REDACTED

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 21-XXX

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Winter 2021/2022 Cost of Gas
Summer 2022 Cost of Gas

DIRECT TESTIMONY

OF

DAVID B. SIMEK

AND

CATHERINE A. MCNAMARA

September 1, 2021

Liberty™

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I. INTRODUCTION

Q. Please state your full name and business address.

A. (DS) My name is David B. Simek. My business address is 15 Buttrick Road, Londonderry, New Hampshire.

(CM) My name is Catherine A. McNamara. My business address is 15 Buttrick Road, Londonderry, New Hampshire.

Q. Please state by whom you are employed.

A. We are employed by Liberty Utilities Service Corp. ("LUSC"), which provides service to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty ("EnergyNorth" or "the Company").

Q. Please describe your educational background and your business and professional experience.

A. (DS) I graduated from Ferris State University in 1993 with a Bachelor of Science in Finance. I received a Master's of Science in Finance from Walsh College in 2000. I also received a Master's of Business Administration from Walsh College in 2001. In 2006, I earned a Graduate Certificate in Power Systems Management from Worcester Polytechnic Institute. In August 2013, I joined LUSC as a Utility Analyst and I was promoted to Manager, Rates and Regulatory Affairs in August 2017. Prior to my employment at LUSC, I was employed by NSTAR Electric & Gas ("NSTAR") as a Senior Analyst in Energy Supply from 2008 to 2012. Prior to my position in Energy

Supply at NSTAR, I was a Senior Financial Analyst within the NSTAR Investment Planning group from 2004 to 2008.

(CM) I graduated from the University of Massachusetts, Boston, in 1993 with a Bachelor of Science in Management with a concentration in Accounting. In November 2017, I joined Liberty as an Analyst in Rates and Regulatory Affairs. Prior to my employment at LUSC, I was employed by Eversource as a Senior Analyst in the Investment Planning group from 2015 to 2017. From 2008 to 2015, I was a Supervisor in the Plant Accounting department. Prior to my position in Plant Accounting, I was a Financial Analyst/General Ledger System Administrator within the Accounting group from 2000 to 2008.

Q. Have you previously testified in regulatory proceedings before the New Hampshire Public Utilities Commission (the "Commission")?

A. (DS) Yes. I have testified on numerous occasions before the Commission.

(CM) Yes. I have testified on multiple occasions before the Commission.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to explain the Company's proposed firm sales cost of gas rates for the 2021/2022 Winter (Peak) Period and the Company's proposed 2021/2022 Local Delivery Adjustment Clause, both effective November 1, 2021. Our testimony also explains the Company's proposed firm sales cost of gas rates for the 2022 Summer (Off-Peak) Period.

II. WINTER 2021/2022 COST OF GAS FACTOR

Q. What are the proposed firm Winter sales and firm transportation cost of gas rates?

A. The Company proposes a firm sales cost of gas rate of $0.9056 per therm for residential customers, $0.9058 per therm for commercial/industrial high winter use customers, and $0.9041 per therm for commercial/industrial low winter use customers as shown on Proposed First Revised Page 95 (Bates 056). The Company proposes a firm transportation cost of gas rate of $0.0001 per therm as shown on Proposed First Revised Page 98 (Bates 058).

Q. Please explain tariff page and Proposed First Revised Page 95 (Bates 056).

A. Proposed First Revised Page 95 contains the calculation of the 2021/2022 Winter Period Cost of Gas Rate and summarize the Company's forecast of firm gas costs and firm gas sales. As shown on Page 95, the proposed 2021/2022 Average Cost of Gas of $0.9056 per therm is derived by adding the Direct Cost of Gas Rate of $0.8557 per therm to the Indirect Cost of Gas Rate of $0.0499 per therm. The estimated total Anticipated Direct Cost of Gas, derived on Page 95, is $74,822,730. The estimated Indirect Cost of Gas, also derived on Page 95, is $4,360,293. The Direct Cost of Gas Rate of $0.8665 and the Indirect Cost of Gas Rate of $0.0499 are determined by dividing each of these total cost figures by the projected winter period firm sales volumes of 87,443,741 therms.

To calculate the total Anticipated Direct Cost of Gas, the Company adds a list of allowable adjustments from deferred gas cost accounts to the projected demand and commodity costs for the winter period supply portfolio. These allowable adjustments, shown on Page 96, total $142,353. These adjustments are added to the Unadjusted

Anticipated Cost of Gas of $74,680,377 to determine the Total Anticipated Direct Cost of Gas of $74,822,730.

