader in customer  
4 experience management solutions, to develop and launch a new Payment Plan Portal  
5 on Eversource.com. The Payment Plan Portal provides customers with an enhanced  
6 digital billing and payment experience and allows customers to initiate a service  
7 reconnection order (as applicable); view and pay bills in as few as two clicks; establish  
8 bill and payment alerts in the channel of their choice; and find support in the online  
9 experience with a virtual assistant, among other items.

10 Eversource Energy also implemented a consolidated credit card processing solution  
11 with additional options and, for residential customers, reduced fees. Lastly, Eversource  
12 Energy moved its payment processing operation to Massachusetts, which has reduced  
13 time and costs for the benefit of customers.

14 Looking ahead, Eversource Energy will continue to focus on improving billing and  
15 payment options for customers. Specifically, Eversource Energy is proposing a fee-  
16 free credit and debit card program in D.P.U. 19-71, which Eversource Energy views as  
17 a meaningful and necessary step forward to accommodate changing customer needs,  
18 expectations, and preferences regarding their payment options for utility service.  
19 Eversource Energy has already implemented a fee-free program in Connecticut and  
20 experienced positive and immediate impacts on customer satisfaction.

1 Eversource Energy has also focused on improving the other channels through which  
2 customers interface with the Company. For example, Eversource Energy has created  
3 focused training for its CSRs; enhanced the tools that CSRs have at their fingertips  
4 when they are interacting with customers; and implemented a CSR facing informational  
5 tool called Knowledgebase. The Knowledgebase tool is searchable by entering a  
6 question or key word and services all Eversource Energy Customer Contact Centers.  
7 Eversource Energy's first call resolution metric is in the top quartile in the industry as  
8 a result of these efforts. Eversource Energy has also recognized that a growing  
9 population of its customer base prefers and is moving toward digital channels. This  
10 preference is driven, in part, by consumers' transactional experiences with service  
11 providers in other industries such as Amazon, Uber, American Express, and Netflix.  
12 In other words, customer service expectations are being set outside of the gas and  
13 electric utility industries.

14 Today's digital consumers want the same type of experience in every transaction with  
15 service providers, and they want that experience to be intuitive, personalized, and fast.  
16 Consequently, customer satisfaction in the utility space is more and more closely linked  
17 to the availability of digital tools and electronic engagement channels. For that reason,  
18 Eversource Energy continues to enhance its website to make it more user friendly. For  
19 example, enhancements to Eversource Energy's online "Start Service" process enable  
20 customers to easily set up their gas and electric service in a single, online transaction.  
21 New features include the ability to schedule move-in service requests and a

1 confirmation email with additional, helpful information following each transaction.  
2 Eversource Energy will continue to improve this process by providing immediate  
3 access to account numbers to facilitate paperless billing and customer preference  
4 enrollment at move-in.

5 Eversource Energy also recently launched its first mobile app for Apple and Android  
6 phones. The new mobile app makes Eversource Energy account management easier  
7 and more convenient and consists of features that include the ability to view and pay a  
8 bill, manage paperless billing, report or check an electric outage, as well as fast access  
9 to Eversource Energy's outage map and customer service contact information. Among  
10 the many yardsticks for best-in-class digital customer experience, mobility ranks high.  
11 I am pleased to report that this has been a hugely popular new offering and it has already  
12 been downloaded more than 108,628 times, and over 3,000,000 customer interactions  
13 have occurred, including 260,000 payments. The app has been well received with high  
14 ratings by customers in the app stores. Overall, the launch of the mobile app has  
15 exceeded initial expectations.

16 Eversource Energy has also taken proactive steps to ensure that its services can be  
17 easily accessed by non-English speakers. For example, Eversource Energy is staffing  
18 its customer contact center with Spanish and Portuguese-speaking CSRs. Eversource  
19 Energy also has a language-line service that provides interpretive services.  
20 Additionally, Eversource Energy is working on an initiative to provide content on its



1 website in Spanish, which is the most predominantly spoken language in Massachusetts  
2 other than English.

3 **Q. Ms. Conner, are there additional initiatives with respect to delivering a superior**  
4 **customer experience that you would like to discuss?**

5 A. Yes. Eversource Energy is implementing a set of critical projects that will improve  
6 operational efficiency and customer satisfaction. These projects are the Enterprise  
7 Work and Asset Management (“WAM”) system, the ClickSoftware Mobile Workforce  
8 Management (“Mobile Gas WAM”) solution, and the Mobile Gas Meter Service  
9 (“MGMS”) project. The projects are also discussed in the joint testimony of William  
10 Akley and Douglas Horton, in the joint testimony of Douglas Horton and Ashley  
11 Botelho, and in the joint testimony of Leanne Landry and Thomas Desrosiers.

12 The legacy work and asset management systems in use across the Eversource Energy  
13 operating companies were outdated, prone to failure, and not equipped to meet the  
14 going forward business needs of Eversource Energy and its customers. Moreover, the  
15 legacy processes for field-service work was largely manual and paper-based, so that  
16 the processes were labor intensive and inefficient. Also, the Eversource Energy  
17 customer contact center had little visibility into the work going on in the field. This  
18 “mobility gap” impeded the operating companies’ ability to meet the expectations of  
19 customers who expect to know where and when a field technician will arrive for an  
20 appointment, and who have grown accustomed to being served by field mobility  
21 solutions as a part of their day-to-day interactions with other service providers. To

1 address these challenges, Eversource Energy is implementing a single Enterprise  
2 Mobile Technology Platform across gas and electric operations with the deployment of  
3 the WAM, integrated with the industry-leading Mobile Gas WAM solution, that will  
4 modernize operating systems and business processes.

5 The Mobile Gas WAM system provides new capabilities to field workers, which  
6 includes access to the geographic information system (“GIS”), maps, standards,  
7 procedures and email/texting to provide field personnel with more timely, accurate  
8 information to perform construction, maintenance, inspection, compliance and  
9 emergency gas work activities required to deliver reliable energy and a better customer  
10 experience. These mobility enhancements are supported by the field mobility devices  
11 that are carried by the Company’s workers in the field. These devices enable two-way  
12 communications between the Company and its field personnel—allowing workers to  
13 provide updates regarding the status of the work, which in turn creates the ability to  
14 provide timely status updates to customers on their service requests. In addition, the  
15 functionality provided by the WAM and Mobile Gas WAM projects allow the  
16 operating companies to remind customers of their appointments and provide customers  
17 alerts when technicians are in transit to the customer’s premises.

18 The Gas WAM project was placed in service for NSTAR Gas and Yankee Gas in March  
19 2019. The Mobile Gas WAM project was placed in service for NSTAR Gas and  
20 Yankee Gas in August 2019.

1    **Q.     Please describe the MGMS project.**

2    A.     The MGMS project is designed to replace two disparate legacy systems, pCad and  
3           Advantex, to provide new and improved appointment booking functionality for the  
4           Company's CSRs and customers who are utilizing the self-service appointment  
5           booking feature. This project will support the Gas Meter Services business, with the  
6           following as its key objectives:

- 7           ▪   Establish a single unified business process for gas meter services and customer  
8               request process for gas meter services work;
- 9           ▪   Improve workload and resource utilization by leveraging automatic scheduling,  
10            route optimization, and "Best Fit" appointment booking;
- 11          ▪   Improve customer experience by improving the appointment process and  
12               working towards reducing the customer appointment window; and
- 13          ▪   Providing job status to CSRs and customers.

14           The MGMS project is in the testing phase and, assuming testing is successful, the  
15           Company anticipates that this project will be placed in service by the first quarter of  
16           2020.

17   **Q.     Have expectations changed with respect to the information customers expect from**  
18           **Eversource Energy regarding the safety of gas service, particularly in the wake of**  
19           **the Merrimack Valley incident?**

20   A.     Yes, customers want reassurance about the safety and reliability of gas service. As  
21           discussed in the joint testimony of William Akley and Douglas Horton, Eversource  
22           Energy's number one priority is to provide safe and reliable gas service to customers  
23           and the Company has made significant capital investments and devoted considerable

1 resources to ensure its operations are designed to deliver safe and reliable gas service.  
2 In the wake of the Merrimack Valley incident, the issue of gas safety has entered the  
3 public conscience and members of the public have requested information about safety  
4 issues and possible gas leaks in their area. In response, Eversource Energy has  
5 enhanced its communications channels, including its website and bill inserts, to provide  
6 customers with information about gas safety, instructions about how to report an odor  
7 of gas, and what to do if an incident should arise.

8 The Company is making significant progress on the accelerated replacement of aging  
9 infrastructure through its Department-approved Gas System Enhancement Program  
10 (“GSEP”), expeditiously addressing leaks in compliance with Massachusetts law and  
11 Department regulations.<sup>2</sup> In addition, Eversource has worked collaboratively with the  
12 Home Energy Efficiency Team (“HEET”), Gas Safety Inc., Mothers Out Front and the  
13 other Massachusetts LDCs to field test multiple methods to measure emissions from  
14 gas leaks. To convey additional information about the safety of the gas distribution  
15 system to customers, the Company is developing a comprehensive Public Safety  
16 Education Campaign as part of the PBR Plan proposed in this proceeding.

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<sup>2</sup> In 2014, the Massachusetts State Legislature passed *An Act Relative to Natural Gas Leaks* (“Gas Act”). The Gas Act permitted local distribution companies (“LDCs”) to submit to the Department annual plans to repair or replace aged natural gas infrastructure. On October 31 of each year since the passage of the Gas Act, NSTAR Gas has submitted its GSEP to the Department setting forth its proposals for replacing aged pipe during the upcoming construction year.

1        **B.        Public Safety Education Campaign**

2        **Q.        Please provide an overview of the Company's efforts to convey additional**  
3        **information about safety to customers.**

4        A.        In the wake of the Merrimack Valley incident, and in line with Eversource's continued  
5        efforts to improve the overall safety and reliability of its gas pipeline system,  
6        Eversource Energy decided it was vital to increase the level of awareness among  
7        customers about how to detect and respond to a gas leak. In 2018, the Company  
8        updated the content on Eversource.com with a focus on gas safety, including how to  
9        detect a leak, and the importance of "calling before you dig." These specific topic areas  
10       were validated by J.D. Power research. In 2019, Eversource Energy began working  
11       with Boathouse Group, Inc, ("Boathouse"), a full-service marketing agency, to develop  
12       the overall creative and media strategy for the customer information and education  
13       campaign. It was important to the Company to reach both individual homeowners and  
14       commercial businesses, as well as customers who are in rental units heated with gas.

15       **Q.        Please provide more detail regarding the messaging and channels through which**  
16       **the Company is communicating gas safety information to customers.**

17       A.        The customer information and education campaign began running in both  
18       Massachusetts and Connecticut in the fall of 2019, and the creative approach is simple  
19       and direct. "Smell, leave, tell" and "Call 811 before you dig" are the prominent  
20       messages, with customers encouraged to click "learn more" on digital links to  
21       Eversource.com. The campaign utilizes digital channels, which allows the Company  
22       to target customers efficiently by zip code, along with billboards and bus shelter

1       messaging to convey information in heavy traffic locations. The Company is also  
2       including the safety messaging in its November 2019 Customer Update bill insert.

3       The campaign has already generated substantial engagement across Connecticut and  
4       Eastern Massachusetts, and the highlights include:

- 5           • Delivered an estimated 7,00,000 offline impressions on billboards and bus  
6           shelters.
- 7           • Reached 87,121 people on Facebook during the first 7 days, delivering 145,920  
8           impressions and 31,874 video views.
- 9           • Streamed over 530,000 audio spots on Pandora.
- 10          • Served 81,969 display ad impressions and drove 223 clicks.
- 11          • Appeared in 3,564 results for Paid Search, driving 131 clicks to the website  
12          from Bing and Google.

13   **Q.   How does the Company plan to build upon and further refine its customer**  
14   **education and information campaign?**

15   A.   A substantial benefit of employing digital channels is the ability to analyze customer  
16   viewing data to determine how many clicks or views the messages generated. Also,  
17   the Company plans to test the impact of its messaging and recall with customers. This  
18   feedback, coupled with the valuable analytics that digital provides, positions the  
19   Company to adjust the creative and/or media strategy in future efforts planned for 2020.  
20   In 2020, Eversource Energy will continue its partnership with Boathouse and the  
21   Company expects to make investments to refine the customer education campaign.

1 **IV. EVERSOURCE ENERGY SUSTAINABILITY VISION**

2 **Q. Is the concept of sustainability integrated into the Company's proposals in this**  
3 **proceeding?**

4 A. Yes. Eversource Energy is working hard to be recognized as one of the greenest energy  
5 companies in the nation. Eversource Energy's commitment to environmental  
6 sustainability is an important part of its daily business operations and key to its vision  
7 to become the best energy company in the nation. Eversource Energy is embedding  
8 sustainability in its operating culture through numerous environmental, social and  
9 governance initiatives that guide the Company's management and operation.

10 **Q. Within the Eversource Energy sustainability vision, how do natural gas customers**  
11 **help to reduce greenhouse gas emissions?**

12 A. In Massachusetts, over 30 percent of homes heat with high CO<sub>2</sub> emitting fuels—  
13 propane, oil, and a very small percentage on coal.<sup>3</sup> Across Massachusetts that's nearly  
14 800,000 homes. Consumers who choose natural gas over oil, or switch from oil to  
15 natural gas to heat their homes can reduce their carbon emissions by as much as 27  
16 percent simply by changing fuel sources to natural gas.<sup>4</sup>

17 The impact of this fuel switch is magnified where the new systems are installed for the  
18 gas customer are highly efficient. The Massachusetts Energy Efficiency programs are  
19 foundational to optimizing energy usage in the Commonwealth. The latest three-year

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<sup>3</sup> How Massachusetts Households Heat Their Homes, <https://www.mass.gov/service-details/how-massachusetts-households-heat-their-homes>.

<sup>4</sup> See U.S. Energy Information Administration, Carbon Dioxide Emissions Coefficients, [https://www.eia.gov/environment/emissions/co2\\_vol\\_mass.php](https://www.eia.gov/environment/emissions/co2_vol_mass.php).

1 energy efficiency plans covering 2019-2021 are expected to reduce natural gas usage  
2 by 1.25 percent of annual sales statewide (1.34 percent of annual sales for NSTAR  
3 Gas)—the highest natural gas savings goal ever set in Massachusetts. Customers who  
4 convert from a baseline efficiency oil heating system to a high-efficiency natural gas  
5 system, can reduce their greenhouse gas emissions by a total of 40 percent.<sup>5</sup>

6 In addition, the efficiency of home heating and water heating equipment has improved  
7 considerably over the past several decades. Regarding heating equipment, when  
8 efficiency is higher, less natural gas needs to be used by the furnace or boiler to get the  
9 same amount of heat output. New gas heating systems can have efficiencies as high as  
10 97 percent while the most efficient oil heating system available only reaches 89 percent.  
11 In Massachusetts, the Mass Save® program offers rebates on high efficiency heating  
12 equipment as well as zero-percent financing for major energy efficiency measures.  
13 These equipment efficiency improvements, combined with initiatives like Mass Save®,  
14 contribute to a reduction in the use of natural gas.

15 Additionally, Massachusetts Building and Energy Codes,<sup>6</sup> and state programs (e.g.,  
16 Pathways to Zero Net Energy Program), in combination with the Commonwealth's

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<sup>5</sup> See the "Energy Consumption, Demand, Customer Cost, and Carbon Emissions Analysis Spreadsheet" produced as part of the "RES21 Energy Optimization Study" energy efficiency evaluation, available at [http://ma-eeac.org/wordpress/wp-content/uploads/RES21\\_Task4\\_Final\\_Spreadsheet\\_Model\\_REVISED\\_2018-09-25\\_v4.xlsx](http://ma-eeac.org/wordpress/wp-content/uploads/RES21_Task4_Final_Spreadsheet_Model_REVISED_2018-09-25_v4.xlsx) and [http://ma-eeac.org/wordpress/wp-content/uploads/RES21\\_Energy-Optimization-Study\\_09OCT2018.pdf](http://ma-eeac.org/wordpress/wp-content/uploads/RES21_Energy-Optimization-Study_09OCT2018.pdf).

<sup>6</sup> In 2009, Massachusetts became the first state to adopt an above-code appendix to the "base" building energy code—the "Stretch Code." (780 CMR Appendix 115.AA). The Stretch Code emphasizes energy



1 nation-leading energy efficiency programs, have produced buildings with better  
2 insulation, smarter thermostats, and more advanced and tighter-fitting windows and  
3 doors—all of which contribute to tighter building envelopes.<sup>7</sup> A tighter building  
4 envelope stays warmer in the winter and cooler in the summer and therefore requires  
5 less fuel for heating and cooling.

6 Collectively, the efforts described above have reduced the usage of natural gas in  
7 customer homes and businesses. According to the American Gas Association, the  
8 average American home consumes 40 percent less natural gas than it did 40 years ago.  
9 Since 1970, the decrease in natural gas use has averaged one percentage point per year.<sup>8</sup>  
10 Consequently, by continuing to serve natural gas customers, the Company is helping  
11 to reduce greenhouse gas emissions and achieve the Commonwealth's environmental  
12 goals, which is a central focus of Eversource Energy's commitment to environmental  
13 sustainability.

14 **Q. Does the Company have evidence of the trend of reduced gas usage among**  
15 **customers within its customer base?**

16 A. Yes. As shown in the table below, an analysis of the billing data for single family  
17 residential gas customers found that the Energy Use Intensity ("EUI") of homes

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performance, as opposed to prescriptive requirements, and is designed to result in cost-effective construction that is more energy efficient than that built to the "base" energy code. Building Energy Code, Summary of State Building Energy Codes including the Stretch Code, <https://www.mass.gov/info-details/building-energy-code>.

<sup>7</sup> On October 1, 2019, ACEEE released its State Energy Efficiency Scorecard and Massachusetts continues to hold the first-place spot, a position it has held for nine years.

<sup>8</sup> AMERICAN GAS ASSOCIATION, *Energy Efficiency and Natural Gas Utilities* (2019), <https://www.aga.org/globalassets/efficiency-fact-sheet---2019-.pdf>.

1 decreased steadily from 2013-2017, with customers using roughly 19 percent less  
2 energy per square foot in 2017 than they did in 2013. More recent gas customers were  
3 particularly efficient, with those coming online in 2016-2017 achieving 20 percent  
4 more efficient usage than existing customers (data for customers added in 2015 and  
5 2018 reflect partial-year usage).

SINGLE FAMILY HOMES								
Year	All Heating Customers				New Heating Customers Since 2015			
	Gas Use Intensity (therms/Sq. Ft)	# Billing Accts	Avg Sq. Ft	Avg Annualized Weather Normalized Usage (therms) <sup>1,2</sup>	Gas Use Intensity (therms/Sq. Ft)	# Billing Accts	Avg Sq. Ft	Avg Annualized Weather Normalized Usage (therms) <sup>1,2</sup>
2013	0.633	78,741	1,885	1,193				
2014	0.607	86,219	1,887	1,146				
2015	0.595	94,052	1,887	1,122	0.350	951	1,978	693
2016	0.526	102,998	1,882	990	0.408	1,746	1,955	797
2017	0.514	113,825	1,879	966	0.401	2,735	1,914	767
2018	0.593	113,314	1,878	1,113	0.483	2,785	1,917	926

6 Table notes:  
7 1. Usage is weather normalized by multiplying by (Normal Worcester EDD/Actual Worcester EDD)  
8 2. Usage is annualized by multiplying by (365 days/Usage days)

9 **Q. What proposals is the Company making in this proceeding that promote**  
10 **sustainability objectives?**

11 A. As discussed in the joint testimony of Company Witnesses Akley and Horton, the  
12 Company is initiating a dialogue in this case regarding the use of renewable natural  
13 gas, which would assist in lowering greenhouse gas emissions associated with gas  
14 usage. Also, as discussed in the joint testimony of Mr. Akley and Mr. Horton, the  
15 Company is proposing specific scorecard metrics that are designed to track the  
16 Company's efforts to reduce CO<sub>2</sub> over the PBR Plan term. Lastly, the Company is

1 proposing two innovative demonstration projects that are designed to test whether  
2 additional environmental benefits would be delivered through the application of  
3 technology and new business models.

4 **A. Overview of Proposed Demonstration Projects**

5 **Q. Why are the proposed demonstration projects important?**

6 A. Demonstration projects are an opportunity to deliver near-term benefits while  
7 advancing the body of knowledge in the field of cutting-edge technologies and new  
8 business models; and to inform the future application of such technologies and business  
9 models.

10 **Q. Would you please describe the Company's proposed demonstration projects?**

11 A. The Company is proposing two demonstration projects that will move the  
12 Commonwealth forward on clean energy innovation; reduce greenhouse gas emissions;  
13 and proactively test the abilities and potential benefits of new technologies and  
14 innovative business models. Specifically, the Company is presenting the following two  
15 demonstration projects:

- 16 • **Gas Demand Response:** The gas demand response demonstration project  
17 would have a duration of three years and is designed to test whether such a  
18 program can shave peak demand; alleviate temporary physical pipeline  
19 constraints; reduce the amount of pipeline capacity the Company needs to buy;  
20 and reduce greenhouse gas emissions by reducing overall gas usage.
- 21 • **Geothermal Network:** The geothermal network demonstration project is  
22 designed to test the viability of this business model; assess the enabling  
23 technology; and evaluate the costs and benefits.

1 **Q. How is the Company proposing to recover the costs of the proposed demonstration**  
2 **projects?**

3 A. In this proceeding, the Company is requesting that the Department approve a factor  
4 within the performance-based ratemaking mechanism (“PBRM”) to recover the costs  
5 of the demonstration projects. The PBRM is discussed in the testimony of Company  
6 Witnesses Akley and Horton. The tariff is included as an attachment to the joint  
7 testimony of Company Witnesses Richard Chin and Lisa Cullen.

8 The Company will update the factor in the PBR formula as part of its annual  
9 compliance filing to be submitted on September 15th of each year. Within that filing,  
10 the Company will file documentation in support of the costs incurred for the  
11 demonstrations and report on the progress towards the identified objectives described  
12 further below. Any stakeholder feedback received upon authorization from the  
13 Department to proceed with the execution of the demonstration projects in this  
14 proceeding will also be presented in each annual filing.

15 **Q. Has the Department set standards of review regarding the authorization of**  
16 **demonstration programs?**

17 A. Yes. The Department’s approval of demonstration projects is based on assessment of  
18 reasonableness of the size, scope, scale of the specific project (and associated budget)  
19 in consideration of the likely benefits to be achieved. NSTAR Electric Company and  
20 Western Massachusetts Electric Company, each d/b/a Eversource Energy, D.P.U. 16-  
21 178, at 26 (2017). It is anticipated that demonstration projects will have measurable  
22 savings and benefits, which means that the projects are not required to be cost-effective

1 at the initial testing and evaluation stages. Id. at 28. Testing and evaluation is intended,  
2 in part, to determine whether the offering, once scaled, will be cost-effective. Id. Thus,  
3 while a showing of cost-effectiveness is not required for a demonstration project,  
4 project descriptions and appropriate analyses must support the potential of the project  
5 to deliver net benefits in the future; there is no assumption of future net benefits. Id.  
6 The demonstration projects must be fully supported by detailed program descriptions  
7 as a means for the Department and stakeholders to evaluate the reasonableness of size,  
8 scope, and scale of the proposed demonstration. Id. at 29-30.

9 In D.P.U. 16-178, the Department acknowledged that as the demonstration planning  
10 and study efforts evolved, the companies would implement any cost-effective programs  
11 and develop targets and benchmarks related to the demonstrations through the energy  
12 efficiency programs. Id. at 25-26. The Department established that demonstration  
13 projects should be designed to test the ability of the projects to deliver cost-effective  
14 benefits to customers. Id. As described below, the Company's projects are sufficiently  
15 detailed to provide the Department with enough information to evaluate the  
16 reasonableness of size, scope, and scale of the proposed demonstrations.

17 For each of the demonstration proposals, described in the sections that follow, the  
18 Company provides the following information: (1) a description of the demonstration  
19 project and the key research questions that the Company seeks to answer; (2) a  
20 description of the target customers and an estimated number of customer participants;  
21 (3) a proposed budget; and (4) an estimated timeline.

1           **B.       Gas Demand Response Demonstration Project**

2   **Q.       Why is the Company interested in conducting a demonstration project to explore**  
3   **natural gas demand response in Massachusetts?**

4   A.       In the context of efforts to expand and realize environmental goals in Massachusetts, a  
5           gas demand response program would offer an additional tool for managing the energy  
6           needs of the region. The Company has started to explore how these types of programs,  
7           which have been conducted in nearby states in various forms, could be beneficial for  
8           the Commonwealth. If the demonstration program successfully reduces overall  
9           demand for natural gas, there will be a corresponding decrease in greenhouse gas  
10          emissions, which is important to customers and to the Commonwealth in achieving its  
11          greenhouse gas reduction goals.

12   **Q.       What is natural gas demand response?**

13   A.       Demand response programs are common in the electricity sector and have been  
14           deployed in the context of the Massachusetts Energy Efficiency plans to help electricity  
15           customers monitor and manage their energy usage for several years. As more homes  
16           and businesses install smart thermostats and other controls, gas demand-response  
17           programs are emerging as a possible avenue to mitigate natural gas demand spikes and  
18           infrastructure constraints.

19           In a general sense, gas demand response programs function similar to electric demand  
20           response programs. Customers reduce their consumption in response to a signal they  
21           receive from the utility for a set time period. In exchange for temporarily reducing

1           their usage, the utility pays the customer an incentive.

2   **Q.    Has Eversource Energy consulted with other utilities running similar programs?**

3   A.    Yes.  Representatives from Eversource Energy have consulted with Consolidated  
4          Edison of New York, National Grid of New York, and Southern California Gas on their  
5          experience with gas demand response initiatives.

6   **Q.    Why is the Company making this proposal in this rate case rather than in the**  
7          **context of the statewide energy efficiency program?**

8   A.    A natural gas demand reduction project currently cannot be screened for cost  
9          effectiveness for possible inclusion in the energy efficiency program.  This is because  
10         many of the benefits that the natural gas demand reduction demonstration project would  
11         be aimed at testing have not been quantified.  As part of its proposed demonstration,  
12         the Company would embark on a study that will take a more holistic look at the benefits  
13         that gas demand response is likely to produce.  This study could be done individually  
14         by the Company or as part of a statewide or regional effort, similar to the Avoided  
15         Energy Supply Cost Study that is typically filed with each Energy Efficiency plan.

16         The Company's initial hypothesis is that there are additional benefits that should be  
17         explored and quantified (i.e., gas capacity and distribution benefits), so it is appropriate  
18         to conduct a demonstration project outside the context of the Energy Efficiency  
19         program.  If this project is successful and the Company is able to better quantify the  
20         benefits produced by this demonstration project, then the Company could consider

1 moving this offering into the Energy Efficiency program in the future under the  
2 applicable standards for that program.

3 **Q. What are the goals of the demonstration project?**

4 A. The overarching goal of the proposed demonstration project is to see if it is possible to  
5 achieve multiple operational objectives through a gas demand response offering. These  
6 objectives include:

- 7 • Reducing demand during peak usage periods
- 8 • Reducing the requirements on the LDCs supply portfolio thereby making  
9 interstate pipeline capacity available to market;
- 10 • Reducing imported LNG requirements;
- 11 • Lowering on-system LNG output; and
- 12 • Reducing the amount of supplemental winter season supplies that the  
13 Company needs to buy in the future.

14 The Company is pursuing these objectives to better understand if it is possible to use  
15 gas demand response to accomplish the following:

- 16 • Reduce LNG vapor use during peak times;
- 17 • Reduce usage at specifically targeted laterals; and
- 18 • Reduce interstate pipeline gas usage during peak times and over 24-hour  
19 periods as pipelines have become more restrictive.

20 A key goal of this demonstration project is to test whether gas demand response is  
21 feasible at scale and to determine the associated benefits. This goal also includes  
22 testing customer acceptance of a gas demand response type of program.



1 **Q. Please describe the technical hypotheses that will be tested as part of this**  
2 **demonstration project.**

3 **A.** The Company has identified three technical hypotheses for this demonstration project.

4 **Technical Hypothesis #1** – Reducing the need to use LNG during cold days:

- 5 • Reducing peak hourly demand would offset the need to use interstate  
6 pipeline/marginal supply (e.g., LNG) in an area to provide support in  
7 another area with relatively limited resources.
- 8 • LNG is a limited resource (limited to storage tank capacity) during the  
9 winter period as it is filled during the ‘off-season’.
- 10 • Reducing LNG vaporization during peak demand hours could extend the  
11 number of days LNG is available for supply and system support.

12 **Technical Hypothesis #2** – Targeting Areas of Need - Single feed systems:

- 13 • Pipeline and/or distribution laterals tend to be “single feed” systems that are  
14 more susceptible to capacity constraints and pressure issues during peak  
15 demand periods and getting supply to them can be more costly.
- 16 • Targeting laterals/relatively more constrained areas may get the best cost  
17 benefit ratio as well as increasing the reliability of a “closed” system.
- 18 • Other parts of the system might have more potential supply and capacity  
19 solutions (The Company would not initially pursue those areas).

20 **Technical Hypothesis #3** – Reducing gas usage during peak hours and over the day:

- 21 • Pipeline capacity needs to be capable of meeting peak demand both in terms  
22 of volume of commodity but also capacity of the pipeline.
- 23 • Capacity contracts are designed based upon the maximum daily quantity  
24 and, as a result, must be large enough to meet 24 hours of demand.
- 25 • Shifting gas usage throughout the day may help address hourly capacity  
26 constraints but wouldn’t necessarily reduce the total volume of gas that  
27 needs to be purchased for the day as pipelines are contracted for on a daily  
28 basis.

1 **Q. What questions are you trying to answer by testing the technical hypotheses listed**  
2 **above as part of this demonstration?**

3 A. There are several key questions the Company expects to answer through this  
4 demonstration project, including:

- 5 • Is it possible to reduce the need for marginal gas supplies on the coldest  
6 days through gas demand response?
- 7 • Is it possible to use a gas demand response program to target areas of the  
8 pipeline/distribution system that are most prone to congestion and may  
9 require expensive upgrades in the future?
- 10 • Is it possible to use a gas demand response program to alleviate times of  
11 peak demand for a few hours **and** reduce overall usage during the course of  
12 a day?

13 **Q. Are there additional questions the Company expects to answer from the gas**  
14 **demand response demonstration?**

15 A. Yes. In addition to testing the technical hypotheses and corresponding “big picture”  
16 questions listed above, the Company intends to use the gas demand response  
17 demonstration and the corresponding evaluation to help answer the following  
18 questions:

- 19 • What is the appropriate \$/therm incentive level to induce program  
20 participation? Is there a minimum total project incentive value needed to  
21 get customers interested?
- 22 • What are the most common strategies employed by customers to reduce gas  
23 usage, both during the times of peak demand and during the course of 24  
24 hours?
- 25 • What are the most common obstacles to customers participating in this type  
26 of program?
- 27 • What, if any, are the impacts on customer comfort?

- 1 • What is the appropriate metering configuration and granularity of data  
2 needed to accurately measure gas reductions?
- 3 • What are the optimal communication and outreach strategies to induce  
4 customer participation?
- 5 • What opportunities exist at customer sites for combining automation and  
6 communication strategies?

7 **Q. Will this demonstration project be subject to independent third-party evaluation?**

8 A. Yes, this demonstration project will be evaluated by a third-party evaluation consultant.  
9 The demonstration project design and subsequent evaluation will be set up to help  
10 answer the questions listed in the sections above. The Company expects to share the  
11 results of this evaluation with other utilities in the Commonwealth through the  
12 appropriate channels.

13 **Q. When will the Company use the results of this demonstration project?**

14 A. The reliability of the gas system is paramount, and as such, the Company intends to  
15 wait until the demonstration project is complete and it has the opportunity to fully  
16 analyze the results of the accompanying evaluation before it makes a determination as  
17 to whether any changes to its planning, procurement, or operational processes are  
18 warranted.

1   **Q.     How will savings likely be measured?**

2   A.     As mentioned above, the Company anticipates utilizing an independent third-party  
3           evaluation firm to assist in calculating and confirming program savings. One likely  
4           approach for calculating savings is using hourly interval data to develop a baseline  
5           using previous similar days and comparing usage during an event day to the baseline.  
6           For example, the baseline may be developed by using the highest average usage during  
7           five of the last ten days from 6:00 a.m. to 9:00 a.m. Certain days would be excluded  
8           from the baseline calculation such as holidays, days when other demand response  
9           events have been called, any days with abnormally low usage, or weekends if the event  
10          happens on a weekday (or weekdays if the events happen on a weekend). The Company  
11          would work with the third-party evaluation firm to determine if any in-day weather  
12          adjustments were appropriate.

13   **Q.     What are the expected benefits of the natural gas demand reduction**  
14          **demonstration project proposed by the Company?**

15   A.     As part of this demonstration, the Company would seek to study and quantify the  
16          potential benefits of a gas demand response program, including:

- 17           •   Avoided costs associated with pipeline/infrastructure/supply contract costs;
- 18           •   Increasing flexibility of existing assets by reducing straining on existing assets  
19               during peak periods;
- 20           •   Reduced need for natural gas, including LNG during peak periods; and
- 21           •   Freeing up capacity or creating a “cushion” to allow for system optimization.

As mentioned above, the Company will work with a third-party evaluation firm to:  
(1) answer the research questions associated with this project that are described above;  
and (2) quantify the project benefits in two ways:

1. What is the actual impact of the gas demand response program, i.e., how much gas was actually saved and when, for both the residential and C&I sectors?
2. What is the conceptual monetary value of those savings – develop a value similar to those values produced in the Avoided Energy Supply Cost study that could be used to screen future projects?

It should be noted that it may be necessary to use two different evaluation firms in order to meet the evaluation objectives listed above.

**Q. Please describe in more detail how the natural gas demand reduction demonstration project would work**

A. The Company is proposing to include both a Commercial & Industrial (“C&I”) component and a residential component within the gas demand demonstration project. Within the C&I sector, the Company is proposing a technology agnostic approach where customers will be asked to reduce gas usage during certain time periods. This will be a pay-for-performance program design where customers will be paid an incentive based on their actual measured reduction during the defined time period. The Company will set up a tiered incentive structure where the bulk of the incentive is earmarked for performance during the defined time period, but a bonus will be paid for

1 customers that can reduce their gas usage over a 24-hour period. C&I customers can  
2 work with curtailment service providers (“CSPs”). CSPs provide demand response  
3 equipment and services. In return for their services, customers split their incentive  
4 payment with them. The split is determined through negotiations with the CSP. There  
5 is not a requirement to use a CSP to participate or earn incentives, but their services  
6 often reduce operational impacts and can provide additional valuable information about  
7 a customer’s energy use.

8 The key components of the C&I program would be as follows:

- 9 • Technology: Technology agnostic approach but liquid fossil fuel backup  
10 system would not be accepted. Anticipated gas load reduction measures include  
11 using electric backup heat source like a heat pump, change industrial processes,  
12 curtail discretionary loads, reduce Combined Heat and Power generation, or  
13 changing heating or hot water set points.
- 14 • Dispatch Trigger Threshold: Temperature based threshold.
- 15 • Number of Anticipated Dispatches: 3-8 calls per season.
- 16 • Customer Notification: At least day ahead notice.
- 17 • Timeline When Events Can Be Called: November, December, January,  
18 February, March.
- 19 • Dispatch Conditions: Measured reduction between the hours of 6:00 a.m. and  
20 9:00 a.m. during event days with a bonus paid for a net reduction over the 24-  
21 hour gas day.
- 22 • Eligibility Requirements: Must take firm gas delivery service from NSTAR  
23 Gas. Cannot be interruptible service.
- 24 • Recruitment: Through approved CSPs or directly through Eversource Energy  
25 account executives.
- 26 • Minimum Election for Inclusion: Minimum of 50 therms of curtailable gas

- 1           • Base Incentive Level: \$45/therm/season (6:00 a.m. to 9:00 a.m.)—all based on  
2           pay for performance.
- 3           • Bonus Incentive: \$2/therm/qualifying event (all day reduction if base  
4           participation met for that event).
- 5           • Metering/Measurement: Need to be able to collect at least hourly interval data.

6           The residential component of the demand response program will leverage experience  
7           gained from the residential electric demand response program design. The Company  
8           will contract for a software platform to enroll customers that have wi-fi thermostats and  
9           gas heating. During gas demand response events, the temperature on the customer's  
10          thermostat will be reduced by a couple of degrees for a few hours. Customers will have  
11          the ability to opt-out of an event if necessary. The Company will also institute a  
12          minimum temperature threshold that the temperature in a house cannot go under.

13          The key components of the residential program are as follows:

- 14           • Technology: Wi-fi thermostat-based demand response.
- 15           • Dispatch Trigger Threshold: Temperature based threshold.
- 16           • Number of Anticipated Dispatches: 3 to 8 calls per season
- 17           • Customer Notification: At least day ahead notice.
- 18           • Timeline When Events Can Be Called: November, December, January,  
19           February, March.
- 20           • Dispatch Conditions: 1 to 3-degree setback for 2 to 8 hours. Minimum  
21           temperature will not go below 64 degrees at night and 68 degrees during the  
22           day. Dispatch will occur from 6:00 a.m. to 9:00 a.m.
- 23           • Eligibility Requirements: NSTAR Gas customer with a gas furnace or boiler  
24           connected to a wi-fi thermostat.

- 1                   • Dispatch Platform: Contracted Software Platform
- 2                   • Recruitment: Similar to electric demand response, will leverage thermostat
- 3                   manufacturer marketing channels through in-app notifications and emails.
- 4                   • Enrollment: Through Contracted Software & OEM platforms.
- 5                   • Incentive: \$25 to sign up and \$20 per heating season (Nov-Mar) payment.
- 6                   • Metering/Measurement: Prescriptive, based on EM&V results.

7   **Q.   How does the Company plan to recruit participants for the demonstration**  
8   **program and has the Company done any outreach thus far?**

9   A.   For the residential part of the program, customers will be recruited through wi-fi  
10       thermostat manufacturer marketing channels such as in-app notifications and emails.  
11       This approach has been successful in the residential electric demand response program.  
12       For the C&I part of the program, customers will be recruited though approved CSPs or  
13       directly through Eversource Energy account executives.

14   **Q.   When do you anticipate calling events?**

15   A.   The Company anticipates calling events between 6:00 a.m. to 9:00 a.m. when system  
16       hourly throughput is typically the highest during winter months.





**Q. Please describe the equipment that will be needed and the investments that will be necessary to enable the natural gas demand reduction demonstration project?**

A. The Company anticipates utilizing existing metering equipment where possible. The Company currently has a type of interval meter for its largest customers. For the purpose of this demonstration, the Company would add a small piece of hardware at the customer site that could read pulse outputs from the meter and would have an embedded mini cell modem in a National Electrical Manufacturers Association rated enclosure. The corresponding software provides a repository of the interval data and some minimal graphing capabilities. This configuration allows the customer data to be pushed into the cloud where it would be accessible for download by the Company and provides more real time access to the gas interval data. The Company is providing a best estimate of the metering costs as part of this proposal, but these costs may increase

1 if the Company is not able to leverage its existing metering infrastructure as currently  
2 envisioned.

3 For the residential portion of this demonstration project, the Company would leverage  
4 the existing software platform that has already been procured through the electric  
5 demand response programs and implemented in the Energy Efficiency program. There  
6 is a fixed cost associated with the software platform paid through the Energy Efficiency  
7 program regardless of whether a gas demand response program is created and approved  
8 by the Department. Therefore, the Company proposes that the fixed cost remain in the  
9 Energy Efficiency program and any incremental variable software or vendor costs for  
10 running a gas demand response program will be recovered through rates.

11 **Q. What is the current estimated cost for the natural gas demand reduction**  
12 **demonstration project?**

13 A. The estimated costs for the natural gas demand reduction project are as follows:

<b>ANTICIPATED RESIDENTIAL COSTS</b>			
<b>Costs</b>	<b>Year 1</b>	<b>Year 2</b>	<b>Year 3</b>
Sign Up Incentive	\$75,000	\$0	\$0
Seasonal Incentive	\$60,000	\$57,000	\$54,150
OEM Costs (per device)	\$105,000	\$99,750	\$94,763
OEM Fixed Set Up Costs	\$25,000	\$0	\$0
<b>Subtotal:</b>	<b>\$265,000</b>	<b>\$156,750</b>	<b>\$148,912.50</b>
Software Platform Variable Costs	\$26,500.00	\$15,675.00	\$14,891.25
Software Platform Fixed Cost	\$0	\$0	\$0
Internal Labor .5 FTE	\$100,000	\$100,000	\$100,000
<b>Total Residential Costs</b>	<b>\$391,500</b>	<b>\$272,425</b>	<b>\$263,804</b>

<b>ANTICIPATED C&amp;I COSTS</b>			
<b>Costs</b>	<b>Year 1</b>	<b>Year 2</b>	<b>Year 3</b>
Base Customer Incentives	\$162,000	\$162,000	\$162,000
Bonus Customer Incentive	\$18,000	\$18,000	\$18,000
Metering Costs	\$96,000	\$96,000	\$96,000
Internal Labor .5 FTE	\$100,000	\$100,000	\$100,000
<b>Total Costs</b>	<b>\$376,000</b>	<b>\$376,000</b>	<b>\$376,000</b>

<b>ANTICIPATED TOTAL COSTS</b>			
<b>Costs</b>	<b>Year 1</b>	<b>Year 2</b>	<b>Year 3</b>
Customer Incentives	\$315,000	\$237,000	\$234,150
Meter Data and Collection	\$96,000	\$96,000	\$96,000
Admin	\$356,500	\$315,425	\$309,653.75
Evaluation	\$250,000	\$0	\$0
<b>Annual Total</b>	<b>\$1,017,500</b>	<b>\$648,425</b>	<b>\$639,804</b>
<b>3 Year Total</b>		<b>\$2,305,729</b>	

1 **Q. How many participants do you expect with the estimated budget above?**

2 A. The Company anticipates that it can recruit up to 3,000 residential program participants  
3 and approximately 50 C&I customers. However, for C&I customers, there must be  
4 some flexibility in the total number of customers in order to get the desired level of  
5 savings. As the demonstration project is rolled it out, it may be necessary to enroll  
6 fewer customers but leverage higher savings per customer in order to reach the desired  
7 savings levels.

8 **Q. How does the Company propose to report on the progress and results of the**  
9 **natural gas demand reduction project?**

10 A. As noted above, the Company will file reports annually on the progress of the  
11 demonstration project and any stakeholder feedback received upon authorization from

1 the Department to proceed with the execution of the demonstration projects in this  
2 proceeding.

3 **Q. Was gas demand response considered as part of the 2019-2021 Energy Efficiency**  
4 **Plans?**

5 A. Yes, gas demand response was considered for possible inclusion in the 2019-2021  
6 Energy Efficiency plans but ultimately rejected by the Program Administrators due to  
7 concerns over cost-effectiveness, safety, and operational effectiveness concerns.

8 **Q. What is different about this proposal that makes it appropriate to test gas demand**  
9 **response at this time?**

10 A. The Company still does not know if offering gas demand response is cost-effective but  
11 as noted earlier, the Company is committed to developing the values necessary to  
12 determine if gas demand response can be cost effective. This will be done in two ways:

13 (1) The Company will determine the level of savings from a gas demand  
14 response program over a defined event horizon and over the course of 24 hours.

15 (2) The Company will support a study that quantifies the dollar values  
16 associated with reducing gas usage at peak times.

17 To alleviate concerns around safety, the Company will institute program parameters  
18 that ensure temperatures in homes do not fall below a certain threshold, which will be  
19 set at 68 degrees during the day and 64 degrees at night per 105 CMR 410.201.<sup>9</sup>

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<sup>9</sup> Massachusetts law about winter heating, <https://www.mass.gov/info-details/massachusetts-law-about-winter-heating>.

1 From an operations perspective, the Company is proposing a program design that is  
2 unique in that it leverages the best practices from other program designs from across  
3 the country. This includes an incentive design that encourages significant reductions  
4 during a short time window and a bonus incentive for reducing gas demand over the  
5 course of the day. The Company is proposing to not allow liquid fossil backup heating  
6 sources as a compliance mechanism so that it can ensure there is an overall beneficial  
7 environmental impact.

8 **C. Geothermal Network Demonstration Project**

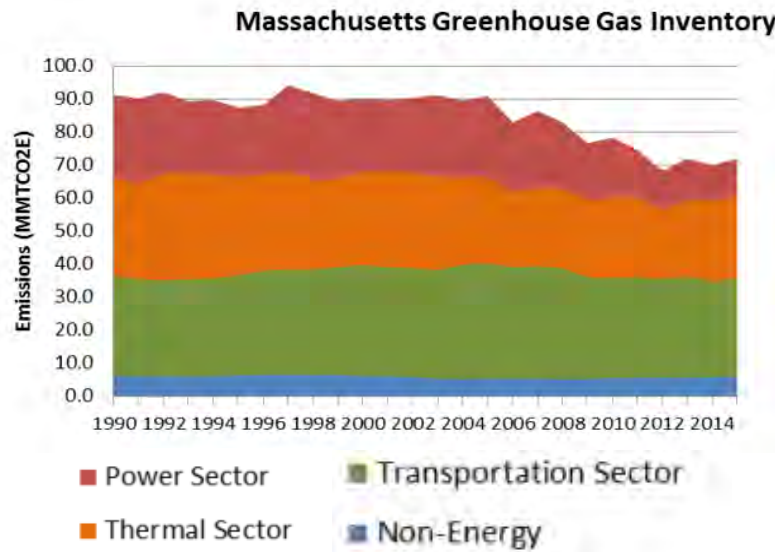
9 **Q. What is a Geothermal Network?**

10 A. A Geothermal Network is the use of geothermal energy to provide heating and/or  
11 cooling to individual and commercial buildings through distribution by pipes.

12 **Q. Why is it important to explore the potential of a geothermal network at this time?**

13 A. Because geothermal networks provide a low-carbon source of heating, exploring the  
14 potential of a geothermal network is critical as the Commonwealth seeks to reduce  
15 greenhouse gas emissions pursuant to the Global Warming Solutions Act. As shown  
16 in the figure below, emissions from the power sector in Massachusetts have declined  
17 over time while emissions from the thermal sector have remained relatively flat.  
18 Testing the viability of geothermal networks at this time will allow the Company to  
19 better understand if this type of offering is scalable and provide the Company with real  
20 world experience of constructing and maintaining these networks. The Company will  
21 share its experiences with interested stakeholders and its peer utilities in the

1 Commonwealth so that the state can benefit from the learnings from the proposed  
2 demonstration project.



3 **Q. Please provide an overview of geothermal technology and more specifically**  
4 **geothermal networks.**

5 A. At a high level, geothermal technologies take advantage of the relatively stable  
6 temperature of the ground to provide heating and cooling. A heat exchanger extracts  
7 heat out of the ground in winter and extracts heat out of buildings and pushes it into the  
8 ground in summer. Geothermal systems tend to be very efficient, with Coefficients of  
9 Performance of 300 to 600 percent. That means that one unit of electricity used to drive  
10 the heat pump can extract three to six times the energy from the ground.

11 To deliver space heating and cooling, geothermal systems transfer energy between a  
12 building and the earth by circulating water (or a non-freezing liquid) to a series of

1 underground piping. This piping can be placed in long horizontal trenches and/or deep  
2 vertical wells ranging between 300 and 1500 feet deep. Local geological conditions,  
3 space availability, costs, permitting and other factors will influence the selection and  
4 design of the system. Because vertical systems require significantly less space when  
5 compared to horizontal systems, they are expected be the primary design to service a  
6 broad range of customers. Proper design requires consideration for both peak and  
7 annual building heating and cooling loads as well as multi-year modeling of water and  
8 ground temperatures.

9 Geothermal systems distribute heating and cooling throughout a building by circulating  
10 warm air, cold air, and water within the building. This is similar to how fossil fuel  
11 furnaces and boilers function, although geothermal systems operate in different  
12 temperature ranges. To accommodate these operating temperatures, existing interior  
13 building equipment may need upgrading and/or replacement to provide adequate  
14 heating and cooling during the coldest and warmest days of the year.

15 **Q. Generally speaking, what are the expected benefits of a geothermal network?**

16 A. The Company expects that there would be many benefits of a geothermal network.  
17 Geothermal networks and ground source heat pumps (“GSHP”) would provide  
18 customers with an additional choice for heating besides natural gas or delivered fuels.  
19 The Company is seeking to test if geothermal heating could be an alternative for  
20 customers that are either too far away from a gas pipeline or simply do not want to use

1 natural gas. From a customer perspective, geothermal networks and GSHPs could  
2 provide the following benefits:

- 3 • Less costly ongoing heating/cooling system;
- 4 • A reliable system that does not have components such as a condensing unit  
5 outside of the house;
- 6 • Cleaner, safer, quieter system (no on-site combustion within the house means no  
7 carbon dioxide);
- 8 • Provides both heating and cooling;
- 9 • GSHP equipment is located inside the building so there is an ease of  
10 repair/maintenance and no aesthetic impacts; and
- 11 • Conventional heating and cooling equipment typically has a life expectancy of 5  
12 to 10 years, whereas GSHPs are estimated at 25 years for the inside heat pumps  
13 and 50+ years for the ground loop.

14 The Company has reviewed estimates that geothermal networks and GSHPs can reduce  
15 carbon emissions by up to 60 percent for an average residential customer. Utilizing  
16 geothermal networks would provide the Commonwealth with an additional avenue to  
17 help meet its aggressive carbon reduction goals.

18 **Q. Please provide an overview of the Company's proposed geothermal network**  
19 **demonstration project.**

20 **A.** The Company is proposing to test geothermal networks in a series of targeted scenarios.  
21 These scenarios include establishing geothermal networks at multi-family buildings, in  
22 mixed-use residential and commercial areas, and residential neighborhoods.

23 These scenarios are reflective of what the Company assumes it would encounter if this  
24 offering was brought to scale, and as such, it is important that the demonstration project  
25 cover these different types of opportunities. The Company proposes an initial three-



1 year term for the demonstration projects so that the Company can gather enough data  
2 to make a determination as to whether or not it should continue to offer geothermal  
3 networks to its customers. It should be emphasized that, although the Company  
4 believes that the scenarios listed below are appropriate as envisioned, it is critical to  
5 retain flexibility while rolling out and executing the demonstration project so that the  
6 Company can target different opportunities if appropriate, adapt to actual experience,  
7 and address case-specific circumstances.

8 **Scenario 1** of the demonstration project would seek to evaluate a large residential load  
9 profile in a dense geographic footprint such as a geothermal network that would serve  
10 a single multi-family building. For the purposes of this demonstration, the Company  
11 would like to target a low-income multi-family building. Part of this aspect of the  
12 demonstration project would require the Company to determine what type of  
13 geothermal network would be most appropriate given the geographic constraints of a  
14 single building and whether it would be necessary to stay within the property boundary  
15 of the building or if it would be necessary to go into the public way.

16 **Scenario 2** of the demonstration project would seek to evaluate a large mixed-use  
17 profile such as a geothermal network in a dense urban environment that comprised both  
18 residential and C&I customers or in an area with different types of C&I customers with  
19 different heating needs. Seeking out an area that has both residential and C&I  
20 customers or different types of C&I customers would allow the Company to better  
21 understand if there are increased efficiencies by having customers with varying heating

1 and cooling needs on the same geothermal network.

2 **Scenario 3** of the demonstration project would seek to evaluate a large residential load  
3 profile in an expanded geographic footprint such as a geothermal network in a  
4 residential neighborhood. Geothermal networks that support single family homes are  
5 expected to have different requirements than in the other scenarios due to a larger  
6 distance expected between each home. The Company would explore opportunities to  
7 develop geothermal networks that need to be placed in public right of ways and in areas  
8 where it may not be necessary to go through public right of ways. The Company could  
9 possibly utilize shared space between houses or go through streets if necessary.  
10 Depending on the opportunity, the Company may be required to obtain easements from  
11 the property holders or permits to perform construction in public streets, or to consider  
12 alternative configurations depending upon the number of customers, the distance  
13 between structures, load profiles, and other unanticipated or unforeseeable  
14 circumstances. The goal of the demonstration projects is to closely mimic the type of  
15 scenarios that the Company is likely to face if the service is offered at scale.

16 In each of these scenarios, the Company would be responsible for contracting with the  
17 well drilling teams, the companies that are responsible for setting up and installing the  
18 pipes for the geothermal network, and for maintaining the appropriate temperature and  
19 pressure within the pipes.

20 The three-part demonstration project will provide the Company with comprehensive

1 field data in the type of scenarios it is most likely to encounter at a more wide-spread  
2 scale, specifically multi-family buildings, mixed-use residential and commercial, and  
3 predominately residential neighborhoods.

4 **Q. What is the proposed timeline for construction and data collection?**

5 A. The Company anticipates that it could substantially complete customer acquisition,  
6 zoning, engineer/contractor selection, technical design, ground loop and pumping  
7 station construction, geothermal network testing and commissioning, and customer  
8 HVAC installation and retrofits within approximately 16-18 months. An illustrative  
9 project Gantt Chart is included as Exhibit ES-PMC/MRG-2. This timeline is a key  
10 assumption that would be tested as part of the demonstration. Data collection and  
11 measurement and verification activities would follow at the completion of the  
12 geothermal network construction and customer HVAC retrofits. It should be noted  
13 that a one-month delay in project approval does not necessarily equate to a one-month  
14 delay in project completion. This is because certain activities such as drilling or street  
15 construction typically cannot happen during certain winter months.

16 **Q. How does the Company plan to identify locations for the geothermal network**  
17 **demonstration project?**

18 A. The Company would use various means it has available to identify appropriate  
19 locations. For example, the Company expects to leverage its existing relationships with  
20 LEAN, ABCD, or other agencies to identify a low-income multi-family building that  
21 would be appropriate for this demonstration. The Company could also leverage its

1 account executives and gas sales team to identify geographic locations or specific  
2 customers that may be good candidates for this demonstration project.

3 **Q. Please describe the investments that will be necessary to enable the geothermal**  
4 **network demonstration project?**

5 A. For the purposes of this demonstration project, the Company anticipates investments  
6 in the drilling of the wells, the installation of pipes and ongoing O&M costs (including  
7 energy costs), and the installation of the necessary heat pump equipment. The  
8 Company expects typical costs and equipment for the geothermal networks to include  
9 pumps, boilers, cooling towers, piping, controls, and enclosures. The Company  
10 expects typical costs and equipment at the customer site to enable this demonstration  
11 project to include ground source heat pumps, duct work upgrades (if necessary), and  
12 increased weatherization. The Company would also be responsible for the upkeep and  
13 maintenance of the geothermal networks outside of any individual customer's physical  
14 facility for the duration of the three-year demonstration project. If this service was  
15 offered more broadly, the installation of the heat pump equipment would be located  
16 inside of a customer's facility and would be the responsibility of the customer. In order  
17 to expedite the timeline for getting projects in the ground, the Company is proposing  
18 as part of this demonstration project only, to fund the heat pump equipment in a  
19 customer's home or business.

1   **Q.    What is the proposed ownership model for the assets that will be developed as part**  
2   **of the proposed geothermal network demonstration project?**

3   A.    The Company would propose to own the geothermal networks that are physically  
4       outside the boundary of a customer's building for the duration of the demonstration  
5       project. The Company would not propose to own any of the equipment that would be  
6       inside of a customer's building such as the ground source heat pump. At the end of the  
7       three-year demonstration project, the Company will either retain ownership of the  
8       equipment in the event that it offers geothermal networks as a permanent service option  
9       or ownership of the in-home equipment would revert to customers if the Company does  
10      not continue the service. In either case, the Company is committed to work with each  
11      individual customer, on a case-by-case basis, to ensure their thermal needs are met.

12   **Q.    What is the current estimated cost for the geothermal network demonstration**  
13   **project?**

14   A.    The following costs are the Company's best estimates, which were developed by  
15       meeting with geothermal network installers, reviewing literature from other projects  
16       from across the country and talking to peer utilities. The estimated costs are inclusive  
17       of drilling wells, installing appropriate piping and pumps, and the ground source heat  
18       pumps within a customer's facility or home. These estimated costs also include the  
19       required internal labor to run the demonstration project and the evaluation necessary to  
20       determine if the demonstration was successful. These estimates are three-year costs  
21       but it should be noted that actual site characteristics will have impacts on the final costs.

1 Detailed cost estimates are included as Exhibit ES-PMC/MRG-3.<sup>10</sup>

Construction Cost	\$10,179,000
Direct Staff and Overhead Expenses	\$1,073,311
O&M and Energy Expenses	\$536,734
O&M Expenses, Maintenance and Performance Monitoring	\$721,600
Third-Party Evaluation	\$300,000
<b>Total Project Cost</b>	<b>\$12,810,645</b>

2 These estimates may be further disaggregated by the different scenarios described  
3 above. Specifically, the estimated costs are disaggregated into more detail as follows:

4 **Scenario 1: Multi-family Building**

Construction Cost	\$1,692,000
Direct Staff and Overhead Expenses	\$165,125
O&M and Energy Expenses	\$82,714
O&M Expenses, Maintenance and Performance Monitoring	\$111,015
<b>Total Project Cost</b>	<b>\$2,050,854</b>

5 **Scenario 2: Dense Urban Environment/Mixed Use Area**

Construction Cost	\$7,506,000
Direct Staff and Overhead Expenses	\$825,624
O&M and Energy Expenses	\$412,482
O&M Expenses, Maintenance and Performance Monitoring	\$555,077
<b>Total Project Cost</b>	<b>\$9,299,182</b>

<sup>10</sup> The conceptual design estimates provided by the Company here may vary from pre-construction engineering design estimates. If approved by the Department, the Company plans to develop a detailed pre-construction engineering design estimate.

1           **Scenario 3: Residential Neighborhood/Community**

Construction Cost	\$981,000
Direct Staff and Overhead Expenses	\$82,562
O&M and Energy Expenses	\$41,538
O&M Expenses, Maintenance and Performance Monitoring	\$55,508
<b>Total Project Cost</b>	<b>\$1,160,608</b>

2           In addition, having a third-party evaluator review the project and its effectiveness  
3           would be beneficial. The estimated cost for the evaluation is \$300,000.

4           **Q. How does the Company plan on procuring the assets associated with the**  
5           **geothermal network demonstration project?**

6           A. The Company anticipates a competitive solicitation process in order to procure and  
7           construct the assets associated with the geothermal network demonstration project.

8           **Q. What are anticipated areas of study related to the geothermal network**  
9           **demonstration project?**

10          A. The Company has developed several high-level questions that are critical to determine  
11          whether it should offer geothermal networks as a service on an ongoing basis. The  
12          Company would gather data in an effort to answer the following high-level questions:

- 13               ▪ Is it feasible to provide geothermal wells/loops and GSHPs as an alternative to  
14               extending gas service?
- 15               ▪ What is the appropriate financial and business model?
- 16               ▪ What is the appropriate rate structure and metering infrastructure?
- 17               ▪ How does the Company leverage existing utility expertise and apply it to new  
18               area?
- 19               ▪ What is required to maintain a GSHP system of wells? How to measure and  
20               maintain well field performance?

- Is a GSHP system sufficient for all heating and cooling needs or is a supplemental system required?
- Can the Company leverage existing trenching or other construction activities that are being undertaken as part of normal gas or electric operations in order to install geothermal equipment?

To answer the questions listed above, the Company would propose to gather data in the following areas with the associated data points.

