INTRODUCTION

Q1. PLEASE STATE YOUR NAME.

A1. John F. Lamb.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A2. I am employed by the Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis (the "Board") which does business as Citizens Energy Group ("Citizens"). The Board is the successor trustee of a public charitable trust and, manages and controls a number of businesses, including the gas utility doing business as Citizens Gas ("Citizens Gas" or "Petitioner"). Since January 2014, I have held the position of Manager, Rates and Business Applications.

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A3. I hold a Bachelor of Science degree with a major in Accounting from Purdue University and a Master of Business Administration degree with a concentration in Accounting from Indiana Wesleyan University.

Q4. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A4. Prior to joining the Citizens Regulatory Affairs department, I was a Senior Accountant in the Citizens Accounting Department since 2011. In that capacity, my work focused on gas accounting, monitoring capital projects, and preparation of the annual report filed with the Indiana Utility Regulatory Commission ("IURC" or "Commission").

Q5. PLEASE DESCRIBE THE DUTIES AND RESPONSIBILITIES OF YOUR PRESENT POSITION.

A5. As Manager of Rates and Business Applications, I am responsible for the implementation and administration of Citizens Energy Group's regulated utilities' rates and charges. Since 2014, I have been responsible for the preparation of GCA changes and other miscellaneous rate matters.

Q6. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION ON BEHALF OF CITIZENS?

A6. Yes.

Q7. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A7. The purpose of my testimony is to describe the tariff sheets and supporting schedules reflecting the gas cost adjustments that Citizens Gas proposes become effective for the months of June, July and August 2022. My testimony also discusses Citizens Gas' projection period, reconciliation period and the Monthly Price Update. Additionally, I describe Citizens Gas' supply portfolio, and provide evidence concerning the gas supply sources and firm gas supply contracts used by Citizens Gas to meet its customers' requirements. Lastly, I provide testimony on demand and supply planning activities, the prepaid gas program, the Citizens Gas hedging program, and any changes to the load forecast.

GAS COST FACTOR CALCULATIONS

EXHIBITS AND SCHEDULES

Q8. PLEASE DESCRIBE EXHIBIT NO. 2.

A8. Exhibit No. 2 is my direct testimony.

Q9. PLEASE PROVIDE A BRIEF EXPLANATION OF ATTACHMENTS

JFL-1 THROUGH JFL - 3.

A9. Attachment JFL-1 is Petitioner's GCA tariff sheet (Rider A), for the periods June, July and August 2022. The rates shown on each Rider A are the result of all appropriate estimations and reconciliations, as previously authorized by the Commission. Attachment JFL-2 shows the impact of the proposed GCA rates on a residential heating customer's bill at 5, 10, 15, 20 and 25 dekatherms, compared to currently effective rates – i.e. April 2022 – and compared to the GCA rates in effect one year ago.

Attachment JFL-3 consists of all schedules required in support of the GCA rates shown in Attachment JFL-1. These schedules were prepared in a manner consistent with Petitioner's prior GCA filings and incorporate the changes approved on May 14, 1986 in Cause No. 37091. The schedules also are in compliance with the changes approved on August 31, 2011 in Cause No. 43975, August 27, 2014 in Cause No. 44374 and November 13, 2018 in Cause No. 37399-GCA 140.

Q10. PLEASE DESCRIBE ATTACHMENT JFL-3 IN MORE DETAIL.

A10. Schedules 1 through 5 of Attachment JFL-3 support the calculation of the GCA Factors. Schedule 1 is the monthly calculation of the GCA Factors based on Load Forecast (Schedule 2), the estimated purchases and gas cost (Schedule 3), allocation factors associated with the rate class and period (Schedule 4), and storage cost (Schedule 5) for the projection period of June, July and August 2022.

Schedules 6 through 12 of Attachment JFL-3 are the reconciliation of actual gas costs and recoveries for December 2021, January and February 2022. Schedule 6 shows the actual gas costs and variance calculation of gas cost incurred versus recoveries in the reconciliation period of December 2021, January and February 2022.

Schedule 7 is the calculation of actual gas costs in the period based on purchases (Schedule 8), unnominated gas cost (Schedule 9), and storage injections/withdrawals (Schedule 10). Schedule 11 calculates the Unaccounted for Gas ("UAFG") percentage. Schedule 12 allocates the variance from the reconciliation period across the next four quarters. The variance to be included in this GCA 154 is based on components from this GCA and the three previous GCAs, as well as refunds and write-offs for the upcoming projection periods

PROJECTION PERIOD

Q11. HOW DID CITIZENS GAS PROJECT THE GAS PRICES FOR THE MONTHS OF JUNE, JULY AND AUGUST 2022?

A11. The majority of the gas costs for June, July and August 2022 were projected using the NYMEX futures prices at Henry Hub for the three-month period. The index is the same index by which Citizens Gas has priced its commodity purchases in the past. The futures prices are adjusted for basis, fuel and transportation for delivery to Citizens Gas' city-gate.

Table 1

NYMEX Price as of 3/18/22	
Jun. 2022	$5.063
Jul. 2022	$5.111
Aug. 2022	$5.119

Q12. ON WHAT ARE THE OTHER GCA COMPUTATIONS CONTAINED IN ATTACHMENT JFL - 3 BASED?

A12. The rates and charges reflected in the transportation and storage costs are based upon pipeline tariffs. The other major components of estimated gas costs are non-pipeline gas costs, which are priced in accordance with the Commission's Order in Cause No. 37475, and purchases from gas suppliers other than pipelines, including financial hedge transactions, as discussed later in my testimony.

Q13. WHAT PERCENTAGE OF TOTAL PURCHASES IS MADE UP OF FINANCIALLY HEDGED TRANSACTIONS FOR THE MONTHS OF JUNE, JULY AND AUGUST 2022?

A13. Financially hedged transactions account for 24.64% of total purchases for the months of June, July and August 2022.

Q14. DO PETITIONER'S GAS SUPPLIES INCLUDE ANY NON-TRADITIONAL SUPPLIES OF GAS?

A14. No. But, if there were any non-traditional gas supplies included in the GCA 154 computation, they would be priced at the lesser of the equivalent cost of pipeline gas or the authorized per unit price, as authorized by the Commission in Cause No. 37475.

Q15. DO YOU BELIEVE THAT THE PROPOSED GCA RATES FOR JUNE, JULY AND AUGUST 2022 ARE ACCURATE?

A15. Yes, I do.

Q16. GIVEN THE REPEAL OF THE INDIANA UTILITY RECEIPTS TAX (URT) EFFECTIVE JULY 1, 2022, HAS THAT DIFFERENCE BEEN REFLECTED IN THE GCA SCHEDULES AND CALCULATONS?

A16. The GCA schedules and calculations are still the same as previous GCA filings, except that in July and August 2022, the URT calculation is no longer included.

RECONCILIATION PERIOD

Q17. HAVE YOU COMPARED PETITIONER'S ESTIMATED GAS COSTS FOR THE PERIOD OF DECEMBER 2021, JANUARY AND FEBRUARY 2022 WITH ACTUAL GAS COSTS EXPERIENCED FOR THAT RECOVERY PERIOD PURSUANT TO IC 8-1-2-42(G)(3)(D)?

A17. Yes.

Q18. IN YOUR OPINION, ARE THE GAS COST VARIANCES INCLUDED WITHIN THIS GCA 154 PROCEEDING ACCURATE AND REASONABLE?

A18. Yes. The resulting percentages of total monthly variance to the total gas costs incurred and the average variance percentage for the trailing 12-month period ending with each of the three months December 2021, January and February 2022 presented in the GCA reconciliation period are shown in Table 2:

Table 2

Twelve Months Ending	Actual Gas Cost	Variance	% Variance
December 2021	$91,294,723	($7,043,992)	(7.72)%
January 2022	$102,950,989	($7,544,397)	(7.33)%
February 2022	$118,731,838	$3,399,518	2.86%

Q19. PLEASE EXPLAIN PETITIONER'S TWELVE-MONTH TRAILING AVERAGES FOR ANY MONTH WITHIN THE GCA RECONCILIATION PERIOD THAT ARE GREATER THAN +/- 10% SHOWN ON ATTACHMENT JFL-3, SCHEDULE 6D.

A19. The 12-month trailing averages for each of the months in the reconciliation period do not exceed the Commission approved level of +/- 10%

Q20. DO THE PROPOSED GCA 154 RATES INCLUDE A RECONCILIATION OF ACTUAL COSTS TO ACTUAL RECOVERIES FOR THE MONTHS OF DECEMBER 2021, JANUARY AND FEBRUARY 2022?

A20. Yes. The proposed GCA rates to be effective June, July and August 2022 include the effect of reconciling actual gas costs incurred for the months of December 2021, January and February 2022 to actual cost recoveries. In accordance with the Commission's August 14, 1986 Order in Cause No. 37091, the gas supply variance was calculated for each customer demand class and is summarized by class on Attachment JFL–3, Schedule 12B, page 1, lines 1 through 5 and Schedule 12B, page 2, lines 1 through 3. The actual gas supply cost incurred compared to actual gas supply revenue for each month, as depicted in Schedule 6, is shown in Table 3:

Table 3

	Net of Schedule 6 and 12C		Schedule 12
	Actual Gas Cost	**Actual Recoveries**	**Cost in Excess of Recoveries**
December 2021	$17,854,580	$16,918,873	$935,707
January 2022	$27,572,173	$28,983,737	($1,411,564)
February 2022	$22,698,284	$22,339,870	$358,414
Total	$68,125,037	$68,242,480	($117,443)

Q21. WHAT PERCENTAGE OF TOTAL PURCHASES WAS MADE UP OF FINANCIALLY-HEDGED TRANSACTIONS FOR THE MONTHS OF DECEMBER 2021, JANUARY AND FEBRUARY 2022?

A21. Financially-hedged transactions accounted for 27.67% of total purchases for the months of December 2021, January and February 2022.

Q22. HAS PETITIONER RECEIVED ANY NEW REFUNDS THAT ARE INCLUDED IN THIS GCA?

A22. No.

MONTHLY PRICE UPDATE

Q23. PLEASE DESCRIBE THE HISTORY OF THE MONTHLY PRICE UPDATE MECHANISM.

A23. In Cause No. 37399-GCA75, the Commission approved the use of a Monthly Price Update mechanism for twelve (12) quarterly GCAs, beginning with GCA 75 and ending with GCA 86. The Second Amended and Restated Stipulation and Settlement Agreement filed with the Commission on August 23, 2005 in Cause No. 37399-GCA 75 extended the monthly price update mechanism for another twelve (12) quarterly GCAs beginning with GCA 87 and ending with GCA 98. The Third Amended and Restated Stipulation and Settlement Agreement filed with the Commission on August 3, 2007 in Cause No. 37399-GCA75, extended the Monthly Price Update Mechanism beginning September 1, 2008 and it continues until further Order of the Commission.

Q24. HAS THE GCA PROCESS, AS DESCRIBED IN IC 8-1-2-42(G) AND INSTITUTED PURSUANT TO THE COMMISSION'S AUGUST 14, 1986 ORDER IN CAUSE NO. 37091, BEEN CHANGED IN ANY SUBSTANTIAL WAY BY THE CITIZENS GAS MONTHLY GCA MECHANISM?

A24. No. The GCA schedules filed with the GCA Petition, and potentially updated 20 days later, remain unchanged. Pursuant to IC 8-1-2-42(g), the Commission reviews all relevant Quarterly GCA evidence, conducts a summary hearing, and issues an order approving the Benchmark Prices and GCA factors for each month of the quarter.

No less than three days prior to the beginning of each month during the Quarterly GCA period, Citizens Gas files with the Commission a Monthly Price Update for the upcoming month. The GCA factors contained in the Monthly Price Update become effective on the first day of the next calendar month, without further hearing.

Q25. PLEASE DESCRIBE THE MPU FILING.

A25. Pursuant to the Commission's Order in Cause No. 44374, the MPU shall be filed no later than three business days before the beginning of the calendar month in which the rates will go into effect. The Cause No. 44374 Order allows for Petitioner to change the mix of volumes between spot, fixed, and storage injections and withdrawal volumes as long as the total volumes remain unchanged from Petitioner's total volumes approved in the applicable GCA period. The MPU is permitted to change the unit price of spot, fixed and storage gas based on current market conditions and subject to applicable price caps.

Q26. WHEN CITIZENS GAS FILES ITS MONTHLY PRICE UPDATE WITH THE COMMISSION, WHAT IS INCLUDED IN THE FILING?

A26. The Monthly Price Update includes the following: (1) a reference to Gas Daily (or other comparable publication) indicating the NYMEX close price being utilized in the Monthly Price Update; (2) a schedule reflecting adjustments made to the NYMEX close price for use in GCA schedules and comparing to the same calculation made in the Quarterly GCA; (3) certain GCA schedules that are impacted; (4) the revised tariff sheet for the upcoming month (Rider A); and (5) a residential heating customer's bill at 5, 10, 15, 20 and 25 dekatherms compared to currently effective rates and compared to the rates in effect one year ago.

Q27. FOR PURPOSES OF IDENTIFYING THE BENCHMARK PRICES AS A REQUIREMENT OF THE MONTHLY PRICE UPDATE MECHANISM, WHAT ARE THE MONTHLY BENCHMARK PRICES FOR JUNE, JULY AND AUGUST 2022 INCLUDED IN THIS FILING?

A27. Table 4 shows the Monthly Benchmark Prices as established by NYMEX +/- basis as of March 18, 2022 by pipeline for June, July and August 2022.

TABLE 4

Benchmark Prices								
	Panhandle Eastern	Texas Gas	Midwestern Gas	Panhandle PrePay	PEAK B	Rockies Express East	PEAK A	TGT-REX
Jun. 2022	$4.6865	$4.8755	$4.7318	$4.3603	$4.8555	$4.4895	$4.7280	$4.7846
Jul. 2022	$4.7329	$4.9164	$4.8377	$4.4067	$4.9035	$4.5236	$4.7760	$4.8911
Aug. 2022	$4.7308	$4.9674	$4.8482	$4.4047	$4.9115	$4.5112	$4.7840	$4.9017

Q28. HAS PETITIONER PROPERLY APPLIED ITS GCA RATES SINCE ITS LAST GCA PROCEEDING IN CAUSE NO. 37399 GCA 153?

A28. Yes.

Q29. ARE PETITIONER'S BOOKS AND RECORDS KEPT ACCORDING TO THE UNIFORM SYSTEM OF ACCOUNTS, AS PRESCRIBED BY THE COMMISSION?

A29. Yes.

GAS SUPPLY

ASSET MANAGEMENT AGREEMENT

Q30. PLEASE DESCRIBE THE ASSET MANAGEMENT AGREEMENT ("AMA") BETWEEN EXELON GENERATION COMPANY, LLC ("EXELON") AND CITIZENS GAS.

A30. The AMA was entered into on April 1, 2021 and the term will expire on March 31, 2024. Pursuant to the AMA, Exelon administers a collection of contracts (the "Portfolio Contracts"), including contracts with Panhandle Eastern Pipe Line Company ("Panhandle"), Texas Gas Transmission Corporation ("Texas Gas"), Midwestern Gas Transmission, and Rockies Express Pipeline ("REX") to meet Citizens Gas' requirements.

Q31. WHAT IS THE EXTENT OF GAS DELIVERABILITY AVAILABLE TO CITIZENS GAS UNDER THE AMA?

A31. A breakdown of the monthly maximum daily deliverability available to Citizens Gas from each of its supply sources is reflected in Table 5 below. The table includes deliverability available from Exelon via the AMA, delivered supplies from BP Canada, maximum deliverability from on-system underground storage, and maximum deliverability from a liquefied natural gas ("LNG") facility.

Table 5

	Exelon	BP	Storage	LNG	Total
Jun. 2022	133,886	20,000	80,000	100,000	333,886
Jul. 2022	133,886	20,000	80,000	100,000	333,886
Aug 2022	133,886	20,000	80,000	100,000	333,886

Q32. PLEASE DESCRIBE GENERALLY THE GAS SALES AND DELIVERY PROVISIONS OF THE AMA.

A32. Under the AMA, Citizens Gas reserves its baseload firm gas supplies with Exelon based on the projected daily requirements Citizens Gas has for each month. Exelon then provides the amount of gas commodity Citizens Gas uses to meet the needs of its customers on a daily, seasonal, and peak day basis. In addition, Exelon provides Citizens Gas with annual agency service for purchases made from the Indiana Municipal Gas Purchasing Authority ("IMGPA").

Q33. WHAT ROLE DOES EXELON PLAY WITH REGARD TO CITIZENS GAS' SUPPLY CONTRACTS?

A33. Exelon administers contracts with producers and gas marketers for firm, long-term (at least one year) gas supplies sufficient to meet Citizens Gas' maximum daily requirements each month. This arrangement ensures the amount of capacity held on the respective pipelines is matched with firm gas supplies. The gas supply contracts provide for "take or release" volumes on a monthly basis. This "take or release" provision gives Citizens Gas or Exelon, on behalf of Citizens Gas, the right to nominate with the producer or supplier any volume greater than the contract minimum up to the contract maximum in any month. These contracts with producers and gas marketers are the same type of contracts which have been included in Citizens Gas' previous GCA filings. In addition, Citizens Gas enters into hedging transactions to meet its gas supply needs, pursuant to our hedging strategy, and Exelon provides agency services for Citizens Gas' purchases from the IMGPA.

Q34. HAS CITIZENS GAS FORECASTED ITS GAS REQUIREMENTS FOR PURPOSES OF THIS PARTICULAR GCA PROCEEDING?

A34. Yes, it has. Petitioner's Attachment JFL-3, Schedules 2A, 2B, and 2C depict Citizens Gas' estimated throughput and retail sales volumes for the twelve months ending May 2023. Estimated sales are calculated annually based on an internal regression model that utilizes normal, 30-year average temperatures and historical data, including sales, the number of customers, and heating degree days. These forecasts use the same methodology Citizens Gas followed in its past GCA proceedings.

Q35. HOW ARE THE PROJECTED GAS SUPPLY QUANTITIES DETERMINED FOR CITIZENS GAS?

A35. In planning for its gas supply requirements, Citizens Gas calculates the total gas required on a daily, monthly and seasonal basis, as reflected in Attachments JFL-3, Schedules 2A, 2B, and 2C. Citizens Gas then considers all available supply sources in preparing a proposed gas supply plan to meet its gas supply requirements. Based upon deliverability, storage inventory levels, transportation costs, gas costs, and other inherent limitations, Citizens Gas determines the optimum supply plan to meet its retail gas requirements.

HEDGING STRATEGY

Q36. PLEASE BRIEFLY DESCRIBE CITIZENS GAS' USE OF PHYSICAL AND/OR FINANCIAL HEDGES AS PART OF ITS HEDGING STRATEGY.

A36. The primary objectives of hedging are to limit market volatility and catastrophic pricing risks for gas customers. Citizens Gas utilizes hedging instruments to mitigate fluctuation gas costs associated with system supply needs. Citizens Gas considers past, present and future market conditions and time-based restrictions to make hedging decisions. The hedge volume is determined by the projected physical natural gas demand required to serve Citizens Gas' system supply customers. Hedge instruments do not ensure that Citizens Gas will procure future gas purchases at prices below the actual market price at the time the gas is purchased and delivered.

Q37. PLEASE DESCRIBE GENERALLY THE GAS PROCUREMENT PROCESS CITIZENS GAS UTILIZES.

A37. Citizens Gas takes a blended approach to gas supply procurement that seeks to obtain a reliable supply while mitigating market volatility for its customers. Citizens Gas uses a blend of gas purchased at current market prices, gas purchased and injected into storage and financial hedges that hedge the gas cost.

On a monthly basis, Citizens Gas creates a plan that meets the projected demands of the system under normal weather. Citizens Gas optimizes swing purchases and storage capabilities, to meet the daily needs of the system based on short-term forecasts.

Q38. PLEASE DESCRIBE THE HEDGING INSTRUMENTS CITIZENS GAS CONSIDERS AND UTILIZES.

A38. Citizens Gas considers and utilizes financial hedging instruments to mitigate price volatility.

Establishing a floor (put) and a ceiling (call), below and above which the purchaser will not pay, creates a collar. If gas prices fall below the established floor, Citizens Gas effectively pays the floor price. If gas prices rise above the established ceiling, Citizens Gas' purchase price effectively is capped at the ceiling price. A collar limits the purchaser's upward gas price exposure by establishing the ceiling; however, when gas prices fall below the floor price, the purchaser is obligated to pay the floor price. When the risk is evenly balanced between the purchaser and the counter-party, cost-less collars can be entered into, which do not require a premium. When more protection is purchased than risk assumed, a premium is required to put the collar into place. The collar allows for a lower floor than typically is available from a fixed price transaction; however, with a collar the purchaser also is at risk of paying a price higher than the fixed price quote (i.e., if market prices rise subsequent to the purchase of the collar).

Financial NYMEX futures may also be used to hedge natural gas. NYMEX futures establish a price for a determined contract month. If Petitioner purchases a NYMEX future, it will earn value to reduce the physical gas costs when the settlement price or offsetting NYMEX future is greater than the trade price. Conversely, the NYMEX future loses value to increase the physical gas costs when the settlement price is less than the trade price.

If Citizens Gas purchases an index future, it will earn value to reduce the physical gas costs when the settlement price or offsetting index future is greater than the trade price. Conversely, the index future loses value to increase the physical gas costs when the settlement price or offsetting index future is less than the trade price.

Citizens Gas may also use physical NYMEX or basis hedges to mitigate price volatility. Physical hedges are negotiated with a counter-party supplier.

Q39. PLEASE DESCRIBE HOW CITIZENS GAS STRUCTURES ITS SUPPLY PORTFOLIO TO HEDGE AGAINST GAS PRICE VOLATILITY.

A39. Financially hedged volume is determined by the anticipated monthly demand. Withdrawals from storage hedge heat load, up to optimum withdrawal levels (assuming normal weather). Citizens Gas utilizes counterparty and company-owned storage assets, supply agreements and transportation contracts to provide reliable supply.

Physical supply agreements and associated financial hedges protect against NYMEX price volatility.

Q40. WHY DOESN'T CITIZENS GAS SIMPLY HEDGE 100 PERCENT OF ITS NORMAL WEATHER SENDOUT?

A40. Three primary factors have caused Citizens Gas to refrain from simply hedging 100 percent of its normal weather sendout: (1) there are practical limits on the ability of Citizens Gas to utilize greater quantities of physically-hedged gas; (2) the missed opportunity to take advantage of falling prices to lower gas costs; and (3) the potential financial exposure associated with financial hedges.

Q41. PLEASE ELABORATE ON THE FOREGOING FACTORS.

A41. Physical hedges result in a situation where Citizens Gas must take delivery of the volumes of gas hedged. Under certain operating or weather conditions, constraints on Citizens Gas' system may limit its ability to physically take the hedged volumes. To mitigate the risk associated with a potential inability to take physically-hedged volumes, Citizens Gas limits physically-hedged volumes to no more than retail base load volumes.

In order to purchase gas for its customers at the lowest gas cost reasonably possible, Citizens Gas believes it must leave some level of its gas purchases priced at index to take advantage of falling gas prices, in the event gas prices drop below the prices at which the hedges were established.

Citizens Gas assumes some risk associated with the use of financial hedges. On a daily basis, as the difference between bid and ask prices changes, the futures commission merchant may make margin calls. These calls can be significant during times of rising prices and require the use of Citizens Gas' working capital. Limitations on the use of Citizens Gas' working capital funds also restrict the level of financial hedges that can be put in place.

Q42. IS IT POSSIBLE THAT CITIZENS GAS MIGHT MAKE CHANGES IN ITS HEDGING STRATEGY IN THE FUTURE?

A42. Yes. Citizens Gas will continue to monitor market activity and adjust the portfolio allocation accordingly. The instruments and the degree to which they are utilized may vary depending on cost, market dynamics and available opportunities. Citizens Gas' hedging strategy will continue to focus on mitigating price volatility appropriate operational flexibility and protection against upward price swings.

Q43. DOES CITIZENS GAS INCUR ADDITIONAL COSTS IN THE ADMINISTRATION OF ITS HEDGING STRATEGY THAT ARE NOT RECOVERED IN BASE RATES AND WHICH SHOULD BE RECOVERABLE IN THE GCA?

A43. Yes, in addition to the premiums described above, which are other expenses related to gas costs, Citizens Gas incurs other similar costs as well, including, but not limited to, commission fees, clearing fees, National Futures Association fees, and transaction fees. In addition, Citizens Gas recognizes gains and losses on the settlement of the contract. Attachment JFL-3, Schedule 3, pages 1, 2, and 3; 8A; 8B; and 8C include certain "Hedging Transaction Costs." The Hedging Transaction Costs reflected in this GCA consist of costs necessary to administer the financial hedge program. Citizens Gas' hedging strategy is intended to address commodity purchases and transactions made to mitigate gas price volatility (i.e., to help stabilize Petitioner's retail natural gas prices).