Q. What are the components of the Unadjusted Anticipated Cost of Gas?

A. The Unadjusted Anticipated Cost of Gas shown on Proposed Original Page 96 consists of the following components:

1.	Purchased Gas Demand Costs	$12,877,649
2.	Purchased Gas Commodity Costs	53,247,154
3.	Storage Demand and Capacity Costs	981,898
4.	Storage Commodity Costs	5,358,244
5.	Produced Gas Cost	2,215,433
	Total	**$74,680,377

**Slightly off due to rounding

Q. What are the components of the allowable adjustments to the Cost of Gas?

A. The allowable adjustments to gas costs, listed on Proposed Original Page 96, are as follows:

1.	Deferred Gas Cost Prior Period Under Collection	$1,431,639
2.	Interest	22,981
3.	Fuel Inventory Revenue Requirement	335,667
4.	Broker Revenues	(3,600)
5.	Transportation COG Revenue	(4,622)
6.	Capacity Release Margin	(1,676,512)
7.	Fixed Price Administrative Cost	36,800
	Total Adjustments	$142,353

These allowable adjustments are standard adjustments made to the deferred gas cost balance through the operation of the Company's cost of gas adjustment clause. We discuss the factors contributing to the prior period under collection later in this testimony.

Q. How does the proposed average cost of gas rate in this filing compare to the average cost of gas rate approved by the Commission in Docket No. DG 20-141 for the 2020/2021 winter period?

A. The average cost of gas rate proposed in this filing of $0.9056 per therm is $0.3485 per therm more than the initial rate of $0.5571 per therm approved by the Commission in Order No. 26,419 (October 30, 2020) in Docket No. DG 20-141. The $0.3485 per therm increase in the rate is primarily due to a $28,544,323 increase in the Total Unadjusted Direct Cost of Gas.

Q. How does the proposed firm transportation winter cost of gas rate compare to the rate approved by the Commission for the 2020/2021 winter period?

A. The proposed firm transportation winter cost of gas rate is $0.0001 per therm. The rate approved in Docket No. DG 20-141 was $0.0001 per therm. There is no change in the firm transportation rate.

Q. In the calculation of its firm transportation winter cost of gas rate, has the Company updated the estimated percentage used for pressure support purposes?

A. No. The pressure support purposes rate of 8.7% stayed the same based on the marginal cost study used for the rate design approved in Docket No. DG 20-105.

Q. Did the Company include a fuel inventory revenue requirement calculation in this filing?

A. Yes (Bates 207). The Company is proposing to collect $335,667 in fuel inventory revenue requirement consistent with the approved rate of return in Order No. 26,505

(July 30, 2021) in Docket No. DG 20-105. The impact of this amount to the overall Cost of Gas rate is \$0.0038 per therm which is determined by dividing the \$335,667 by the estimated November 2021 through October 2022 COG sales volumes of 87,443,741 therms.

Q. How was the statutory tax rate of 27.08% calculated (Bates 207)?

A. The statutory rate of 27.08% was calculated by using a 21% federal tax rate and a 7.7% tax rate for the State of New Hampshire (0.21 + 0.077 – (0.21 x 0.077) = 0.27083).

Q. How was the common equity pre-tax rate of 6.640% calculated (Bates 207)?

A. The common equity pre-tax rate of 6.640% was calculated by dividing the 9.30% rate of return on common equity, approved in Docket No. DG 20-105, by 0.72917 (1 – 0.27083) [statutory tax rate – see previous question]) and multiplied by 52.00% (equity component of the capital structure approved in DG 20-105) [0.093 / 0.72917 x 0.5200 = 0.06664].

Q. Has the bad debt percentage in this filing of 0.700% changed from the bad debt percentage calculated in the Winter 2020/2021 Cost of Gas Reconciliation?

A. Yes. The bad debt percentage of 0.70% used in this filing is the calculated rate for the period of May 2020–April 2021. The bad debt percentage that was calculated in the Winter 2020/2021 Cost of Gas Reconciliations for the period of May 2019–April 2020 was 1.1%.

Q. What was the actual weighted average firm sales cost of gas rate for the 2020/2021 winter period?

A. The weighted average cost of gas rate was $0.5100 per therm (Bates 104, Line 54). This was calculated by applying the actual monthly cost of gas rates for November 2020 through April 2021 to the monthly therm usage of an average residential heating customer using 667 therms for the six winter period months.