Topic Area	Data Points to Collect
<b>Validate Installation and Costs</b>	<ul style="list-style-type: none"> <li>• System installation costs</li> <li>• Ongoing O&amp;M costs</li> </ul>
<b>Customer Acceptance</b>	<ul style="list-style-type: none"> <li>• Customer Satisfaction surveys</li> <li>• Customer comfort</li> </ul>
<b>Carbon Reductions</b>	<ul style="list-style-type: none"> <li>• Emission reductions</li> <li>• System performance</li> </ul>
<b>Technology Performance</b>	<ul style="list-style-type: none"> <li>• System performance</li> <li>• Changes in customer energy consumption</li> </ul>
<b>Cost Savings</b>	<ul style="list-style-type: none"> <li>• Changes in customer heating and cooling costs</li> </ul>

**Q. In addition to the data points above, are there specific data points the Company is seeking to collect that would allow it to better understand the requirements to deploy geothermal networks at scale?**

**A.** Yes, in addition to the data points listed above, the Company is interested in better understanding the specific data points below.



Data Point	Significance & Learning	How Measured / Collected
Ground loop water supply temperatures (°F) to buildings; seasonal variations	Determine appropriate and acceptable seasonal variations in wellfield temperatures given customer-side equipment requirements	Btu and temperature meters on the ground-loop heat exchanger's supply and return connections; heat flows and temperatures logged and stored every hour throughout operational life of project
Ground loop water supply temperatures (°F) to buildings; year-over-year comparisons	Assess the need for supplemental heating and cooling equipment ( <u>i.e.</u> , cooling tower and boiler) in order to maintain the effectiveness of the ground loop throughout its operational life	Btu and temperature meters on the ground-loop heat exchanger's supply and return connections; heat flows and temperatures logged and stored every hour throughout operational life of project
Ground loop delta T (°F) between return and supply over time	Study the allowable tolerance for delta T based on customer's equipment ratings, performance, etc.	Btu and temperature meters on the ground-loop heat exchanger's supply and return connections; heat flows and temperatures logged and stored every hour throughout operational life of project
Cost / time required to charge the wellfield (if needed to balance the wellfield temperature)	Best practices for cost-effectively, sustainably charging the wellfield (e.g. during nighttime off-peak hours if an electric boiler on a TOU rate structure)	Boiler trends (supply/return temperatures, fire rate, flow) logged on an hourly basis and stored throughout operational life of project
Ground loop water flow (GPM) over time	Assess the flow requirements of the system during varying climate conditions; identify any central flow imbalances ( <u>i.e.</u> , leaks)	Flow meters on the ground-loop heat exchanger's supply and return connections; water flows (GPM) logged and stored every hour throughout operational life of project
Addition of make-up water/glycol (gallons) over time (if required due to leaks, flushing, etc.)	Assess the typical volume and cost requirements of keeping the system full of working fluid	Consumption meter (gallons) on the make-up system; log of glycol purchases, if applicable

Data Point	Significance & Learning	How Measured / Collected
Run-time and electricity consumption (hours and kWh) of central loop infrastructure	Better understand the operational load profile and cost of the central pumping system	Trends programmed for each central pump
Cost of customer building-side HVAC installation (maximum, minimum, median, average)	Better understand (and, in the future, advise on) the cost to install or retrofit existing customer-side HVAC systems to function with a community ground loop; understand cost range across system types	Log using invoiced cost for each customer's system
Cost of annual customer-side preventative maintenance and unscheduled repairs	Better understand (and, in the future, advise on) the customer-side maintenance and repair costs to be incurred when connecting to a community ground-loop	Log using invoiced cost for each customer's system
Amount of water quality impact / scale buildup (from both Company and customer sides of loop)	Understand the tendency of scale to occur and whether condenser water should be provided directly to customers or via a heat exchanger; determine who would own the heat exchanger	Monthly water quality tests (PPM, scale, etc.) in two locations within the central loop as well as at two randomly-selected customer connections
Occupant comfort / space conditioning	Understand customers' satisfaction levels with the GSHP condenser water service	Surveys
Timeframes	Better understand time requirements for customer acquisition, equipment and labor procurement, and construction activities across a range of installation types	Information logged during course of project management

1 **Q. What are the expected benefits of the specific geothermal network demonstration**  
2 **project proposed by the Company?**

3 A. Many of the expected benefits of a geothermal network demonstration project have  
4 been listed above. This demonstration project specifically will allow the Company to

1 obtain first-hand operational experience on how to construct and maintain geothermal  
2 networks. It will allow the Company to become familiarized with the geothermal  
3 vendor ecosystem. The Company will be exposed to operating geothermal networks  
4 in the Massachusetts-specific climate, which will also allow the Company to  
5 understand if GSHPs can provide all of the heating and cooling needs of a customer  
6 while maintaining an appropriate level of customer comfort.

7 **Q. Please describe the Company's proposed evaluation plan for the geothermal**  
8 **network demonstration project.**

9 A. The Company will contract with an independent third-party evaluation firm to help the  
10 Company review the success of the demonstration project. The Company will review  
11 the main objectives of the demonstration project with the evaluation firm ahead of time  
12 and lay out the key research questions to be answered in order to ensure that the final  
13 evaluation provided the necessary feedback for the Company to decide if it should offer  
14 this service more broadly. The Company will work with the evaluation vendor  
15 throughout the demonstration project so that the appropriate protocols can be put in  
16 place to ensure that outcomes are accurately measured.

17 **Q. How does the Company propose to report on the progress and results of the**  
18 **geothermal network demonstration project?**

19 A. As noted above, the Company will file reports as part of its annual PBRM filing to  
20 report on the progress of the demonstration project and any stakeholder feedback  
21 received upon authorization from the Department to proceed with the execution of the  
22 demonstration projects in this proceeding.

1    **Q.    Why is this demonstration project appropriate in the context of this case?**

2    A.    Fundamentally, NSTAR Gas provides a service that allows customers to heat their  
3           home or business. Similarly, the provision of a geothermal network would allow  
4           customers to heat their home or business. Both the natural gas business and providing  
5           geothermal networks share common aspects such as:

- 6           ■ Capital intensive – there are large upfront costs for infrastructure;
- 7           ■ Buried/underground infrastructure: trenching, installing pipes in the ground;
- 8           ■ Long lived assets – 30+ year lifespan;
- 9           ■ Regulated service – siting and right of way issues; and
- 10          ■ Monitoring system conditions – pumping, monitoring, and maintaining proper  
11           pressure and temperature in pipes.

12           Due to these similarities, it is appropriate and a natural extension of the natural gas  
13           business to offer—at a minimum—the proposed demonstration project, and if  
14           successful, a more comprehensive offering.

15   **Q.    Would offering geothermal networks through NSTAR Gas help overcome many**  
16   **of the common barriers to more widespread adoption of geothermal networks and**  
17   **ground source heat pumps?**

18   A.    Yes. Many common barriers that currently prevent the more widespread adoption of  
19           geothermal networks and GSHPs may be alleviated if this service is provided by the  
20           utility. Common customer obstacles to installing GSHPs include:

- 21          ■ Large upfront capital costs for the geothermal network;
- 22          ■ Reluctance to spend money on infrastructure when customer might be in space  
23           for limited time period; and

- Maintaining infrastructure outside of the customer's premises.

Each one of these obstacles can be overcome by the utility and in fact many of these issues are commonplace for the existing natural gas business model. The Company frequently tackles projects with large upfront capital costs as it can make investments in capital projects and then rate base those investments. The Company is in the business of owning, operating, and maintaining assets over a long-time period, and as such, does not have similar concerns of a customer that may be in a building for only a limited time period and does not want to invest in a geothermal network. And lastly, the Company has expertise in building and operating infrastructure that might be in public or private right of ways. This includes extensive experience in permitting and obtaining permission to construct in rights of way. This would alleviate a customer's concern about needing to construct or maintain a geothermal network that might span outside of its property boundary.

**Q. Is the Company proposing any new rates as part of this demonstration project?**

A. As part of this demonstration, the Company plans to test how best to charge customers for access to geothermal networks. It is not anticipated that customers would be charged a fee equivalent to the cost of the project but that a nominal rate schedule may be set up to test how best to charge for this new service. Additionally, the Company will consider how best to charge customers for this service in order to make sure that at scale, customers are equitably paying for the service they were receiving.

**V. SCORECARD METRICS**

**Q. Is the Company subject to service-quality requirements and associated penalties under the Department's Service Quality Guidelines?**

A. Yes. The Company is subject to the Department's Service Quality Guidelines ("SQ Guidelines"), which include penalty metrics for performance falling below the requirement benchmarks.

Pursuant to G.L. c. 164, §§ 1E and 1I, all LDCs must file annual service-quality reports with the Department on or before March 1st. Each report compares annual performance by the respective LDC with the Department's service-quality metrics established in Order Adopting Revised Service Quality Standards, D.P.U. 12-120-D (2015) and D.P.U. 12-120-D, Attachment A (2015) ("SQ Guidelines"). The SQ Guidelines establish three penalty measures for LDCs: (1) Class I and Class II Odor Call Response; (2) Service Appointments Kept as Scheduled; and (3) Customer Complaints and Customer Credit Cases.

Under the first measure, the Company must respond to 97 percent of all Class I and Class II Odor Calls in 60 minutes and the Company is subject to a fixed revenue penalty formula if the metric is not met. SQ Guidelines at Sections IV.B.1, V.B.2. The second metric measures the percentage of scheduled Service Appointments met by Company personnel on the same day requested. SQ Guidelines at Section II.A. The Company is subject to a revenue penalty for this metric if performance is below the Company's average performance. SQ Guidelines at Section V.B.3. The third metric measures

1 residential customer contact with the Department, which is categorized by the  
2 Department as a residential Customer Complaint relating to payment and arrearage  
3 management plans, inability to pay, shut-off notices, and terminations. SQ Guidelines  
4 at Sections II.B.2, V.B.3. The Company is subject to a revenue penalty for this metric  
5 if performance is below the Company's average performance.

6 **Q. What is the purpose of scorecard metrics, and why are they helpful to the**  
7 **Department and to the Company's customers?**

8 A. The Company's proposed scorecard metrics are aligned with several of the  
9 Department's policy objectives and will allow the Department and stakeholders to  
10 monitor the Company's progress during the term of the PBR Plan.

11 **Q. Please describe the scorecard metrics that the Company is proposing in this**  
12 **proceeding.**

13 A. The Company is proposing 12 scorecard metrics, organized by three high-level  
14 categories that are summarized in the tables below.

1

<b>SAFETY AND RELIABILITY</b>	
<b>Scorecard Metric</b>	<b>High-Level Summary Description</b>
<b>Emergency Response Rate Within 45 Minutes</b>	The metric will measure the elapsed time from when a report of a gas odor call is received and when a Company representative arrives at the scene. The Company is committing to a target of a 95-percent response within 45 minutes, which <b>exceeds</b> the Department's current requirement.
<b>Total Damages Per 1,000 Tickets</b>	This metric will measure the ratio of the number of times the Company's gas distribution facilities are damaged per 1,000 tickets. The Company is committing to a 10-percent improvement over the baseline by Year Five.
<b>DART Rate</b>	This metric will measure the number of cases resulting in Days Away from Work, Restricted Work Activity, and/or Job Transfer expressed as the number of events per 200,000 hours worked. The Company is committing to a 10-percent improvement over the baseline by Year Five.
<b>Total Grade 2 Leaks Older than 9 Months</b>	This metric will measure the number of Open Grade 2 Leaks older than nine months recorded at the end of the calendar year. The Company is committing to completing 75 percent of Grade 2 leaks in 9 months or less (which is three months faster than statutory requirement).
<b>PSMS Implementation</b>	This metric evaluates the annual implementation of the Pipeline Safety Management System (PSMS), as measured by a third-party assessment.



<b>CUSTOMER SATISFACTION &amp; ENGAGEMENT</b>	
<b>Scorecard Metric</b>	<b>High-Level Summary Description</b>
<b>J.D. Power Survey (Safety &amp; Reliability Factor)</b>	This metric will measure in the Safety & Reliability factor as measured by J.D. Power. The Company is committing to a 23-point improvement in its Safety & Reliability score by Year Five.
<b>Web Satisfaction Survey</b>	This metric will measure improvement in customer satisfaction with on-line tools. The Company is committing to increase this rating to 8.15 out of 10.
<b>Digital Engagement</b>	This metric will measure digital engagement with customers via self-service and alert notifications. The Company is committing to increase the ratio of digital transactions to total transactions to 85 percent.
<b>Gas Emergency Calls - Average Speed of Answer</b>	This metric will measure improvement in the average speed of answer of Gas Emergency Calls. The Company is committing to maintain 10 seconds as the average speed of answer for gas emergency calls.
<b>New Customer Connect Gas</b>	This metric will measure customer satisfaction with respect to the new gas customer interconnection process based on customer survey data. The Company is committing to maintain a satisfaction rating of 9.23 out of 10.

<b>EMISSION REDUCTIONS</b>	
<b>Scorecard Metric</b>	<b>High-Level Summary Description</b>
<b>Methane Emissions</b>	This metric will measure progress in emission reductions, in metric tons, associated with replacement of aged distribution infrastructure through the GSEP program. The Company is committing to reduce methane emissions by 39 percent from the baseline by Year Five of the PBR plan.
<b>Grade 3 Environmentally Significant Leaks</b>	This metric will measure the repair of environmentally significant Grade 3 leaks within 12 months of designation. The Company is committing to repair all non-GSEP environmentally significant Grade 3 leaks within 12 months of designation, which <b>exceeds</b> the Department's regulations.

1   **Q.    Is the Company proposing any incentives or penalties with respect to the**  
2   **scorecard metrics it is proposing in this case?**

3    A.    No, the Company is not proposing any incentives or penalties with respect to the  
4           scorecard metrics it is proposing in this case. The Company is already subject to the  
5           Department's rigorous SQ Guidelines, which include penalty metrics. The  
6           Department's SQ Guidelines will apply during the period of the PBR Plan.

7   **Q.    Ms. Conner, which scorecard metrics will you be discussing as part of your**  
8   **testimony?**

9    A.    I will be discussing the proposed customer engagement and satisfaction metrics as part  
10          of my testimony. Company Witnesses Akley and Horton discuss the safety and  
11          reliability and emissions reduction metrics as part of their joint testimony.

12   **Q.    What are the scorecard metrics the Company is proposing in the area of Customer**  
13   **Satisfaction & Engagement?**

14    A.    The Department has long recognized the importance of customer satisfaction and its  
15          direct alignment with customer interests. NSTAR Electric Co. and Western  
16          Massachusetts Electric Co.; D.P.U. 17-05, at 408, 409 n. 197 (2017); Revised Service  
17          Quality Guidelines, D.P.U. 12-120-D at 56 (2015); Grid Modernization, D.P.U. 12-76-  
18          B at 33 (2014); Western Massachusetts Electric Co., D.P.U. 10-70, at 104 (2011);  
19          Boston Gas National Grid and Colonial Gas National Grid, D.P.U. 10-55, at 253-254  
20          (2010). The Company is proposing five scorecard metrics focused on customer  
21          satisfaction and engagement: (1) a metric that measures the Company's J.D. Power  
22          score for Safety and Reliability (2) a metric that measures customer satisfaction with

1 the Company's on-line tools; (3) a measure of digital engagement with customers; (4)  
2 a metric that measures the average speed at which gas emergency calls are answered;  
3 and (5) a metric that measures customer satisfaction relative to the Company's  
4 performance on new service interconnections .

5 **Q. What is the basis for establishing targets for 2024?**

6 A. The targets and specific basis for the five metrics are identified below. Generally, the  
7 targets are a function of improvement over historic performance and utilize a  
8 logarithmic curve model or experiential results. Achieving the targeted results will  
9 require the implementation of the initiatives described throughout my testimony. Each  
10 of the five Customer Engagement and Satisfaction metrics currently have a high level  
11 of performance that influences the magnitude of expected future gains. This is  
12 particularly true given the changing customer demographics and expectations  
13 (regarding millennials, youth) described earlier in my testimony. In our experience,  
14 and that of J.D. Power regarding their research on customer satisfaction, high  
15 performing measures experience a "ceiling effect." A logarithmic curve fit was used  
16 to set the targets since it depicts the relationship of diminishing improvements as a  
17 metric approaches its ceiling.

18 **Q. Please describe the scorecard metric that is based on J.D. Power performance.**

19 A. The Company is proposing a scorecard metric based on Eversource Energy's  
20 performance on the Safety & Reliability factor in J.D. Power's Gas Utility Residential  
21 Customer Satisfaction Study. J.D. Power is widely recognized as the authority on

1 measuring customer satisfaction and engagement across a broad range of industries,  
2 including the gas distribution industry.

3 J.D. Power has conducted its Gas Utility Residential Customer Satisfaction Study for  
4 18 years running and its results are based on responses from online interviews with  
5 residential customers of the 84 largest gas utility brands (including Eversource Energy)  
6 across the United States, which represent more than 62 million households. The Gas  
7 Utility Residential Customer Satisfaction Index segments the customer experience into  
8 six factors, one of which is Safety and Reliability.<sup>11</sup>

9 J.D. Power uses a customer satisfaction “index” to determine the relative rankings of  
10 gas utility companies. Based on data obtained from its surveys, J.D. Power creates an  
11 “index” that quantifies the impact that the factors and the attributes within them have  
12 on customer satisfaction. The index is a calculated roll-up of performance scores,  
13 weighted relative to the importance of each factor to overall satisfaction. Those  
14 calculations are used to derive an overall customer satisfaction score for each utility  
15 company in the study.

16 **Q. How does the Company propose to measure the J.D. Power metric?**

17 **A.** The Company will use Eversource Energy’s scores for the Safety and Reliability factor

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<sup>11</sup> The six factors measured by J.D. Power are (1) Safety and Reliability; (2) Billing and Payment; (3) Corporate Citizenship; (4) Customer Service; (5) Price; and (6) Communications. J.D. Power, 2019 Gas Utility Residential Customer Satisfaction Study at 4, *available at* [https://www.jdpower.com/sites/default/files/gasutilityresidential\\_brochure\\_final\\_040519.pdf](https://www.jdpower.com/sites/default/files/gasutilityresidential_brochure_final_040519.pdf).

1 in J.D. Power's Gas Utility Residential Customer Satisfaction Study to measure its  
2 performance under this metric.

3 **Q. How did the Company establish the baseline measure for the J.D. Power metric?**

4 A. The baseline measure for this metric is Eversource Energy's 2018 year-end score for  
5 the Safety and Reliability factor in J.D. Power's Gas Utility Residential Customer  
6 Satisfaction Index.

7 **Q. What target does the Company propose for the J.D. Power metric and what steps**  
8 **will it take to achieve that target?**

9 A. Using Eversource Energy's 2018 J.D. Power Safety and Reliability score of 775 as a  
10 baseline, the Company will target achieving a 23-point increase to achieve a score of  
11 798 by the end of the five-year PBR Plan term. The Company plans to achieve this  
12 improvement by focusing on Company initiatives having the greatest relative impact  
13 on Safety and Reliability. To determine this target, logarithmic modeling was used to  
14 provide projected 2024 year-end results.

15 **Q. Please describe the scorecard metric that is designed to measure web satisfaction.**

16 A. As discussed in this testimony, a primary interface between the Company and its  
17 customers is the Eversource.com website, and about 90 percent of those visits are to  
18 view and pay utility bills. Given the importance of this customer channel, the Company  
19 proposes to measure customer satisfaction with the online tools available on the  
20 Eversource.com website.

1 In the first quarter of 2018, Eversource Energy implemented a function on its website  
2 where customers are invited to participate in a survey about their experience at the  
3 conclusion of their transaction. As part of the survey, customers rate their satisfaction  
4 with the Eversource.com website on a scale of one to ten. The Company proposes to  
5 use the average scores from these customer ratings to measure web satisfaction.

6 **Q. How did the Company establish the baseline measure for the web satisfaction and**  
7 **what is the Company proposing for a performance target?**

8 A. The baseline measure for the web satisfaction metric is 7.76 out of 10, which is based  
9 on 2018 data of customer ratings for web satisfaction. The Company proposes to set a  
10 web satisfaction rating of 8.15 as its performance target over the five-year PBR Plan  
11 term. To determine this target, logarithmic modeling was used to provide projected  
12 2024 year-end results.

13 **Q. Please describe the scorecard metric that is based on Digital Engagement.**

14 A. In the past, the primary channels for customers to interact with their gas and electric  
15 companies were telephone, paper, fax, and in-person transactions. However, as  
16 discussed in this testimony, a growing population of the customer base prefers digital  
17 channels. This preference is driven, in part, by transactional experiences that  
18 consumers have with service providers in other industries such as Amazon, Uber,  
19 American Express, and Netflix. In other words, customer-service expectations are  
20 being set outside of the gas and electric utility industries.

1 Today's digital consumer wants the same experience in every transaction with service  
2 providers, and they want that experience to be intuitive, personalized, and fast.  
3 Consequently, customer satisfaction in the utility space is more closely linked to the  
4 availability of digital tools and electronic engagement channels.

5 For Eversource Energy, the voice of the customer is and will continue to be a key driver  
6 of the customer experience transformation. To adapt to evolving customer  
7 expectations, we have taken major steps to improve the digital and self-service  
8 customer experience; to implement a dynamic and robust outage and billing and  
9 payment alert system; to launch the first mobile app, and to pursue a Fee Free  
10 credit/debit card payment options for customers in D.P.U. 19-71. This proposed metric  
11 will measure digital engagement with customers through self-service channels and alert  
12 notifications.

13 **Q. How does the Company propose to measure the digital engagement metric?**

14 A. For this metric, the Company will provide the Department with data on the number of  
15 "digital transactions," as a percentage of total transactions that are processed through  
16 the Company's digital platforms in each year of the five-year PBR Plan. A digital  
17 transaction is defined as web interactions, Interactive Voice Response, or IVR,  
18 interactions, alerts delivered, mobile application interactions and two-way text  
19 interactions.

1   **Q.    How did the Company establish the baseline measure for the digital engagement**  
2   **metric and what target does the Company propose?**

3   A.    The baseline for the digital engagement metric is 83.2 percent based on the number of  
4       “digital transactions,” as a percentage of total transactions, in 2018. Given the  
5       Company’s high-level of performance on this metric in 2018, it is appropriate to set a  
6       minimum performance target of 85 percent for the digital engagement metric over the  
7       five-year PBR Plan term. To determine this target, logarithmic modeling was used to  
8       provide projected 2024 year-end results.

9   **Q.    Please describe the scorecard metric that is designed to measure performance on**  
10   **gas emergency calls.**

11   A.    This metric is designed to measure the Company’s call response time to gas leak, odor  
12       and emergency calls generated by the public and non-Company personnel. As the  
13       response time lengthens for this initial customer contact, there is an increased potential  
14       of an incident or safety threat to the public. Therefore, it is important to minimize the  
15       average speed of answer to gas leaks or odors calls.

16   **Q.    How does the Company propose to measure the gas emergency call metric?**

17   A.    The gas emergency call metric measures the time, in seconds, for an Eversource Energy  
18       customer service representative to answer a customer call to report a gas leak, odor or  
19       other emergency.



1   **Q.    How did the Company establish the baseline measure for the gas emergency call**  
2   **handling metric and what target does the Company propose?**

3    A.    The 10-second target proposed for this metric is based on the three-year average (2016  
4           to 2018). Given the Company's exceptional performance, and the targets set by  
5           industry peers (10 – 15 seconds), it is appropriate to use the 10 second baseline as a  
6           minimum performance target over the five-year PBR Plan term.

7   **Q.    Please describe the scorecard metric the Company is proposing for new customer**  
8   **connections?**

9    A.    The Company invites new gas customers to complete a survey regarding their  
10          satisfaction with the Company's performance on new service installations. This survey  
11          allows customers to rate the Company's performance on a scale of one to ten and this  
12          metric would be based on the average score in these customer ratings.

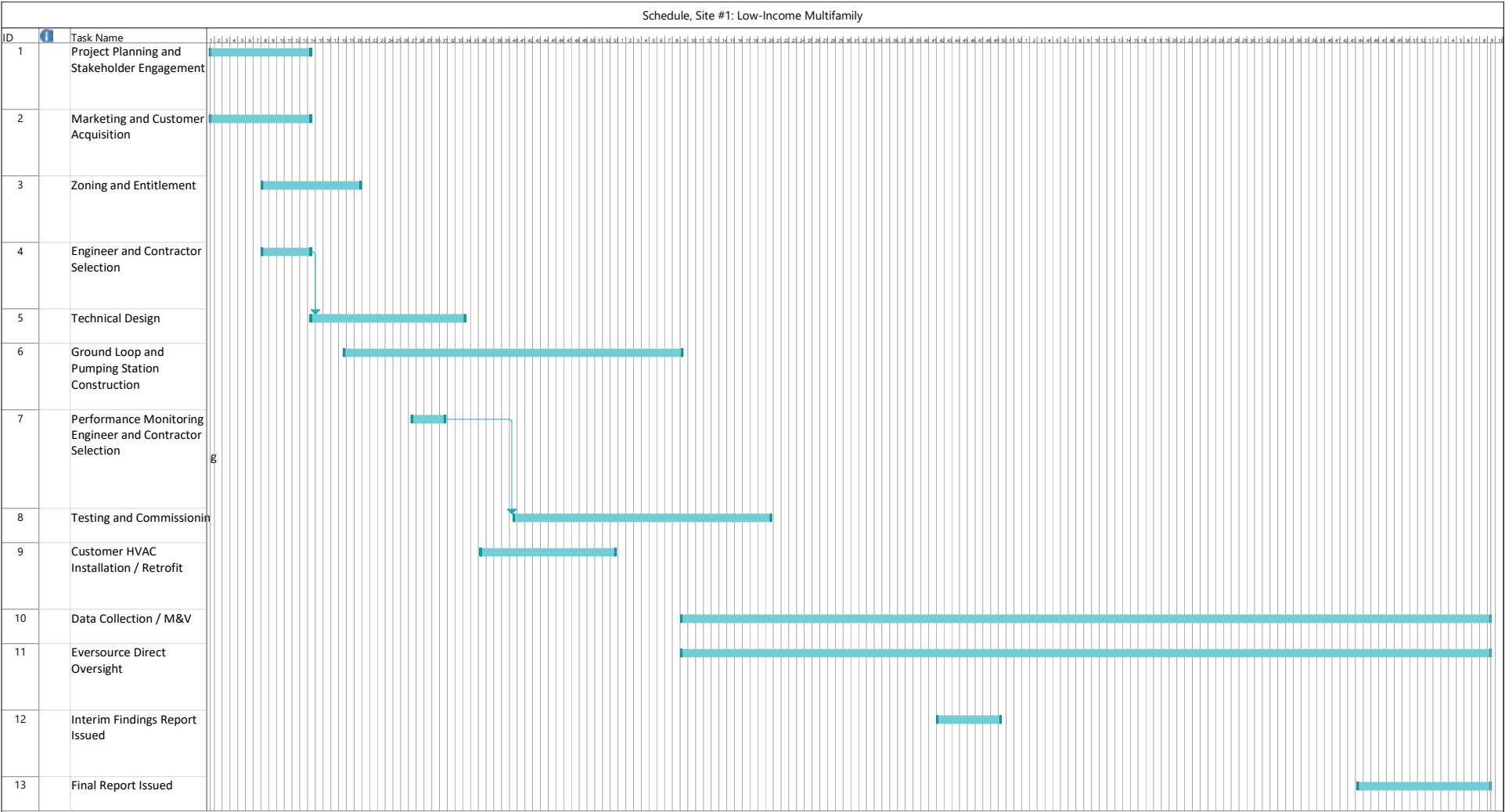
13   **Q.    How did the Company establish the baseline measure for the customer**  
14   **connections metric and what is the Company proposing for a performance target?**

15    A.    The baseline measure of 9.23 out of 10 for this metric is based on the three-year average  
16          (2016 to 2018) customer rating in the new customer connect survey. Because the  
17          Company is already performing at such a high-level, only 0.77 points from a perfect  
18          score of 10, it is appropriate to use the baseline as a minimum performance target over  
19          the five-year PBR Plan term.

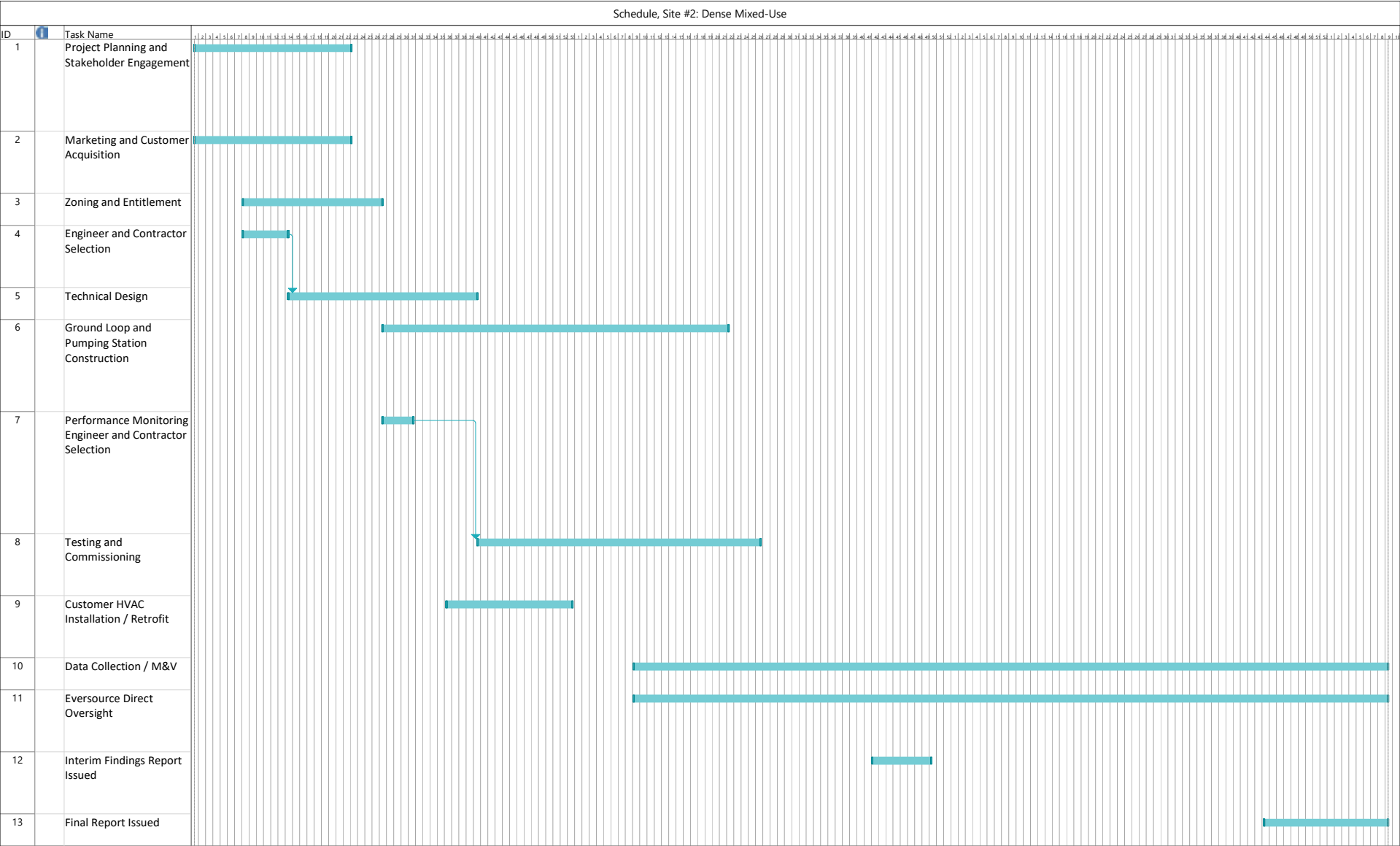
20   **VI.    CONCLUSION**

21   **Q.    Does this conclude your testimony?**

22    A.    Yes, it does.



Schedule, Site #2: Dense Mixed-Use



Schedule, Site #3: Single-Family Housing Development																																																																																																																				
ID	Task Name	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	1	2	3	4	5	6	7	8	9	10	11
1	Project Planning and Stakeholder Engagement																																																																																																																			
2	Marketing and Customer Acquisition																																																																																																																			
3	Zoning and Entitlement																																																																																																																			
4	Engineer and Contractor Selection																																																																																																																			
5	Technical Design																																																																																																																			
6	Ground Loop and Pumping Station Construction																																																																																																																			
7	Performance Monitoring Engineer and Contractor Selection																																																																																																																			
8	Testing and Commissioning																																																																																																																			
9	Customer HVAC Installation / Retrofit																																																																																																																			
10	Data Collection / M&V																																																																																																																			
11	Eversource Direct Oversight																																																																																																																			
12	Interim Findings Report Issued																																																																																																																			
13	Final Report Issued																																																																																																																			

**Overall Program Cost: \$12,810,645**

**Cost By Component**

Construction Cost:	\$10,179,000
Direct Staff & OH:	\$1,073,311
O&M Expense, Energy:	\$536,734
O&M Expense, Maintenance / Performance Monitoring:	\$721,600
Third-Party Evaluation	\$300,000
<b>Total Project Cost:</b>	<b>\$12,810,645</b>

**Cost By Site**

Site #1:	
Construction Cost:	\$1,692,000
Direct Staff & OH:	\$165,125
O&M Expense, Energy:	\$82,714
O&M Expense, Maintenance / Performance Monitoring:	\$111,015
<b>Site #1 Total:</b>	<b>\$2,050,854</b>
Site #2:	
Construction Cost:	\$7,506,000
Direct Staff & OH:	\$825,624
O&M Expense, Energy:	\$412,482
O&M Expense, Maintenance / Performance Monitoring:	\$555,077
<b>Site #2 Total:</b>	<b>\$9,299,182</b>
Site #3:	
Construction Cost:	\$981,000
Direct Staff & OH:	\$82,562
O&M Expense, Energy:	\$41,538
O&M Expense, Maintenance / Performance Monitoring:	\$55,508
<b>Site #3 Total:</b>	<b>\$1,160,608</b>
<b>All Sites, Total:</b>	<b>\$12,510,645</b>

## Construction Costs

<b><u>Grand Total:</u></b>	Site 1:	\$1,692,000
	Site 2:	\$7,506,000
	Site 3:	\$981,000
		<b>\$10,179,000</b>

### Site 1: Low-Income Multifamily

30 HVAC units  
2 tons/unit  
60 tons overall  
75 ton well capacity (NB: 25% capacity for heat of compression)

#### Ground Loop:

75 tons  
\$5,000 /ton  


---

**\$375,000**

#### Pumps, Boiler and Supp Clg:

15.17 pump power needed (calc's under "Electricity Consumption" tab)  
10 HP pumps purchased  
3 quantity purchased (N+1 redundancy)  
\$25,000 assumed pump cost  
\$75,000 pump cost  
\$50,000 boiler cost  
\$50,000 dry cooler cost  


---

**\$175,000**

#### Piping and Specialties:

75 tons  
\$1,000 per ton  


---

**\$75,000**

#### Controls:

75 points  
\$1,000 /point  


---

**\$75,000**

#### Enclosure:

---

**\$50,000** cost

#### Site HVAC Costs:

60 tons  
\$6,000 per ton, GSHP  
\$4,000 per ton, internal distribution  
\$1,000 Building weatherization (i.e. customer costs after EE incentive funds)  


---

**\$660,000**

#### Other Costs:

\$1,410,000 subtotal  
10% Design fees  
10% Contingency / scope increases  


---

**\$282,000**

**Site 1 Total Costs: \$1,692,000**

**Site 2: Dense Urban Installation**

100 HVAC units  
3 tons/unit  
300 tons overall  
375 ton well capacity (NB: 25% capacity for heat of compression)

**Ground Loop:**

375 tons  
\$5,000 /ton  

---

**\$1,875,000**

**Pumps, Boiler and CT:**

75.83 pump power needed (calc's under "Electricity Consumption" tab)  
40 HP pumps purchased  
3 quantity purchased (N+1 redundancy)  
\$60,000 assumed pump cost  
\$180,000 pump cost  
\$150,000 boiler cost  
\$150,000 dry cooler cost  

---

**\$480,000**

**Piping and Specialties:**

375 tons  
\$1,000 per ton  

---

**\$375,000**

**Controls:**

75 points  
\$1,000 /point  

---

**\$75,000**

**Enclosure:**

---

**\$150,000** assumed cost

**Site HVAC Costs:**

300 tons  
\$6,000 per ton, GSHP  
\$4,000 per ton, internal distribution  
\$1,000 Building weatherization (i.e. customer costs after EE incentive funds)  

---

**\$3,300,000**

**Other Costs:**

\$6,255,000 subtotal  
10% Design fees  
10% Contingency / scope increases  

---

**\$1,251,000**

**Site 2 Total Costs: \$7,506,000**

**Site 3: Residential Community Development**

10 HVAC units  
3 tons/unit  
30 tons overall  
37.5 ton well capacity (NB: 25% capacity for heat of compression)

**Ground Loop:**

38 tons  
\$5,000 /ton  


---

\$187,500

**Pumps, Boiler and CT:**

7.58 pump power needed (calc's under "Electricity Consumption" tab)  
5 HP pumps purchased  
3 quantity purchased (N+1 redundancy)  
\$12,500 assumed pump cost  
\$37,500 pump cost  
\$50,000 boiler cost  
\$50,000 dry cooler cost  


---

\$137,500

**Piping and Specialties:**

37.5 tons  
\$1,000 per ton  


---

\$37,500

**Controls:**

75 points  
\$1,000 /point  


---

\$75,000

**Enclosure:**

\$50,000 assumed cost

**Site HVAC Costs:**

30 tons  
\$6,000 per ton, GSHP  
\$4,000 per ton, internal distribution  
\$1,000 Building weatherization (i.e. customer costs after EE incentive funds)  


---

\$330,000

**Other Costs:**

\$817,500 subtotal  
10% Design fees  
10% Contingency / scope increases  


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\$163,500

<b>Site 3 Total Costs:</b>	<b>\$981,000</b>
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## Direct Staff/FTE and Overhead Expenses

Project Revenue (Customer Access Fee)								Revenue Distribution				Revenue Distribution				Revenue Dist.
Project Name	Units	Access Fee (per unit per quarter)	na	2020- Q1	2020- Q2	2020- Q3	2020- Q4	2021- Q1	2021- Q2	2021- Q3	2021- Q4	2022- Q1	2022- Q2	2022- Q3	2022- Q4	2023- Q1
Low-Income Multi-Family	30	\$ 15	na	\$ 450	\$ 450	\$ 450	\$ 450	\$ 450	\$ 450	\$ 450	\$ 450	\$ 450	\$ 450	\$ 450	\$ 450	\$ 450
Dense Urban High-Rise	100	\$ 60	na	\$ 6,000	\$ 6,000	\$ 6,000	\$ 6,000	\$ 6,000	\$ 6,000	\$ 6,000	\$ 6,000	\$ 6,000	\$ 6,000	\$ 6,000	\$ 6,000	\$ 6,000
Residential Development	10	\$ 60	na	\$ 600	\$ 600	\$ 600	\$ 600	\$ 600	\$ 600	\$ 600	\$ 600	\$ 600	\$ 600	\$ 600	\$ 600	\$ 600
<b>Total Project Revenue</b>	na	na	\$ -	\$ 7,050	\$ 7,050	\$ 7,050	\$ 7,050	\$ 7,050	\$ 7,050	\$ 7,050	\$ 7,050	\$ 7,050	\$ 7,050	\$ 7,050	\$ 7,050	\$ 7,050

Eversource Project Management Expenses								Expense Distribution				Expense Distribution				Expense Dist.
Role	Employee	Hourly Rate (incl OH)	Percent of Time to Project	2020- Q1	2020- Q2	2020- Q3	2020- Q4	2021- Q1	2021- Q2	2021- Q3	2021- Q4	2022- Q1	2022- Q2	2022- Q3	2022- Q4	2023- Q1
Program General Management	Program Manager	\$ 120	100%	\$ 62,352	\$ 62,352	\$ 62,352	\$ 62,352	\$ 62,352	\$ 62,352	\$ 62,352	\$ 62,352	\$ 62,352	\$ 62,352	\$ 62,352	\$ 62,352	\$ 62,352
Construction Oversight	Project Manager	\$ 85	100%	\$ 44,166	\$ 44,166	\$ 44,166	\$ 44,166	\$ 44,166	\$ 44,166	\$ 44,166	\$ 44,166	\$ 44,166	\$ 44,166	\$ 44,166	\$ 44,166	\$ 44,166
Construction Coordination	Project Engineer	\$ 70	100%	\$ 36,372	\$ 36,372	\$ 36,372	\$ 36,372	\$ 36,372	\$ 36,372	\$ 36,372	\$ 36,372	\$ 36,372	\$ 36,372	\$ 36,372	\$ 36,372	\$ 36,372
Project Sponsorship	ES Director / VP	Assume \$5K/Qtr.	na	\$ 5,000	\$ 5,000	\$ 5,000	\$ 5,000	\$ 5,000	\$ 5,000	\$ 5,000	\$ 5,000	\$ 5,000	\$ 5,000	\$ 5,000	\$ 5,000	\$ 5,000
Misc Expenses (Travel, Mileage)		na	na	\$ 7,800	\$ 7,800	\$ 7,800	\$ 7,800	\$ 7,800	\$ 7,800	\$ 7,800	\$ 7,800	\$ 7,800	\$ 7,800	\$ 7,800	\$ 7,800	\$ 7,800
Subtotal				\$ 155,690	\$ 155,690	\$ 155,690	\$ 155,690	\$ 155,690	\$ 155,690	\$ 155,690	\$ 155,690	\$ 155,690	\$ 155,690	\$ 155,690	\$ 155,690	\$ 155,690
Escalation (3%/yr)				\$ 1,155	\$ 2,319	\$ 3,491	\$ 4,673	\$ 5,862	\$ 7,061	\$ 8,269	\$ 9,485	\$ 10,711	\$ 11,946	\$ 13,190	\$ 14,443	\$ 15,705
<b>Total Expenses</b>		na	na	\$ 156,845	\$ 158,009	\$ 159,181	\$ 160,363	\$ 161,552	\$ 162,751	\$ 163,959	\$ 165,175	\$ 166,401	\$ 167,636	\$ 168,880	\$ 170,133	\$ 171,395

Sum Total

\$ (149,795) \$ (150,959) \$ (152,131) \$ (153,313) \$ (154,502) \$ (155,701) \$ (156,909) \$ (159,351) \$ (160,586) \$ (161,830) \$ (163,083) \$ (164,345)

\$ (1,073,311)

## Notes:

1. Monthly labor expenses based upon (40 hours per week) x (4.33 weeks per mo.) x (3 months per quarter) x (Hourly Rate) x (Percent of Time to Project)
2. Travel, phone, expenses: Assume \$200/week x (4.33 weeks per mo.) x (3 months per quarter) x (3 FTE)

Electricity Consumption Cost

	1,325,269 kWh	(MA EIA fully-loaded
	\$0.162 /kWh	commercial elec cost,
	\$214,694 /yr	June 2019)
	2.5 yrs operation	
<b>Grand Total (3 Sites):</b>	<b>\$536,734 total</b>	

Site 1: Low-Income Multifamily

Total:

204,232

**Pumps**

30 indoor HVAC unit  
2 tons/unit  
75 ton well capacity (NB: 25% capacity for heat of compression)  
180 GPM (at 10°F dT)  
15.2 HP (operating HP assuming 150' head, 50% pump eff, 90% motor eff)  
8000 full-load run hours  


---

90,516 kWh

**Electric Boiler**

200 full-load run hours  
180 GPM loop flow (from above)  
20 °F temperature rise (assumed)  
95% efficiency (assumed)  
555 kW out  


---

111,031 kWh

**Dry Cooler**

500 full-load run hours  
180 GPM loop flow (from above)  
6 Dry cooler # of fans  
1.5 HP per fan  
9 HP total  
5.37 kW total (assuming 80% of fan nameplate power)  


---

2,686 kWh

**Site 2: Dense Urban Environment****Total:****1,018,474****Pumps**

100 indoor HVAC unit  
3 tons/unit  
375 ton well capacity (NB: 25% capacity for heat of compression)  
900 GPM (at 10°F dT)  
75.8 HP (operating HP assuming 150' head, 50% pump eff, 90% motor eff)  
8000 full-load run hours

---

452,578 kWh**Electric Boiler**

200 full-load run hours  
900 GPM loop flow (from above)  
20 °F temperature rise (assumed)  
95% efficiency (assumed)

---

2,776 kW out

555,153 kWh

**Dry Cooler**

500 full-load run hours  
900 GPM loop flow (from above)  
24 Dry cooler # of fans  
1.5 HP per fan  
36 HP total  
21.48 kW total (assuming 80% of fan nameplate power)

---

10,742 kWh**Site 3: Residential Community Development****Total:****102,564****Pumps**

10 indoor HVAC unit  
3 tons/unit  
37.5 ton well capacity (NB: 25% capacity for heat of compression)  
90 GPM (at 10°F dT)  
7.6 HP (operating HP assuming 150' head, 50% pump eff, 90% motor eff)  
8000 full-load run hours

---

45,258 kWh**Electric Boiler**

200 full-load run hours  
90 GPM loop flow (from above)  
20 °F temperature rise (assumed)  
95% efficiency (assumed)

---

278 kW out

55,515 kWh

**Dry Cooler**

500 full-load run hours  
90 GPM loop flow (from above)  
4 Dry cooler # of fans  
1.5 HP per fan  
6 HP total  
3.58 kW total (assuming 80% of fan nameplate power)

---

1,790 kWh

## Performance Monitoring and O&M Expenses

<b>Total Performance Monitoring / O&amp;M:</b>	<b>\$721,600</b>
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### Performance Monitoring / Data Collection Expense

# data reads / month:	1	
Hours / data read & log:	30	
Labor cost:	\$150 /hr	(typical fully-loaded cost for senior engineering consultant)
	\$4,500 /month	
Months of data collection:	24	
	\$108,000	
Reports:	2	
Hours per report:	200	
Labor cost:	\$150 /hr	
	\$60,000	
Subtotal:	\$168,000	
Other expenses:	20% of contract	(travel, meetings, printing, etc.)
	\$33,600	
<b>Total:</b>	<b>\$201,600</b>	

### O&M Expense

Operator hours/week:	10	
Labor cost:	\$250 /hr	(boiler operator & replacement parts)
weeks of operation:	104	
	\$260,000	
Material cost:	\$260,000	Assume equal to labor cost
<b>Total:</b>	<b>\$520,000</b>	

**DIRECT WRITTEN TESTIMONY OF**

**Julia Frayer  
Marie Fagan**

**Exhibit ES-JF/MF-1**



**London Economics International LLC**

717 Atlantic Avenue, Suite 1A

Boston, MA 02111

**November 8, 2019**

## TABLE OF CONTENTS

I.	INTRODUCTION.....	1
II.	INTRODUCTION TO PBR FOR LDCs.....	10
III.	SUMMARY OF X FACTOR RECOMMENDATION .....	18
IV.	SUMMARY OF TOTAL COST BENCHMARKING STUDY .....	35
V.	IMPLICATIONS FOR THE COMPANY’S REVENUE CAP PER CUSTOMER PROPOSAL .....	43

**DIRECT WRITTEN TESTIMONY OF JULIA FRAYER**

**I. INTRODUCTION**

**Q. Please state your name and business address.**

A. My name is Julia Frayer. I am one of the partners and a Managing Director of London Economics International LLC ("LEI"), a Massachusetts-based consulting firm specializing in the energy, water, and other infrastructure industries. My business address is 717 Atlantic Avenue, Suite 1A, Boston, MA 02111.

**Q. What is the purpose of your testimony in this proceeding?**

A. I was retained by NSTAR Gas Company d/b/a Eversource Energy ("NSTAR Gas" or the "Company") to provide expert technical analysis for its performance-based ratemaking ("PBR") plan. More specifically, I am presenting a total factor productivity ("TFP") study as the basis for the X factor that NSTAR Gas should use for its "I-X" rate escalation mechanism. In addition, I am presenting the results of a Total Cost Benchmarking Study, which estimates the Company's efficiency level relative to its peers.

**Q. Please summarize your relevant professional background.**

A. As Managing Director of LEI, I supervise and manage many of LEI's engagements involving market analysis in the electricity sector, including

1 advisory services on regulation and tariff design, as well as consulting  
2 related to commercial activities in deregulated power markets. I have  
3 worked extensively in the United States, Canada, Europe, and Asia for  
4 more than 20 years in valuing electricity generation and wires assets, water  
5 and wastewater networks, as well as gas transportation assets, and in  
6 advising on regulatory reforms, development of competitive market rules,  
7 innovative rate design, and institutional best practices for the electric and  
8 gas utility sectors.

9 PBR is an area that I have specialized in with respect to regulatory design.  
10 I have extensively studied regulatory regimes involving PBR and advised  
11 utilities, regulators, and investors on best practices with respect to the  
12 design of PBR formula and implementation. In some of my work, I have  
13 advised on how PBR implementation may affect consumers, while in other  
14 engagements, I have focused on implications for regulated utilities and  
15 regulators. That work has exposed me to various forms of PBR and the  
16 technical studies that regulators and utilities use to calibrate the trajectory  
17 of future rates, consider investment needs and align the incentives of  
18 customers, the regulated utility, and the regulator. Such engagements have  
19 occurred in North America (U.S. and Canada), Europe (for example,



1 Austria, Germany, the Netherlands, and the United Kingdom), Asia  
2 (Malaysia), and South America (Argentina). I have also conducted  
3 workshops for regulators and industry stakeholders on PBR.

4 I am very familiar with the evaluation of productivity trends and the  
5 development of TFP studies. I have examined TFP trends in electric  
6 transmission, distribution, and generation sectors, as well as water and  
7 wastewater networks. I have also studied productivity matters as  
8 applicable to gas distribution. My work in PBR straddles various  
9 regulatory models. I have advised on the formulaic approach of an “I-X”  
10 application and have studied the building-blocks approach historically  
11 applied in the United Kingdom and Australia.<sup>1</sup> A few years ago, I headed  
12 a team that assisted the largest Southeast Asian utility, Tenaga Nasional  
13 Berhad, in the preparation of their first comprehensive PBR application.

14 I have also testified before a number of regulators on various aspects of rate  
15 design broadly, and PBR specifically, as discussed further below. My

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<sup>1</sup> A “building blocks” approach is a framework where revenue requirements are “built up” based on the utilities’ future estimated efficient costs and return of and return on an efficient asset base.

1 curriculum vitae is provided as Exhibit ES-JF/MF-1, Attachment A  
2 included with this written testimony.

3 **Q. Where have you testified on PBR matters?**

4 A. In recent years, I have served as an expert witness in a number of Canadian  
5 jurisdictions that have applied PBR to regulated electric and gas utilities.  
6 Most recently, I have testified before the Ontario Energy Board (“OEB” or  
7 “the Board”) on behalf of the Ontario Power Generation (“OPG”)  
8 presenting LEI’s TFP study for OPG’s first generation Incentive Regulation  
9 Mechanism plan for its regulated hydroelectric fleet. I am currently  
10 working with OPG on their next-generation rate application. I have also  
11 appeared before the OEB on behalf of Enbridge Gas regarding its second-  
12 generation Customized Incentive Regulation plan for 2014-2018. In this  
13 testimony, I set out the underlying theory and practical experience of using  
14 the building blocks approach in incentive regulation regimes and compared  
15 it with the OEB’s Custom IR approach. Furthermore, in 2008, I advised the  
16 Coalition of Large Distributors in Ontario on the 3<sup>rd</sup> generation Incentive  
17 Regulation Mechanism proceedings before the OEB.

18 I also provided expert testimony in support of FortisAlberta Inc. in its first  
19 filing for a PBR plan with the Alberta Utilities Commission. That testimony

1 provided a detailed analysis (including recommendations on inflation and  
2 TFP trends), summarized the underpinning economic theory for PBR, and  
3 reviewed best practices in various North American and international  
4 jurisdictions. Furthermore, I prepared a white paper for the Canadian  
5 Electricity Association, describing the basic principles of PBR and analyzing  
6 the state of incentive ratemaking and PBR implementation across Canada.

7 **Q. Do you have other experience relevant to this project?**

8 A. Yes, I have participated in several other engagements relevant to the  
9 expertise required in this project. I am also knowledgeable about the  
10 natural gas local distribution company ("LDC") sector in New England, as  
11 well as across North America, and I am familiar with Massachusetts energy  
12 policies. Many of my recent engagements with respect to electric power  
13 and wholesale market rules development required an in-depth  
14 understanding of gas dynamics in the region, including the planning and  
15 operational issues prevalent for New England's LDCs. I have also worked  
16 with the Maine Public Utilities Commission on the new gas pipelines,  
17 which required examination of the business trends and customer dynamics  
18 for the New England LDC sector.

1 Further, I have studied, on behalf of state regulators, the economics of  
2 energy efficiency programs, some of which specifically target the gas sector.  
3 Also, as mentioned above, in Ontario, I have worked with Enbridge Gas  
4 and Union Gas on their PBR plans, planned investments, and customer  
5 growth strategies. Over the last several years, I have had the opportunity  
6 to work with many of the diverse entities involved in the Massachusetts  
7 energy sector, including generators and electricity transmission and  
8 distribution firms. The diversity of past clients and their perspectives gave  
9 me an in-depth and unique appreciation of policy issues in Massachusetts.  
10 Lastly, I have testified on a variety of issues before U.S. state and Canadian  
11 provincial regulators, as well as the Federal Energy Regulatory  
12 Commission ("FERC") in the U.S. I have also served as an expert in  
13 litigation and arbitration proceedings.

14 **Q. Have you testified previously before the Massachusetts Department of**  
15 **Public Utilities ("Department")?**

16 **A.** Yes, I have testified before the Department and associated state agencies,  
17 such as the Energy Facilities Siting Board ("EFSB"). I have led a number of  
18 engagements with Eversource Energy and National Grid, jointly and  
19 separately, to determine the technical and economic viability of non-  
20 transmission alternatives. For example, I provided testimony to the EFSB

1 for the following electric transmission projects: Greater Springfield  
2 Reliability Project (2010); Merrimack Valley Reliability Project (2015);  
3 Mystic to Woburn Project (2015 to 2016); Wakefield – Woburn (2015 to  
4 2016); and Sudbury-Hudson (mainly 2017, but the project began in late 2016  
5 and continued through 2018).

6 **Q. Are you sponsoring any exhibits in conjunction with your testimony?**

7 A. Yes. Exhibit ES-JF/MF-1, Attachment A presents my curriculum vitae and  
8 Dr. Marie's Fagan's curriculum vitae. Exhibit ES-JF/MF-2 LEI's Industry  
9 TFP Study, and Exhibit ES-JF/MF-3 presents LEI's Benchmarking Report.

10 **Q. How is your testimony organized?**

11 A. This testimony is organized into five sections. In this section, I briefly  
12 review our expertise and experience relevant to this engagement and the  
13 purpose of this testimony. The next section provides an introduction to  
14 PBR, including the benefits of PBR for consumers and the regulated utility.  
15 I also describe and comment on the Company's specific PBR plan. The third  
16 section presents a summary of my findings and recommendations  
17 stemming from LEI's Industry TFP Study. The fourth section summarizes  
18 the results of LEI's Total Cost Benchmarking Study for the Company and  
19 its peers. The last section, Section 5, discusses the implications of these two

1 analyses for the NSTAR Gas revenue cap per customer proposal in this  
2 proceeding.

3 **Q. Dr. Fagan, please state your name, position, and business address.**

4 A. My name is Dr. Marie N. Fagan. I am a Managing Consultant and Lead  
5 Economist at LEI. My business address is 717 Atlantic Avenue, Suite 1A,  
6 Boston, MA 02111.

7 **Q. What is the purpose of your testimony in this proceeding?**

8 A. I worked with Julia Frayer on the Total Cost Benchmarking Study, which  
9 estimates the Company's efficiency level relative to its peers.

10 **Q. Please summarize your relevant professional background.**

11 A. As Managing Consultant and Lead Economist, I lead LEI's engagements  
12 related to oil and natural gas analysis. I direct LEI's gas pipeline modeling  
13 efforts and support LEI's outlook for natural gas prices and basis forecasts  
14 for different hubs across North America. I have served as an expert witness  
15 on issues such as basis differentials, pipeline capacity, gas utilization in key  
16 regions, and LNG imports and export supply and demand.

17 I have over 25 years of experience in research and consulting for the energy  
18 sector, and my career has spanned international upstream and downstream

1 oil and gas, global coal, North American gas markets, and power markets.  
2 Prior to joining LEI, I was Senior Director of the Upstream Strategy, North  
3 American Gas and Power, and CERA View Institutional Investor at IHS,  
4 Inc. (formerly Cambridge Energy Research Associates). I also held multiple  
5 positions with Cambridge Energy Research Associates, Energy Information  
6 Administration, Analysis Corporation of Virginia, and the US Department  
7 of Energy.

8 Lastly, I have deep experience in econometric analysis. I have performed  
9 economic benchmarking analysis of utility performance as well as  
10 economic analysis of oil demand.

11 **Q. Do you have other experience relevant to this project?**

12 A. Yes, I have conducted various econometric and benchmarking analyses.  
13 Currently, I am leading a team in performing an econometric  
14 benchmarking analysis of unit-level O&M costs for a cross-sectional data  
15 set of over 300 hydropower generation units. I also led a comprehensive  
16 study of price and income elasticities of oil demand for Columbia  
17 University's Center on Global Energy Policy. The foundation of the study  
18 was a detailed econometric analysis that employed variety of specifications  
19 of econometric models, including static and dynamic models, symmetric

1 and asymmetric models, and tests of time-series properties of the data. The  
2 scope of the work encompassed separate models for crude oil, gasoline, and  
3 diesel demand, and relied on combined cross-section time-series data for  
4 OECD and non-OECD countries.

5 I am also very familiar with the Northeast LDC market. Recently, I led the  
6 analysis of the cost and benefits of several contracts for firm transportation  
7 service on natural gas pipelines. I also evaluated the value of firm  
8 transportation and interruptible transportation legacy contracts for a  
9 private client operating in the electric power generation business.

10 **II. INTRODUCTION TO PBR FOR LDCs**

11 **Q. What is PBR?**

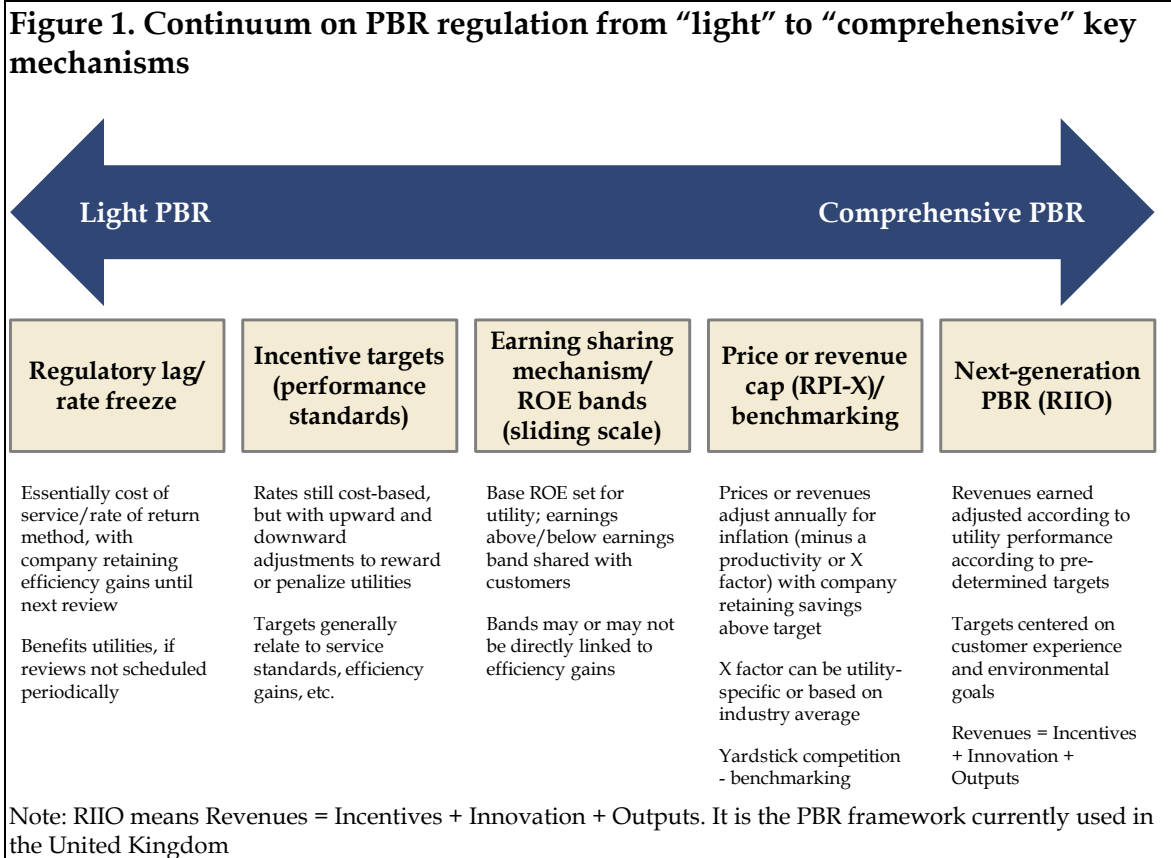
12 A. PBR is a form of utility regulation that mimics the forces that would have  
13 been in play if there was competition, where firms compete to provide the  
14 best service at the lowest cost through efficient operations. Under PBR, a  
15 formula is used to set the trajectory for the “price” of monopoly service by  
16 reference to inflationary pressures and industry productivity trends over  
17 time (or to target profit levels), rather than to the specific costs of the  
18 regulated firm. PBR is typically implemented as an alternative to  
19 traditional cost of service (“COS”) ratemaking, where rates would change



1 over time with the utility's costs. The objective of PBR is to strengthen the  
2 financial incentive for the regulated firm to lower costs and improve  
3 efficiency (as the price it is able to receive is set independently of its costs  
4 for the term of the PBR regime).