As a result, Citizens Gas incurs unavoidable costs which are associated with its hedging strategy. In my opinion, those costs are reasonably incurred and are expenses related to gas costs that should be included for purposes of obtaining Commission approval to recover them through the GCA mechanism.

Q44. HAS PETITIONER'S HEDGING STRATEGY BEEN CONSISTENT WITH PREVIOUS YEARS?

A44. While the overall approach has been consistent -- i.e. a hedging target for winter sendout currently at 80 percent, the mix of hedge components that Petitioner uses has changed from time to time in response to market dynamics. Storage has been and continues to be a significant component of the hedging volume mix. The volumes not covered by storage are hedged using financial or physical hedges. Initially, Citizens Gas used more physical hedge contracts. However, as the dynamics of the market have changed, the mix between physical and financial hedges has shifted resulting in financial hedges being the dominant non-storage hedge component.

Q45. WHY DID PETITIONER MAKE THE SHIFT FROM FIXED-PRICE CONTRACTS TO FINANCIAL HEDGES?

A45. Petitioner had used a mix of physical fixed-price contracts and financial hedges for a period of time. However, Petitioner wanted to gain greater operational flexibility and to take advantage of falling natural gas prices for the benefit of its gas customers.

Physical fixed-price contracts are settled in an exchange for the physical product -- i.e. the actual delivery of natural gas to the purchasing counterparty. Obviously, Petitioner needs natural gas to serve its customers. However, there are times, as mentioned earlier, when it is disadvantageous for Petitioner to take delivery of the physical gas. In contrast, financial hedges could be NYMEX futures, NYMEX call or put options, basis futures or index futures. While financial hedges are related to an underlying volume of natural gas, they are settled financially -- i.e. an exchange of goods is not required. With financial hedges, Petitioner still needs to purchase natural gas on the market to physically receive supply. In scenarios where the amount of natural gas actually needed is less than that which has been hedged, financial hedges allow Petitioner to settle the hedges financially and simply apply the gain or loss to the cost of gas actually purchased. In other words, with a financial hedge, Petitioner would not be required to accept delivery of gas that it does not need. Thus, Petitioner gains increased operational flexibility through the use of financial hedges because it can hedge the volumes needed based on its supply plan, yet "flex" the amount actually purchased based on observed customer demand. Similar to fixed-price contracts, financial hedges, and in particular call options, provide the requisite protection against unexpected and significant upward changes in the market price of natural gas. However, financial hedges also allow Petitioner to take advantage of market prices in a declining market. This contrasts to a fixed-price contract where the purchaser must pay the agreed upon price regardless of what the market price may be. In a market where the market price of natural gas is increasing and exceeds the strike price of the options, the financial hedges are "in the money." Here, Petitioner would purchase the volumes in the market and offset that market price with proceeds from the financial settlement of the hedge. The combination of these two transactions results in a net acquisition price of the financial hedge strike price and the transaction cost of the hedge. In a falling market, where the market price of natural gas is decreasing and is below the strike price, financial hedges are "out of the money." In that case, Petitioner would purchase the physical volumes at the market price and the financial hedges would expire valueless. The combination of these two transactions results in a net acquisition price of the market price and the transaction cost of the hedge.

Q46. IS IT REALISTIC TO BELIEVE THAT PETITIONER'S HEDGING STRATEGY, OR THAT OF ANY GAS UTILITY, WOULD GENERATE THE ABSOLUTE LOWEST COST OF NATURAL GAS?

A46. No. It is not realistic. Financial theory shows us that when hedging any asset with an option, the net cost of the asset always will be higher than the market price because of the addition of the cost of the option. Furthermore, the cost of natural gas does not have to be the absolute lowest cost to be recoverable in the GCA process. Rather, under Indiana Code 8-1-2-42(g)(3)(A), the petitioning gas utility must show that "...the gas utility has made every reasonable effort to acquire long term gas supplies so as to provide gas to its retail customers at the *lowest gas cost reasonably possible....*"(emphasis added)

PREPAID NATURAL GAS PURCHASES

Q47. PLEASE PROVIDE FURTHER INFORMATION ON CITIZENS GAS' PURCHASES FROM THE IMGPA.

A47. In cooperation with the Indiana State Treasurer's Office and the Indiana Bond Bank, Citizens Gas, Batesville Water & Gas Utility, and Lapel Gas formed the IMGPA in 2007 to implement the state's first-ever prepaid natural gas program. The IMGPA is an Indiana nonprofit corporation and an instrumentality of the three previously-mentioned municipal gas utilities, for the purpose of aggregating the current prepaid program. The IMPGA has enough flexibility to serve as a vehicle for future prepaid transactions, as well as to include additional municipal gas utilities.

Effective with gas delivered September 1, 2007, Citizens Gas began purchasing approximately 10% of its then annual retail load (about 3.0 Bcf per year) at a 44 cent per Dth discount from index prices. Over a 15-year period, the prepaid gas program will have provided Citizens Gas customers approximately $24 million in gas cost savings.

Q48. WILL CITIZENS GAS' MONTHLY PURCHASES OF PREPAID GAS BE DISCOUNTED THE FULL 44 CENTS PER DTH AS IT IS DELIVERED?

A48. No. On a monthly basis, Citizens Gas will pay a price equal to the "Panhandle Eastern Pipe Line Co.: Texas Oklahoma (mainline)" index price of Platts *Inside F.E.R.C.'s Gas Market Report* minus a discount of 32 cents per Dth. On November 15th after the end of each contract year ending August 31st, the IMGPA will determine the difference between its revenues and expenses for the contract year. If this difference demonstrates that the IMGPA's revenues exceeded its expenses during the calendar year, IMGPA will make a refund to Citizens Gas equal to the ratio of Citizens Gas' calendar year prepaid gas volumes to the total prepaid gas volumes of all three municipal utilities. The refund also will be credited to customers through Citizens Gas' GCA mechanism as a reduced gas cost and is anticipated to result in an additional 12 cents per Dth discount on the prepaid gas volumes delivered during the contract year, providing a total discount on contract year prepaid gas volumes of 44 cents per Dth.

Q49. HAS PETITIONER RECEIVED A REFUND FROM IMGPA THIS CALENDAR YEAR?

A49. No.

Q50. PLEASE PROVIDE FURTHER INFORMATION ON CITIZENS GAS' PURCHASES FROM THE PUBLIC ENERGY AUTHORITY OF KENTUCKY ("PEAK").

A50. PEAK was formed to provide discounted prepay gas to its municipal members. PEAK approached Citizens Gas about a potential prepaid gas opportunity similar to the IMGPA transaction. In February 2018, Petitioner entered into an agreement with PEAK to purchase discounted prepay natural gas. The transaction has a term of thirty years divided into five periods of six years each. During each six-year period, members of PEAK may elect to participate or not depending on the availability and the minimum threshold of the discount. If the minimum discount is not available, members have no purchase obligations for that period. Citizens Gas' customers will receive the benefit directly through commodity purchases in the GCA.

Effective with gas delivered April 1, 2018, Citizens Gas began purchasing approximately 10,000 Dth per day at a 39 cent per Dth discount from index prices. This discount for gas purchases was effective through October 31, 2020. The discount changed to 33.5 cents per Dth starting November 1, 2020 through October 31, 2023 and 28 cents per Dth discount from November 1, 2023 through February 29, 2024

In March 2020, Petitioner entered into a second agreement with PEAK to purchase additional discounted prepay natural gas. Effective with gas delivered November 1, 2020, Citizens Gas will begin purchasing an additional 10,000 Dth per day at a discount of 20.75 cents per Dth from index prices. This discount will remain for gas purchases through April 30, 2026.

LOAD FORECAST

Q51. HAS PETITIONER'S ANNUAL LOAD FORECAST CHANGED SINCE THE PREVIOUS GCA?

A51. Yes.

Q52. PLEASE DESCRIBE THE CHANGES MADE TO PETITIONER'S ANNUAL LOAD FORECAST.

A52. Petitioner has updated sales volumes after analyzing customer usage. These updated sales volumes affect all rate classes and will continue to be analyzed on a quarterly basis. Thus, it is important to accurately reflect customer usage to minimize variances from projected volumes to actual volumes.

WHOLESALE SERVICES

Q53. IN CAUSE NO. 45577, CITIZENS GAS WAS AUTHORIZED TO OFFER WHOLESALE SERVICES. HAS CITIZENS GAS BEEN ENGAGED IN WHOLESALE NATURAL GAS SALES?

A53. Yes, Citizens Gas did engage in wholesale natural gas sales in the months of December 2021, January and February 2022. The associated volume and revenue with these sales are include on Schedule 8.

Q54. DOES THIS CONCLUDE YOUR TESTIMONY?

A54. Yes, it does.

VERIFICATION

The undersigned affirms under the penalties for perjury that the foregoing testimony is true to the best of his knowledge, information, and belief.

John F. Lamb

John F. Lamb

Citizens Gas
2020 North Meridian Street
Indianapolis, IN 46202

One-Hundred Twenty-Ninth Revised Page No. 501
Superseding Substitute One-Hundred Twenty-Eighth Revised Page No. 501

RIDER A

CURRENT GAS SUPPLY CHARGES

Listed below are the charges applicable to the Utility's Gas Supply Services for all Therms delivered on or after June 1, 2022

1. Gas Rate No. S1 Variable Rate Supply: $ per Therm

Gas Rate No. D1	Gas Supply Charge	$	**0.5060**
Gas Rate No. D2	Gas Supply Charge	$	**0.6178**
Gas Rate No. D3	Gas Supply Charge	$	**0.4329**
Gas Rate No. D4	Gas Supply Charge	$	**0.5734**
Gas Rate No. D5	Gas Supply Charge	$	-
Gas Rate No. D7	Gas Supply Charge	$	**0.4266**

2. Gas Rate No. S2 Back-up Gas Supply Service: $ per Therm

Capacity	$	**0.1033**
Commodity	$	**0.4311**
Gas Supply Charge	$	**0.5344**

3. Balancing Charges: $ per Therm

Gas Rate No. D3	$	**0.0044**	$	**0.0002**	for Basic Delivery Service Option
Gas Rate No. D4	$	**0.0046**	$	**0.0002**	for Basic Delivery Service Option
Gas Rate No. D5	$	**0.0055**	$	**0.0003**	for Basic Delivery Service Option
Gas Rate No. D7	$	**0.0043**			
Gas Rate No. D9	$	**0.0389**	$	**0.0019**	for Basic Delivery Service Option

Citizens Gas
2020 North Meridian Street
Indianapolis, IN 46202

One-Hundred Thirtieth Revised Page No. 501
Superseding One-Hundred Twenty-Ninth Revised Page No. 501

RIDER A

CURRENT GAS SUPPLY CHARGES

Listed below are the charges applicable to the Utility's Gas Supply Services for all Therms delivered on or after July 1, 2022

1. Gas Rate No. S1 Variable Rate Supply: $ per Therm

Gas Rate No. D1	Gas Supply Charge	$	**0.5177**
Gas Rate No. D2	Gas Supply Charge	$	**0.6341**
Gas Rate No. D3	Gas Supply Charge	$	**0.4323**
Gas Rate No. D4	Gas Supply Charge	$	**0.5742**
Gas Rate No. D5	Gas Supply Charge	$	-
Gas Rate No. D7	Gas Supply Charge	$	**0.4323**

2. Gas Rate No. S2 Back-up Gas Supply Service: $ per Therm

Capacity	$	**0.1059**
Commodity	$	**0.4282**
Gas Supply Charge	$	**0.5341**

3. Balancing Charges: $ per Therm

Gas Rate No. D3	$	**0.0045**	$	**0.0002**	for Basic Delivery Service Option
Gas Rate No. D4	$	**0.0047**	$	**0.0002**	for Basic Delivery Service Option
Gas Rate No. D5	$	**0.0057**	$	**0.0003**	for Basic Delivery Service Option
Gas Rate No. D7	$	**0.0045**			
Gas Rate No. D9	$	**0.0385**	$	**0.0019**	for Basic Delivery Service Option

RIDER A

CURRENT GAS SUPPLY CHARGES

Listed below are the charges applicable to the Utility's Gas Supply Services for all Therms delivered on or after August 1, 2022

1. Gas Rate No. S1 Variable Rate Supply: $ per Therm

Gas Rate No. D1	Gas Supply Charge	$	**0.5059**
Gas Rate No. D2	Gas Supply Charge	$	**0.6215**
Gas Rate No. D3	Gas Supply Charge	$	**0.4215**
Gas Rate No. D4	Gas Supply Charge	$	**0.5623**
Gas Rate No. D5	Gas Supply Charge	$	-
Gas Rate No. D7	Gas Supply Charge	$	**0.4215**

2. Gas Rate No. S2 Back-up Gas Supply Service: $ per Therm

Capacity	$	**0.1057**
Commodity	$	**0.4169**
Gas Supply Charge	$	**0.5226**

3. Balancing Charges: $ per Therm

Gas Rate No. D3	$	**0.0045**	$	**0.0002**	for Basic Delivery Service Option
Gas Rate No. D4	$	**0.0047**	$	**0.0002**	for Basic Delivery Service Option
Gas Rate No. D5	$	**0.0057**	$	**0.0003**	for Basic Delivery Service Option
Gas Rate No. D7	$	**0.0045**			
Gas Rate No. D9	$	**0.0385**	$	**0.0019**	for Basic Delivery Service Option

CITIZENS GAS

Impact Statement for Residential Heating Customers

Proposed GCA Factor June 2022
vs.
Currently Approved GCA Factor April 2022

Table No. 1

Consumption Dth	Bill At Proposed GCA Factor $6.1780	Bill At Current GCA Factor $3.7020	Dollar Increase (Decrease)	Percent Change
5	$58.93	$46.55	$12.38	26.60 %
10	$101.36	$76.60	$24.76	32.32 %
15	$143.79	$106.65	$37.14	34.82 %
20	$186.22	$136.70	$49.52	36.23 %
25	$228.65	$166.75	$61.90	37.12 %

Proposed GCA Factor June 2022
vs.
GCA Factor One Year Ago June 2021

Table No. 2

Consumption Dth	Bill At Proposed GCA Factor $6.1780	Bill At Prior Year's GCA Factor $4.2170	Dollar Increase (Decrease)	Percent Change
5	$58.93	$49.24	$9.69	19.68 %
10	$101.36	$81.99	$19.37	23.62 %
15	$143.79	$114.73	$29.06	25.33 %
20	$186.22	$147.48	$38.74	26.27 %
25	$228.65	$180.22	$48.43	26.87 %

CITIZENS GAS

Impact Statement for Residential Heating Customers

Proposed GCA Factor July 2022
vs.
Currently Approved GCA Factor April 2022

Table No. 1

Consumption Dth	Bill At Proposed GCA Factor $6.3410	Bill At Current GCA Factor $3.7020	Dollar Increase (Decrease)	Percent Change
5	$59.74	$46.55	$13.19	28.34 %
10	$102.99	$76.60	$26.39	34.45 %
15	$146.23	$106.65	$39.58	37.11 %
20	$189.48	$136.70	$52.78	38.61 %
25	$232.72	$166.75	$65.97	39.56 %

Proposed GCA Factor July 2022
vs.
GCA Factor One Year Ago July 2021

Table No. 2

Consumption Dth	Bill At Proposed GCA Factor $6.3410	Bill At Prior Year's GCA Factor $4.6730	Dollar Increase (Decrease)	Percent Change
5	$59.74	$51.52	$8.22	15.95 %
10	$102.99	$86.55	$16.44	18.99 %
15	$146.23	$121.57	$24.66	20.28 %
20	$189.48	$156.60	$32.88	21.00 %
25	$232.72	$191.62	$41.10	21.45 %

CITIZENS GAS

Impact Statement for Residential Heating Customers

Proposed GCA Factor August 2022
vs.
Currently Approved GCA Factor April 2022

Table No. 1

Consumption Dth	Bill At Proposed GCA Factor $6.2150	Bill At Current GCA Factor $3.7020	Dollar Increase (Decrease)	Percent Change
5	$59.11	$46.55	$12.56	26.98 %
10	$101.73	$76.60	$25.13	32.81 %
15	$144.34	$106.65	$37.69	35.34 %
20	$186.96	$136.70	$50.26	36.77 %
25	$229.57	$166.75	$62.82	37.67 %

Proposed GCA Factor August 2022
vs.
GCA Factor One Year Ago August 2021

Table No. 2

Consumption Dth	Bill At Proposed GCA Factor $6.2150	Bill At Prior Year's GCA Factor $4.7070	Dollar Increase (Decrease)	Percent Change
5	$59.11	$51.69	$7.42	14.35 %
10	$101.73	$86.89	$14.84	17.08 %
15	$144.34	$122.08	$22.26	18.23 %
20	$186.96	$157.28	$29.68	18.87 %
25	$229.57	$192.47	$37.10	19.28 %

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated For June 2022

Line No.		A Demand	B Commodity and Other	C Total
	Estimated Cost of Gas			
1	Purchased gas cost (Schedule 3, Page 1, ln 16)	$752,776	$6,596,626	$7,349,402
2	PEPL Unnominated Quantities cost (Schedule 4 pg 1, ln 16 col A + ln 23)	-	604,143	604,143
3	Gas (injected into) withdrawn from storage - net cost (Schedule 5, ln 3)	(481,530)	(4,219,215)	(4,700,745)
4	Total estimated gas cost (ln 1 through ln 3)	$271,246	$2,981,554	$3,252,800
5	Total Gas Supply variance (Sch 1, June, total of ln 17)	-	65,538	65,538
6	Total Balancing Demand variance (Sch 1 pg 2 ln 11 + Sch. 1, ln 28)	-	4,024	4,024
7	Dollars to be refunded (Schedule 12A, ln 16 * Sch 2B, ln 27, col. F)	-	-	-
8	Total cost to be recovered through GCA (ln 4 + ln 5 + ln 6 - ln 7)	$271,246	$3,051,116	$3,322,362
9	Net Write-Off Recovery Costs (ln 8 *1.10%)			$36,546
10	Total cost to be recovered through GCA (ln. 8 + ln 9)			$3,358,908

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated For June 2022
To Be Applied To June 2022

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5
	Calculation of Gas Supply Charge per Unit (Dth)					
11	Balancing Demand Cost Variance (Sch12B, pg. 2, ln 13 * Sch 2C, ln 22)	($18)	($1,227)	-	-	-
12	Throughput excluding Basic - Dth (Sch 2C, ln 1)	4,071	367,277	-	-	-
13	Total Balancing Demand Cost variance per unit of throughput (ln 11/ ln 12)	($0.004)	($0.003)	-	-	-
14	Retail demand cost per unit sales (Sch 1A, pg 1 ln 8)	0.218	0.541	0.058	0.443	-
15	Monthly balancing demand cost per unit for GR D1 & D2 only (Sch 1A, pg 1, ln 11)	0.000	0.000	-	-	-
16	Total demand cost to be recovered through GCA (ln 13 + ln 14 + ln 15)	$0.214	$0.538	$0.058	$0.443	$0.000
17	Total Gas Supply variance (Sch 12B, pg 1, ln 15) * (Sch 2B, ln 27)	366	51,025	(416)	14,563	0
18	Dollars to be refunded ((ln 7) * Sch 2B, ln 23)	0	0	0	0	0
19	Other non-demand gas costs (ln 4, col B - ln 2, col B) * (Sch 2B, ln 23)	16,994	1,533,155	177,081	650,181	0
20	Total monthly non-demand costs to be recovered through Gas Supply Charge (ln 17 - ln 18 + ln 19)	$17,360	$1,584,180	$176,665	$664,744	$0
21	Sales subject to GCA - Dth (Schedule 2B, ln 1)	4,071	367,277	42,421	155,755	0
22	Total monthly non-demand costs per unit sales (ln 20 / ln 21)	$4.264	$4.313	$4.165	$4.268	$0.000
23	Net Write-Off Recovery Cost (Sch 1C, pg 1, ln 4)	0.038	0.090	0.002	0.020	0.000
24	PEPL Unnominated Quantites Retail Cost (Schedule 4, pg. 1 ln 8)	0.421	1.098	0.041	0.919	0.000
25	PEPL Balancing Cost for Gas Rates D1 & D2 only (Sch 4, pg 1, ln 15)	0.049	0.049	-	-	-
26	Gas Supply Charge to be recovered through GCA (ln 16 + ln 22 + ln 23 + ln 24 + ln 25)	$4.986	$6.088	$4.266	$5.650	$0.000
27	Gas Supply Charge modified for Indiana Utility Receipts Tax (ln 26 / (1 - 1.46%))	$5.060	$6.178	$4.329	$5.734	$0.000

Citizens Gas
Determination of Balancing Demand Charge per Unit (Dth)
Estimated for the Period June 2022
To Be Applied to the June 2022 Throughput

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No. D9
	Calculation of Balancing Demand Charge per Unit (Dth)				
28	Balancing Demand Cost Variance (Sch12B, pg. 2, ln 13 * Sch 2C, ln 22)	($1,197)	($1,386)	$859	$6,993
29	Throughput excluding Basic - Dth (Sch 2C, ln 1)	211,241	342,835	154,500	20,940
30	Total Balancing Demand Cost variance per unit of throughput (ln 28/ ln 29)	($0.0057)	($0.0040)	$0.0056	$0.3340
31	Monthly balancing demand charge per unit of throughput (Sch 1A, pg 1, ln 11)	0.000	0.000	0.000	0.000
32	PEPL balancing demand charge per unit of throughput (Sch 4, pg 1, ln 15)	0.0490	0.0490	0.0490	0.0490
33	Total balancing demand charge per unit of throughput (ln 30 + ln 31 + ln 32)	0.0433	$0.0450	$0.0546	$0.3830
34	Total balancing demand charge modified for Indiana Utilities Receipts Tax (ln 33 / (1-1.46%))	$0.044	$0.046	$0.055	$0.389

Citizens Gas
Determination of Basic Balancing Charge
Estimated for June 2022
To Be Applied to June 2022

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No.D9
	Calculation of Basic Balancing Charge per unit (Dth)				
35	Basic balancing charge per unit ((Sch 1, ln 30 + ln 31 + ln 32) * .05)	0.0022	0.0023	0.0027	0.0192
36	Basic balancing charge modified for Indiana Utilities Receipts Tax (ln 35/ (1-1.46%))	$0.002	$0.002	$0.003	$0.019

Citizens Gas
Determination of Back-up Gas Supply Charge
Estimated for June 2022
To Be Applied to June 2022

Line No.		
	Calculation of Back-up Gas Supply Charge per unit (Dth)	
37	PEPL retail demand costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 1, ln 2)	$130,279
38	Monthly retail demand costs for Gas Rate Nos. D3 & D4 (Sch 1A, pg 1, ln 6)	71,502
39	Total retail demand costs for Gas Rates Nos. D3 & D4 (ln 37 + ln 38)	$201,781
40	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, line 1)	198,176
41	Back-up supply capacity charge per unit (ln 39 / ln 40)	$1.018
42	Back-up supply capacity charge modified for Indiana Utilities Receipts Tax (ln 41 / (1-1.46%))	$1.033
43	PEPL monthly variable costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 1, ln 5)	$14,646
44	Total monthly non-demand costs for Gas Rate Nos. D3 & D4 (Sch 1, ln 19 - ln 18)	827,262
45	Total retail non-demand costs for Gas Rates Nos. D3 & D4 (ln 43 + ln 44)	$841,908
46	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, ln 1)	198,176
47	Back-up supply commodity charge per unit (ln 45 / ln 46)	$4.248
48	Back-up supply commodity charge modified for Indiana Utilities Receipts Tax (ln 47 / (1-1.46%))	$4.311
49	Total Back-up Gas Supply Charge (ln 42 + ln 48)	$5.344

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for July 2022

Line No.		A Demand	B Commodity and Other	C Total
	Estimated Cost of Gas			
1	Purchased gas cost (Schedule 3, Page 2, ln 16)	$799,776	$6,561,511	$7,361,287
2	PEPL Unnominated Quantities cost (Schedule 4 pg 2, ln 16 col A + ln 23)	-	596,145	$596,145
3	Gas (injected into) withdrawn from storage - net cost (Schedule 5, ln 6)	(530,014)	(4,348,059)	($4,878,073)
4	Total estimated gas cost (ln 1 through ln 3)	$269,762	$2,809,597	$3,079,359
5	Total Gas Supply variance (Sch 1, July, total of ln 17)	-	59,302	$59,302
6	Total Balancing Demand variance (Sch 1 pg 2 ln 11 + Sch. 1, ln 28)		4,197	$4,197
7	Dollars to be refunded (Schedule 12A, ln 16 * Sch 2B, ln 28, col. F)	-	-	-
8	Total cost to be recovered through GCA (ln 4 + ln 5 + ln 6 - ln 7)	$269,762	$2,873,096	$3,142,858
9	Net Write-Off Recovery Costs (ln 8 * 1.10%)			$34,571
10	Total cost to be recovered through GCA (ln. 8 + ln 9)			$3,177,429