Q. What is the current percentage used to calculate the maximum increase to the Cost of Gas rate?

A. The current percentage used to calculate the maximum allowed increase to the Cost of Gas rate is 25% for both Winter and Summer period Cost of Gas rates.

Q. Is the Company requesting an increase to the percentage used to calculate the maximum allowed Cost of Gas Rate?

A. Yes, the Company is requesting that the percentage used to calculate the maximum allowed cost of Gas rate be increased for the Summer period of May through October. The Company is not requesting a change to the maximum allowed percentage increase applicable to the Winter period.

Q. Why is the Company asking to increase the percentage used to calculate the maximum allowed cost of Gas rate be increased for the summer period of May through October?

A. In the past eighteen summer months (i.e., the last three Summer periods) the Company has been at the maximum allowed rate for twelve of those months. In the summer of

2021, the Company has been at the maximum allowed rate for all six months. The under collected balance has grown to approximately $4.5M. That under collection is the beginning balance for the summer portion of this filing. In the summer of 2020, the Company's calculated Cost of Gas rate was at the maximum allowed rate for three out of the six months and the under collected balance grew to $3.5M but was primarily offset by an out of period accounting adjustment. Given these circumstances, the Company feels the 25% used to calculate the maximum allowed Cost of Gas rate is insufficient. While the 25% maximum increase was appropriate in prior years when there was a separate filing for the Summer Cost of Gas rate, once the Winter and Summer periods were combined into one filing, the amount of time between the filing and the effective date for the Summer Cost of Gas rate increased by six months, thus increasing the likelihood of the forecasted Summer Cost of Gas rate differing significantly from the market conditions during the applicable summer period. One of the reasons for having a "trigger" adjustment to the Cost of Gas rate it to try to reduce potential under collections at the end of the rate period. As shown by the size of the under collections during the recent summer periods, the 25% limit has been insufficient to serve for that purpose.

Q. What percentage used to calculate the maximum allowed Summer Cost of Gas Rate is the Company asking for approval of?

A. The Company is asking for the percentage used to calculate the maximum allowed Summer Cost of Gas rate to be increased from 25% to 40%.

Q. How did the Company determine that an increase of the maximum allowed Summer Cost of Gas from 25% to 40% was appropriate?

A. The Company did an analysis of the past four years. We started with the original summer cost of gas monthly adjustment filings, removed out of period adjustments and then calculated what the four-year average increase would have been if we were able to increase the rates beyond 25%. The average increase was 47.2%. We then rounded down to 40%.

Q. Why should the Commission increase the percentage used to calculate the maximum allowed Cost of Gas rate for the Summer period?

A. When the Company reaches the maximum allowed rate, the under collected balance continues to grow. In the summer of 2021, the projected under collected balance is $4,472,186. Based on the 2021 estimated summer therms of 36,033,006, the rate for next summer will be starting with an increase of $0.1241 per therm just to recover that under collection. The Commission should approve the increased percentage used to calculate the maximum allowed Summer Cost of Gas because the only other option is the Company would be forced to file for additional rate increase approvals which would defeat the purpose of having a single annual Cost of Gas filing

Q. Why doesn't the Company make an interim filing when the maximum allowed Cost of Gas is reached?

A. An additional filing would be an administrative burden for all parties. The primary reason for combining the winter and summer filing into one, was to reduce this administrative burden.

Q. Is the 25% used to calculate the maximum allowed Cost of Gas sufficient, for the Winter period?

A. Yes, the 25% used to calculate the maximum allowed Cost of Gas increase, in the winter period, is sufficient. The volume of therms sold is approximately 40% higher than the amount of therms sold during the summer months. The same $4.5M under collection referenced above would cause an automatic increase of only $0.0519 per therm during the winter. Also, rates for the Winter Cost of Gas are calculated using more near-term market information than those for the future Summer period.

III. PRIOR WINTER PERIOD UNDER-COLLECTION

Q. Please explain the prior period under collection of $1,431,639.

A. The prior period under-collection is detailed in the 2020/2021 winter period reconciliation that was filed with the Commission on July 29, 2021. The $1,431,639 under-collection is the sum of the deferred gas cost, bad debt, and working capital over- and under-collection balances as of April 30, 2021. The under-collection was driven mainly by the lag in the timing of monthly cost of gas rate adjustments as compared to changes in the underlying costs.