5 The concept of PBR includes a variety of mechanisms that could be used in  
6 varying combinations to motivate the regulated utility to be efficient. As  
7 such, PBR is best conceptualized as a continuum, ranging from "light" to  
8 "comprehensive" mechanisms, rather than a single type of regulatory  
9 regime. "Light" mechanisms include relatively minor adaptations to a  
10 traditional COS framework, such as including performance incentive  
11 mechanisms, regulatory lags (where rates may be fixed for a period of time),  
12 and efficiency audits and reviews. By contrast, price or revenue cap and  
13 outcomes-based PBR are on the other end of the more "comprehensive"  
14 forms of PBR. Figure 1 shows a diagram of this continuum.

15



PBR regimes are most likely to be successful when the regulated utility is operating in a steady-state environment, where the historical conditions and trends affecting the regulated utility and its peers in the industry are a reasonable indicator of future conditions. When the future is very different from the past, for example, the need for capital investment in the future far exceeds the typical pace of capital investment, or there is a situation where output growth in the future is different from the past, then a price or

1 revenue cap with an I-X escalation mechanism (under a comprehensive  
2 PBR plan) may not be adequate to ensure a viable regulatory environment  
3 for the utility. Therefore, PBR regimes need to be tailored to the expected  
4 future circumstances.

5 **Q. What form of PBR design is the Company proposing?**

6 A. The Company is proposing to continue with the revenue cap per customer  
7 that it has had under the Revenue Decoupling framework. Thus, the PBR  
8 framework starts with the revenue cap per customer, established based on  
9 a review of the costs of service for a historical test year.<sup>2</sup> The Company's  
10 PBR framework then applies a rate adjustment formula to that base revenue  
11 per customer year over year, which is based on a pre-set X factor or  
12 productivity target and an I factor or an inflation adjuster (which tracks  
13 actual inflation trends in the economy).<sup>3</sup>

14 The Company's PBR plan also includes common additional PBR formula  
15 elements like a Y factor, Z factor, and earnings sharing mechanism  
16 ("ESM").<sup>4</sup> The Company proposes a Y factor for the recovery of

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<sup>2</sup> Exhibit ES-WJA-DPH-1.

<sup>3</sup> Exhibit ES-WJA-DPH-1.

<sup>4</sup> Exhibit ES-WJA-DPH-1.

1 incremental costs associated with two clean energy demonstration  
2 projects.<sup>5</sup> The Y factor is a flow-through cost that is generally outside the  
3 normal business operations but can be anticipated and thus is pre-approved  
4 by the regulator. It is appropriate for the two demonstration projects to be  
5 considered under Y factor and recovered on a pass-through basis as they  
6 are costs that are expected but outside the Company's normal business  
7 operations.

8 The Z factor, also known as exogenous factor, is a mechanism that allows  
9 for adjustment in revenues or rates in case of occurrence of events that are  
10 perceived as beyond the reasonable control of utility management, were  
11 neither foreseen nor foreseeable at the time a formula was set, and that have  
12 a significant impact on the utility's finances.

13 The ESM is generally designed so that the extraordinary earnings (or losses)  
14 are shared amongst the LDC and its customers, rather than retained (or  
15 absorbed) entirely by the utility if formulae-driven price adjustments result  
16 in a too wide divergence between price and costs. The Company is  
17 proposing an ESM with a 100-basis point deadband above and below the  
18 allowed return of equity ("ROE") and share the surplus/deficient earnings

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<sup>5</sup> Exhibit ES-WJA-DPH-1.

1 with customers outside of this deadband on a 75%-25%  
2 (customers/shareholders) basis.<sup>6</sup>

3 The Company is proposing a five-year term over which it would be subject  
4 to the PBR plan, but is also open to an option to stay out even longer if there  
5 is an opportunity at the end of the PBR term to update rates to reflect capital  
6 investments made since the start of the PBR term.<sup>7</sup>

7 **Q. What are the benefits of this type of PBR design for the Company?**

8 A. The revenue cap per customer and PBR rate-adjustment mechanism will  
9 create a strong economic incentive for the Company to manage its costs. If  
10 the Company can reduce its costs more substantially than its peers in the  
11 industry, it will be able to increase its profitability. In other words, if the  
12 Company reduces its costs at a faster pace than that which is implied by the  
13 I-X rate adjustment mechanism, it will see its net income increase. This  
14 aspect of the PBR plan mirrors the market discipline in competitive  
15 markets, where firms focus on reducing their own costs rather than trying

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<sup>6</sup> Exhibit ES-WJA-DPH-1.

<sup>7</sup> Exhibit ES-WJA/DPH-1.

1 to influence prices charged to customers. The Company's PBR plan allows  
2 the Company to retain (some) of those incremental profits.

3 In addition, the PBR framework will enable the Company to manage its  
4 own costs over the term of the PBR, including the timing, choice, and  
5 amount of costs deployed for operating the LDC business, including  
6 decisions regarding the mixture of capital and operating expense to achieve  
7 intended operating outcomes. The PBR plan proposed by the Company  
8 also provides the utility with a level of predictability as to how external  
9 factors that have the potential to derail the PBR will be addressed. Given  
10 that there are near-term uncertainties in Massachusetts and nationally  
11 regarding new rules and regulations on safety and environmental factors,  
12 incorporating a path forward on the treatment of unknown, incremental  
13 costs arising as a result of new rules and regulations is important to a utility  
14 committing to an extended stay-out. This approach will allow the  
15 Company to focus on improving its operations and servicing its customers  
16 in light of the changing rules and regulations. The use of the revenue cap  
17 per customer approach allows for an alignment of the regulatory  
18 framework with state initiatives for energy efficiency.

1        Lastly, the reduction in regulatory burden (through a predictable, annual  
2        rate adjustment thereby avoiding intensive base rate reviews) will benefit  
3        not only the Company but also the regulator and, ultimately, consumers.

4        **Q.    What are the benefits of a PBR plan for customers?**

5        A.    The primary objective of a PBR plan is to motivate the regulated LDC to be  
6        efficient and reduce its costs of operation, which benefits customers over  
7        time. A revenue cap per customer will create strong incentives for NSTAR  
8        Gas management to control operating costs. This will benefit consumers,  
9        as they will know those base rate revenues will not rise above the I-X  
10       trajectory in the longer term, while the cost savings will lead to a lower rate  
11       for customers over the long-term. In the future, when the Department re-  
12       evaluates the costs of the Company and resets the base rate, the cost savings  
13       achieved by the Company as a result of PBR will yield a lower base rate  
14       than the base rate that would have otherwise been set.

15       As noted already, the five-year term and stay-out provision also reduce the  
16       regulatory burden on the Department and the Company, which creates cost  
17       savings that ultimately benefit customers.

18       The ESM provides safeguard that the PBR plan will not overcompensate  
19       the Company and that customers can share in the achievements of the

1 Company – even before the next full rate review - if the Company achieves  
2 a reduction in costs that materially raise profits. The ESM has some  
3 similarities with the concept of Consumer Dividend, which is essentially  
4 giving customers and shareholders contemporaneous access to the financial  
5 benefits of much lower costs that were motivated by the PBR regime.

6 In summary, the revenue cap per customer proposed by NSTAR Gas allows  
7 for a “win-win” situation where both customers and the Company share  
8 the benefits of a PBR plan.

9 **III. SUMMARY OF X FACTOR RECOMMENDATION**

10 **Q. What is an Industry TFP study?**

11 A. An Industry TFP study is used to measure the productive efficiency of an  
12 industry by assessing the total **quantity** of outputs that the firms in the  
13 industry produce relative to the **quantity** of inputs employed across all  
14 those firms. The TFP calculus should include consideration of all relevant  
15 physical inputs to production, such as labor, materials (and services), and  
16 capital. The output(s) typically reflected in a TFP analysis represent the  
17 volume of the product or service sold by firms in the industry, which may  
18 be proxied by the number of customers served by LDCs.



1 For purposes of PBR, and specifically in the design of price caps and  
2 revenue caps, regulators are interested in changes in TFP levels over time.  
3 For example, historical productivity growth can inform regulators and the  
4 regulated utility on the level of productivity change, to guide the choice of  
5 an explicit productivity target or X factor under an I-X rate adjustment  
6 mechanism.

7 **Q. What methodology did you use for calculating the trend in TFP for the**  
8 **LDC industry?**

9 A. LEI relied on the index method discussed in Section 2 of LEI's Industry TFP  
10 Study. Figure 10 of LEI's Industry TFP Study report provides an overview  
11 of some of the methods employed by practitioners for estimating TFP  
12 growth. LEI chose to use an index method because it is a relatively  
13 straightforward numerical method and is easy to explain. The index  
14 method also requires significantly fewer observations to estimate trends in  
15 TFP, as compared to other quantitative techniques. Moreover, regulators  
16 have most commonly relied on index-based studies of industry TFP trends  
17 for purposes of setting an X factor for a PBR formula.

18 It is important to note that the index method, because it is a numerical  
19 technique as opposed to a statistical technique, does not lend itself to  
20 statistical analyses (confidence levels or forecast error measures).

1 Therefore, interpreting differences in index values necessarily involves  
2 certain qualitative considerations. The Department has previously  
3 approved PBR plans using the index method and has affirmed the use of  
4 the index approach for purposes of determining TFP growth trends and  
5 ratemaking for gas and electric companies under its jurisdiction.<sup>8</sup>

6 In addition, LEI specifically used the chained Fischer Ideal index for  
7 calculating the trends in the TFP Study for the LDC industry.<sup>9</sup> There are a  
8 number of alternate index number formulations that have been used by  
9 practitioners for purposes of TFP analysis, including the Laspeyres index,  
10 Paasche index, and the Törnqvist index.<sup>10</sup> However, other studies have  
11 proven that the Fischer Ideal index possesses the maximum number of  
12 desirable properties for an index number method and therefore is  
13 theoretically preferred over other index number formulations.<sup>11</sup> That said,  
14 the results of the Industry TFP study are not very sensitive to the selected

---

<sup>8</sup> See, e.g., NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy, D.P.U. 17-05 (November 30, 2017).

<sup>9</sup> Indexes are chained by comparing data for each year to the data from the year immediately preceding it (with the exception of the base year). This method provides a more accurate portrayal of year over year growth.

<sup>10</sup> Note that the Fischer Ideal index is a geometric average of the Laspeyres and the Paasche indices.

<sup>11</sup> Diewert and Nakamura. *Concepts and Measures of Productivity: An Introduction*. 2005.

1 index, because LEI focused on estimating an average trend over a 15-year  
2 timeframe rather than an average spanning just a few years.<sup>12</sup>

3 **Q. Which firms did you include in your industry group?**

4 A. LEI's Industry TFP Study was constructed based on the aggregation of data  
5 from 83 U.S. LDCs. These 83 LDCs are located across 31 states and  
6 represent 70.0% of gas customers nationally and 69.5% of the total volume  
7 of gas sales in the U.S. in 2017. I refer to these 83 LDCs as the "Study  
8 Group." For the Northeast Regional group, LEI's Industry TFP Study was  
9 based on 29 LDCs located across seven states comprising the Northeast  
10 Region as used by the Bureau of Labor Statistics ("BLS"). These 29 LDCs  
11 accounted for 94% of gas customers in the Northeast Region and 81% of the  
12 total volume of gas sales in the Northeast Region, as of 2017.

13 The 83 LDCs encompass both small and large utilities, ranging from 1,200  
14 to 2.2 million customers in 2017 (for reference, the Company had  
15 approximately 291,000 customers as of 2017), and across all regions of the  
16 U.S. For an industry TFP to be useful for PBR formula design purposes, it

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<sup>12</sup> In general, the Fisher Ideal index produces very similar results to other index formulations such as the Laspeyres index, Paasche index, and Törnqvist index. The differences are more pronounced over a short timeframe, where the weighting scheme reflected in the Fischer Ideal can produce numerically different values.

1       should capture the trends in productivity across all peers, not just the  
2       historical productivity trends of the regulated firm applying for PBR  
3       treatment. The LEI Industry TFP Study does not capture 100% of all LDCs  
4       in the U.S. because of data limitations. However, LEI's Study Group is  
5       larger and more comprehensive than any other similar LDC TFP study  
6       submitted prior to this point with state regulators across the U.S. As a  
7       result, I have confidence that the sample of 83 LDCs (for the U.S.) and 29  
8       LDCs (for the Northeast Region) appropriately reflect the TFP trends for  
9       the national LDC industry and the Northeast Regional LDC industry,  
10      respectively.

11   **Q.    You mentioned that the LEI Industry TFP Study does not capture 100%**  
12   **of all LDCs in the U.S. because of data limitations. Would you explain**  
13   **this further?**

14   **A.**LEI aimed to include as many LDCs as possible, subject to availability of  
15       quality data over the entire study timeframe. However, financial and  
16       operating data for LDCs is not available in a single, centralized repository  
17       (such as the FERC Form 1 that has data for all U.S. investor-owned electric  
18       utilities). LDCs file their annual reports to their respective state regulators,  
19       and public filing policies vary by state regulator. After acquiring a basic

1 data set, LEI expended significant additional effort, manually checking and  
2 adding data, where readily and publicly available.

3 **Q. Over what timeframe is the TFP growth rate calculated, and is this a valid**  
4 **timeframe for purposes of ratemaking?**

5 A. LEI's Industry TFP Study was conducted over the timeframe of 2003 to  
6 2017. The most recent financial and performance data available in early  
7 2019, when LEI began its research, was calendar year 2017. By starting with  
8 2003 financial and operating statistics, LEI has estimated a 15-year trend for  
9 the growth rate in the LDC industry TFP. To perform the index calculations  
10 beginning in 2003, LEI collected capital quantity data back to 1998, to build  
11 up the capital input quantity. LEI chose 1998, as that was the year with  
12 consistent data available for LDCs in the Industry Group.

13 The primary purpose of conducting an Industry TFP Study for ratemaking  
14 purposes is to estimate an average rate of change in productivity, which is  
15 naturally going to span multiple years. Looking over many years of data  
16 will reduce the bias that can be caused by numerical outliers or one-off  
17 events that affect productivity in any single set of consecutive years. At the  
18 same time, one must be careful not to include outdated information about  
19 productivity that is not going to be representative of current operating

1 dynamics and future possibilities, especially as the historical TFP growth  
2 trends are intended to inform future rates.

3 Given data availability and quality (see Section 3 of LEI's Industry TFP  
4 Study report for further details) and best practices for TFP analysis, the 15-  
5 year timeframe of 2003-2017 is appropriate for setting the Company's X  
6 factor under an I-X revenue cap per customer for the next five years, as it  
7 provides a robust, up-to-date, and stable estimate of average industry  
8 trends (eliminating the impact of any year-on-year outliers). Estimated  
9 industry TFP trends from further back in time would have predated the  
10 industry's move towards the use of plastic mains and intense focus on leak  
11 prevention. Older data would also not capture the slow-down in customer  
12 growth or the policy emphasis on more efficient customer consumption.

13 **Q. What inputs did LEI examine in its Industry TFP Study?**

14 A. LEI constructed a two-input model consisting of quantities of capital and  
15 quantities of non-capital inputs (based on deflated operating costs). Capital  
16 quantities were based on an estimation of the real capital stock (capital  
17 additions and retirements) and weighted by the implicit rental price of

1 capital, developed in a seminal paper by Christensen and Jorgenson  
2 (1969)<sup>13</sup> (see Section 3.3 in LEI's Industry TFP Study for further details).

3 Non-capital quantities were based on reported annual operations,  
4 maintenance, and administration ("OM&A") expenses, including labor  
5 costs, non-labor distribution operations, and maintenance costs, storage  
6 costs, customer accounts, customer service-related operating expenses and  
7 reported administrative & general expenses. This data was taken directly  
8 from utility filings (see Section 3.3 of the LEI Industry TFP Study for a  
9 description of the data that LEI relied on to calculate the OM&A and capital  
10 inputs).

11 **Q. Why are you referring to quantities of inputs?**

12 A. The LEI Industry TFP Study is designed to capture the trend in physical  
13 productivity for LDCs. Because this is not a financial or accounting study,  
14 raw financial data should not be used. Instead, LEI converted raw financial  
15 data from monetary values to physical unit proxies. Price deflators were  
16 used to convert nominal monetary values into "real" dollar-denominated  
17 quantities.

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<sup>13</sup> L.R. Christensen and D.W. Jorgenson (1969), "The Measurement of Real Capital Input, 1929 - 1967," Review of Income and Wealth, Series 15, No. 4, December, pp. 293-320.

1    **Q.    What output metric did LEI use in its Industry TFP Study?**

2    A.    LEI used the total number of customers served in each year using the  
3           distribution system as an output metric, including customers that may be  
4           receiving gas acquired by non-utility retail suppliers. The use of total  
5           customers served is a common practice for TFP studies for the LDC  
6           industry, as well as other network industries. An advantage of using the  
7           total number of customers as an output metric is that the number of  
8           customers is a numerical data point that is both available and consistently  
9           measured across LDCs. Gas sales, which LEI also considered as an output,  
10          are primarily driven by weather patterns that can vary considerably across  
11          the years. However, operational procedures and capital investment plans  
12          will not change in response to weather variability. Therefore, the use of gas  
13          sales as an output metric may introduce volatility in the TFP index that is  
14          not truly reflective of the industry's physical productivity trends.

15        Additionally, gas utilities typically build pipeline systems to serve  
16        customers and not necessarily the specific amount of gas consumed per  
17        customer, as that is likely to change with time. Figures 17 and 18 of LEI's  
18        Industry TFP Study show the number of customers and gas sales, as well  
19        as the corresponding growth rates.



1    **Q.    What were the key results in LEI's Industry TFP Study?**

2    A.    The TFP for the national Study Group grew by 0.09% on average over the  
3           2003-2017 timeframe. The TFP results are described in detail in Section 4 of  
4           LEI's Industry TFP Study. The marginally positive TFP growth rate is the  
5           result of an increase in the quantity of inputs deployed by LDCs in the U.S.,  
6           which is slightly smaller than the growth rate in outputs (number of  
7           customers served).

8           Capital inputs grew by 0.76% per annum on average, while non-capital  
9           (OM&A) inputs grew by 0.52% per annum on average over the 2003-2017  
10          timeframe for the U.S. LDC industry. Capital inputs represented about  
11          52% of the total quantity of inputs. When combining the two inputs into a  
12          composite input index, the annual average growth rate in input quantities  
13          amounted to 0.65% per annum. Output grew on average at 0.73% per  
14          annum over this same timeframe. The 0.09% average TFP growth rate  
15          suggests that over the last 15 years, the number of customers grew slightly  
16          faster than the quantity of inputs expended per customer.

17          Growth in the quantity of capital inputs can be attributed to network  
18          investment motivated by customer growth, replacement of aging capital,  
19          and expanding safety-related requirements (such as the new regulations

1 enacted by the U.S. Pipeline and Hazardous Materials Safety  
2 Administration (“PHMSA”) requiring utilities to establish and implement  
3 a Distribution Integrity Management Program by August 2011.

4 Growth of non-capital quantity inputs can be attributed to several factors,  
5 such as support for energy policy objectives, the implementation of safety  
6 programs (e.g., leak management program) to comply with PHMSA’s  
7 requirements, and increasing labor costs.

8 LEI also calculated the growth in TFP for LDCs located in the Northeast  
9 Region of the U.S., which is defined by the BLS and includes the nine states  
10 of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New  
11 York, Pennsylvania, Rhode Island, and Vermont.<sup>14</sup> The TFP growth rate for  
12 the Northeast Region is -0.39% per annum, on average, over the 2003-2017  
13 timeframe. The negative TFP trend for the LDCs operating in the Northeast  
14 Region is attributed mainly to higher growth rates in inputs (both capital  
15 and OM&A) and slower growth in output (number of customers), as  
16 compared to the trends for the U.S. as a whole.

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<sup>14</sup> As shown in Figure 16 of LEI’s Industry TFP Study, LEI included 29 LDCs in the Northeast Region, which cover all the states in the region except for Maine and Rhode Island.

1   **Q.   Are there specific factors that set the Northeast Region apart from the rest**  
2   **of the U.S for purposes of assessing TFP growth for LDCs?**

3   A.   Yes. There are several potentially important factors that may impact  
4   productivity growth in the LDC sector that appear to vary materially  
5   between the Northeast Region and the rest of the U.S. LEI focused on three  
6   drivers of TFP growth: economies of scale, technology, and output growth.  
7   LDCs in the Northeast Region have, on average, smaller gas pipeline  
8   systems with fewer customers, which can affect TFP growth.<sup>15</sup> In terms of  
9   technology, LDCs in the Northeast Region have greater proportion of cast  
10   (or wrought) iron mains on their systems, which may lead to a different  
11   trend in TFP over time for the Northeast Region relative to the rest of the  
12   U.S. In addition, LDCs in the Northeast Region in the aggregate have  
13   experienced slower growth in the number of customers in the past few  
14   years as compared to LDCs in the rest of the U.S. Output growth is a major  
15   component of TFP growth.

16   LEI examined the significance of the difference in the number of customers  
17   as of 2017 as a reference for the size of an LDC and a proxy for economies  
18   of scale. In 2017, the average number of customers per LDC outside the

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<sup>15</sup>   Eatwell, John, Murray Millgate, and Peter Newman. "The New Palgrave: A Dictionary of Economics." Pages 660-661.

1 Northeast Region (669,822 customers per LDC) was nearly 65% higher than  
2 the average customer count for LDCs in the Northeast Region (408,082  
3 customers per LDC). This difference in size has been consistently observed  
4 over the last past 15 years.

5 LEI also considered the technology used by the LDCs in the Northeast  
6 Region versus the rest of the U.S., as proxied by the relative quantity of cast  
7 (or wrought) iron mains deployed on LDCs' systems. LEI identified that  
8 the share of the mains made up of cast (or wrought) iron in use by LDCs in  
9 the states that make up the Northeast Region are substantially higher,  
10 compared to LDCs in other states in the continental U.S.<sup>16</sup> For example, in  
11 2018, states in the Northeast Region had a materially higher share of  
12 average total main miles of cast/wrought iron than the other regions in the  
13 U.S.<sup>17</sup> This is an indication that the technology factors for LDCs in the  
14 Northeast Region are different from the other U.S. regions, and this could  
15 impact opportunities for productivity growth.

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<sup>16</sup> PHMSA. "2010+ Pipeline Miles and Facilities." Accessed on October 25, 2019. Available online: <https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-mileage-and-facilities>

<sup>17</sup> The Northeast states had an average of 11.0% of total main miles of cast/wrought iron versus 2.8% for non-Northeast states in 2018.

1        Lastly, over the past 15 years (2003-2017), the average annual growth rate  
2        in the total customers served by the LDCs in the Northeast Region lagged  
3        than the rest of the U.S. by almost 25%. In recent years (e.g., in the last 3  
4        years of the Study timeframe (2015-2017)), the differential between average  
5        annual growth rates of the Northeast Region LDCs versus the LDCs in the  
6        rest of the Study Group has expanded to more than 40%. Slower output  
7        growth will affect TFP trends.

8        Based on economies of scale, technology in use, and output growth, LEI  
9        recommends a Northeast Region TFP growth rate for setting NSTAR Gas'  
10       X factor.

11    **Q.    How should the observed industry TFP trends be used in the Company's**  
12    **rate proposal?**

13    A.    LEI understands that NSTAR Gas is proposing a revenue per customer cap  
14        for a five-year term, with an I-X adjustment mechanism. The Company is  
15        proposing that the use of the TFP trend derived by LEI for LDC  
16        productivity in the Northeast Region of -0.39%, rather than the national  
17        Study Group trend of 0.09%. In either case, the TFP trend would be  
18        adjusted before it becomes the X factor, in order to align with the selected  
19        inflation factor ("I factor").

1 Consistent with Department precedent, the Company is proposing to use  
2 the U.S. Gross Domestic Product Price Index (“GDP-PI”) as the I factor, as  
3 it is simple and accessible for purposes of the escalation mechanism.<sup>18</sup>  
4 However, given that GDP-PI is an economy-wide inflation indicator,  
5 several adjustments need to be made to the TFP trend to have an  
6 appropriate X factor in pairing with the GDP-PI index. The X factor should  
7 include a TFP differential and an input price differential between the LDC  
8 industry and the U.S. economy as a whole.

9 The TFP differential is the difference between rates of change in the  
10 industry TFP and TFP for the overall economy. The broadest measure of  
11 TFP for the U.S. economy is the Bureau of Labor Statistics (“BLS”)   
12 multifactor productivity (“MFP”) index for the private business sector.<sup>19</sup>  
13 LEI used this BLS MFP index as a proxy measure of TFP trends in the U.S.  
14 economy. The TFP trend differential over the 2003-2017 timeframe for the  
15 Northeast Region is -0.98%. The TFP trend for the national industry, on the  
16 other hand, is -0.51%.

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<sup>18</sup> Exhibit ES-WJA-DPH-1.

<sup>19</sup> Department of Labor, Bureau of Labor Statistics, Multifactor Productivity for the Private Business Sector, Series ID MPU4900012 (02). <<http://www.bls.gov/mfp/>>

1 The input price differential is the difference between rates of change in  
2 input prices for the overall economy and the LDC industry. LEI used the  
3 GDP-PI and the industry input price index from the LEI Industry TFP Study  
4 to estimate the input price differential. The input price differential over this  
5 15-year timeframe is -0.32% for the Northeast Region LDCs, and -0.28% for  
6 the national Study Group. The adjustments to the TFP trend to yield the X  
7 factor are discussed in greater detail in Section 5 of LEI's Industry TFP  
8 Study. In total, these adjustments result in a recommended X factor  
9 of -1.30% using the Northeast Region TFP trend.<sup>20</sup>

10 **Q. How does this recommended X factor compare with the X factor accepted**  
11 **by the Department for NSTAR Electric and the X factor proposed in other**  
12 **recent PBR plans for the LDC sector?**

13 A. LEI's X factor is reasonable and appropriate given the findings from several  
14 recent TFPs, including NSTAR Electric's approved X factor. There are a  
15 number of similarities between the NSTAR Gas and NSTAR Electric  
16 revenue cap formulas. First, both the electric and gas utilities are proposing  
17 to use an index-based approach to estimate the TFP trend. Second, both  
18 the electric and gas industry TFP studies relied on a 15-year period. NSTAR  
19 Electric's sample period is from 2001 to 2015, while the study timeframe for

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<sup>20</sup> The X factor using the national Study Group trend is -0.79%.

1 NSTAR Gas is from 2003 to 2017. Third, both utilities have over 60  
2 companies reflected in the industry sample. The TFP Study for NSTAR  
3 Electric used 67 electric LDCs, while LEI used data from 83 LDCs across the  
4 U.S. Fourth, both utilities appropriately utilized the One Hoss Shay  
5 (“OHS”) approach to quantify the physical deterioration of capital inputs,  
6 as explained in Section 3.2.2 of LEI’s Industry TFP Study.

7 Certain differences between the TFP studies for electric distribution sector  
8 and the LDC industry are related to the data. As discussed earlier, TFP  
9 studies for the electric distribution industry in the United States can utilize  
10 data from a single source (FERC Form 1), unlike the LDCs. Given the  
11 differences among state requirements, it is not surprising that LEI  
12 encountered difficulty in obtaining historical data for LDCs in its Study  
13 Group going back further in time than 1998.

14 There are also inherent technical differences between electric distribution  
15 and the LDC industries. For example, the average service life assumption  
16 LEI developed was explicitly geared at gas distribution network  
17 infrastructure.

18 Some methodological differences are based on practitioner preference but  
19 are generally immaterial on the conclusions (for example, in the NSTAR



1 Electric rate case, Christensen Associates used the Tornqvist index while  
2 LEI used the chained Fisher Ideal index for NSTAR Gas).

3 **IV. SUMMARY OF TOTAL COST BENCHMARKING STUDY**

4 **Q. Please describe the key aspects of a Total Cost Benchmarking Study.**

5 A. Total cost benchmarking allows LEI to study the relative productivity of  
6 firms, through cross-sectional comparison across companies of each LDC's  
7 total cost of operations with the outputs (or services) each provides, after  
8 controlling for size of an LDC's business and other important factors (also  
9 referred to as business condition, or drivers). The ultimate purpose of a  
10 Total Cost Benchmarking Study is to be able to compare an LDC's actual  
11 costs to its predicted cost, given input prices, the size of the LDC, and key  
12 business drivers. For purposes of determining which LDCs are relatively  
13 efficient and ranking companies accordingly, each LDC's actual cost is  
14 compared to its predicted cost. LDCs with actual costs lower than predicted  
15 are more efficient than average; LDCs with actual costs that are higher than  
16 predicted are less efficient than average. LDCs are then ranked by the size  
17 (and sign) of the gap between actual and predicted costs. The most efficient  
18 LDCs have large negative gaps (actual costs are much lower than  
19 predicted). The least efficient LDCs have large positive gaps (actual costs  
20 are much higher than predicted).

1    **Q.    How would a regulator use a Total Cost Benchmarking Study?**

2    A.    Under a revenue cap per customer, the regulator will be setting a trajectory  
3           for rate adjustments over the term of the PBR rate plan. The regulator will  
4           also be approving the starting point for escalation, namely the base rate.  
5           The results of a Total Cost Benchmarking Study provide empirical evidence  
6           that may be used to inform the regulator's judgment on an appropriate  
7           expectation for further efficiency improvements for the regulated LDC, in  
8           addition to the industry's average TFP growth trend. An LDC that has  
9           actual costs that are lower than the costs predicted by the benchmarking  
10          model is more efficient than what is otherwise predicted given its location,  
11          customer base, type of customer, network characteristics, etc.

12          By identifying the relative efficiency of the regulated firm, the Total Cost  
13          Benchmarking Study helps the regulator calibrate the I-X mechanism.  
14          Generally, an LDC that is more efficient relative to its peers has less room  
15          for further cost savings; whereas a company that is less efficient than its  
16          peers has more room for improvement. As such, regulators may set  
17          "stretch factors" (above and beyond the industry-average X factor target)  
18          to motivate a relatively inefficient regulated firm to catch up to its peers.

1        On the other hand, if a Total Cost Benchmarking Study suggests the  
2        regulated LDC is relatively efficient, then the proposed base rate is already  
3        reflecting the relative efficient levels of cost of service. Also, for this  
4        relatively efficient LDC, additional incentives (in the form of stretch factor)  
5        are not necessary. This conclusion should not be interpreted to suggest that  
6        an efficient firm will be given an opportunity to slack off and fall behind.  
7        The X factor will still provide an incentive for this LDC to achieve  
8        productivity gains consistent with the industry norm.

9        **Q.    What methodology did LEI apply to conduct the Total Cost**  
10       **Benchmarking Study?**

11       A.    LEI conducted an econometrics-based Total Cost Benchmarking Study.  
12       Econometrics-based benchmarking is a well-established approach for  
13       comparing firms based on their total costs and outputs. An econometric  
14       model allowed LEI to control for factors such as the price of inputs (such as  
15       the price of labor) and the size of the LDC (which can be measured by the  
16       number of customers served). The model can also include other factors that  
17       could impact total cost, such as composition of the firm's LDC network (for  
18       example, miles of pipeline not made of cast iron or bare steel, age of  
19       network, customer density), the profile of customers served (for example,  
20       percentage of residential customers served), and regional factors (like

1 population density of the region where the LDC's service territory is  
2 located). Controlling for business factors such as these, which are outside  
3 of the control of management, is important for arriving at a measure of cost  
4 efficiency that can be interpreted as the result of business decisions and  
5 activities that are under the control of management at the firm.

6 **Q. What are the prerequisites for conducting an econometrics-based**  
7 **benchmarking analysis?**

8 A. The use of econometrics requires a large set of standardized data to provide  
9 reliable results. LEI's Total Cost Benchmarking Study for the LDC sector  
10 used the same dataset as LEI's Industry TFP Study, with certain additional  
11 factors and metrics compiled from reliable sources like the United States  
12 Energy Information Administration ("EIA"). The LDC data collected from  
13 state regulatory filings, FERC, and EIA is sufficiently standardized because  
14 of the existence of EIA and FERC reporting requirements, as well as  
15 common accounting practices for state regulatory filings.

16 The econometric approach has been used in many PBR submissions and  
17 has been accepted by regulators in numerous jurisdictions, including in  
18 Australia, Colorado, New Zealand, Oklahoma, Ontario, and the United  
19 Kingdom, to name a few.

1    **Q.    How does the econometric analysis work for purposes of benchmarking?**

2    A.    An econometric model estimates the statistical relationship between a  
3           dependent variable (in this case, the total cost of service) and a set of  
4           independent variables (in this case, input prices, firm size, and other  
5           important business conditions). The econometric process allows us to track  
6           how changes to the independent variables individually are related to  
7           changes in the dependent variable.

8           For example, when the number of customers served is higher, common  
9           sense tells us that total costs will be higher. The econometric process allows  
10          for estimating how much higher total costs will be for an additional number  
11          of customers. The econometric process also allows isolating the impact of  
12          the number of customers from other factors that impact the total cost. The  
13          econometric results also indicate how well the independent variables as a  
14          whole explain (or, alternatively, predict) the level of the total cost for a given  
15          utility. This is referred to as the “fit” of the econometric model and is the  
16          main focus of utility benchmarking analysis. Utility benchmarking requires  
17          a model with a good fit. This is because, in order to evaluate an individual  
18          LDC’s efficiency relative to its peers, the total cost for each LDC as predicted  
19          by the model is compared to the actual total cost for each firm.

1 LEI selected to use the transcendental logarithmic (“translog,” or “TLC”)  
2 cost function to benchmark performance. The TLC is a tried-and-tested tool  
3 for empirical research of costs in many sectors of the economy, with  
4 examples as diverse as oil and gas production, banking, airports, and school  
5 systems, as well as utilities. To use the TLC, the raw data is logged (using  
6 the natural logarithm of each data point) and normalized. This process  
7 eliminates wide variations in the data and provides predicted total costs  
8 which are readily comparable across firms.

9 **Q. What data is used in the Benchmarking Study?**

10 A. Unlike the LEI Industry TFP Study, where LEI was interested in the trends  
11 for the industry (and therefore LEI aggregated firm-level data into a  
12 representative industry value), an econometric benchmarking study leaves  
13 the data at the individual firm level. The LEI Industry TFP Study evaluated  
14 83 LDCs. These same firms were analyzed in the LEI Benchmarking Study  
15 (although one firm was removed<sup>21</sup> as it has incomplete data for one of the  
16 independent variables). There is no need to, nor is it desirable to narrow  
17 down the list of firms analyzed in the Benchmarking Study to those most

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<sup>21</sup> The company that was removed in the benchmarking study is the Avista Corporation as it lacked data on miles of pipeline across the Study timeframe.

1 similar to NSTAR Gas, based on size or other business conditions. These  
2 factors are controlled for in the econometric process.

3 **Q. What costs were included in the Total Cost Benchmarking Study?**

4 A. Total costs consisted of OM&A costs and capital costs, both of which were  
5 sourced from the dataset used in the LEI's Industry TFP Study.

6 **Q. What other independent variables were included in the Total Cost**  
7 **Benchmarking Study?**

8 A. A number of variables were considered for inclusion. The goal was to  
9 identify factors that impact the total costs of service for LDCs. The final set  
10 of independent variables in the TLC equation included: the number of  
11 customers served (an important variable which controls for the size of the  
12 company), the price of capital, the price of OM&A, the percentage of  
13 pipeline mains (by length) not made of cast iron or bare steel, the share of  
14 residential customers, percentage of pipeline (by miles) built in the last 10  
15 years, network density, and population density in the region where the  
16 LDC is located.

17 **Q. What timeframe was analyzed in LEI's Total Cost Benchmarking Study?**

18 A. The Total Cost Benchmarking Study, for purposes of forward-looking  
19 ratemaking, should focus on understanding the current efficiency of LDCs.

1 Unlike the TFP analysis, which is used to establish the trend in productivity  
2 improvement over time, a benchmarking study must reflect the current  
3 efficiency of a firm to develop the efficiency level of the firm at the start of  
4 the next regulatory period for the purpose of ratemaking. Therefore, LEI  
5 examined only the period of 2014-2017, rather than a longer time series of  
6 data found in LEI's TFP Industry Study. LEI used four years of data, rather  
7 than only one, to ensure that results would not be overly influenced by  
8 events or issues that only impacted the LDC data for a single year. Also,  
9 four years of data provided LEI with more observations: in econometrics,  
10 reliability of results is correlated with the number of observations.

11 **Q. Please summarize the results of LEI's Total Cost Benchmarking Study for**  
12 **NSTAR Gas.**

13 A. LEI's Total Cost Benchmarking Study indicates that NSTAR Gas is  
14 relatively efficient. The Company had actual total costs below those  
15 predicted by the econometric model for three of the last four years, which  
16 suggests that the Company is a relatively efficient operator. LEI also  
17 constructed a ranking of all LDCs, based on the size of the difference  
18 between actual cost and predicted costs. As noted previously, companies  
19 with the largest negative difference (i.e., average costs lower than  
20 predicted) are the most efficient; companies with the largest positive



1 difference (actual costs greater than predicted) are the least efficient.  
2 Because LEI used logged and normalized data in the econometric model,  
3 the relative size of the difference between actual and predicted costs do not  
4 reflect the size of the firm, it only reflects the firm's efficiency. Based on this  
5 ranking, the Company placed in the second quartile of all LDCs in the Study  
6 Group for the U.S. sample and was in the first quartile of LDCs located in  
7 the Northeast Region.

8 **Q. What do the results of the Total Cost Benchmarking Study mean for**  
9 **setting the I-X escalation mechanism for NSTAR Gas?**

10 A. In our professional opinion, the results of LEI's Total Cost Benchmarking  
11 Study confirm that NSTAR Gas is already a relatively efficient LDC and,  
12 therefore, should not be required to achieve any additional stretch factor or  
13 higher X factor than what is justified based on industry average TFP trends.

14 **V. IMPLICATIONS FOR THE COMPANY'S REVENUE CAP PER**  
15 **CUSTOMER PROPOSAL**

16 **Q. Do you support the I factor proposed by NSTAR Gas?**

17 A. Yes. The I factor proposed by the Company is consistent with the  
18 Department's most recent decisions, and it also reflects the three basic  
19 requirements for an I factor. When deciding upon the inflation factor, I  
20 considered the following criteria:

- 1           • *Data availability and Reliability* – data to be used to calculate the I  
2           factor should be readily available in time for setting the rates, and  
3           the data should come from a reputable and reliable source (the  
4           proposed GDP-PI is drawn from data produced by the Bureau of  
5           Economic Analysis);
- 6           • *Implement-ability and Simplicity* – the I factor should be easy to  
7           calculate and understand; and
- 8           • *A representative of the Utility's Observed Inflationary Cost*  
9           *Pressures but Also Not Self-Referential* – the I factor should not only  
10          reflect inflationary input cost pressures faced by the LDCs but also  
11          should not be susceptible to being manipulated or affected by the  
12          Company.

13          NSTAR Gas proposes to use the GDP-PI for the I factor. The GDP-PI meets  
14          all the criteria mentioned above for the development of an appropriate I  
15          factor. More specifically, it is published by a reputable independent agency,  
16          and it reflects cost pressures across all inputs such as labor, capital,  
17          materials, and services faced by all businesses (not just LDCs). Lastly, the  
18          Company cannot impact the GDP-PI trends.

1   **Q.    How is the observed industry TFP trend reflected in the NSTAR Gas**  
2   **revenue cap per customer proposal?**

3   A.    Since NSTAR Gas is proposing an economy-wide inflation index (GDP-PI),  
4       the TFP growth rate results need to be calibrated to reflect the industry cost  
5       trends. More specifically, the X factor should consist of a TFP differential  
6       and an input price differential if an economy-wide measure is used for the  
7       I factor, as discussed further in Section 5 of LEI's Industry TFP Study. As  
8       described in an earlier section of this testimony, the Northeast Region  
9       industry TFP trends are the appropriate benchmark for calibrating NSTAR  
10      Gas' X factor and PBR formula. The TFP trend of -0.39% needs to be  
11      adjusted by the -0.32% input price differential and -0.98% TFP differential.  
12      As such, the X factor that should be reflected in the Company's revenue cap  
13      per customer proposal is -1.30%.

14   **Q.    What are the key takeaways from LEI's Total Cost Benchmarking Study**  
15   **for the Company's revenue cap per customer proposal?**

16   A.    Because NSTAR Gas is already relatively efficient, there is empirical  
17       evidence to suggest that there is no need for additional stretch factor or  
18       other adjustments to the estimated base rate, which will anchor the revenue  
19       cap per customer proposal.

1   **Q.    Are adjustments to the X factor necessary to account for the legislated Gas**  
2   **System Enhancement Plan (“GSEP”) program?**

3   **A.**    No, I do not believe that adjustments to the X factor are warranted. The  
4           GSEP program and the X factor are two distinct aspects of the utility  
5           regulatory regime. The X factor measures improvements in physical  
6           productivity over time for the industry, and as part of the I-X formula, the  
7           X factor will dictate how rates will change in the future and that will in turn  
8           incentivize the Company to become more efficient. In contrast, the GSEP  
9           program is an accounting mechanism for timely recovery of qualifying  
10          spending and investments in rates.

11         As I have previously described in this testimony, the TFP trend measures  
12         the change over time in the physical productivity of the industry. That  
13         productivity trend, in combination with inflationary cost pressures for the  
14         industry’s inputs, leads to calibrated values under the I-X formula. It is this  
15         same I-X formula that provides the primary incentive for the Company to  
16         become more efficient. In contrast, the GSEP program is not measuring  
17         physical productivity, nor is it creating an overarching incentive for the  
18         Company to improve its productivity. The GSEP program simply sets out  
19         the process for the Company to apply for timely recovery of qualified

1 expenditures and capital investments aimed at repairing or replacing aging  
2 or leaking natural gas infrastructure.<sup>22</sup>

3 According to the American Gas Association, “47 utilities in 22 states serving  
4 24 million residential natural gas customers are using full or limited special  
5 rate mechanisms to recover their replacement infrastructure  
6 investments.”<sup>23</sup> The aggregate effect of all such accounting programs and  
7 regulatory treatments are not distinguished in the LEI Industry TFP Study,  
8 nor should it be. It is standard practice to include as many firms as the data  
9 allows in the Industry Study Group for productivity growth analysis,  
10 irrespective of regulatory arrangements.

11 Furthermore, it is not possible to quantify accurately or exclude the changes  
12 in capital inputs that are may be related to GSEP-type investments for peer  
13 companies of NSTAR Gas, as the sources of data that are publicly available

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<sup>22</sup> I understand that the GSEP program provides for timely rate recovery of qualified expenditures and capital investments that repair or replace aging or leaking natural gas infrastructure, including replacement of mains, services, and other facilities. Each year, LDCs in Massachusetts submit an annual plan to the Department. A cap of 3% of the LDC’s most recent calendar year total firm revenues, including gas revenues attributable to sales and transportation customers, is set for the yearly changes in the revenue requirement. If the plan is accepted, the LDC may begin recovering the estimated GSEP revenue requirement on May 1 of the year following submission of the plan.

<sup>23</sup> Report is available online at <https://www.aga.org/sites/default/files/legacy-assets/our-issues/RatesRegulatoryIssues/ratesregpolicy/rateroundup/Documents/2012%20Jun%20Update%20%20Infrastructure%20Investment.pdf>

1 for gas companies do not disaggregate capital investment by the form of  
2 accounting treatment. Therefore, incorporating an offset to the X factor to  
3 specifically align the factor with GSEP expenditures will undermine the  
4 validity of the X factor.

5 **Q. Are you concerned that a revenue cap per customer may cause NSTAR**  
6 **Gas to implement unduly severe cost reductions and/or defer**  
7 **investments, leading to deteriorating service quality for the utility**  
8 **consumer?**

9 A. No. I understand that the Company is seeking to continue its commitment  
10 to monitor service quality (and adhere to the goals of its scorecard metrics).  
11 As such, the revenue cap per customer, while encouraging the Company to  
12 seek out cost reductions, will also motivate the Company to continue to  
13 adhere to the performance targets previously set by the Department for its  
14 operations.

15 **Q. Will the proposed revenue cap per customer with the I-X rate adjustment**  
16 **mechanism create the appropriate incentives?**

17 A. Yes. NSTAR Gas has not sought base-rate relief since 2014, and prior to that  
18 case, the Company did not petition for base-rate relief for over 20 years.  
19 Therefore, in effect, the Company has been operating under an implicit  
20 form of PBR where the X factor was equal to the rate of inflation (which has  
21 averaged 1.73% per annum from 2016 through 2018). Although the

1 inflation rate was positive, the Company has experienced declining  
2 customer growth and anticipates that this will continue.<sup>24</sup> Moreover, the  
3 Company is facing several challenges that are requiring expanding OM&A  
4 and incremental capital investment due to increasing requirements related  
5 to system safety.<sup>25</sup> As stated in Exhibit ES-WJA/DPH-1, these include gas-  
6 safety directives associated with the Merrimack Valley event and various  
7 investigations related to this, non-GSEP work related to pressure regulation  
8 modernization, pressure protection devices, and system resiliency  
9 investments to mitigate energy disruptions, to name a few.<sup>26</sup>

10 A revenue cap with an I-X adjustment mechanism allows the Company to  
11 commit to a five-year PBR term. The five-year term will mean lower overall  
12 regulatory costs for the Company and the regulator, ultimately benefiting  
13 customers. The efficiency incentives of a revenue cap design will also create  
14 valuable benefits for consumers as well as the Company, as discussed  
15 above.

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<sup>24</sup> Exhibit ES-DPH-ANB-1.

<sup>25</sup> As stated in Exhibit ES-WJA/DPH-1.

<sup>26</sup> As stated in Exhibit ES-WJA/DPH-1.

1    **Q.     Does this conclude your testimony?**

2    **A.     Yes.**



**Curriculum Vitae of:**

**Julia Frayer**

**Marie Fagan**

**Exhibit ES-JF/MF-1, Attachment A**

## Curriculum Vitae

**JULIA FRAYER**

*Managing Director, London Economics International LLC*



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### KEY QUALIFICATIONS:

Julia Frayer is a Managing Director with London Economics International LLC (“LEI”), specializing in economic analysis and evaluation of infrastructure assets, such as power plants, natural gas-related infrastructure, electricity transmission and distribution systems, and utilities, as well as market design and expert economic advisory services for regulated and competitive power markets. She has worked extensively in the US, Canada, Europe, and Asia in valuing electricity generation and wires assets, water and wastewater networks, as well as gas transportation assets. She also provides expert advice on market rules, innovative rate design, and institutional best practices for the management of infrastructure assets.

Julia manages LEI’s quantitative financial and business practice area and also specializes in market and organizational design issues related to electricity. In addition to electric generation sector market power and anti-trust analysis, sample projects include cost of capital estimation; rate-setting analysis; short- and long-term forecasting of wholesale power prices; valuation of generators and vertically-integrated utilities; assessment of retail market design including provider-of-last resort portfolios and contracts; design of energy sales agreements; and advisory on structuring request for proposals and sale processes for energy assets and derivative contracts. As part of these analyses, Julia and her team of economists and consultants have developed and applied proprietary real-options based valuation tools, portfolio risk analytics, models of strategic bidding behavior, and sophisticated power system simulation tools, as well as customized econometric models. Julia also leads many of the firm’s regulatory economics projects, spanning such diverse issues as cost-benefit analysis, market power mitigation, tariff ratemaking, auction design (including competitive solicitations for procurement), wholesale market rules design, productivity analysis and efficiency benchmarking.

Prior to joining LEI, Julia was working as an Investment Banker with Merrill Lynch in New York.

### EDUCATION:

Boston University, Boston, MA, B.A. in Economics and International Affairs.

Boston University, Boston, MA, M.A. in Economics.

- ***performing a total factor productivity (“TFP”) and benchmarking analysis:*** LEI is currently engaged to support a Canadian utility in relation to its second-generation hydroelectric payment amounts price-cap application before the Ontario Energy Board (“OEB”). The project involves performing an updated TFP study reflecting the OEB’s 2017 Decision on the first-generation price-cap index. Other key tasks include the preparation of analysis and written evidence assessing whether the inflation factor and treatment of the Capacity Refurbishment Variance Account remain appropriate.
- ***provided an analysis of building block incentive ratemaking approaches and their applicability to Enbridge, a natural gas distribution utility in Ontario:*** LEI’s report supported the client’s distribution tariff proposal submission to the Ontario Energy Board (“OEB”) for a second-generation Customized Incentive Regulation (“IR”) plan for the period of five years (2014-2018). The testimony set out the theory behind as well as the practical experience of using the building blocks approach in incentive regulation regimes. Julia Frayer appeared before the OEB for cross-examination. [OEB File No. EB-2012-0459]
- ***prepared a report for Ontario Power Generation (“OPG”) entitled “Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry:”*** The purpose of this report was to share findings from LEI’s TFP study, which estimated TFP trends for a select group of peers from the North American hydroelectric generation industry. Data for this study covered eleven years from 2002-2012. The purpose of this new engagement is to update this study for newly available data (encompassing operating costs and other statistics for calendar years 2013 and 2014). In February 2016, this analysis was updated for newly available data from calendar years 2013 and 2014. LEI supported OPG through 2017 in recommending an appropriate X factor, and I factor to use in an I-X regime for hydroelectric generation.
- ***provided expert testimony in support of FortisAlberta Inc. (“FAI”) in its filing for a performance-based ratemaking (“PBR”) plan with the Alberta Utilities Commission (“AUC”):*** The testimony provided detailed data analysis (including inflation and TFP trends), underpinning PBR economic theory, and reviews of best practices in various North

American and International jurisdictions. The testimony offers back up elements for each of the various components of the PBR plan that is being proposed by FAI. Julia testified at the AUC in the Spring of 2012. [AUC Proceeding No. 566]

- ***prepared total factor productivity study and presented testimony in respect of Ontario Power Generation's ("OPG") hydroelectric incentive ratemaking plan:*** LEI was retained by OPG to assist in the development of its first generation IRM plan, following the formulaic I-X approach. LEI prepared an industry study of TFP trends spanning the North American hydroelectric sector. LEI also recommended an inflation index, which reflected cost drivers relevant to OPG while also aligning with the regulatory precedent in Ontario. LEI testified before the Ontario Energy Board. LEI's analysis supported the successful approval of OPG's first generation IRM plan for its regulated hydroelectric fleet. [OEB EB 2012-0340]
- ***advised the Coalition of Large Distributors in Ontario on 3rd generation Incentive Regulation Mechanism proceedings of the Ontario Energy Board:*** The work involved expert testimony filed with the Board with detailed analysis of the theory behind the various components of PBR system, including inflation and efficiency gains factors, treatment of capital expenditures among others. The analysis was supplemented with a comparison of actual factors and indices, and determination of the more robust and appropriate indices for Ontario's distribution industry, including total factor productivity analysis for the sector. [OEB Docket No. EB-2007-0683]
- ***advised on regulatory processes:*** LEI was engaged by Ontario Power Generation ("OPG") to support senior management through regulatory processes related to performance-based rates. Julia and her team of experts prepared a discussion paper on incentive regulation mechanisms ("IRM") currently in place in Ontario for electricity and natural gas distribution utilities and presented it at a technical workshop at the Ontario Energy Board ("OEB").
- ***advised on policy and governance framework to Malaysia client:*** LEI was engaged by Tenaga Nasional Berhad ("TNB") to work as the project manager of its Incentive-Based Regulation ("IBR") submission for the 2nd regulatory term. LEI provided advice on the policy and governance framework for the implementation of IBR, providing strategic advice to IBR Council and TNB management regarding the IBR submission, managing and monitoring the submission process, coordinating with business entities, and attending IBR Council meetings, progress meetings, and challenge workshops. Moreover, LEI reviewed the current Regulatory Implementation Guidelines ("RIGs") set by the Energy Commission and proposed enhancements to the RIGs. LEI is also currently involved in negotiations with the Energy Commission regarding proposed changes to the RIGs. LEI is also updating and providing enhancements to TNB's Revenue Requirement Model ("RRM"), which sets the IBR tariff for each business entity. Furthermore, LEI assisted in the writing of the IBR submission report to the Energy Commission.
- ***prepared white paper for Canadian electricity regulators and utilities on the comparative advantages and drawbacks of various tariff-setting regimes, from performance-based regimes to cost-of-service:*** This project involved a general overview of tariff-setting

practices across Canadian provinces as well as highly detailed Canadian and international case studies and an examination of the key-lessons to be learned from each case. Detailed case studies covered the tariff-setting regimes in place in the UK, the Australian National Electricity Market, and the Netherlands. As part of its deliverables, two workshops were conducted with a variety of regulators and utilities.

### **Written and Oral Testimony**

- ***expert services for approval of a settlement:*** LEI was engaged by a private client to provide expert services in connection with the motion of the Financial Management and Oversight Board of Puerto Rico, as representative of the Puerto Rico Electric Power Authority ("PREPA"), and the Puerto Rico Fiscal Agency and Financial Advisory Authority for approval of a settlement with PREPA's bondholders in PREPA's PROMESA Title III case. LEI's expert services included performing economic analyses, preparing an opening expert report, sitting for a deposition, and testifying at the hearing on the motion.
- ***evaluate the costs and benefits of the Maine Power Delivery Authority:*** LEI was retained by the Maine Public Utilities Commission to analyze the short- and long-term costs and benefits of the Maine legislature's proposal (as presented in L.D. 1646) to establish the Maine Power Delivery Authority ("MPDA"). LEI examined the legal, regulatory, technical, financial, and operational issues related to the L.D. 1646 proposal and its implementation, assessed the anticipated impacts of electricity rates, utility employees and ratepayers, and developed alternatives and amendments to the L.D. 1646 proposal to address any identified obstacles to its implementation. The results of LEI's findings were presented to the Maine Legislatures' Joint Standing Committee on Energy, Utilities, and Technology.
- ***independent evaluation of New England Clean Energy Connect transmission project in its siting proceeding at the Maine Public Utility Commission ("MPUC"):*** LEI was retained in 2017 to advise the MPUC staff on the wholesale electricity market impacts and macroeconomic effects of the new transmission project on Maine's economy and the economies of other New England states. LEI prepared an independent forecast of future energy and capacity market benefits, carbon emissions reductions, and local GDP and employment impacts as a result of the construction and operations of the project; LEI also critically reviewed the submission of other parties on this topic. After providing written testimony, LEI staff led by Julia Frayer testified at the MPUC in late 2018. [MPUC Docket 2017 – 00232]
- ***provided independent assessment of Alberta's Comprehensive Market Design:*** LEI provided a critical review of the new capacity and energy market design being proposed by the Alberta Electricity System Operator ("AESO") in a written report submitted, on behalf of a market participant, to the Alberta Utilities Commission ("AUC"). LEI identified criteria for evaluation of the new market design, compared the AESO's proposal against other well-established organized wholesale electricity markets, and then categorized associated rules

based on an objective evaluation of both positive and negative features. [AUC Proceeding No. 23757]

- ***assessment of Efficiency Maine Trust's submission of its program plan and specifically the avoided cost of energy supply:*** LEI was retained by the Maine Public Utility Commission ("MPUC") to provide an independent forecast of future natural gas prices, wholesale energy and capacity prices, which would be relevant for cost-effectiveness analysis of future energy efficiency programs. LEI was also asked to review the multi-stakeholder report that Efficiency Maine Trust and other New England program administrators commissioned in 2014 (and 2015 Update), and subsequently in 2017. LEI staff testified before the MPUC on several occasions over the course of this multi-year engagement. [MPUC Docket 2018-00321]
- ***efficacy of distributed generation as a non-transmission solution to local transmission reliability problems:*** LEI prepared direct testimony and rebuttal testimony related to the technical efficacy and cost-effectiveness of various non-transmission alternatives and specifically distribution level solar and battery storage solution to a known reliability problem in a load pocket within Massachusetts. [Massachusetts, docket EFSB 17-02/D.P.U. 17-82/17-83]
- ***conducted a non-transmission alternative study:*** LEI was hired to conduct a Non-Transmission Alternatives ("NTA") analysis for the two transmission projects, which are a component of larger transmission solutions being proposed by Eversource for the Greater Hartford and Central Connecticut ("GHCC") area. The objective of the NTA analysis was to determine the feasibility and viability of other non-transmission resources – such as new generation and new demand-side resources – to be developed in lieu of these two specific transmission projects to relieve transmission reliability concerns. The NTA analysis was filed as part of Eversource's application with the Connecticut Siting Council ("CSC") for each of these transmission projects. [CSC Docket No. 474]
- ***assessment of congestion in the New York power market:*** LEI was commissioned by a coalition of community groups to prepare an independent outlook of the New York power wholesale market conditions and assess the level of congestion anticipated on major transmission interfaces within the state. LEI studied multiple scenarios to illustrate the impact of major drivers on congestion levels. LEI presented the findings at a technical conference organized by the New York Public Service Commission ("NYPSC") for the purpose of evaluating the benefits of new AC transmission projects. [NYPSC Case 12-T-0502]
- ***engaged by Eversource and National Grid to determine the economic viability of non-transmission alternatives ("NTAs"):*** LEI started the analysis by screening prospective NTA technologies based on their technical characteristics, their relevance in the New England market and their technical applicability. LEI conducted a comparative cost analysis to estimate the levelized cost per kW-month over the economic life of each of the technologies. Finally, the most probable combinations of NTA technologies identified in the selection

process were further evaluated based on criteria, including physical constraints such as land availability, siting issue, financing hurdle, etc. This NTA analysis was conducted for three separate NTA projects that together formed a part of the overall Greater Boston Reliability Project (also known as “AC Solution”). LEI also provided oral testimony about its analysis to the Massachusetts regulator for each of these projects: Wakefield-Woburn NTA Analysis (DPU 15-140 & 15-141), Mystic-Woburn NTA Analysis (DPU 15-64 & 15-65) and Merrimack Valley Reliability Project (DPU 15-44 & 15-45).