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for July 2022
To Be Applied to July 2022 Sales

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5
	Calculation of Gas Supply Charge per Unit (Dth)					
11	Balancing Demand Cost Variance (Sch 12B, pg 2, ln 13 * Sch 2C, ln 23)	($15)	($1,090)	-	-	-
12	Throughput excluding Basic - Dth (Sch 2C, ln 2)	3,374	326,459	-	-	-
13	Total Balancing Demand Cost per unit of throughput (ln 11 /ln 12)	($0.004)	($0.003)	-	-	-
14	Retail demand cost per unit sales (Sch 1A, pg 2 ln 8)	0.262	0.606	0.057	0.457	-
15	Monthly balancing demand cost per unit for GR D1 & D2 only (Sch 1A, pg 2, ln 11)	0.000	0.000	-	-	-
16	Total demand cost to be recovered through GCA (ln 13 + ln 14 + ln 15)	$0.258	$0.603	$0.057	$0.457	$0.000
17	Total Gas Supply variance (Sch 12B, pg 1, ln 15) * (Sch 2B, ln 28)	304	45,354	(419)	14,063	0
18	Dollars to be refunded ((ln 7) * Sch 2B, ln 24)	0	0	0	0	0
19	Other non-demand gas costs (ln 4, col B - ln 2, col B) * (Sch 2B, ln 24)	14,281	1,381,836	180,693	636,642	0
20	Total monthly non-demand costs to be recovered through Gas Supply Charge (ln 17 - ln 18 + ln 19)	$14,585	$1,427,190	$180,274	$650,705	$0
21	Sales subject to GCA - Dth (Schedule 2B, ln 2)	3,374	326,459	42,689	150,407	0
22	Total monthly non-demand costs per unit sales (ln 20 / ln 21)	$4.323	$4.372	$4.223	$4.326	$0.000
23	Net Write-Off Recovery Cost (Sch 1C, pg 2, ln 4)	0.043	0.096	0.002	$0.019	$0.000
24	PEPL Unnominated Quantites Retail Cost (Sch 4, pg 2 ln 8)	0.501	1.219	0.041	0.940	0.000
25	PEPL Balancing Cost for Gas Rates D1 & D2 only (Sch 4, pg 2, ln 15)	0.052	0.051	-	-	-
26	Gas Supply Charge to be recovered through GCA (ln 16 + ln 22 + ln 23 + ln 24 + ln 25)	$5.177	$6.341	$4.323	$5.742	$0.000

Citizens Gas
Determination of Balancing Demand Charge per Unit (Dth)
Estimated for July 2022
To Be Applied to the July 2022 Throughput

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No. D9
	Calculation of Balancing Demand Charge per Unit (Dth)				
27	Balancing Demand Cost Variance (Sch12B, pg. 2, ln 13 * Sch 2C, ln 23)	($1,195)	($1,330)	$850	$6,977
28	Throughput excluding Basic - Dth (Sch 2C, ln 2)	210,913	328,967	152,892	20,894
29	Total Balancing Demand Cost variance per unit of throughput (ln 27/ ln 28)	($0.0057)	($0.0040)	$0.0056	$0.3339
30	Monthly balancing demand charge per unit of throughput (Sch 1A, pg 2, ln 11)	0.000	0.000	0.000	0.000
31	PEPL balancing demand charge per unit of throughput (Sch 4, pg 2, ln 15)	0.0510	0.0510	0.0510	0.0510
32	Total balancing demand charge per unit of throughput (ln 29 + ln 30 + ln 31)	$0.0453	$0.0470	$0.0566	$0.3849

Citizens Gas
Determination of Basic Balancing Charge
Estimated for July 2022
To Be Applied to July 2022

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No. D9
	Calculation of Basic Balancing Charge per unit (Dth)				
33	Basic balancing charge per unit ((Sch 1, ln 29 + ln 30 + ln 31) * .05)	0.0023	0.0024	0.0028	0.0192

Citizens Gas
Determination of Back-up Gas Supply Charge
Estimated for July 2022
To Be Applied to July 2022

Line No.		
	Calculation of Back-up Gas Supply Charge per unit (Dth)	
34	PEPL retail demand costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 2, ln 2)	$133,440
35	Monthly retail demand costs for Gas Rate Nos. D3 & D4 (Sch 1A, pg 2, ln 6)	71,111
36	Total retail demand costs for Gas Rates Nos. D3 & D4 (ln 34 + ln 35)	$204,551
37	Estimated Monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, line 2)	193,096
38	Back-up supply capacity charge per unit (ln 36 / ln 37)	$1.059
39	PEPL monthly variable costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 2, ln 5)	$9,567
40	Total monthly non-demand costs for Gas Rate Nos. D3 & D4 (Sch 1, ln 19 - ln 18)	817,335
41	Total retail non-demand costs for Gas Rates Nos. D3 & D4 (ln 39 + ln 40)	$826,902
42	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, ln 2)	193,096
43	Back-up supply commodity charge per unit (ln 41 / ln 42)	$4.282
44	Total Back-up Gas Supply Charge (ln 38 + ln 43)	$5.341

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for August 2022

Line No.		A Demand	B Commodity and Other	C Total
	Estimated Cost of Gas			
1	Purchased gas cost (Schedule 3, Page 3, ln 16)	$753,896	$6,137,313	$6,891,209
2	PEPL Unnominated Quantities cost (Schedule 4 pg 3, ln 16 col A + ln 23)	-	589,813	589,813
3	Gas (injected into) withdrawn from storage - net cost (Schedule 5, ln 9)	(490,235)	(3,990,876)	(4,481,111)
4	Total estimated gas cost (ln 1 through ln 3)	$263,661	$2,736,250	$2,999,911
5	Total Gas Supply variance (Sch 1, August, total of ln 17)	-	58,989	58,989
6	Total Balancing Demand variance (total of Sch 1 pg 2 ln 11 + Sch. 1, ln 28)		4,203	4,203
7	Dollars to be refunded (Schedule 12A, ln 16 * Sch 2B, ln 29, col. F)	-	-	-
8	Total cost to be recovered through GCA (ln 4 + ln 5 + ln 6 - ln 7)	$263,661	$2,799,442	$3,063,103
9	Net Write-Off Recovery Costs (ln 8 * 1.10%)			$33,694
10	Total cost to be recovered through GCA (ln. 8 + ln 9)			$3,096,797

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for August 2022
To Be Applied to August 2022 Sales

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5
	Calculation of Gas Supply Charge per Unit (Dth)					
11	Balancing Demand Cost Variance (Sch 12B, pg 2, ln 13 * Sch 2C, ln 24)	($16)	($1,085)	-	-	-
12	Throughput excluding Basic - Dth (Sch 2C, ln 3)	3,371	324,772	-	-	-
13	Total Balancing Demand Cost per unit of throughput (ln 11/ln 12)	($0.005)	($0.003)	-	-	-
14	Retail demand cost per unit sales (Sch 1A, pg 3 ln 8)	$0.257	$0.595	$0.056	$0.449	-
15	Monthly balancing demand cost per unit for GR D1 & D2 only (Sch 1A, pg 3, ln 11)	0.000	0.000	-	-	-
16	Total demand cost to be recovered through GCA (ln 13 + ln 14 + ln 15)	$0.252	$0.592	$0.056	$0.449	$0.000
17	Total variance (Sch 12B, pg 1, ln 15) * (Sch 2B, ln 29)	303	45,119	(416)	13,983	0
18	Dollars to be refunded ((ln 7) * Sch 2B, ln 25)	0	0	0	0	0
19	Other non-demand gas costs (ln 4, col B - ln 2, col B) * (Sch 2B, ln 25)	13,911	1,340,286	175,081	617,159	0
20	Total monthly non-demand costs to be recovered through Gas Supply Charge (ln 17 - ln 18 + ln 19)	$14,214	$1,385,405	$174,665	$631,142	$0
21	Sales subject to GCA - Dth (Schedule 2B, ln 3)	3,371	324,772	42,425	149,547	0
22	Total monthly non-demand costs per unit sales (ln 20 / ln 21)	$4.217	$4.266	$4.117	$4.220	$0.000
23	Net Write-Off Recovery Cost (Sch 1C, pg 3 ln 4)	0.042	0.094	0.002	0.019	0.000
24	PEPL Unnominated Quantites Retail Cost (Sch 4, pg 3 ln 8)	0.497	1.212	0.040	0.935	0.000
25	PEPL Balancing Cost for Gas Rates D1 & D2 only (Sch 4, pg 3, ln 15)	0.051	0.051	-	-	-
26	Gas Supply Charge to be recovered through GCA (ln 16 + ln 22 + ln 23 + ln 24 + ln 25)	$5.059	$6.215	$4.215	$5.623	$0.000

Citizens Gas
Determination of Balancing Demand Charge per Unit (Dth)
Estimated For the Period August 2022
To Be Applied to the August 2022 Throughput

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No. D9
	Calculation of Balancing Demand Charge per Unit (Dth)				
27	Balancing Demand Cost Variance (Sch12B, pg. 2, ln 13 * Sch 2C, ln 24)	($1,194)	($1,329)	$850	$6,977
28	Throughput excluding Basic - Dth (Sch 2C, ln 3)	210,649	328,727	153,016	20,894
29	Total Balancing Demand Cost variance per unit of throughput (ln 28/ ln 29)	($0.0057)	($0.0040)	$0.0056	$0.3339
30	Monthly balancing demand charge per unit of throughput (Sch 1A, pg 3, ln 11)	0.000	0.000	0.000	0.000
31	PEPL balancing demand charge per unit of throughput (Sch 4, pg 3, ln 15)	0.0510	0.0510	0.0510	0.0510
32	Total balancing demand charge per unit of throughput (ln 29 + ln 30 + ln 31)	$0.0453	$0.0470	$0.0566	$0.3849

Citizens Gas
Determination of Basic Balancing Charge
Estimated for August 2022
To Be Applied to August 2022

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No. D9
	Calculation of Basic Balancing Charge per unit (Dth)				
33	Basic Balancing Charge per unit ((Sch 1, ln 29 + ln 30 + ln 31) * .05)	0.0023	0.0024	0.0028	0.0192

Citizens Gas
Determination of Back-up Gas Supply Charge
Estimated for August 2022
To Be Applied to August 2022

Line No.	Calculation of Back-up Gas Supply Charge per unit (Dth)	
34	PEPL retail demand costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 3, ln 2)	$133,440
35	Monthly retail demand costs for Gas Rate Nos. D3 & D4 (Sch 1A, pg 3, ln 6)	69,503
36	Total retail demand costs for Gas Rates Nos. D3 & D4 (ln 34 + ln 35)	$202,943
37	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, line 3)	191,972
38	Back-up supply capacity charge per unit (ln 36 / ln 37)	$1.057
39	PEPL monthly variable costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 3, ln 5)	$8,049
40	Total monthly non-demand costs for Gas Rate Nos. D3 & D4 (Sch 1, ln 19 - ln 18)	792,240
41	Total retail non-demand costs for Gas Rates Nos. D3 & D4 (ln 39 + ln 40)	$800,289
42	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, ln 3)	191,972
43	Back-up supply commodity charge per unit (ln 41 / ln 42)	$4.169
44	Total Back-up Gas Supply Charge (ln 38 + ln 43)	$5.226

Citizens Gas
Allocation of Monthly Demand Cost
June 2022

Line No.	Calculation of Demand Cost per Unit	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G Total
1	Retail Peak day demand allocation factors Cause No. 37399 GCA 140	0.003153	0.740425	0.006293	0.250129	-	-	1.000000
2	Retail Throughput demand allocation factors Cause No. 37399 GCA 140	0.003754	0.705611	0.019399	0.271236	-	-	1.000000
3	Peak day / Throughput allocation factors (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	-	-	1.000000
4	Monthly retail demand costs (ln 17 * ln 3)	$889	$198,855	$2,453	$69,049	-	-	$271,246
5	Monthly TGT Unnom. demand costs - retail (ln 18 * 90%) * ln 3)	0	0	0	0	-	-	0
6	Total monthly retail demand costs (ln 4 + ln 5)	$889	$198,855	$2,453	$69,049	-	-	$271,246
7	Estimated monthly retail sales- Dth (Sch 2B, ln 1)	4,071	367,277	42,421	155,755	-	-	569,524
8	Monthly retail demand cost per unit sales (ln 6 / ln 7)	$0.218	$0.541	$0.058	$0.443	-	-	$0.476
9	Monthly balancing demand costs (ln 18 * 10%) * (Sch. 2C, ln 18)	0	0	0	0	0	0	0
10	Estimated monthly total throughput excl. Basic - Dth (Sch 2C, ln 1)	4,071	367,277	211,241	342,835	154,500	20,940	1,100,864
11	Monthly balancing demand cost per unit of throughput (ln 9 / ln 10)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000

Line No.	Calculation of Monthly Demand Costs	Demand Cost
	Exelon Generation Company, LLC	
12	Nominated Demand Costs	$ 942,422
13	TGT Unnominated Demand Costs	$ -
14	IMGPA Prepay Demand Costs	$ 90,195
15	Demand Cost (Sch 3 ln 15 col G)	$ (279,841)
16	Demand Cost (Sch 5 ln 3 col G)	$ (481,530)
17	Monthly retail demand costs (ln 12 + sum(ln14 + ln15 + ln16))	$ 271,246
18	Unnominated Demand Costs (ln 13)	$0
19	Total monthly demand costs (ln 17 + ln 18)	$271,246

Citizens Gas
Allocation of Monthly Demand Cost
July 2022

Line No.	Calculation of Demand Cost per Unit	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G Total
1	Retail Peak day demand allocation factors Cause No. 37399 GCA 140	0.003153	0.740425	0.006293	0.250129	-	-	1.000000
2	Retail Throughput demand allocation factors Cause No. 37399 GCA 140	0.003754	0.705611	0.019399	0.271236	-	-	1.000000
3	Peak day / Throughput allocation factors (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	-	-	1.000000
4	Monthly retail demand costs (ln 17 * ln 3)	$885	$197,766	$2,440	$68,671	-	-	$269,762
5	Monthly TGT Unnom. demand costs - retail (ln 18 * 90%) * ln 3)	0	0	0	0	-	-	0
6	Total monthly retail demand costs (ln 4 + ln 5)	$885	$197,766	$2,440	$68,671	-	-	$269,762
7	Estimated monthly retail sales- Dth (Sch 2B, ln 2)	3,374	326,459	42,689	150,407	-	-	522,929
8	Monthly retail demand cost per unit sales (ln 6 / ln 7)	$0.262	$0.606	$0.057	$0.457	-	-	$0.516
9	Monthly balancing demand costs (ln 18 * 10%) * (Sch. 2C, ln 19)	0	0	0	0	0	0	0
10	Estimated monthly total throughput - Dth (Sch 2C, ln 2)	3,374	326,459	210,913	328,967	152,892	20,894	1,043,499
11	Monthly balancing demand cost per unit of throughput (ln 9 / ln 10)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000

	Calculation of Monthly Demand Costs	Demand Cost
	Exelon Generation Company, LLC	
12	Nominated Demand Costs	$ 956,974
13	TGT Unnominated Demand Costs	$ -
14	IMGPA Prepay Demand Costs	$ 93,202
15	Demand Cost (Sch 3 ln 15 col G)	$ (250,400)
16	Demand Cost (Sch 5 Ln 6 Col G)	$ (530,014)
17	Monthly retail demand costs (ln 12 + sum(ln 14 + ln15 + ln16))	$ 269,762
18	Unnominated Demand Costs (ln 13)	$0
19	Total Monthly demand costs (ln 17 + ln 18)	$ 269,762

Citizens Gas
Allocation of Monthly Demand Cost
August 2022

Line No.	Calculation of Demand Cost per Unit	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G Total
1	Retail Peak day demand allocation factors Cause No. 37399 GCA 140	0.003153	0.740425	0.006293	0.250129	-	-	1.000000
2	Retail Throughput demand allocation factors Cause No. 37399 GCA 140	0.003754	0.705611	0.019399	0.271236	-	-	1.000000
3	Peak day / Throughput allocation factors (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	-	-	1.000000
4	Monthly retail demand costs (ln 17 * ln 3)	$865	$193,293	$2,385	$67,118	-	-	$263,661
5	Monthly TGT Unnom. demand costs - retail (ln 18 * 90%) * ln 3)	0	0	0	0	-	-	0
6	Total monthly retail demand costs (ln 4 + ln 5)	$865	$193,293	$2,385	$67,118	-	-	$263,661
7	Estimated monthly retail sales- Dth (Sch 2B, ln 3)	3,371	324,772	42,425	149,547	-	-	520,115
8	Monthly retail demand cost per unit sales (ln 6 / ln 7)	$0.257	$0.595	$0.056	$0.449	-	-	$0.507
9	Monthly balancing demand costs (ln 18 * 10%) * (Sch. 2C, ln 20)	0	0	0	0	0	0	0
10	Estimated monthly total throughput - Dth (Sch 2C, ln 3)	3,371	324,772	210,649	328,727	153,016	20,894	1,041,429
11	Monthly balancing demand cost per unit of throughput (ln 9 / ln 10)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000

Line No.	Calculation of Monthly Demand Costs	Demand Cost
	Exelon Generation Company, LLC	
12	Nominated Demand Costs	$ 956,974
13	TGT Unnominated Demand Costs	$ -
14	IMGPA Prepay Demand Costs	$ 93,202
15	Demand Cost (Sch 3 ln 15 col G)	$ (296,280)
16	Demand Cost (Sch 5 Ln 9 Col G)	$ (490,235)
17	Monthly retail demand costs (ln 12 + sum(ln 14 + ln15 + ln16))	$ 263,661
18	Unnominated Demand Costs (ln 13)	$0
19	Total Monthly demand costs (ln 17 + ln 18)	$263,661

Citizens Gas
Determination of Gas Cost Adjustment (GCA)
Estimation Period June 1, 2022 through August 31, 2022
UAF Component in Rates ($/DTH)

Line No.		A June 2022	B July 2022	C August 2022	D Total
1	Volume of pipeline gas purchases (Sch. 3) - Dths	1,641,636	1,597,092	1,526,746	4,765,474
2	Volume of Gas (injected into) withdrawn from storage (See Schedule 3B) - Dths	(1,062,216)	(1,066,108)	(999,444)	(3,127,768)
3	Total volume supplied - Dths	579,420	530,984	527,302	1,637,706
4	Less: Gas Division usage - Dths	(5,069)	(3,632)	(2,796)	(11,497)
5	Total volume of gas available for sale - Dths (ln 3 + ln 4)	574,351	527,352	524,506	1,626,209
6	UAF Percentage 0.840%	0.840%	0.840%	0.840%	
7	UAF Volumes - Dths (ln 5 * ln 6)	4,825	4,430	4,406	13,661
8	Average Commodity Rate - Schedule 3A	$4.0183	$4.1084	$4.0199	
9	UAF Costs (ln7 * ln8)	$19,388	$18,200	$17,712	$55,300
10	Schedule 2B Retail sales volumes	569,524	522,929	520,115	1,612,568
11	UAF Component in rates - $ per Dth (ln9 / ln10) 1/	$0.0340	$0.0348	$0.0341	

1/ For informational purposes only.

Citizens Gas
Allocation of Net Write-Off Recovery Cost
June 2022

Line No.	Calculation of Net Write-Off Recovery Cost per Unit (Dth)	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Total
1	Net Write-Off Recovery allocation factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
2	Net Write-Off Recovery cost (Sch. 1, ln 9) * ln 1	$154	$33,220	$94	$3,053	$25	$36,546
3	Estimated retail sales- Dth (Sch 2B, ln 1)	4,071	367,277	42,421	155,755	0	569,524
4	Net Write-Off Recovery cost per unit sales (ln 2 / ln 3)	$0.038	$0.090	$0.002	$0.020	$0.000	

Citizens Gas
Allocation of Net Write-Off Recovery Cost
July 2022

Line No.	Calculation of Net Write-Off Recovery Cost per Unit (Dth)	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Total
1	Net Write-Off Recovery allocation factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
2	Net Write-Off Recovery cost (Sch. 1, ln 9) * ln 1	$145	$31,425	$89	$2,888	$24	$34,571
3	Estimated retail sales- Dth (Sch 2B, ln 2)	3,374	326,459	42,689	150,407	0	522,929
4	Net Write-Off Recovery cost per unit sales (ln 2 / ln 3)	$0.043	$0.096	$0.002	$0.019	$0.000	

Citizens Gas
Allocation of Net Write-Off Recovery Cost
August 2022

Line No.	Calculation of Net Write-Off Recovery Cost per Unit (Dth)	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Total
1	Net Write-Off Recovery allocation factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
2	Net Write-Off Recovery cost (Sch. 1, ln 9) * ln 1	$142	$30,627	$87	$2,815	$23	$33,694
3	Estimated retail sales- Dth (Sch 2B, ln 3)	3,371	324,772	42,425	149,547	0	520,115
4	Net Write-Off Recovery cost per unit sales (ln 2 / ln 3)	$0.042	$0.094	$0.002	$0.019	$0.000	

Citizens Gas
Estimated Total Throughput for Twelve Months Ending May 2023

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G Total Throughput Subject to GCA
	Estimated Total Throughput Volumes (Dth) for Twelve Months Ending May 2023							
1	June 2022	4,071	367,277	225,581	346,795	225,660	512,580	1,681,964
2	July 2022	3,374	326,459	225,297	332,873	223,076	785,718	1,896,797
3	August 2022	3,371	324,772	225,033	332,633	223,262	785,780	1,894,851
4	First Quarter	10,816	1,018,508	675,911	1,012,301	671,998	2,084,078	5,473,612
5	September 2022	4,016	340,286	227,337	391,331	234,060	762,060	1,959,090
6	October 2022	4,875	639,013	255,742	598,451	283,588	810,332	2,592,001
7	November 2022	8,947	1,899,779	274,043	1,210,994	348,600	564,180	4,306,543
8	Second Quarter	17,838	2,879,078	757,122	2,200,776	866,248	2,136,572	8,857,634
9	December 2022	16,893	3,431,482	301,675	2,011,024	413,106	332,506	6,506,686
10	January 2023	20,152	4,011,918	288,366	2,424,531	441,812	344,162	7,530,941
11	February 2023	19,750	4,047,002	264,148	2,183,895	398,944	326,704	7,240,443
12	Third Quarter	56,795	11,490,402	854,189	6,619,450	1,253,862	1,003,372	21,278,070
13	March 2023	14,517	2,875,562	249,151	1,703,382	358,670	575,910	5,777,192
14	April 2023	9,496	1,843,982	236,735	1,081,575	291,660	783,960	4,247,408
15	May 2023	5,403	984,281	231,883	593,882	248,248	795,948	2,859,645
16	Fourth Quarter	29,416	5,703,825	717,769	3,378,839	898,578	2,155,818	12,884,245
17	Total Throughput - Dth	114,865	21,091,813	3,004,991	13,211,366	3,690,686	7,379,840	48,493,561
	Quarterly Allocation Factor							
18	First Quarter (line 4/line 17)	0.094163	0.048290	0.224929	0.076624	0.182079	0.282401	0.112873
19	Second Quarter (line 8/line 17)	0.155295	0.136502	0.251955	0.166582	0.234712	0.289515	0.182656
20	Third Quarter (line 12/line 17)	0.494450	0.544780	0.284257	0.501042	0.339737	0.135961	0.438781
21	Fourth Quarter (line 16/line 17)	0.256092	0.270428	0.238859	0.255752	0.243472	0.292123	0.265690
	Current Throughput Allocation Factor							
22	Allocation of June 2022 Estimated Throughput (line 1/line 1, column G)	0.002420	0.218361	0.134118	0.206185	0.134165	0.304751	1.000000
23	Allocation of July 2022 Estimated Throughput (line 2/line 2, column G)	0.001779	0.172110	0.118778	0.175492	0.117607	0.414234	1.000000
24	Allocation of August 2022 Estimated Throughput (line 3/line 3, column G)	0.001779	0.171397	0.118760	0.175546	0.117826	0.414692	1.000000
25	Allocation of Quarter Estimated Throughput (line 4/line 4, column G)	0.001976	0.186077	0.123485	0.184942	0.122770	0.380750	1.000000
	Monthly Allocation Factors							
26	June 2022 (line 1/line 4)	0.376387	0.360603	0.333744	0.342581	0.335805	0.245950	0.307286
27	July 2022 (line 2/line 4)	0.311945	0.320527	0.333323	0.328828	0.331959	0.377010	0.346535
28	August 2022 (line 3/line 4)	0.311668	0.318870	0.332933	0.328591	0.332236	0.377040	0.346179
29	Total Throughput Allocation Factor (line 17/line 17, col. G)	0.002369	0.434940	0.061967	0.272435	0.076107	0.152182	1.000000