IV. FIXED PRICE OPTION

Q. Has the Company established a winter period fixed price pursuant to its Fixed Price Option Program?

A. Yes. Pursuant to Order No. 24,515 in Docket No. DG 05-127, the Fixed Price Option Program (“FPO”) rates are set at $0.0200 per therm higher than the initial proposed COG rate. Proposed First Revised Page 94 (Bates 055) contains the FPO rate for the

2021/2022 winter period, which is $0.9256 per therm for residential customers. This compares to the FPO rate approved for the 2020/2021 winter period of $0.5771 per therm for residential customers. This represents a $0.3485 per therm or 60.4% increase in the residential FPO rate. The total bill impact on the winter period bills for an average FPO heating customer using 667 therms is an increase of approximately $305.01 or 34.4% compared to last winter. The estimated winter period bill for an average residential heating customer opting for the FPO would be approximately $13.34 (or 1.12%) higher than the bill under the proposed cost of gas rates, assuming no monthly adjustments to the COG rate during the course of the winter. Schedule 23 (Bates 204) contains the historical results of the FPO program.

V. <u>LOCAL DELIVERY ADJUSTMENT CLAUSE ("LDAC")</u>

Q. What are the surcharges that will be billed under the LDAC?

A. As shown on Proposed First Revised Page 101 (Bates 061), the Company is submitting for approval an LDAC of $0.1733 per therm for the residential non-heating class and residential heating class, and $0.0860 per therm for the commercial/industrial bundled sales classes, effective November 1, 2021. The surcharges proposed to be billed under the LDAC are the Energy Efficiency Charge, the Revenue Decoupling Adjustment Factor, the Environmental Surcharge for Manufactured Gas Plant ("MGP") remediation, the Residential Gas Assistance Program charge, and the rate case expense reconciliation surcharge from Docket No. DG 20-105.

Q. Which customers are billed an LDAC?

A. All EnergyNorth customers including those in Keene are billed an LDAC charge. When calculating the LDAC charge, the November 1, 2021, through October 31, 2022, forecasted Keene therm sales of 1,405,237 are added to the EnergyNorth therm sales forecast of 181,424,635 for a total therm sales forecast of 182,829,872.

Q. Please explain the Energy Efficiency Charge.

A. The Energy Efficiency Charge is designed to recover the projected expenses associated with the Company's energy efficiency programs for the November 2021 through October 2022 period. In the calculation of the Energy Efficiency Charge, the Company has also included the projected prior period under-recovery of the Company's residential and commercial energy efficiency programs as of October 2021. As shown on Schedule 19 Energy Efficiency (Bates 132–134), the proposed Energy Efficiency charge is $0.0861 per therm for residential customers and $0.0408 per therm for commercial and industrial customers.

Q. Please explain the Revenue Decoupling Adjustment Factor ("RDAF").

A. The purpose of the RDAF is to recover or refund, on an annual basis, the difference between the Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer. Schedule 19 RDAF (Bates 130) shows the prior period difference (September 2020 through August 2021) between the proposed Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer calculation of a total under-collection of $2,426,364. Schedule 19 RDAF (Bates 129) also includes a reconciliation of the amount of prior refunds (accumulated through October 2020 and refunded November 2020 through August 2021) of $969,938 remaining to be refunded. New to this filing and pursuant to the Settlement Agreement in Docket No. DG 20-105 (Order No. 26,505) is the prior period reconciliation of the Gas Assistance Program (previously the Residential Low-Income Program) customers allowed revenue, as shown on Schedule 19 RDAF (Bates 131). The Gas Assistance Program ("GAP") revenue per customer used in the allowed revenue calculations are no longer different from residential customers not categorized as GAP.[1] The allowed revenue correction allows the Company to recover $4,024,830 which was improperly refunded to residential customers over the past two years. The Company is also proposing to recover the $4,024,830 over the next two years since the issue occurred over a two-year period. As shown on Schedule 19 RDAF (Bates 128), the proposed RDAF charge is $0.0459 per therm for residential customers and $0.0039 per therm for commercial and industrial customers.