- ***independent evaluation of the costs and benefits of the Northern Pass transmission project:*** LEI submitted written testimony to the Site Evaluation Committee (“SEC”) in New Hampshire on the costs and benefits of the proposed transmission project; the analysis focused on wholesale electricity market impacts as well as macroeconomic effects of lower electricity rates and infrastructure investment at the state level in New Hampshire and other states in the region; Julia Frayer also provided oral testimony as part of the SEC’s hearings on the project. [SEC Docket No. 2015-06]
- ***assisted in exploring options to expand Maine’s natural gas supply:*** LEI was engaged by the State of Maine Public Utilities Commission to assist the MPUC in evaluating options for expansion of natural gas supply into Maine (to reduce the cost of gas and power to Maine customers). LEI reviewed and evaluated proposals for firm natural gas transportation service by pipeline developers. These evaluations included LEI’s review of commercial terms include in the pipeline Precedent Agreements that underpin capacity expansion projects, review of contract provisions for Firm Transportation Agreements and Negotiated Rate Agreements; and evaluation of the status of the FERC and state-level permitting process for each pipeline proposal. The project also included natural gas network modeling (using GPCM, an industry-standard network model of the North American natural gas system) and power simulation modeling (using LEI’s proprietary POOLMod model) to arrive at a quantitative cost-benefit analysis of proposals. The Regional Analysis was an additional modeling exercise, to extend the analysis to address the impact on Maine if it were to go forward under a regional initiative to procure pipeline capacity. Testimony was filed in February 2016, and LEI testified in March 2016. [MPUC Docket Number 2014-00071]
- ***estimation of the spot market and forward market impacts around the discretionary timing of outages by large generation owner in Alberta:*** LEI prepared an independent analysis of the spot market and forward market impacts of outage scheduling practices by TransAlta over the period of 2010-2011; the analysis was filed with the Alberta Utilities Commission (“AUC”) as part of a litigated case of alleged market power abuse. [AUC Proceeding No. 3110]
- ***testified on behalf of the NEPOOL in a jump ball filing at FERC regarding the Performance Incentive scheme proposed by ISO-NE:*** in written testimony submitted to FERC, Julia Frayer identified shortcoming in ISO-NE’s proposed performance incentive scheme for its forward capacity market. [Docket No. ER14-1050 at FERC]

- ***served as testifying witness on the issue of utility joining a wholesale market:*** Julia served as testifying witness and lead author in evaluating Entergy's decision to join the Midwest Independent Transmission System Operator ("MISO") Regional Transmission Organization ("RTO") on the behalf of the Public Utility Commission of Texas. LEI evaluated several existing cost/benefit studies related to Entergy's decision to join MISO over the Southwest Power Pool ("SPP") and will be providing quantitative and qualitative analysis of specific costs/benefits attributable to ETI and its customers following membership in either MISO or SPP, including but not limited to net trade benefits, transmission cost allocation, governance issues, and continued participation in the Entergy Service Agreement following RTO membership. [SOAH Docket No. 473-12-6206; PUC Docket No. 40346]
- ***served as Independent Expert regarding Load Following Service products:*** ENMAX retained LEI to act as an independent expert on matters related to proposed auctioning for the Load Following Service ("LFS") product. LEI provided an independent evaluation of the proposed auction, including evaluation of both the product being auctioned and the auction mechanism and key parameters. The LFS product, as proposed to be auctioned was meant to represent the "shape risk" in the RRO service. LEI's evaluation considered whether the product and auction mechanism would result in an efficient, competitive, and fair outcome for the Alberta market, RRO providers, potential suppliers of the auctioned product, and customers of the RRO service. LEI prepared a report titled "Independent assessment of proposed market-based determination of shape risk in RRO supply" dated January 24, 2014, which was filed in ENMAX's Application No. 1610120 before the Alberta Utilities Commission ("AUC"). [AUC Proceeding No. 2941]
- ***testimony in support of transmission operating rules and curtailment protocols for interties into Alberta:*** Julia provided testimony in support of transmission operating rules and curtailment protocols for interties into Alberta, as proposed by the Alberta Electricity System Operator ("AESO"), in order to support a fair, efficient and openly competitive power market. The testimony was made in front of the Alberta Utilities Commission ("AUC"), on behalf of Morgan Stanley Capital Group ("MSCG"), a customer of the Montana-Alberta Transmission Line. Julia's analysis considered commercial as well as operating protocols in deregulated power markets and considers how market rules incentivize new entry and produce dynamic efficiency gains related to more intense competition. The AUC issued a favorable decision to MSCG in early 2013. [AUC Proceeding No. 1633]
- ***provided testimony regarding the proposed merger of two regional utilities at PURA:*** Julia provided written testimony and oral testimony at the Connecticut Public Utility Regulatory Authority ("PURA") related to the market power consequences of proposed merger of NU-NSTAR. [PURA Docket No. 12-01-07]
- ***prepared testimony and testified in support of TransAlta in relation to a settlement for contravention of FEOC Regulation related to the timing of exports from 2010:*** The settlement was crafted by the Market Surveillance Administrator and filed with the Alberta



Utilities Commission ("AUC") for approval in December 2011. LEI assessed the economic and policy considerations of the settlement and its appropriateness in context of enforcement and sufficiency of penalty payment. [AUC Proceeding No. 1553]

- ***conducted RPS review:*** Pursuant to *An Act To Reduce Energy Prices for Maine Consumers*, P.L. 2011, ch.413, sec. 6 (the "Act"), the Maine Public Utilities Commission ("MPUC") was directed by the Legislature to study Maine's renewable portfolio requirement established in 35-A M.R.S.A. § 3210 (3-A). LEI was engaged by MPUC to conduct an in-depth analysis of the renewable portfolio standards ("RPS") required by the Act which would support the MPUC's study and report to the Legislature. Julia led the team in preparation of the report, which was submitted to the Commission in January 2012 and later testified at the state legislature on the key findings of that report. [MPUC Docket No. 2011-271]
- ***prepared detailed cost-benefit analysis and macroeconomic impact analysis in support of the Champlain Hudson Power Express ("CHPE") application for siting approval at the New York Department of Public Service ("DPS" or also known as "NYPSC"):*** LEI's analysis on economic effects was the cornerstone of the settlement agreement reached between TDI and a number of New York agencies. Julia acted as an independent expert on behalf of TDI and prepared updated study results on energy market impacts, capacity market impacts and also macroeconomic benefits stemming from the operation of the CHPE project. Julia's testimony was used in the DPS proceeding in the summer of 2012 and CHPE was successfully granted its Article VII permit. [NYPSC Case 10-T-0149]
- ***served as lead expert witness for a private equity investor in matter related to a contractual dispute regarding a long term power purchase agreement between a municipal utility located in New England and a landfill gas generator:*** Ms. Frayer analyzed key contractual terms of the PPA and provided an expert's review of how those terms compared to the industry norm when the contract was signed and became effective. Ms. Frayer provided an independent estimate of potential contractual damages. The case was scheduled to be heard in Massachusetts Superior Court; however, Julia's analysis helped support a successful settlement.
- ***merger analysis between hydroelectric operators:*** Julia and her team of economists supported the client in preparation of a merger application to the Federal Energy Regulatory Commission ("FERC") under Section 203 of the Federal Power Act, in conjunction with the client's acquisition of a Maine-based hydroelectric generation portfolio. LEI performed a full Delivered Price Test analysis for the ISO New England control area. LEI's analysis was filed with FERC, and the Merger Application was approved in early 2013; market-based rate authority was subsequently granted in mid-2013. [FERC Docket No. ER13-1613]
- ***merger analysis in support of the NRG, Inc. and GenOn merger:*** LEI staff, under Julia's direction and guidance, performed Delivered Price Tests analysis for the Federal Energy Regulatory Commission ("FERC") under Section 203 of the Federal Power Act and submitted the extensive analysis to FERC in the summer of 2012. The Merger Application

was successfully approved by FERC in December 2012. Subsequently, LEI assisted the client in preparation of the 205 market-based rate authority analysis. [FERC Docket No. EC12-134]

- ***provided expert testimony before FERC related to Shell Energy's sale of capacity commitments from facilities in New York to New England in an alleged market manipulation case:*** Julia examined market rules, operating procedures, and pricing arrangements in New England and New York at the time of the investigation, and examined the participation of Shell in the capacity markets and compliance offers in the energy markets, commenting on the economic rationale behind the client's must offer strategies in the energy market for capacity compliance. [FERC Docket No. EL-09-47 and EL-09-48]
- ***provided testimony on behalf of NRG Energy, Inc. in opposition to the proposed acquisition of NRG by Exelon Corp (Exelon):*** LEI performed a preliminary Herfindahl-Hirschman Index test for market power for all regions affected, and a Delivered Price Test, for the PJM East and ComEd regions. In addition, LEI examined Exelon's post-merger optimal bidding strategies using our proprietary model of strategic, known as CUSTOMBid. LEI also assessed the impact of changes in the parent company Exelon's cost of capital on the activities of the company's two regulated subsidiaries: ComEd and PECO. LEI also estimated the impact on customer costs from potential debt downgrades following the merger and assessed the effectiveness of Exelon's proposed ring-fencing measures. LEI's written evidence was filed with FERC and Pennsylvania Public Utility Commission. [FERC Docket No. EC-12-134]
- ***prepared testimony on cost-benefit analysis:*** Julia submitted testimony on behalf of the Staff of the Maryland Public Service Commission ("MPSC") to the MPSC to conduct a cost-benefit analysis in relation to the proposed transaction between Constellation Energy Group, Inc. ("CEG") and Électricité de France ("EDF") whereby EDF would purchase from CEG a 49.99% interest in Constellation Energy Nuclear Group, LLC ("CENG"). Benefits related to the decreased likelihood of a Baltimore Gas & Electric ("BGE") downgrade increased the likelihood of the Calvert Cliffs expansion being completed and several macroeconomic benefits stipulated to by EDF. Costs related to the limitation on the allocation costs of CEG corporate support services to CENG increased risk of capital deprivation and reduced quality of service, and implications of CEG's more aggressive nuclear development. [MPSC, Case No. 9173]
- ***assessed the costs and benefits of new transmission versus generation alternatives to the system:*** New England wholesale electricity markets were simulated in order to determine whether the Greater Springfield Reliability Project would produce economic benefits to the New England region. In order to ensure that economic benefits were not subject to the forced outage and availability schedule of the simulated energy markets, LEI simulated the energy market with 30 different random forced outage and availability schedules. Using these simulations, the distribution of results was used to calculate confidence intervals and hypothesis tests run on the results, hence increasing the robustness of our findings. The study results were used to produce written testimony to the Connecticut Siting Council

("CSC"), and oral testimony was provided in late August and early September 2009. [CSC Docket No. 370B]

- ***prepared proposal on pricing safeguards:*** In September 2005, Julia's proposal for pricing safeguards in the wholesale market, referred to as the Peaker Entry Test, was submitted to the Public Utility Commission of Texas as an alternative to the Commission staff's proposal initially under Project No. 24255 which was later moved to and renamed by the PUCT a Project No. 31972. In April 2006, the PUCT adopted a variant of this proposal for use as pricing safeguards – the Scarcity Pricing mechanism (as specified in the above-mentioned project). Under Project No. 29042, in September 2005, Julia looked at the Pivotal Supplier Test and supplied a critique of the PUCT staff's initial market power mitigation proposal. In June 2005, Julia participated on panel discussing market monitoring issues, as well as market power safeguards for wholesale electricity markets. In 2004, she also provided testimony on pricing safeguards proceeding, which looked at alternative market power testing procedures for market power, analyzed implications on investment, and discussed efficiency consequences of certain bidding behavior. She also prepared and filed comment testimony and quantitative analysis on questions of market definition and market integration for the Public Utility Commission review in Project No. 29042. [In November 2005, pursuant to PUCT decision, both Project Nos. 24255 and 29042 were rolled into the PUCT Project No. 31972.]
- ***served as independent evaluator and RFP manager for the Connecticut Department of Public Utility Control's ("DPUC") request for proposals for incremental capacity:*** LEI was retained by the Connecticut state regulator to help realize a legislated mandate to hedge the risks of evolving capacity markets and import constraints through a competitive RFP aimed at securing incremental capacity located electrically in the state of Connecticut. LEI authored a report determining the range of investment needs that could be required in Connecticut over the next 15 years due to localized ISO-NE markets for capacity and forward reserves. LEI then designed a procurement process, including the RFP and associated contracts. The RFP solicited for that capacity from both supply-side and demand-side resources. LEI served as the RFP manager for the process and provided independent evaluation services of the bids and recommending the winning portfolio. LEI also served as the DPUC's expert witness in the hearings approving the winning portfolio. LEI's analysis helped the DPUC successfully defend the contracts from legal appeal. [DPUC Docket No. 05-07-14PH2]
- ***testimony at FERC on market power issues on behalf of intervener in proposed Exelon-PSEG merger per Section 203 of the Federal Power Act:*** In May 2005, Julia provided direct and supplemental testimony outlining key considerations relating to the potential for adverse competitive effects in light of the proposed merger and recommended additional mitigation measures to cure horizontal market power concerns through independent analysis of merger's impact on wholesale energy and capacity markets in PJM. [FERC Docket No. EC09-32]

- ***prepared MBR authorization:*** In the matter of Hawk Nest Hydro LLC acquisition of Hawk Nest-Glen Ferris Hydroelectric Project Julia and the LEI team prepared the MBR Authorization for the FERC filing. [FERC Docket No. ER06-1446-000]
- ***testimony regarding confidentiality of long-range supply and demand forecasts by California utilities:*** LEI represented the California Energy Commission (“CEC”) staff in a CEC and in a state regulatory proceeding at the California Public Utilities Commission (“CPUC”) in respect of the merits of making public the investor-owned utilities long-range energy and capacity supply forecasts, as part of the integrated resource planning process. LEI served as an independent expert and supported the CEC in successfully arguing for the release of certain information, despite the utilities’ assertions that such data would undermine competitive markets. [CPUC Rulemaking No. 05-06-040]
- ***provided testimony regarding the price elasticity of demand for transmission service:*** In the context of a transmission rate case for Hydro Quebec TransÉnergie, and consideration of alternative transmission rate designs, Julia led an economic analysis on behalf of Brascan Energy Marketing, Inc. that examined the impact on trade from increased transmission costs, involving multi-factor regression analysis of nodal electricity prices, price spreads across markets, and interchange flows (imports and exports) across borders. Julia also considered the impact of the elasticity of demand for transmission services between Canadian provinces and US markets in the Northeast for maximizing revenues in rate setting. Julia presented oral testimony at the Régie de l’Énergie du Québec. [Dossier R-3549-2004]
- ***served as Independent Monitor in a multi-state renewables solicitation process:*** Julia was part of a consortium that served as the Independent Monitor for PacifiCorp’s renewable solicitation process for the 2008R-1 solicitation process for additional renewable power supplies. The Independent Monitor reported to the Utah Public Service Commission (“Utah PSC”), but filings were also made with the Oregon regulator. This process included review and assessment of the solicitation process, documents, and modeling methodologies; valuation of the bidder pre-approved process; development of review criteria, monitoring, auditing, and validation of bid evaluation process; bid evaluation; contract negotiation. [Docket No. UM1368]
- ***monitored power procurement processes for Connecticut Light & Power:*** The Department of Public Utility Control retained the services of LEI to assist the DPUC in monitoring the power procurement processes for Connecticut Light & Power’s (CL&P) Transitional Standard Offer auction in November 2004 for services in 2005 and 2006, and once again selected LEI in September 2005 to monitor the November 2005 auction for services in 2006. Julia led LEI’s team in providing advisory services to the DPUC, including guidance on communications protocols, design of sales contract agreement (between CL&P and winning bidders), and also valuation of final bids vis-à-vis the forward market alternatives available to the utility. In November 2004 and 2005, Julia filed an affidavit after completion of the

procurement process, which the Commissioners used to approve the process and the contracts between CL&P and the winning bidder. [DPUC Docket No. 03-07-18PH02]

- ***performed market power analysis:*** Bear Swamp Power Company LLC (a pumped storage generation unit) asked LEI to perform a market power analysis in conjunction with Bear Swamp's application for market-based rate authorization. A similar study was done for Carr Street Generating Station L.P., Erie Boulevard Hydropower L.P., Brascan Power St. Lawrence River LLC, and Piney and Deep Creek LLC. [FERC Docket No. ER05-639 et al.]
- ***prepared expert testimony related to horizontal market power considerations:*** In support of various acquisitions by IPPs spanning many years, Julia has prepared expert testimony for filing with FERC, related to Market-based Rate Authorization applications, Triennial Reviews, and Section 203 (merger) applications. LEI has a 100% track record in getting its clients' applications for market-based rate authority and/or mergers approved by FERC.

### **Market design work**

- ***retained by the Massachusetts Attorney General's Office ("MA AGO") to evaluate wholesale market design efforts by ISO-NE to address fuel security/winter-time energy reliability issues:*** LEI staff assisted the MA AGO in 2018 to evaluate the problem statement, and the market design fixes being proposed by ISO-NE staff as well as other NEPOOL market participants. In early 2019, LEI has also made a counter-proposal for an energy storage-based ancillary services product and adjustments to the existing capacity market design. For the remainder of 2019, LEI will support the MA AGO throughout the stakeholdering process and through the submission of the application for rules, changes with FERC in 2019.
- ***prepared an independent white paper reviewing the merits of various expert's positions with respect to re-design of the competitive retail market in New York and imposition of price caps on competitive retail providers based on the embedded costs of incumbent utilities:*** LEI staff, led by Julia, reviewed the competition-related testimony of various experts in the retail case proceeding before the NY PSC and provided an independent critique of the substantive arguments (and flaws thereof). LEI concluded that certain experts misdefined the market for competitive retail services, and misapplied standard concepts in competition theory and anti-trust policy. LEI proposed alternative theories for observed price differences and customer switching trends.
- ***provided independent guidance to Alberta stakeholders on electricity market reforms in the face of evolving environmental and electricity industry policy:*** LEI supported the largest independent power producer in Alberta through the initial negotiations around climate change policies, including introduction of a renewable investment program, coal generation settlement, carbon taxation, and design of a capacity market. More recently, LEI has been involved in nearly two years of industry consultation and stakeholdering on what kind of capacity market design to introduce in the Province. LEI staff work closely with several

industry participants and have presented at AESO-led working groups on a variety of issues, including the setting of the demand curve, and market power rules and regulations.

- ***prepared a White Paper to identify and debunk the myths about transmission investment and prove the truth with real-world case studies.*** In order to offer a more accurate portrayal of the need to invest in transmission infrastructure, the White Paper concluded with recommendations for practical and feasible improvements to the process of evaluating transmission projects. The paper is publicly available at [www.wiresgroup.com](http://www.wiresgroup.com).
- ***advised private clients on the intersection of state and Federal policies in wholesale market rules and specifically MOPR-related issues in organized capacity markets:*** LEI modeled the latest proposals from PJM and stakeholders on its evolving MOPR design, and compared and contrasted the rules with ISO-NE's FERC-approved solution for dealing with investments mandated by state policy (e.g., CASPR). LEI advised clients on FERC strategy and discussed opportunities for existing resources to enhance end-of-life economics via the CASPR.
- ***presented to the NY Public Service Commission ("PSC") regarding NYISO's proposed changes to the energy market to include social cost of carbon:*** LEI advocated in committee meetings for neutrality of treatment between imports and local resources in setting of the carbon bidder
- ***conducted an empirical analysis of market design change to the Forward Capacity Market to align with states' clean energy initiatives:*** Specifically, LEI examined the Competitive Auctions with State Policy Resources ("CASPR") proposal from ISO-NE. The CASPR proposal involves adding a second or "substitution" auction to the current Forward Capacity Market ("FCM") framework. LEI examined the fundamentals for this substitution auction and integrated it within the Contractor's overall FCM model. LEI evaluated the financial incentives for incumbent (existing) resources to remain in operation versus the financial incentive to retire (and therefore, the bidding strategy of these resources). LEI considered critically the tradeoffs that existing generators will be making in the face of the substitution auction, including the opportunity/risk of continuing to operate versus the opportunity/risk of submitting a retirement bid and participating in the substitution auction.
- ***performed economic advisory in a matter relating to market design strategy for a large Canadian generator:*** LEI performed a case study-oriented comparative review of energy-only and energy and capacity markets in North America and abroad, with lessons learned from other jurisdictions. LEI's work plan called for the simulation modeling of three forms of market design: an energy-only market, energy, and capacity market, akin to Eastern US RTO markets, and a hybrid market with long term contracts and a spot market for capacity. The third phase involved the creation of a customized tool for future analysis, based on the simulation modeling results.

- ***provided expert insight on capacity performance schemes, on behalf of NEPOOL:*** LEI was retained by NEPOOL to provide expert insight into the proposed Performance Incentives scheme for ISO New England's Forward Capacity Market. LEI considered the implications for generators' risk profiles and, ultimately, the costs to consumers. LEI's report was filed with FERC as part of the Jump Ball filing.
- ***advised client on electricity capacity product:*** LEI advised the California Energy Commission and other stakeholders on the design and development of a web-based software system supporting the trading of an electricity capacity product tracked by state regulators in connection with resource adequacy requirements. LEI analyzed similar systems in other jurisdictions, defined potential core functionalities of the California system – including, for example, posting of bids and offers. The engagement also required LEI to track titles, examine bilateral and/or multi-lateral trades, and compliance reporting. LEI conducted a survey of industry participants to identify required and desired system capabilities.
- ***market design in support of electricity sector restructuring in Greece, specifically consideration of alternatives to physical divestiture of generation assets:*** On behalf of PPC, the government-owned vertically integrated national utility, LEI examined the following options: virtual power plant ("VPP") auctions, contract for difference ("CFD") and physical energy swaps. In the case study format, the various options were compared against the following criteria: instrument objective, contract structure, contract terms, sale platform, settlement structure, and the extent of physical control right transfer. Real-world experience from France, UK, Belgium, Denmark, Netherlands, Australia, and Alberta (Canada) helped shape the discussion of comparative advantages and disadvantages, taking into account the unique concerns for Greek policymakers.
- ***conducted modeling and forecasting related to the Alberta government's recent announcements to transition to a capacity market and continue meeting its carbon emissions reduction plans:*** as part of this engagement, LEI developed several scenarios that evaluated the impact of various policy and market-related changes in the Alberta market on incumbent and new generators in the province. These changes included market design (energy only or energy & capacity market), plants' retirements/repowering plans, varying carbon tax regimes, and different renewable investment targets. Results from these scenarios were designed to identify specific operational and regulatory risk for the client and develop a strategic best-response to optimize the client's portfolio in light of these uncertainties.
- ***advised on Strawdog related to the estimation of market harm:*** LEI was retained by a market participant in Alberta to develop comments on MSA's Strawdog for the Framework for the Assessment of Market Harm. More specifically, LEI was asked to comment on the economic issues associated with the proposed Strawdog pertaining to the definition of harm in the context of Alberta's market design and the impact of the implementation of the

Strawdog on wholesale power market design, market manipulation and market power abuse.

- *conducted a capacity market modeling exercise to evaluate the potential impacts of different resource adequacy mechanisms:* LEI was engaged by a major US utility where the objective of the study was to identify a market design that would provide the maximum profits at the lowest possible risk, including market and regulatory risk. LEI modeled market prices, market revenues, and gross profits under three supply-demand scenarios and tried to simulate the impact of market intervention policies on such market revenues in order to understand the potential risks and benefits to the client's baseload fleet under different market designs.
- *provided economic advisory on market power mitigation tests for a large US-based utility:* LEI consulted on market design features related to a proposed nodal market, including most significantly the market power analysis framework. LEI proposed a strategy and is assisting in the development of an implementation framework for the local market, including prepared reports for the market design team and state commission. In addition, the approach will be proposed for federal review at FERC.
- *conducted review of capacity market rules:* DECC was interested in whether US power markets evaluate generation bids based on criteria other than the price bid, specifically, if the length of the contract had a role in the auctions. LEI reviewed capacity market rules for PJM, ISO-New England, and the New York ISO. LEI also examined whether and for how long a "lock-in" option for the first-year capacity price is offered to new generation assets bidding into the auctions. LEI also reviewed international spectrum auctions, North American gas transmission open season rules, and international auctions for toll roads to examine whether and how duration or length of contract is incorporated into bidding rules and auction clearing processes.
- *provided a comprehensive analysis of the proposed market power mitigation measures for Alberta's electricity market for a major utility:* Julia and her team looked at various scenarios and presented the likely outcomes given various generation portfolio configurations under each proposal and whether these mitigation measures will result in the desired results. Led by Julia, the LEI staff made a case that more rigorous and robust approaches are needed than the proposed measures. Additionally, Julia's team conducted a comparative analysis of the procurement processes and compensation schemes of the different ancillary services products in eight markets, namely: New York, New England, Pennsylvania-New Jersey-Maryland, Texas, UK, Alberta, Australia, and Ontario. The results of this analysis were used to support the client in Alberta's stakeholder process to redesign a system operator's procurement process.
- *authored paper on a virtual power plant auction format:* Julia and the LEI team prepared a white paper outlining the concept of a Virtual Power Plant product and auction format, as part of a multi-consultant engagement in support of restructuring of the Greek power sector.



- ***prepared and filed testimony and quantitative analysis on questions of market definition and market integration:*** In June 2005, Julia participated on a panel discussing market monitoring issues, as well as market power safeguards for wholesale electricity markets. In 2004, she also provided testimony on pricing safeguards proceeding, which looked at alternative market power testing procedures for market power, analyzed implications on investment, and discussed efficiency consequences of certain bidding behavior.

### **Electricity and Natural Gas Asset Valuation and Transaction Advisory Work**

- ***valuation for a cogeneration project:*** LEI assisted a private equity firm with valuation of a large urban cogeneration facility in the Northeast US. LEI developed a dispatch profile and calculated all electricity, steam, environmental, and maintenance revenues and costs to determine the gross margins of the plant for the next 20 years; LEI's analysis was prepared for purposes of independent asset valuation.
- ***analyzed opportunity for a transmission tariff rebate based on going forward financial viability of a customer:*** LEI was engaged by Emera Maine, a transmission utility in Maine, to assess the financial viability of a customer to continue to operate several power plants in coming years with and without a transmission tariff rebate. LEI's analysis supported public discussions regarding the transmission rebate and a FERC filing by Emera Maine.
- ***prepared a tutorial on power markets:*** For a client looking to acquire an asset in New York City, LEI prepared a tutorial on power markets tailored specifically to market rules and market drivers of electricity, capacity, and ancillary services markets in the city
- ***assisted with the evaluation of an investment in a new gas-fired power project in Alberta:*** LEI created a Baseline forecast for the Alberta market to allow the client to evaluate the energy & capacity market dynamics in the Province, which was paired with detailed reporting for the financial and operational details for the client's project. Also, LEI created two sensitivities to assess the upside and downside opportunities.
- ***conducted due diligence of a potential asset acquisition in MISO-South:*** LEI reviewed the contracts and financial analysis, with a specific focus on the assumed market value of capacity in the long term, and locational marginal prices for energy. LEI also reviewed certain contracts and supporting materials, and participated in due diligence calls.
- ***retained by large private equity firm to present a market overview of the markets where it owns generation assets:*** These markets include PJM, New York, New England, ERCOT, and SERC. In addition to this, LEI presented an investment opportunity presentation to senior management.
- ***consulting services and forecasts related to avoided energy supply costs:*** LEI conducted an empirical analysis of proposed key New England wholesale electricity market design change to the Forward Capacity Market, which included long term modeling of the New

England energy and capacity markets. Specifically, LEI examined the Competitive Auctions with State Policy Resources ("CASPR") proposal from ISO-NE. The CASPR proposal involves adding a second or "substitution" auction to the current Forward Capacity Market ("FCM") framework. LEI examined the fundamentals for this substitution auction and integrated it within the Contractor's overall FCM model. LEI evaluated the financial incentives for incumbent (existing) resources to remain in operation versus the financial incentive to retire (and therefore the bidding strategy of these resources). LEI considered critically the tradeoffs that existing generators will be making in the face of the substitution auction, including the opportunity/risk of continuing to operate versus the opportunity/risk of submitting a retirement bid and participating in the substitution auction.

- *research paper demonstrating best practices for measuring the benefits of transmission* for a WIRES-funded research project, LEI prepared a "how-to" guide and demonstrated its application on two hypothetical transmission projects, showcasing how system planners and other decision-makers can measure objectively the benefits of transmission investment from the perspective of various stakeholders, and also over the short-medium- and longer-term.
- *conducted empirical analysis of key features of proposed capacity markets in Alberta and Ontario*: LEI assisted the client in understanding the capacity market design initiatives across Canada. LEI staff presented a series of work paper on various topics, related to market mechanics and resource adequacy and setting of the demand curve. LEI also assisted the client in critical evaluation of design options from the perspective of the existing generation fleet, new entry, and consumers through detailed quantitative modeling and simulation-based analysis of the target markets.
- *advised a major utility in Canada in its call for tenders strategy for procuring firm capacity over a long term horizon from neighbouring jurisdictions*: Julia evaluated the opportunity for purchasing capacity from interconnected jurisdictions and devising a procurement that would efficiently overcome seams issues and market design issues that attach different counting and valuation methods for capacity across jurisdictions.
- *devised an innovative approach for evaluating the economics, environmental, and siting costs and benefits of transmission (and generation investment) for the California Independent System Operator*: building upon the traditional economic framework for cost-benefit analysis, the LEI team devised an approach to quantitatively value the expected net benefits from various infrastructure projects, taking into account market uncertainties as well as the classic deregulated market coordination problem of planning for transmission given uncertain generation investment and vice versa. A scoring technique for environmental permitting and siting issues was also developed in order to quantify the potential impact of the proposed project on the local environment and economy, as well as to measure the impact of such factors on the project timetable and eventual net benefits to society. Real option techniques were also considered in this engagement to assess the

potential value of uncertainty and the benefits of delaying various investment strategies. The methodology was also expanded to handle the potential to evaluate numerous competing projects, in recognition of the fact that transmission and generation investments (and other potential investments) could be both complements and substitutes.

- ***served as Independent Examiner for Western Interconnect transmission line:*** LEI was selected by developers of the Western Interconnect transmission line in New Mexico to serve as Independent Examiner for their Open Season process, through which WI offered transmission capacity over the line to any interested party at the same rates, terms and conditions as those offered to anchor customers on the line. LEI designed and managed the entire process, which included creating the evaluation criteria, drafting announcements and press releases, preparing the Open Season documents and forms, conducting information sessions, overseeing the process website, and evaluating and ranking bids. After the process, LEI prepared and submitted a report to FERC (in docket ER15-2647), attesting that the process was market-driven, fair, transparent, and non-discriminatory.
- ***capacity price review on auction bidding:*** The UK market regulator was interested in whether US power markets evaluate generation bids based on criteria other than the price bid, specifically, if the length of the contract had a role in the auctions. LEI reviewed capacity market rules for PJM, ISO-New England, and the New York ISO. LEI examined whether and for how long a "lock-in" option for the first year capacity price is offered to new generation assets bidding into the auctions. LEI also reviewed international spectrum auctions, North American gas transmission open season rules, and international auctions for toll roads to examine whether and how the duration or length of the contract is incorporated into bidding.
- ***provided independent market analysis to clients interested in understanding the implications of the expansion of natural gas supply into New England:*** LEI began with a review and evaluation of the numerous proposals for pipeline expansions. LEI staff also performed natural gas network modeling (using GPCM, an industry-standard network model of the North American natural gas system) and power simulation modeling (using LEI's proprietary POOLMod model) to arrive at a quantitative impacts assessment of various projects on the Northeast gas markets and electricity markets.
- ***conducted cost of electricity comparisons across Canada:*** LEI was engaged by a consortium of private companies to estimate and compare the delivered cost of electricity for all Canadian provinces over the 2011-2015 timeframe: In addition, LEI also forecasted how the delivered cost of electricity in Alberta could develop over the next fifteen years (2017-2031) under the Climate Leadership Plan ("CLP"). LEI forecasted energy, transmission, and distribution rate components, using three modeling scenarios in addition to a Base Case, evaluating different assumptions for renewable investments, demand levels, and reserve margin targets. The Base Case and scenarios were designed to inform the general public about the impacts of various policy and market based interventions on the delivered cost of electricity to consumers in Alberta in the future.

- ***conducted gas price forecasting:*** For a private equity client, LEI forecasted the energy and capacity revenues of various gas-fired plants in PJM for 20 years. More specifically, LEI projected the energy and capacity prices, plants' annual generation, load factor, and operating costs. LEI's analysis influenced the client's going forward investment decisions.
- ***price forecasting for wind facilities:*** LEI analyzed the revenue potential for wind facilities in CAISO, SPP, and PJM, developing price forecasts through 2045 and also assessing market rules to identify any potential penalties that may apply to intermittent generation and deviations from generation profiles. Three cases of merchant forecasted revenues, Base Case, High Case, and Low Case, were developed in order to identify key uncertainties and opportunities.
- ***served as Independent Examiner for a proposed merchant transmission project's Open Solicitation process:*** The project entailed designing the solicitation process, meeting with potential shippers on the line to garner early interest, drafting announcements and press releases, conducting information sessions, updating the solicitation website, evaluating and ranking bids, assisting with bilateral negotiations with shippers, and submitting a report to FERC as part of the developers' Section 205 filing.
- ***conducted independent analysis on power market in support of transmission development:*** LEI supported a major transmission developer in the Northeast US in its analysis of opportunities and market impacts from a number of potential projects to bring energy into the New England region. LEI performed independent analysis measuring the impacts of numerous project designs on the power market (including energy and capacity markets, production cost savings, and environmental benefits) and local macroeconomic analysis as well.
- ***retained by private equity firm to provide 20-year monthly energy and capacity prices and operating metrics results for several CCGT plants in PJM:*** LEI reviewed plant parameters, financial model, and market consultant reports provided by the seller and delivered price forecast and dispatch results to the client.
- ***conducted New England modeling:*** LEI conducted an empirical analysis of New England wholesale electricity market dynamics, including long term simulation based on the New England wholesale market to measure energy and capacity market impacts, production cost savings, generators profitability under various future market conditions. The client used LEI's modeling results to perform policy analysis and prepare a research report that the client released publicly in 2017.
- ***Alberta market analysis:*** For a major stakeholder in Alberta, LEI conducted empirical analysis to identify how a change in offer behavior of some resource owners affected spot and forward markets in Alberta. LEI developed two separate econometric models (a time-series analysis for spot, and a panel (or a cross-sectional time-series) regression for forward markets) to estimate the price impacts from the change in the offer behavior, lost value in wholesale markets, and foregone revenues for key market participants. The engagement

also involved a detailed analysis of historical offer bid data to determine when the offer behavior changes occurred, and an analysis of select Alberta power plants' financial losses due to uneconomic offer behavior.

- ***conducted wind price forecasting:*** LEI used its proprietary dispatch model, POOLMod, to project energy prices in ERCOT for a wind developer undertaken financing of its projects in West Texas. LEI also examined the implications of PPA related to the two wind farms. LEI also provided energy, capacity, and solar renewable revenues for an operating solar plant in New Jersey as part of the same engagement.
- ***reviewed energy storage installations in New England:*** For a transmission and distribution company in New England, LEI analyzed the cost and benefit to consumers on different configurations of energy storage installations in the ISO-NE grid. The engagement involved modeling multiple configurations of energy storage solutions, including different storage capacity and duration, as well as various charging and discharging cycles.
- ***developed a simulation model for forecasting ancillary services revenues:*** The engagement involved analyzing the dynamics of ancillary market prices and revenue under different market scenarios. The model developed was able to simulate hourly dispatch and clearing of the ancillary services market, and was integrated with LEI's Alberta energy market model.
- ***reviewed trading activities within energy market:*** On behalf on an electricity marketer, LEI liaised with the NYISO Market Monitoring & Analysis (MMA) department in respect of trading activities in the energy market.
- ***serves as Independent Examiner for a proposed merchant transmission project open solicitation process:*** The project entailed designing the solicitation process, meeting with potential shippers on the line to garner early interest, drafting announcements and press releases, conducting information sessions, updating the solicitation website, evaluating and ranking bids, assisting both bilateral negotiations with shippers, and submitting a report to FERC as part of the developers' Section 205 filing.
- ***performed analysis of HVDC transmission projects:*** LEI was retained by a transmission developer to perform a high-level analysis of the cost-competitiveness of HVDC transmission as a regulated solution with respect to generation resource. The work included comparing the revenue requirement for HVDC transmission projects with the net Levelized Cost of Entry ("LCOE") of comparatively sized and located generation resources.
- ***advised on New York transmission project:*** LEI provided advisory service to a transmission developer looking to position its project in New York. LEI provided an overview of the current regulatory and legislative framework and assisted in identifying and targeting potential shippers on the line.
- ***provided analysis on new HVDC transmission line:*** Julia Frayer led an LEI team that provided strategic support and analysis of various regulated and unregulated business

models for proposed new HVDC transmission line, including identification of potential shippers and RFP opportunities, as well as categorization of potential private and social benefits of the project

- ***advised on climate change policy in Alberta:*** LEI provided research, analytical and advisory support to a client in Canada as the Alberta government implemented its climate change policy, which will shut down coal plants early, ramp up renewable generation, and put province-wide carbon tax in place.
- ***assisted a client to perform the competitive landscape analysis for projects participating in the Clean Energy RFP:*** LEI's competitive landscape study employed a three-step approach. At Step I, LEI identified the potential projects that can qualify for the Clean Energy RFP and the production of a matrix of competitors. The comparative analysis then graded each project from Step I, using the type of criteria listed in the evaluation and selection process section of the Clean Energy RFP. In summary, LEI's comparative analysis looked at both the (a) minimum threshold requirements and (b) the characteristics of each project relative to the quantitative and qualitative benefits enumerated in the Clean Energy RFP. Lastly, based on the rankings from the comparative analysis in Step II, LEI concluded with the SWOT analysis for the client's project relative to possible competitors and examined the relative strengths, weaknesses, opportunities, and threats in the Clean Energy RFP.
- ***provided a 20-year market outlook report for New England:*** The market outlook report was to include a 20-year regional price forecast for the energy and capacity markets, summary of recent market developments, comparison of monthly and peak versus off-peak prices, and a Tier-1 Renewable Energy Credits ("RECs") forward price forecast.
- ***reviewed NYISO due diligence materials:*** For an infrastructure investment fund, LEI reviewed due diligence materials for the client's potential acquisition of a cogeneration plant participating in the NYISO markets. LEI further performed an analysis to forecast future fuel and operating costs for the plant, revenues from the sale of energy and capacity in the wholesale markets, and revenues from the sale of steam to an off-taker.
- ***analysis of congestion in the New York market:*** For a transmission project developer, LEI performed an analysis of congestion in the NY markets for proposed renewable generation resources as well as a new transmission link. LEI relied on results from a power flow study to properly model the proposed resources and transmission constraints in POOLMod.
- ***analyzed the impact of a new transmission project between upstate and downstate New York:*** LEI used its proprietary energy and capacity market simulation models to assess the impact of the proposed transmission line on New York energy and capacity markets over a 20-year horizon. LEI further prepared a forecast of revenues for potential shippers from the results of the simulations.
- ***supported a risk management assessment:*** LEI assisted in a large provincial institution in the development and assessment of alternative risk management and investment strategies for its trading and investment businesses. As part of this work, LEI completed a Risk

Assessment Survey of the Board of Directors as well as additional Value-at-Risk (“VaR”) modeling, scenario, and stress testing.

- ***conducted New England gas price forecasting:*** LEI was retained to forecast delivered gas prices in New England (Connecticut) and PJM (New Jersey) and locational marginal prices as well as retail electricity prices in Connecticut.
- ***engaged by an investment firm in association with its acquisition of a proposed natural gas-fired plant in Ohio:*** Work involved asset valuation, due diligence support, and market analysis. LEI reviewed the documents in a virtual data room, and performed analysis related to drivers of gross margin for the asset: macroeconomics, fuel, and electricity cost projections, and overview of gas and electricity market in the region where the asset was located.
- ***led a workshop to review New England markets:*** LEI was hired by a New England transmission & distribution utility to prepare a two-day workshop for company executives detailing the current state of the New England markets, major players across all sectors of the industry, major investment drivers and investment analysis methodology. LEI staff prepared workshop material and traveled to the client’s office to present the material and answer client’s questions.
- ***conducted price driver analysis on the gas-fired asset:*** LEI was engaged by a private client to conduct a price driver analysis and strategy optimization exercise to enhance the bidding and dispatch strategy on a jointly-owned gas-fired asset. This included a report on ISO-New England’s Winter Reliability Program to identify and evaluate key wholesale price drivers in the New England region. LEI also examined the generating asset’s financial data to help optimize its bidding strategy.
- ***prepared a quantitative analysis to test the efficacy of a proposed cross hedging strategy for a merchant transmission project that will be bringing energy from Canada:*** The proposed strategy is to use natural gas futures contracts to hedge energy market exposure and revenues. Analysis will include ordinary least squares regressions as well as an error correction model to determine the appropriateness of the hedge.
- ***analyzed revenue/gross margin modules for various district energy assets in Illinois being considered for acquisition:*** LEI reviewed information received from the client, including detailed documents in the data room, and presented analysis in a slide deck relating to contract revenues (prices and volumes) and fuel costs (electricity) along with revenue and cost drivers. LEI also presented sensitivity analysis for high/low sales volumes, new customers, expiry dates of existing contracts, fuel costs, etc.
- ***provided due diligence analysis and support on the acquisition of a portfolio of small hydropower plants in the PJM region:*** The portfolio consisted of a mix of mini and small run-of-river hydropower plants. LEI’s scope of work was threefold. Firstly LEI provided an overview of PJM RTO market, describing market fundamentals, key players, supply mix, retirements, and newly built, as well as discussing historical market trends. Then, LEI used

its proprietary dispatch and simulation cost production model POOLMod to simulate power market dynamics and develop forecasts of energy prices in the assets' location over a 20-year horizon. As part of this modeling exercise, LEI used its in-house capacity market to develop capacity prices forecasts over a similar horizon. Finally given the conventional storage capability of one of the unit, the client requested LEI to provide a description of the frequency regulation market in PJM and to determine potential revenue opportunities for the plant. LEI provided results of its modeling exercise in Excel format and prepared a slide deck summarizing key messages, key findings, and recommendations to the clients.

- ***provided due diligence review on New England plant:*** LEI worked with private equity investors on an M&A due diligence review of a combined heat and power generation unit in New England. LEI provided market analysis, price forecasting services, and supported the investor in its valuation of the asset.
- ***conducted review of Maine hydro facilities:*** For an infrastructure investment fund, LEI reviewed due diligence materials for the client's potential acquisition of a portfolio of hydro facilities located in Maine, and provided an independent valuation of the projects based on forecast energy market dynamics and REC opportunities.
- ***reviewed NESCOE Gas Electric Phase Three study:*** LEI conducted a comprehensive review of the NESCOE Gas Electric Phase Three study in order to ensure that the appropriate economic models and techniques were being used to accurately model the hydro and gas solutions. LEI also aided the client in identifying any assumptions and modeling approaches which may be suboptimal, and communicated how these issues could be addressed and improved in future studies.
- ***asset valuation, due diligence support and market analysis for an infrastructure fund:*** The engagement involved reviewing documents in a virtual data room, and analysis related to drivers of gross margin for the asset: macroeconomics, weather fluctuations, fuel and electricity cost projections, and overview of gas and electricity market in the region where the asset was located.
- ***conducted market study regarding renewable generation:*** Julia led the preparation of a market study to support the financing of a renewable generation portfolio in New England. The market analysis supported a successful multi-million dollar debt raise for the client.
- ***developed HHI screens in support of a valuation of a gas-fired facility:*** LEI developed simplified HHI screens looking at the summer peak period for a client's potential acquisition of a gas-fired facility in New York. Several scenarios were developed to test the impact on HHI.
- ***conducted evaluation of fair market sales value of a coal-fired unit in Arizona, as required by a lease that expires in 2015:*** Results from LEI's proprietary modeling tool, PoolMod, on market prices and dispatch were used as inputs in the financial model, which used discounted cash flow techniques. Two cases (Base Case and High Case) were created to develop a range of values with a weighted average point estimate. In addition to the



discounted cash flow model, the market approach, which looks at comparable transactions, and the cost approach, which looks at the cost of building the same facility, were considered.

- ***provided valuation services for a waste coal facility located in the Pennsylvania-New Jersey-Maryland ("PJM") regional market:*** Specific tasks consist of i) due diligence review of documents such as past financial statements, operational statistics report, fuel agreements and power purchase agreements ("PPA"); ii) forecasts energy and capacity prices in the PJM regional market; iii) create a pro forma financial model to evaluate the market value of the plant as of expiration of its PPA; iv) writing a final report documenting assumptions, methodologies used and modeling results.
- ***provided forecasting and modeling support for a start-up company:*** Julia and her team assisted Tres Amigas LLC, a start-up company on the revenue forecasting and modeling for the second stage financing. The start-up company aims to develop, own, and operate a unique three-way AC/DC transmission facility located in New Mexico. In 2010, for the feasibility analysis stage, LEI provided extensive transmission evaluation, financial modeling, price forecasting, and market analysis for the markets, including the Arizona/New Mexico/Southern Nevada sub-region of the Western Electricity Coordinating Council, the Electric Reliability Council of Texas, and the Southwest Power Pool. LEI's analysis support over \$15 million of development stage funding. LEI continues to serve as economic advisor to Tres Amigas, as it seeks debt and equity financing to support construction of Phase I.
- ***market power analysis as a result of a proposed merger:*** in support of a client's opposition to a proposed utility merger in the Northeast US, LEI provided a white paper analyzing the impact of the merger on competition. The white paper covers analysis on buyer market power concerns with utility's returning to rate base generation and vertical market power.
- ***conducting forecasting for electricity generation assets in New England:*** Using LEI's proprietary simulation model of electricity wholesale markets in ISO New England, LEI forecasted future cash flows for a portfolio of electricity generation assets and applied the net present value analysis to evaluate the portfolio's economic value under different potential future market conditions. This analysis supported the investment fund's decision to acquire and hold the generation portfolio's distressed debt.
- ***led research on biomass plants regarding renewable energy revenue options:*** Julia investigated opportunities for portfolio of biomass plants to earn renewable energy revenues from RECs, capacity markets, and carbon offsets given regulations in all states belonging to MISO, PJM, and ISO-NE. Engagement also involved formulating strategies for client to optimize the generation assets' revenue potentials by exploiting the identified renewable energy opportunities.
- ***analyzed potential revenues of pumped storage hydroelectric facilities (energy, capacity, ancillary services) proposed in various locations in ISO-NE and NYISO:*** The analysis

included detailed simulations of the wholesale electricity markets, application of sophisticated statistical tools to estimate the volume and the price level of various ancillary services.

- ***assisted a major Canadian renewable power company in its economic valuation of a New England based renewable company, prior to acquisition:*** Work involved due diligence, analyzing the revenue potential of the potential acquiree's assets over the 2009-18 period across all major ISO-NE product markets, and separately analyzed the market power implications of the acquisition in preparation of a potential FERC application, including analysis of market power issues in ancillary services market.
- ***evaluated potential value of assets available under various regional auctions for a dominant IPP player:*** Julia worked with the client in composing a bid proposal by assessing market risks posed by various factors, such as fuel price shifts, merchant plant construction scenarios, site conversion potential, and transmission constraints and through extensive production cost modeling.
- ***conducted an indicative valuation of a proposed new transmission line, known as the International Transmission Line:*** LEI forecasted the revenues associated with the project and combined this revenue forecast with the estimated costs of the project to arrive at an estimate of the net present value of the project and return on investment.

### **Power, Gas, and Infrastructure Sector Business Development and Strategy**

- ***strategic analysis of the value of on-site peakers for an Alberta industrial client:*** LEI was engaged by an industrial client in Alberta that was considering the addition of on-site gas peakers. LEI's scope of work consisted of identifying potential technology type candidates that would suit the client's needs, reviewing historical and projected site loads, developing a status quo estimation for the cost of delivered power rates, and finally creating a relative economic model that compared the use of on-site generation against the status quo.
- ***portfolio optimization strategy:*** LEI was engaged by a Canadian client to explore options associated with entering into a service agreement with a third-party. LEI prepared a report which identified a number of firms that could provide this service and provided a more detailed profile of the firms which best meet the requirements of the client. LEI also acted as an independent advisor to guide the client through a process of potentially contracting with a third-party service provider.
- ***conducted Total Factor Productivity study:*** In December 2014, LEI prepared a report for Ontario Power Generation ("OPG") entitled "Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry." The purpose of this report was to share findings from LEI's TFP study, which estimated TFP trends for a select group of peers from the North American hydroelectric generation industry. Data for this study covered an eleven year period from 2002-2012. The purpose of

this new engagement is to update this study for newly available data (encompassing operating costs and other statistics for calendar years 2013 and 2014).

- ***performed a forward analysis and market simulation of potential wholesale revenues for a proposed wind project in Wyoming:*** analysis was used by developer to attract potential counterparties for a long term PPA.
- ***conducted a comprehensive cost-benefit analysis of a proposed transmission project in New England using simulation-based analysis of the ISO-NE wholesale power markets:*** LEI's analysis included detailed examination of the benefits to consumers from lower energy and capacity prices, as well as emissions reductions and local economic impacts (associated with spending during construction and lower retail costs of electricity).
- ***conducted a Non-Transmission Alternatives ("NTA") analysis for the two transmission projects, which are components of a larger transmission solution in New England:*** The objective of the NTA analysis was to determine the feasibility and viability of other non-transmission resources – such as new generation and new demand-side resources – to be developed in lieu of these two specific transmission projects to relieve transmission reliability concerns. The NTA analysis was to be filed as part of the client's application with the Connecticut Siting Council. [Docket N5179515].
- ***supported a client in administering its compliance program:*** For all the US regions where the client (international IPP) is currently active, LEI was engaged to support the client's Regulatory Group in its administering of the company's compliance program. LEI provided a monthly report covering developments by regional market and products which included: energy, capacity, long-term transmission service, FTR auctions, ancillary services, diesel oil, PRB coal, natural gas commodity, transmission, and storage, RECs, and CO2. The purpose of this monthly update was to ensure that client's transactional and business groups were made aware of market rules and regulatory risks.
- ***provided due diligence support:*** LEI was engaged by a private equity company in association with asset valuation, due diligence support, and market analysis for a wind generation and HVDC transmission project proposing delivering wind-based renewable energy from Wyoming into California.
- ***authored report on pollutants emissions:*** LEI was hired by a large Canadian IPP to prepare a report providing an overview of past and current initiatives pertaining to pollutants emissions regulation with the purpose to inform the potential paths forward for future carbon regulation in the US. The engagement was initiated following the Executive Office of the President released the President's Climate Action Plan ("CAP") to reduce greenhouse gas ("GHG") emissions, and to prepare for the impacts of climate change. Under this engagement, LEI performed a detail literature review of the President's directive, past Environment Protection Agency ("EPA") regulations, as well as exiting regional carbon reduction programs. The overarching purpose of this exercise was to estimate the potential shape of a future carbon rule in the US (with associate features such as timing, mechanisms,

and regulatory framework) based on EPA's legal authority scope, procedures and lessons learned from failed or successful rules implementation. LEI identified various market-based and non-market-based regulatory frameworks/scenarios and ranked them on their relative likelihood based on a set of established criteria including affordability of the regulatory scenario, impact on generation retirement and system reliability, alignment with EPA's precedents, congruency with Presidential directives, consistency with EPA's jurisdiction, and political palatability.

- *evaluated the impact of the implementation of potential future Federal regulation limiting carbon emissions on ERCOT's energy markets and on Energy Future Holdings' ("EFH") portfolio:* For a large Canadian IPP, LEI used its dispatch and simulation model POOLMod to develop forecasts of energy prices in ERCOT under a variety of potential frameworks under which carbon emissions could be regulated. The purpose of this exercise was twofold: a) evaluate the impact of a carbon rule (of any shape) on wholesale energy prices, and on the performance of the EFH' portfolios; b) determine the most impactful carbon rule regulatory framework.
- *conducted New York price forecast:* LEI was retained to do a 30-year (2015-2044) energy price forecast for Western New York, capacity price forecast for the Rest of the State, and revenue forecasts for a small hydroelectric plant in preparation for an asset sale process.
- *assisted an Ontario electricity generator in performing a productivity study on their hydroelectric assets to fulfill the mandate of the Ontario Energy Board ("OEB"):* LEI proposed a structured approach to address how productivity should be measured, what methods are available, identify a relevant peer group, and ultimately provide the client with a productivity study for filing with the OEB.
- *reviewed client's risk management practices and provided meaningful insights with regards to the risk management related issues:* Analysis included quantification of the magnitude and probability of risks being faced by trading and other operational activities of the client, as well as research into the best practices of other similar organizations.
- *engaged by a global investment firm to provide a market outlook for three assets located in ERCOT:* LEI provided a 10-year detailed market revenue forecast for the three plants under base case assumptions.
- *provided independent review and assessment of cost-benefit analysis related to termination of certain PPAs between Entergy Texas Inc. and Entergy Louisiana:* LEI's assessment was requested by the Public Utility Commission of Texas, as follow on to previous consultative services that LEI has provided.
- *served as Independent Evaluator ("IE") for Pacific Gas & Electric Company ("PG&E") for PG&E Electric Fuels Department's Natural Gas Storage Services Request for Offer ("RFO"):* Specifically, LEI worked with PG&E to ensure that Offers were evaluated consistently and appropriately in accordance with the solicitation protocol and in

accordance with applicable rules and processes of the California Public Utilities Commission ("CPUC").

- ***prepared a study of the Value of Lost Load ("VoLL") in ERCOT and evaluated current utility practices for manual load shedding:*** LEI's report on VoLL was filed with the PUCT in June 2013 under PUCT Docket 40000.
- ***engaged by a Japanese research institute to research the environment for investment and financing of new generation in the US competitive electricity markets as well as the types of approaches used to manage investment risk:*** The LEI team researched the impact of market restructuring in the US on generation investment, methods for financing new generation, and analyzed policies promoting generation investment. LEI also performed four case studies on projects that were successfully financed and built in recent years, including assets in California (CAISO), Maryland (PJM), New York (NYISO) and Texas (ERCOT).
- ***provided support to FortisAlberta Inc. ("FAI"), a Canadian electricity utility, in its filing for its capital tracker application with the regulator:*** LEI reviewed the submissions of the interveners and advised FAI on how to address the issues raised by these interveners.
- ***led a comprehensive ratepayer-focused cost-benefit study of integrating a remote service territory of a single-state utility into a Northeast RTO's footprint:*** The cost-benefit analysis looked that at the long-run the benefits of joining an RTO versus the costs of new infrastructure that would be needed to accomplish the integration. LEI's analysis was used with regulators and state policymakers to pursue a transmission investment strategy by the utility.
- ***provided a study on electricity sector unbundling in the US for a Japanese client:*** The study starts with an overview of the electricity sector unbundling in the US, including the history of restructuring and unbundling efforts, the categorization of unbundling, and the organizational impact of unbundling. Three case studies were also provided on specific unbundling experiences of TXU Corp., Commonwealth Edison, and Consolidated Edison.
- ***supported the negotiation of fuel supply and energy sales agreements for a biomass to energy facility:*** In particular, LEI's analysis focused on the appropriateness and risk associated with price and cost escalation factors. Reviewed similar power purchase agreements and analyzed a suite of available indices.
- ***counseled on transmission cost allocation:*** LEI advised Maine Public Utilities Commission on methodologies for transmission cost allocation by comparing and contrasting alternative planning approaches and pricing models employed within the US and one international jurisdiction, the United Kingdom. The final report provided a 'strawman' recommendation for an effective cost allocation methodology, which was used by the Maine PUC to guide it in its filings at FERC related to Order 1000 and the preceding NOPR on the same issue.

- ***served as Independent Monitor for Energy New Orleans:*** Julia acted as manager for LEI's engagement with the City of New Orleans. LEI was engaged to act as the independent monitor for Entergy New Orleans' solicitation of a Third Party Administrator to implement and deliver conservation and demand management programs on behalf of the utility. LEI provided guidance to Entergy and the City on the development of the request for proposals, including mandatory requirements and commercial terms. LEI oversaw the bid receipt as well as the review and selection process. A final report was provided outlining LEI's opinion as to the fairness of the overall process.
- ***assisted a client with certain matters pertaining to a FERC investigation:*** Specifically, the scope of this retention includes economic and market analysis in support of a market participant in ISO New England's day-ahead load response program ("DALRP"). Julia also provided affidavits and deposed in connection with FERC investigation of behind-the-fence industrial generator and participation in a wholesale power market in New England. Julia helped the client to respond to assertions of market manipulation and estimate market benefit provided through its participation in demand response program.
- ***advised a major transmission company on financial implications of proposed new 400kV transmission line to New York City and Connecticut:*** LEI analyzed the impact of new transmission, assuming it delivered 100% carbon-free energy, on electricity prices and emissions levels in New York and New England.
- ***served as an independent economic expert, opinion on specific matters related to a market participant's participation in the day-ahead demand response program implemented by ISO-NE:*** LEI staff reviewed the specific facts of the case related to how the customer baseline was developed and the offering strategy of the market participant in the demand response program. LEI conducted an independent analysis of the decision making process that had been undertaken in support of the customer baseline and offer strategy. LEI also prepared an analysis of the market benefits created for the market as a whole through the demand reductions offered by the market participant (a customized VBA model was created to reconstruct day-ahead ("DAH") and real-time ("RT") energy market clearing prices using public historical hourly offer and bid data.
- ***supported a client in preparing an offer to provide new capacity:*** LEI evaluated projects submitted in the context of a competitive solicitation (RFP) for new capacity, aimed at reducing Connecticut consumers' Federally Mandated Congestion Charges ("FMCC"). LEI drafted and administered the RFP. LEI then served as an independent evaluator on behalf of the DPUC and performed a comprehensive evaluation of the proposed projects, using LEI's proprietary production cost model, POOLMod. Julia testified at the Connecticut Department of Public Utility Control ("DPUC") regarding the RFP process and recommended the selection of winners and award of contracts.
- ***authored FERC addendum:*** Julia wrote the report that served as an Addendum to the market power analyses that were filed with FERC in Docket No. ER05-665-001. The

objective of this Addendum was to address the items requested by FERC in the deficiency letter issued on June 23, 2005, in this docket.

- *managed theoretical analysis and quantitative simulation modeling in the design and testing of recommended new regulatory regime:* Analysis and recommendations were presented to stakeholders.
- *conducted market assessment:* For a major Canadian utility, Julia undertook a comprehensive market assessment of the New England REC markets, and specifically the Massachusetts and Connecticut markets, under three different scenarios, the status quo, with the utility's resource commercialization schedule, and assuming sporadic participation by the utility.

### **Regulatory Economics**

- *retained to advise on stranded cost obligation for cooperative leaving G&T utility:* in context of a FERC possible dispute, LEI analyzed and considered the retail and wholesale market factors for a distribution utility seeking to exit its existing contractual arrangements.
- *reviewed utility's internal analysis and conducted a fatal flaw analysis to provide comments and critiques regarding investment planning:* LEI also prepared an analysis describing qualitatively the challenges to various NTA solutions identified in the utility's internal analysis. LEI also conducted an independent analysis to estimate the costs of any possible NTA solutions. This involved talking to engineering firms, other utilities (on a no-names basis), and gathering specific data on DG and microgrid generation installations. LEI also commented on the practical feasibility/challenges associated with siting specific NTA technologies in the project region.
- *performed benefits analysis on proposed New York transmission line:* LEI performed an analysis of benefits to NY consumers from a proposed transmission line between New York State and New England, analyzing the impacts from the proposed project's investments on GDP, jobs, tax revenues, and system reliability. LEI also performed a cursory review of the proposed project's environmental impact, based on criteria established by the NY DPS Staff in previous cases before the Public Service Commission
- *analyzed Chicago congestion issues:* LEI was retained to do a resource analysis in the Chicago area and to analyze the congestion within the Chicago area and MISO zones surrounding Lake Michigan.
- *reviewed energy and capacity prices in PJM:* A private client was interested in acquiring a pumped storage hydro generation facility owned by LS Power in the PJM region. The client asked LEI to prepare a proposal that will forecast the energy and capacity prices for the next 20 years of the relevant zone for this target asset. The price forecast exercise required LEI to model both energy and capacity markets on an integrated basis, as well as using a Real

Options Model to simulate the target unit's operational decision in arbitraging the peak versus off-peak hours in the energy market.