Citizens Gas
Estimated Retail Sales Volume for Twelve Months Ending May 2023

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Total Retail Sales Subject to GCA
	Estimated Retail Sales Volumes (Dth) for Twelve Months Ending May 2023						
1	June 2022	4,071	367,277	42,421	155,755	0	569,524
2	July 2022	3,374	326,459	42,689	150,407	0	522,929
3	August 2022	3,371	324,772	42,425	149,547	0	520,115
4	First Quarter	10,816	1,018,508	127,535	455,709	0	1,612,568
5	September 2022	4,016	340,286	42,077	172,031	0	558,410
6	October 2022	4,875	639,013	54,043	194,292	0	892,223
7	November 2022	8,947	1,899,779	55,854	578,198	0	2,542,778
8	Second Quarter	17,838	2,879,078	151,974	944,521	0	3,993,411
9	December 2022	16,893	3,431,482	67,193	1,151,651	0	4,667,219
10	January 2023	20,152	4,011,918	46,577	1,464,340	0	5,542,987
11	February 2023	19,750	4,047,002	33,241	1,374,253	0	5,474,246
12	Third Quarter	56,795	11,490,402	147,011	3,990,244	0	15,684,452
13	March 2023	14,517	2,875,562	28,455	1,035,363	0	3,953,897
14	April 2023	9,496	1,843,982	32,995	649,077	0	2,535,550
15	May 2023	5,403	984,281	39,142	314,101	0	1,342,927
16	Fourth Quarter	29,416	5,703,825	100,592	1,998,541	0	7,832,374
17	Total Retail Sales - Dth	114,865	21,091,813	527,112	7,389,015	0	29,122,805
	Quarterly Retail Allocation Factor						
18	First Quarter (line 4/line 17)	0.094163	0.048290	0.241951	0.061673	0.000000	0.055371
19	Second Quarter (line 8/line 17)	0.155295	0.136502	0.288314	0.127828	0.000000	0.137123
20	Third Quarter (line 12/line 17)	0.494450	0.544780	0.278899	0.540024	0.000000	0.538563
21	Fourth Quarter (line 16/line 17)	0.256092	0.270428	0.190836	0.270475	0.000000	0.268943
22	Annual (line 17 / line 17, Column F)	0.003944	0.724237	0.018100	0.253719	0.000000	1.000000
	Current Retail Sales Allocation Factor						
23	Allocation of June 2022 Estimated Throughput (line 1/line 1, column F)	0.007148	0.644884	0.074485	0.273483	0.000000	1.000000
24	Allocation of July 2022 Estimated Throughput (line 2/line 2, column F)	0.006452	0.624290	0.081634	0.287624	0.000000	1.000000
25	Allocation of August 2022 Estimated Throughput (line 3/line 3, column F)	0.006481	0.624424	0.081568	0.287527	0.000000	1.000000
26	Allocation of Quarter Estimated Retail Sales (line 4/line 4, column F)	0.006707	0.631607	0.079088	0.282598	0.000000	1.000000
	Monthly Retail Allocation Factors						
27	June 2022 (line 1/line 4)	0.376387	0.360603	0.332622	0.341786	0.000000	0.353179
28	July 2022 (line 2/line 4)	0.311945	0.320527	0.334724	0.330051	0.000000	0.324283
29	August 2022 (line 3/line 4)	0.311668	0.318870	0.332654	0.328163	0.000000	0.322538

Citizens Gas
Estimated Total Throughput Excluding Basic Volume (Dth) for Twelve Months Ending May 2023

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G Total Throughput Subject to GCA
	Estimated Total Throughput Excluding Basic Volumes (Dth) for Twelve Months Ending May 2023							
1	June 2022	4,071	367,277	211,241	342,835	154,500	20,940	1,100,864
2	July 2022	3,374	326,459	210,913	328,967	152,892	20,894	1,043,499
3	August 2022	3,371	324,772	210,649	328,727	153,016	20,894	1,041,429
4	First Quarter	10,816	1,018,508	632,803	1,000,529	460,408	62,728	3,185,792
5	September 2022	4,016	340,286	212,997	387,251	159,840	21,120	1,125,510
6	October 2022	4,875	639,013	241,205	593,615	191,084	22,258	1,692,050
7	November 2022	8,947	1,899,779	259,549	1,205,174	232,080	23,760	3,629,289
8	Second Quarter	17,838	2,879,078	713,751	2,186,040	583,004	67,138	6,446,849
9	December 2022	16,893	3,431,482	287,264	2,004,266	272,800	25,296	6,038,001
10	January 2023	20,152	4,011,918	273,955	2,417,339	290,904	25,916	7,040,184
11	February 2023	19,750	4,047,002	249,711	2,177,343	263,872	24,920	6,782,598
12	Third Quarter	56,795	11,490,402	810,930	6,598,948	827,576	76,132	19,860,783
13	March 2023	14,517	2,875,562	234,677	1,697,430	238,452	23,994	5,084,632
14	April 2023	9,496	1,843,982	222,241	1,076,595	196,140	22,440	3,370,894
15	May 2023	5,403	984,281	217,346	589,604	168,764	21,452	1,986,850
16	Fourth Quarter	29,416	5,703,825	674,264	3,363,629	603,356	67,886	10,442,376
17	Total Throughput excl. Basic - Dth	114,865	21,091,813	2,831,748	13,149,146	2,474,344	273,884	39,935,800
	Current Throughput Excl. Basic Allocation Factor							
18	Allocation of June 2022 Estimated Throughput (line 1/line 1, column G)	0.003698	0.333626	0.191887	0.311424	0.140344	0.019021	1.000000
19	Allocation of July 2022 Estimated Throughput (line 2/line 2, column G)	0.003233	0.312850	0.202121	0.315254	0.146519	0.020023	1.000000
20	Allocation of August 2022 Estimated Throughput (line 3/line 3, column G)	0.003237	0.311852	0.202269	0.315650	0.146929	0.020063	1.000000
21	Total Throughput Excl. Basic Allocation Factor (line 17/line 17, col. G)	0.002876	0.528143	0.070908	0.329257	0.061958	0.006858	1.000000
	Monthly Total Throughput less Basic							
22	June 2022 (line 1/line 4)	0.376387	0.360603	0.333818	0.342654	0.335572	0.333822	0.345554
23	July 2022 (line 2/line 4)	0.311945	0.320527	0.333300	0.328793	0.332079	0.333089	0.327548
24	August 2022 (line 3/line 4)	0.311668	0.318870	0.332882	0.328553	0.332349	0.333089	0.326898

Citizens Gas
Purchased Gas Cost - Estimated
June 2022

		A	B	C	D	E	F	G	H	I	J
		Estimated Purchases			Supplier Rates Estimated			Estimated Costs			
			Commodity								
Line No.	Month and Supplier	Demand	MCF	DTH	Demand $/DTH	Commodity $/DTH	Other $/MCF	Demand (A x D)	Commodity (C x E)	Other	Total (G+H+I)
	June 2022										
Exelon	Generation Company, LLC										
1	Panhandle Eastern Pipeline - TOR			447,545		$4.6865			2,097,420		2,097,420
2	Texas Gas Transmission - TOR			211,130		4.8755			1,029,364		1,029,364
3	TGT-REX			211,130		4.7846			1,010,173		1,010,173
4	Indiana Municipal Gas Purchasing Authority - TOR			-		4.6865			-		-
5	Indiana Municipal Gas Purchasing Authority - Prepay			147,180		4.3603			641,749		641,749
6	PEAK B			300,000		4.8555			1,456,650		1,456,650
7	Rockies Express Pipeline - TOR			592,728		4.4895			2,661,052		2,661,052
8	PEAK A			300,000		4.7280			1,418,400		1,418,400
9	Midwestern Gas Transmission Purchases			-		4.7318			-		-
10	Fixed Price Purchases								-		-
11	Hedging Transaction Costs								(1,479,631)		(1,479,631)
12	Boil-off / Peaking purchase			42,263		5.0630			213,978		213,978
13	Net Demand Cost Charges - AMA							942,422	-		942,422
14	Demand Cost Charges -IMGPA - Prepay	5,000			18.0390			90,195	-		90,195
15	Texas Gas - NNS - (Injections)/Withdrawls			(610,340)	0.4585	4.0183		(279,841)	(2,452,529)		(2,732,370)
16	Total			1,641,636				$752,776	$6,596,626	-	$7,349,402

Citizens Gas
Purchased Gas Cost - Estimated
July 2022

		A	B	C	D	E	F	G	H	I	J
		Estimated Purchases			Supplier Rates Estimated			Estimated Costs			
			Commodity								
Line No.	Month and Supplier	Demand	MCF	DTH	Demand $/DTH	Commodity $/DTH	Other $/MCF	Demand (A x D)	Commodity (C x E)	Other	Total (G+H+I)
	July 2022										
Exelon	Generation Company, LLC										
1	Panhandle Eastern Pipeline - TOR			447,545		$4.7329			2,118,186		2,118,186
2	Texas Gas Transmission - TOR			211,130		4.9164			1,038,000		1,038,000
3	TGT-REX			211,130		4.8911			1,032,658		1,032,658
4	Indiana Municipal Gas Purchasing Authority - TOR			-		4.7329			-		-
5	Indiana Municipal Gas Purchasing Authority - Prepay			152,086		4.4067			670,197		670,197
6	PEAK B			310,000		4.9035			1,520,085		1,520,085
7	Rockies Express Pipeline - TOR			412,938		4.5236			1,867,966		1,867,966
8	PEAK A			310,000		4.7760			1,480,560		1,480,560
9	Midwestern Gas Transmission Purchases			-		4.8377			-		-
10	Fixed Price Purchases								-		-
11	Hedging Transaction Costs								(1,327,947)		(1,327,947)
12	Boil-off / Peaking purchase			42,263		5.1110			216,006		216,006
13	Net Demand Cost Charges - AMA							956,974	-		956,974
14	Demand Cost Charges -IMGPA - Prepay	5,000			18.6404			93,202	-		93,202
15	Texas Gas - NNS - (Injections)/Withdrawls			(500,000)	0.5008	4.1084		(250,400)	(2,054,200)		(2,304,600)
16	Total			1,597,092				$799,776	$6,561,511	-	$7,361,287

Citizens Gas
Purchased Gas Cost - Estimated
August 2022

Line No.	Month and Supplier	A Estimated Purchases Demand	B Commodity MCF	C Commodity DTH	D Supplier Rates Estimated Demand $/DTH	E Commodity $/DTH	F Other $/MCF	G Estimated Costs Demand (A x D)	H Commodity (C x E)	I Other	J Total (G+H+I)
	August 2022										
	Exelon Generation Company, LLC										
1	Panhandle Eastern Pipeline - TOR			447,545		$4.7308			2,117,246		2,117,246
2	Texas Gas Transmission - TOR			211,130		4.9674			1,048,767		1,048,767
3	TGT-REX			211,130		4.9017			1,034,896		1,034,896
4	Indiana Municipal Gas Purchasing Authority - TOR			-		4.7308			-		-
5	Indiana Municipal Gas Purchasing Authority - Prepay			-		4.4047			-		-
6	PEAK B			300,000		4.9115			1,473,450		1,473,450
7	Rockies Express Pipeline - TOR			614,678		4.5112			2,772,935		2,772,935
8	PEAK A			300,000		4.7840			1,435,200		1,435,200
9	Midwestern Gas Transmission Purchases			-		4.8482			-		-
10	Fixed Price Purchases										
11	Hedging Transaction Costs								(1,549,645)		(1,549,645)
12	Boil-off / Peaking purchase			42,263		5.1190			216,344		216,344
13	Net Demand Cost Charges - AMA							956,974	-		956,974
14	Demand Cost Charges -IMGPA - Prepay	5,000			18.6404			93,202	-		93,202
15	Texas Gas - NNS - (Injections)/Withdrawls			(600,000)	0.4938	4.0198		(296,280)	(2,411,880)		(2,708,160)
16	Total			1,526,746				$753,896	$6,137,313	-	$6,891,209

Citizens Gas
Calculation of the Projected Average Pipeline Rates
Non-pipeline Supplies, Storage Injections, and Company Usage

Line No	Description	Jun 2022	Jul 2022	Aug 2022	Total
	Commodity Volumes (Dth)				
	Purchases for Retail:				
1	Panhandle TOR	447,545	447,545	447,545	1,342,635
2	IMGPA TOR	0	0	0	0
3	IMGPA Prepay	147,180	152,086	0	299,266
4	Midwestern Gas	0	0	0	0
5	Rockies Express TOR - Monthly	592,728	412,938	614,678	1,620,344
6	PEAK A	300,000	310,000	300,000	910,000
7	Fixed Price Purchases (Sch. 3)	0	0	0	0
8	Texas Gas TOR	211,130	211,130	211,130	633,390
9	TGT-Rex East	211,130	211,130	211,130	633,390
10	PEAK B	300,000	310,000	300,000	910,000
11	Texas Gas NNS	(610,340)	(500,000)	(600,000)	(1,710,340)
12	Boil-off/ Peaking purchases (Sch. 3)	42,263	42,263	42,263	126,789
	Total Retail Volumes				
13	(Ln1 through Ln12)	1,641,636	1,597,092	1,526,746	4,765,474
	Demand Rate				
14	Total Demand Costs (Sch. 3)	$752,776	$799,776	$753,896	$2,306,448
15	Demand Cost per Dth (Line 14 / Line 13)	$0.4586	$0.5008	$0.4938	$0.4840
	Commodity Rate				
16	Panhandle TOR	$4.6865	$4.7329	$4.7308	
17	IMGPA TOR	4.6865	4.7329	4.7308	
18	IMGPA Prepay	4.3603	4.4067	4.4047	
19	Annual Delivery Service - Midwestern Gas	4.7318	4.8377	4.8482	
20	Rockies Express TOR - Monthly	4.4895	4.5236	4.5112	
21	PEAK A	4.7280	4.7760	4.7840	
22	Fixed Price Purchases (Sch. 3)	0.0000	0.0000	0.0000	
23	Texas Gas TOR	4.8755	4.9164	4.9674	
24	TGT-Rex East	4.7846	4.8911	4.9017	
25	Texas Gas NNS	4.0183	4.1084	4.0198	
26	Boil-off/ Peaking purchases (Sch. 3)	5.0630	5.1110	5.1190	
27	PEAK B	4.8555	4.9035	4.9115	
	Commodity Costs				
28	PEPL (Ln 1 x Ln 16)	$2,097,420	$2,118,186	$2,117,246	$6,332,852
29	IMGPA - TOR (Ln 2 x Ln 17)	0	0	0	0
30	IMGPA - Authority Prepay (Ln 3 x Ln 18)	641,749	670,197	0	1,311,946
31	Midwestern (Ln 4 x Ln 19)	0	0	0	0
32	Rockies Express TOR (Ln 5 X Ln 20)	2,661,052	1,867,966	2,772,935	7,301,953
33	PEAK A (Ln 6 X Ln 21)	1,418,400	1,480,560	1,435,200	4,334,160
34	Fixed Price Purchases (Ln 7 x Ln 22)	0	0	0	0
35	Texas Gas (Ln 8 x Ln 23)	1,029,364	1,038,000	1,048,767	3,116,131
36	TGT-Rex East (Ln 9 x Ln 24)	1,010,173	1,032,658	1,034,896	3,077,727
37	Texas Gas -Unnominated Gas (Ln 11 x Ln 25)	(2,452,529)	(2,054,200)	(2,411,880)	(6,918,609)
38	Boil-off/ Peaking purchases (Ln 12 x Ln 26)	213,978	216,006	216,344	646,328
39	PEAK B (Ln 10 x Ln 27)	1,456,650	1,520,085	1,473,450	4,450,185
40	Hedging Transaction Costs (Sch 3)	(1,479,631)	(1,327,947)	(1,549,645)	(4,357,223)
41	Subtotal(Ln 28 through Ln 40)	$6,596,626	$6,561,511	$6,137,313	$19,295,450
	Commodity Cost per Dth				
42	(Line 41/Line 13)	$4.0183	$4.1084	$4.0199	$4.0490
	Total Average Rate per Dth				
43	(Line 15 + Line 42)	$4.4769	$4.6092	$4.5137	$4.5330

Citizens Gas
Projected Information
For Three Months Ending August 31, 2022

	A	B		C	D	E
				Commodity		
Line No.	Jun 2022	Volumes in Dths		Cost per Dth	% of Total	Reference
1	Fixed Price Purchases	-	$	-	0.00%	Sch 3 pg 1 line 10
2	Monthly Spot Market - Index Purchases	2,209,713	$	3.9983	381.37%	Sch 3 pg 1 (line 16 - line 10 - line 12 - line 15)
3	Boil off/Peaking Purchases	42,263	$	5.0630	7.29%	Sch 3 pg 1 line 12
4	Unnominated Seasonal Gas Purchases	(610,340)	$	4.0183	-105.34%	Sch 3 pg 1 line 15
5	Storage Withdrawal - Net	-	$	-	0.00%	Sch 5 ln 3 col B - Sch 4pg 1 ln 22 Col E
6	Storage Injection - Gross	(1,062,216)	$	4.0183	-183.32%	Sch 5 ln 3 col A - Sch 4 pg 1 ln 20 Col E
7	Total Net Purchases	579,420			100.00%	
				Commodity		
	Jul 2022	Volumes in Dths		Cost per Dth	% of Total	
8	Fixed Price Purchases	-	$	-	0.00%	Sch 3 pg 2 line 10
9	Monthly Spot Market - Index Purchases	2,054,829	$	4.0878	386.98%	Sch 3 pg 2 (line 16 - line 10 - line 12 - line 15)
10	Boil off/Peaking Purchases	42,263	$	5.1110	7.96%	Sch 3 pg 2 line 12
11	Unnominated Seasonal Gas Purchases	(500,000)	$	4.1084	-94.16%	Sch 3 pg 2 line 15
12	Storage Withdrawal - Net	-	$	-	0.00%	Sch 5 line 6 col B - Sch 4pg 2 ln 22 Col E
13	Storage Injection - Gross	(1,066,108)	$	4.1084	-200.78%	Sch 5 line 6 col A - Sch 4 pg 2 ln 20 Col E
14	Total Net Purchases	530,984			100.00%	
				Commodity		
	Aug 2022	Volumes in Dths		Cost per Dth	% of Total	
15	Fixed Price Purchases	-	$	-	0.00%	Sch 3 pg 3 line 10
16	Monthly Spot Market - Index Purchases	2,084,483	$	3.9976	395.32%	Sch 3 pg 3 (line 16 - line 10 - line 12 - line 15)
17	Boil off/Peaking Purchases	42,263	$	5.1190	8.01%	Sch 3 pg 3 line 12
18	Unnominated Seasonal Gas Purchases	(600,000)	$	4.0198	-113.79%	Sch 3 pg 3 line 15
19	Storage Withdrawal - Net	-	$	-	0.00%	Sch 5 line 9 col B - Sch 4pg 3 ln 22 Col E
20	Storage Injection - Gross	(999,444)	$	4.0199	-189.54%	Sch 5 line 9 col A - Sch 4 pg 3 ln 20 Col E
21	Total Net Purchases	527,302			100.00%	

Citizens Gas
Allocation of Panhandle Unnominated Quantities Cost
June 2022

Ln. No.	Calc. of PEPL Unnom.Costs / Unit	Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	Total
1	Retail seasonal demand allocation factor Cause No. 37399 GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	-	1.000000
2	PEPL retail demand costs (ln 17 * ln 1)	$1,543	$362,389	$1,564	$128,715	$0	-	$494,211
3	Estimated monthly retail sales- Dth (Sch 2B, ln 1)	4,071	367,277	42,421	155,755	0	-	569,524
4	Fixed cost per unit retail sales (ln 2 / ln 3)	$0.379	$0.987	$0.037	$0.826	$0.000	-	
5	PEPL monthly retail variable costs (ln 24 * ln 1)	$173	$40,740	$176	$14,470	$0	-	$55,559
6	Estimated monthly retail sales- Dth (Sch 2B, ln 1)	4,071	367,277	42,421	155,755	0	-	569,524
7	Net monthly retail variable costs per unit sales (ln 5 / ln 6)	$0.042	$0.111	$0.004	$0.093	$0.000	-	
8	Total PEPL cost per unit retail sales (ln 4 + ln 7)	$0.421	$1.098	$0.041	$0.919	$0.000	-	
9	PEPL balancing demand costs (ln 18 * Sch 2C, ln 18)	$181	$16,306	$9,379	$15,222	$6,860	$930	$48,878
10	Est. monthly total throughput excl. Basic - Dth (Sch 2C, ln 1)	4,071	367,277	211,241	342,835	154,500	20,940	1,100,864
11	Fixed balancing cost per unit throughput (ln 9 / ln 10)	$0.044	$0.044	$0.044	$0.044	$0.044	$0.044	
12	PEPL monthly balancing variable costs (ln 25 * Sch 2C, ln 18)	$20	$1,834	$1,054	$1,711	$771	$105	$5,495
13	Estimated monthly total throughput excl Basic- Dth (Sch 2C, ln 1)	4,071	367,277	211,241	342,835	154,500	20,940	1,100,864
14	Net monthly balancing variable costs per unit throughput (ln12 / ln13)	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	
15	Total PEPL Balancing cost per unit throughput (ln 11 + ln 14)	$0.049	$0.049	$0.049	$0.049	$0.049	$0.049	

Ln. No.	Calculation of Monthly Fixed Costs	A Monthly Fixed Costs
16	PEPL demand cost	$543,089
17	PEPL Retail Demand Costs (line 16 * 91%) 1/	$494,211
18	PEPL Balancing Demand Costs (line 16 * 9%) 1/	$48,878

Ln. No.	Calculation of Monthly Variable Costs	A	B	C	D	E	F	G	H	I
		Volumes		Storage Rates			Costs			
	June 2022	Inject.	W/Drl.	Inject.	W/Drl.	Comp. Fuel	Inject. (A x C)	W/Drl. (B x D)	Compressor Fuel	Total (F+G+H)
19	PEPL Injections (Net)	550,000		0.0020			$1,100			$1,100
20	(100 - day firm) (Midpoint)	559,967		0.0094		12,216	5,264		$54,690	59,954
21	PEPL Withdrawals (Gross)		0		0.0020			0		0
22	(100 - day firm) (Net)		0		0.0094	0		0	0	0
23	Total (ln 19 + ln20 + ln21 + ln22)						$6,364	$0	$54,690	$61,054
24	PEPL Retail Variable Costs (line 23 * 91%) 1/									$55,559
25	PEPL Balancing Variable Costs (line 23* 9%) 1/									$5,495

1/ Percentages from Balancing Study - 2 year average Apr., 2008 - Mar., 2010 PEPL-WSS

Citizens Gas
Allocation of Panhandle Unnominated Quantities Cost
July 2022

Ln. No.	Calc. of PEPL Unnom.Costs / Unit	Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	Total
1	Retail seasonal demand allocation factor Cause No. 37399 GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	-	1.000000
2	PEPL retail demand costs (ln 17 * ln 1)	$1,580	$371,179	$1,602	$131,838	$0	-	$506,199
3	Estimated monthly retail sales - Dth (Sch 2B, ln 2)	3,374	326,459	42,689	150,407	0	-	522,929
4	Fixed cost per unit retail sales (ln 2 / ln 3)	$0.468	$1.137	$0.038	$0.877	$0.000	-	
5	PEPL monthly retail variable costs (ln 24 * ln 1)	$113	$26,613	$115	$9,452	$0	-	$36,293
6	Estimated monthly retail sales - Dth (Sch 2B, ln 2)	3,374	326,459	42,689	150,407	0	-	522,929
7	Net monthly retail variable costs per unit sales (ln 5 / ln 6)	$0.033	$0.082	$0.003	$0.063	$0.000	-	
8	Total PEPL cost per unit retail sales (ln 4 + ln 7)	$0.501	$1.219	$0.041	$0.940	$0.000	-	
9	PEPL balancing demand costs (ln 18 * Sch 2C, ln 19)	$162	$15,663	$10,119	$15,783	$7,335	$1,002	$50,064
10	Estimated monthly total throughput - Dth (Sch 2C, ln 2)	3,374	326,459	210,913	328,967	152,892	20,894	1,043,499
11	Fixed balancing cost per unit throughput (ln 9 / ln 10)	$0.048	$0.048	$0.048	$0.048	$0.048	$0.048	
12	PEPL monthly balancing variable costs (ln 25 * Sch 2C, ln 19)	$12	$1,123	$725	$1,131	$526	$72	$3,589
13	Estimated monthly total throughput excl Basic - Dth (Sch 2C, ln 2)	3,374	326,459	210,913	328,967	152,892	20,894	1,043,499
14	Net monthly balancing variable costs per unit throughput (ln 12 / ln 13)	$0.004	$0.003	$0.003	$0.003	$0.003	$0.003	
15	Total PEPL Balancing cost per unit throughput (ln 11 + ln 14)	$0.052	$0.051	$0.051	$0.051	$0.051	$0.051	