Q. What is the proposed Gas Assistance Program charge?

A. As shown on Schedule 19 Gas Assistance (Bates 135–136), the proposed GAP charge is $0.0138 per therm. It is designed to recover administrative costs, revenue shortfall, and the prior period reconciliation adjustment relating to this program. For the 2021/2022 winter period, the Company is providing a 45% base rate and cost of gas discount, consistent with the settlement agreement approved by the Commission in Order No. 26,397 (August 27, 2020) in Docket No. DG 20-013. The proposed Residential Gas Assistance charge is designed to recover $2,526,541, of which $2,318,301 is for the

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1 This issue was discovered as part of the Company's recent rate case, Docket No. DG 20-105.

revenue shortfall resulting from 5,320 customers receiving a 45% discount off their base and cost of gas rates, and $208,239 for the prior year reconciling adjustment.

Q. In Order No. 24,824 (Feb. 29, 2008) in Docket No. DG 06-122 relating to short-term debt issues, the Company agreed to adjust its short-term debt limits each year as part of the Company's Winter Period Cost of Gas filing. Did the Company calculate the short-term debt limit for fuel and non-fuel purposes in accordance with this settlement?

A. Yes, the Company included in Schedule 24 (Bates 205) the short-term debt limit for fuel and non-fuel purposes for the 2021/2022 winter period. As shown, the short-term debt limit for fuel inventory financing for the period November 1, 2021, through October 31, 2022, is calculated to be $23,754,907 and the limit for non-fuel purposes is calculated to be $115,471,436.

Q. Has the Company updated the Environmental Surcharge (Tariff Page 95)?

A. Yes, it has. The costs submitted for recovery through the MGP remediation cost recovery mechanism, as well as the third-party recoveries, are included in the Environmental Cost Summary in Schedule 20 (Bates 138) of this filing. The environmental investigation and remediation costs that underlie these expenses are the result of efforts by the Company to respond to its legal obligations with regard to these sites, as described by Ms. Casey in her pre-filed direct testimony in this proceeding and as set forth in the MGP site summaries included in this filing under Schedule 20. The Summary included in Schedule 20 shows the remediation cost pools for the Concord Pond, Concord MGP, Manchester, Nashua, and Laconia sites, and a General Pool for costs that cannot be directly assigned to a specific site.

A summary sheet and detailed backup spreadsheets that support the 2020/2021 costs are provided in Schedule 20 of this filing. Ms. Casey's testimony describes the Company's activities with regard to all five sites.

Q. Please describe how the Company calculated the Environmental Surcharge included in this filing.

A. The proposed Manufactured Gas Plant Remediation surcharge for the period beginning November 1, 2021, and ending October 31, 2022, is $0.0155 per therm. Consistent with filings made over the past few years, this surcharge will recover a total of $2,833,284 in amortized remediation costs. The amortized actual to forecast true-up recovery costs through June 2019 of $341,389 (total amount is $1,024,167 which is amortized over three years). The $1,024,167 is the amount approved by Order No. 26,419 in Docket No. DG 20-141. Also, the actual to forecast true-up recovery cost for the period July 2020 through June 2021 is $140,090. The costs submitted for recovery are shown in the Environmental Cost Summary included in Schedule 20 of this filing.

Q. Did the Company include a Rate Case Expense (RCE) surcharge in this filing?

A. Yes. As shown on Schedule 19 RCE (Bates 126–127), the Company is proposing to collect $2,214,505 in uncollected rate case and recoupment expense consistent with Order No. 26,505 (July 30, 2021) in Docket No. DG 20-105. The RCE rate of $0.0121 per therm is determined by dividing the $2,214,505 by the estimated November 2021 through October 2022 sales volumes of 182,829,875 therms.

Q. Has the Company also updated its Company Allowance percentage for the period November 2021 through October 2022 in accordance with Section 8 of the Company's Delivery Terms and Condition?

A. Yes, in Schedule 25 (Bates 206) the Company has recalculated its Company Allowance for the period November 2021 through October 2022. The Company calculated the Company Allowance of 1.22% based on sendout and throughput data for the twelve-month period ending June 2021. The Company proposes to apply this recalculated Company Allowance to all supplier deliveries beginning in November 2021.

VI. CUSTOMER BILL IMPACTS

Q. What are the estimated impacts of the proposed firm sales cost of gas rate and proposed LDAC surcharges on an average heating customer's winter bill as compared to the winter rates in effect last year?

A. The bill impact analysis is presented in Schedule 8 (Bates 104) of this filing. These bill impacts reflect the implementation of the increases approved in Docket No. DG 20-105 effective August 1, 2021, relating to the EnergyNorth distribution rate case. The total bill impact over the winter period for an average residential heating customer is an increase of approximately $336.41 or 39.52%. The total bill impact over the winter period for an average commercial/industrial G-41 customer is an increase of approximately $843.54 or 39.34% (Bates 105). Schedule 8 of this filing provides more detail of the impact of the proposed rate adjustments on heating customers.