- ***analyzed the potential investment opportunities for a large IOU in energy storage in New England:*** Through intensive research and analysis, including simulation-based modeling, LEI identified potential opportunities for energy storage investment in New England and prepared estimates of societal benefits from such investment.
- ***conducted forecast on potential energy revenues of two proposed wind farms in Texas:*** In addition, LEI also analyzed the merchant energy, capacity, and solar renewable revenues for a solar plant in New Jersey.
- ***prepared overview of the PJM market:*** LEI was hired to put together a presentation about the PJM market and investment opportunities in generation for the Public Utilities Commission of Ohio.
- ***evaluated impact of changes to Alberta's climate change and carbon emission regulations on the portfolio of the power sector as a whole, and electricity consumers:*** The analysis included modeling various scenarios using POOLMod relating to different specific regulations and assumptions to determine the financial impact on selected plants as well as the prevailing Pool Price forecasts for the province.
- ***reviewed procurement process:*** LEI was retained by Delaware Public Services Commission ("PSC") to assist with review of the procurement process for the provision of Delmarva Power & Light Company ("Delmarva Power")'s standard offer services, and to provide information and analysis regarding alternative long-term electricity procurement options for Delmarva Power to meet its Standard Offer Service residential and small commercial retail load. [Docket 14-0283]
- ***advised on market power screening analysis in contemplation of large scale utility merger:*** LEI provided advise on analytical approach and potential mitigation strategies for horizontal market power concerns.
- ***authored report on IPP investment decisions:*** LEI was engaged by a private equity company to provide a briefing paper that compares the opportunities and tradeoffs of the "Buy" versus "Build" investment decision in the IPP sector. The paper contains quantitative and qualitative research and analysis, based on market data on purchase prices from recent transactions (focused on New York, New England, and PJM), versus the cost of new-build assets.
- ***reviewed New England REC prices:*** LEI was retained by a renewable investor to review REC prices in the New England region and provide a forecast for various classes of REC prices for the purpose of investment appraisal.
- ***provided assistance developing marketing materials for a transmission developer's roadshow:*** As part of this engagement, LEI developed a series of ready-to-share slide decks



tailored to the specific target customers. Three categories of customers were considered: traders, utilities, and wind developers.

- ***investigated the costs and benefits of proposed transmission line projects across New York State:*** The study included reviewing the proposed projects from each of the applicants to identify key characteristics of each project. LEI also undertook simulation-based modeling of the New York market to assess the potential magnitude of future congestion on the New York system under varying levels of projected gas prices. [Case 13-E-0488]
- ***conducted a simulation-based modeling exercise to determine the potential revenues for the proposed transmission project wheeling power from western MISO to eastern MISO (and eventually PJM):*** LEI evaluated both the revenue opportunities to the investors (e.g., private benefits of the line based on market price differences and the market value of the transmission) as well as social benefits to the MISO system (i.e., wholesale price reductions and capacity market price differences); and evaluated the incremental value of the business strategy of selling the energy (and capacity) out of East MISO to third parties who will serve customers ultimately in PJM. LEI's modeling exercise entailed evaluating intrinsic revenues (originating from power markets), extrinsic revenue (originating from price volatility), along with the green value of the Project (originating from the purchase of low-cost renewable energy).
- ***conducted due diligence on gas-fired assets in the US:*** LEI was engaged by a private equity firm to conduct due diligence on a 3,000 MW portfolio of gas-fired assets in PJM and ISO-NE. LEI was responsible for developing the model that was used in the pro forma financial statements.
- ***reviewed operation status of nuclear plants:*** LEI was retained to assess the impact of the continued operations of nuclear plants in the Midwest with state subsidies versus the closure of these nuclear plants in the electricity rates and the state's local economy.
- ***provided asset valuation due diligence and market analysis in support of the evaluation of geothermal resource opportunities in Germany as well as other investment initiatives in the region:*** LEI's scope included a comprehensive review of Germany's electricity sector, renewable energy policies, and integration within surrounding European power markets.
- ***Authored paper on MRAs:*** LEI was engaged by WIRES to prepare a White Paper on Market Resource Alternatives ("MRAs") which provides external parties with a clear understanding of MRAs and a concise description of how MRAs can work effectively alongside transmission investment in US power markets to support market development, reliability, and cost-effective supply.
- ***analyzed clean energy export opportunities:*** LEI was retained by Corporate Knights Inc. to perform a high-level estimation and analysis of potential opportunity for developing clean energy exports from Canadian markets to target US power markets. Julia Frayer presented a preview of her analysis at the ABB Energy and Automation Forum in September 2014.

- ***provided a market outlook for a portfolio of assets located in ERCOT:*** For a global investment firm, LEI provided a 10-year detailed market revenue forecast for the assets under base case assumptions. LEI also used its Real Options model to estimate a scarcity premium that would be included in addition to the intrinsic energy revenues.
- ***assisted a New England incumbent utility in evaluating the economic benefits of two solutions aiming to relieve energy congestion in the metropolitan area of Boston:*** LEI modeled various transmission solutions. The objective of the economic analysis from the energy market perspective was to examine whether there are any production cost savings or market price ("LMP") impacts from either proposal, and to describe under what conditions (assumptions) these benefits are realized.
- ***prepared a 10-year energy market price outlook for the New England wholesale power market and forecast the impact of a proposed project on New England market prices:*** LEI also determined the benefits of the proposed transmission project on employment, economic activity, and tax revenues in New England. LEI utilized the dynamic input-output ("I/O") economic model developed by Regional Economic Models, Inc. ("REMI") to measure the economic benefits to various New England states from the project on employment, economic activity, and tax revenues. LEI separated the economic impact caused by the construction of the project, and the impact caused by the reduction in energy prices due to the commercial operation of the project, taking into account issues such as usage of electricity in residential, commercial, and industrial sectors in the region, and also existing long-term energy contracts that would limit the impact of the project.
- ***analyzed revenue/gross margin modules for a district cooling asset being considered for acquisition in Ohio:*** Under this engagement, LEI performed a due diligence review of the information received from the seller (including documentation from the data room) and designed a series of models aiming at quantifying the asset's potential revenues. Part of LEI's scope work also consisted of identifying and assessing the opportunities to enhance and extend the customers base within the Cincinnati existing and future market conditions. LEI also evaluated the risks associated with prospective/existing customers forgoing the asset's services in exchange of self-supplying their cooling needs.
- ***provided expert analysis and insight on how the restructuring of the US electricity markets has affected the economics of nuclear power plants:*** For a Japanese research institute, LEI provided a Briefing Memo that responded to discrete questions related to the role of government, and the impact restructuring had on nuclear plant operations and financing.
- ***assessed proposed transmission project:*** LEI assessed the economics of the proposed Lake Erie HVDC transmission project to investors and potential customers, by projecting revenue streams associated with the sale of energy, capacity and other products via transit on the Lake Erie HVDC transmission project ("LEP"). The LEP is a 100-km long 1,000 MW bi-directional HVDC transmission line that will connect the Ontario energy market with the PJM market. LEI prepared a comprehensive report that includes a review of the Ontario and PJM markets, a 20-year (2017 to 2036) market outlook and prices for electricity, capacity and

renewable energy credits in Ontario and the relevant zone/s in PJM; the total gross arbitrage value for the energy congestion rents, the capacity revenue potentials for PJM, and the renewable energy credits revenue potential in PJM.

- ***for a utility in the northeastern US, LEI prepared a cost-benefit analysis of a proposed transmission line with the potential to change existing market arrangements:*** In the analysis, LEI developed a base case and multiple project cases based on different configurations of the transmission project. Using its proprietary modeling tool, POOLMod, LEI simulated energy and capacity prices in each configuration over a 15-year timeframe, and compared the price differences against various cost allocation scenarios for the transmission line's construction. LEI also tested the statistical significance of the project case results against the base case results, and conducted further analysis on the economic effects of additional renewable generation projects that construction of the transmission line would make possible.
- ***assessed proposed transmission project:*** LEI was retained to assist a private client in assessing the economics of this proposed transmission project and determining additional revenue streams or value adders from the perspective of third-party shippers. LEI was specifically asked to isolate and measure the spot market volatility premium.
- ***performed a due diligence and market study for three hydro units in PJM:*** LEI's tasks included reviewing the merchant prices and REC prices, evaluating the power purchase agreement and capacity charges and providing energy, capacity and REC forecasts.
- ***performed a review and analysis of rate-making approaches applied to the client's capital expenditure profile including demonstration of the negative potential impact of "I-X" rate-making approaches on a utility's ability to earn a fair return:*** The objective of this engagement will be to demonstrate to stakeholders and the Ontario Energy Board the reasonableness of the revenue cap per customer model that the client has previously relied upon and planned to propose in its next ratemaking review. Furthermore, the secondary objective was to conceptualize the insufficiency of the "I-X" regime, even with a revenue cap per customer model, in consideration of the fair return standard and given the client's business is operating in an environment where substantial capital expenditure needs are projected over the next Incentive Regulation Plan ("IRP") period. Docket Number EB 2012-0459
- ***prepared 10-year (2014-2023) energy and capacity markets price outlooks for the New England market:*** This report presents results of a base case and low case long term price forecasts for the New England market using updated market information, as well as underlying assumptions, methodology, and a brief overview of the market along with a review of relevant regulatory considerations.
- ***testified in front of the New Mexico Finance Authority Oversight Committee regarding the potential economic benefits of new investment in transmission in the state of New Mexico:*** Julia considered the impacts of local spending during construction of the proposed HVDC

project on the state economy, using BEA RIMS multipliers to estimate the boost to economic activity. Julia also employed the DOE's JEDI model to estimate the potential for new jobs and GDP growth as a result of new renewables development in state (wind and solar) as a result of the transmission access that would be provided by the HVDC project.

- ***provided independent review of market benefit reports:*** LEI was engaged by NRG to provide an independent review of the economic analysis in two reports: "Report and recommendations comparing repowering of Dunkirk Power LLC and transmission system reinforcements", published by National Grid ("NG") on May 17, 2013, and "NRG Dunkirk Repowering Project Economic Impact Analysis", published by Longwood Energy Group LLC ("LEG") on March 20, 2013. Both reports forecasted market benefits, production cost savings and macroeconomic benefits. LEI's review compared methodologies and assumptions used by each report, and how these may have affected their results; LEI's review was subsequently submitted by NRG to Case 12-E-0577 at the New York Public Service Commission.
- ***conducted macroeconomic analysis of HVDC project:*** Julia was part of a team of economists that performed a macroeconomic analysis to estimate the local economic benefits accruing to taxpayers, residents, and businesses along the 800+mile route during construction of the Zephyr HVDC project, which runs from Wyoming to Colorado, Utah, and Nevada. LEI performed the analysis using the REMI P1+ model.
- ***conducted regulatory review in PJM:*** LEI was hired to review regulatory and market drivers of energy and capacity prices in PJM, and forecast prospective revenues of a portfolio of pumped storage and conventional hydro generation facilities offered by FirstEnergy, over a 20 year horizon.
- ***assessed market opportunities for industry-scale battery storage technology in the US and selected European jurisdictions for energy arbitrage and ancillary services provision:*** Under this assignment, LEI modeled the operation regime of a battery operating in energy and ancillary services markets in order to monetize added revenues for a wind and solar generators. Findings and modeling results were analyzed and presented before the client's management team and were then deployed to develop strategy for marketing battery technology to renewable developers and utilities. Another objective of the project was to identify most suitable markets and products to optimize the strategy of the battery's market entry.
- ***managed a market study reviewing historical electric rates (and projecting forward electric rates) for large commercial customers in the New England market:*** The electric rates analysis was composed of a number of components, such as the commodity costs of electricity, compliance costs for certain state programs (like RPS), delivery charge for delivering electricity, and ancillary services and administrative supply charges. LEI created projection for each of these components and considered state retail sales requirements for renewables, etc.

- ***triennial market power analysis:*** in support of various clients' application to renew market-based rate authorization under the provision of the Federal Energy Regulatory Commission ("FERC"), LEI performed Pivotal Suppliers Analysis and Market Share Analysis for the Northeast region, including New England, New York, PJM as well as the Connecticut, NYC and PJM East submarkets; as well as California and Southwest US markets.
- ***conducted a modeling analysis, in which the market price impact of incremental wind resources was projected:*** LEI staff completed a simulation-based forecast of the New England system for a future test year (2015) with varying levels of wind generation. Using the multi-scenario approach, we then estimated the energy market price reductions across a range of incremental wind generation scenarios. The simulation modeling was further supplemented with statistical analysis. The one year analysis was also supplemented with sensitivities employing different baseline assumptions with respect to fuel prices.
- ***conducted market analysis on Maine transmission:*** LEI performed a fifteen (15) year simulation analysis to estimate the market impacts resulting from a new transmission interconnection (covering the timeframe 2015-2029) and project the impact on Maine customers (including Northern Maine customers). LEI evaluated the market evolution with and without the interconnection and described the potential ramifications for purchasing electricity for Northern Maine customers. The analysis also estimated the potential impact on ratepayers from the re-allocation of the ISO-NE Pool Transmission Facility rate to incorporate the Northern Maine load and franchise area under a pro forma 10-year transitional agreement. LEI performed the modeling using our up-to-date ISO-NE simulation model (which covers the energy and capacity markets), extended to represent in detail the Maritimes control area.
- ***prepared presentation material on the electricity market impacts and the benefits of Northern Pass Transmission project for New Hampshire and New England consumers:*** In addition, LEI staff assisted the client in preparation of an op-ed piece for dissemination to New Hampshire press outlets. LEI staff also attended an internal company meeting and testified on behalf of the client. Lastly, LEI staff assisted in the preparation for and attended the live New Hampshire Public Radio program "The Exchange" to discuss the benefits of the Northern Pass Transmission over the hour-long live show.
- ***provided extensive late-stage development due diligence for an investor in four potential merchant transmission investments:*** LEI prepared three presentations analyzing four proposed merchant HVDC transmission projects across the US. Analysis included detailing the development roadmap for HVDC projects and the current status of the proposed projects, identifying potential competitive threats from other similar competing transmission lines and proposed local generation, and examining the renewable needs and willingness to pay of utilities in the "sink".
- ***authored report on capital expenditure recovery mechanisms:*** For a Canadian client, Julia prepared a report that looks into the different capital expenditure recovery mechanisms utilized in four markets namely Australia, New Zealand, Ontario, and the UK for electric

network utilities. The report also provided different options that the client can propose for its performance-based ratemaking filing.

- *evaluated third-party energy price forecast for the New England and Texas (ERCOT) regions, with a specific eye on the underlying assumptions:* LEI recommended that certain key assumptions should be updated, including demand projections and CO2 price forecasts. We also argued that some underlying assumptions were unrealistic given actual market conditions, and should be adjusted or eliminated.
- *assisted the Maine Public Utilities Commission in developing an electric resource adequacy plan to aid MPUC in the development of a strategy for the pursuit of the long-term contracts:* The LEI team, led by Julia, submitted a report that builds up a set of recommendations for a long-term investment strategy based on an analysis of the current supply-demand situation, a review of the existing wholesale market rules for energy and the Forward Capacity Market, an examination of historical price trends, and review of the investment needs assessments prepared by the utilities and ISO-NE, as well as relevant sub-regional planning studies.
- *led a due diligence team and assisting in the exclusivity negotiations with respect to an acquisition of a 400+ MW coal-fired plant in the PJM market by a group of private investors:* Julia's role included management of LEI's economic appraisal, coordination of preliminary technical due diligence, negotiations with third parties on possible off-take arrangements, and oversight over financial modeling.
- *prepared a market study of the Ontario electricity market for a major potential investor in Ontario's generation assets:* This report contained an overview of the Ontario electricity market, including a description of market evolution, a summary of key institutions, regulatory and policy initiatives that have impacted the market landscape, and a long term projection for the market going forward.
- *authored report on California capacity markets:* LEI prepared for the California Energy Commission a background report on the design evolution of a capacity market in California and its potential future impact on the generating assets in Mexico that import into the California ISO market.
- *Analyzed Kentucky electricity industry:* To satisfy the requirements of a recently passed statutory mandate, Julia and the LEI team conducted a broad-based analysis of current practices and the potential for reform within Kentucky's electricity industry in four areas: (i) energy efficiency and demand-side management; (ii) use of renewables; (iii) full cost accounting; and (iv) tariffs. Reported results to the state's regulatory commission, including a complete set of recommendations in each of the four areas for overcoming existing impediments to legislative objectives for improvements in the industry's overall efficiency and reductions in its environmental impact.
- *offered feedback on benchmarking methodology:* Julia provided comments on the benchmarking methodology suggested by OEB consultants, looking at the analytical aspects

of defining and benchmarking the performance of multiple utilities across a long period of time. The critique provided details on how each criterion affects the benchmarking study and what are the remedies available to improve the results.

- ***conducted review on Ontario transmission:*** Julia led a team that reviewed industry best practices in other jurisdictions and the current situation in Ontario to advise OEB on the appropriateness of the uniform transmission rate, as well as on the feasibility of moving to long-run zonally-differentiated marginal cost pricing. As part of this process, LEI undertook a comprehensive stakeholder review.
- ***prepared MBR filings:*** Over the course of 2007 and 2008, LEI prepared over a dozen MBR filings for various markets coming under the FERC's triennial schedule as established in Order 697.
- ***electricity price forecasting:*** For an infrastructure fund, LEI used our propriety production cost simulation model to forecast electricity prices and generation from each plant. In addition, LEI provided capacity price forecasts for California based on the Resource Adequacy Requirement (RAR) at the system and local level.
- ***conducted price forecasting analysis throughout North America:*** Julia headed the analysis of long-term price forecasts and energy market dynamics for many of the regions in the US and Canada, including New England, Pacific Northwest, California, Alberta, Southwest Power Pool, SERC, the Midwest US (ECAR, MAIN, and MAPP), Maritimes, Ontario, New England, and PJM. In this practice area, she manages a team of economists that use a variety of modeling tools to forecast one-year to fifteen-year wholesale energy, capacity (where relevant), and market-based ancillary services price forecasts. As part of the modeling effort, LEI proprietary dispatch simulation model, POOLMod, as well as other tools that have been developed by LEI, such as CUSTOMBid, ConjectureMod, ViTAL, and LEI's real options spark-spread module. This type of modeling effort required a detailed investigation of the micro and macro-economic issues facing these regional markets: demand profiling, growth forecasting, reserve margin, and new entry activity assessment. Such analyses are used by clients in establishing market values for assets they have targeted to acquire, consideration of portfolio risk and exposure, and assessments of procurement opportunities. This same modeling has supported regulatory analysis of utility acquisitions and planning strategies, consideration of the impact of market rules and "reservation prices" for sale processes.
- ***reviewed power purchasing options at a large industrial customer's Southeastern facilities over three years:*** LEI assessed the probability of a supply interruption over the next three years due to the state of the transmission system in this region. We also assessed the facility's options for purchasing power for this load in the wholesale market.
- ***assisted in strategizing for the upcoming Clean Energy RFP:*** For a leading New England law firm, LEI modeled a number of potential eligible projects that could offer into the RFP,

and then performed a mock evaluation, with various cost-benefit ratios. Through this analysis, LEI identified key drivers and assumptions that could affect project ranking.

## **SPEAKING ENGAGEMENTS AND PUBLICATIONS:**

*"Investing Trends in Canadian Energy,"* Calgary Energy Roundtable Conference, Calgary, Alberta, October 9, 2019.

*"Reflections on US Market Developments,"* IPPSA Annual Conference 2019, Banff, Alberta. March 12, 2019.

*"Outlook for US Eastern Electricity Markets: ISO-NE, NYISO and PJM,"* Bank of America Merrill Lynch 2019 Gas, Power, and Solar Leaders Conference, Boston, Massachusetts. March 5, 2019.

*"Alternate Regulatory Approaches"* CAMPUT 2018 Conference. May 10, 2018.

*"The Transformation of the Energy Sector" and "Role of Women in Energy"* SIPA's Women in Energy Event at Columbia University. March 28, 2018.

*"Market pricing of oil: are there lessons for the electricity market?"* Gulf Coast Power Association 31<sup>st</sup> Annual Spring Conference - Session VIII -Valuing Dispatchable Resources, Houston, Texas. April 20, 2017.

*"Studying the impact of environmental policies on electricity market design."* AIEE Energy Symposium: Current and Future Challenges to Energy Security, The University of Milan - Bicocca, Milan, Italy. December 1, 2016.

*"Energy storage - how will it be part of the "Grid of Things" in the future?"* WIRES' 2016 Spring Meeting. April 16, 2016.

*"Implications of Energy Infrastructure Investment on Local Economies in New England,"* REMI E3 Conference 2015: Energy, the Environment and the Economy, Amherst, Massachusetts, United States. July 30, 2015.

*"Renewables: No Longer a Noble Way to Lose Money?"* Moderator. SuperReturn US 2015 Conference, Boston, Massachusetts, United States. June 15, 2015

*"Perspectives on future trade opportunities between Canada and the US, and benefits to US consumers"* EUCI US/Canada Cross Border Power Summit Conference, Boston, Massachusetts, United States. April 8, 2015.



*"Are transmission expansions and upgrades compatible with both small and large scale clean energy?"* Panelist. Southwest Clean Energy Transmission Summit, Albuquerque, New Mexico, United States. April 1, 2015.

*"CEO Panel"* Moderator. ABB Energy & Automation Forum, Calgary, Alberta, Canada. September 10, 2014.

*"International Views and Addressing the Need for More Underground Transmission in the US"* Panelist. Platts 2014 Transmission Planning and Development Conference: Ensuring Grid Reliability, Planning Timelines, and a Robust Market's Relationship with New Build, Arlington, Virginia, United States. June 18, 2014.

*Julia Frayer "System Operator's Response to 1000 - How Can the Various Regions Work Together?"* Moderator. Platts 2013 Transmission Planning and Development Conference, Washington DC, United States. September 23, 2013.

*"Merchant Transmission: Planning and Development and Lessons Learned from North America,"* Integrated Transmission Planning and Delivery, Imperial College - Workshop for OFGEM, London, United Kingdom. January 11, 2013.

*"Demand for wind in New England: an economist's perspective,"* AWEA Regional Wind Energy Summit, Portland, Maine, USA (with Shawn Carraher). September 5, 2012.

*"Cost effective procurement of Renewables to Meet Policy Requirements,"* NECPUC Symposium, Rockport, Maine, USA. May 22, 2012.

*"Best Practices for Transmission Asset Valuation,"* Transmission Grid Conference, London, United Kingdom (with Shawn Carraher and Yifei Zhang). March 16, 2012.

*"How effective is US technology policy on clean energy."* 30th USAEE/IAEE North American Conference, Washington, DC, USA. October 10, 2011.

*"Are Markets Ready for New Energy Storage Technologies?"* 34th IAEE, Stockholm, Sweden. June 21, 2011.

*"Long Term Market Impact of Demand Response"* 33rd IAEE International Conference, Rio de Janeiro, Brazil (with Furhana Hasani and Yunpeng Zhang). June 7, 2010.

*"Applications of Information Policy Principles from Auction Theory in the Deregulated Electricity Market"* 32nd IAEE International Conference, San Francisco, California (with Zvika Neeman and Matthew Wittenstein). June 21-24, 2009.

*"Prepared Presentation of Julia Frayer for Market Monitoring and Surveillance in the context of Market Design."* Panelist, PUCT Workshop for Project #28500, Austin, Texas. June 10, 2005.

*"Written Statement of Julia Frayer for the January 27th, 2005 Technical Conference in Docket RM04-7-000"* Panelist, FERC Technical Conference, Washington D.C. January 27, 2005.

*"Competitive procurement options for Ontario's LDCs"* Speaker, APPrO 2004 Conference, Toronto, Ontario (Canada). November 24, 2004.

*"Beyond market shares and cost-plus pricing: designing a horizontal market power mitigation framework for today's electricity markets."* *Electricity Journal* (with Nazli Uludere, and Sam Lovick). November 2004.

*"Alternative to LMP pricing for transmission: a case study of the ICRP approach used by National Grid Company in the UK."* Speaker, Electric Power Conference 2004, Baltimore, Maryland. March 31, 2004.

*"The World Changed on August 14th: the (Second) Great Northeast blackout."* Chairman of Panel Session, Electric Power Conference 2004, Baltimore, Maryland. March 30, 2004.

*"Big ticket leasing - what next for the future?"* Panelist, Big Ticket Leasing 2003, London (United Kingdom). March 12, 2003.

*"Evaluating the Electron Highway"* Speaker, IPPSO 2001 Conference, Richmond Hill, Ontario (Canada). November 2001.

*"What is it worth? Application of real options theory to the valuation of generation assets"* *Electricity Journal* (with Nazli Uludere). November 2001.

*"X Marks the Spot: How UK Utilities Have Fared Under Performance-Based Ratemaking"* *Public Utilities Fortnightly* (with AJ Goulding and Jeffrey Waller). July 15, 2001.

*"How much is it worth? Applying real options valuation framework to generation assets"* Speaker, Electric Power 2001, Baltimore, Maryland. March 22, 2001.

*"Dancing with Goliath: Prospects After the Breakup of Ontario Hydro"* *Public Utilities Fortnightly* (with AJ Goulding and Nazli Z. Uludere). March 1, 2001.

## Curriculum Vitae

**Marie N. Fagan, PhD**

*Managing Consultant and Lead Economist, London  
Economics International LLC*



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### KEY QUALIFICATIONS:

Marie Fagan is Managing Consultant and Lead Economist at London Economics International, LLC, based in Boston, Massachusetts. With over 25 years of experience in research and consulting for the energy sector, Marie's career has spanned international upstream and downstream oil and gas, global coal, North American gas markets, and North American power markets. She has advised C-suite industry clients, buy-side and sell-side financial clients, legislators, and regulators. At LEI, Marie's expertise across electricity markets and fuels provides integrated perspectives and supports sound strategic advice for clients.

Marie leads LEI's engagements related to oil and natural gas analysis. She directs LEI's gas pipeline modeling efforts based on a sophisticated network model, which supports outlooks for natural gas prices and basis and analysis of flows on North American interstate pipelines. Marie has served as an expert witness in matters involving the Enbridge oil pipeline system, which required detailed analysis of pipeline flows and activities of shippers. She provides in-depth expert testimony on issues such as basis differentials, pipeline capacity and utilization in key regions, and LNG import and export supply and demand.

Marie has experience as a project manager for complex, multi-year engagements, include a two-year project for the Maine Public Utilities Commission in 2014-2016 and a two-year project for the Mississippi Public Service Commission in 2017-2019. She has deep experience in econometric analysis, including econometric analysis for utility performance benchmarking.

Marie is a member of industry and academic associations, including the Boston Economic Club, the Energy Bar Association, the International Association for Energy Economics, and New England Women in Energy and Environment. She is the Vice President for Business for the US Association for Energy Economics.

### EDUCATION:

The American University, Washington, DC. Ph.D. in Economics, 1995. Dissertation: "Measuring Cost and Efficiency in US Crude Oil Resource Development, 1977-1990: A Frontier Translog Cost Function Approach"

The University of Connecticut, B.S. in Business Administration (Finance), 1984.

**EMPLOYMENT RECORD:**

<b>From:</b> 2014 <b>Employer:</b>	<b>To:</b> present <i>London Economics International LLC</i> Managing Consultant and Lead Economist
<b>From:</b> 2012 <b>Employer:</b>	<b>To:</b> 2014 <i>IHS, Inc (formerly Cambridge Energy Research Associates ("CERA"))</i> <b><i>Senior Director, Upstream Strategy</i></b>
<b>From:</b> 2007 <b>Employer:</b>	<b>To:</b> 2012 <i>IHS, Inc (formerly Cambridge Energy Research Associates)</i> <b><i>Senior Director, North American Gas and Power</i></b>
<b>From:</b> 2004 <b>Employer:</b>	<b>To:</b> 2007 <i>IHS, Inc (formerly Cambridge Energy Research Associates)</i> <b><i>Director/Senior Director, CERAView Institutional Investor</i></b>
<b>From:</b> 2003 <b>Employer:</b>	<b>To:</b> 2004 <i>Cambridge Energy Research Associates</i> <b><i>Director, North American Gas</i></b>
<b>From:</b> 2001 <b>Employer:</b>	<b>To:</b> 2002 <i>International Human Resources Development Corporation</i> <b><i>Director, Global Gas Program</i></b>
<b>From:</b> 1998 <b>Employer:</b>	<b>To:</b> 2001 <i>Cambridge Energy Research Associates</i> <b><i>Associate Director, Global Oil</i></b>
<b>From:</b> 1996 <b>Employer:</b>	<b>To:</b> 1998 <i>Cambridge Energy Research Associates</i> <b><i>Associate, Global Oil</i></b>
<b>From:</b> 1994 <b>Employer:</b>	<b>To:</b> 1996 <i>Energy Information Administration</i> <b><i>Economist</i></b>
<b>From:</b> 1991	<b>To:</b> 1994

**Employer:** *Decision Analysis Corporation of Virginia  
Associate*

**From:** 1989                      **To:** 1990  
**Employer:** *Decision Analysis Corporation of Virginia  
Research Associate*

**From:** 1988                      **To:** 1988  
**Employer:** *United States Department of Energy  
Intern, Office of Policy Planning, and Analysis*

## **RECENT PROJECT EXPERIENCE:**

The projects briefly described below are typical of the work Marie Fagan has performed at London Economics International.

### **Econometric analysis and benchmarking**

- *econometric benchmarking analysis of distribution utility performance:* LEI was engaged by an investor-owned local gas distribution company to support its rate filing for performance-based ratemaking. Marie led an econometric benchmarking analysis of utility performance in terms of O&M and capital costs. The econometric analysis used a transcendental logarithmic (“translog”) cost function to help set expectations for further efficiency improvement, for use in the setting of the X- factor.
- *econometric benchmarking analysis of generation unit performance:* LEI was engaged by a Canadian hydropower generation company to support its rate filing. Marie led an econometric benchmarking analysis of unit-level O&M costs for a cross-sectional data set of over 300 hydropower generation units.
- *econometric analysis of oil demand:* Marie led a comprehensive study of price and income elasticities of oil demand for Columbia University’s Center on Global Energy Policy (“CGEP”). The foundation of the study was a detailed econometric analysis which employed a variety of specifications of econometric models, including static and dynamic models, symmetric and asymmetric models, and tests of time-series properties of the data. The scope of the work encompassed separate models for crude oil, gasoline, and diesel demand, and relied on combined cross-section time-series data for OECD and non-OECD countries.

### **Crude oil and natural gas**

- *independent expert in assessing role of Enbridge Line 3 for Minnesota:* Marie served as an independent market expert assisting the Minnesota Department of Commerce in

evaluating the application of Enbridge Energy for a Certificate of Need for its Line 3 oil pipeline expansion project (Docket No. PL-9/CN-14-916, OAH Docket No. 65-2500-32764). Marie's analysis covered global and local trends in refined product demand and crude oil supply, refinery utilization rates, and utilization of high-conversion refinery capacity in Petroleum Administration for Defense District ("PADD") 2 and in the local Minnesota region. Her analysis required detailed examination of the assumptions and methodology of an oil pipeline linear programming-based model in order to assess another witness's testimony, which relied on the model. Marie provided written testimony; responded to interrogatory requests, provided written surrebuttal, and oral testimony.

- ***independent research into the role of Enbridge Line 5 in NGLS and crude oil transport in Michigan:*** For a non-governmental organization ("NGO") Marie produced three white papers examining the current and future role of Enbridge Line 5 in Michigan related to three issues: propane supply in Michigan, transportation for crude oil producers in Michigan, and supply of crude oil to Michigan-area refineries. Marie's analysis of the propane market included a comparative static econometric analysis of the supply and demand from propane in Michigan, explained in non-technical language. The white papers were used by the client in discussions with the Governor of Michigan and other stakeholders.
- ***evaluation of the costs and benefits of the expansion of natural gas pipelines into New England:*** Marie led analysis of the costs and benefits of a number of contracts for firm transportation ("FT") service on natural gas pipelines. She reviewed pipeline precedent agreements and rate agreements and provided a qualitative analysis and comparison of contracts offered. She led the quantitative analysis of the impacts of pipelines on gas and power prices, which was underpinned by LEI's proprietary simulation model of the New England power system ("PoolMod"), combined with a widely-used industry standard model of the gas pipeline system (known as "GPCM"). She provided insight and direction of research in gas price basis differentials, pipeline capacity and utilization in key regions, and LNG import and export supply and demand.
- ***analysis of Western Canadian natural gas costs and production:*** LEI was retained by counsel to provide support in the matter of NOVA Gas Transmission Limited ("NGTL")'s application to the National Energy Board ("NEB"). LEI reviewed the evidence and prepared testimony: Marie led analysis of the natural gas and natural gas liquids ("NGLs") market in Alberta and British Columbia, and the impact of a pipeline surcharge on producers of natural gas.

### **Expert testimony**

- *expert witness report in support of litigation:* In Case 15CV-04225 in the District Court of Johnson County, Kansas, LEI was retained by counsel to examine the value of the green attributes of landfill gas ("LFG") produced by a project in Kansas City, Kansas, and sold under long-term contract to the Sacramento Municipal Utility District ("SMUD"). Marie's report demonstrated several flaws in the opposing counsel's expert's methodology. Marie proposed an alternative, more appropriate methodology for valuing the green attributes of LFG, based on market fundamentals driven by the California RPS requirements.
- *independent market expert, and expert witness for public utilities commission:* For the Maine Public Utilities Commission, in the evaluation of the costs and benefits of alternatives for expansion of natural gas supply into Maine (MPUC Docket #2015-00071), Marie authored reports provided to the Commission; responded to discovery from other parties; prepared discovery questions and cross-examined witnesses; reviewed testimony by other parties and provided assessments of the issues presented; and served as an expert witness in the proceedings.

### **ERCOT/Texas power market**

- *assessment of political support for large-scale transmission expansion:* Marie examined the political, legislative, and economic drivers of ERCOT's Competitive Renewable Energy Zones ("CREZ") to support due diligence for an investor interested in wind assets in ERCOT, and provided an assessment of state-level support for further expansion of CREZ transmission lines. She also provided an assessment of and outlook for ERCOT's and the Public Utility Commission of Texas's views of the "system cost" (the potential increased need for ancillary services and firm capacity) of wind.
- *forecast of potential energy revenues of two wind farms in Texas:* LEI used its proprietary dispatch model, PoolMod, to project energy prices for the West zone in ERCOT. Marie led the project, and also examined the implications of the PPA related to the two wind farms.

### **Procurement advisory**

- *analysis of the macroeconomic impact of biomass electric power generation:* For Maine Public Utility Commission Docket No. 2016-00084, Marie conducted a macroeconomic study comparing the impacts of bids related to biomass power procurement. Marie used the IMPLAN model to estimate impacts on direct, indirect, and induced jobs, payments to the state and municipalities, payments for fuel harvested in the state, and other macroeconomic impacts.

- ***independent evaluator for solar procurement:*** for PacifiCorp, Marie led the independent evaluator team for PacifiCorp's system-wide 2017 Solar RFP. The project included a review of PacifiCorp's Solar RFP, the facilitation and monitoring of communications between PacifiCorp and bidders, reviewing the initial shortlist and final shortlist evaluation, and scoring.

### **Market rules and practices**

- ***analysis of key characteristics of capacity markets:*** To support Board-level understanding of the implications of potential capacity market designs in Alberta, Marie prepared a detailed review and comparison of capacity markets across international and North American jurisdictions. The report concluded that "the devil is in the details" of capacity market design. Market design details with potentially large impacts on the client were resource eligibility definitions, price-setting mechanism, demand curve design, performance requirements, and market power mitigation rules.
- ***advisory on a wide variety of market rules and regulatory risks:*** LEI was engaged to support a client's Regulatory Group in its administering of the company's compliance program. This involved creating and delivering a monthly report covering developments by regional market and traded products, which included: energy, capacity, long-term transmission service, FTR auctions, ancillary services, diesel oil, PRB coal, natural gas commodity, transmission, and storage, RECS, and CO2. Marie served as project manager and executive editor of the monthly report.
- ***advisory for an investigation related to the timing of outage scheduling:*** For a law firm, Marie provided research and expertise covering US Federal Energy Regulatory Commission ("FERC") practices related to monitoring, enforcement, and definition and prosecution of alleged market manipulation.
- ***advisory to provincial government:*** LEI was engaged to perform analysis of the organization and governance of electricity systems both cross-jurisdictionally and within the province of Nova Scotia. Marie provided a review of the Nova Scotia gas and power sectors, including governing institutions, the legal and regulatory framework, recent developments and challenges, and SWOT analysis.
- ***advisory to UK Department of Energy and Climate Change:*** Marie participated in an evaluation of auction design for the UK DECC. The UK market regulator was interested in whether US power markets evaluate capacity bids based on criteria other than the price bid, specifically, if the length of contract had a role in the auctions. Marie reviewed capacity market auction rules for PJM, ISO-New England and the New York ISO, as well as international spectrum auctions, North American gas transmission open season rules, and international auctions for toll roads.



### **Electricity and natural gas asset valuation and transaction advisory**

- *evaluation of behind-the-meter solar business models:* Marie led a project examining US federal and state incentives for solar adoption, and assessed business models used for targeting commercial, institutional, and industrial sectors to support a client's due diligence related to a potential investment in business-to-business behind-the-meter solar in the Northeast United States. Marie's team also developed key questions the client should ask, as part of its evaluation of potential transactions in the solar sector.
- *evaluation of contracts for firm gas transportation capacity:* For plants located in Virginia and Connecticut, Marie evaluated the value of firm transportation and interruptible transportation legacy contracts. The client also retained LEI to forecast delivered gas prices in New England (Connecticut) and PJM (New Jersey) and locational marginal prices as well as retail electricity prices in Connecticut. Marie led the gas market analysis for this project.
- *assessment of congestion/curtailment risk:* Marie led a project for a wind developer, providing a quantitative assessment, of congestion/curtailment risk for a wind asset in New England. LEI incorporated information from the interconnection impact study to examine system limits and provided an assessment of risk of outages based on NERC outage data for NPCC.
- *forecast of reserves market prices:* To support potential acquisition of hydropower assets, Marie provided analysis of ISO-New England's Locational Forward Reserves Market.
- *due diligence related to a district cooling asset:* Marie reviewed contracts and developed a model for projecting revenues and gross margins for the asset. Marie provided insight by identifying the potential for lower customer contract prices at renewal (in contrast to the seller's assumptions) and other areas of revenue risk.

# **EMPIRICAL ANALYSIS OF TOTAL FACTOR PRODUCTIVITY TRENDS IN THE U.S. GAS DISTRIBUTION INDUSTRY**

*Prepared for*

**NSTAR Gas Company**

*By*



**London Economics International LLC**

717 Atlantic Avenue, Suite 1A  
Boston, MA 02111

**November 8, 2019**

NSTAR Gas Company  
d/b/a Eversource Energy  
D.P.U. 19-120  
Exhibit ES-JF/MF-2  
November 8, 2019  
H.O. Kevin Crane

**Prepared by:**

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**Denis Lawrence**  
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**(Economics Insights)**

## DISCLAIMER

London Economics International LLC ("LEI") was retained by NSTAR Gas Company ("NSTAR Gas" or "the Company") to prepare an industry total factor productivity study ("TFP Study"). LEI has made the qualifications noted below with respect to the information contained in this TFP Study and the circumstances under which the report was prepared.

While LEI has taken all reasonable care to ensure that its analysis is complete, gas markets are highly dynamic, and thus certain recent developments may or may not be included in LEI's analysis. It should be noted that:

- LEI's analysis is not intended to be a complete and exhaustive analysis of productivity trends in the gas local distribution utility ("LDC") sector. The provision of an analysis by LEI does not obviate the need for potential investors to make further appropriate inquiries as to the accuracy of the information included therein, and to undertake their own analysis and due diligence.
- No results provided or opinions given in LEI's analysis should be taken as a promise or guarantee as to the occurrence of any future events.
- There can be substantial variation between assumptions and market outcomes analyzed by various consulting organizations specializing in the LDC sector and investments in such markets. Neither LEI nor its employees make any representation or warranty as to the consistency of LEI's analysis with that of other parties.

The contents of LEI's analysis do not constitute investment advice. LEI, its officers, employees, and affiliates make no representations or recommendations to any party other than NSTAR Gas. LEI expressly disclaims any liability for any loss or damage arising or suffered by any third party as a result of that party's, or any other party's, direct or indirect reliance upon LEI's analysis and this report.

## Table of contents

<b>ACRONYMS.....</b>	<b>3</b>
<b>1 EXECUTIVE SUMMARY .....</b>	<b>4</b>
1.1 WHAT IS TFP? .....	4
1.2 OVERVIEW OF THE LDC INDUSTRY IN THE U.S. AND THE NORTHEAST REGION .....	5
1.3 WHAT DATA WAS USED FOR THIS LDC INDUSTRY TFP STUDY? .....	10
1.4 WHAT ARE THE RESULTS OF THE TFP STUDY FOR THE U.S. LDC INDUSTRY? .....	11
1.5 TFP GROWTH IN THE NORTHEAST REGION OF THE LDC INDUSTRY .....	12
1.6 HOW DO YOU TRANSLATE THE INDUSTRY AVERAGE TFP GROWTH RATE INTO AN X FACTOR FOR NSTAR GAS' PBR PLAN? .....	13
<b>2 BASICS OF TOTAL FACTOR PRODUCTIVITY.....</b>	<b>15</b>
2.1 WHAT IS PRODUCTIVITY?.....	15
2.2 OVERVIEW OF TFP METHODS .....	16
2.3 SELECTING AN INDEXING TECHNIQUE .....	18
2.4 APPROPRIATE LENGTH OF TFP STUDY .....	19
2.5 MEASURING TFP GROWTH RATES.....	20
2.6 NUMBER OF GAS UTILITIES.....	21
<b>3 TFP METHODOLOGY AND DATA SOURCES .....</b>	<b>25</b>
3.1 OVERVIEW OF DATA SOURCES .....	25
3.2 OUTPUT .....	25
3.3 INPUTS .....	27
3.3.1 OM&A input .....	27
3.3.2 Capital input quantity .....	29
3.3.3 Capital input price index .....	35
<b>4 TFP RESULTS.....</b>	<b>38</b>
4.1 U.S. INDUSTRY TRENDS .....	38
4.1.1 Output index .....	38
4.1.2 Input index .....	39
4.1.3 TFP and PFP growth.....	40
4.2 NORTHEAST REGION TFP TRENDS .....	41
4.4 NSTAR GAS HISTORICAL TFP GROWTH.....	43
<b>5 X FACTOR RESULTS.....</b>	<b>46</b>
<b>6 APPENDIX: ALTERNATIVE OUTPUT METRIC .....</b>	<b>48</b>

## Table of figures

FIGURE 1. TOP 5 LDCs IN TERMS OF 2017 TOTAL SALES VOLUME ACROSS THE U.S. ....	6
FIGURE 2. TOP 5 LDCs IN TERMS OF 2017 TOTAL NUMBER OF CUSTOMERS ACROSS THE U.S. ....	6
FIGURE 3. TOP 5 LDCs IN THE NORTHEAST IN TERMS OF TOTAL SALES VOLUME IN THE NORTHEAST REGION.....	8
FIGURE 4. TOP 5 LDCs IN TERMS OF THE TOTAL NUMBER OF CUSTOMERS IN THE NORTHEAST REGION .....	8
FIGURE 5. MILES BARE STEEL MAINS IN USE IN THE U.S. AS OF 2018.....	9
FIGURE 6. MILES OF CAST AND WROUGHT IRON STEEL MAINS IN USE IN THE U.S. AS OF 2018 .....	10
FIGURE 7. TFP GROWTH RATES FOR U.S. LDC INDUSTRY (2003-2017) .....	12

FIGURE 8. TFP GROWTH RATES FOR NORTHEAST LDCs (2003-2017).....	13
FIGURE 9. GENERALIZED CONCEPT OF A TFP GROWTH RATE .....	15
FIGURE 10. EMPIRICAL TECHNIQUES FOR ESTIMATING TFP .....	17
FIGURE 11. FISHER IDEAL INDEX.....	19
FIGURE 12. CALCULATING AVERAGE TFP GROWTH FOR A STUDY PERIOD OF 2003-2017 .....	20
FIGURE 13. TREND REGRESSION OF TFP GROWTH FOR A STUDY PERIOD OF 2003-2017 .....	21
FIGURE 14. STATES COVERED IN THE INDUSTRY TFP STUDY .....	22
FIGURE 15. LDCs INCLUDED IN THE INDUSTRY TFP STUDY (ALPHABETICAL, BY REGION).....	23
FIGURE 16. MAP OF THE LOCATION OF LDCs IN THE NORTHEAST REGION .....	24
FIGURE 17. TOTAL NUMBER OF CUSTOMERS SERVED VS. GAS SALES FOR THE U.S. LDC INDUSTRY IN THE INDUSTRY TFP STUDY (REFLECTING ALL 83 LDCs STUDIED) .....	26
FIGURE 18. GROWTH RATE TRENDS OF THE NUMBER OF CUSTOMERS SERVED VS. GAS SALES FOR THE U.S. LDC INDUSTRY IN THE INDUSTRY TFP STUDY (REFLECTING ALL 83 LDCs STUDIED).....	26
FIGURE 19. REPORTED OM&A COSTS OF THE 83 LDCs IN LEI'S U.S. INDUSTRY SAMPLE (NOMINAL \$) .....	28
FIGURE 20. INPUT PRICE INDEX FOR OM&A.....	29
FIGURE 21. RANGE OF SERVICE LIFE OF SELECT GAS DISTRIBUTION ASSETS (YEARS).....	32
FIGURE 22. SHARE OF EACH ASSET TO THE TOTAL GROSS VALUE OF THE DISTRIBUTION PLANT .....	33
FIGURE 23. ILLUSTRATION OF THE BLS PPI .....	34
FIGURE 24. REAL CAPITAL QUANTITY FROM 2003 TO 2017 FOR THE U.S. LDCs, 1998 DOLLAR TERMS.....	35
FIGURE 25. FEDERAL AND STATE CORPORATE TAX RATES BY STATE.....	37
FIGURE 26. TFP GROWTH RATES FOR THE U.S. AND NORTHEAST REGION.....	38
FIGURE 27. CHAINED FISHER IDEAL INDICES FOR QUANTITIES OF INPUTS AND OUTPUTS FOR THE U.S. LDC INDUSTRY.....	39
FIGURE 28. ANNUAL GROWTH RATES FOR OUTPUT AND INPUT QUANTITIES AND RESULTING PFP AND TFP TRENDS FOR THE U.S. LDC INDUSTRY.....	40
FIGURE 29. ANNUAL GROWTH RATES FOR OUTPUT AND INPUT QUANTITIES AND RESULTING PFP AND TFP TRENDS FOR THE NORTHEAST REGION LDC INDUSTRY .....	41
FIGURE 30. CHAINED FISHER IDEAL INDICES FOR QUANTITIES OF INPUTS AND OUTPUTS FOR THE NORTHEAST REGION LDC INDUSTRY .....	42
FIGURE 31. OM&A INPUT QUANTITIES INDEX FOR NSTAR GAS AND THE U.S. LDC INDUSTRY .....	44
FIGURE 32. ANNUAL GROWTH RATES FOR OUTPUT AND INPUT QUANTITIES AND RESULTING PFP AND TFP TRENDS FOR NSTAR GAS.....	45
FIGURE 33. X FACTOR RESULTS FOR THE LDC INDUSTRY (2003-2017).....	47
FIGURE 34. X FACTOR RESULTS FOR THE NORTHEAST LDCs.....	47
FIGURE 35. OUTPUT INDEX: NUMBER OF CUSTOMERS SERVED VERSUS ANNUAL GAS SALES FOR THE U.S. LDC INDUSTRY.....	48
FIGURE 36. ANNUAL TFP GROWTH RATES USING GAS SALES AS AN OUTPUT MEASURE FOR THE U.S. LDC INDUSTRY.....	49
FIGURE 37. X FACTOR RESULTS FOR THE U.S. LDC INDUSTRY USING GAS SALES AS AN OUTPUT MEASURE .....	49

## Acronyms

A&G	Administrative and general expenses
BEA	Bureau of Economic Analysis
BLS	Bureau of Labor Statistics
Capex	Capital expenditure
DEA	Data Envelopment Analysis
DPU	Department of Public Utilities (Massachusetts)
EIA	Electricity Information Administration
FERC	Federal Energy Regulatory Commission
GDP-PI	Gross Domestic Product Price Index
HWI	Handy Whitman Index
LDC	Local distribution company
LEI	London Economics International LLC
OHS	One hoss shay
OM&A	Operations, maintenance, and administrative
Opex	Operating expenditure
PEG	Pacific Economics Group
PBR	Performance-based regulation
PFP	Partial factor productivity
PPI	Producer price index
ROE	Return on equity
SFA	Stochastic Frontier Analysis
TFP	Total factor productivity
X factor	Productivity factor
WACC	Weighted average cost of capital

## 1 Executive Summary

London Economics International (“LEI”) was engaged by NSTAR Gas Company (“NSTAR Gas” or “the Company”) to perform a Total Factor Productivity (“TFP”) study for the gas local distribution company (“LDC”) industry in the U.S. Based on an index-based analysis of input quantities (labor, non-labor operations, maintenance, and administration (“OM&A”), and capital) and output quantities (number of customers served), the U.S. LDC industry experienced an annual average TFP trend of 0.09% between 2003 and 2017. This calculated TFP trend, if paired with an inflation factor (“I factor”) that relies on U.S. Gross Domestic Product-Price Index (“GDP-PI”), results in a proposed productivity factor (“X factor”) of -0.79%. In addition, LEI also evaluated TFP trends for LDCs operating in the Northeast Region (with the region defined consistent with conventions employed by the U.S. Bureau of Labor Statistics (“BLS”)).<sup>1</sup> The LDCs in the Northeast Region experienced an average TFP growth rate of -0.39% over the 2003-2017 timeframe. This TFP growth, coupled with an I factor based on GDP-PI, results in an X factor of -1.30%.

This report is structured as follows: Section 0 presents an overview of the various methods of measuring productivity and explains why an index method was selected for this Industry TFP Study. Section 0 discusses the different input and output measures that were used in the calculation of TFP trends and the source of the underlying data. Section 4 presents the TFP growth rate results for the national sample and the Northeast region sample of LDCs. Section 0 provides the recommended X factor for the Company. Lastly, in the appendix, LEI presents the detailed results of the TFP calculations using an alternative output metric.

### 1.1 What is TFP?

TFP measures the total quantity of output(s) produced by a firm (or firms) relative to the quantity of inputs employed. As implied in the name, a **total** factor productivity metric should cover all inputs to the production process (in contrast, a partial factor productivity (“PFP”) metric evaluates a single input).

For purposes of ratemaking and specifically for input to a comprehensive price cap or revenue cap plan under PBR, an industry TFP study is needed that reports the growth rate or year-over-year rate of change in TFP levels. Moreover, those TFP trends should be based on **quantities** of

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<sup>1</sup> The Northeast region, according to the Bureau of Labor Statistics (“BLS”), includes the states of New England (namely Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont), New Jersey, New York, and Pennsylvania.



inputs and outputs, not simply annual operating costs.<sup>2</sup> In this way, the industry TFP Study captures the changes in the overall physical productivity of firms within the industry.

A TFP study for purposes of setting an X factor for a rate escalation mechanism should not focus on any single firm nor report the efficiency levels of any specific firm. The firm's own performance should have little or no impact on the broad comparative measure chosen for the X factor so that the firm is given an incentive to match (or even outperform) the industry average productivity growth rate. Also, it is important to keep in mind that a TFP study, by its nature, is not a forecast of future productivity – it is squarely based on historical data. However, the historical growth rates or trends in physical productivity for the industry as a whole over time can be informative for setting the parameters for a firm's PBR plan on a going-forward basis, if the observed TFP trends accurately capture industry conditions that are expected to continue into the future.

## 1.2 Overview of the LDC industry in the U.S. and the Northeast Region

In the U.S., there is a total of 196 investor-owned LDCs. As of 2017, the total number of customers served by these LDCs was 69 million, mostly residential customers.<sup>3</sup> The total number of customers grew by an average of 1.6% per year for the past three years (2015-2017).<sup>4</sup> On the other hand, gas sales in the same period have been decreasing by an average of 1.9% per annum.<sup>5</sup> To conduct an industry TFP study, LEI required detailed data going back to 1998 for each LDC. Notwithstanding the variability in records available, LEI was able to get a consistent data set for 83 LDCs. The 83 LDCs included in the Industry TFP Study covered 69.5% of the customers served in the U.S. LDC industry in 2017.

The largest LDCs in the U.S., in terms of total sales volume and the number of customers, are Southern California Gas Company, Pacific Gas and Electric Company, Northern Illinois Gas Company, Piedmont Natural Gas, Consumers Energy Company, and CenterPoint Energy Resources, as shown in Figure 1 and Figure 2 below. These five companies represent more than 20% of the U.S. market for LDCs, based on the total volume of gas sold and customers served. None of these large LDCs are located in the Northeast Region. NSTAR Gas is less than 16% of the size of these larger LDCs in terms of number of customers and gas sales.

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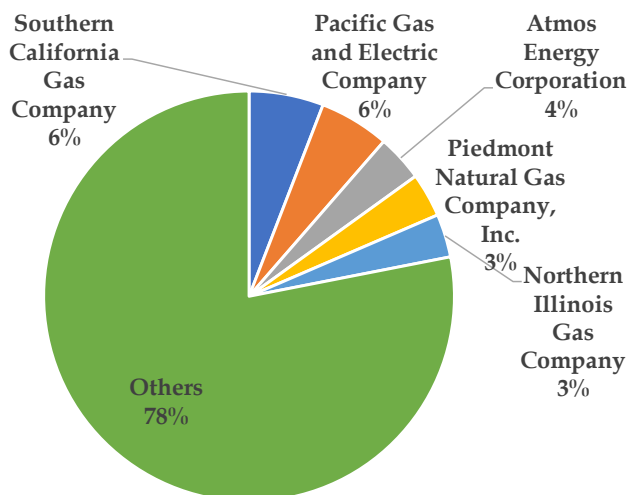
<sup>2</sup> LEI commenced the data collection process with identification of operating expenses and other financial data. LEI then deflated the data by an appropriate input price index in order to estimate a proxy for a physical quantity. Prices are also needed to form input weights; this is described further in Section 0.

<sup>3</sup> EIA 716. Data through 2017, Natural Gas Annual Respondent Query System, <<https://www.eia.gov/naturalgas/ngqs/#?year1=2014&year2=2017&company=Name>>.

<sup>4</sup> Ibid.

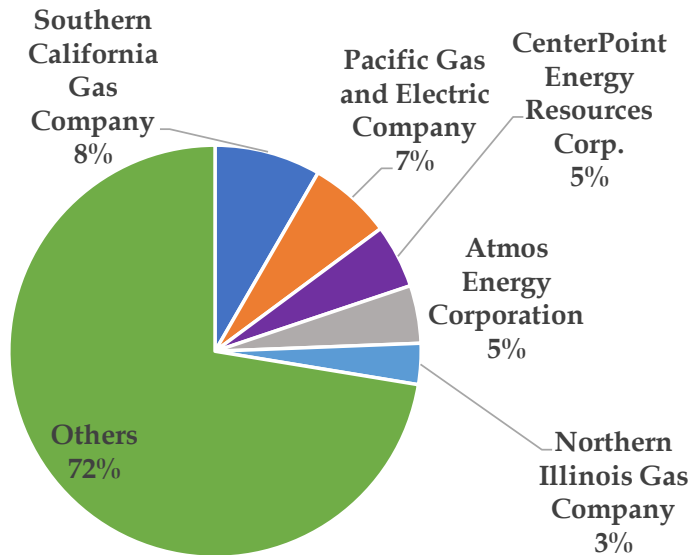
<sup>5</sup> Ibid.

**Figure 1. Top 5 LDCs in terms of 2017 total sales volume across the U.S.**



Source: EIA 716; LEI analysis

**Figure 2. Top 5 LDCs in terms of 2017 total number of customers across the U.S.**



Source: EIA 716; LEI analysis

LEI also estimated the industry TFP trends for the Northeast Region, in which NSTAR Gas operates. Several states comprise the Northeast Region, according to the BLS. These include

Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont. There is a total of 40 investor-owned LDCs in the Northeast Region, and these LDCs served a total of 12.6 million gas customers in 2017.<sup>6</sup> LEI was able to collect the requisite data for 29 LDCs, covering 94% of the number of customers served in this region.<sup>7</sup>

Year-over-year growth in the number of customers served is lower in the entire Northeast Region at 0.8% per year, compared to the U.S. as a whole, at 1.6% per year for the past three years. Likewise, gas sales have declined faster in the Northeast Region (at 2.9% per year) as compared to the U.S. (1.9% per annum) for the past three years.

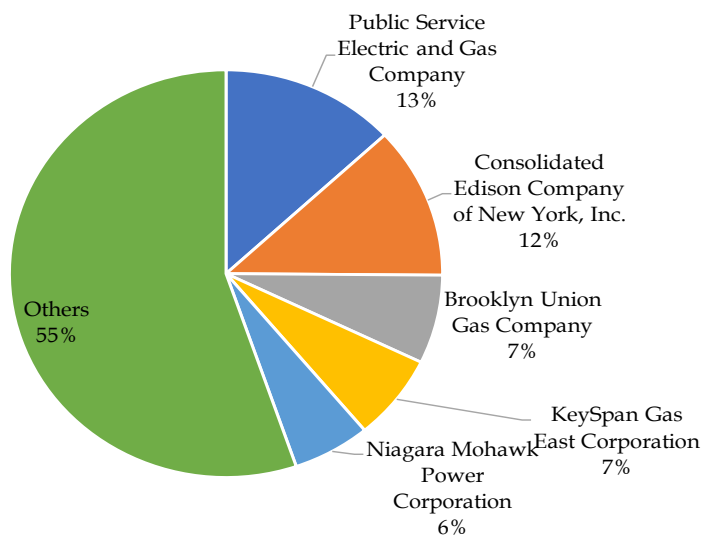
The Public Service Electric and Gas Company in New Jersey is the largest LDC in the Northeast Region as of 2017 in terms of sales volume and number of customers, garnering 13% to 14% of the regional market share in terms of sales volume and customers, respectively. The other large LDCs in the region (in terms of both sales and number of customers) are Consolidated Edison Company of New York, Inc., Brooklyn Union Gas Company, KeySpan East Corporation, Niagara Mohawk Power Corporation, and National Fuel Gas Distribution Company as shown in the figures below. These companies are included in LEI's Industry TFP Study.

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<sup>6</sup> EIA 716.

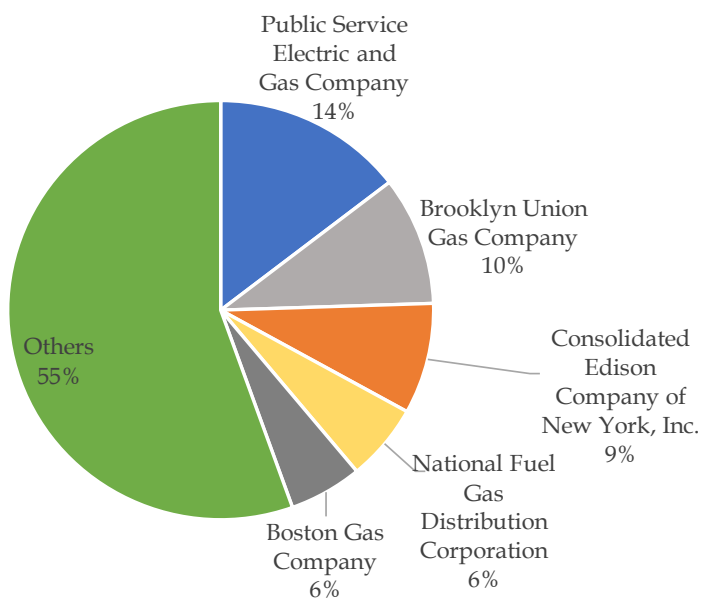
<sup>7</sup> LEI's Industry TFP Study for the Northeast Region covered seven out of nine states in the Northeast Region. See Section 2.6 for more information.