Ln. No.	Calculation of Fixed Costs	A Monthly Fixed Costs
16	PEPL demand cost	$556,263
17	PEPL Retail Demand Costs (line 16 * 91%) 1/	$506,199
18	PEPL Balancing Demand Costs (line 16 * 9%) 1/	$50,064

Ln. No.	Calculation of Monthly Variable Costs	A	B	C	D	E	F	G	H	I
		Volumes		Storage Rates			Costs			
	July 2022	Inject.	W/Drl.	Inject.	W/Drl.	Comp. Fuel	Inject. (A x C)	W/Drl. (B x D)	Compressor Fuel	Total (F+G+H)
19	PEPL Injections (Net)	350,000		0.0020			$700			$700
20	(100 - day firm) (Midpoint)	356,343		0.0094		7,774	3,350		$35,832	39,182
21	PEPL Withdrawals (Gross)		0		0.0020			0		0
22	(100 - day firm) (Net)		0		0.0094	0		0	0	0
23	Total (ln 19 + ln20 + ln21 + ln22)						$4,050	$0	$35,832	$39,882
24	PEPL Retail Variable Costs (line 23 * 91%) 1/									$36,293
25	PEPL Balancing Variable Costs (line 23 * 9%) 1/									$3,589

1/ Percentages from Balancing Study - 2 year average Apr., 2008 - Mar., 2010 PEPL-WSS

Citizens Gas
Allocation of Panhandle Unnominated Quantities Cost
August 2022

Ln. No.	Calc. of PEPL Unnom.Costs / Unit	Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	Total
1	Retail seasonal demand allocation factor Cause No. 37399 GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	-	1.000000
2	PEPL retail demand costs (ln 17 * ln 1)	$1,580	$371,179	$1,602	$131,838	$0	-	$506,199
3	Estimated monthly retail sales- Dth (Sch 2B, ln 3)	3,371	324,772	42,425	149,547	0	-	520,115
4	Fixed cost per unit retail sales (ln 2 / ln 3)	$0.469	$1.143	$0.038	$0.882	$0.000	-	
5	PEPL monthly retail variable costs (ln 24 * ln 1)	$95	$22,387	$97	$7,952	$0	-	$30,531
6	Estimated monthly retail sales- Dth (Sch 2B, ln 3)	3,371	324,772	42,425	149,547	0	-	520,115
7	Net monthly retail variable costs per unit sales (ln 5 / ln 6)	$0.028	$0.069	$0.002	$0.053	$0.000	-	
8	Total PEPL cost per unit retail sales (ln 4 + ln 7)	$0.497	$1.212	$0.040	$0.935	$0.000	-	
9	PEPL balancing demand costs (ln 18* Sch 2C, ln 20)	$162	$15,613	$10,126	$15,803	$7,356	$1,004	$50,064
10	Estimated monthly total throughput - Dth (Sch 2C, ln 3)	3,371	324,772	210,649	328,727	153,016	20,894	1,041,429
11	Fixed balancing cost per unit throughput (ln 9 / ln 10)	$0.048	$0.048	$0.048	$0.048	$0.048	$0.048	
12	PEPL monthly balancing variable costs (ln 25 * Sch 2C, ln 20)	$10	$941	$611	$953	$444	$61	$3,020
13	Estimated monthly total throughput excl Basic - Dth (Sch 2C, ln 3)	3,371	324,772	210,649	328,727	153,016	20,894	1,041,429
14	Net monthly balancing variable costs per unit throughput (ln 12 / ln 13)	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	
15	Total PEPL Balancing cost per unit sales (ln 11 + ln 14)	$0.051	$0.051	$0.051	$0.051	$0.051	$0.051	

Ln. No.	Calculation of Fixed Costs	A Monthly Fixed Costs
16	PEPL demand cost	$556,263
17	PEPL Retail Demand Costs (line 16 * 91%) 1/	$506,199
18	PEPL Balancing Demand Costs (line 16 * 9%) 1/	$50,064

Ln. No.	Calculation of Monthly Variable Costs	A	B	C	D	E	F	G	H	I
		Volumes		Storage Rates			Costs			
	August 2022	Inject.	W/Drl.	Inject.	W/Drl.	Comp. Fuel	Inject. (A x C)	W/Drl. (B x D)	Compressor Fuel	Total (F+G+H)
19	PEPL Injections (Net)	300,000		0.0020			$600			$600
20	(100 - day firm) (Midpoint)	305,437		0.0094		6,664	2,871		$30,079	32,950
21	PEPL Withdrawals (Gross)		0		0.0020			0		0
22	(100 - day firm) (Net)		0		0.0094	0		0	0	0
23	Total (ln 19 + ln20 + ln21 + ln22)						$3,471	$0	$30,079	$33,550
24	PEPL Retail Variable Costs (line 23 * 91%) 1/									$30,531
25	PEPL & 3 Balancing Variable Costs (line 23 * 9%) 1/									$3,020

1/ Percentages from Balancing Study - 2 year average Apr., 2008 - Mar., 2010 PEPL-WSS

Citizens Gas
Estimated Cost of Gas Injections and Withdrawals
For Three Months Ending August 31, 2022

		A	B	C	D	E	F	G	H	I
		Estimated Change		Estimated Cost of Gas						
				Injections		Withdrawals		Net		
Line No.		Injections Dth	Withdrawals Dth	Demand	Commodity	Demand	Commodity	Demand	Commodity	Total
	June 2022									
1	Greene Co.	500,000	0	$229,300	$2,009,150	$0	$0	($229,300)	($2,009,150)	($2,238,450)
2	PEPL FS	550,000	0	252,230	2,210,065	0	0	(252,230)	(2,210,065)	(2,462,295)
3	Subtotal	1,050,000	0	481,530	4,219,215	0	0	(481,530)	(4,219,215)	(4,700,745)
	July 2022									
4	Greene Co.	708,334	0	354,734	2,910,119	0	0	(354,734)	(2,910,119)	(3,264,853)
5	PEPL FS	350,000	0	175,280	1,437,940	0	0	(175,280)	(1,437,940)	(1,613,220)
6	Subtotal	1,058,334	0	530,014	4,348,059	0	0	(530,014)	(4,348,059)	(4,878,073)
	August 2022									
7	Greene Co.	692,780	0	342,095	2,784,906	0	0	(342,095)	(2,784,906)	(3,127,001)
8	PEPL FS	300,000	0	148,140	1,205,970	0	0	(148,140)	(1,205,970)	(1,354,110)
9	Subtotal	992,780	0	490,235	3,990,876	0	0	(490,235)	(3,990,876)	(4,481,111)
10	Grand Total	3,101,114	0	$1,501,779	$12,558,150	$0	$0	($1,501,779)	($12,558,150)	($14,059,929)

Citizens Gas
Demand Allocation of Injections and Withdrawals
Greene Co.
For Three Months Ending August 31, 2022

Line No.		A Volume DTH	B Demand Cost	C Commodity Cost	D Total Cost	E Total $/DTH	F Comm $/DTH
1	Beginning Balance @ June 2022	2,781,532	$1,389,357	$8,295,661	$9,685,018	$3.4819	$2.9824
2	Add: Net injections at cost	500,000	229,300	2,009,150	2,238,450	4.4769	4.0183
3	Less: Gross withdrawals - avg. unit cost	0	0	0	0	0.0000	0.0000
4	Beginning Balance @ July 2022	3,281,532	1,618,657	10,304,811	11,923,468	3.6335	3.1402
5	Add: Net injections at cost	708,334	354,734	2,910,119	3,264,853	4.6092	4.1084
6	Less: Gross withdrawals - avg. unit cost	0	0	0	0	0.0000	0.0000
7	Beginning Balance @ August 2022	3,989,866	1,973,391	13,214,930	15,188,321	3.8067	3.3121
8	Add: Net injections at cost	692,780	342,095	2,784,906	3,127,001	4.5137	4.0199
9	Less: Gross withdrawals - avg. unit cost	0	0	0	0	0.0000	0.0000
10	Ending balance @ August 31, 2022	4,682,646	$2,315,486	$15,999,836	$18,315,322	$3.9113	$3.4168

Citizens Gas
Demand Allocation of Injections and Withdrawals
From PEPL FS
For Three Months Ending August 31, 2022

Line No.		A Volume DTH	B Demand Cost	C Commodity Cost	D Total Cost	E Total $/DTH	F Comm $/DTH
1	Beginning Balance @ June 2022	1,613,455	$806,640	$4,266,646	$5,073,286	$3.1444	$2.6444
2	Add: Net injections at cost	550,000	252,230	2,210,065	2,462,295	4.4769	4.0183
3	Less: Gross withdrawals - avg. unit cost	0	0	0	0	0.0000	0.0000
4	Beginning Balance @ July 2022	2,163,455	1,058,870	6,476,711	7,535,581	3.4831	2.9937
5	Add: Net injections at cost	350,000	175,280	1,437,940	1,613,220	4.6092	4.1084
6	Less: Gross withdrawals - avg. unit cost	0	0	0	0	0.0000	0.0000
7	Beginning Balance @ August 2022	2,513,455	1,234,150	7,914,651	9,148,801	3.6399	3.1489
8	Add: Net injections at cost	300,000	148,140	1,205,970	1,354,110	4.5137	4.0199
9	Less: Gross withdrawals - avg. unit cost	0	0	0	0	0.0000	0.0000
10	Ending balance @ August 31, 2022	2,813,455	$1,382,290	$9,120,621	$10,502,911	$3.7331	$3.2418

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
December 2021

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	All GCA Classes
	Calculation of Gas Supply Variance						
1	Retail Peak day demand allocation factor Cause No. 37399 - GCA 140	0.003153	0.740425	0.006293	0.250129	0.000000	1.000000
2	Retail Throughput demand allocation factor Cause No. 37399 - GCA 140	0.003754	0.705611	0.019399	0.271236	0.000000	1.000000
3	Retail Peak day/Retail throughput demand allocation factor (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	0.000000	1.000000
4	Normalized Retail Seasonal Demand Allocation Factor Cause No. 37399 - GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	1.000000
5	Actual net Demand cost allocated (ln 3 * Schedule 7, pg. 1, ln 1 Col A)	$6,773	$1,514,381	$18,684	$525,842	$0	$2,065,680
6	Allocated other demand costs (ln 2 * (Schedule 7, pg. 1, ln 4 Col A)	2,348	441,342	12,134	169,651	0	625,475
7	Allocated contracted storage costs (ln 4 * Schedule 7 pg. 1, ln 3 Col B))	2,107	494,772	2,135	175,736	0	$674,750
8	Actual other non-demand gas costs (Sch. 7 pg. 1, Col B, ln 2 + ln 4) * (Sch. 6A, ln 30))	53,931	10,339,520	128,734	3,666,497	0	14,188,682
9	Total actual cost of gas incurred (ln 5 + ln 6 + ln 7 + ln 8)	$65,159	$12,790,015	$161,687	$4,537,726	$0	$17,554,587
10	Actual cost of gas billed including Utility Gross Receipts Tax (Sch. 6A, ln 33)	$54,063	$10,825,649	$125,095	$3,739,089	$0	$14,743,896
11	Actual cost of gas billed excluding Utility Gross Receipts Tax (ln 10 * (1 - 1.40%)	53,306	10,674,089	123,344	3,686,742	0	14,537,481
12	Net - Write Off Recovered (Sch 12 C ln 3)	705	143,459	240	13,696	0	158,100
13	Variance from Cause No. 37399-GCA 152 Filing (Sch. 1, pg. 2 Dec., 2021 ln 17)	(8,857)	(1,523,470)	(20,056)	(608,938)	0	(2,161,321)
14	Refund from cause No. 37399- GCA 152 Filing (Sch. 1, pg. 2 Dec., 2021 ln 18)	439	89,169	1,866	30,938	0	122,412
15	Gas cost recovered to be reconciled with actual cost of gas incurred (ln 11 - ln 12 - ln 13 + ln 14)	61,897	12,143,269	145,026	4,312,922	0	16,663,114
16	Gas cost variance (over)/underrecovery (ln 9 - ln 15)	$3,262	$646,746	$16,661	$224,804	$0	$891,473

Citizens Gas
Calculation of Actual Gas Cost Variance
December 2021

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	All GCA Classes
	Calculation of Balancing Demand Variance							
17	Allocated actual Balancing Demand cost (Sch. 7, pg. 2, Col A ln 1 * ln 31)	$102	$19,620	$1,815	$11,627	$2,422	$4,574	$40,160
18	Allocated PEPL Balancing Demand & variable cost (Sch. 7, pg. 2, Col A ln 2 * ln 31)	170	32,601	3,017	19,321	4,024	7,600	66,733
19	Total actual Balancing Demand cost incurred (ln 17 + ln 18)	272	52,221	4,832	30,948	6,446	12,174	106,893
20	Actual Balancing Demand Cost Billed including Utility Gross Receipts Tax (Sch. 6A, ln 38)	$201	$41,382	$2,695	$22,812	$5,215	$7,903	$80,208
21	Actual Balancing Demand Cost Billed excluding Utility Gross Receipts Tax (ln 20 * (1-1.40%)	198	40,803	2,663 1/	22,493	5,142	7,792	79,091
22	Balancing Demand Cost Variance from Cause No. 37399 - GCA 152 (Sch. 1, pg. 2 Dec., 2021 ln 11)	(73)	(11,849)					(11,922)
23	Balancing Demand Cost Variance from Cause No. 37399 - GCA 152 (Sch. 1, pg. 3 Dec., 2021 ln 28)			(1,998)	(8,695)	1,228	2,819	(6,646)
24	Balancing Demand cost recovered to be reconciled with actual Balancing Demand Cost Incurred (ln21 - ln22 - ln23)	$271	$52,652	$4,661	$31,188	$3,914	$4,973	$97,659
25	Balancing Demand cost variance (over)/underrecovery (ln 19 - ln 24)	$1	($431)	$171	($240)	$2,532	$7,201	$9,234

1/ Calculation is ((213,531 * 0.011) + (11,262 * 0.001) * 0.986 + (30,496 * 0.011)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
December 2021

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G All GCA Classes
	Calculation of Allocation Factors							
26	Retail gas sales - Dths	14,390	2,758,830	34,348	978,307	-		3,785,875
27	Standard Delivery - Dths			209,679	650,676	221,548	27,430	1,109,333
28	Basic Delivery - Dths			11,262	6,056	119,017	615,713	752,048
29	Total Throughput - Dths (ln 26+ ln 27 + ln 28)	14,390	2,758,830	255,289	1,635,039	340,565	643,143	5,647,256
30	Retail sales allocation factor (ln 26 / ln 26, col. G)	0.003801	0.728716	0.009073	0.258410	0.000000	0.000000	1.000000
31	Throughput subject to Balancing GCA allocation factor (ln 29/ln 29, column G)	0.002548	0.488526	0.045206	0.289528	0.060306	0.113886	1.000000
	Calculation of Gas Supply Charge Recovery							
32	Gas Supply Charge Cause No. 37399 - GCA 152 (D1 & D2 excludes balancing charges) per Dth	$3.757	$3.924	$3.642	$3.822	$0.000	$0.000	
33	Gas Supply Charge Recovery (ln 26 * ln 32)	$54,063	$10,825,649	$125,095	$3,739,089	$0	-	$14,743,896
	Calculation of Balancing Charge Recovery							
34	Balancing GCA Charge Cause No. 37399 - GCA 152 Standard & Retail Customers (per Dth)	$0.014	$0.015	$0.011	$0.014	$0.023	$0.131	
35	Balancing GCA Charge Cause No. 37399 - GCA 152 Basic Delivery Customers (per Dth)			$0.001	$0.001	$0.001	$0.007	
36	Balancing Charge Recovery - Standard & Retail (ln 26 + ln 27) * (ln 34)	$201	$41,382	$2,684	$22,806	$5,096	$3,593	$75,762
37	Balancing Charge Recovery - Basic (ln 28 * ln 35)			$11	$6	$119	$4,310	$4,446
38	Total Balancing Charge Recovery (ln 36 + ln 37)	$201	$41,382	$2,695	$22,812	$5,215	$7,903	$80,208

1/ Line 36 Column C calculation is (213,531 * 0.011) + (30,496 * 0.011)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
January 2022

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	All GCA Classes
	Calculation of Gas Supply Variance						
1	Retail Peak day demand allocation factor Cause No. 37399 - GCA 140	0.003153	0.740425	0.006293	0.250129	0.000000	1.000000
2	Retail Throughput demand allocation factor Cause No. 37399 - GCA 140	0.003754	0.705611	0.019399	0.271236	0.000000	1.000000
3	Retail Peak day/Retail throughput demand allocation factor (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	0.000000	1.000000
4	Normalized Retail Seasonal Demand Allocation Factor Cause No. 37399 - GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	1.000000
5	Actual net Demand cost allocated (ln 3 * Schedule 7, pg. 1,Col C ln 1)	$7,183	$1,606,037	$19,815	$557,668	$0	$2,190,703
6	Allocated other demand costs (ln 2 * ((Schedule 7 pg. 1, Col C ln 4))	6,535	1,228,380	33,771	472,187	0	1,740,873
7	Allocated contracted storage costs (ln 4 * Schedule 7 pg. 1, Col D ln 3))	2,174	510,601	2,203	181,358	0	696,336
8	Actual other non-demand gas costs (Sch. 7 pg. 1, Col D, ln 2 + ln 4) * (Sch. 6B, ln 30))	114,463	15,870,983	270,753	6,280,226	0	22,536,425
9	Total actual cost of gas incurred (lns 5+6+7+8)	$130,355	$19,216,001	$326,542	$7,491,439	$0	$27,164,337.0
10	Actual cost of gas billed including Utility Gross Receipts Tax (Sch. 6B, ln 33)	$130,131	$18,901,521	$323,583	$7,160,380	$0	$26,515,615
11	Actual cost of gas billed excluding Utility Gross Receipts Tax (ln 10 * (1 - 1.46%)	128,231	18,625,559	318,859	7,055,838	0	26,128,487
12	Net - Write Off Recovered (Sch 12 C ln 9)	1,686	252,847	977	24,541	0	280,051
13	Variance from Cause No. 37399-GCA 152 Filing (Sch. 1, pg. 2 Jan., 2022 ln 17)	(10,566)	(1,781,180)	(14,333)	(771,174)	0	(2,577,253)
14	Refund from cause No. 37399- GCA 152 Filing (Sch. 1, pg. 2 Jan., 2022 ln 18)	524	104,251	1,334	39,181	0	145,290
15	Gas cost recovered to be reconciled with actual cost of gas incurred (ln 11 - ln 12 - ln 13 + ln 14)	$137,635	$20,258,143	$333,549	$7,841,652	$0	$28,570,979
16	Gas cost variance (over)/underrecovery (ln 9 - ln 15)	($7,280)	($1,042,142)	($7,007)	($350,213)	$0	($1,406,642)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
January 2022

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	All GCA Classes
	Calculation of Balancing Demand Variance							
17	Allocated actual Balancing Demand cost ((Sch. 7, pg. 2, Col B ln 1 *) *ln 31)	$154	$21,382	$1,425	$12,650	$1,776	$2,773	$40,160
18	Allocated ADS2 Balancing Demand & variable cost ((Sch. 7, pg. 2, Col B ln 2) * ln 31)	264	36,669	2,443	21,692	3,045	4,755	68,868
19	Total actual Balancing Demand cost incurred (ln17 + ln 18)	$418	$58,051	$3,868	$34,342	$4,821	$7,528	$109,028
20	Actual Balancing Demand Cost Billed including Utility Gross Receipts Tax (Sch. 6B, ln 38)	$413	$62,019	$2,761	$33,779	$5,521	$7,716	$112,209
21	Actual Balancing Demand Cost Billed excluding Utility Gross Receipts Tax (ln 20 * (1-1.46%)	407	61,114	2,723 1/	33,286	5,440	7,603	110,573
22	Balancing Demand Cost Variance from Cause No. 37399 - GCA 152 (Sch. 1, pg. 2 Jan., 2022 ln 11)	(87)	(13,853)	-	-	-	-	(13,940)
23	Balancing Demand Cost Variance from Cause No. 37399 - GCA 152 (Sch. 1, pg. 3 Jan., 2022 ln 28)	-	-	(1,905)	(10,486)	1,309	2,888	(8,194)
24	Balancing Demand cost recovered to be reconciled with actual Balancing Demand Cost Incurred (ln 21 - ln 22 - ln 23)	$494	$74,967	$4,628	$43,772	$4,131	$4,715	$132,707
25	Balancing Demand cost variance (over)/underrecovery (ln 19 - ln 24)	($76)	($16,916)	($760)	($9,430)	$690	$2,813	($23,679)

1/ Calculation is ((276,299 * 0.009) + (12,613 * 0.001) * 0.9854 + (28,960 * 0.009)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
January 2022

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G All GCA Classes
	Calculation of Allocation Factors							
26	Retail gas sales - Dths	34,408	4,770,702	81,384	1,887,788	0	0	6,774,282
27	Standard Delivery - Dths		-	223,875	926,432	256,230	32,557	1,439,094
28	Basic Delivery - Dths	-	-	12,613	7,964	139,923	586,070	746,570
29	Total Throughput - Dths (ln 26 + ln 27 + ln 28)	34,408	4,770,702	317,872	2,822,184	396,153	618,627	8,959,946
30	Retail sales allocation factor (ln 26 / ln 26, col. G)	0.005079	0.704237	0.012014	0.278670	0.000000	0.000000	1.000000
31	Throughput subject to Balancing GCA allocation factor (ln 29 / ln 29, column G)	0.003840	0.532447	0.035477	0.314978	0.044214	0.069044	1.000000
	Calculation of Gas Supply Charge Recovery							
32	Gas Supply Charge Cause No. 37399 - GCA 152 (D1 & D2 excludes balancing charges) per Dth	$3.782	$3.962	$3.976	$3.793	$0.000	$0.000	
33	Gas Supply Charge Recovery (ln 26* ln 32)	$130,131	$18,901,521	$ 323,583	$7,160,380	$0	$0	$26,515,615
	Calculation of Balancing Charge Recovery							
34	Balancing GCA Charge Cause No. 37399 - GCA 152 Standard & Retail Customers (per Dth)	$0.012	$0.013	$0.009	$0.012	$0.021	$0.129	
35	Balancing GCA Charge Cause No. 37399 - GCA 152 Basic Delivery Customers (per Dth)	-	-	$0.001	$0.001	$0.001	$0.006	
36	Balancing Charge Recovery - Standard & Retail (ln 26 + ln 27) * (ln 34)	$413	$62,019	$2,748	$33,771	$5,381	$4,200	$108,532
37	Balancing Charge Recovery - Basic (ln 28 * ln 35)	-	-	$13	$8	$140	$3,516	$3,677
38	Total Balancing Charge Recovery (ln 36 + ln 37)	$413	$62,019	$2,761	$33,779	$5,521	$7,716	$112,209

1/ Line 36 Column C calculation is (276,299 * 0.009) + (28,960 * 0.009)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
February 2022

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	All GCA Classes
	Calculation of Gas Supply Variance						
1	Retail Peak day demand allocation factor Cause No. 37399 - GCA 140	0.003153	0.740425	0.006293	0.250129	0.000000	1.000000
2	Retail Throughput demand allocation factor Cause No. 37399 - GCA 140	0.003754	0.705611	0.019399	0.271236	0.000000	1.000000
3	Retail Peak day/Retail throughput demand allocation factor (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	0.000000	1.000000
4	Normalized Retail Seasonal Demand Allocation Factor Cause No. 37399 - GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	1.000000
5	Actual net Demand cost allocated (ln 3 * Schedule 7 pg. 1, Col E ln 1)	$5,935	$1,327,010	$16,372	$460,780	$0	$1,810,097
6	Allocated other demand costs (ln 2 * (Schedule 7 pg. 1, Col E, ln 4))	5,445	1,023,533	28,139	393,445	0	1,450,562
7	Allocated contracted storage costs (ln 4 * Schedule 7 pg. 1,Col F ln 3)	2,041	479,371	2,068	170,266	0	653,746
8	Actual other non-demand gas costs ((Sch. 7 pg. 1, ln 2 + ln 4) * (Sch. 6C, ln 30))	37,796	12,987,956	162,762	5,248,528	0	18,437,042
9	Total actual cost of gas incurred (ln 5 + ln 6 + ln 7 + ln 8)	$51,217	$15,817,870	$209,341	$6,273,019	$0	$22,351,447
10	Actual cost of gas billed including Utility Gross Receipts Tax (Sch. 6C, ln 33)	$39,334	$14,081,105	$189,377	$5,534,445	$0	$19,844,261
11	Actual cost of gas billed excluding Utility Gross Receipts Tax (ln 10 * (1 - 1.46%)	38,760	13,875,521	186,612	5,453,642	0	19,554,535
12	Net - Write Off Recovered (Sch 12 C ln 15)	514	187,412	723	20,390	0	209,039
13	Variance from Cause No. 37399-GCA 152 Filing (Sch. 1, pg. 2 Feb., 2022, ln 17)	($10,356)	($1,796,709)	($10,528)	($721,564)	$0	(2,539,157)
14	Refund from cause No. 37399- GCA 152 Filing (Sch. 1, pg. 2 Feb., 2022, ln 18)	514	105,160	980	36,660	0	143,314
15	Gas cost recovered to be reconciled with actual cost of gas incurred (ln 11 - ln 12 - ln 13 + ln 14)	$49,116	$15,589,978	$197,397	$6,191,476	$0	$22,027,967
16	Gas cost variance (over)/underrecovery (ln 9 - ln 15)	$2,101	$227,892	$11,944	$81,543	$0	$323,480