VII. OTHER TARIFF CHANGES

Q. Is the Company updating its Delivery Terms and Conditions in the filing?

A. Yes. The Company is submitting Proposed First Revised Page 153 (Bates 062) relating to Supplier Balancing and Peaking Demand Charges and Proposed First Revised Page 154 (Bates 063) relating to Capacity Allocation.

Q. Please describe the changes to tariff Page 153.

A. In Proposed First Revised Page 153, the Company is updating the Peaking Demand Charge from $17.32 per MMBtu of Peak MDQ to $56.10 per MMBtu of Peak MDQ. This calculation is also presented in Schedule 21 (Bates 187–197).

Q. Please describe the changes to tariff Page 154.

A. Proposed First Revised Page 154 updates the Capacity Allocator percentages used to allocate pipeline, storage, and local peaking capacity to high and low load factor customers under the mandatory capacity assignment requirement for firm transportation service. Schedule 22 (Bates 198–203) contains the six-page worksheet that backs up the calculations for the updated allocators.

VIII. SUMMER 2021 COST OF GAS FACTOR

Q. What are the proposed 2022 summer firm sales cost of gas rates?

A. The Company proposes a firm sales cost of gas rate of $0.5002 per therm for residential customers, $0.5007 per therm for commercial/industrial high winter use customers, and $0.4994 per therm for commercial/industrial low winter use customers as shown on Proposed First Revised Page 92 (Bates 211).

Q. Please explain tariff pages Proposed First Revised Page 91 and Proposed First Revised Page 91.

A. Proposed First Revised Page 91 (Bates 210) and Proposed First Revised Page 92 (Bates 211) contain the calculation of the 2022 Summer Period Cost of Gas Rate and summarize the Company's forecast of firm gas sales, firm gas sendout, and gas costs. On Proposed First Revised Page 89, the 2022 Average Cost of Gas of $0.5002 per therm is derived by adding the Direct Cost of Gas Rate of $0.4958 per therm to the Indirect Cost of Gas Rate of $0.0044 per therm. The estimated total Anticipated Direct Cost of gas is $13,447,446 and the estimated Indirect Cost of Gas is $120,343. The Direct Cost of Gas Rate and the Indirect Cost of Gas Rates are determined by dividing each of these total cost figures by the projected Summer firm sales volumes of 27,125,444 therms. Proposed First Revised Page 92 further shows that the Residential Cost of Gas Rate of $0.5002 per therm is equal to the Average Cost of Gas for all firm sales customers. It also shows the calculation of the Commercial/Industrial High Winter Use Cost of Gas Rate of $0.5007 per therm and the Commercial/Industrial Low Winter Use Cost of Gas Rate of $0.4994 per therm.

The calculation of the Anticipated Direct Cost of Gas is shown on Proposed First Revised Page 91. To derive the total Anticipated Direct Cost of Gas of $13,447,446, the Company starts with the Unadjusted Anticipated Cost of Gas of $8,755,985 and adds the Net Adjustment totaling $4,691,461.

Q. What are the components of the Unadjusted Anticipated Cost of Gas?

A. The Unadjusted Anticipated Cost of Gas consists of the following:

1. Purchased Gas Demand Costs	$3,276,842
2. Purchased Gas Supply Costs	5,393,517
3. Produced Gas Costs	85,626
Total Unadjusted Anticipated Cost of Gas	$8,755,985

Q. What are the components of the adjustments to the cost of gas?

A. The adjustments to gas costs, listed on proposed First Revised Page 88, are as follows:

1. Prior Period (Over)/Under Collection	$4,472,186
2. Interest	219,275
Total Adjustments	$4,691,461

Q. How does the proposed average Residential Summer cost of gas rate in this filing compare to the initial cost of gas rate approved by the Commission for the 2021 Summer Period?

A. The cost of gas rate proposed in this filing is $0.1854 per therm higher than the initial rate approved by the Commission for the 2020 Summer Period ($0.3148 vs. $0.5002) (Schedule 8, Bates 232). This increase is primarily due to a $4,472,186 estimated under-collection compared to the under-collection from the prior summer period. There was such a large under collection due to an increase in commodity costs since the original filing. The Company was at the maximum allowed rate all six summer months.

Q. Does this conclude your testimony?

A. Yes, it does.