**Figure 3. Top 5 LDCs in the Northeast in terms of total sales volume in the Northeast Region**



Source: EIA 716; LEI analysis

**Figure 4. Top 5 LDCs in terms of the total number of customers in the Northeast Region**



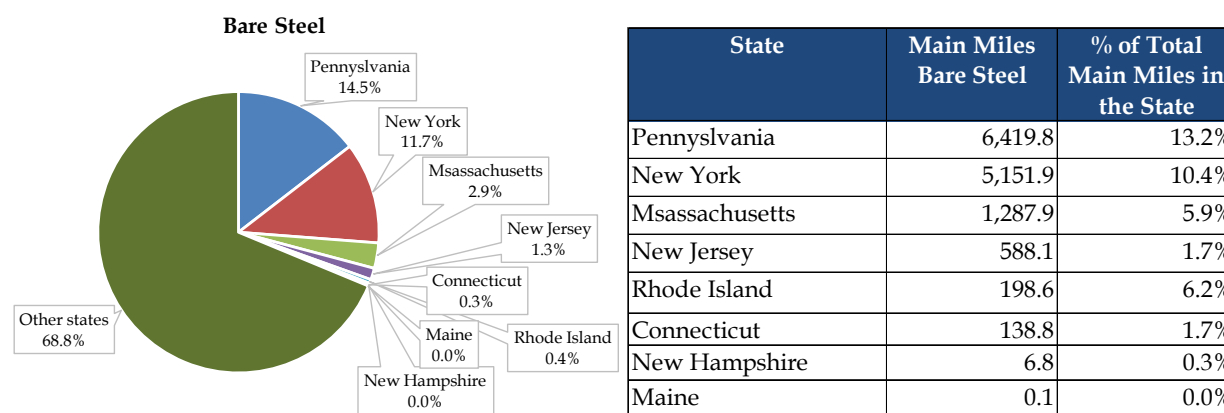
Source: EIA 716; LEI analysis

Gas pipelines are generally made of bare steel, cast or wrought iron, plastic, and copper. Cast or wrought iron pipelines were utilized through the 1940s and are among the oldest pipelines constructed in the country.<sup>8</sup> Since the 1950s, steel has been used widely, while plastic pipelines for gas distribution became prevalent in the early 1970s.<sup>9</sup> Although many cast iron and bare steel pipelines have been replaced over the years, some still remain in operation. In 2018, a total of 13,792 main miles of bare steel (or 45% of the U.S.) were located in the Northeast Region, as shown in Figure 5 below. In contrast to the 45% share of bare steel mains, the Northeast Region only had 18.3% of 2017 total number customers in the U.S.

Similarly, many cast and wrought iron mains are still in use in the Northeast Region. A total of 14,580 main miles of cast and wrought iron (or 64% of the U.S.) are located in the Northeast Region as of 2018,<sup>10</sup> as shown in Figure 6 below. This indicates that the Northeast Region has a relatively older system compared to the rest of the U.S.

**Figure 5. Miles bare steel mains in use in the U.S. as of 2018**

**Share of bare steel by main miles in the U.S. Main miles of bare steel in the Northeast state**



Source: PHMSA "Pipeline Replacement Updates." Accessed on September 17, 2019

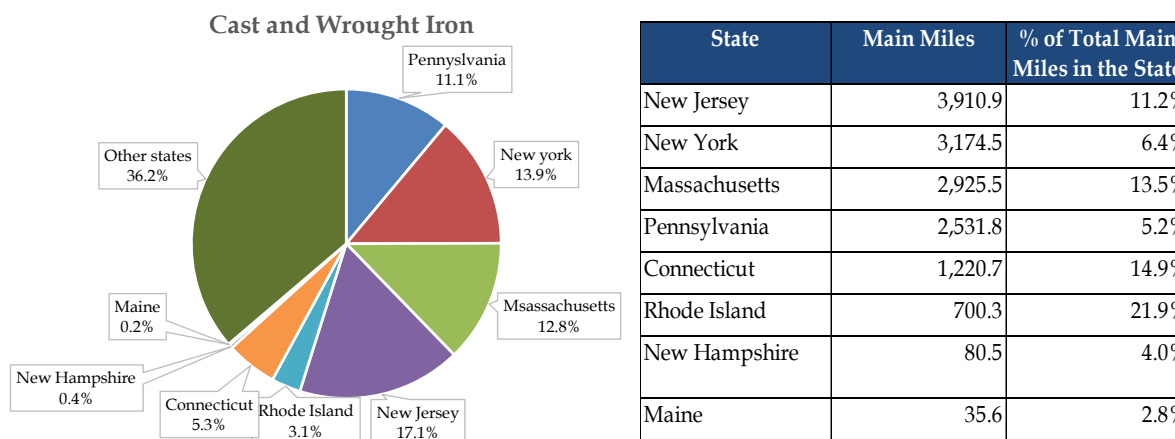
<sup>8</sup> PHMSA. "Pipeline Materials." Accessed on September 18, 2019. <<https://www.phmsa.dot.gov/technical-resources/pipeline/pipeline-materials>>

<sup>9</sup> Ibid.

<sup>10</sup> Ibid.

**Figure 6. Miles of cast and wrought iron steel mains in use in the U.S. as of 2018**

**Share of cast iron by main miles in the U.S.    Main miles of cast iron in the Northeast states**



Source: PHMSA "Pipeline Replacement Updates." Accessed on September 17, 2019

### 1.3 What data was used for this LDC industry TFP study?

Based on best practices of estimating industry TFP trends for PBR plan design, LEI selected the number of customers served<sup>11</sup> as the measure of output. For the inputs, LEI included an input measure that reflects comprehensively the total cost of service, including inputs that measure the quantity of capital deployed,<sup>12</sup> and the quantity of operations maintenance and administration ("OM&A") costs.<sup>13</sup> Sections 3.2 and 3.3 provide a discussion of the inputs and output measures LEI used in this Industry TFP Study.

The data selection and gathering process was a fundamental and critical step that required a significant amount of effort in conducting the industry TFP Study. Unlike the electric industry, data for investor-owned LDCs is not available from a single source. Most of the LDCs file their annual LDC reports with their respective state regulators. LDCs that serve multiple states also

<sup>11</sup> It should be noted that this is not only the captive customers but also includes customers using the distribution system that are being supplied by a competitive (alternative) gas supplier.

<sup>12</sup> LEI used a monetary approach for estimating capital quantities and have assumed a One Hoss Shay ("OHS") physical decay profile. A detailed discussion of this is found in Section 3.3.2.2.

<sup>13</sup> See Section 0 for details on how this data is used.

submit information with FERC using FERC Form 2. Primary data sources used in this TFP Study include the annual LDC filings to the state public utility commissions, FERC Form 2, and EIA 716 (Natural Gas database for consumption – company level supply and disposition).<sup>14</sup>

Based on data availability, this Industry TFP Study included 83 LDCs<sup>15</sup> across 31 states. The Northeast Region included 29 of the 83 LDCs. LEI's Industry TFP Study reported the TFP growth over a timeframe of fifteen years, from 2003 through 2017. Section 2.6 provides a discussion of the LDCs included in LEI's Industry TFP Study.

#### **1.4 What are the results of the TFP Study for the U.S. LDC industry?**

LEI estimated an annual average TFP growth rate of 0.09% for the U.S. LDC industry.<sup>16</sup> Although it is very close to zero, it is nevertheless marginally positive. A positive TFP growth rate implies that the quantity of output (number of customers served) grew faster than the quantity of inputs (capital and OM&A). As shown in Figure 7 below, total customers served grew at a slightly higher rate (at 0.73% per year) compared to the quantity of inputs deployed by U.S. LDCs (at 0.65% per year). The results of the industry TFP study are discussed further in Section 4.<sup>17</sup>

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<sup>14</sup> Available online at <https://www.eia.gov/naturalgas/data.php#consumption>.

<sup>15</sup> Of this, 40 LDCs are located in Northeast. LEI has included 29 out of 40 LDCs in the Northeast.

<sup>16</sup> LEI checked the robustness of this TFP growth rate by using a trend regression method. The results show that the industry TFP growth rate is 0.12% per annum.

<sup>17</sup> LEI tested several alternative assumptions to confirm the robustness of the overall results of the industry TFP study. In all cases, alternative assumptions would have resulted in a more negative annual average TFP growth rate. Section 6 (Appendix) provides a discussion of the alternative assumptions and results.

**Figure 7. TFP growth rates for U.S. LDC industry (2003-2017)**

Year	Output Customers	OM&A	Inputs Capital	Total	TFP Growth Customers
2003					
2004	1.08%	-0.30%	0.97%	0.34%	0.73%
2005	1.26%	6.07%	0.12%	3.06%	-1.80%
2006	0.79%	-7.20%	0.06%	-3.49%	4.28%
2007	1.00%	6.78%	0.12%	3.33%	-2.32%
2008	0.36%	2.32%	0.34%	1.30%	-0.94%
2009	0.03%	3.11%	0.25%	1.64%	-1.60%
2010	0.28%	-1.40%	0.64%	-0.36%	0.64%
2011	0.67%	-0.41%	0.63%	0.11%	0.55%
2012	0.74%	-1.69%	0.44%	-0.60%	1.34%
2013	0.33%	0.12%	-0.23%	-0.06%	0.39%
2014	0.35%	0.84%	1.63%	1.25%	-0.90%
2015	2.08%	-2.99%	1.83%	-0.47%	2.56%
2016	0.61%	0.33%	1.36%	0.87%	-0.26%
2017	0.68%	1.71%	2.52%	2.14%	-1.45%
<b>Average (2003-2017)</b>	<b>0.73%</b>	<b>0.52%</b>	<b>0.76%</b>	<b>0.65%</b>	<b>0.09%</b>

### 1.5 TFP growth in the Northeast Region of the LDC industry

There are 29 firms represented in the Northeast Region LDC sample; these firms (and their customers) represent 94% of the LDC industry in this geographical region based on the number of customers. The average TFP growth rate from 2003 to 2017 for the LDCs located in the Northeast is -0.39%, as shown in Figure 8 below. The TFP growth rate for LDCs for this region is negative because of the faster growth in the quantity of inputs (capital and OM&A) relative to the increase in output (number of customers served).



**Figure 8. TFP growth rates for Northeast LDCs (2003-2017)**

Year	Output	Inputs			TFP Growth Customers
	Customers	OM&A	Capital	Total	
2003					
2004	0.35%	-2.85%	0.55%	-1.08%	1.43%
2005	0.18%	1.61%	0.81%	1.19%	-1.01%
2006	0.52%	-9.82%	0.81%	-4.05%	4.57%
2007	0.84%	7.20%	0.82%	3.66%	-2.82%
2008	0.35%	3.83%	0.96%	2.25%	-1.89%
2009	0.73%	4.50%	1.32%	2.76%	-2.03%
2010	0.49%	-1.43%	1.34%	0.08%	0.40%
2011	1.02%	1.10%	1.56%	1.35%	-0.33%
2012	0.85%	4.38%	1.54%	2.86%	-2.01%
2013	0.63%	-2.74%	0.34%	-1.08%	1.71%
2014	0.54%	5.84%	2.23%	3.90%	-3.36%
2015	0.94%	-3.79%	2.26%	-0.52%	1.46%
2016	1.01%	-1.19%	1.21%	0.13%	0.89%
2017	0.61%	3.25%	2.84%	3.03%	-2.42%
<b>Average (2003-2017)</b>	<b>0.65%</b>	<b>0.71%</b>	<b>1.33%</b>	<b>1.03%</b>	<b>-0.39%</b>

**1.6 How do you translate the industry average TFP growth rate into an X factor for NSTAR Gas' PBR plan?**

LEI understands that the Company will be proposing an I-X escalation mechanism, where the I factor would be based on GDP-PI trends, reflecting general inflation across the economy. With this specification, the X factor should reflect not only the productivity trends of the LDC industry but also the TFP and input price differentials between the economy as a whole and the LDC industry. As such, for the entire U.S. LDC sector, given the TFP growth rate of 0.09%, LEI estimated an X factor of -0.79%. For the Northeast Region TFP growth rate of -0.39%, LEI estimated an X factor of -1.3%. As discussed in Section 0, to derive this X factor, LEI applied a differential in expected input price index growth between the overall economy and the industry, as well as a TFP differential. Both the input and TFP differentials were negative.

A negative X factor does not imply that the PBR plan lacks productivity incentives; rather, it acknowledges that the LDC will need to increase its capital and operating expenditures relative to customer numbers and therefore rates will need to rise by more than just general inflation to ensure the utility can continue to provide reliable service to its customers.

LEI recommends a Northeast Region TFP growth rate for setting the Company's X factor due to differences in key drivers of TFP between the Northeast Region versus the rest of the U.S., namely differences in economies of scale (size of LDCs), technology (materials used to construct mains), and growth in output. This is discussed further in Section 4.3.

## 2 Basics of Total Factor Productivity

### 2.1 What is productivity?

Productivity is the ratio of (a) quantity of outputs produced and (b) quantity of inputs deployed. Productivity growth is a trend variable based on the year-on-year change in the productivity ratio. In other words, productivity growth documents the rate of change in the quantity of outputs relative to the rate of change in the quantity of inputs. Even though an industry TFP study is based on historical data, the historical growth rates or trends can be useful for determining goals for the future, so long as the future has conditions similar to the past.<sup>18</sup> The long-run<sup>19</sup> average productivity growth rate achieved by the industry can serve as a reasonable level of productivity change that can be targeted for the future, and that informs regulators on the choice of an explicit productivity target or X factor under an “I-X” price cap or revenue cap regulatory regime.

**Figure 9. Generalized concept of a TFP growth rate**

$$\text{TFP growth rate} = \frac{\% \Delta \text{ weighted sum of the quantities of all outputs}}{\% \Delta \text{ weighted sum of the quantities of all inputs}}$$

If a business uses many inputs, then there are many types of productivities that could be measured. For example, to assess labor productivity, one would look at the ratio that represents the quantity of output relative to the quantity of labor inputs used. Capital productivity would be measured as a ratio of the quantity of output relative to the quantity of capital deployed. Labor and capital productivity are each partial measures of productivity, also known as partial factor productivity (“PFP”). In contrast, a TFP measure covers output(s) relative to all inputs.<sup>20</sup> The distinction between the TFP measure and the PFP measure, therefore, lies in the number of inputs analyzed.

<sup>18</sup> Economic theory for PBR assumes a “steady state” environment, where generally, depreciation expense should be sufficient to cover normal going-forward capital expenditures to maintain the operable capacity of aging assets. Nevertheless, situations arise when these conditions do not perfectly hold, such as when capital investments are made to address reliability needs, or when the nominal cost of sustainment capital to replace or maintain aging infrastructure exceeds the depreciation expense, which is based on a historical cost basis of the original equipment.

<sup>19</sup> It is preferable to have 10 or more years of growth rate figures; see Section 2.4 for discussion of the appropriate length of TFP study.

<sup>20</sup> OECD. *Measuring Productivity: Measurement of aggregate and industry-level productivity growth*. 2001.

An industry TFP study measures the changes in overall productivity over time. A TFP study is not a benchmarking study, as it does not report out relative efficiency levels at a given point in time.<sup>21</sup> And typically, an industry TFP study, by definition, will not focus on any single regulated firm, but rather the industry as a whole. The premise of PBR rests on the idea that firms in the same industry will face similar pressures for costs and output growth, and therefore an industry TFP growth is a reasonable target to impose on a regulated firm.

## 2.2 Overview of TFP methods

The following section is an overview of the various methods of performing a TFP study. TFP methods can be broadly categorized into deterministic methodologies, which “calculate” TFP, and econometric methodologies, which “estimate” TFP. Figure 10 below gives an overview of some of the methods LEI considered. These methods include the index method, data envelopment analysis (“DEA”), and Stochastic Frontier Analysis (“SFA”).

LEI chose to use an index method. The index method is deterministic, and by far, the most straightforward technique for estimating TFP growth over time. Firm-level data is aggregated to an industry-level number representing the quantity of inputs and outputs. Chained indices are formed based on these numbers, and the growth of the input and output indices over time allows for the estimation of the growth rate of TFP.

The index method will not measure performance relative to a hypothetical efficiency frontier;<sup>22</sup> instead, it will measure the actual industry average productivity over time. It is also important to note that an index method, because it is a numerical technique as opposed to a statistical technique, does not give a forecast error measure. Therefore, interpreting differences in index values requires qualitative considerations. Moreover, with an index-based approach, the resulting TFP cannot be segregated into different drivers (e.g., technology versus economies of scale). Also, index methods cannot take into account other business factors affecting productivity – those must be considered in the selection of the peer grouping for the industry and the input and output data itself.

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<sup>21</sup> LEI separately prepared a Total Cost Benchmarking Study for the LDC industry. Please refer to the LEI Benchmarking Report, dated November 1, 2019.

<sup>22</sup> Deterministic methodologies “calculate” TFP values, as opposed to econometric methodologies which “estimate” TFP values. Non-frontier econometric methods assume production is always efficient in the use of existing technology and estimate the potential level of production at each moment in time. Non-frontier methods do not provide separate estimates of technical change and efficiency change which can be provided by stochastic frontier econometric methods.

**Figure 10. Empirical techniques for estimating TFP**

	Non-Frontier technique	Frontier techniques	
Parameters	Index Method	Data Envelopment Analysis ("DEA")	Stochastic Frontier Analysis ("SFA")
<b>Description</b>	Index number measures the ratio of all outputs (weighted by revenue shares) to all inputs (weighted by cost shares)	Linear programming technique which identifies best practice within a sample by fitting a frontier over the top of the data points and measures relative inefficiencies	Same as DEA but following econometric methods to estimate the efficiency frontier
<b>Data needs</b>	Quantity and price data on inputs and outputs for 2 or more firms	Quantity data on inputs and outputs for a sample of firms; price data required to get information on allocative efficiency	Quantity data on inputs and outputs for a sample of firms; price data required to get information on allocative efficiency
<b>Advantages</b>	Relatively simple and robust technique. Can incorporate many inputs and outputs with few observations	Can decompose cost efficiency into component parts, breaking down allocative and technical efficiencies. Can easily handle multiple outputs	Can decompose cost efficiency into component parts, breaking down allocative and technical efficiencies. Accounts for "data noise" (data errors, omitted variables, etc.) and allows for the use of standard statistic tests
<b>Drawbacks</b>	Does not allow for identification of various factors of TFP change such as technical efficiency, scale efficiency, etc.	Requires a large dataset. Sensitive to the way outputs and inputs specified. Can be difficult to explain in a regulatory setting	Requires large sample size for robust estimates. Requires specification of production or cost function. Can be difficult to explain in a regulatory setting

Source: Coelli et al. "A Primer on Efficiency Measurement for Utilities and Transport Regulators." World Bank Institute. February 2003

The benefits of the index method include relative simplicity in calculation and ease of communication. Index methods are more transparent when dealing with outliers, unlike DEA and econometric techniques, and also require significantly fewer data points/observations to reach a robust conclusion. For these reasons, index methods are often used for informing regulators in ratemaking proceedings.

Finally, LEI notes that the Massachusetts Department of Public Utilities (or “Massachusetts DPU” or “the Department”) and other regulators are familiar with the index approach and that this approach meets the Department’s goal of simplicity in designing utility rate structures.<sup>23</sup>

### 2.3 Selecting an indexing technique

Under the index method, one needs to choose the type of indexing technique. There are several well-known number indexation techniques and resulting index formulations: Laspeyres index, Paasche index, Fisher Ideal index, and Törnqvist index.

LEI utilized the Fisher Ideal index in this Industry TFP Study, which is a geometric mean of the Laspeyres and the Paasche indices (see Figure 11 below).<sup>24</sup> The Fisher Ideal has been shown to have the most reasonable numerical index properties, whereas other population indices may not.<sup>25, 26</sup>

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<sup>23</sup> In D.P.U. 17-05-B, The Department stated that “The Department has determined that the goals of designing utility rate structures are to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability..... The Department has determined that a rate structure achieves the goal of simplicity if it is easily understood by consumers.”

<sup>24</sup> Indexes are chained by comparing data for each year to the data from the year immediately preceding it (with the exception of the base year). This method provides a more accurate portrayal of year-over-year growth.

<sup>25</sup> Diewert and Nakamura. *Concepts and Measures of Productivity: An Introduction*. 2005. Diewert and Nakamura used the ‘axiomatic’ approach to the selection of an appropriate index formulation which specifies the number of desirable properties an index formulation should possess: constant quantities test, constant basket test, the proportional increase in outputs test, and time reversal test. Only the Fisher Ideal index satisfied all four criteria that an index number method needs to meet. Specifically, the Fisher Ideal index overcomes the classic ‘index number problem’ suffered by the Laspeyres and Paasche indices, whereas one moves further away from the set of prices used, the representative quality of the index decreases (since prices change over time).

<sup>26</sup> Diewert (1993) *The Measurement of Productivity: A Survey*, Swan Consultants (Canberra) conference on Measuring the Economic Performance of Government Enterprises, Sydney. reviewed alternate index number formulations to determine which index was best suited to TFP calculations. An axiomatic procedure was used and Diewert proposed certain tests to evaluate the alternate indexes. These included: (i) the constant quantities test: if quantities are the same in two periods, then the output index should be the same in both periods irrespective of the price of the goods in both periods; (ii) the constant basket test: this states that if prices are constant over two periods, then the level of output in period 1 compared to period 0 is equal to the value of output in period 1 divided by the value of output in period 0; (iii) the proportional increase in outputs test: this states that if all outputs in period t are multiplied by a common factor, l, then the output index in period t compared to period 0 should increase by l also; and (iv) the time reversal test: this states that if the prices and quantities in period 0 and t are interchanged, then the resulting output index should be the reciprocal of the original index. When the four indexes were evaluated against these tests, only the Fisher Ideal passed all four tests The Laspeyres and Paasche index failed the time reversal test while the Tornqvist index failed the constant basket test. On

**Figure 11. Fisher Ideal index**

$$\text{Fisher Ideal Index} = \sqrt{(\text{Laspeyres Index}) * (\text{Paasche Index})}$$

The Fisher Ideal index can be formed as a chained or unchained index.<sup>27</sup> LEI used the chained Fisher Ideal index because it avoids the index number problem, which arises with fixed weights. The chained Fisher Ideal index overcomes this common “index number problem” by changing the base annually - in each period, the base is the previous period’s observation. This allows for the most representative weights possible for each observation.

## **2.4 Appropriate length of TFP study**

The main purpose of conducting a TFP study of this nature is to establish industry trends, which are inherently long term. Logically, the best method of creating a trend is by looking at multiple years of data and performance. The use of multiple years of data limits bias that can be caused by numerical outliers or one-off events that affect performance in any single year. Therefore, a productivity trend should cover a period that extends through a sufficiently long timeframe, to limit exposure to year-on-year productivity changes as well as one-off circumstances with respect to factors like weather, consumption, lumpy capital spending, and fluctuations in labor costs.

However, if the range of data is too long, the estimated average trend may be irrelevant for the purposes of informing future ratemaking initiatives. The timeframe should ideally incorporate more recent data that captures the latest trends in the industry while eliminating earlier time periods with productivity growth drivers that are no longer relevant.

Given data availability and quality (see Section 0 for further details) and best practices for TFP analysis for regulatory decision-making, LEI believes that the fifteen-year timeframe of 2003-2017 is appropriate for this study of the U.S. LDC industry. The most recent 15 years reflect the changing business circumstances in the LDC industry, which are likely to be driving productivity in the future. These changing business conditions include the pressures stemming from retail competition, technological developments in pipeline materials (which is exemplified by the movement away from cast iron/bare steel mains and services), stricter safety standards (which are requiring adjustments in how LDCs operate), and increasing energy efficiency programs that

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the basis of his analysis, Diewert recommended that the Fisher Ideal index be used for TFP work, although he indicated that the Tornqvist index could also be used as it closely approximates Fisher Ideal index.

<sup>27</sup> Indexes are chained by comparing data for each year to the data from the year immediately preceding it (with the exception of the base year). This method provides a more accurate portrayal of year over year growth.



have a substantial impact on volumes of gas consumed per customer and will continue to impact the services that U.S. LDCs provide.

In summary, the fifteen-year study period overcomes the high variability of year-on-year trends but is also not so long term as to capture “stale” industry trends that would not likely repeat themselves in the future.

## 2.5 Measuring TFP growth rates

The key finding of an industry TFP study is a numerical estimate of the TFP growth rate over the study period. LEI calculated the growth rates using natural logs, which calculate the year-on-year changes in the TFP Index. LEI then reported the average of the resulting year-on-year growth rates throughout the study period.<sup>28</sup> As further outlined in Figure 12, a mathematical equivalent can be calculated by (i) taking the natural logarithm of the ratio of the last TFP index value divided by the first TFP index value, and (ii) then dividing the resulting value by the number of annual year-on-year observations between the start and end year.<sup>29</sup>

**Figure 12. Calculating average TFP growth for a study period of 2003-2017**

$$\text{Average industry TFP growth} = \ln \left( \frac{2017 \text{ industry TFP index}}{2003 \text{ industry TFP index}} \right) / 14$$

‘Average growth’ is the more common method of measuring the study-period TFP growth rate and has been used in previous studies presented before the Department.<sup>30</sup> The preference for this method can be attributed to the fact that it calculates the annual growth rates for the TFP index values throughout the study period. However, in certain instances, the ‘average growth’ method can be misleading, most notably when a series exhibits volatility at its endpoints. Because the ‘average growth’ method tracks the exact growth from start to end, if the endpoints of a series are outliers with respect to the trend, then the average method may not give a very good estimate of the underlying TFP trend.

<sup>28</sup> Economic Insights. *Total Factor Productivity Index Specification Issues*. December 7, 2009.

<sup>29</sup> The number of annual changes can be calculated as the number of years for which data is collected as part of the TFP study period minus one. In the example, a study period of 2003-2017 has 15 years of data and (15 – 1 = 14) annual changes over that period.

<sup>30</sup> For example, the average growth approach was used in the most recent TFP study for NSTAR Electric (D.P.U. 17-05) and National Grid (D.P.U. 18-150).



Therefore, LEI also checked the robustness of the 'average growth' method by performing a 'trend regression' of the annual TFP growth rates, as discussed further below.<sup>31</sup> The regression is carried out by estimating the linear relationship between the TFP index values and the number of years of the study period (starting from 0), as seen in Figure 13 below. The estimated beta on the time variable is the normalized average annual TFP growth rate.

**Figure 13. Trend regression of TFP growth for a study period of 2003-2017**

$$\text{Regress: } \ln(\text{industry TFP index}) = \beta * T + \alpha$$

**Where:**

$\beta$  = trend growth rate for the industry TFP index over the study period

T = time in years (0, ...,10)

$\alpha$  = constant term

The trend regression analysis results in an average TFP growth rate of 0.12% for the U.S. LDC Industry composed of the 83 LDCs; this value is similar to the value established by using the 'average growth' method (0.09%).<sup>32</sup> LEI concluded that the index-based approach for calculating the TFP over the 2003 to 2017 timeframe has no start or end-year bias.<sup>33</sup>

## 2.6 Number of gas utilities

For this Industry TFP Study, LEI aimed to include as many LDCs as LEI could, subject to the quality of data and availability of data over the entire study timeframe. From an initial list of 196 investor-owned LDCs operating in the U.S. as of 2017, LEI selected LDCs with sufficiently complete data over the required timeframe (1998 to 2017).<sup>34</sup> Financial data availability for LDCs does not go as far back as electric utilities in the U.S. More specifically, LDCs file their annual reports to their respective state regulator, and there is no central electronic depository of gas

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<sup>31</sup> The trend regression method has been used to calculate trend growth rates in Australia and New Zealand. For example, the average growth approach was used in the most recent TFP study for NSTAR Electric (D.P.U. 17-05) and National Grid (D.P.U. 18-150).

<sup>32</sup> This TFP result is discussed in detail in Section 3.

<sup>33</sup> However, because the 'trend regression' method is only a linear estimate of the TFP growth rate, in the case where endpoints are outliers it may not track the actual endpoint to endpoint growth rate as well as the 'average growth' method.

<sup>34</sup> Data for this period is needed to calculate the capital stock for each LDC for each year. Even though the start year of the TFP study is 2003, the benchmark year must begin earlier in order to properly estimate the capital input quantity. LEI selected 1998 as the benchmark year. Good quality data must be available for proper capital estimation as of 1998 for LDCs included in the TFP Study.

In total, LEI was able to collect quality data on 83 LDCs across 31 states, as highlighted in the figure below. This industry peer sample reflects serving 69.5% of the 2017 total sales in the U.S. and 70.0% of customers served across the 48 continental states in the U.S. The 83 LDCs are a robust representation of the industry, representing both small and large utilities with diverse customer mixes, various suburban and urban topologies, as well as diverse customer mixes, and covers LDCs all of the BLS regions.<sup>36</sup> Figure 15 lists the LDCs included in LEI's Industry TFP Study.

**Figure 14. States covered in the industry TFP Study**

The map displays the following states categorized by region:

- Northeast (Dark Blue):** VT, ME, NY, NJ, PA, DE, MD, DC.
- South (Orange):** TX, AR, LA, MS, AL, GA, FL, SC, NC, VA, WV, KY, TN.
- West (Teal):** WA, OR, ID, NV, UT, CO, CA, AZ, NM.
- Midwest (Light Green):** WI, MI, IL, IN, OH, MO, KS.
- Other (Light Gray):** MT, ND, SD, MN, IA, NE, OK, NM, AK, HI.

36 A sample of 83 firms is more extensive than other TFP studies for U.S. LDC sector. For instance, Pacific Economics Group (“PEG”) covered 58 LDCs in its most recent gas industry TFP study in Ontario, while Concentric had examined 25 LDCs for Enbridge Gas. See Lowry, Mark Newton. “IRM Framework for the Proposed Merger of Enbridge and Union Gas. April 11, 2018 and Concentric Energy Advisors (2013) Incentive Ratemaking Report, prepared for Enbridge Gas Distribution’s 2014 to 2018 IR plan filing (EB-2012-0459, Exhibit A2, Tab 9, Schedule 1).

**Figure 15. LDCs included in the industry TFP Study (alphabetical, by region)**

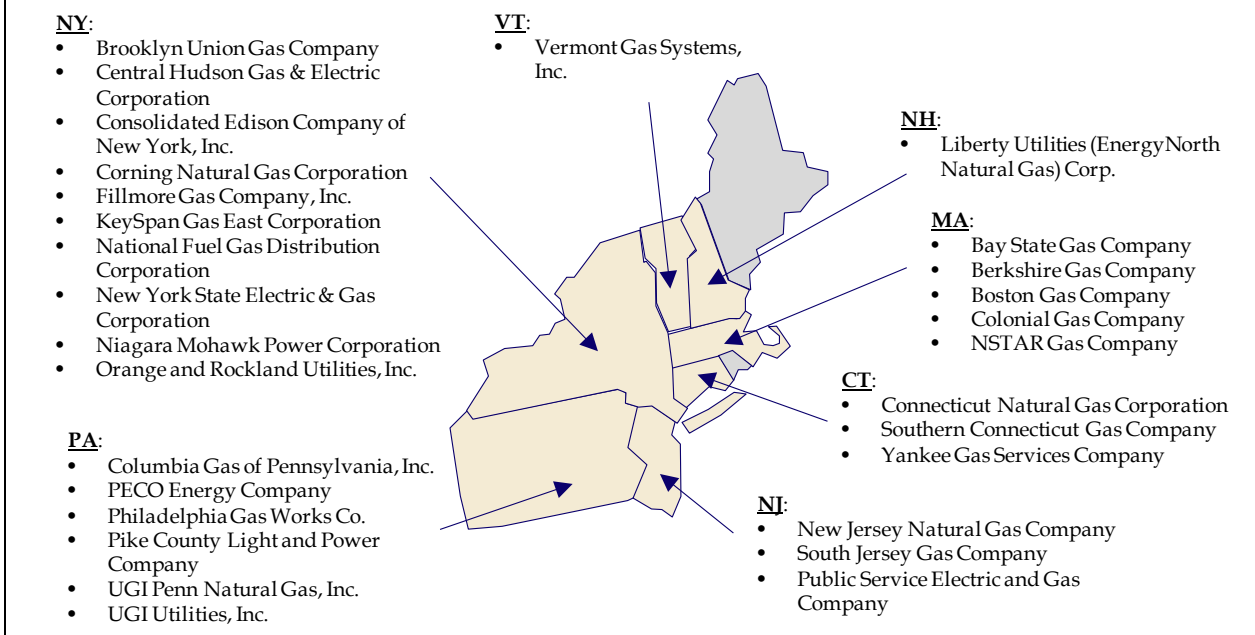
Midwest		Northeast	
1	Citizens Gas Fuel Company	27	Bay State Gas Company
2	Columbia Gas of Ohio, Inc.	28	Berkshire Gas Company
3	Consumers Energy Company	29	Boston Gas Company
4	DTE Gas Company	30	Brooklyn Union Gas Company
5	Eastern Natural Gas Company	31	Central Hudson Gas & Electric Corporation
6	Illinois Gas Company	32	Colonial Gas Company
7	Indiana Gas Company, Inc.	33	Columbia Gas of Pennsylvania, Inc.
8	Kansas Gas Service Company, Inc.	34	Connecticut Natural Gas Corporation
9	Madison Gas and Electric Company	35	Consolidated Edison Company of New York, Inc.
10	Midwest Natural Gas Corporation	36	Corning Natural Gas Corporation
11	Midwest Natural Gas, Inc.	37	Fillmore Gas Company, Inc.
12	North Shore Gas Company	38	KeySpan Gas East Corporation
13	Northern Illinois Gas Company	39	Liberty Utilities (EnergyNorth Natural Gas) Corp.
14	Northern Indiana Public Service Company	40	National Fuel Gas Distribution Corporation
15	Northern States Power Company - WI	41	New Jersey Natural Gas Company
16	Ohio Gas Company	42	New York State Electric & Gas Corporation
17	Ohio Valley Gas Corporation	43	Niagara Mohawk Power Corporation
18	Peoples Gas Light and Coke Company	44	NSTAR Gas Company
19	Pike Natural Gas Co	45	Orange and Rockland Utilities, Inc.
20	Southern Indiana Gas and Electric Company	46	PECO Energy Company
21	Spire Missouri Inc.	47	Philadelphia Gas Works Co.
22	Superior Water, Light and Power Company	48	Pike County Light and Power Company
23	The East Ohio Gas Company	49	Public Service Electric and Gas Company
24	Vectren Energy Delivery of Ohio, Inc.	50	South Jersey Gas Company
25	Wisconsin Gas LLC	51	Southern Connecticut Gas Company
26	Wisconsin Power and Light Company	52	UGI Penn Natural Gas, Inc.
		53	UGI Utilities, Inc.
		54	Yankee Gas Services Company
		55	Vermont Gas Systems, Inc.

South		West	
56	Atlanta Gas Light Company	74	Avista Corporation
57	Atmos Energy Company	75	Cascade Natural Gas Corporation
58	Baltimore Gas and Electric Company	76	Cheyenne Light, Fuel and Power Company
59	Black Hills Energy Arkansas, Inc.	77	Pacific Gas and Electric Company
60	Bluefield Gas Company	78	Puget Sound Energy, Inc.
61	Columbia Gas of Kentucky, Incorporated	79	Questar Gas Company
62	Columbia Gas of Maryland, Incorporated	80	San Diego Gas & Electric Company
63	Columbia Gas of Virginia, Incorporated	81	Sierra Pacific Power Company
64	Delta Natural Gas Company, Inc.	82	Southern California Gas Company
65	Duke Energy Kentucky, Inc.	83	Wyoming Gas Company
66	Hope Gas, Inc.		
67	Louisville Gas and Electric Company		
68	Mountaineer Gas Company		
69	Peoples Gas System		
70	Public Service Company of North Carolina, Inc.		
71	St. Joe Natural Gas Co, Inc.		
72	Texas Gas Service Company, Inc.		
73	Virginia Natural Gas, Inc.		

As mentioned earlier, for the Northeast Region, LEI included 29 LDCs in its Industry TFP Study. These 29 LDCs cover almost all the states in the region, except for Maine and Rhode Island, as shown below. Similar to the Industry TFP Study, the LDCs in the Northeast Region represent both small and large gas utilities with different suburban and urban topologies. Figure 16 shows the LDCs included in the Industry TFP Study in the Northeast Region by state.

**Figure 16. Map of the location of LDCs in the Northeast region**



### 3 TFP methodology and data sources

Selecting the appropriate inputs and outputs is a crucial part of a TFP study. Intuitively, selected inputs and outputs would be those that most accurately represent the physical process behind the distribution of gas. At the most basic level, inputs to a TFP study should reflect capital deployed and OM&A expenditures. If data was available, the OM&A input metric could be broken down further into sub-categories like labor, materials, services, etc. However, such data is not readily and consistently available for U.S. LDCs over the 15-year study timeframe, and therefore LEI used a two-input model formulation: capital and non-capital (OM&A). Outputs should reflect key products or services. For this Industry TFP Study, LEI determined it would be best to use a single output metric, namely the total number of customers served by the distribution network of each LDC, as discussed in Section 3.2.

#### 3.1 Overview of data sources

LEI's analysis is primarily based on company-level data provided by SNL Financial, which sources information directly from state LDC filings, FERC Form 2, and the EIA. In the instances where there is missing data from SNL Financial, LEI supplemented the data either based on FERC Form 2 submissions or review of state regulatory filings for particular years. In several instances, LEI had to interpolate missing data points (for example, when one year of data was missing, but there was complete data for the year before and after the missing data). LEI also relied on data from the EIA, the U.S. Bureau of Economic Analysis ("BEA"), the U.S. BLS, the Federal Reserve, and Moody's, as described further in the subsections below.

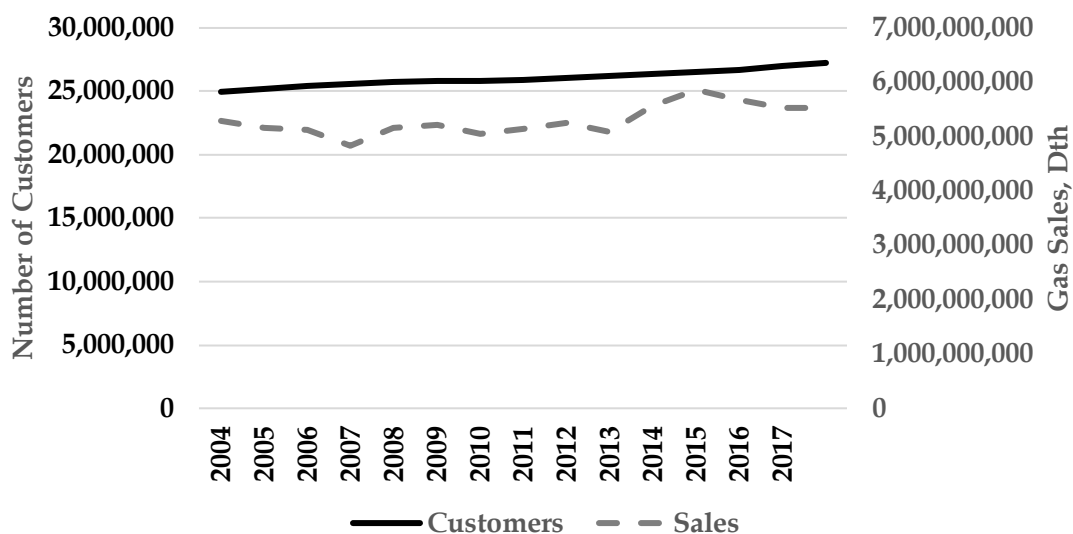
#### 3.2 Output

LEI used the number of customers served by the distribution network(s) as the output measure. A key advantage of using this dataset is that it is a numerical data point which is both available and consistently measured across LDCs. Gas sales, which LEI also considered as an output, are affected by weather patterns, which can vary considerably across geographies and years and therefore cause some distortion to the resulting TFP trends. Additionally, utilities build systems to serve customers and not necessarily the specific amount of gas consumed per customer as that is likely to change with time. Figure 17 below shows the trends in the number of customers and gas sales, as well as their corresponding growth rates. Notably, the use of total customers served is a common practice among TFP studies for the LDC industry.<sup>37</sup>

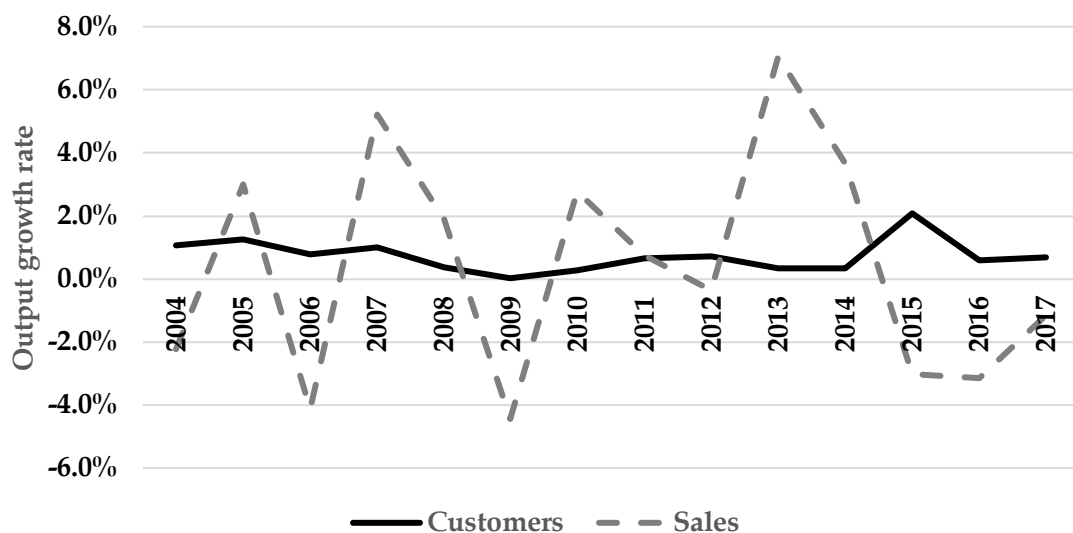
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<sup>37</sup> Examples of gas TFP studies that used number of customers as output measure include another consultant's TFP studies on the following (i) IRM Framework for the Proposed Merger of Enbridge and Union Gas (April 2018), (ii) X factor Research for Fortis PBR Plans (January 2014), and (iii) Incentive Ratemaking Report for Enbridge Gas Distribution (June 2013).

**Figure 17. Total number of customers served vs. gas sales for the U.S. LDC industry in the Industry TFP Study (reflecting all 83 LDCs studied)**



**Figure 18. Growth rate trends of the number of customers served vs. gas sales for the U.S. LDC industry in the Industry TFP Study (reflecting all 83 LDCs studied)**



The number of customers was compiled at the operating subsidiary level from EIA-176,<sup>38</sup> which includes gas customers by type, such as commercial, residential, and industrial customers. This dataset includes customers who have competitive retail suppliers for the gas commodity but are using the distribution network (i.e., unbundled utility customers). This is important to note because this Industry TFP Study is only looking at the productivity of the distribution network, and is not impacted by sales, which can be affected in some states by retail competition laws.

### 3.3 Inputs

LEI used a two-input model consisting of capital and non-capital (or total OM&A) inputs. Both inputs were estimated based on monetary data taken from the annual financial reports and regulatory filings. LEI primarily relied on data at the operating subsidiary level from the state LDC and FERC Form 2 filings compiled by SNL Financial. When data were missing and not available directly through the SNL Financial database, LEI conducted additional research (including outreach to state regulatory bodies and manually inputted the data from the state LDC filings or FERC Form 2).<sup>39</sup> The conversion of financial asset data and OM&A cost data into capital quantities and OM&A quantities, respectively, involved several steps that are described further below.

#### 3.3.1 OM&A input

OM&A inputs reflect the non-capital related expenses associated with storage, distribution customer service account, sales, and administration and general expenses. OM&A costs were collected from Annual LDC filings by the expense category. LEI used all OM&A expense categories except for transmission and fuel procurement because those categories are not directly relevant to physical productivity of the distribution function of LDCs, nor part of the distribution rate design under PBR (for example, fuel procurement is generally treated as a pass-through cost, and potentially subject to its own set of rate incentives). Administration expenses are the largest share in total OM&A expenses, averaging at 39% per year, followed by distribution expenses, which account for another 29% of total OM&A costs at the industry aggregate level). Figure 19 shows the breakdown of the OM&A costs recorded for the industry in this TFP Study. The aggregate total of OM&A costs in nominal terms (not yet converted to input quantities) for the 83 LDCs in the U.S. industry sample grew at an average rate of 3.3% per year over the 2003-2017 period.

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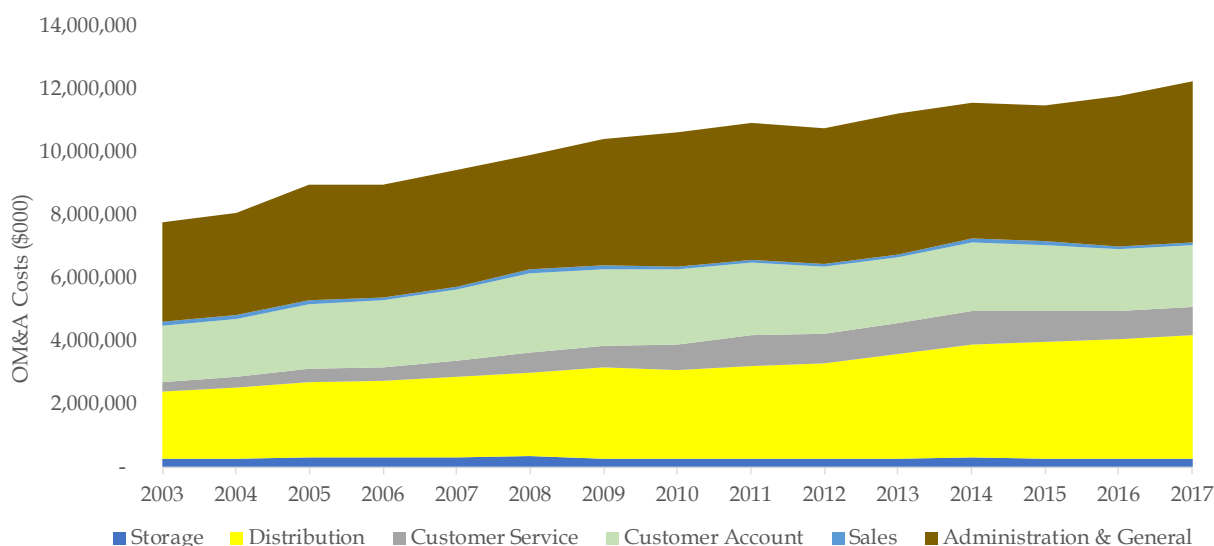
<sup>38</sup> EIA-176 Data through 2017, Natural Gas Annual Respondent Query System, <<https://www.eia.gov/naturalgas/ngqs/#?year1=2014&year2=2017&company=Name>>.

<sup>39</sup> If a company does not have interstate pipelines it is solely under the jurisdiction of the state public utility commissions and would not file FERC Form 2 which is for companies under federal jurisdiction given that they have interstate pipelines.



It is important to note that for LDCs, labor costs are reflected as part of OM&A expenses. Labor costs, as a separate expense, were not available for all gas utilities over the sample period in this Industry TFP Study. However, for purposes of developing an appropriate deflator for labor (as part of the OM&A input price index), LEI created an estimate of labor expenses for a sub-set of utilities (for those that did release employee data) and used that to derive the typical industry share of labor costs in total OM&A.

**Figure 19. Reported OM&A costs of the 83 LDCs in LEI's U.S. Industry sample (nominal \$)**



Sources: LDC state filings, FERC Form 2, and SNL Financial

To create a bottom-up estimate of the labor cost share, LEI first collected available data for the average number of employees for each gas utility that reported such information. Such data were available for 41 LDCs over the 2007 to 2017 timeframe. Then, LEI used the BLS Employer Cost Index ("ECI") for Total Compensation (which is available on a regional basis for the gas utility industry) to get the compensation rate (note that the ECI was also used as the labor price index). To calculate an annual labor cost estimate, the average number of employees was multiplied by the compensation rate. LEI then compared the yearly labor cost estimate to the total OM&A costs. LEI found that approximately 54% of total O&M costs is attributed to labor on average for the U.S. LDC industry.<sup>40</sup> This labor cost share (54%) implies a non-labor cost share of 46%. These

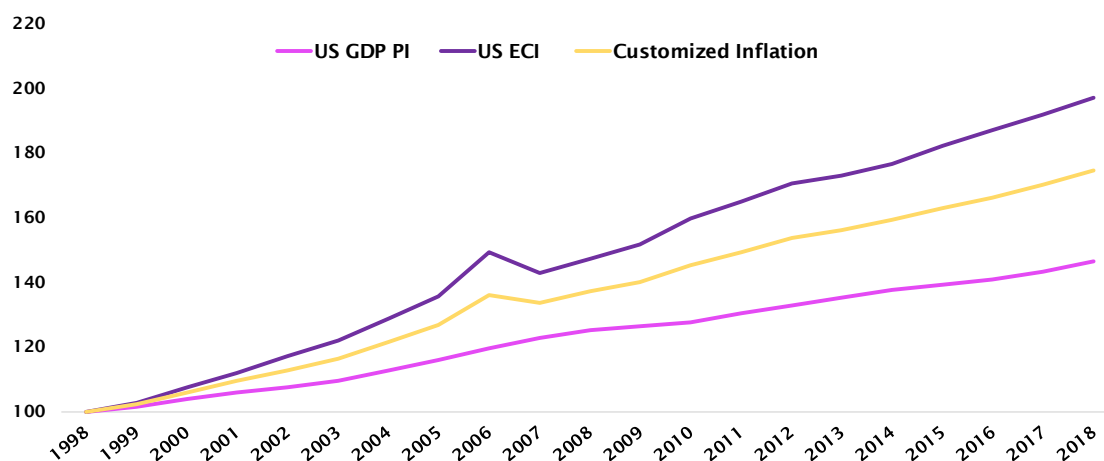
<sup>40</sup> LEI tested other sensitivities with different labor cost weights to examine the robustness of the labor to non-labor relationship, and the impact of these variations on overall TFP results was not material. Based on these tests, if LEI assumed a 49% labor cost share, the OM&A input price would grow slower, and the OM&A quantity growth rate would increase by 0.07 percentage points (from 0.52% to 0.59%), which would increase



cost shares were used to combine (i.e., weight) the labor and non-labor price indices into a single OM&A price index.

As noted above, LEI used the regional ECI as the labor cost index. LEI used the GDP-PI as the proxy for inflation in non-labor OM&A expenses because it is representative of various materials and services that LDCs would have deployed. The GDP-PI and the ECI are then combined based on the non-labor and labor cost shares, as shown below in Figure 20.

**Figure 20. Input price index for OM&A**



Source: BEA, BLS, LEI calculations

### 3.3.2 Capital input quantity

LEI employed the monetary approach for calculating the capital input quantity for the LDCs in this Industry TFP Study. The calculation of the capital input quantity under a monetary approach centers around an estimate of the real capital stock of each LDC. This capital stock includes a mix of gas assets classified under storage plant, distribution plant, and general plant. For the capital input quantity, LEI could not merely take the capital expenditures (“capex”) from financial data,

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the TFP growth by only 0.04 percentage points. On the other hand, if LEI assumed a 59% labor cost share, the OM&A input price would grow faster, and the OM&A quantity would decrease by 0.07 percentage points (from 0.52% to 0.45%), and that would reduce the TFP growth rate by 0.03 percentage points. Furthermore, LEI conducted a statistical analysis of the sample data on the aggregate industry basis, and it shows that the share of labor cost to the total OM&A costs did not materially change over time during the sample period.

because capex is spent in one year, but the physical capital assets that such capex finances will be used for many years.

### **3.3.2.1 Method for estimating the capital input quantity**

There are two approaches for calculating the capital input quantity: (i) a physical or direct approach and (ii) a monetary or indirect approach. The advantage of the monetary approach is that the monetary value of the firm's capital equipment is aggregated using monetary value as the unifying element. Thus, the monetary approach allows for consideration of various capital assets into one capital input quantity. The monetary method also directly accounts for the magnitude of improvements made to capital assets from time-to-time.

The shortcoming of the monetary method is that financial data on capital spending is typically not reported on a disaggregated basis, for each piece of equipment. LDCs normally only report the change in asset value (gross book value) for their entire stock of assets. The values of the new asset are added (or subtracted, when an asset is retired) based on its original historical cost at the time of the acquisition, and therefore the gross book value mixes assets acquired over different time periods (which makes it challenging to ascertain a "real dollar" value). Furthermore, the financial data typically does not get adjusted for the condition of the capital equipment. Thus, one must apply exogenous assumptions regarding the physical deterioration of the capital stock over time under the monetary approach.

The physical approach has several advantages if a metric could be identified that comprehensively and accurately describes the capital assets of an LDC and the services that such capital assets provide in relation to the distribution business of the LDC. If such a measure were available, it would not need to be further manipulated (for example, one would not need to deflate/inflate historical asset value) and presumably, it could reflect the physical capability directly (so then no further assumptions would need to be made as to physical deterioration or depreciation of the capital employed).

However, such a measure does not exist for LDCs in the U.S., as there is no single measure reported by LDCs that uniformly and comprehensively estimates how different capital equipment that an LDC may deploy contributes to the distribution services that an LDC provides for its customers (for example, mains are typically measured and reported by LDCs in terms of rated pressure levels and miles, while compressor (pumping) stations are described by their size and number of compressors, and services and meters are typically characterized by the number of installations). For this reason, LEI relied on the monetary approach.

### **3.3.2.2 Physical depreciation of capital under the monetary approach**

Physical deterioration (decay or depreciation) is generally very limited in the LDC industry as the majority of the capital equipment deployed is not electrical or mechanical. Main and service pipelines are the largest capital assets of an LDC and can provide service for up to 75 years and

over 50 years, respectively, according to various depreciation studies that LEI reviewed (see Section 3.3.2.3 for additional information). Also, according to a study for the INGAA Foundation, pipelines can tolerate some degree of deterioration without failing because of the inherent safety factors included in their design.<sup>41</sup> In addition, the study stated that “the fitness of a pipeline for service does not necessarily expire at some point in time.”<sup>42</sup> In fact, “a well maintained and periodically assessed pipeline can safely transport natural gas indefinitely.”<sup>43</sup>

Therefore, LEI chose to use the classic One Hoss Shay (“OHS”) depreciation profile, which assumes that capital assets can provide the same level of capital ‘service’ over its entire service life. Under OHS, it is assumed that an asset provides a constant level of services over the lifetime of that asset, meaning the asset’s ability to provide services does not deteriorate with age. This is not to be confused with accounting depreciation, in which the financial value of an asset declines over its lifetime. The Department has already recognized the appropriateness of the OHS profile for other network industries, and this profile has also been used by other experts conducting LDC TFP studies.<sup>44</sup>

### **3.3.2.3 Service life of capital under the monetary approach**

LEI estimated the average service life of the LDC capital stock by looking at technical studies of different capital assets used by LDCs.

LEI calculated an average service life of 51 years for U.S. LDCs. This 51-year average service life is based on the weighted arithmetic average of typical LDC’s distribution asset lives. To derive this number, LEI first reviewed the average service life of different gas assets from 17 publicly available depreciation studies, including the Company’s 2013 depreciation study.<sup>45</sup> These

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<sup>41</sup> John Kiefner and Michael Rosenfeld. “The Role of Pipeline Age in Pipeline Safety.” November 8, 2012. Page 25.

<sup>42</sup> Ibid, page 5.

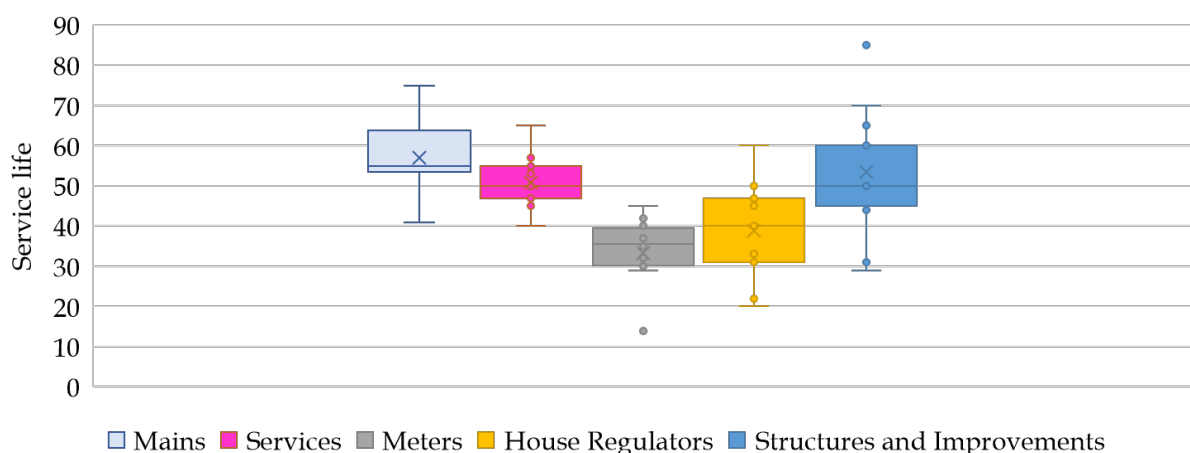
<sup>43</sup> Ibid, page 5.

<sup>44</sup> Studies that use OHS include NSTAR Electric and National Grid’s most recent filings to the Department. In addition, TFP studies conducted for cases in Alberta, Ontario, the UK, Australia, and New Zealand have all utilized OHS.

<sup>45</sup> These depreciation studies include the following: Corning Natural Gas Corporation (2010); Great Plains Natural Gas (2006 & 2010 Update); Florida Public Utilities Company (2014); Intermountain Gas Company (2003); MidAmerican Energy (2015); Montana-Dakota Utilities Co. Gas Division (2015); Narragansett Electric Company (2017); National Fuel Gas (2018); NSTAR Gas Company (2013); Oklahoma Gas and Electric Company (2018); Peoples TWP LLC (2013); Pacific Gas and Electric Company (2006); Piedmont Natural Gas Company, Inc. (2004); Sierra Pacific Power Company Gas Department (2015); Southern California Gas Company (2010); and UGI Penn Natural Gas, Inc. (2016).

depreciation studies are generally conducted by independent engineering firms hired by LDCs periodically. These independent engineering firms estimate typically the service life based on “informed judgment which incorporated analyses of historical plant retirement data for a given period, a review of the company practice, and outlook as they relate to plant operation and retirement, and consideration of current practice in the gas industry, including knowledge of service lives and net salvage estimates used for other gas companies.”<sup>46</sup> According to these depreciation studies, the process of calculating the service lives consists of gathering historical data for plant accounts or depreciable groups, assessing the history through the use of generally recognized practices, and forecasting the survivor characteristics for each depreciable group based on the evaluation of the historical data analyses and the probable future.<sup>47</sup> These depreciation studies report service lives for various capital equipment and assets, including mains, services, meters, house regulators, structures and improvements, to name a few. The graph below shows the range of service lives specified for each type of gas asset across the 17 depreciation studies examined by LEI.