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
February 2022

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	All GCA Classes
	Calculation of Balancing Demand Variance							
17	Allocated actual Balancing Demand cost (Sch. 7, pg. 2, ln 1 * ln 31)	$52	$17,975	$1,289	$11,386	$1,746	$3,867	$36,315
18	Allocated ADS2 Balancing Demand cost (Sch. 7, pg. 2, ln 2 * ln 31)	$93	$32,002	$2,295	$20,272	$3,109	$6,885	$64,656
19	Total actual Balancing Demand cost incurred (ln 17 + ln 18)	$145	$49,977	$3,584	$31,658	$4,855	$10,752	$100,971
20	Actual Balancing Demand Cost Billed including Utility Gross Receipts Tax (ln 38)	$115	$43,249	$1,960	$25,042	$4,436	$7,996	$82,798
21	Actual Balancing Demand Cost Billed excluding Utility Gross Receipts Tax (ln 20 * (1-1.46%)	113	42,618	1,934 1/	24,676	4,371	7,879	81,591
22	Balancing Demand Cost Variance from Cause No. 37399 - GCA 152 (Sch. 1, pg. 2 Feb., 2022 ln 11)	(85)	(13,973)	-	-	-	-	(14,058)
23	Balancing Demand Cost Variance from Cause No. 37399 - GCA 152 (Sch. 1, pg. 3 Feb., 2022 ln 28)	-	-	(1,736)	(9,445)	1,188	2,778	(7,215)
24	Balancing Demand cost recovered to be reconciled with actual Balancing Demand Cost Incurred (ln21 - ln22 - ln23)	$198	$56,591	$3,670	$34,121	$3,183	$5,101	$102,864
25	Balancing Demand cost variance (over)/underrecovery (ln 19 - ln 24)	($53)	($6,614)	($86)	($2,463)	$1,672	$5,651	($1,893)

1/ Calculation is ((219,321 * 0.008) + (13,504 * 0) * 0.9854 + (25,618 * 0.008)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
February 2022

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G All GCA Classes
	Calculation of Allocation Factors							
26	Retail gas sales - Dth	10,489	3,604,071	45,165	1,456,433	-	-	5,116,158
27	Standard Delivery - Dths	-	-	199,774	819,513	215,072	27,407	1,261,766
28	Basic Delivery - Dths	-	-	13,504	7,068	135,111	747,920	903,603
29	Total Throughput - Dths (ln 26 + ln 27 + ln 28)	10,489	3,604,071	258,443	2,283,014	350,183	775,327	7,281,527
30	Retail sales allocation factor (ln 26 / ln 26, col. G)	0.002050	0.704449	0.008828	0.284673	0.000000	0.000000	1.000000
31	Throughput subject to Balancing GCA allocation factor (ln 29 / 29, column G)	0.001440	0.494961	0.035493	0.313535	0.048092	0.106479	1.000000
	Calculation of Gas Supply Charge Recovery							
32	Gas Supply Charge Cause No. 37399 - GCA 152 (D1 & D2 excludes balancing charges) per Dth	$3.750	$3.907	$4.193	$3.800	$0.000	$0.000	
33	Gas Supply Charge Recovery (ln 26 * ln 32)	$39,334	$14,081,105	$189,377	$5,534,445	-	-	$19,844,261
	Calculation of Balancing Charge Recovery							
34	Balancing GCA Charge Cause No. 37399 - GCA 152 Standard & Retail Customers (per Dth)	$0.011	$0.012	$0.008	$0.011	$0.020	$0.128	
35	Balancing GCA Charge Cause No. 37399 - GCA 152 Basic Delivery Customers (per Dth)	-	-	$0.000	$0.001	$0.001	$0.006	
36	Balancing Charge Recovery - Standard & Retail (ln 26 + ln 27) * (ln 34)	$115	$43,249	$1,960	$25,035	$4,301	$3,508	$78,168
37	Balancing Charge Recovery - Basic (ln 28 * ln 35)	-	-	$0	$7	$135	$4,488	$4,630
38	Total Balancing Charge Recovery (ln 36 + ln 37)	$115	$43,249	$1,960	$25,042	$4,436	$7,996	$82,798

1/ Line 36 Column C calculation is (219,321 * 0.008) + (25,618 * 0.008)

Citizens Gas
Trailing Twelve Month Variance
For January 2021 through February 2022

Line No.			A January 2021	B February 2021	C March 2021	D April 2021	E May 2021	F June 2021	G July 2021	H August 2021	I September 2021	J October 2021	K November 2021	L December 2021	M January 2022	N February 2022
1	Actual Cost of Gas	Total Sch 6 pg 1 ln 9 + Sch 6 pg 2 ln 19	$15,617,099	$6,671,569	$10,281,208	$5,870,899	$4,260,330	$2,296,200	$2,355,258	$2,316,123	$2,592,283	$5,031,393	$16,340,881	$17,661,480	$27,273,365	$22,452,418
2	Variance	Total Sch 6 pg 1 ln 16 + Sch 6 pg 2 ln 25	($929,916)	($10,622,328)	$197,451	$38,554	$517,107	($214,791)	$189,857	$157,937	$102,932	$359,782	$2,258,716	$900,707	($1,430,321)	$321,587
3										Gas Cost Trailing Twelve Months (ln 1, col A-L)				$91,294,723		
4										Variance Trailing Twelve Months (ln 2, col A-L)				($7,043,992)		
5										Total Trailing Twelve Months % Variance (ln 4 / ln 3)				-7.72%		
6										Gas Cost Trailing Twelve Months (ln 1, col B-M)					$102,950,989	
7										Variance Trailing Twelve Months (ln 2, col B-M)					($7,544,397)	
8										Total Trailing Twelve Months % Variance (ln 7 / ln 6)					-7.33%	
9										Gas Cost Trailing Twelve Months (ln 1, col C-N)						$118,731,838
10										Variance Trailing Twelve Months (ln 2, col C-N)						$3,399,518
11										Total Trailing Twelve Months % Variance (ln 10 / ln 9)						2.86%

Citizens Gas
Determination of Actual Retail Gas Costs
For Three Months Ending February 28, 2022

Line No.		A	B	C	D	E	F
		December 2021		January 2022		February 2022	
		Demand	Non-Demand	Demand	Non-Demand	Demand	Non-Demand
1	Demand gas costs (Sch. 8)	$2,065,680	-	$2,190,703	-	$1,810,097	-
2	Pipeline non-demand gas costs (Schedule 8)	-	10,807,543	-	12,987,382	-	10,513,126
3	PEPL Contracted storage and related transportation costs (Sch. 9)	-	674,750	-	696,336	-	653,746
4	Net cost of gas (injected into) withdrawn from storage (Schedule 10)	625,475	3,381,139	1,740,873	9,549,043	1,450,562	7,923,916
5	Total gas costs	$2,691,155	$14,863,432	$3,931,576	$23,232,761	$3,260,659	$19,090,788

Citizens Gas
Determination of Actual Balancing Costs
For Three Months Ending February 28, 2022

Line No.		A December 2021	B January 2022	C February 2022
1	Balancing Demand Costs (Schedule 8)	$40,160	$40,160	$36,315
2	PEPL Balancing Demand Costs (Sch. 9)	66,733	68,868	64,656
3	Total Balancing Costs	$106,893	$109,028	$100,971

Citizens Gas
Purchased Gas Cost - Per Books
December 2021

Line No.		A Demand - Dth	B Commodity Dth	C Demand $/Unit	D Commodity $/Dth	E Other $/Unit	F Demand (A x C)	G Commodity (B x D)	H Other	I Total (F + G + H)
	Accrual -November, 2021									
	Exelon Generation Company									
1	Panhandle Eastern Pipeline - TOR	33,463	-	$ 12.4863	$ -		$ 417,828	$ -		$ 417,828
2	MGT Pipeline -	1,350,000	-	0.1104	-		149,090	-		149,090
3	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
4	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	497,460	18.0390	5.9101		308,287	2,940,047		3,248,334
5	Texas Gas Transmission - Nominated Demand	1,303,050		0.3543	-		461,671			461,671
6	Texas Gas Transmission - Unnominated Demand	1,096,950		0.3543	-		388,649			388,649
7	Texas Gas Transmission - Commodity - TOR		-	-	-			-		-
8	Texas Gas Transmission - Unnominated Injection	(7,916)	(7,916)	0.5643	4.1801		(4,467)	(33,090)		(37,557)
9	Texas Gas Transmission - Unnominated Withdrawal	403,601	403,601	0.4091	3.6967		165,113	1,491,992		1,657,105
10	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
11	Rockies Express - Delivered Supply - (BP PEAK B)		300,000	-	5.9945		-	1,798,350		1,798,350
12	Rockies Express - Delivered Supply - (BP PEAK A)		300,000	-	5.8670		-	1,760,100		1,760,100
13	Rockies Express - EAST	20,000	600,000	16.7292	5.7658		334,583	3,459,499		3,794,082
14	Intraday Purchases		-	-	-			-		-
15	Fuel Retention Volumes		-	-	-					-
16	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		1,779,247	-	4.8123		-	8,562,287		8,562,287
17	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
18	Hedging Transaction Cost			-	-			(3,032,186)		(3,032,186)
19	Imbalance		(42,806)	-	4.1260			(176,618)		(176,618)
20	Utilization Fee			-	-		(254,167)	-		(254,167)
21	Net Demand Cost Charges - AMA			-	-		-			-
22	REX Winter 2021	-	-	-	-		-	-		-
23	Third Party Supplier Balancing Gas Costs		(176,033)	-			-	(1,661,304)		(1,661,304)
24	Boil-off / Peaking purchase		79,390	-	6.2020		-	492,377		492,377
25	MGT Cash Out Imbalance		-	-	-			-		-
26	NSS Injection fuel loss	-	-	-	-		-			-
27	Backup Supply Sales		(179,500)		5.2371			(940,060)		(940,060)
28	Subtotal		3,553,443				$1,966,587	$14,661,394	$0	$16,627,981
	Actual -November, 2021									
	Exelon Generation Company									
29	Panhandle Eastern Pipeline - TOR	33,463	-	$ 12.4863	$ -		$ 417,828	$ -		$ 417,828
30	MGT Pipeline -	1,350,000	-	0.1104	-		149,090	-		149,090
31	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
32	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	497,460	17.9355	5.9360		306,517	2,952,914		3,259,431
33	Texas Gas Transmission - Nominated Demand	1,303,050		0.3543	-		461,671			461,671
34	Texas Gas Transmission - Unnominated Demand	1,096,950		0.3543	-		388,649			388,649
35	Texas Gas Transmission - Commodity - TOR		-	-	-			-		-
36	Texas Gas Transmission - Unnominated Injection	(7,916)	(7,916)	0.5647	4.1908		(4,470)	(33,174)		(37,644)
37	Texas Gas Transmission - Unnominated Withdrawal	403,601	403,601	0.5647	4.1907		227,913	1,691,371		1,919,284
38	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
39	Rockies Express - Delivered Supply - (BP PEAK B)		300,000	-	5.9945		-	1,798,350		1,798,350
40	Rockies Express - Delivered Supply - (BP PEAK A)		300,000	-	5.8670		-	1,760,100		1,760,100
41	Rockies Express - EAST	20,000	600,000	16.7292	5.7658		334,583	3,459,499		3,794,082
42	Intraday Purchases		-	-	-			-		-
43	Fuel Retention Volumes		-	-	-					-
44	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		1,779,247	-	4.8123		-	8,562,287		8,562,287
45	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
46	Hedging Transaction Cost			-	-			(3,032,186)		(3,032,186)
47	Imbalance		(42,807)	-	4.1907			(179,391)		(179,391)
48	Utilization Fee			-	-		(254,167)	-		(254,167)
49	Net Demand Cost Charges - AMA			-	-		-			-
50	REX Winter 2021	-	-	-	-		-	-		-
51	Third Party Supplier Balancing Gas Costs		(176,033)	-				(1,661,304)		(1,661,304)
52	Boil-off / Peaking purchase		79,390	-	6.2020			492,377		492,377
53	MGT Cash Out Imbalance		(5,841)	-	0.6598			(3,854)		(3,854)
54	NSS Injection fuel loss	-	-							-
55	Backup Supply Sales		(179,500)	-	5.2371		-	(940,060)		(940,060)
56	Subtotal		3,547,601				$2,027,614	$14,866,929	$0	$16,894,543

Citizens Gas
Purchased Gas Cost - Per Books
December 2021

		A	B	C	D	E	F	G	H	I
		Demand - Dth	Commodity Dth	Demand $/Unit	Commodity $/Dth	Other $/Unit	Demand (A x C)	Commodity (B x D)	Other	Total (F + G + H)
	Accrual - December, 2021									
	Exelon Generation Company									
57	Panhandle Eastern Pipeline - TOR	33,463	-	$ 12.5884	$ -		$ 421,247	$ -		$ 421,247
58	MGT Gas Pipeline -	1,395,000	-	0.1069	-		149,090	-		149,090
59	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
60	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	514,042	18.6403	5.3020		318,563	2,725,472		3,044,035
61	Texas Gas Transmission - Nominated Demand	1,346,485		0.3543	-		477,060			477,060
62	Texas Gas Transmission - Unnominated Demand	1,133,515	-	0.3543	-		401,604			401,604
63	Texas Gas Transmission - Commodity - TOR		-	-	-			-		-
64	Texas Gas Transmission - Unnominated Injection	(23,508)	(23,508)	0.9365	4.4635		(22,015)	(104,928)		(126,943)
65	Texas Gas Transmission - Unnominated Withdrawal	530,540	530,540	0.4125	3.3551		218,848	1,780,015		1,998,863
66	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
67	Rockies Express - Deliverod Supply - (BP PEAK B)		310,000	-	5.2395			1,624,245		1,624,245
68	Rockies Express - Delivered Supply - (BP PEAK A)		310,000	-	5.1120			1,584,720		1,584,720
69	Rockies Express - EAST	20,000	620,000	16.7292	5.1824		334,583	3,213,074		3,547,657
70	Intraday Purchases		25,000	-	3.8360			95,900		95,900
71	Fuel Retention Volumes		-	-	-					-
72	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		90,767	-	4.2951			389,857		389,857
73	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
74	Hedging Transaction Cost			-	-			(1,191,034)		(1,191,034)
75	Imbalance		27,192	-	4.2266			114,930		114,930
76	Utilization Fee			-	-		(254,167)	-		(254,167)
77	Net Demand Cost Charges - AMA			-	-		-			-
78	Wholesale Sales		(437,556)	-	3.6190		-	(1,583,494)		(1,583,494)
79	Third Party Supplier Balancing Gas Costs		482,403	-				1,634,068		1,634,068
80	Boil-off / Peaking purchase		58,598	-	5.4470			319,183		319,183
81	MGT Cash Out Imbalance		-	-	-			-		-
82	NSS Injection fuel loss		(88)	-	-		-			-
83	Backup Supply Sales		-		-			-		-
84	Subtotal		2,507,390				$ 2,044,813	$ 10,602,008	$ -	$ 12,646,821
85	Total Purchased Costs (line 84 + line 56 - line 28)		2,501,548				$ 2,105,840	$ 10,807,543	$ -	$ 12,913,383
86	Total TGT Unnominated Demand Cost (line 62 + line 34 - line 6)						$ 401,604			
87	Total Purchase Cost excluding TGT Demand Unnom. (ln 85 - ln 86)		2,501,548				$ 1,704,236			
88	TGT Unnominated Demand Cost - Retail (line 86 * 90%)						$ 361,444			
89	Balancing Demand Cost (line 86 * 10%)						$ 40,160			

Citizens Gas

Purchased Gas Cost - Per Books

January 2022

Line No.		A Demand - Dth	B Commodity Dth	C Demand $/Unit	D Commodity $/Dth	E Other $/Unit	F Demand (A x C)	G Commodity (B x D)	H Other	I Total (F + G + H)
	Accrual - December, 2021									
	Exelon Generation Company									
1	Panhandle Eastern Pipeline - TOR	33,463	-	$ 12.5884	$ -		$ 421,247	$ -		$ 421,247
2	MGT Gas Pipeline -	1,395,000	-	0.1069	-		149,090	-		149,090
3	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
4	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	514,042	18.6403	5.3020		318,563	2,725,472		3,044,035
5	Texas Gas Transmission - Nominated Demand	1,346,485		0.3543	-		477,060			477,060
6	Texas Gas Transmission - Unnominated Demand	1,133,515	-	0.3543	-		401,604			401,604
7	Texas Gas Transmission - Commodity - TOR		-	-	-			-		-
8	Texas Gas Transmission - Unnominated Injection	(23,508)	(23,508)	0.9365	4.4635		(22,015)	(104,928)		(126,943)
9	Texas Gas Transmission - Unnominated Withdrawal	530,540	530,540	0.4125	3.3551		218,848	1,780,015		1,998,863
10	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
11	Rockies Express - Delivered Supply - (BP PEAK B)		310,000	-	5.2395			1,624,245		1,624,245
12	Rockies Express - Delivered Supply - (BP PEAK A)		310,000	-	5.1120			1,584,720		1,584,720
13	Rockies Express - EAST	20,000	620,000	16.7292	5.1824		334,583	3,213,074		3,547,657
14	Intraday Purchases		25,000	-	3.8360			95,900		95,900
15	Fuel Retention Volumes		-	-	-					-
16	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		90,767	-	4.2951			389,857		389,857
17	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
18	Hedging Transaction Cost			-	-			(1,191,034)		(1,191,034)
19	Imbalance		27,192	-	4.2266			114,930		114,930
20	Utilization Fee			-	-		(254,167)	-		(254,167)
21	Net Demand Cost Charges - AMA			-	-		-			-
22	Wholesale Sales	-	(437,556)	-	3.6190		-	(1,583,494)		(1,583,494)
23	Third Party Supplier Balancing Gas Costs		482,403	-				1,634,068		1,634,068
24	Boil-off / Peaking purchase		58,598	-	5.4470			319,183		319,183
25	MGT Cash Out Imbalance		-	-	-			-		-
26	NSS Injection fuel loss		(88)	-	-		-	-		-
27	Backup Supply Sales		-		-			-		-
28	Subtotal		2,507,390				$ 2,044,813	$ 10,602,008	$ -	$ 12,646,821
	Actual - December, 2021									
29	Panhandle Eastern Pipeline - TOR	33,463	-	$ 12.5884	-		$ 421,247	$ -		$ 421,247
30	MGT Gas Pipeline -	1,395,000	-	0.1069	-		149,090	-		149,090
31	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
32	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	514,042	18.5521	5.3660		317,055	2,758,352		3,075,407
33	Texas Gas Transmission - Nominated Demand	1,346,485	-	0.3543	-		477,060			477,060
34	Texas Gas Transmission - Unnominated Demand	1,133,515	-	0.3543	-		401,604			401,604
35	Texas Gas Transmission - Commodity - TOR		-	-	-		-	-		-
36	Texas Gas Transmission - Unnominated Injection	(23,508)	(23,508)	0.9351	4.3967		(21,982)	(103,358)		(125,340)
37	Texas Gas Transmission - Unnominated Withdrawal	521,173	521,173	0.4125	3.3551		214,984	1,748,588		1,963,572
38	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
39	Rockies Express - Delivered Supply - (BP PEAK B)		310,000	-	5.2395			1,624,245		1,624,245
40	Rockies Express - Delivered Supply - (BP PEAK A)		310,000	-	4.5733			1,417,720		1,417,720
41	Rockies Express - EAST	20,000	620,000	16.7198	5.1824		334,395	3,213,074		3,547,469
42	Intraday Purchases		25,000	-	3.8360		-	95,900		95,900
43	Fuel Retention Volumes		-	-	-					-
44	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		90,767	-	4.2900			389,387		389,387
45	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)		-	-	-					-
46	Hedging Transaction Cost			-	-			(1,191,034)		(1,191,034)
47	Imbalance		27,192	-	4.1773			113,589		113,589
48	Utilization Fee		-	-	-		(254,167)	-		(254,167)
49	Net Demand Cost Charges - AMA			-	-		-	-		-
50	Wholesale Sales	-	(437,556)	-	3.6190		-	(1,583,494)		(1,583,494)
51	Third Party Supplier Balancing Gas Costs		482,403	-			-	1,634,068		1,634,068
52	Boil-off / Peaking purchase		58,598	-	5.4470		-	319,183		319,183
53	MGT Cash Out Imbalance		1,078	-	6.9462		-	7,488		7,488
54	NSS Injection fuel loss		(88)	-	-					-
55	Backup Supply Sales		-		-			-		-
56	Subtotal		2,499,101				$ 2,039,286	$ 10,443,708	$0	$ 12,482,994

Citizens Gas

Purchased Gas Cost - Per Books

January 2022

Accrual - January, 2022	A Demand - Dth	B Commodity Dth	C Demand $/Unit	D Commodity $/Dth	E Other $/Unit	F Demand (A x C)	G Commodity (B x D)	H Other	I Total (F + G + H)
Exelon Generation Company									
57 Panhandle Eastern Pipeline - TOR	33,463	-	$ 12.5884	$ -		$ 421,247	$ -		$ 421,247
58 MGT Pipeline	1,395,000	-	0.1069	-		149,090	-		149,090
59 Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
60 Indiana Municipal Gas Purchasing Authority - Prepay	17,090	514,042	18.6403	5.2150		318,563	2,680,737		2,999,300
61 Texas Gas Transmission - Nominated Demand	1,346,485		0.3543	-		477,060			477,060
62 Texas Gas Transmission - Unnominated Demand	1,133,515	-	0.3543	-		401,604			401,604
63 Texas Gas Transmission - Commodity - TOR	-	-	-	-			-		-
64 Texas Gas Transmission - Unnominated Injection	-	-	-	-		-	-		-
65 Texas Gas Transmission - Unnominated Withdrawal	768,064	768,064	0.5057	3.8120		388,410	2,927,860		3,316,270
66 Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
67 Rockies Express - Delivered Supply - (BP PEAK B)	-	310,000	-	3.8165		-	1,183,115		1,183,115
68 Rockies Express - Delivered Supply - (BP PEAK)		310,000	-	3.6890			1,143,590		1,143,590
69 Rockies Express - EAST	20,000	620,000	16.7292	3.4697		334,583	2,151,189		2,485,772
70 Intraday Purchases		20,000	-	4.3400			86,800		86,800
71 Fuel Retention Volumes		-	-	-					-
72 TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		1,095,108	-	4.1896			4,588,034		4,588,034
73 TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
74 Hedging Transaction Cost			-	-			365,851		365,851
75 Imbalance		(926)	-	3.8488			(3,564)		(3,564)
76 Utilization Fee			-	-		(254,167)			(254,167)
77 Net Demand Cost Charges - AMA			-	-		-			-
78 Wholesale Sales	-	(633,742)	-	5.3038		-	(3,361,218)		(3,361,218)
79 Third Party Supplier Balancing Gas Costs		367,407	-				1,204,381		1,204,381
80 Boil-off / Peaking purchase		44,460	-	4.0240			178,907		178,907
81 MGT Cash Out Imbalance		-	-	-			-		-
82 NSS Injection fuel loss		-							-
83 Backup Supply Sales		-		-			-		-
84 Subtotal		3,414,413				$ 2,236,390	$ 13,145,682	$0	$15,382,072
85 Total Purchased Costs (line 84 + line 56 - line 28.)		3,406,124				$2,230,863	$12,987,382	$0	$15,218,245
86 Total TGT Unnominated Demand Cost (line 62 + line 34 - line 6)						401,604			
87 Total Purchase Cost excluding TGT Demand Unnom. (ln 85 - ln 86)		3,406,124				$1,829,259			
88 TGT Unnominated Demand Cost - Retail (line 86 * 90%)						$361,444			
89 Balancing Demand Cost (line 86 * 10%)						$40,160			

Citizens Gas
Purchased Gas Cost - Per Books
February 2022

Line No.		A Demand - Dth	B Commodity Dth	C Demand $/Unit	D Commodity $/Dth	E Other $/Unit	F Demand (A x C)	G Commodity (B x D)	H Other	I Total (F + G + H)
	Accrual - January, 2022									
	Exelon Generation Company									
1	Panhandle Eastern Pipeline - TOR	33,463	-	$ 12.5884	$ -		$ 421,247	$ -		$ 421,247
2	MGT Pipeline	1,395,000	-	0.1069	-		149,090	-		149,090
3	Indiana Municipal Gas Purchasing Authority - TOR	-	-	-	-		-	-		-
4	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	514,042	18.6403	5.2150		318,563	2,680,737		2,999,300
5	Texas Gas Transmission - Nominated Demand	1,346,485	-	0.3543	-		477,060			477,060
6	Texas Gas Transmission - Unnominated Demand	1,133,515	-	0.3543	-		401,604	-		401,604
7	Texas Gas Transmission - Commodity - TOR		-	-	-			-		-
8	Texas Gas Transmission - Unnominated Injection	-	-	-	-		-	-		-
9	Texas Gas Transmission - Unnominated Withdrawal	768,064	768,064	0.5057	3.8120		388,410	2,927,860		3,316,270
10	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill		-	-	-		-	-		-
11	Rockies Express - Delivered Supply - (BP PEAK B)	-	310,000	-	3.8165		-	1,183,115		1,183,115
12	Rockies Express - Delivered Supply - (BP PEAK)	-	310,000	-	3.6890		-	1,143,590		1,143,590
13	Rockies Express - EAST	20,000	620,000	16.7292	3.4697		334,583	2,151,189		2,485,772
14	Intraday Purchases		20,000	-	4.3400			86,800		86,800
15	Fuel Retention Volumes		-	-	-		-	-		-
16	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		1,095,108	-	4.1896		-	4,588,034		4,588,034
17	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)		-	-	-		-	-		-
18	Hedging Transaction Cost			-	-			365,851		365,851
19	Imbalance		(926)	-	3.8488			(3,564)		(3,564)
20	Utilization Fee		-	-	-		(254,167)	-		(254,167)
21	Net Demand Cost Charges - AMA		-	-	-		-			-
22	Wholesale Sales	-	(633,742)	-	5.3038		-	(3,361,218)		(3,361,218)
23	Third Party Supplier Balancing Gas Costs		367,407	-				1,204,381		1,204,381
24	Boil-off / Peaking purchase		44,460	-	4.0240		-	178,907		178,907
25	MGT Cash Out Imbalance		-	-	-		-	-		-
26	NSS Injection fuel loss		-							
27	Backup Supply Sales		-		-		-	-		-
28	Sub-total		3,414,413				$2,236,390	$13,145,682	$0	$15,382,072
	Actual - January, 2022									
	Exelon Generation Company									
29	Panhandle Eastern Pipeline - TOR	33,463	-	$ 12.5884	$ -		$ 421,247	$ -		$ 421,247
30	MGT Pipeline	1,395,000	-	0.0790	-		110,183	-		110,183
31	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
32	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	514,042	16.1727	5.2150		276,391	2,680,737		2,957,128
33	Texas Gas Transmission - Nominated Demand	1,346,485		0.3543	-		477,060			477,060
34	Texas Gas Transmission - Unnominated Demand	1,133,515		0.3547	-		402,012			402,012
35	Texas Gas Transmission - Commodity - TOR		-	-	-			-		-
36	Texas Gas Transmission - Unnominated Injection	-	-	-	-		-	-		-
37	Texas Gas Transmission - Unnominated Withdrawal	768,064	768,064	0.5057	3.8120		388,410	2,927,860		3,316,270
38	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
39	Rockies Express - Delivered Supply - (BP PEAK B)	-	310,000	-	3.8165		-	1,183,115		1,183,115
40	Rockies Express - Delivered Supply - (BP PEAK)	-	310,000	-	3.6890		-	1,143,590		1,143,590
41	Rockies Express - EAST	20,000	620,000	16.7292	3.4697		334,583	2,151,189		2,485,772
42	Intraday Purchases		20,000	-	4.3400			86,800		86,800
43	Fuel Retention Volumes		-	-	-					-
44	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		1,095,108	-	4.1896			4,588,034		4,588,034
45	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
46	Hedging Transaction Cost			-	-			365,851		365,851
47	Imbalance		(926)	-	3.8521			(3,567)		(3,567)
48	Utilization Fee			-	-		(254,167)			(254,167)
49	Net Demand Cost Charges - AMA			-	-		-			-
50	Wholesale Sales	-	(633,742)	-	5.3038		-	(3,361,218)		(3,361,218)
51	Third Party Supplier Balancing Gas Costs		367,407	-				1,204,381		1,204,381
52	Boil-off / Peaking purchase		44,460	-	4.0240			178,907		178,907
53	MGT Cash Out Imbalance		473	-	11.7252			5,546		5,546
54	NSS Injection fuel loss		-							
55	Backup Supply Sales		-		-			-		-
56	Sub-total		3,414,886				$ 2,155,719	$ 13,151,225	$ -	$ 15,306,944

Citizens Gas
Purchased Gas Cost - Per Books
February 2022

Line No.	Accrual -February, 2022	A Demand - Dth	B Commodity Dth	C Demand $/Unit	D Commodity $/Dth	E Other $/Unit	F Demand (A x C)	G Commodity (B x D)	H Other	I Total (F + G + H)
	Exelon Generation Company									
57	Panhandle Eastern Pipeline - TOR	33,463	-	$ 12.2819	$ -		$ 410,989	$ -		$ 410,989
58	MGT Pipeline	1,260,000	-	0.0874	-		110,183	-		110,183
59	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
60	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	464,296	16.8364	6.4518		287,734	2,995,535		3,283,269
61	Texas Gas Transmission - Nominated Demand	1,216,180		0.3543	-		430,893			430,893
62	Texas Gas Transmission - Unnominated Demand	1,023,820		0.3543	-		362,739			362,739
63	Texas Gas Transmission - Commodity - TOR		-	-	-			-		-
64	Texas Gas Transmission - Unnominated Injection	(12,601)	(12,601)	0.9486	4.8198		(11,953)	(60,734)		(72,687)
65	Texas Gas Transmission - Unnominated Withdrawal	543,237	543,237	0.4714	3.8828		256,082	2,109,281		2,365,363
66	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
67	Rockies Express - Delivered Supply - (BP PEAK B)		280,000	-	6.0575		-	1,696,100		1,696,100
68	Rockies Express - Delivered Supply - (BP PEAK A)		280,000	-	5.9300		-	1,660,400		1,660,400
69	Rockies Express - EAST	20,000	560,000	16.7292	6.1041		334,583	3,418,275		3,752,858
70	Intraday Purchases		60,000	-	4.8333			290,000		290,000
71	Fuel Retention Volumes		-	-	-					-
72	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		633,050	-	4.7629			3,015,170		3,015,170
73	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
74	Hedging Transaction Cost			-	-			(436,100)		(436,100)
75	Imbalance		(2,405)	-	4.5992			(11,061)		(11,061)
76	Utilization Fee			-	-		(254,167)			(254,167)
77	Net Demand Cost Charges - AMA			-	-		-			-
78	Wholesale Sales	-	(828,851)	-	6.4459		-	($5,342,729)		(5,342,729)
79	Third Party Supplier Balancing Gas Costs		256,432	-				739,701		739,701
80	Boil-off / Peaking purchase		69,233	-	6.2650			433,745		433,745
81	MGT Cash Out Imbalance		-	-	-			-		-
82	NSS Injection fuel loss		(47)							-
83	Backup Supply Sales		-		-			-		-
84	Sub-total		2,302,344				1,927,083	10,507,583	$ -	12,434,666
85	Total Purchased Costs (line 56 + line 84 - line 28)		2,302,817				$1,846,412	$10,513,126	$0	$12,359,538
86	Total TGT Unnominated Demand Cost (line 62+ line 34 - line 6)						363,147			
87	Total Purchase Cost excluding TGT Demand Unnom. (ln 85 - ln 86)		2,302,817				$1,483,265			
88	TGT Unnominated Demand Cost - Retail (line 86 * 90%)						$326,832			
89	Balancing Demand Cost (line 86 * 10%)						$36,315			

Citizens Gas
Actual Information
For Three Months Ending February 28, 2022

Line No.	A	B	C	D	E
	December 2021	Volumes in Dths	Commodity Cost per Dth	% of Total	Reference
1	Intraday Purchases	25,000	$ 3.8360	1.02%	Sch8A, lns 14, 42, 70
2	Index Purchases / Spot	1,754,042	$ 5.2224	71.33%	Sch8A, lns 1,2,3,4,7,11,12,13,29,30,31,32,35,39,40,41,57,58,59,60,63,67,68,69
3	Swing Gas	90,767	$ 4.2951	3.69%	Sch8A, lns 16, 44, 72
4	Boil off/Peaking Purchases	58,598	$ 5.4470	2.38%	Sch8A, lns 24, 52, 80
5	Unnominated Seasonal Gas Purchases	-		0.00%	
6	Storage Withdrawal	530,540	$ 3.7309	21.58%	Sch8A, lns 9, 37, 65
7	Total Purchases	2,458,947		100.00%	
8	Wholesale Sales	(437,556)			Sch8A, lns 22,50,78
9	Third Party	482,403			Sch8A, lns 23, 51, 79
10	Imbalance	27,191			Sch8A, lns 19, 47, 75
11	Fuel Retention	-			Sch8A, lns 15, 43, 71
12	MGT Cash Out Imbalance	(5,841)			Sch8A, lns 25, 53, 81
13	Unnominated Seasonal Gas Payback	-			
14	NNS Injection Loss	(88)			Sch8A, lns 26, 54, 82
15	Backup Supply Sales	-			Sch8A, lns 27, 55, 83
16	Storage Injection	(23,508)	$ 4.4671		Sch8A, lns 8, 36, 64
17	Net Purchases	2,501,548			
	January 2022	Volumes in Dths	Commodity Cost per Dth	% of Total	
18	Intraday Purchases	20,000	$ 4.3400	0.54%	Sch8B, lns 14, 42, 70
19	Index Purchases	1,754,042	$ 4.0048	47.77%	Sch8B, lns 1,2,3,4,7,11,12,13,29,30,31,32,35,39,40,41,57,58,59,60,63,67,68,69
20	Swing Gas	1,095,108	$ 4.1891	29.82%	Sch8B, lns 16, 44, 72
21	Boil off/Peaking Purchases	44,460	$ 4.0240	1.21%	Sch8B, lns 24, 52, 80
22	Unnominated Seasonal Gas Purchases	-		0.00%	
23	Storage Withdrawal	758,697	$ 3.8176	20.66%	Sch8B, lns 9, 37, 65
24	Total Purchases	3,672,307		100.00%	
25	Wholesale Sales	(633,742)			Sch8B, lns 22,50,78
26	Third Party	367,407			Sch8B, lns 23, 51, 79
27	Imbalance	(926)			Sch8B, lns 19, 47, 75
28	Fuel Retention	-			Sch8B, lns 15, 43, 71
29	MGT Cash Out Imbalance	1,078			Sch8B, lns 25, 53, 81
30	Unnominated Seasonal Gas Payback	-			
31	NNS Injection Loss	-			Sch8B, lns 26, 54, 82
32	Backup Supply Sales	-			Sch8B, lns 27, 55, 83
33	Storage Injection	-	$ -		Sch8B, lns 8, 36, 64
34	Net Purchases	3,406,124			
	February 2022	Volumes in Dths	Commodity Cost per Dth	% of Total	
35	Intraday Purchases	60,000	$ 4.8333	2.08%	Sch8C, lns 14, 42, 70
36	Index Purchases	1,584,296	$ 6.1670	54.81%	Sch8C, lns 1,2,3,4,7,11,12,13,29,30,31,32,35,39,40,41,57,58,59,60,63,67,68,69
37	Swing Gas	633,050	$ 4.7629	21.91%	Sch8C, lns 16, 44, 72
38	Boil off/Peaking Purchases	69,233	$ 6.2650	2.40%	Sch8C, lns 24, 52, 80
39	Unnominated Seasonal Gas Purchases	-		0.00%	
40	Storage Withdrawal	543,237	$ 3.8828	18.80%	Sch8C, lns 9, 37, 65
41	Total Purchases	2,889,816		100.00%	
42	Wholesale Sales	(828,851)			Sch8C, lns 22,50,78
43	Third Party	256,432			Sch8C, lns 23, 51, 79
44	Imbalance	(2,405)			Sch8C, lns 19, 47, 75
45	Fuel Retention	-			Sch8C, lns 15, 43, 71
46	MGT Cash Out Imbalance	473			Sch8C, lns 25, 53, 81
47	Unnominated Seasonal Gas Payback				
48	NNS Injection Loss	(47)			Sch8C, lns 26, 54, 82
49	Backup Supply Sales	-			Sch8C, lns 27, 55, 83
50	Storage Injection	(12,601)	$ 4.8198		Sch8C, lns 8, 36, 64
51	Net Purchases	2,302,817			

Citizens Gas
Calculation of the Average Accrual Pipeline Rate
Non-pipeline Supplies, Storage Injection, and Company Usage

Line No.	Description	December 2021 Dth	December 2021 Rate	December 2021 Amount	January 2022 Dth	January 2022 Rate	January 2022 Amount	February 2022 Dth	February 2022 Rate	February 2022 Amount
1	Panhandle Eastern Pipeline - Demand	33,463	$ 12.5884	$ 421,247	33,463	$ 12.5884	$ 421,247	33,463	$ 12.2819	$ 410,989
2	MGT Pipeline - Demand	1,395,000	0.1069	149,090	1,395,000	0.1069	149,090	1,260,000	0.0874	110,183
3	Indiana Municipal Gas Purchasing Authority - Demand	17,090	18.6403	318,563	17,090	18.6403	318,563	17,090	16.8364	287,734
4	Texas Gas Transmission - Nominated Demand	1,346,485	0.3543	477,060	1,346,485	0.3543	477,060	1,216,180	0.3543	430,893
5	Texas Gas Transmission - Unnominated Demand	1,133,515	0.3543	401,604	1,133,515	0.3543	401,604	1,023,820	0.3543	362,739
6	Texas Gas Transmission - Unnominated Injections	(23,508)	0.9365	(22,015)	-	-	-	(12,601)	0.9486	(11,953)
7	Texas Gas Transmission - Unnominated Withdrawal	530,540	0.4125	218,848	768,064	0.5057	388,410	543,237	0.4714	256,082
8	Rockies express - Delivered Supply - (BP REX)	-	-	-	-	-	-	-	-	-
9	Rockies Express - EAST (Demand)	20,000	16.7292	334,583	20,000	16.7292	334,583	20,000	16.7292	334,583
10	TGT-PEPL-MGT-REX- Swing Gas (Demand)	-	-	-	-	-	-	-	-	-
11	Utilization Fee	-	-	(254,167)	-	-	(254,167)	-	-	(254,167)
12	Panhandle Eastern/MGT Pipeline/Rockies Express East- Commodity	620,000	5.1824	3,213,074	620,000	3.4697	2,151,189	560,000	6.1041	3,418,275
13	Indiana Municipal Gas Purchasing Authority - Commodity	-	-	-	-	-	-	-	-	-
14	Indiana Municipal Gas Purchasing Authority - Prepay Commodity	514,042	5.3020	2,725,472	514,042	5.2150	2,680,737	464,296	6.4518	2,995,535
15	Texas Gas Transmission - Commodity	-	-	-	-	-	-	-	-	-
16	Texas Gas Transmission - Unnominated Injection - Commodity	(23,508)	4.4635	(104,928)	-	-	-	(12,601)	4.8198	(60,734)
17	Texas Gas Transmission - Unnominated Withdrawal - Commodity	530,540	3.3551	1,780,015	768,064	3.8120	2,927,860	543,237	3.8828	2,109,281
18	Rockies Express - Delivered Supply - (BP PEAK B)	310,000	5.2395	1,624,245	310,000	3.8165	1,183,115	280,000	6.0575	1,696,100
19	Rockies Express - Delivered Supply - (BP PEAK A)	310,000	5.1120	1,584,720	310,000	3.6890	1,143,590	280,000	5.9300	1,660,400
20	Intra-DayPurchases	25,000	3.8360	95,900	20,000	4.3400	86,800	60,000	4.8333	290,000
21	TGT-PEPL-MGT-REX- Swing Gas (Commodity)	90,767	4.2951	389,857	1,095,108	4.1896	4,588,034	633,050	4.7629	3,015,170
22	Hedging Transaction Cost	-	-	(1,191,034)	-	-	365,851	-	-	(436,100)
23	Imbalance	27,192	4.2266	114,930	(926)	3.8488	(3,564)	(2,405)	4.5992	(11,061)
24	Wholesale Sales	(437,556)	3.6190	(1,583,494)	(633,742)	5.3038	(3,361,218)	(828,851)	6.4459	(5,342,729)
25	Third Party Supplier Balancing Gas Costs	482,403		1,634,068	367,407		1,204,381	256,432		739,701
26	Boil-off / Peaking purchase	58,598	5.4470	319,183	44,460	4.0240	178,907	69,233	6.2650	433,745
27	MGT Cash Out Imbalance	-	-	-	-	-	-	-	-	-
28	Fuel Retention Volumes	-	-		-	-		-	-	-
29	NSS Injection fuel loss	(88)		-	-			(47)		-
30	Backup Supply Sales	-	-	-	-	-	-	-	-	-
31	Current Pipeline Rate Per Dth	2,507,390	$5.0438	$ 12,646,821	3,414,413	$4.5050	$ 15,382,072	2,302,344	$5.4009	$ 12,434,666
32	Current Commodity Rate Per Dth	2,507,390	$4.2283	$10,602,008	3,414,413	$3.8501	$13,145,682	2,302,344	$4.5639	10,507,583

Lines 4 & 16 - includes TGT Unnom. Storage Refill Adjustment

Citizens Gas
Calculation of the Average Actual Pipeline Rate
Non-pipeline Supplies, Storage Injection, and Company Usage

		November 2021			December 2021			January 2022		
Line No.	Description	Dth	Rate	Amount	Dth	Rate	Amount	Dth	Rate	Amount
1	Panhandle Eastern Pipeline - Demand	33,463	$ 12.4863	$ 417,828	33,463	$ 12.5884	$ 421,247	33,463	$ 12.5884	$ 421,247
2	MGT Pipeline - Demand	1,350,000	0.1104	149,090	1,395,000	0.1069	149,090	1,395,000	0.0790	110,183
3	Indiana Municipal Gas Purchasing Authority - Demand	17,090	17.9355	306,517	17,090	18.5521	317,055	17,090	16.1727	276,391
4	Texas Gas Transmission - Nominated Demand	1,303,050	0.3543	461,671	1,346,485	0.3543	477,060	1,346,485	0.3543	477,060
5	Texas Gas Transmission - Unnominated Demand	1,096,950	0.3543	388,649	1,133,515	0.3543	401,604	1,133,515	0.3547	402,012
6	Texas Gas Transmission - Unnominated Injections	(7,916)	0.5647	(4,470)	(23,508)	0.9351	(21,982)	-	-	-
7	Texas Gas Transmission - Unnominated Withdrawal	403,601	0.5647	227,913	521,173	0.4125	214,984	768,064	0.5057	388,410
8	Rockies express - Delivered Supply - (BP REX)	-	-	-	-	-	-	-	-	-
9	Rockies Express - EAST- (Demand)	20,000	16.7292	334,583	20,000	16.7198	334,395	20,000	16.7292	334,583
10	TGT-PEPL-MGT-REX- Swing Gas (Demand)	-	-	-	-	-	-	-	-	-
11	Utilization Fee	-	-	(254,167)	-	-	(254,167)	-	-	(254,167)
12	Panhandle Eastern/MGT Pipeline/Rockies Express East- Commodity	600,000	5.7658	3,459,499	620,000	5.1824	3,213,074	620,000	3.4697	2,151,189
13	Indiana Municipal Gas Purchasing Authority - Commodity	-	-	-	-	-	-	-	-	-
14	Indiana Municipal Gas Purchasing Authority - Prepay Commodity	497,460	5.9360	2,952,914	514,042	5.3660	2,758,352	514,042	5.2150	2,680,737
15	Texas Gas Transmission - Commodity	-	-	-	-	-	-	-	-	-
16	Texas Gas Transmission - Unnominated Injection - Commodity	(7,916)	4.1908	(33,174)	(23,508)	4.3967	(103,358)	-	-	-
17	Texas Gas Transmission - Unnominated Withdrawal - Commodity	403,601	4.1907	1,691,371	521,173	3.3551	1,748,588	768,064	3.8120	2,927,860
18	Rockies Express - Delivered Supply - (BP PEAK B)	300,000	5.9945	1,798,350	310,000	5.2395	1,624,245	310,000	3.8165	1,183,115
19	Rockies Express - Delivered Supply - (BP PEAK A)	300,000	5.8670	1,760,100	310,000	4.5733	1,417,720	310,000	3.6890	1,143,590
20	Intra-DayPurchases	-	-	-	25,000	3.8360	95,900	20,000	4.3400	86,800
21	TGT-PEPL-MGT-REX- Swing Gas (Commodity)	1,779,247	4.8123	8,562,287	90,767	4.2900	389,387	1,095,108	4.1896	4,588,034
22	Hedging Transaction Cost	-	-	(3,032,186)	-	-	(1,191,034)	-	-	365,851
23	Imbalance	(42,807)	4.1907	(179,391)	27,192	4.1773	113,589	(926)	3.8521	(3,567)
24	Wholesale Sales	-	-	-	(437,556)	3.6190	(1,583,494)	(633,742)	5.3038	(3,361,218)
25	Third Party Supplier Balancing Gas Costs	(176,033)		(1,661,304)	482,403		1,634,068	367,407		1,204,381
26	Boil-off / Peaking purchase	79,390	6.2020	492,377	58,598	5.4470	319,183	44,460	4.0240	178,907
27	MGT Cash Out Imbalance	(5,841)	0.6598	(3,854)	1,078	6.9462	7,488	473	11.7252	5,546
28	Fuel Retention Volumes	-	-	-	-	-	-	-	-	-
29	NSS Injection fuel loss	-	-	-	(88)	-	-	-	-	-
30	Backup Supply Sales	(179,500)	5.2371	(940,060)	-	-	-	-	-	-
31	Current Pipeline Rate Per Dth	3,547,601	$4.7622	$ 16,894,543	2,499,101	$4.9950	$ 12,482,994	3,414,886	$4.4824	$ 15,306,944
32	Current Commodity Rate Per Dth	3,547,601	$4.1907	14,866,929	2,499,101	$4.1790	10,443,708	3,414,886	$3.8511	13,151,225

Lines 4 & 16 - includes TGT Unnom. Storage Refill Adjustment

Citizens Gas
PEPL Unnominated Quantities Cost
December 2021

Line No.		A Compres. Fuel-Dth	B Demand Costs	C Volumes	D Storage Rates	E Compres. Fuel	F Total
	Accrual -November, 2021						
	PEPL						
1	Demand Cost		$674,143				$674,143
2	PEPL Injection fuel cost	41				192	192
3	PEPL Injection (Net)			1,721	$0.0020		3
4	(100-day Firm) (Midpoint)			1,750	0.0094		16
5	PEPL Withdrawal fuel cost	13,041				38,950	38,950
6	PEPL Withdrawal (Midpoint)			666,668	0.0020		1,333
7	(100-day Firm) (Net)			662,136	0.0094		6,224
8	PEPL - Sub Total		$674,143			$39,142	$720,861
	Actual -November, 2021						
	PEPL						
9	Demand Cost		$676,525				$676,525
10	PEPL Injection fuel cost	41				195	195
11	PEPL Injection (Net)			1,721	0.0020		3
12	(100-day Firm) (Midpoint)			1,750	0.0094		16
13	PEPL Withdrawal fuel cost	13,041				38,950	38,950
14	PEPL Withdrawal (Midpoint)			666,668	0.0020		1,333
15	(100-day Firm) (Net)			662,136	0.0094		6,224
16	PEPL - Sub Total		$676,525			$39,145	$723,246
	Accrual - December, 2021						
	PEPL						
17	Demand Cost		$687,317				$687,317
18	PEPL Injection fuel cost	221				1,115	1,115
19	PEPL Injection (Net)			9,391	0.0020		19
20	(100-day Firm) (Midpoint)			9,547	0.0094		90
21	PEPL Withdrawal fuel cost	14,174				42,342	42,342
22	PEPL Withdrawal (Midpoint)			724,667	0.0020		1,449
23	(100-day Firm) (Net)			719,741	0.0094		6,766
24	PEPL - Sub Total		$687,317			$43,457	$739,098
25	Total (line 24 + line 16 - line 8)		$689,699			$43,460	$741,483
26	PEPL - Balancing Costs (ln 25 * 9%)						$66,733
27	PEPL - Retail Costs (ln 25 * 91%)						$674,750