**Figure 21. Range of service life of select gas distribution assets (years)**



Source: Various depreciation studies (see footnote 45 for the list)

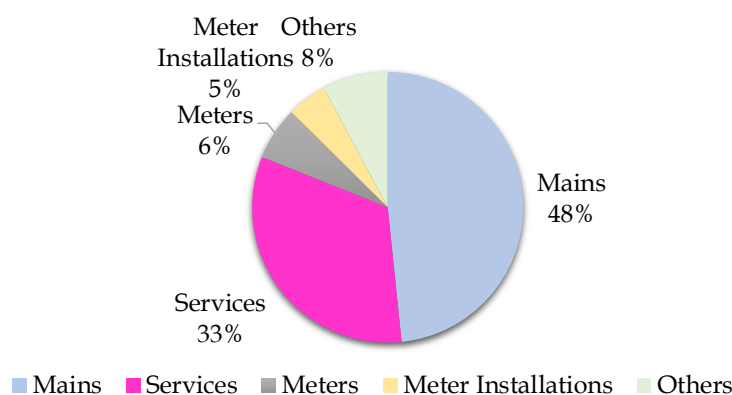
Then, LEI gathered the gross value of the distribution plant of 37 gas utilities broken down by these gas asset classes during the benchmark year (1998). This information allowed LEI to determine the share of each gas asset relative to the total gross value of the distribution plant. Not surprisingly, mains and services represent over 81% of the total gross value of the plant, as

<sup>46</sup> Gannett Fleming. “NSTAR Gas Company 2013 Depreciation Study.” December 31, 2013. Page I-2.

<sup>47</sup> Ibid. Page I-4.

shown in the figure below. The shares were used then to weight the average lives by asset class to get to an aggregate distribution level figure for the service life.

**Figure 22. Share of each asset to the total gross value of the distribution plant**



Source: LEI analysis based on multiple LDC filings and FERC Form 2

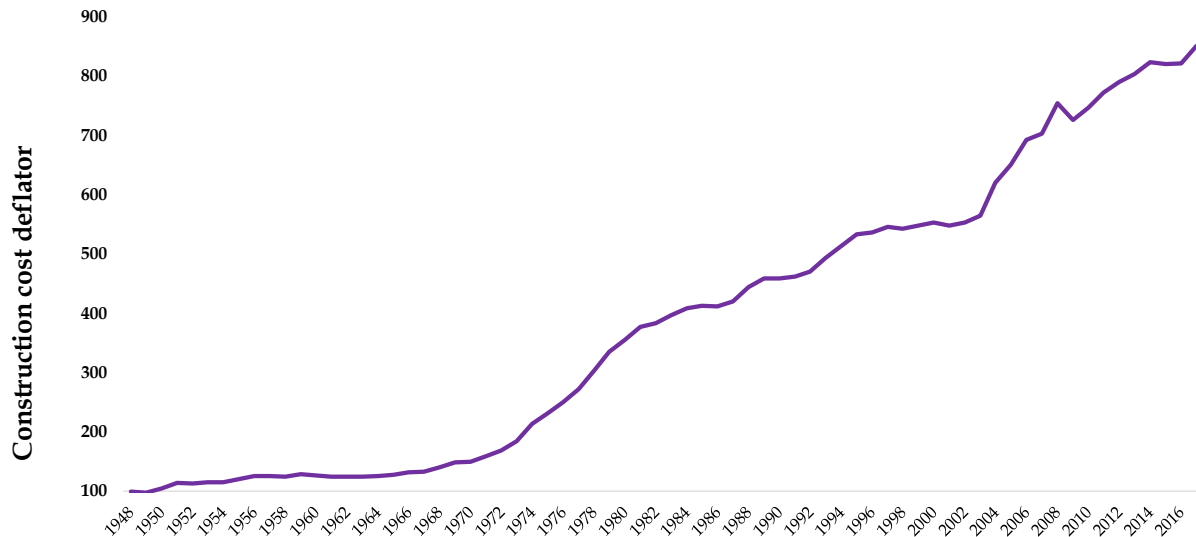
### 3.3.2.4 Deriving the capital input quantity

LEI obtained the quantity of capital stock using the perpetual inventory equation, which has been adopted in numerous TFP studies used in ratemaking globally.<sup>48</sup> To calculate the capital stock in the current year ( $K_t$ ), the perpetual inventory equation takes the end of year capital stock (gross book value) from the previous year ( $K_{t-1}$ ) and adds in the gross book value of new additions ( $I$ ) and deducts the gross book value of retirements ( $R$ ) in year  $t$ . The new additions and retirement data were collected directly from the SNL dataset or directly from state LDC filings or FERC Form 2. However, because the equation is incorporating the monetary value of assets of different vintages (and therefore in nominal dollars from different years), the capital additions and retirements must be deflated. LEI used a construction cost index (BLS's Producer Price Index ("PPI" for construction materials) to deflate the assets into real (1998) dollars; the trend in BLS PPI is illustrated in the figure below.<sup>49</sup>

<sup>48</sup> This approach has been used in TFP studies that were ultimately accepted in Alberta, Australia, the United Kingdom, and Massachusetts.

<sup>49</sup> Other U.S. TFP studies have frequently used the Handy Whitman Index ("HWI"). LEI selected the BLS PPI index over the HWI because of concerns around the observed escalation and volatility in the HWI index in the last ten to fifteen years. LEI found the trends in the BLS PPI for construction materials to be more appropriate for purposes of deflating and inflating historical capital costs to a single unifying cost basis.

**Figure 23. Illustration of the BLS PPI**



Source: LEI analysis based on BLS PPI data

Because new additions are added in nominal dollars at time  $t$ , annual capex values are divided by the BLS PPI index also at time  $t$ . However, under the OHS approach, the retirements need to be re-based to reflect their full real monetary value when they occur at the end of their service life (i.e.,  $t$  minus the average service life  $s$ ). As noted above, LEI assumed average service life of 51 years (therefore  $s$  is equal to 1966 for a retirement that is taking place in 2017).

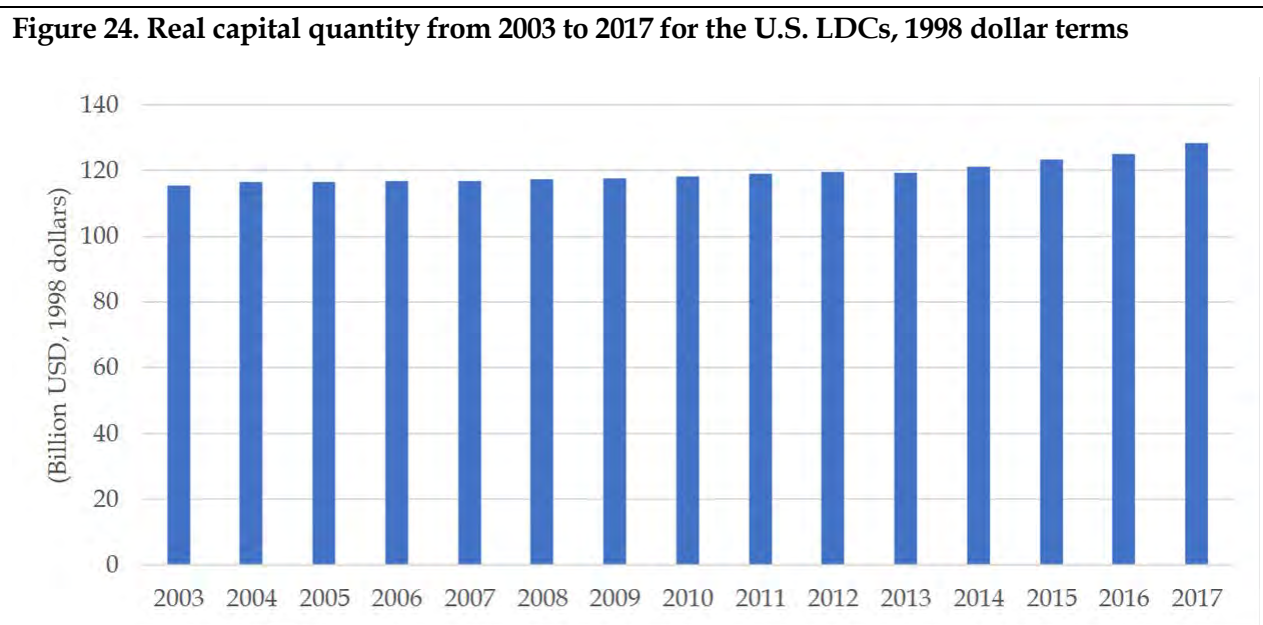
The equation for estimating the real capital quantity in any given year  $t$  under the perpetual inventory formula is shown below:

$$K_t = K_{t-1} \frac{I_t}{BLS\_PPI_t} - \frac{R_t}{BLS\_PPI_{t-s}}$$

The first year for which one estimates the capital input quantity is called the “Benchmark Year.” The best available information to construct a benchmark value is the gross book value of all capital assets and equipment, which is made up of assets of different vintages. The capital stock measure is sensitive to the age of the various capital components in the gross book value. To improve the precision of the capital stock estimates for the years in the TFP study, it is useful to select a benchmark year that is well before the beginning of the TFP study period (in the case of LEI’s Industry TFP Study, the first year of the study period is 2003).

Data for U.S. gas utilities are either non-existent or incomplete before the 1990s; therefore, LEI chose 1998 as the benchmark year based on data completeness. The capital stock for LDCs in

1998 is determined by dividing the estimated gross book value of the entire gas distribution asset base in 1998 by the 51-year average of BLS PPI values for 1998, and the previous 51 years (51 years is the average service life). Once the benchmark year capital quantity is estimated, the capital flow in each subsequent year is added by the new capital additions (divided by the BLS PPI value in the year that capital was added) minus any retirements (divided by the BLS PPI value in the year that capital was initially added, which is assumed to be 51 years prior to the retirement date). Figure 24 shows the real capital stock used in this Industry TFP Study from 2003 to 2017 for the industry (aggregation of the capital stock of all 83 LDCs).



### 3.3.3 Capital input price index

The capital input price measures the trend in the implicit rental price corresponding to a unit of capital quantity. Unlike the OM&A input price index, the capital input price index is not used to deflate the capital input quantity. Instead, the capital input price index is used to weight the capital input quantity in the total input quantities over time (mechanically, this is achieved by multiplying the capital input quantity by the capital input price index, which results in the total



capital quantity that is then represented in the calculation of the composite input index and the resulting TFP index).<sup>50</sup>

LEI used the implicit rental price formula developed in a seminal paper by Christensen and Jorgenson (1969) to estimate the capital input price index, which has also been used in numerous TFP studies.<sup>51</sup> The price of capital under this approach is based on an equilibrium relationship between the price an investor is willing to pay for an asset and the after-tax expected value of services that the asset will provide over the asset's lifetime. This relationship is called the implicit rental price formula and has the following mathematical representation:

$$PK_t = \frac{1 - uz}{1 - u} (r - i) \left[ 1 - \left( \frac{1 + i}{1 + r} \right)^{51} \right]^{-1} BLS\_PPI_{t-1}$$

The variable  $u$  represents the corporate income tax rate, the variable  $z$  represents the present value of tax depreciation charges on one dollar of investment in distribution assets, the variable  $r$  represents the forward-looking cost of capital, and the variable  $i$  represents the forward-looking inflation rate. The service life (51 years) is also used in the implicit rental price formula.

**Corporate income tax rate ( $u$ ):** LEI used the applicable average corporate tax rate in each state for  $u$  for the 2003-2017 period. A 35% federal tax rate was used for states with no state tax. These states include Nevada, Ohio, Texas, Washington, and Wyoming.

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<sup>50</sup> The exogenous approach to weighting the capital input quantity is sometimes referred to as the "direct" approach as the annual cost of using capital inputs can be measured directly by applying the sum of an estimated depreciation rate and a rate reflecting the opportunity cost of capital to the value of the assets. This is different from an endogenous approach, which assumes that the capital cost weighting is the residual of the utility's total revenue minus OM&A.

<sup>51</sup> Originally derived from L.R. Christensen and D.W. Jorgenson (1969), "The Measurement of Real Capital Input, 1929 - 1967," Review of Income and Wealth, Series 15, No. 4, December, pp. 293-320.



**Figure 25. Federal and state corporate tax rates by state**

PA	41 %	MD	40 %	FL	39 %
NJ	41 %	IL	40 %	MI	35 %
CA	41 %	IN	40 %	NV	35 %
MA	41 %	NY	40 %	OH	35 %
NH	41 %	KY	39 %	TX	35 %
CT	40 %	AR	39 %	WA	35 %
WV	40 %	KS	39 %	WY	35 %
WI	40 %	VA	39 %		

**Present value of tax depreciation charges (z):** This represents the present value of future depreciation on new investment. This component is used because depreciation for tax purposes typically takes place over a much shorter period than what is allowed for ratemaking purposes. *z* is a function of the tax depreciation method used, the service life, and the weighted average cost of capital (“WACC”). LEI applied the sum of years’ digits method, and the resulting value for this study was 0.683. *z* is summarized as follows:

$$z = \frac{2}{RT} \left[ 1 - \left[ \frac{(1+R)}{R(T+1)} \right] \left[ 1 - \left( \frac{1}{(1+R)} \right)^{T+1} \right] \right]$$

**Forward-looking cost of capital (“WACC”) and inflation rate (r):** A common method is to assume that investor’s forward-looking real rate of return (cost of capital less the inflation rate) is constant through time. This method produces a relatively stable input price series (in contrast to using just the current’ years WACC and inflation rates). The resulting average WACC<sup>52</sup> of 7.27% and expected long-term inflation rate<sup>53</sup> of 1.98% (over the study timeframe) was then used in the implicit rental price formula for all U.S. LDCs.

<sup>52</sup> In calculating the WACC, the average cost of debt is based on the average Moody’s seasoned AAA bond yield, published by the Federal Reserve Bank of St. Louis (Source: Moody’s Seasoned Aaa Corporate Bond Yield. <https://fred.stlouisfed.org/series/AAA>). The cost of equity is based on the average approved ROE of U.S. gas utilities over time (Source: reported ROEs in SNL Financial). The debt/equity ratio was assumed to be 50%, based on an average of reported debt/equity ratios for U.S. gas utilities. (Source: SNL Financial, Rate Case History. Average Rate of Return on Equity).

<sup>53</sup> The long-term expected inflation rate is calculated using the Fisher Ideal equation based on rates of the 10-Year U.S. Treasury bonds and the 10-Year U.S. Treasury Inflation-Protected Securities (“TIPS”) from 1997-2017. (Source: U.S. Treasury, Daily Treasury Yield Curves 10-YR. <https://www.treasury.gov/resource-center/data-chart-center/interest-rates/pages/textview.aspx?data=yield>, and the Bureau of the Fiscal Service. <https://www.treasurydirect.gov/instit/annceresult/tipsdpi/tipsdpi.htm>)

## 4 TFP results

Growth in the industry's productivity is measured by the difference between the growth rate of the industry's outputs and the growth rate of the industry's inputs. TFP for the U.S. LDC Industry grew by 0.09% per year on average over the 2003-2017 timeframe. The slightly positive value is due to an output index (0.73% per year on average) that grew marginally faster than the composite input index (0.65% per year on average). Notably, the TFP trend for the U.S. is higher than the TFP calculated over the same timeframe for the LDCs in the Northeast Region (-0.39% per year on average). Figure 26 shows the TFP growth rates for the U.S. and Northeast Region. The succeeding sections will discuss the TFP results in detail.

**Figure 26. TFP growth rates for the U.S. and Northeast region**

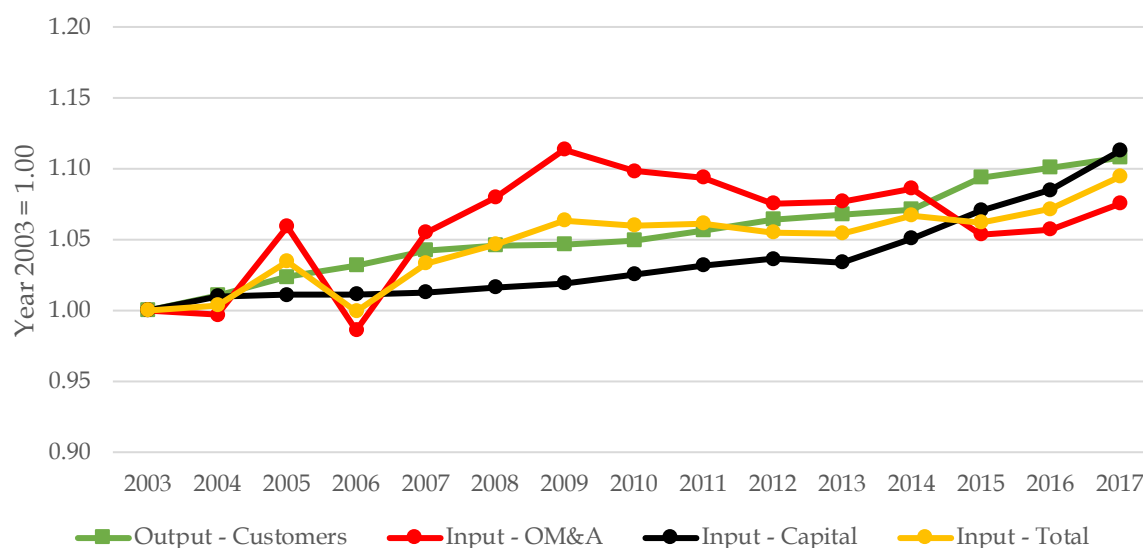
	<b>U.S.</b>	<b>Northeast Region</b>
2004	0.73%	1.43%
2005	-1.80%	-1.01%
2006	4.28%	4.57%
2007	-2.32%	-2.82%
2008	-0.94%	-1.89%
2009	-1.60%	-2.03%
2010	0.64%	0.40%
2011	0.55%	-0.33%
2012	1.34%	-2.01%
2013	0.39%	1.71%
2014	-0.90%	-3.36%
2015	2.56%	1.46%
2016	-0.26%	0.89%
2017	-1.45%	-2.42%
<b>Average</b>	<b>0.09%</b>	<b>-0.39%</b>

### 4.1 U.S. Industry trends

#### 4.1.1 Output index

The average growth rate in the number of customers (output) for the industry was 0.73% per year on average. Figure 27 below shows that customer growth has been relatively consistent over the 2003-2017 study timeframe, except for slower customer growth between 2007 and 2009, which corresponds with the economic recession in the U.S. Moreover, in all years, customer growth has remained positive.

**Figure 27. Chained Fisher Ideal indices for quantities of inputs and outputs for the U.S. LDC industry**



#### 4.1.2 Input index

The composite input index (see yellow line in the figure above, labeled as “Input-Total”) is based on the combination of the capital and OM&A input quantity indices. The average growth rate in the OM&A input quantity index for the industry between 2003-2017 was 0.65% per year, which includes both positive and negative values for year-over-year changes, as shown in Figure 28 below. Until 2013, OM&A input quantities for the U.S. LDC industry were growing more rapidly than capital input quantities. Over the study timeframe, OM&A input quantities grew at an annual average rate of 0.52%. The capital input quantity index grew between 2003 and 2017 at an annual average rate of 0.76%. Capital quantities have grown at a faster rate in the last few years, but the rate of change has been positive throughout the entire forecast. And importantly, the average growth rate for capital input quantities is consistent with the average rate of growth observed in miles of mains for the U.S. LDC industry (0.77% per year on average over the 2003 - 2017 timeframe, in the aggregate for the 83 LDCs).<sup>54</sup>

<sup>54</sup> Increased capital investment can be attributed partly to the new regulations enacted by the U.S. Pipeline and Hazardous Materials Safety Administration requiring utilities to establish and implement a Distribution Integrity Management Program by August 2011.

To get the total (composite) input index, LEI used the capital to OM&A split of 52%/48%, as implied by the OM&A cost versus total capital cost. This resulted in a total input quantity index that has an annual average growth rate over the 2003-2017 timeframe of 0.65% per year.

#### 4.1.3 TFP and PFP growth

The partial and total factor productivity growth rates are summarized below in Figure 28. TFP for the U.S. LDC industry grew by 0.09% per year on average over the 2003-2017 timeframe. This result indicates the quantity of output was increasing marginally faster than the quantity of inputs.

**Figure 28. Annual growth rates for output and input quantities and resulting PFP and TFP trends for the U.S. LDC industry**

Year	Output		Input		Productivity		
	Customers	Capital	OM&A	Total	Capital	OM&A	TFP
	[A]	[B]	[C]	[D]	[A-B]	[A-C]	[A-D]
2003-2004	1.08%	0.97%	-0.30%	0.34%	0.10%	1.38%	0.73%
2004-2005	1.26%	0.12%	6.07%	3.06%	1.14%	-4.81%	-1.80%
2005-2006	0.79%	0.06%	-7.20%	-3.49%	0.73%	7.99%	4.28%
2006-2007	1.00%	0.12%	6.78%	3.33%	0.88%	-5.78%	-2.32%
2007-2008	0.36%	0.34%	2.32%	1.30%	0.02%	-1.96%	-0.94%
2008-2009	0.03%	0.25%	3.11%	1.64%	-0.22%	-3.07%	-1.60%
2009-2010	0.28%	0.64%	-1.40%	-0.36%	-0.36%	1.68%	0.64%
2010-2011	0.67%	0.63%	-0.41%	0.11%	0.04%	1.08%	0.55%
2011-2012	0.74%	0.44%	-1.69%	-0.60%	0.30%	2.43%	1.34%
2012-2013	0.33%	-0.23%	0.12%	-0.06%	0.56%	0.21%	0.39%
2013-2014	0.35%	1.63%	0.84%	1.24%	-1.28%	-0.49%	-0.90%
2014-2015	2.08%	1.83%	-2.99%	-0.47%	0.25%	5.07%	2.56%
2015-2016	0.61%	1.35%	0.33%	0.87%	-0.75%	0.27%	-0.26%
2016-2017	0.68%	2.52%	1.71%	2.14%	-1.84%	-1.03%	-1.45%
<b>Average</b>	<b>0.73%</b>	<b>0.76%</b>	<b>0.52%</b>	<b>0.65%</b>	<b>-0.03%</b>	<b>0.21%</b>	<b>0.09%</b>

As previously described, a PFP index evaluates the trend in a single input. The PFP for capital resulted in an annual average growth rate of -0.03% for the U.S. LDC industry. A negative PFP for capital indicates that the quantity of capital inputs grew faster than customers. The PFP for OM&A resulted in an annual average growth rate of 0.21% for the U.S. LDC industry, which suggests that the number of customers was increasing faster than the quantity of OM&A inputs.

## 4.2 Northeast Region TFP trends

The growth in Northeast Region TFP was calculated to be -0.39% over the 2003-2017 timeframe, as illustrated in the figure below. This indicates that the inputs are growing faster than the outputs for LDCs in the Northeast Region.

**Figure 29. Annual growth rates for output and input quantities and resulting PFP and TFP trends for the Northeast Region LDC industry**

Year	Output		Input		Productivity		
	Customers	Capital	OM&A	Total	Capital	OM&A	TFP
	[A]	[B]	[C]	[D]	[A-B]	[A-C]	[A-D]
2003-2004	0.35%	0.55%	-2.85%	-1.08%	-0.21%	3.20%	1.43%
2004-2005	0.18%	0.81%	1.61%	1.19%	-0.63%	-1.43%	-1.01%
2005-2006	0.52%	0.81%	-9.82%	-4.05%	-0.29%	10.34%	4.57%
2006-2007	0.84%	0.82%	7.20%	3.66%	0.02%	-6.36%	-2.82%
2007-2008	0.35%	0.96%	3.83%	2.25%	-0.60%	-3.48%	-1.89%
2008-2009	0.73%	1.32%	4.50%	2.76%	-0.59%	-3.78%	-2.03%
2009-2010	0.49%	1.34%	-1.43%	0.08%	-0.86%	1.91%	0.40%
2010-2011	1.02%	1.56%	1.10%	1.35%	-0.54%	-0.08%	-0.33%
2011-2012	0.85%	1.54%	4.38%	2.86%	-0.70%	-3.54%	-2.01%
2012-2013	0.63%	0.34%	-2.74%	-1.08%	0.29%	3.37%	1.71%
2013-2014	0.54%	2.23%	5.84%	3.90%	-1.69%	-5.30%	-3.36%
2014-2015	0.94%	2.26%	-3.79%	-0.52%	-1.31%	4.73%	1.46%
2015-2016	1.01%	1.21%	-1.19%	0.13%	-0.20%	2.20%	0.89%
2016-2017	0.61%	2.84%	3.25%	3.03%	-2.24%	-2.64%	-2.42%
<b>Average</b>	<b>0.65%</b>	<b>1.33%</b>	<b>0.71%</b>	<b>1.03%</b>	<b>-0.68%</b>	<b>-0.06%</b>	<b>-0.39%</b>

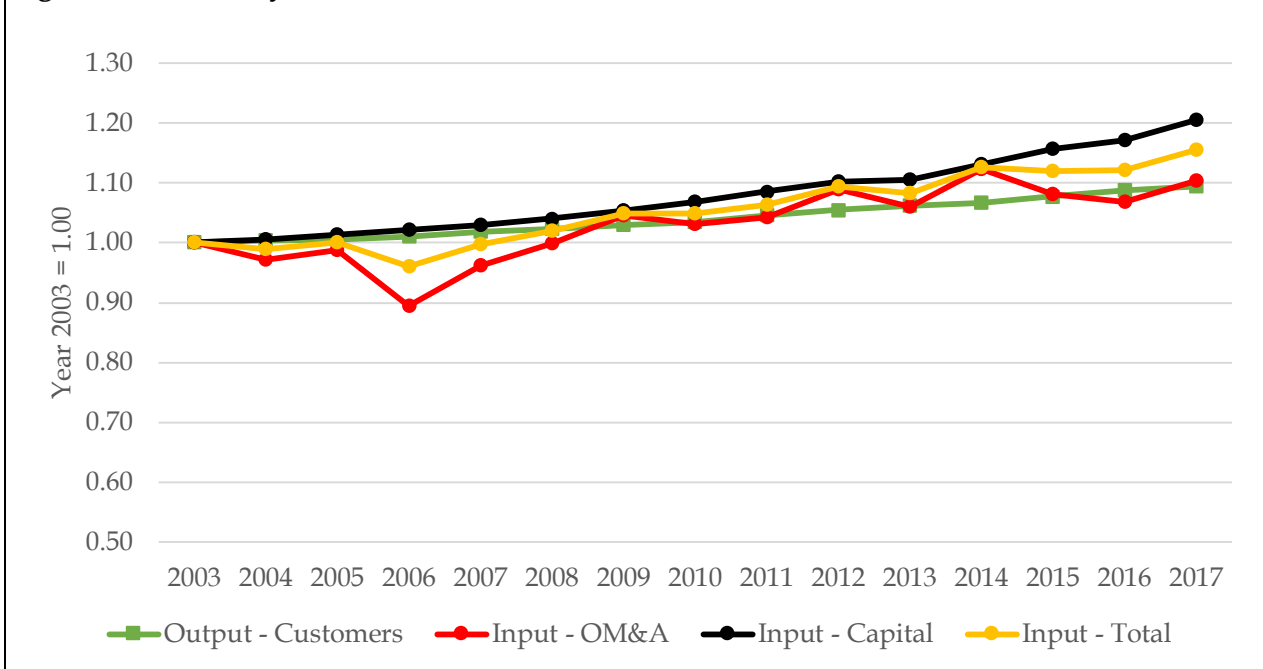
There are three factors explaining the differences in observed TFP trends for the U.S. versus Northeast Region. The primary input-related driver is the much higher rate of capital quantity input growth among LDCs in the Northeast Region, as compared to the rest of the U.S. Since 2003, the Northeast Region experienced a much higher growth rate in the capital inputs as compared to the national average rate (1.33% per annum for the Northeast Region versus 0.76% per annum for the U.S.). The Northeast Region's capital PFP is -0.68% over the study timeframe, compared to -0.03% for the U.S.

In addition to the capital input quantity, the OM&A input quantity is also growing at a slightly higher rate in the Northeast Region as compared to the national (U.S.) average (0.52% per year for the national average, compared to 0.71% per year for the Northeast Region average). The

Northeast Region's OM&A PFP growth rate is -0.06% over the study timeframe, compared to an OM&A PFP growth rate of 0.21% for the U.S.

Finally, the pace of output growth has been slower on average over the study timeframe in the Northeast Region versus the U.S.-wide trends, as seen by comparing the output growth trends in Figure 28 and Figure 29.

**Figure 30. Chained Fisher Ideal indices for quantities of inputs and outputs for the Northeast region LDC industry**



#### 4.3 Relevance of the Northeast Region TFP for setting the Company's X factor

LEI recommends a Northeast Region<sup>55</sup> TFP growth rate for setting the X factor for NSTAR Gas. There are many drivers for total factor productivity. Specifically, for the LDC sector, it is important to consider economies of scale, technology, and output growth. LDCs in the Northeast Region have generally smaller gas pipeline systems with fewer customers, which indicates more

<sup>55</sup> The Northeast region as defined by the BLS includes Connecticut, Maine, Massachusetts, New Hampshire, New York, New Jersey, Pennsylvania, Rhode Island, and Vermont.

limited economies for scale.<sup>56</sup> LDCs in the Northeast Region have mains that are made up of a greater proportion of cast (or wrought) iron. Finally, as noted above, LDCs in the Northeast Region have recently experienced slower growth in the number of customers.

In assessing whether LDCs in the Northeast Region operate at a different scale than their peers in other parts of the U.S., LEI examined the number of customers for each LDC as of 2017 by region. The average number of customers per LDC outside the Northeast Region (669,822 customers per LDC) was nearly 65% higher than the average customer count for LDCs in the Northeast Region (408,082 customers per LDC). This difference in LDC size has been consistently over the past 15 years. NSTAR Gas may be one of the larger LDCs in the Northeast Region, but far smaller than some of its peers in the rest of the U.S. This information suggests that the opportunities for TFP growth related to economies of scale will differ between the Northeast Region and the rest of the U.S.

The technology used by the LDCs in the Northeast Region is also different from that used by LDCs in other parts of the U.S., as evidenced by the higher proportion of cast/wrought iron mains in the Northeast Region (see Figure 6 on page 10 of Section 1.2). The average share of cast/wrought iron mains in use in the 8 states of Northeast Region totaled 11.0%. In contrast, the average share of cast/wrought iron in use by LDCs in the other 39 continental U.S. states averaged only 3%. The higher share of main pipelines made from cast/wrought iron distinguishes the technology profile of the Northeast Region LDCs from other LDCs, and such technology differences will affect total factor productivity trends.

Growth in the number of outputs that a firm can produce is major driver of total factor productivity. Over the 15-year timeframe, the average annual growth rate in the total customers served by the LDCs in the Northeast Region fell behind the other regions by almost 25%. In recent years, more specifically the last 3 years, the differential has increased to more than 40%.

Based on an assessment of the drivers of total factor productivity, such as economies of scale, technology, and output growth, the Northeast Region TFP is the most relevant historical trend to use to for calibration of NSTAR Gas' I-X under PBR formula.

#### **4.4 NSTAR Gas historical TFP growth**

Although it is not necessary for purposes of ratemaking and setting the X factor, LEI also estimated the historical TFP trends for the Company. The growth in NSTAR Gas TFP was

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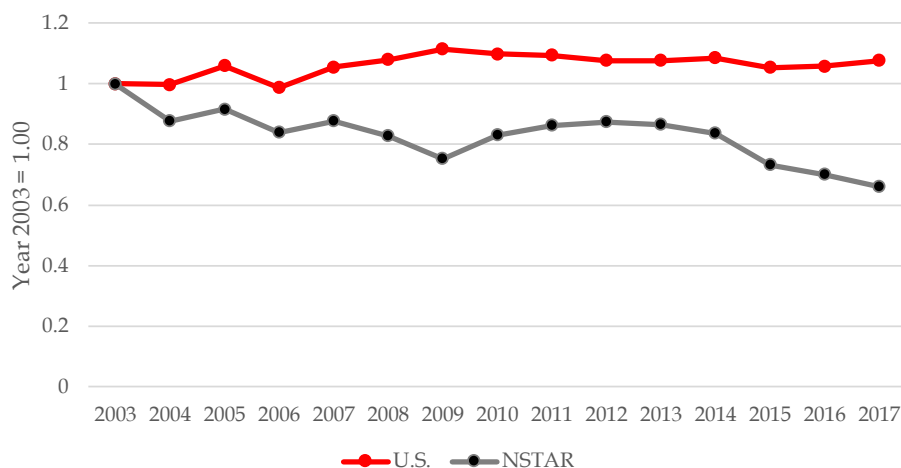
<sup>56</sup> Eatwell, John, Murray Millgate, and Peter Newman. "The New Palgrave: A Dictionary of Economics." Pages 660-661.

calculated to be 1.10% over the 2003-2017 timeframe. This indicates that the outputs were growing faster than the inputs for NSTAR Gas, historically.

Part of the reason the NSTAR Gas TFP is higher than the industry is due to the higher growth in the number of customers it experienced over the historical study timeframe. NSTAR Gas experienced customer growth over the 2003-2017 period of 1.09% per year on average, compared to 0.73% per year for the U.S. LDC industry. This faster rate of growth in outputs allowed NSTAR Gas to make greater strides in productivity improvements than the industry average.

However, the main driver for the higher TFP for the Company compared to the industry has to do with the negative trend in the quantity of OM&A inputs. Since 2003, NSTAR Gas OM&A input quantity growth has been declining much more rapidly than the rest of the industry. For instance, NSTAR Gas OM&A fell at an average rate of 2.96% per annum compared to 0.52% average growth rate for the industry (at the national, U.S. level). The trend in OM&A input quantities for the Company and the U.S. industry is shown below in Figure 31.

**Figure 31. OM&A input quantities index for NSTAR Gas and the U.S. LDC industry**





Capital input quantity growth for the Company has been considerably higher and has increased much faster than the industry (2.48% per year on average compared to 0.76% per year on average for the U.S. LDC industry). The resulting PFP trend for capital is -1.39% for the Company. Much of the steady increase in capital quantity for NSTAR Gas has occurred in recent years. Figure 32 below shows the growth rates for each input and output quantity for NSTAR Gas, as well as the overall PFP and TFP annual growth rates.

**Figure 32. Annual growth rates for output and input quantities and resulting PFP and TFP trends for NSTAR Gas**

Year	Output	Input			Productivity		
	Customers	Capital	OM&A	Total	Capital	OM&A	TFP
	[A]	[B]	[C]	[D]	[A-B]	[A-C]	[A-D]
2003-2004	1.01%	2.25%	-13.19%	-6.15%	-1.24%	14.20%	7.16%
2004-2005	0.72%	0.76%	4.41%	2.68%	-0.04%	-3.68%	-1.96%
2005-2006	1.03%	-0.77%	-8.87%	-4.96%	1.80%	9.90%	5.99%
2006-2007	0.90%	2.64%	4.40%	3.53%	-1.74%	-3.50%	-2.62%
2007-2008	0.40%	0.62%	-5.61%	-2.43%	-0.22%	6.01%	2.83%
2008-2009	2.39%	2.72%	-9.66%	-2.99%	-0.32%	12.05%	5.38%
2009-2010	0.59%	1.25%	9.85%	5.20%	-0.66%	-9.26%	-4.61%
2010-2011	0.72%	1.69%	3.76%	2.69%	-0.97%	-3.04%	-1.97%
2011-2012	0.94%	3.36%	1.43%	2.43%	-2.42%	-0.49%	-1.49%
2012-2013	1.32%	2.79%	-1.10%	0.95%	-1.47%	2.41%	0.37%
2013-2014	1.42%	2.76%	-3.38%	-0.06%	-1.34%	4.80%	1.48%
2014-2015	1.24%	3.06%	-13.19%	-3.97%	-1.82%	14.44%	5.21%
2015-2016	1.36%	6.83%	-4.46%	2.28%	-5.47%	5.83%	-0.92%
2016-2017	1.19%	4.72%	-5.80%	0.70%	-3.53%	6.99%	0.49%
<b>Average</b>	<b>1.09%</b>	<b>2.48%</b>	<b>-2.96%</b>	<b>-0.01%</b>	<b>-1.39%</b>	<b>4.05%</b>	<b>1.10%</b>

## 5 X factor results

Since NSTAR Gas is proposing to use the GDP-PI, which is an economy-wide inflation index, as an I factor, the X factor needs to be calibrated to reflect differences between the industry and the entire economy. As such, adjustments need to be made to reflect the TFP differential and an input price differential.

The TFP differential is the difference between the industry TFP growth rate and the TFP growth rate for the overall economy. The broadest measure of TFP growth for the U.S. economy is the BLS multifactor productivity ("MFP") index for the private business sector.<sup>57</sup> LEI used this BLS MFP index as a proxy measure of TFP trends in the U.S. economy.

The input price differential is the difference between rates of change in input prices for the overall economy and the LDC industry. The U.S. economy input price is calculated as the sum of the MFP growth rate for the year and the BEA GDP-PI growth rate. The industry input price is based on the weighted average of the growth rate of OM&A input price and capital input price, as estimated in LEI's Industry TFP Study.

Using the national (U.S.) TFP trend of 0.60% and input price differential of -0.28%, these adjustments produce an average X factor -0.79% over the 15-year timeframe, as summarized in Figure 33.

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<sup>57</sup> U.S. Department of Labor, Bureau of Labor Statistics, Multifactor Productivity for the Private Business Sector, Series ID MPU4900012 (02). <<http://www.bls.gov/mfp/>>

**Figure 33. X factor results for the LDC industry (2003-2017)**

Year	TFP			Input Price			X Factor (x) = (c) + (f)
	Industry (a)	US (b)	Difference (c) = (a) - (b)	US (d)	Industry (e)	Difference (f) = (d) - (e)	
2003	-	-	-		-	-	-
2004	0.73%	2.29%	-1.56%	4.94%	3.20%	1.73%	0.17%
2005	-1.80%	1.51%	-3.31%	4.57%	6.85%	-2.28%	-5.60%
2006	4.28%	0.46%	3.82%	3.47%	5.92%	-2.46%	1.36%
2007	-2.32%	0.49%	-2.81%	3.14%	2.48%	0.66%	-2.15%
2008	-0.94%	-1.12%	0.18%	0.77%	2.09%	-1.32%	-1.14%
2009	-1.60%	0.40%	-2.00%	1.18%	4.70%	-3.52%	-5.53%
2010	0.64%	2.55%	-1.91%	3.71%	-0.23%	3.94%	2.03%
2011	0.55%	-0.27%	0.82%	1.79%	2.82%	-1.03%	-0.20%
2012	1.34%	0.57%	0.77%	2.47%	3.03%	-0.56%	0.21%
2013	0.39%	0.36%	0.03%	2.12%	1.99%	0.13%	0.16%
2014	-0.90%	0.42%	-1.32%	2.29%	1.80%	0.48%	-0.84%
2015	2.56%	0.86%	1.69%	1.89%	2.41%	-0.52%	1.17%
2016	-0.26%	-0.55%	0.28%	0.54%	0.79%	-0.25%	0.03%
2017	-1.45%	0.38%	-1.83%	2.28%	1.23%	1.04%	-0.78%
Average (2003-2017)	0.09%	0.60%	-0.51%	2.51%	2.79%	-0.28%	-0.79%

Using the recommended TFP trend for the Northeast Region, the resulting X factor is -1.30%, as shown in Figure 34 below.

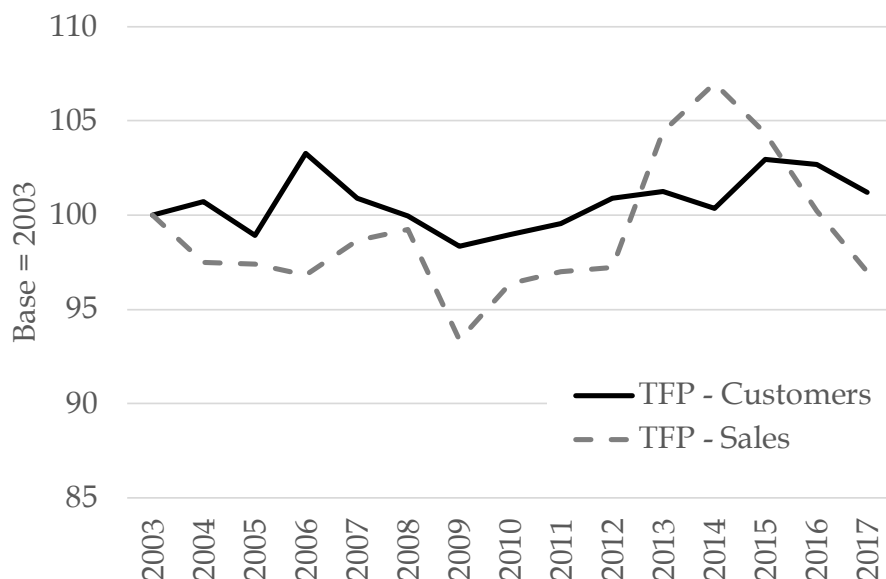
**Figure 34. X factor results for the Northeast LDCs**

Year	TFP			Input Price			X Factor (x) = (c) + (f)
	Industry (a)	US (b)	Difference (c) = (a) - (b)	US (d)	Industry (e)	Difference (f) = (d) - (e)	
2003	-	-	-		-	-	-
2004	1.43%	2.29%	-0.87%	4.94%	3.28%	1.66%	0.79%
2005	-1.01%	1.51%	-2.52%	4.57%	6.96%	-2.39%	-4.91%
2006	4.57%	0.46%	4.11%	3.47%	6.00%	-2.53%	1.58%
2007	-2.82%	0.49%	-3.31%	3.14%	2.62%	0.52%	-2.79%
2008	-1.89%	-1.12%	-0.77%	0.77%	2.06%	-1.29%	-2.06%
2009	-2.03%	0.40%	-2.43%	1.18%	4.82%	-3.64%	-6.07%
2010	0.40%	2.55%	-2.14%	3.71%	-0.25%	3.96%	1.82%
2011	-0.33%	-0.27%	-0.06%	1.79%	2.82%	-1.03%	-1.09%
2012	-2.01%	0.57%	-2.58%	2.47%	2.97%	-0.49%	-3.07%
2013	1.71%	0.36%	1.35%	2.12%	1.99%	0.12%	1.47%
2014	-3.36%	0.42%	-3.78%	2.29%	1.82%	0.46%	-3.32%
2015	1.46%	0.86%	0.60%	1.89%	2.48%	-0.59%	0.01%
2016	0.89%	-0.55%	1.43%	0.54%	0.77%	-0.23%	1.20%
2017	-2.42%	0.38%	-2.80%	2.28%	1.22%	1.06%	-1.74%
Average (2003-2017)	-0.39%	0.60%	-0.98%	2.51%	2.83%	-0.32%	-1.30%

## 6 Appendix: Alternative Output Metric

In addition to the TFP analysis described above using the total number of customers as the measure of output, LEI conducted a sensitivity test using gas sales as an output metric for the national (U.S.) Study Group. Using annual gas sales volume as an output measure generates a more negative TFP trend and a more negative X factor, compared to the Main Case. As shown in the figure below, year-on-year trends in annual gas sales volume were more volatile, and on average, lower than the average growth in the number of customers served. The average growth rate in gas sales volumes was affected primarily by the negative annual changes in volumes in the early and mid-2000s, as shown in Figure 35. The associated X factor under this sensitivity is also more negative at -1.10% (as compared to -0.79% for the national sample). LEI would expect broadly similar directional impacts for the Northeast Region LDC Industry TFP.

**Figure 35. Output index: number of customers served versus annual gas sales for the U.S. LDC industry**



As discussed in Section 3.2, total customers served is a preferred metric for assessing productivity trends in the LDC industry. Furthermore, for purposes of setting the X factor under a price or revenue cap, gas sales as a measure of output are less appropriate because of the typical regulatory accounting treatment of weather impacts on gas sales (there are usually weather variance accounts that true-up revenues for weather factors) and the presence of decoupling arrangements. Therefore, LEI recommends that the Department focus on the results of the Main Case for informing its regulatory decision-making.

**Figure 36. Annual TFP growth rates using gas sales as an output measure for the U.S. LDC industry**

Year	Output	Inputs			TFP Growth Sales
	Customers	OM&A	Capital	Total	
2003					
2004	1.08%	-0.30%	0.97%	0.34%	-2.6%
2005	1.26%	6.07%	0.12%	3.06%	-0.1%
2006	0.79%	-7.20%	0.06%	-3.49%	-0.6%
2007	1.00%	6.78%	0.12%	3.33%	1.9%
2008	0.36%	2.32%	0.34%	1.30%	0.6%
2009	0.03%	3.11%	0.25%	1.64%	-6.1%
2010	0.28%	-1.40%	0.64%	-0.36%	3.1%
2011	0.67%	-0.41%	0.63%	0.11%	0.7%
2012	0.74%	-1.69%	0.44%	-0.60%	0.3%
2013	0.33%	0.12%	-0.23%	-0.06%	7.1%
2014	0.35%	0.84%	1.63%	1.24%	2.4%
2015	2.08%	-2.99%	1.83%	-0.47%	-2.5%
2016	0.61%	0.33%	1.35%	0.87%	-4.0%
2017	0.68%	1.71%	2.52%	2.14%	-3.3%
Average (2003-2017)	0.73%	0.52%	0.76%	0.65%	-0.22%

**Figure 37. X factor results for the U.S. LDC industry using gas sales as an output measure**

Period	TFP			Input Price			X Factor (x) = (c) + (f)
	Industry (a)	US (b)	Difference (c) = (a) - (b)	US (d)	Industry (e)	Difference (f) = (d) - (e)	
2003	-	-	-	0	-	-	-
2004	-2.55%	2.61%	-5.16%	5.25%	3.20%	2.05%	-3.11%
2005	-0.06%	1.53%	-1.59%	4.58%	6.85%	-2.27%	-3.86%
2006	-0.63%	0.35%	-0.98%	3.36%	5.92%	-2.57%	-3.55%
2007	1.89%	0.39%	1.51%	3.04%	2.48%	0.56%	2.07%
2008	0.58%	-1.19%	1.77%	0.70%	2.09%	-1.39%	0.38%
2009	-6.08%	-0.26%	-5.82%	0.52%	4.70%	-4.18%	-10.00%
2010	3.14%	3.25%	-0.11%	4.42%	-0.23%	4.65%	4.54%
2011	0.65%	0.07%	0.58%	2.13%	2.82%	-0.69%	-0.11%
2012	0.25%	0.69%	-0.44%	2.60%	3.03%	-0.44%	-0.87%
2013	7.13%	0.41%	6.73%	2.16%	1.99%	0.18%	6.90%
2014	2.43%	0.87%	1.56%	2.73%	1.80%	0.92%	2.49%
2015	-2.53%	0.93%	-3.46%	1.96%	2.41%	-0.45%	-3.91%
2016	-4.00%	-0.46%	-3.54%	0.62%	0.79%	-0.17%	-3.71%
2017	-3.27%	0.76%	-4.02%	2.66%	1.23%	1.42%	-2.60%
Average	-0.22%	0.71%	-0.93%	2.62%	2.79%	-0.17%	-1.10%

# **BENCHMARKING THE TOTAL COST OF NSTAR GAS COMPANY**

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London Economics International LLC ("LEI") was retained by NSTAR Gas Company ("NSTAR Gas" or "the Company") to prepare a total cost benchmarking study ("Total Cost Benchmarking Study"). LEI has made the qualifications noted below with respect to the information contained in this Study and the circumstances under which the report was prepared.

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## Table of Contents

<b>1</b>	<b>EXECUTIVE SUMMARY .....</b>	<b>3</b>
1.1	LEI'S APPROACH .....	3
1.2	SUMMARY OF RESULTS.....	4
1.3	STRUCTURE OF THIS REPORT.....	5
<b>2</b>	<b>THE PURPOSE OF TOTAL COST BENCHMARKING .....</b>	<b>6</b>
<b>3</b>	<b>BENCHMARKING USING ECONOMETRICS.....</b>	<b>8</b>
3.1	ESTABLISHING THE APPROPRIATE ECONOMIC MODEL .....	9
3.1.1	<i>Functional form of the economic model .....</i>	<i>9</i>
3.1.2	<i>Definitions of variables used in the translog .....</i>	<i>9</i>
3.2	DATASET USED .....	12
3.3	THE ECONOMETRIC PROCESS.....	14
<b>4</b>	<b>BENCHMARKING RESULTS AND IMPLICATIONS .....</b>	<b>17</b>
4.1	KEY FINDINGS .....	17
4.2	IMPLICATIONS OF THE RANKING RESULTS .....	18
<b>5</b>	<b>APPENDIX A: DETAILS OF THE BENCHMARKING APPROACH .....</b>	<b>20</b>
5.1	ECONOMIC FOUNDATION OF BENCHMARKING ANALYSIS: TRANSLOG COST FUNCTION .....	20
5.2	THE ECONOMETRIC PROCESS.....	21
5.3	ECONOMETRIC RESULTS.....	21
5.3.1	<i>Overall explanatory power of the model is significant .....</i>	<i>21</i>
5.3.2	<i>Linear fit of the model is good.....</i>	<i>22</i>
5.3.3	<i>Coefficient estimates and their individual statistical significance.....</i>	<i>22</i>
5.3.4	<i>Alternative econometric approaches considered.....</i>	<i>25</i>
<b>6</b>	<b>APPENDIX B: FULL LIST OF EFFICIENCY RANKINGS FOR 82 LDCS IN THE U.S.....</b>	<b>27</b>
<b>7</b>	<b>APPENDIX C: FULL LIST OF EFFICIENCY RANKINGS FOR 29 LDCS IN THE NORTHEAST REGION .....</b>	<b>29</b>
<b>8</b>	<b>APPENDIX D: LEI TEAM'S QUALIFICATION FOR THE TOTAL COST BENCHMARKING STUDY .....</b>	<b>30</b>

## Table of Figures

FIGURE 1. NSTAR GAS' RANKING AMONG 82 U.S. LDCs IN THE BENCHMARKING STUDY (2014-2017).....	5
FIGURE 2. NSTAR GAS' RANKING AMONG 29 NORTHEAST LDCs IN THE BENCHMARKING STUDY (2014-2017) ....	5
FIGURE 3. ILLUSTRATION OF THE "CONVERGENCE EFFECT" .....	7
FIGURE 4. SOURCES OF DATA USED IN THE LEI TOTAL COST BENCHMARKING STUDY .....	12
FIGURE 5. STATES COVERED IN LEI'S TOTAL COST BENCHMARKING STUDY AND INDUSTRY TFP STUDY.....	13
FIGURE 6. GAS UTILITIES INCLUDED IN LEI'S TOTAL COST BENCHMARKING STUDY .....	13
FIGURE 7. ILLUSTRATIVE AND SIMPLIFIED EXAMPLE OF THE IMPACT OF NUMBER OF CUSTOMERS ON THE TOTAL COST .....	15
FIGURE 8. RELATIVE EFFICIENCY OF 82 U.S. LDCs.....	18
FIGURE 9. OVERALL EXPLANATORY POWER OF THE MODEL .....	22
FIGURE 10. COEFFICIENT ESTIMATES FOR TOTAL COST FUNCTION AND STATISTICAL SIGNIFICANCE .....	25
FIGURE 11. LEI'S RANKING OF 82 U.S. LDCs (AVERAGE OF RANKING 2014-2017).....	27
FIGURE 12. LEI'S RANKING OF 29 LDCs IN THE NORTHEAST REGION (AVERAGE RANKING OF 2014-2017) .....	29

## Acronyms

BEA	Bureau of Economic Analysis
BLS	Bureau of Labor Statistics
Capex	Capital expenditure
COLS	Corrected ordinary least squares
EIA	Electricity Information Administration
FE	Fixed effects
FERC	Federal Energy Regulatory Commission
GDP-PI	Gross Domestic Product Price Index
I-X	Inflation – (minus) Productivity factor
LDC	Local distribution company
LEI	London Economics International LLC
Mcf	Million cubic feet
MW	Midwest region of the U.S. (Census)
NE	Northeast region of the U.S. (Census)
OM&A	Operations, maintenance, and administrative
PBR	Performance-based regulation
PHMSA	Pipeline and Hazardous Materials Safety Administration
RE	Random effects
SFA	Stochastic frontier analysis
SO	South region of the U.S. (Census)
TC	Total cost
TFP	Total factor productivity
TLC	Transcendental logarithmic
WACC	Weighted average cost of capital
WE	West region of the U.S. (Census)
X factor	Productivity factor

## 1 Executive Summary

London Economics International (“LEI”) was engaged by NSTAR Gas Company (“NSTAR Gas” or the “Company”) to perform a total cost (“TC”) benchmarking study to evaluate the company’s efficiency compared to other local gas distribution companies (“LDCs”) in the United States.

Total cost benchmarking evaluates the performance of an individual firm, by comparing it cross-sectionally to other firms in the same industry at a given snapshot in time. The econometric technique that LEI employed allows for estimation of a hypothetical “average firm” against which all LDCs are compared. The econometrics also allows for the ranking of LDCs by their relative efficiency, where efficiency is defined as the extent to which costs are lower than the expected average level.

LEI’s Total Cost Benchmarking Study aims to help the regulator calibrate the “I-X” mechanism as a supplement to the total factor productivity (“TFP”) study (“LEI’s Industry TFP Study”), which measures the historical productivity growth rate of the U.S. gas industry.<sup>1</sup> LEI’s Industry TFP Study determines the productivity or the X factor that should be applied to NSTAR Gas for its “I-X” rate escalation mechanism, while a benchmarking study, such as the one described in this report, supports other adjustments to the rate escalation mechanism. More specifically, a benchmarking study assesses whether a firm has room for improving its efficiency compared to other LDCs and if a “stretch factor” (i.e., an adder to the X factor) is needed to incentivize such improvement.

### 1.1 LEI’s approach

To evaluate the Company’s efficiency compared to other LDCs in the U.S., LEI conducted an econometrics-based total cost benchmarking analysis. The econometric analysis involves applying statistical analysis to a defined economic model; in this case, a total cost model. The economic model and the econometric analysis are discussed in more detail in Section 3. Econometric benchmarking is a well-established and widely used approach to total cost benchmarking.

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<sup>1</sup> Please refer to *Empirical Analysis of Total Factor Productivity Trends in The U.S. Gas Local Distribution Industry*, prepared by LEI for NSTAR Gas Company (draft July 15, 2019).

Econometric analysis generates an estimate of the average relationship between total cost and a number of other explanatory factors that illuminate how each factor contributes to the total costs for LDCs. The fitted econometric model is then used to predict the total cost of each individual firm. If a company's actual total cost is lower than that predicted by the fitted econometric model, it is deemed to be relatively efficient. If its actual total cost is higher than predicted, it is deemed to be relatively less efficient. In LEI's study, the econometric process controls for the size of the company's operations (measured as number of customers served, for example), and other factors (such as the price of key inputs, customer profile, and the age of a gas system and other legacy factors, that could impact costs but may be outside the management control of the firm).

The size and sign of the difference between the predicted total cost and the actual total cost for a firm allow not only an assessment of the firm but also enables ranking of all the firms in the dataset. The companies with the lowest (i.e., most negative) percentage difference from the predicted cost are the most efficient; conversely, the companies with the highest (most positive) percentage difference from the predicted cost are the least efficient.

## **1.2 Summary of Results**

LEI's Total Cost Benchmarking Study is based on the same dataset used in LEI's Industry TFP Study, which includes 83 LDCs, with certain additional factors and metrics. One company was excluded from the benchmarking dataset due to incomplete pipeline miles data, an important driver of costs.<sup>2</sup> Therefore, a total of 82 U.S. LDCs are analyzed in LEI's Total Cost Benchmarking Study. LEI's econometric analysis indicates that NSTAR Gas' actual costs for the years 2014 through 2017 were, on average lower than predicted; therefore, the Company was more efficient than the average LDC.

The ranking exercise showed that the Company was among the more efficient performers in the U.S., ranking top 40% among the 82 LDCs for the four-year period overall (see Figure 1). In the Northeast Region (defined by U.S. Bureau of Labor Statistics ("BLS") as consisting of the six New England states, Pennsylvania, New York, and New Jersey), NSTAR Gas consistently ranked as one of the top 10 most efficient LDCs during 2014-2017 (see Figure 2).

---

<sup>2</sup> Avista Corporation was included in LEI's the TFP study but was taken out from the benchmarking analysis because of incomplete data for pipeline miles reported by PHMSA.

**Figure 1. NSTAR Gas' ranking among 82 U.S. LDCs in the benchmarking study (2014-2017)**

Year	Ranking	Quartile
2014	31	2
2015	26	2
2016	31	2
2017	32	2
<b>Average</b>	<b>31*</b>	<b>2</b>

\*Note: The *average* ranking reflects the ranking of NSTAR Gas' average ranking over the entire timeframe (2014-2017) among the 82 U.S. LDCs. It is not the simple average of the Company's ranking in each year.

**Figure 2. NSTAR Gas' ranking among 29 Northeast LDCs in the benchmarking study (2014-2017)**

Year	Ranking	Quartile
2014	6	1
2015	5	1
2016	7	1
2017	7	1
<b>Average</b>	<b>6*</b>	<b>1</b>

\*Note: The *Average* ranking reflects the ranking of NSTAR Gas' average ranking of the four years among the 29 NE companies. It is not the simple average of the Company's ranking in each year.

### 1.3 Structure of this report

This report is structured as follows: Section 2 explains what an econometrics-based benchmarking study is and how it is typically used in PBR regulatory proceedings. Section 3 provides a high-level overview of the technical methodology adopted in LEI's analysis. Section 4 discusses the outcomes of the study and the Company's relative efficiency rankings. Appendix A in Section 5 provides the details of the economic model and econometric approach used for the benchmarking. Section 6 and Section 7 provide the full set of rankings for the 82 U.S. LDCs and 29 Northeast LDCs, respectively. Section 8 provides highlights of LEI's qualifications for performing utility benchmarking studies.

## 2 The purpose of total cost benchmarking

The purpose of benchmarking is to compare the performance of an individual firm to the performance of other individual firms. Total cost benchmarking studies provide empirical evidence that can be used to inform the regulator's judgment on an appropriate expectation for further efficiency improvement for a regulated company. By identifying the relative efficiency of a regulated firm, a total cost benchmarking study can help the regulator calibrate the I-X mechanism.

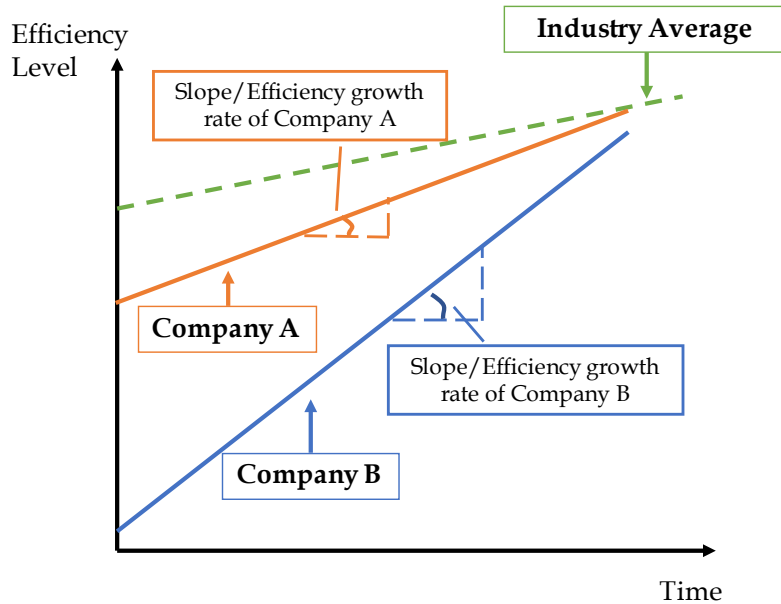
Generally, a company that is more efficient relative to its peers has less room for further cost savings; conversely, a company that is less efficient than its peers has more room for improvement. Regulators may set "stretch factors" (above and beyond the industry-average X factor target) to motivate a relatively inefficient regulated firm to catch up with its peers. However, the effect of the stretch factor will not last forever. As a firm gets closer to the best-practice efficiency level of the industry, its rate of productivity growth will slow down as it becomes exceedingly harder to find incremental cost efficiencies and outperform the industry average growth in TFP. Eventually, firms that have exhausted any "catch-up" opportunities will be constrained by the rate of industry average TFP growth. This phenomenon has been named the "convergence effect."<sup>3</sup> As illustrated in Figure 3, the efficiency growth rate of the relatively less efficient Company B slows down over time as it catches up with the better performer, Company A, and approaches the industry average.