Citizens Gas
PEPL Unnominated Quantities Cost
January 2022

Line No.		A Compres. Fuel-Dth	B Demand Costs	C Volumes	D Storage Rates	E Compres. Fuel	F Total
	Accrual - December, 2021						
	PEPL						
1	Demand Cost		$687,317				$687,317
2	PEPL Injection fuel cost	221				1,115	1,115
3	PEPL Injection (Net)			9,391	$0.0020		19
4	(100-day Firm) (Midpoint)			9,547	0.0094		90
5	PEPL Withdrawal fuel cost	14,174				42,342	42,342
6	PEPL Withdrawal (Midpoint)			724,667	0.0020		1,449
7	(100-day Firm) (Net)			719,741	0.0094		6,766
8	PEPL - Sub Total		$687,317			$43,457	$739,098
	Actual - December, 2021						
	PEPL						
9	Demand Cost		$689,660				$689,660
10	PEPL Injection fuel cost	221				1,104	1,104
11	PEPL Injection (Net)			9,391	0.0020		19
12	(100-day Firm) (Midpoint)			9,547	0.0094		90
13	PEPL Withdrawal fuel cost	14,174				42,342	42,342
14	PEPL Withdrawal (Midpoint)			724,667	0.0020		1,449
15	(100-day Firm) (Net)			719,741	0.0094		6,766
16	PEPL - Sub Total		$689,660			$43,446	$741,430
	Accrual - January, 2022						
	PEPL						
17	Demand Cost		$687,317				$687,317
18	PEPL Injection fuel cost	-				-	-
19	PEPL Injection (Net)			-	0.0020		-
20	(100-day Firm) (Midpoint)			-	0.0094		-
21	PEPL Withdrawal fuel cost	21,159				63,293	63,293
22	PEPL Withdrawal (Midpoint)			1,081,681	0.0020		2,163
23	(100-day Firm) (Net)			1,074,327	0.0094		10,099
24	PEPL - Sub Total		$687,317			$63,293	$762,872
25	Total (line 24+ line 16 - line 8)		$689,660			$63,282	$765,204
26	PEPL Balancing Costs (ln 25 * 9%)						$68,868
27	PEPL Retail Costs (ln 25 * 91%)						$696,336

Citizens Gas
PEPL Unnominated Quantities Cost
February 2022

Line No.		A Compres. Fuel-Dth	B Demand Costs	C Volumes	D Storage Rates	E Compres. Fuel	F Total
	Accrual - January, 2022						
	PEPL						
1	Demand Cost		$687,317				$687,317
2	PEPL Injection Fuel Cost	-				-	-
3	PEPL Injection (Net)			-	$0.0020		-
4	(100-day Firm) (Midpoint)			-	0.0094		-
5	PEPL Withdrawal Fuel Cost	21,159				63,293	63,293
6	PEPL Withdrawal (Midpoint)			1,081,681	0.0020		2,163
7	(100-day Firm) (Net)			1,074,327	0.0094		10,099
8	PEPL Total		$687,317			$63,293	$762,872
	Actual - January, 2022						
	PEPL						
9	Demand Cost		$688,208				$688,208
10	PEPL Injection Fuel Cost	-				-	-
11	PEPL Injection (Net)			-	$0.0020		-
12	(100-day Firm) (Midpoint)			-	0.0094		-
13	PEPL Withdrawal Fuel Cost	21,199				63,413	63,413
14	PEPL Withdrawal (Midpoint)			1,083,701	0.0020		2,167
15	(100-day Firm) (Net)			1,076,333	0.0094		10,118
16	PEPL Total		$688,208			$63,413	$763,906
	Accrual -February, 2022						
	PEPL						
17	Demand Cost		$647,794				$647,794
18	PEPL Injection Fuel Cost	-				-	-
19	PEPL Injection (Net)			-	$0.0020		-
20	(100-day Firm) (Midpoint)			-	0.0094		-
21	PEPL Withdrawal fuel cost	19,484				58,281	58,281
22	PEPL Withdrawal (Midpoint)			996,207	0.0020		1,992
23	(100-day Firm) (Net)			989,434	0.0094		9,301
24	PEPL Total		$647,794			$58,281	$717,368
25	Total (line 24 + line 16 - line 8)		$648,685			$58,401	$718,402
26	PEPL Balancing Costs (ln 25 * 9%)						$64,656
27	PEPL Retail Costs (ln 25 * 91%)						$653,746

Citizens Gas
Cost of Gas Injections and Withdrawals
For the period December 1, 2021 - February 28, 2022

		A	B	C	D	E	F	G	H	I
		Estimated Change		Cost of Gas						
				Injections		Withdrawals		Net		
Line No.		Injections Dth	Withdrawals Dth	Demand	Commodity	Demand	Commodity	Demand	Commodity	Total
	December 2021									
1	UGS	80,028	712,493	$76,764	$379,493	$352,399	$2,009,017	$275,635	$1,629,524	$1,905,159
2	PEPL	9,612	719,741	7,871	40,756	357,711	1,792,371	349,840	1,751,615	2,101,455
3	Subtotal	89,640	1,432,234	$84,635	$420,249	$710,110	$3,801,388	$625,475	$3,381,139	$4,006,614
	January 2022									
4	UGS	2,266	2,425,605	$1,524	$4,779	$1,207,709	$6,874,407	$1,206,185	$6,869,628	$8,075,813
5	PEPL	-	1,074,327	4	(473)	534,692	2,678,942	534,688	2,679,415	3,214,103
6	Subtotal	2,266	3,499,932	1,528	4,306	1,742,401	9,553,349	1,740,873	9,549,043	11,289,916
	February 2022									
7	UGS	15,127	1,947,646	$12,607	$69,041	$969,927	$5,520,603	$957,320	$5,451,562	$6,408,882
8	PEPL	-	991,440	-	-	493,242	2,472,354	493,242	2,472,354	2,965,596
9	Subtotal	15,127	2,939,086	12,607	69,041	1,463,169	7,992,957	1,450,562	7,923,916	9,374,478
10	Grand Total	107,033	7,871,252	$98,770	$493,596	$3,915,680	$21,347,694	$ 3,816,910	$ 20,854,098	$ 24,671,008

Citizens Gas
Demand Allocation of Injections and Withdrawals
From PEPL
For Three Months Ending February 28, 2022

Line No.		A Volume DTH	B Demand Cost	C Commodity Cost	D Total Cost	E Total $/DTH	F Commodity $/DTH
1	Beginning balance @ December 2021	5,444,429	$2,705,609	$13,558,064	$16,263,973	$2.9873	$2.4903
2	Less: Net W/D @ avg. unit cost						
3	Prior mo. accrual reversal	662,136	329,082	1,648,520	1,977,602	2.9867	2.4897
4	Prior mo. actual	(662,136)	(329,082)	(1,648,520)	(1,977,602)	2.9867	2.4897
5	Current mo. accrual	(719,741)	(357,711)	(1,792,371)	(2,150,082)	2.9873	2.4903
6	Add: Gross Injections						
7	Prior mo. accrual reversal	(1,762)	(975)	(7,270)	(8,245)	4.6794	4.1260
8	Prior mo. actual	1,762	1,007	7,384	8,391	4.7622	4.1907
9	Current mo. accrual	9,612	7,839	40,642	48,481	5.0438	4.2283
10	Less: Compressor Fuel						
11	Prior mo. accrual reversal - W/D	13,041	6,482	32,468	38,950	2.9867	2.4897
12	Prior mo. accrual reversal - Injections	41	23	169	192	4.6794	4.1260
13	Prior mo. Actual - W/D	(13,041)	(6,482)	(32,468)	(38,950)	2.9867	2.4897
14	Prior mo. Actual - Injections	(41)	(23)	(172)	(195)	4.7622	4.1907
15	Current mo. Accrual -Inj	(221)	(181)	(934)	(1,115)	5.0438	4.2283
16	Current mo. Accrual-W/D	(14,174)	(7,044)	(35,298)	(42,342)	2.9873	2.4903
17	Beginning balance @ January 2022	4,719,905	2,348,544	11,770,214	14,119,058	2.9914	2.4937
18	Less: Net W/D @ avg. unit cost						
19	Prior mo. accrual reversal	719,741	357,711	1,792,371	2,150,082	2.9873	2.4903
20	Prior mo. actual	(719,741)	(357,711)	(1,792,371)	(2,150,082)	2.9873	2.4903
21	Current mo. accrual	(1,074,327)	(534,692)	(2,678,942)	(3,213,634)	2.9913	2.4936
22	Add: Gross Injections						
23	Prior mo. accrual reversal	(9,612)	(7,839)	(40,642)	(48,481)	5.0438	4.2283
24	Prior mo. actual	9,612	7,843	40,169	48,012	4.9950	4.1790
25	Current mo. accrual	-	-	-	-	-	-
26	Less: Compressor Fuel						
27	Prior mo. accrual reversal - W/D	14,174	7,044	35,298	42,342	2.9873	2.4903
28	Prior mo. accrual reversal - Inj	221	181	934	1,115	5.0438	4.2283
29	Prior mo. Actual - W/D	(14,174)	(7,044)	(35,298)	(42,342)	2.9873	2.4903
30	Prior mo. Actual - Injections	(221)	(180)	(924)	(1,104)	4.9950	4.1790
31	Current mo. accrual - Inj	-	-	-	-	-	-
32	Current mo. Accrual-W/D	(21,159)	(10,531)	(52,762)	(63,293)	2.9913	2.4936
33	Beginning balance @ February 2022	3,624,419	1,803,326	9,038,047	10,841,373	2.9912	2.4937
34	Less: Net W/D @ avg. unit cost						
35	Prior mo. accrual reversal	1,074,327	534,692	2,678,942	3,213,634	2.9913	2.4936
36	Prior mo. actual	(1,076,333)	(535,691)	(2,683,944)	(3,219,635)	2.9913	2.4936
37	Current mo. accrual	(989,434)	(492,243)	(2,467,352)	(2,959,595)	2.9912	2.4937
38	Add: Gross Injections						
39	Prior mo. accrual reversal	-	-	-	-	-	-
40	Prior mo. actual	-	-	-	-	-	-
41	Current mo. Accrual	-	-	-	-	-	-
42	Less: Compressor Fuel						
43	Prior mo. accrual reversal - W/D	21,159	10,531	52,762	63,293	2.9913	2.4936
44	Prior mo. accrual reversal - Inj	-	-	-	-	-	-
45	Prior mo. Actual - W/D	(21,199)	(10,551)	(52,862)	(63,413)	2.9913	2.4936
46	Prior mo. Actual - Injections	-	-	-	-	-	-
47	Current mo. accrual -Inj	-	-	-	-	-	-
48	Current mo. Accrual-W/D	(19,484)	(9,694)	(48,587)	(58,281)	2.9912	2.4937
49	Ending balance @ February 28, 2022	2,613,455	1,300,370	6,517,006	7,817,376	$2.9912	$2.4936

Citizens Gas
Demand Allocation of Injections and Withdrawals
From UGS
For Three Months Ending February 28, 2022

		A	B	C	D	E	F
Line No.		Volume	Demand Cost	Commodity Cost	Total Cost	Total $/Unit	Commodity $/Unit
1	Beginning balance @ December 2021	8,232,930	$4,059,940	$23,173,591	$27,233,531	$3.3079	$2.8147
2	Add: Gross Injections						
3	Less: Prior mo. accrual	(635,419)	(351,641)	(2,621,739)	(2,973,380)	4.6794	4.1260
4	Add: Prior mo. actual	635,419	363,142	2,662,850	3,025,992	4.7622	4.1907
5	Add: Current mo. accrual	80,028	65,263	338,382	403,645	5.0438	4.2283
6	Less: Net Withdrawals						
7	Prior mo. accrual reversal	-	-	-	-	-	-
8	Prior mo. Actual	-	-	-	-	-	-
9	Current mo. accrual	(712,493)	(352,399)	(2,009,017)	(2,361,416)	3.3143	2.8197
10	Less: Blowoff						
11	Current mo. Blowoff	(1,701)	(842)	(4,796)	(5,638)	3.3143	2.8197
12	Beginning balance @ January 2022	7,598,764	3,783,463	21,539,271	25,322,734	3.3325	2.8346
13	Add: Gross Injections						
14	Less: Prior mo. accrual	(80,028)	(65,263)	(338,382)	(403,645)	5.0438	4.2283
15	Add: Prior mo. actual	80,028	65,303	334,437	399,740	4.9950	4.1790
16	Add: Current mo. accrual	2,266	1,484	8,724	10,208	4.5050	3.8501
17	Less: Net Withdrawals						
18	Prior mo. accrual reversal	712,493	352,399	2,009,017	2,361,416	3.3143	2.8197
19	Prior mo. actual	(712,493)	(352,399)	(2,009,017)	(2,361,416)	3.3143	2.8197
20	Current mo. accrual	(2,425,605)	(1,207,709)	(6,874,407)	(8,082,116)	3.3320	2.8341
21	Less: Blowoff						
22	Current mo. Blowoff	(12,819)	(6,383)	(36,330)	(42,713)	3.3320	2.8341
23	Beginning balance @ February 2022	5,162,606	2,570,895	14,633,313	17,204,208	3.3325	2.8345
24	Add: Injections						
25	Less: Prior mo. accrual	(2,266)	(1,484)	(8,724)	(10,208)	4.5050	3.8501
26	Prior mo. actual	2,266	1,430	8,727	10,157	4.4824	3.8511
27	Current mo. accrual	15,127	12,661	69,038	81,699	5.4009	4.5639
28	Less: Withdrawals						
29	Prior mo. accrual reversal	2,425,605	1,207,709	6,874,407	8,082,116	3.3320	2.8341
30	Prior mo. actual	(2,425,914)	(1,207,862)	(6,875,283)	(8,083,145)	3.3320	2.8341
31	Current mo. Accrual	(1,947,337)	(969,774)	(5,519,727)	(6,489,501)	3.3325	2.8345
32	Less: Blowoff						
33	Current mo. Blowoff	(10,185)	(5,073)	(28,869)	(33,942)	3.3325	2.8345
34	Ending balance @ February 28, 2022	3,219,902	1,608,502	9,152,882	10,761,384	$3.3421	$2.8426

Citizens Gas
Determination of "Unaccounted For" Percentage and Manufacturing / Steam Division Costs
For Three Months Ending February 28, 2022

Line No.		A December 2021	B January 2022	C February 2022	D Total
1	Volume of pipeline gas purchases - Dths (See Schedule 8)	2,501,548	3,406,124	2,302,817	8,210,489
2	Gas (injected into) withdrawn from storage (See Schedule 10)	1,342,594	3,497,666	2,923,959	7,764,219
3	Transported gas received	2,152,192	2,233,724	2,317,178	6,703,094
4	Transported gas (injected into) withdrawn from storage	0	0	0	0
5	Reverse transport imbalance already on Sch 8	(482,403)	(367,407)	(256,432)	(1,106,242)
6	Total volume supplied	5,513,931	8,770,107	7,287,522	21,571,560
7	Less: Gas Division usage	(6,999)	(13,065)	(14,773)	(34,837)
8	Total volume available for sale	5,506,932	8,757,042	7,272,749	21,536,723
9	Retail Volume of gas sold - Dths (Schedule 6, Page 3, ln 26)	3,785,875	6,774,282	5,116,158	15,676,315
10	Total Transport Usage (Sch 6 , Page 3, ln 27 + ln 28)	1,861,381	2,185,664	2,165,369	6,212,414
11	"Unaccounted for" gas (ln 8- ln 9 - ln 10)	(140,324)	(202,904)	(8,778)	(352,006)
12	Percentage of "unaccounted for" gas (line 11 / line 8)	-2.55%	-2.32%	-0.12%	-1.63%

CITIZENS GAS
Initiation of Refund

Line No.	Refunds	
1	Supplier:	
2	Date received:	
3	Amount of refund:	$0
4	Reason for Refund:	
5	Docket Number:	
6	Total to be refunded	$0

Distribution of Refunds to GCA Quarters

Line No.	Quarter	A Sales % (All GCA Classes)		B Refund (line 6 * column A)
7	Jun., 2022 - Aug., 2022	5.5371%	(Sch. 2B, ln 18)	$0
8	Sept., 2022 - Nov., 2022	13.7123%	(Sch. 2B, ln 19)	$0
9	Dec., 2022- Feb., 2023	53.8563%	(Sch. 2B, ln 20)	$0
10	Mar., 2023 - May, 2023	26.8943%	(Sch. 2B, ln 21)	$0
11	Total			$0

Calculation of Refund to be Returned in this GCA

Line No.		
12	Refund from Cause No. 37399-GCA 151	$0
13	Refund from Cause No. 37399-GCA 152	0
14	Refund from Cause No. 37399-GCA 153	0
15	Refund from this Cause (line 7)	0
16	Total to be refunded in this Cause (Sum of lines 12 through 15)	$0

Citizens Gas
Allocation of Gas Supply Variance

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/ No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Cost Variances
	Calculation of Total Gas Cost Variances						
1	Dec., 2021 Total Gas Supply Variance (Sch 6A, pg. 1,ln 16)	3,262	646,746	16,661	224,804	0	891,473
2	Jan., 2022 Total Gas Supply Variance (Sch 6B, pg. 1, ln 16)	(7,280)	(1,042,142)	(7,007)	(350,213)	0	(1,406,642)
3	Feb., 2022 Total Gas Supply Variance (Sch 6C, pg. 1, ln 16)	2,101	227,892	11,944	81,543	0	323,480
4	Total Net Write Off Gas Cost Variance (over)/under recover (Sch 12C, ln19)	194	86,913	(40)	3,004	513	90,584
5	Annual Unaccounted for over-recovery (Sch 11a, ln 18, col. D * Sch 2B, ln 22)	0	0	0	0	0	0
6	Sub-Total Gas Supply Variance (over)/underrecovery (ln 1 + ln 2 + ln 3 + ln 4 + ln 5)	($1,723)	($80,591)	$21,558	($40,862)	$513	(101,105)
	Distribution of variances to quarters by rate class						
7	First quarter Total Gas Supply Variance (ln 6 * Sch 2B, ln 18)	($162)	($3,892)	$5,216	($2,521)	$0	($1,359)
8	Second quarter Total Gas Supply Variance (ln 6 * Sch 2B, ln 19)	(268)	(11,001)	6,215	(5,223)	0	(10,277)
9	Third quarter Total Gas Supply Variance (ln 6 * Sch 2B, ln 20)	(852)	(43,904)	6,013	(22,066)	0	(60,809)
10	Fourth quarter Total Gas Supply Variance (ln 6 * Sch 2B, ln 21)	(441)	(21,794)	4,114	(11,052)	0	(29,173)
	Calculation of variances for this Cause						
11	Cause No. 37399 - GCA 151 Total Gas Supply Variance (Sch 12B pg 1, ln 10)	(9)	32,005	(2,154)	6,481	0	36,323
12	Cause No. 37399 - GCA 152 Total Gas Supply Variance (Sch 12B pg 1, ln 9)	(52)	10,976	(10,934)	(514)	0	(524)
13	Cause No. 37399 - GCA 153 Total Gas Supply Variance (Sch 12B pg 1, ln 8)	1,196	102,409	6,621	39,163	0	149,389
14	This Cause Total Gas Supply Variance (line 7)	(162)	(3,892)	5,216	(2,521)	0	($1,359)
15	Total Gas Supply Variance to be included in GCA (Over)/Underrecovery (ln 11 + ln 12 + ln 13 + ln 14)	$973	$141,498	($1,251)	$42,609	$0	$183,829

Citizens Gas
Allocation of Balancing Demand Cost Variance

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3 / No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G Balancing Demand Cost Variance
	Calculation of Total Balancing Demand Cost Variances							
1	Dec., 2021 Total Balancing Demand Cost Variance (Sch 6A, pg. 2, ln 25)	$1	($431)	$171	($240)	$2,532	$7,201	$9,234
2	Jan., 2022 Total Balancing Demand Cost Variance (Sch 6B, pg. 2, ln 25)	($76)	($16,916)	($760)	($9,430)	$690	$2,813	($23,679)
3	Feb., 2022 Total Balancing Demand Cost Variance (Sch 6C, pg. 2, ln 25)	($53)	($6,614)	($86)	($2,463)	$1,672	$5,651	($1,893)
4	Balancing Demand Cost Variance (Line 1 + Line 2 + Line 3)	($128)	($23,961)	($675)	($12,133)	$4,894	$15,665	($16,338)
	Distribution of variances to quarters by rate class							
5	First quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 18)	($12)	($1,157)	($152)	($930)	$890	$4,424	$3,063
6	Second quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 19)	($20)	($3,271)	($170)	($2,021)	$1,149	$4,535	$202
7	Third quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 20)	($63)	($13,053)	($192)	($6,079)	$1,663	$2,130	($15,594)
8	Fourth quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 21)	($33)	($6,480)	($161)	($3,103)	$1,192	$4,576	($4,009)
	Calculation of variances for this Cause							
9	Cause No. 37399 - GCA 151 Total Balancing Demand Cost Variance (Sch 12B, pg. 2, ln 8)	$4	$111	$318	$205	$1,378	$2,276	$4,292
10	Cause No. 37399 - GCA 152 Total Balancing Demand Cost Variance (Sch 12B, pg. 2, ln 7)	($22)	($869)	($2,454)	($1,600)	($241)	$6,493	$1,307
11	Cause No. 37399 - GCA 153 Total Balancing Demand Cost Variance (Sch 12B, pg. 2, ln 6)	($19)	($1,487)	($1,298)	($1,720)	$532	$7,754	$3,762
12	This Cause Total Current Balancing Demand Cost Variance (line 5)	($12)	($1,157)	($152)	($930)	$890	$4,424	$3,063
13	Total Balancing Demand Cost Variance to be included in GCA (Over)/Underrecovery (ln 9 + ln 10 + ln 11 + ln 12)	($49)	($3,402)	($3,586)	($4,045)	$2,559	$20,947	$12,424

CITIZENS GAS
SCHEDULE 12C
DETERMINATION OF NET WRITE-OFF GAS COST RECOVERIES

Line No.		A	B	C	D	E	F
	December 2021						
		D1	**D2**	**D3**	**D4**	**D5**	**Total**
1	Actual Retail Sales in Dth (Sch 6A, line 26)	14,390	2,758,830	34,348	978,307	-	3,785,875
2	Net Write-Off Gas Cost Component per Dth Cause No. 37399-GCA 152, MPU Sch 1 pg 2, ln 23	$0.0490	$0.0520	$0.0070	$0.0140	$0.0000	
3	Actual Net Write Off Gas Cost Recovery (ln 1 * ln 2)	$705	$143,459	$240	$13,696	$0	$158,100
4	Net Write Off Recovery Allocation Factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
5	Recoverable Net-Write Off Gas Costs (Sch 6A, ln 9, Total * 1.10% * ln 4)	$811	$175,527	$497	$16,131	$134	$193,100
6	Net Write Off Gas Cost Variance (over)/under recovery (ln 5 - ln 3)	**$106**	**$32,068**	**$257**	**$2,435**	**$134**	**$35,000**
	January 2022						
7	Actual Retail Sales in Dth (Sch 6B, line 26)	34,408	4,770,702	81,384	1,887,788	-	6,774,282
8	Net Write-Off Gas Cost Component per Dth Cause No. 37399-GCA 152, MPU Sch 1 pg 2, ln 23	$0.0490	$0.0530	$0.0120	$0.0130	$0.0000	
9	Actual Net Write Off Gas Cost Recovery (ln 7 * ln 8)	$1,686	$252,847	$977	$24,541	$0	$280,051
10	Net Write Off Recovery Allocation Factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
11	Recoverable Net-Write Off Gas Costs (Sch 6B, ln 9, Total * 1.10% * ln 10)	$1,255	$271,614	$770	$24,961	$208	$298,808
12	Net Write Off Gas Cost Variance (over)/under recovery (ln 11 - ln 9)	**($431)**	**$18,767**	**($207)**	**$420**	**$208**	**$18,757**
	February 2022						
13	Actual Retail Sales in Dth (Sch 6C, line 26)	10,489	3,604,071	45,165	1,456,433	-	5,116,158
14	Net Write-Off Gas Cost Component per Dth Cause No. 37399-GCA 152, MPU Sch 1 pg 2, ln 23	$0.0490	$0.0520	$0.0160	$0.0140	$0.0000	
15	Actual Net Write Off Gas Cost Recovery (ln 13 * ln 14)	$514	$187,412	$723	$20,390	$0	$209,039
16	Net Write Off Recovery Allocation Factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
17	Recoverable Net-Write Off Gas Costs (Sch 6C, ln 9, Total * 1.10% * ln 16)	$1,033	$223,490	$633	$20,539	$171	$245,866
18	Net Write Off Gas Cost Variance (over)/under recovery (ln 17 - ln 15)	**$519**	**$36,078**	**($90)**	**$149**	**$171**	**$36,827**
19	Total Net Write Off Gas Cost Variance (over)/under recovery (ln 6 + ln 12 + ln 18)	$194	$86,913	($40)	$3,004	513	$90,584