If the results of a total cost benchmarking study suggest that the regulated firm is already efficient, this provides evidence that additional stretch factors are unnecessary and that the proposed X factor, based on industry average TFP trends, already reflects expectations for future efficiency gains. Therefore, additional incentives (in the form of stretch factor) are not necessary for setting the PBR formula. The lack of additional stretch factors does not mean that the regulator is lowering the bar for the efficient firm: the presence of an X factor that has been calibrated to industry TFP trends requires that the regulated firm must still keep its rate of productivity growth in line with the industry average.

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<sup>3</sup> Schmidt, Michael, *Performance-Based Ratemaking: Theory and Practice*. USA: Public Utilities Reports, Inc., 2000; Cambridge Economic Policy Associates Ltd, *Productivity Improvements in Distribution Network Operators Final Report*, November 2003; Roberts, B.F, *Performance-Based Regulation: Efficiency and the Measurement of Productivity Offset*, ESC Electric Utility Analysis Report 95-1.

**Figure 3. Illustration of the “convergence effect”**



### 3 Benchmarking using econometrics

Econometrics-based benchmarking is a well-established approach for comparing firms based on their total costs and outputs. It has been presented to regulators in many rate filing submissions in jurisdictions such as California, Georgia, Illinois, Kentucky, Maine, Michigan, and Oklahoma, to name a few, and has been accepted for use by regulators in Colorado, Ontario, Australia, New Zealand, and the UK.

An econometric process estimates the statistical relationship between a dependent variable and one or more independent variables. A dependent variable “depends” on the value of another variable. For example, the level of total cost a company incurs will depend on, among other things, the total number of customers it serves. A larger company serving more customers will have higher total costs than a small company with few customers. Therefore, the total cost is the dependent variable. An independent variable explains the level of the dependent variable. The total cost of an LDC can be explained by the number of customers it serves, the price of labor and capital, and potentially other independent variables. These independent variables are sometimes referred to as drivers of total costs, business conditions, and other factors that affect total costs. Controlling for these independent variables is important for arriving at a measure of relative efficiency that can be interpreted as the result of business decisions and activities which are under the control of a firm’s management.

The econometric process allows one to measure how much and in what direction each of these factors impacts total cost, on average, for a set of firms operating in the same industry. The econometrics-based approach requires a large set of standardized data to provide reliable results, which is why, if such data are not available, other benchmarking approaches are used.<sup>4</sup> However, in the case of NSTAR Gas, the foundations of the necessary large dataset are available from public sources such as the United States Energy Information Administration (“EIA”), Federal Energy Regulatory Commission (“FERC”), Pipeline and Hazardous Materials Safety Administration (“PHMSA”), U.S. Bureau of Labor Statistics (“BLS”), and state commissions (see Figure 4 in Section 3.2 for a full list of data sources). However, though this foundational data is publicly available, it requires auditing and cross-checking with state regulatory filings and individual company sources, as some of the data may not be reported consistently. LEI acquired an initial dataset for U.S. LDCs from a third-party data vendor and then audited, reviewed, and supplemented the data with research. LEI’s Total Cost Benchmarking Study relies on data

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<sup>4</sup> When such data is not available, an index-based alternative is sometimes used. The index-based approach involves calculating the ratios of performance variables for the target utility and a selected set of peer companies. The index-based approach can be adjusted to control for a limited number of drivers, and it can be appropriate in some circumstances. However, it also requires selection of a peer group of comparable LDCs, which in practice usually means a smaller cross-sectional set of companies as compared to an econometrics benchmarking study.



points for the 83 LDCs used in the LEI's Industry TFP Study (see Section 2.6 of LEI's Industry TFP Study for a more detailed description of the industry data).

### **3.1 Establishing the appropriate economic model**

Econometrics involves the application of statistical techniques to an economic model. So, before performing econometrics, LEI defined a suitable economic model which describes the total cost of an LDC.

#### **3.1.1 Functional form of the economic model**

LEI used the transcendental logarithmic ("TLC" or "translog") cost function. The translog cost function provides a flexible, functional form which does not require a priori assumptions about scale economies or the extent of input substitution.<sup>5</sup> The translog is a tried-and-tested tool for empirical research of costs in many sectors of the economy, with examples as diverse as oil and gas production, banking, airports, school systems, and utilities.<sup>6</sup>

The translog cost function posits that the dependent variable (total cost) depends on the level of output of a firm, the price of the firm's inputs, and possibly other factors that can impact the total cost. Appendix A provides additional technical details of the translog cost function used in this study.

#### **3.1.2 Definitions of variables used in the translog**

The dependent variable in LEI's benchmarking model is the total cost of the LDC. This consists of operations, maintenance, and administration ("OM&A") costs plus capital costs (defined as capital quantity multiplied by the implied rental price of capital, which yields user cost of capital). The total cost data was developed based on LEI's Industry TFP dataset.

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<sup>5</sup> The translog function was first developed by Christiansen, Laurits R., Jorgenson, Dale W., and Lau, Lawrence W. in the article "Transcendental logarithmic production frontiers." *Review of Economics and Statistics*. 55 (1) February 1973. It has stood the test of time and is still in widespread use.

<sup>6</sup> For example, see Fagan, Marie. "Resource Depletion and Technical Change: Effects on U.S. Crude Oil Finding Costs from 1977 to 1994," *The Energy Journal*. Vol. 18, No. 4. 1997; McCarthy, Patrick. "U.S. Airport Costs and Production Technology A Translog Cost Function Analysis." *Journal of Transport Economics and Policy*, Vol. 48, Part 3, September 2014; Daglish, Toby; Robertson, Oliver; Tripe, David; and Weill, Laurent. "Translog Cost Function Estimation: Banking Efficiency." No 4180, Working Paper Series from Victoria University of Wellington, The New Zealand Institute for the Study of Competition and Regulation. March 3, 2015; and Yu, Jeong-Joon; Yoo, Seong-Hoon; and Baek, Chulwoo. "Economies of Scale in the South Korean Natural Gas Industry." *Energies* 2019, 12, 1557; doi:10.3390/en12081557. April 24, 2019.

The independent variables in the TLC, which represent prices and output, include the following:<sup>7</sup>

1. **OM&A price (referred to as “W<sub>1</sub>” in Appendix A):** defined as the weighted average of labor price and non-labor price. The labor price is represented by the compensation index of the U.S. gas utilities sector reported by the U.S. Bureau of Labor Statistics (“BLS”). The non-labor price is represented by the Gross Domestic Product Price Index (“GDP-PI”) reported by the U.S. Bureau of Economic Analysis (“BEA”). LEI allocated 54% to labor cost and 46% to the non-labor cost, based on the total cost of labor vs. non-labor material costs share, as explained in Section 3.2.1 of LEI’s Industry TFP Report. The OM&A price is in the form of an index;
2. **Capital price (“W<sub>2</sub>” in Appendix A):** represents the implied rental price of capital as calculated in LEI’s Industry TFP study (see Section 3.3.3). The price is in the form of an index; and
3. **Total number of customers (“Y<sub>1</sub>” in Appendix A):** the total number of customers who had their gas delivered using the LDC’s system from the utility. This controls the size of the firm and also serves as a proxy for the output (or level of service) of an LDC. LEI expects that the more customers an LDC serve, the higher its total costs will be. This expectation will be verified by the econometric process.

It is standard practice to ensure that only differences in costs at the firm level (i.e., costs that are under the control of management) be attributed to the measure of greater or less efficiency. Therefore, other factors that impact the total costs need to be accounted for in the economic model. LEI hypothesized that a number of other independent variables could potentially impact the total costs for LDCs. Typically, variables such as type of pipeline material (proxied by percentage of pipe which is not cast iron or bare steel); age of the pipeline system; characterizations of the customer base; and exogenous changes over time (if the study covers a long period of time).<sup>8</sup>

Therefore, the other independent variables LEI included in the translog cost model were:

1. **Percentage of the net increase of miles of mains in the last ten years (referred to as “Z<sub>1</sub>” in Appendix A):** measures the relative age of the system. A new system is likely to have lower OM&A costs, holding all else constant, but also higher capital costs.

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<sup>7</sup> All price and cost data are in real 1998 dollars.

<sup>8</sup> As discussed in Section 3.1.2, the data LEI used for the econometric benchmarking covers four years (2014-2017). For this short time series, LEI did not deem it necessary to control for exogenous changes over time.

Therefore, on a total cost basis, it is not possible to predict the direction of the impact of this factor on the total cost before estimation with econometrics;

2. **Percentage of mains (measured initially in terms of miles) not made of cast iron or bare steel ("Z<sub>2</sub>" in Appendix A):** measures the material composition of the distribution system. A higher percentage of bare steel and cast iron will likely to be associated with higher OM&A costs. However, mains not made from cast iron or bare steel tend to be newer and therefore result in higher capital costs. Consequently, it is not possible to predict the direction of the impact of this factor on total costs before econometric estimation;
3. **Percentage of residential customers ("Z<sub>3</sub>" in Appendix A):** captures the customer profile (residential, commercial, or industrial) of each LDC. LEI expects that total costs will be higher with a higher share of residential customers. Residential customers of electric or gas service are typically more expensive to serve compared to commercial or industrial customers, because their demand varies more dramatically across the year (in other words, their "load factors" are low) so there is less gas consumption over which to spread the cost of infrastructure; and because each residential customer typically has a much lower demand for gas than a typical commercial or industrial customer, which also results in less gas consumption over which to spread the cost of infrastructure;<sup>9</sup>
4. **Population density (Regional "PPL\_Dens" in Appendix A):** defined as the number of people per square mile for each BEA U.S. region (Northeast, Midwest, South, and West). An LDC's total cost is likely to be impacted by the population density of its geographical location. However, the direction of such an impact cannot be predicted in advance because a company might need less pipeline per customer for delivering gas in a highly population-dense area, yet it might be faced with greater technical and regulatory challenges to building new infrastructure in such an area, which will increase the costs of doing business. Unlike all the other independent variables, this factor varies only by BEA region (Northeast, Midwest, South, and West) not by company; and
5. **Customer density ("Cus\_Dens" in Appendix A):** calculated as the number of customers an LDC serves divided by the total miles of mains that the LDC owns. Customer density is another factor that affects an LDC's total costs but is beyond the control of the company's management. The directional impact of customer density on the total cost cannot be predicted. Utilities serving areas with high customer density may require more investment in services. On the other hand, there may be synergies in operating costs if high customer density reflects the existence of many multi-customer buildings.

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<sup>9</sup> EIA. <https://www.eia.gov/energyexplained/electricity/prices-and-factors-affecting-prices.php>

## 3.2 Dataset used

LEI used a combination of cross-section and time-series data (referred to as “panel data”) that contains a time series of 4 years, from 2014-2017, and a cross-section of 82 LDCs. As noted previously, the sample of LDCs included is the same as what is included in LEI’s Industry TFP Study (with one exception)<sup>10</sup> and reflects the most complete dataset of firms for which the time series was long enough to develop a robust total cost of capital. Figure 4 below summarizes the data sources.

**Figure 4. Sources of data used in the LEI Total Cost Benchmarking Study**

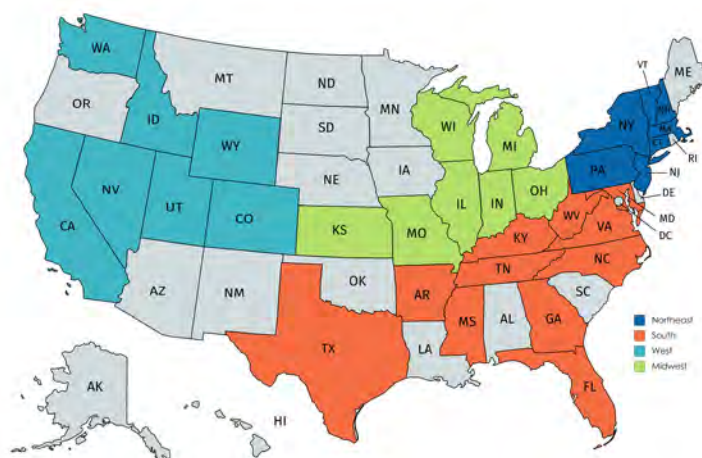
<i>Dependent variable</i>	
<b>Total Costs</b>	<b>Source</b>
Total costs = OM&A costs + Capital costs Where OM&A costs and Capital costs are calculated in LEI's Industry TFP study	FERC Form 2, LDC State Filing
<i>Independent variable</i>	
<b>Customers Served</b>	<b>Source</b>
<b>Total End User Natural Gas Customers</b> - Including Residential, Commercial, Industrial, Electric Power, Vehicle Fuel, and other natural gas customers - Including both Delivery only (LDC owns the gas) and Bundled customers (LDC does not own the gas)	EIA Form 176
<b>Share of Residential Customers</b> - Dividing the number of residential customers by total customers served	
<b>OM&amp;A Price</b>	<b>Source</b>
<b>Labor Price:</b> Compensation Rate and Employer Cost Index for Compensation by region for the Utilities sector	BLS
<b>Non-labor Price:</b> GDP-PI	BEA
<b>Capital Price</b>	<b>Source</b>
Investment tax credit	Internal Revenue Service
Corporate profits tax rate	Internal Revenue Service
Asset tax lifetime	MACRS Depreciation Table
Average service life	Calculated from a sample of utilities' depreciation reports
Rate of return for discounting depreciation deductions	Utilities' weighted average cost of capital ("WACC")
Inflation rate - GDPPI	BEA
Inflation rate - CPI	BLS
Average bond yield - US Treasury Yield Curve (30-Year)	SNL Financial
Moody's AAA average bond yields for US corporates	St. Louis Federal Reserve
PPI for Commodity - Construction Materials	BLS
<b>Length and Material Composition of Mains</b>	<b>Source</b>
Length of Mains by material	Pipeline and Hazardous Materials Safety Administration ("PHMSA")
<b>Population density</b>	<b>Source</b>
Calculated by total population in each BLS-defined region by the area of the corresponding region.	U.S. Census Bureau, World Population Review

\* Calculation of capital price, i.e., the implied rental price for capital, is explained in LEI’s Industry TFP Study, Section 3.2.3.

<sup>10</sup> One LDC was removed from the LEI Total Cost Benchmarking Study as compared to LEI’s Industry TFP Study: Avista Corporation did not have complete data for miles of mains, so it could not be examined in the benchmarking study.

These 82 LDCs are located in 31 states across the U.S., covering all four census regions (Northeast, Midwest, South, West) defined by BLS<sup>11</sup> (see Figure 5 and 6).

**Figure 5. States covered in LEI's Total Cost Benchmarking Study and Industry TFP Study**



**Figure 6. Gas utilities included in LEI's Total Cost Benchmarking Study**

Midwest	Northeast	South	West
Citizens Gas Fuel Company Columbia Gas of Ohio, Inc. Consumers Energy Company DTE Gas Company Eastern Natural Gas Company Illinois Gas Company Indiana Gas Company, Inc. Kansas Gas Service Company, Inc. Madison Gas and Electric Company Midwest Natural Gas Corporation Midwest Natural Gas, Inc. North Shore Gas Company Northern Illinois Gas Company Northern Indiana Public Service Company Northern States Power Company - WI Ohio Gas Company Ohio Valley Gas Corporation Peoples Gas Light and Coke Company Pike Natural Gas Co Southern Indiana Gas and Electric Company Spire Missouri Inc. Superior Water, Light and Power Company The East Ohio Gas Company Vectren Energy Delivery of Ohio, Inc. Wisconsin Gas LLC Wisconsin Power and Light Company	Bay State Gas Company Berkshire Gas Company Boston Gas Company Brooklyn Union Gas Company Central Hudson Gas & Electric Corporation Colonial Gas Company Columbia Gas of Pennsylvania, Inc. Connecticut Natural Gas Corporation Consolidated Edison Company of New York, Inc. Corning Natural Gas Corporation Fillmore Gas Company, Inc. KeySpan Gas East Corporation Liberty Utilities (EnergyNorth Natural Gas) Corp. National Fuel Gas Distribution Corporation New Jersey Natural Gas Company New York State Electric & Gas Corporation Niagara Mohawk Power Corporation NSTAR Gas Company Orange and Rockland Utilities, Inc. PECO Energy Company Philadelphia Gas Works Co. Pike County Light and Power Company South Jersey Gas Company Southern Connecticut Gas Company UGI Penn Natural Gas, Inc. UGI Utilities, Inc. Yankee Gas Services Company Public Service Electric and Gas Company Vermont Gas Systems, Inc.	Atlanta Gas Light Company Atmos Energy Company Baltimore Gas and Electric Company Black Hills Energy Arkansas, Inc. Bluefield Gas Company Columbia Gas of Kentucky, Incorporated Columbia Gas of Maryland, Incorporated Columbia Gas of Virginia, Incorporated Delta Natural Gas Company, Inc. Duke Energy Kentucky, Inc. Hope Gas, Inc. Louisville Gas and Electric Company Mountaineer Gas Company Peoples Gas System Public Service Company of North Carolina, Inc. St. Joe Natural Gas Co, Inc. Texas Gas Service Company, Inc. Virginia Natural Gas, Inc.	Cascade Natural Gas Corporation Cheyenne Light, Fuel and Power Company Pacific Gas and Electric Company Puget Sound Energy, Inc. Questar Gas Company San Diego Gas & Electric Company Sierra Pacific Power Company Southern California Gas Company Wyoming Gas Company

<sup>11</sup> The four regions are defined by BLS: [https://www.bls.gov/regions/southwest/news-release/employercostsforemployeeecompensation\\_regions.htm](https://www.bls.gov/regions/southwest/news-release/employercostsforemployeeecompensation_regions.htm)

Unlike the industry TFP analysis, which is used to establish the trend in productivity improvement over time, a benchmarking study must reflect the *current* efficiency of a firm relative to its peers. Therefore, LEI examined only the period of 2014-2017, rather than a longer time series.<sup>12</sup> LEI used four years of data, rather than only one, to ensure that results would not be overly influenced by events or issues that only impacted a single year. Also, four years of data provide more observations, which improves the rigor of the econometric analysis, and makes the results more reliable.

As noted previously, LEI included 82 LDCs in this Total Cost Benchmarking Study. When performing an econometrics analysis, it is not necessary to narrow down the list of peers based on size or business conditions of the Company, because the relevant factors are controlled for in the econometric process.

### 3.3 The econometric process

An efficient firm produces the maximum output for a given set of inputs; alternatively, it uses the lowest-cost set of inputs (i.e., the lowest total cost) to provide a given level of output.

Total costs depend on the size of the firm, so LEI accounted for the size of each of the firms. And, as discussed in the previous section, there are other independent variables that impact the total cost. This is where the econometrics process plays a significant role. The econometric process uses the economic model (in this case, the translog cost function) and the data, and estimates (based on a statistical process) the impact of each individual driver on the total cost.

For example, the orange line in Figure 7 illustrates a (simplified) econometric result.<sup>13</sup> It traces the average impact of the independent variable (number of customers, in the logarithmic form) on the dependent variable (total cost, in logarithmic form). The blue dots represent the data used in econometrics. Each individual dot represents the number of customers and the total cost for one LDC in the set of companies across a specific timeframe. The line slopes upward, indicating that firms with more customers tend to have higher total costs. This is often referred to as a positive relationship, whereas if the line sloped downward, it would indicate a negative relationship.

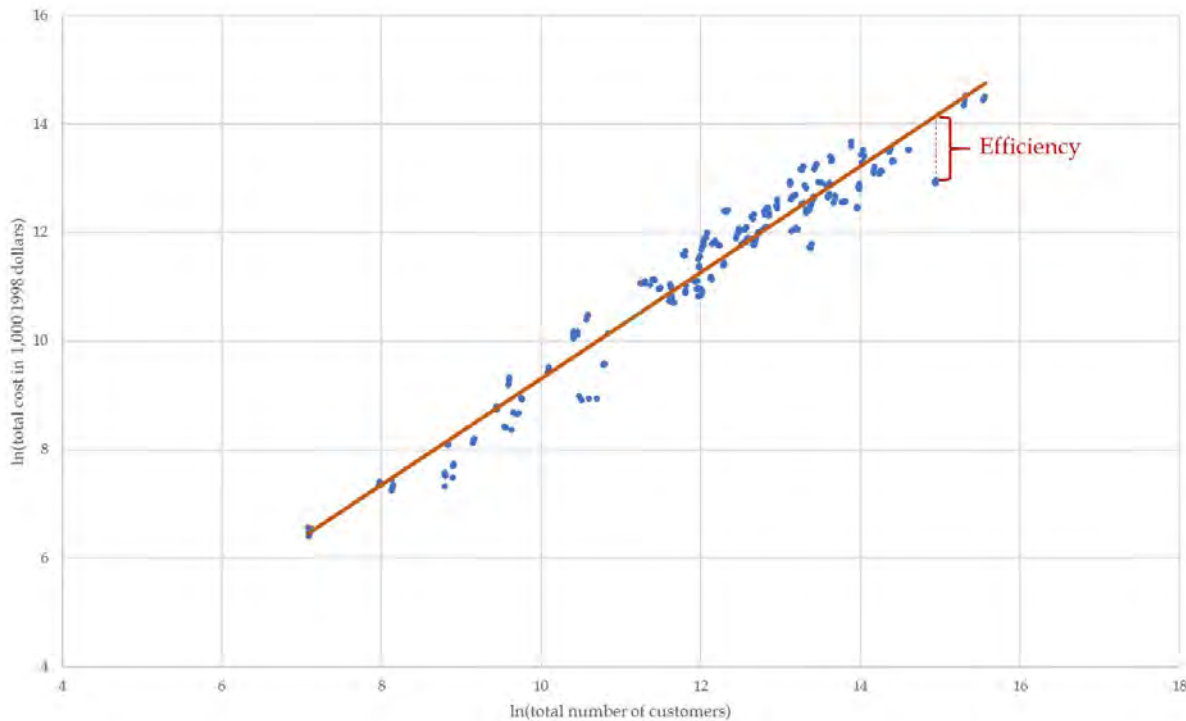
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<sup>12</sup> However, the capital cost component of total cost was derived from longer data series.

<sup>13</sup> Figure 7 is simply illustrative; it is not a result of the full translog cost model discussed in the previous section. It shows a very simplified model with only one independent variable, the number of customers, with the data points shown in logarithmic form.



**Figure 7. Illustrative and simplified example of the impact of number of customers on the total cost**



The orange line is generated by the econometrics. It is a prediction. It answers the following question: “given the number of customers, what is the expected (i.e., predicted) total cost for this company?” As can be seen in Figure 7, the orange line does not go through every point in the data – it is simply the line that fits the data set best. The part leftover (the vertical distance between the orange prediction and an individual data point) is known as a residual, which is assumed, in the econometric specification used here, to be fully representative of the efficiency difference between the average hypothetical firm and the individual observation.<sup>14</sup>

If a firm is below the orange line, its residual is negative, and it is more efficient than average, given the number of customers. If a firm is above the orange line, its residual is positive, which means it has a higher-than-predicted cost, so it is less efficient than average. Companies can then be ranked by how far their actual total cost is above or below the predicted costs. As noted previously, the companies with the lowest (i.e., most negative) difference from the predicted

<sup>14</sup> There are other approaches to estimating efficiency, which LEI considered but rejected as less accurate for this dataset – these are discussed in more detail in Appendix A.

value are the most efficient. Companies with the highest (most positive) difference from the predicted value are the least efficient.



## 4 Benchmarking results and implications

The ultimate purpose of benchmarking using econometrics is to be able to compare a company's actual cost to its predicted cost while accounting for factors which are outside of the control of management. LEI's cost benchmarking analysis indicates that the Company is relatively efficient, with actual costs below the predicted costs in three of the four years, based on the econometrics relationship.

To arrive at estimates of predicted values (such as the orange line in Figure 7 above), which are reliable, the econometric model must provide a good fit to the data. LEI's model has an overall high explanatory power and a good linear fit (see Appendix A for additional details).

The individual coefficient estimates of the model measure the size and direction of the impact of the independent variables on total cost (e.g., akin to the direction of the slope and the steepness of the orange line in Figure 7). The individual coefficient estimates are of less importance in the benchmarking than the overall fit of the model. This is because benchmarking does not require determining elasticities of substitution across inputs, for example, for which precise measurements of individual price impacts are needed. Nonetheless, LEI reports these individual price impacts and their statistical significance in Appendix A.

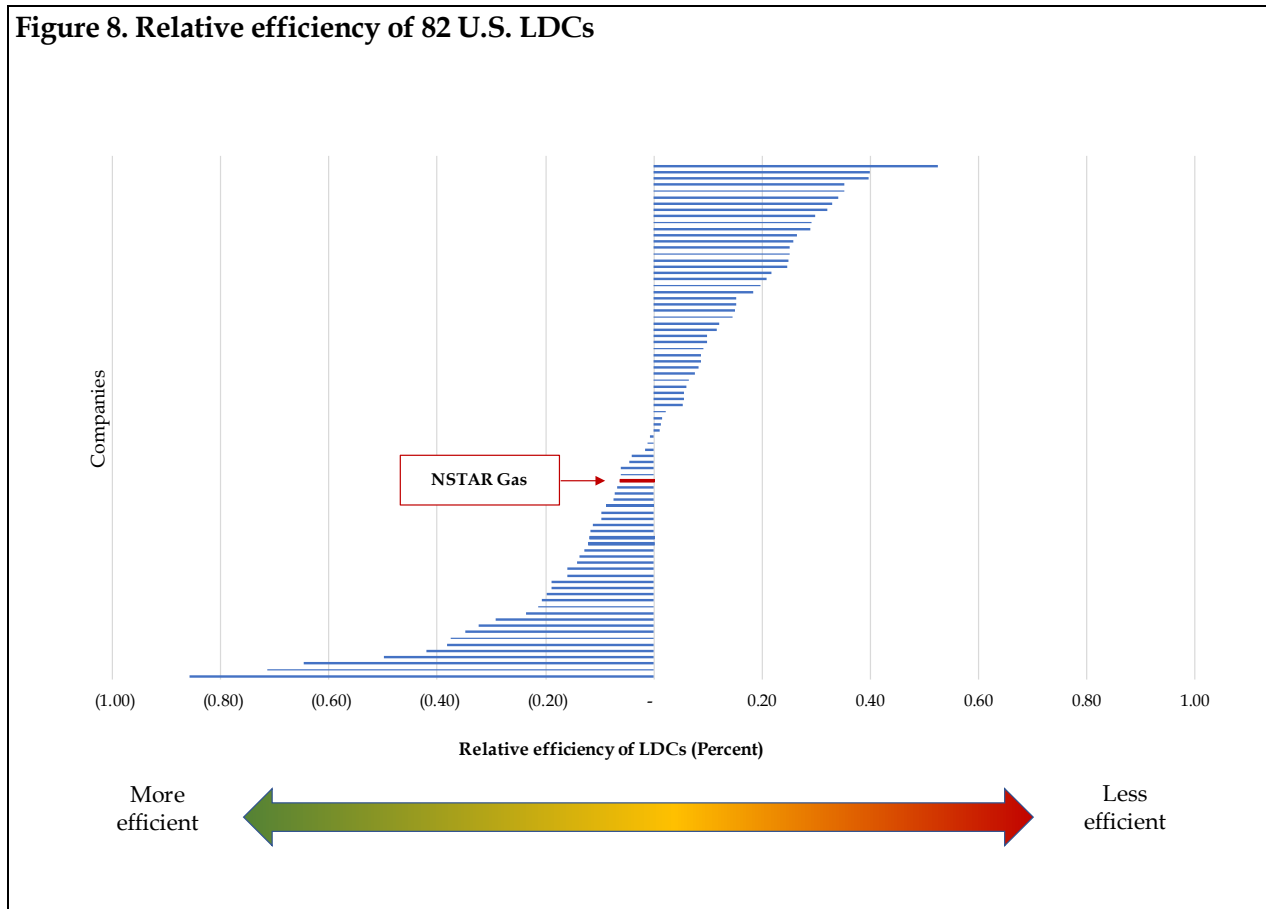
### 4.1 Key findings

The total cost benchmarking analysis indicates that the Company is relatively efficient. In three of the four years from 2014 to 2017, NSTAR Gas had actual total costs below those predicted by the econometric model, which indicates that the Company is more efficient than average. The methodology controls for the impact on the cost of firm size ( $Y_1$ ), input prices ( $W_1$  and  $W_2$ ), and other business conditions (the various  $Z$ s and regional population density) that are captured in the model (as discussed previously).

LEI also constructed a ranking based on the sign and size of the difference between actual cost and predicted costs for all LDCs examined (see Figure 11 on page 27 in Appendix B for the Company's ranking among U.S. LDCs and Figure 12 on page 29 in Appendix C for the Company's ranking among Northeast Regional LDCs). As noted previously, companies with the largest negative difference (i.e., average costs lower than predicted) are the most efficient; companies with the largest positive difference (actual costs greater than predicted) are the least efficient. Based on this ranking, the NSTAR Gas ranked top 10 among the Northeast Region LDCs (and in the second quartile of the U.S. LDCs). Figure 8 below illustrates the ranking of 82 U.S. LDCs by their relative efficiency determined by each company's average residuals over the 2014-2017 timeframe. The most efficient firm during 2014-2017 was almost 60% more efficient

than average; the least efficient was about 85% worse than average. This is fairly wide range, but such ranges are not uncommon for the results of efficiency studies.<sup>15</sup>

**Figure 8. Relative efficiency of 82 U.S. LDCs**



## 4.2 Implications of the ranking results

In three of the four years from 2014 through 2017, the Company had actual total costs that were lower than the predicted costs, indicating it is more efficient than average. The Company also ranked in the first quartile of the 29 LDCs in the Northeast Region. Given these conclusions, it is not necessary for the regulator to apply a stretch factor to motivate NSTAR Gas to “catch up”

<sup>15</sup> “Empirical Research in Support of Incentive Rate Setting in Ontario: Report to The Ontario Energy Board.” *Pacific Economics Group Research, LLC*. May 2013; “Statistical Research for Public Service Company of Colorado’s Multiyear Rate Plan.” *Pacific Economics Group Research, LLC*. May 2017.

to the industry average. The Company is already outperforming the majority of the companies in the Northeast Region and across the U.S.

## 5 Appendix A: Details of the Benchmarking Approach

### 5.1 Economic foundation of benchmarking analysis: Translog cost function

The basic translog cost function for one output (denoted  $Y_1$ ), two input prices (denoted  $W_1$  and  $W_2$ ) and one term ( $Z$ ) to account for a business condition such pipeline material type takes the form:<sup>16</sup>

$$\begin{aligned}\ln(\text{TC}) = & \alpha_0 + \alpha_1 \ln(W_1) + \alpha_2 \ln(W_2) + \alpha_{y1} \ln(Y_1) + \alpha_{z1} \ln(Z) \\ & + \frac{1}{2} \gamma_{11} [\ln(W_1)]^2 + \frac{1}{2} \gamma_{22} [\ln(W_2)]^2 + \gamma_{12} [\ln(W_1) * \ln(W_2)] \\ & + \frac{1}{2} \gamma_{y11} [\ln(Y_1)]^2 + \gamma_{y1w1} [\ln(Y_1) * \ln(W_1)] + \gamma_{y1w2} [\ln(Y_1) * \ln(W_2)] \\ & + \frac{1}{2} \gamma_{z1z1} [\ln(Z)]^2 + \gamma_{z1w1} [\ln(Z) * \ln(W_1)] + \gamma_{z1w2} [\ln(Z) * \ln(W_2)]\end{aligned}$$

Where:

- $\ln$  = the natural logarithm
- $\text{TC}$  = total cost
- $Y_1$  =  $Y_{\text{cust}}$  = output measured as number of customers
- $W_1$  =  $W_{\text{OM\&A}}$  = price of OM\&A (a combination of labor price and non-labor price)
- $W_2$  =  $W_{\text{cap}}$  = price of capital (implied rental price of capital)
- $Z$  = business condition (LEI's model includes more than one business condition. The equation above is for illustration purpose only)
- $\alpha, \gamma$  = coefficients to be estimated using econometrics.

If LEI defined the cost share of input  $i$  as  $S_i = W_i * X_i / \text{TC}$  (and  $X$ =the amount of the input) subject to cost-minimizing behavior, that share will always be equal to the first partial derivative of cost with respect to a change in the input price,  $W_i$ .

Using Shephard's lemma, the cost shares for the OM\&A input in the cost equation above can be derived as:

$$\begin{aligned}S_1 &= \partial \ln(\text{TC}) / \partial \ln(W_1) \\ S_1 &= \alpha_1 + \gamma_{11} \ln(W_1) + \gamma_{12} \ln(W_2) + \gamma_{y1w1} \ln(Y_1) + \gamma_{z1w1} \ln(Z)\end{aligned}$$

---

<sup>16</sup> The translog cost function requires interacting the price variables ( $W_1$  and  $W_2$ ) with the output variables ( $Y_1$ ) and other variables, so that  $Y_1$  will appear in the share equations. Otherwise the functional form loses its flexibility and one is by default assuming constant elasticities of substitution or some other restrictive form.

Similarly, for the capital input:

$$S_2 = \partial \ln(TC) / \partial \ln(W_2)$$
$$S_2 = \alpha_2 + \gamma_{22} \ln(W_2) + \gamma_{12} \ln(W_1) + \gamma_{y2w2} \ln(Y_1) + \gamma_{z1w2} \ln(Z).$$

## 5.2 The econometric process

To estimate the translog function using econometrics, an error term,  $\xi$ , is added to the total cost and share equations. The independent variables and dependent variable are logged and normalized to be suitable for use in the translog cost function model.

To ensure that theoretical requirements for the translog are met, LEI imposed the following constraints on the coefficients, before performing the econometric process:

- $\sum \alpha_i = 1$  (i.e., the sum of the first-order coefficients on price regressors = 1);
- $\sum \gamma_{ij} = 0$  (i.e., the sum of the second-order coefficients on the cross-price regressors = 0 when summed over  $i$  and when summed over  $j$ );
- $\sum \gamma_{iy} = 0$  (i.e., the sum of the coefficients on the second-order price-output regressors = 0 when summed over output  $y$ ); and
- Symmetry of the second-order coefficients requires  $\gamma_{ij} = \gamma_{ji}$ .

These constraints amount to eliminating one of the share equations for the purposes of the econometric process. The econometric process entailed estimating the cost function and one share equation simultaneously.

LEI used the econometric process known as “iterative seemingly unrelated regression” to estimate the model. All work was performed in Stata. This technique enables more precise estimates of the coefficients than the estimation of each equation separately.

## 5.3 Econometric results

### 5.3.1 Overall explanatory power of the model is significant

The overall explanatory power of the model is reflected in its F-statistic. In general, an F-statistic is a ratio of two quantities that are expected to be roughly equal under the null hypothesis (i.e., if the model explains none of the variations of the dependent variable). In that case, the calculation produces an F-statistic of approximately one (1). The further away from 1, the more the model explains. The F-statistic of LEI’s model is 1025.35 (see Figure 9). The F-statistic required for 99% confidence for a model with 328 observations and 19 parameters is

about 1.9; the F-statistic is much higher, indicating that LEI can be more than 95% confident that the model as a whole explains total cost very well.

**Figure 9. Overall explanatory power of the model**

Equation	Observation	Parameters	R-sq	F-Stat	P
lnTC	328	19	0.98	1025.35	0.000
S1	328	5	0.28	25.89	0.000

### 5.3.2 Linear fit of the model is good

The coefficient of correlation (“R<sup>2</sup>”) measures the dispersion of the data around the line-of-best-fit. The R<sup>2</sup> value for any line-of-best-fit will range from 1 (if all the data points are exactly on the line-of-best-fit, i.e., a perfect correlation) to as low as 0 (if the data are so dispersed, noisy, or have an intrinsically non-linear relationship to the dependent variable). An R<sup>2</sup> of 0 implies that there is no correlation that can be explained by the line-of-best-fit. Keep in mind that the R<sup>2</sup> statistic does not measure the relationship between the dependent variable and independent variables. It simply measures the dispersion of the data around the line-of-best-fit.

The R<sup>2</sup> for LEI’s model is very high, at 0.98 (see Figure 9). The high R<sup>2</sup> is the result of including the output variable Y<sub>1</sub> in the model. LEI tested an alternative model in which Y<sub>1</sub> was omitted, and the R<sup>2</sup> fell substantially. Of course, the output is a crucial driver of the total cost, so such an independent variable obviously belongs in a total cost analysis.

LEI conducted other tests of model statistical and theoretical performance, and the results of these tests indicated that the model was properly formulated.

### 5.3.3 Coefficient estimates and their individual statistical significance

The individual coefficient estimates are of less importance in benchmarking than the overall fit of the model. This is because LEI is not attempting to determine elasticities of substitution across inputs, for example, for which precise measurements of individual price impacts are needed. However, as a matter of record, LEI reports the individual coefficient estimates and their statistical significance (see Figure 10). The regressors with probability value (“p-value”) of 0.05 or less are statistically significant at a 95% or higher confidence level. This means one can be at least 95% confident that the coefficient estimate (for example, the 1.38 for lnY<sub>1</sub> in Figure 10) is accurate and not the result of random sampling error or statistical noise.

The coefficient estimates measure the impact of each regressor on the dependent variable (total cost). Because the regression is conducted with logged and normalized data, the meaning and

units of these estimates are not intuitive. These coefficients can be combined algebraically to arrive at elasticities of substitution, but that is beyond the scope of a benchmarking analysis such as this. LEI does, however, comment on the signs of the coefficients, and whether or not they are statistically significant. Several explanatory variables were not statistically significant, but LEI did not remove them from the regression model. This is because, in a panel dataset such as the one used in this study, sometimes there is not enough variation in an independent variable to generate a statistically significant coefficient estimate. Therefore, for the purposes of ranking, there is not enough differentiation across firms. However, such an outcome does not mean the variable should be removed from the model - it could still be an important driver of cost for an individual firm. Given that, LEI retained several explanatory variables in the model, which were not statistically significant. The coefficient estimates for all the variables were:

- **$W_1$  is the price of OM&A inputs (labor and materials).** It is negative and not statistically significant at the 95% level;
- **$W_2$  is the implied rental price of capital.** It is positive and not statistically significant at the 95% level<sup>17</sup>;
- **$Y_1$  is the total number of customers who have their gas delivered using the LDC's system.** It has a positive coefficient, meaning the more customers a utility has, the higher its total cost will be. It is statistically significant at the 95% level;
- **$Z_1$  is the percentage of the net increase in miles of mains in the past ten years.** This is an indicator of the age of the LDC system. The coefficient on  $Z_1$  is positive but not statistically significant.  $Z_1$  probably has opposite effects on OM&A costs versus capital costs (a newer pipeline system may have lower OM&A costs, but may have higher capital costs, as noted in other LDC benchmarking studies)<sup>18</sup>;
- **$Z_2$  is the percentage of mains which are not bare steel or cast iron.** This coefficient has a negative sign but is not statistically significant.  $Z_2$  probably has an ambiguous effect on the utility's total costs, as a utility with a higher percentage of non-bare-steel and non-cast-iron mains may have lower OM&A costs but have invested more in the capital for upgrading the system, and thus have a higher capital cost;

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<sup>17</sup> Note that economic theory requires the sum of the coefficients for  $W_1$  and  $W_2$  to equal 1, as imposed by the constraints shown previously.

<sup>18</sup> "Statistical Research for Public Service Company of Colorado's Multiyear Rate Plan." Pg. 24. Pacific Economics Group Research, LLC. May 31, 2017.

- **$Z_3$  is the percentage of residential customers.**  $Z_3$  has a positive coefficient (indicating the impact on cost is potentially large) but is not statistically significant because it does not vary much across the companies;
- **InPPL\_Dens is regional-level population density.** It is standard practice to ensure that only differences in costs at the firm level are attributed to greater or less efficiency. Therefore, other impacts on costs need to be controlled. LEI tested several variables across regions (Northeast, Midwest, South, and West) of the country, including weather (heating degree days), and population density to examine whether an LDC's location in the country had an impact on cost. The population density variable best-captured differences across the regions. This variable could have ambiguous directional impacts on the total costs for LDCs. On the one hand, it can reflect the difficulty of building energy infrastructure in densely populated areas, which in turn may make it harder to get infrastructure projects completed. Projects can take longer and need more permits, which increase costs, but such an impact is not captured in the price of capital or price of OM&A. On the other hand, delivering gas in a highly-populated area requires less infrastructure per customer, which may imply lower costs for LDCs. The results of the econometrics indicate that the cost-increasing effect dominates because the sign of the coefficient is positive and statistically significant at the 95% level.
- **InCus\_Dens is the customer density of a utility's service territory.** The coefficient of this variable is positive and statistically significant at the 95% level, meaning a utility that has a higher customer density tends to have higher costs.



**Figure 10. Coefficient estimates for total cost function and statistical significance**

lnTC	Coef.	Std. Err.	t	P>t	[95% Conf. Interval]	
lnW1	-0.91	1.17	-0.77	0.44	-3.21	1.40
lnW2	1.91	1.17	1.62	0.11	-0.40	4.21
lnY1	1.38	0.10	13.65	0.00	1.18	1.58
lnZ1	1.26	1.68	0.75	0.45	-2.04	4.56
lnZ2	-4.65	13.15	-0.35	0.72	-30.47	21.17
lnZ3	5.24	16.14	0.32	0.75	-26.45	36.93
lnW1W1	0.21	0.40	0.53	0.60	-0.57	1.00
lnW2W2	0.21	0.40	0.53	0.60	-0.57	1.00
lnW1W2	-0.21	0.40	-0.53	0.60	-1.00	0.57
lnY1Y1	-0.01	0.00	-1.80	0.07	-0.02	0.00
lnY1W1	-0.09	0.01	-9.74	0.00	-0.11	-0.07
lnY1W2	0.09	0.01	9.74	0.00	0.07	0.11
lnZ1Z1	-0.01	0.01	-1.36	0.18	-0.03	0.01
lnZ1W1	-0.03	0.02	-1.57	0.12	-0.06	0.01
lnZ1W2	0.52	0.74	0.69	0.49	-0.95	1.98
lnZ2Z2	-0.58	0.51	-1.12	0.26	-1.58	0.43
lnZ2W1	-0.55	0.10	-5.49	0.00	-0.74	-0.35
lnZ2W2	-2.64	5.93	-0.45	0.66	-14.29	9.01
lnZ3Z3	2.07	5.18	0.40	0.69	-8.09	12.24
lnZ3W1	2.03	0.44	4.66	0.00	1.18	2.89
lnZ3W2	5.05	6.54	0.77	0.44	-7.78	17.89
lnPPL_Dens	0.21	0.02	8.29	0.00	0.16	0.26
lnCus_Dens	0.14	0.05	2.94	0.00	0.05	0.24
_cons	6.00	4.82	1.25	0.21	-3.46	15.47

#### 5.3.4 Alternative econometric approaches considered

In the approach used by LEI, there is a stochastic component in the residual (think of it as random noise) as well as an efficiency component. LEI assumes that the random noise component impacts each firm equally so that it can be ignored for purposes of benchmarking firms.

There are other approaches to measuring efficiency using econometrics. LEI considered them, but each had drawbacks:

1. **Corrected ordinary least squares ("COLS")** is a partly deterministic and partly statistical technique which identifies a cost frontier (rather than an average cost function) by identifying the observation (a single firm, in a single year) with the maximum negative residual in a cost function regression and using that residual to shift the whole cost function. The implicit assumption is that all observed deviations from the frontier are due to firm inefficiency. However, this technique ignores random noise or measurement error and can be unduly influenced by outliers.
2. **Stochastic frontier analysis ("SFA")** allows estimation of a cost function directly with two components in the residual, one for random noise, and the other for efficiency. SFA is only reliable in a large sample, i.e., as  $t$  (the time series feature of the panel) approaches a very large number of years. As LEI used only four years of data (to capture recent cost efficiency), this approach was not appropriate.
3. **Fixed-effects ("FE") estimation** includes a dummy variable which allows intercept terms to be estimated for each firm. These firm-specific intercepts are interpreted as differences in efficiency. However, FE results are sometimes dependent on the size of the firm (even in a cost function which controls for firm size) so that a larger firm will necessarily appear more inefficient than a smaller one. For this reason, LEI decided this approach was not appropriate.
4. **Random-effects ("RE") estimation** is similar to FE but allows the firm-specific effect to be a random variable rather than a fixed coefficient. This has the same drawback as the FE approach; it also requires a long time series for reliable results. Consequently, LEI decided to not use this approach.

With the above considerations, LEI used the approach by which relative firm efficiency was estimated using the residuals of the translog cost function. LEI tested whether the residuals were correlated with the size of the firm. They were not, which implies that the residuals provide a comparison across firms which does not disadvantage large firms.

## 6 Appendix B: Full list of efficiency rankings for 82 LDCs in the U.S.

**Figure 11. LEI's ranking of 82 U.S. LDCs (average of ranking 2014-2017)**

Company	State	Region	Number of Customers (2017)	Rankings in the U.S.	
				Average	
				Ranking	Quartile
Atmos Energy Corporation	TX	SO	3,126,009	1	1
Texas Gas Service Company, Inc.	TX	SO	656,470	2	1
Cheyenne Light, Fuel and Power Company	WY	WE	36,754	3	1
Public Service Electric and Gas Company	NJ	NE	1,832,201	4	1
Black Hills Energy Arkansas, Inc.	AR	SO	166,734	5	1
Pike Natural Gas Co	OH	MW	7,370	6	1
Eastern Natural Gas Company	OH	MW	6,601	7	1
Midwest Natural Gas Corporation	IN	MW	15,351	8	1
Ohio Gas Company	OH	MW	49,432	9	1
Mountaineer Gas Company	WV	SO	216,598	10	1
Columbia Gas of Kentucky, Incorporated	KY	SO	135,734	11	1
Wisconsin Power and Light Company	WI	MW	188,117	12	1
Midwest Natural Gas, Inc.	WI	MW	16,685	13	1
Spire Missouri Inc.	MO	MW	1,164,174	14	1
Brooklyn Union Gas Company	NY	NE	1,249,659	15	1
Public Service Company of North Carolina, Incorporated	NC	SO	552,993	16	1
Pike County Light and Power Company	PA	NE	1,215	17	1
Consolidated Edison Company of New York, Inc.	NY	NE	1,077,472	18	1
Illinois Gas Company	IL	MW	9,462	19	1
Bluefield Gas Company	WV	SO	3,386	20	1
Northern States Power Company - WI	WI	MW	113,793	21	2
Baltimore Gas and Electric Company	MD	SO	673,937	22	2
Louisville Gas and Electric Company	KY	SO	324,488	23	2
Northern Illinois Gas Company	IL	MW	2,217,017	24	2
The East Ohio Gas Company	OH	MW	1,186,786	25	2
Madison Gas and Electric Company	WI	MW	156,577	26	2
Vermont Gas Systems, Inc.	VT	NE	51,027	27	2
San Diego Gas & Electric Company	CA	WE	880,387	28	2
Kansas Gas Service Company, Inc.	KS	MW	638,049	29	2
Wisconsin Gas LLC	WI	MW	626,570	30	2
<b>NSTAR Gas Company</b>	<b>MA</b>	<b>NE</b>	<b>291,213</b>	<b>31</b>	<b>2</b>
UGI Utilities, Inc.	PA	NE	384,728	32	2
Sierra Pacific Power Company	NV	WE	163,591	33	2
Atlanta Gas Light Company	GA	SO	1,577,838	34	2
PECO Energy Company	PA	NE	519,473	35	2
National Fuel Gas Distribution Corporation	NY	NE	744,885	36	2
Columbia Gas of Ohio, Inc.	OH	MW	1,439,462	37	2
Southern Indiana Gas and Electric Company	IN	MW	113,445	38	2
New Jersey Natural Gas Company	NJ	NE	534,425	39	2
Southern Connecticut Gas Company	CT	NE	196,147	40	2
Columbia Gas of Pennsylvania, Inc.	PA	NE	426,527	41	2

Company	State	Region	Number of Customers (2017)	Rankings in the U.S.	
				Average	
				Ranking	Quartile
Northern Indiana Public Service Company	IN	MW	820,527	42	3
Questar Gas Company	UT	WE	990,924	43	3
Colonial Gas Company	MA	NE	207,713	44	3
South Jersey Gas Company	NJ	NE	380,764	45	3
Fillmore Gas Company, Inc.	NY	NE	1,245	46	3
Virginia Natural Gas, Inc.	VA	SO	296,062	47	3
Hope Gas, Inc.	WV	SO	111,607	48	3
Liberty Utilities (EnergyNorth Natural Gas) Corp.	NH	NE	91,615	49	3
Corning Natural Gas Corporation	NY	NE	14,778	50	3
Niagara Mohawk Power Corporation	NY	NE	614,718	51	3
Superior Water, Light and Power Company	WI	MW	12,724	52	3
Southern California Gas Company	CA	WE	5,744,043	53	3
Bay State Gas Company	MA	NE	317,651	54	3
Vectren Energy Delivery of Ohio, Inc.	OH	MW	318,054	55	3
New York State Electric & Gas Corporation	NY	NE	266,345	56	3
Citizens Gas Fuel Company	MI	MW	17,476	57	3
Peoples Gas System	FL	SO	373,672	58	3
Indiana Gas Company, Inc.	IN	MW	592,618	59	3
Central Hudson Gas & Electric Corporation	NY	NE	81,143	60	3
Duke Energy Kentucky, Inc.	KY	SO	98,448	61	3
Consumers Energy Company	MI	MW	1,760,212	62	4
Ohio Valley Gas Corporation	IN	MW	24,239	63	4
Boston Gas Company	MA	NE	700,052	64	4
UGI Penn Natural Gas, Inc.	PA	NE	170,797	65	4
DTE Gas Company	MI	MW	1,253,989	66	4
Berkshire Gas Company	MA	NE	39,960	67	4
Columbia Gas of Virginia, Incorporated	VA	SO	265,534	68	4
Philadelphia Gas Works Co.	PA	NE	503,607	69	4
Orange and Rockland Utilities, Inc.	NY	NE	135,078	70	4
Wyoming Gas Company	WY	WE	6,879	71	4
North Shore Gas Company	IL	MW	160,128	72	4
Connecticut Natural Gas Corporation	CT	NE	176,851	73	4
St. Joe Natural Gas Co, Inc.	FL	SO	2,993	74	4
Columbia Gas of Maryland, Incorporated	MD	SO	33,267	75	4
Pacific Gas and Electric Company	CA	WE	4,494,485	76	4
Cascade Natural Gas Corporation	WA	WE	283,471	77	4
KeySpan Gas East Corporation	NY	NE	593,036	78	4
Peoples Gas Light and Coke Company	IL	MW	846,670	79	4
Puget Sound Energy, Inc.	WA	WE	820,624	80	4
Delta Natural Gas Company, Inc.	KY	SO	34,892	81	4
Yankee Gas Services Company	CT	NE	230,058	82	4

\* The four regions (Northeast – NE, Midwest – MW, South – SO, West – WE) are defined by BLS:

[https://www.bls.gov/regions/southwest/news-release/employercostsforemployeecompensation\\_regions.htm](https://www.bls.gov/regions/southwest/news-release/employercostsforemployeecompensation_regions.htm)

\* The 82 LDCs included in LEI's Total Cost Benchmarking Study are the same as the LDCs included in LEI's Industry TFP Study, except for Avista Corporation, which was taken out due to lack of pipeline data.

\*Note: The *average* ranking reflects the ranking of each firm's average ranking over the entire timeframe among the 82 U.S. LDCs. It is not the simple average of each firm's ranking in each year.

## 7 Appendix C: Full list of efficiency rankings for 29 LDCs in the Northeast Region

**Figure 12. LEI's ranking of 29 LDCs in the Northeast Region (average ranking of 2014-2017)**

Company	State	Number of Customers (2017)	Rankings in the Northeast	
			Average	
			Ranking	Quartile
Public Service Electric and Gas Company	NJ	1,832,201	1	1
Brooklyn Union Gas Company	NY	1,249,659	2	1
Pike County Light and Power Company	PA	1,215	3	1
Consolidated Edison Company of New York, Inc.	NY	1,077,472	4	1
Vermont Gas Systems, Inc.	VT	51,027	5	1
<b>NSTAR Gas Company</b>	<b>MA</b>	<b>291,213</b>	<b>6</b>	<b>1</b>
UGI Utilities, Inc.	PA	384,728	7	1
PECO Energy Company	PA	519,473	8	2
National Fuel Gas Distribution Corporation	NY	744,885	9	2
New Jersey Natural Gas Company	NJ	534,425	10	2
Southern Connecticut Gas Company	CT	196,147	11	2
Columbia Gas of Pennsylvania, Inc.	PA	426,527	12	2
Colonial Gas Company	MA	207,713	13	2
South Jersey Gas Company	NJ	380,764	14	2
Fillmore Gas Company, Inc.	NY	1,245	15	3
Liberty Utilities (EnergyNorth Natural Gas) Corp.	NH	91,615	16	3
Corning Natural Gas Corporation	NY	14,778	17	3
Niagara Mohawk Power Corporation	NY	614,718	18	3
Bay State Gas Company	MA	317,651	19	3
New York State Electric & Gas Corporation	NY	266,345	20	3
Central Hudson Gas & Electric Corporation	NY	81,143	21	3
Boston Gas Company	MA	700,052	22	4
UGI Penn Natural Gas, Inc.	PA	170,797	23	4
Berkshire Gas Company	MA	39,960	24	4
Philadelphia Gas Works Co.	PA	503,607	25	4
Orange and Rockland Utilities, Inc.	NY	135,078	26	4
Connecticut Natural Gas Corporation	CT	176,851	27	4
KeySpan Gas East Corporation	NY	593,036	28	4
Yankee Gas Services Company	CT	230,058	29	4

\*The Northeast Region is defined by U.S. BLS as consisting of Connecticut, Maine, Massachusetts, New Hampshire, Pennsylvania, and New Jersey, New York, Rhode Island, and Vermont.

[https://www.bls.gov/regions/southwest/news-release/employercostsforemployeecompensation\\_regions.htm](https://www.bls.gov/regions/southwest/news-release/employercostsforemployeecompensation_regions.htm)

\*Note: The *average* ranking reflects the ranking of each firm's average ranking over the entire timeframe among the 29 LDCs in the Northeast Region. It is not the simple average of each firm's ranking in each year.

## 8 Appendix D: LEI team's qualification for the Total Cost Benchmarking Study

LEI has advised on rate design and regulation in the natural gas and electricity industries, for both public and private clients worldwide and has extensive knowledge of the natural gas and electricity sector in New England. Moreover, LEI has performed a broad range of regulatory services for various utilities around the world, including providing regulatory support pertaining to rate cases, TFP studies, benchmarking, and design of service quality indicators over the last two decades. LEI team's project experience related to performing benchmarking studies include:

- ***Prepared a presentation regarding benchmarking in the distribution business:*** In this instance, LEI was retained by an industry advocacy group in the electricity industry to provide a presentation on the benchmarking regimes in the electricity industry, which included theory, application, and case studies.
- ***Performed corporate costs benchmarking for Ontario Power Generation ("OPG"):*** LEI performed an independent benchmarking assessment of OPG's corporate support costs. In addition to the independent benchmarking analysis, LEI supported OPG through the rate application process, in the preparation of evidence, and provision of expert testimony, supporting OPG in attaining its reasonable costs for the provision of corporate support services.
- ***Performed a benchmarking analysis for a major Australian investment bank:*** LEI was retained by a major Australian Investment bank to research embedded costs for electric distribution companies, which included benchmark analysis for Emera, Hydro One, and National Grid.
- ***Corporate costs benchmarking:*** LEI performed an independent benchmarking assessment of a large Canadian generator's corporate support costs. In addition to the independent benchmarking analysis, supported the utility through its rate application process, in particular in the preparation of evidence, and provision of expert testimony, supporting it in attaining its reasonable costs for the provision of corporate support services.
- ***Proposed a benchmarking method to arrive at a reasonable return margin for the Regulated Rate Option service providers:*** LEI provided an expert opinion regarding an appropriate return margin for the Regulated Rate Option service providers ("RSP"), which was filed with the Alberta Utilities Commission as evidence in the proceeding to review the RSPs' current energy price-setting plans ("EPSP"). LEI concluded that a reasonable return margin could be established using a benchmarking method and that

competitive electricity retailers in Alberta were the most appropriate peer set against which to benchmark RRO returns. LEI recommended a comprehensive return margin, expressed in \$/MWh, calculated using the average competitive retailer markup as a base and adjusting for customer acquisition costs.

- ***Utilizing benchmarking analysis for the cost of capital and capital structure analysis:*** LEI advised Jordan's power regulator on the weighted average cost of capital and optimal capital structure for the country's three distribution companies: EDCO, IDECO, and JEPSCO. LEI's work included identifying salient risk factors for the distribution companies, identifying appropriate local and international metrics and benchmarks, developing a usable cost of the capital model, and providing training workshops for local staff. The recommended optimal capital structure was consistent with targeted debt service and interest coverage ratios in line with the rating methodology for distribution companies from the global credit rating agencies.

Dr. Marie Fagan, who led this econometrics-based benchmarking study, is Managing Consultant and Lead Economist at LEI. With over 25 years of experience in research and consulting for the energy sector, Marie's career has spanned international upstream and downstream oil and gas, global coal, North American gas markets, and North American power markets. Marie has experience as a project manager for complex, multi-year engagements, and has deep experience in econometric analysis.

Some of Marie's relevant project experience includes:

- ***Independent research into the role of Enbridge Line 5 in NGL and crude oil transport in Michigan:*** For a non-governmental organization, Marie produced three white papers examining the current and future role of Enbridge Line 5 in Michigan related to three issues: propane supply in Michigan, transportation for crude oil producers in Michigan, and supply of crude oil to Michigan-area refineries. Marie's analysis of the propane market included a comparative static econometric analysis of the supply and demand for propane in Michigan, explained in non-technical language. The white papers were used by the client in discussions with the Governor of Michigan and other stakeholders.
- ***Econometric analysis of crude oil price and income elasticities of demand for Columbia University, Center for Global Energy Policy ("CGEP"):*** Marie directed and managed the project, the foundation of which was a detailed econometric analysis of price and income elasticities of oil demand. Marie employed a variety of specifications of econometric models (including static and dynamic models, and symmetric and asymmetric models) and estimated separate models for crude oil, gasoline, and diesel demand. She used country-level data covering 40 years (1977-2016), aggregated into the panel (cross-section and time-series) datasets for OECD, non-OECD, and oil-producing countries. Marie examined and reported the results of econometric tests covering time-

series properties of the data (tests for integration and cointegration), the performance of the logarithmic model specification as compared to an intrinsically non-linear specification, and the pool-ability of cross-sectional data. LEI's results were provided in a comprehensive report titled "Oil demand: Up the down staircase," which underwent academic review outside of CGEP. The report will be published by CGEP.

- *Performed a critical review of the methodology and assumptions which underpinned other consultants' analysis of avoided energy supply costs ("AESc"):* Marie led a careful examination of the economic theory and econometric techniques used by the other consultants to estimate demand-induced price reduction effects ("DRIPE").