CITIZENS GAS

Petition for Approval of Gas Cost Adjustments
To Be Applicable in the Months of
June, July and August 2021

Cause No. 37399 – GCA 150

Prefiled Direct Testimony and Attachments

Korlon L. Kilpatrick II
and
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INTRODUCTION

Q1. PLEASE STATE YOUR NAME.

A1. Korlon L. Kilpatrick II.

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"). 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 September 2013, I have held the position of Director, Regulatory Affairs.

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A3. I hold a Bachelor of Arts degree with a concentration in Computer Science from Harvard College and a Master of Business Administration degree with a major in Finance from the University of North Carolina at Chapel Hill.

Q4. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A4. I began my employment with Citizens Energy Group in 2010. Prior to joining Citizens Energy Group, I worked for the Indiana Office of Utility Consumer Counselor as a Utility Analyst. In that capacity, my work focused on economic and financial analysis of various regulatory issues including demand-side management / energy efficiency issues (DSM/EE) and cost of equity analysis. I regularly attended Midcontinent ISO stakeholder committee meetings and served as the Public Consumer Advocate sector representative to their Finance subcommittee. Prior to that, I was part of the senior management team of a start-up business, and prior to that, I worked for several years as a management consultant performing economic and financial analysis for clients in various industries.

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

A5. As Director of Regulatory Affairs, I am responsible for the development, implementation, and administration of Citizens Energy Group's regulated utilities' rates and charges and Terms and Conditions for Service. I prepare, or supervise the preparation of, rate design testimony for Citizens Energy Group's regulated utilities. Since 2010, I have been responsible for the preparation of GCA and FAC 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 2021. 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. 1.

A8. Exhibit No. 1 is my direct testimony.

Q9. PLEASE PROVIDE A BRIEF EXPLANATION OF EACH OF ATTACHMENTS KLK - 1 THROUGH KLK - 4.

A9. Attachment KLK-1 is Petitioner's Verified Petition filed in this matter. Attachment KLK-2 is Petitioner's GCA tariff sheet (Rider A), for the periods June, July and August 2021. The rates shown on each Rider A are the result of all appropriate estimations and reconciliations, as previously authorized by the Commission. Attachment KLK-3 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 2021 – and compared to the GCA rates in effect one year ago.

Attachment KLK-4 consists of all schedules required in support of the GCA rates shown in Attachment KLK-2. 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 KLK-4 IN MORE DETAIL.

A10. Schedules 1 through 5 of Attachment KLK-4 support the calculation of the GCA Factor. 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 2021.

Schedules 6 through 12 of Attachment KLK-4 are the reconciliation of actual gas costs and recoveries for December 2020, January and February 2021. Schedule 6 shows the actual gas costs and variance calculation of gas cost incurred versus recoveries in the reconciliation period of December 2020, January and February 2021. 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 150 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 2021?

A11. The majority of the gas costs for June, July and August 2021 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 03/18/21	
Jun. 2021	$2.6130
Jul. 2021	$2.6750
Aug. 2021	$2.6910

Q12. ON WHAT ARE THE OTHER GCA COMPUTATIONS CONTAINED IN ATTACHMENT KLK - 4 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 2021?

A13. Financially hedged transactions account for 57.14% of total purchases for the months of June, July and August 2021.

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 150 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 2021 ARE ACCURATE?

A15. Yes, I do.

RECONCILIATION PERIOD

Q16. HAVE YOU COMPARED PETITIONER'S ESTIMATED GAS COSTS FOR THE PERIOD OF DECEMBER 2020, JANUARY AND FEBRUARY 2021 WITH ACTUAL GAS COSTS EXPERIENCED FOR THAT RECOVERY PERIOD PURSUANT TO IC 8-1-2-42(G)(3)(D)?

A16. Yes.

Q17. IN YOUR OPINION, ARE THE GAS COST VARIANCES INCLUDED WITHIN THIS GCA 150 PROCEEDING ACCURATE AND REASONABLE?

A17. 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 2020, January and February 2021 presented in the GCA reconciliation period are shown in Table 2:

Table 2

Twelve Months Ending	Actual Gas Cost	Variance	% Variance
December 2020	$74,377,655	($6,669,360)	(8.97)%
January 2021	$77,203,731	($6,098,763)	(7.09)%
February 2021	$71,254,641	($15,940,956)	(22.37)%

Q18. PLEASE EXPLAIN PETITIONER'S TWELVE-MONTH TRAILING AVERAGES FOR ANY MONTH WITHIN THE GCA RECONCILIATION PERIOD THAT ARE GREATER THAN +/- 10% SHOWN ON ATTACHMENT KLK-4, SCHEDULE 6D.

A18. The (22.37)% variance in February is due to the significant price volatility in the month of February. Petitioner's witness J.P. Ghio discusses the transactions that created the variance in his testimony.

Q19. DO THE PROPOSED GCA RATES INCLUDE A RECONCILIATION OF ACTUAL COSTS TO ACTUAL RECOVERIES FOR THE MONTHS OF DECEMBER 2020, JANUARY AND FEBRUARY 2021?

A19. Yes. The proposed GCA rates to be effective June, July and August 2021 include the effect of reconciling actual gas costs incurred for the months of December 2020, January and February 2021 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 KLK–4, 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 2020	$14,769,386	$14,876,283	($106,897)
January 2021	$15,787,713	$16,715,857	($928,144)
February 2021	$6,743,835	$17,469,003	($10,725,168)
Total	$37,300,934	$49,061,143	($11,760,209)

Q20. WHAT PERCENTAGE OF TOTAL PURCHASES WAS MADE UP OF FINANCIALLY-HEDGED TRANSACTIONS FOR THE MONTHS OF DECEMBER 2020, JANUARY AND FEBRUARY 2021?

A20. Financially-hedged transactions accounted for 28.72% of total purchases for the months of December 2020, January and February 2021.

Q21. HAS PETITIONER RECEIVED ANY NEW REFUNDS THAT ARE INCLUDED IN THIS GCA?

A21. No.

MONTHLY PRICE UPDATE

Q22. PLEASE DESCRIBE THE HISTORY OF THE MONTHLY PRICE UPDATE MECHANISM.

A22. 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.

Q23. 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?

A23. 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.

Q24. PLEASE DESCRIBE THE MPU FILING.

A24. 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.

Q25. WHEN CITIZENS GAS FILES ITS MONTHLY PRICE UPDATE WITH THE COMMISSION, WHAT IS INCLUDED IN THE FILING?

A25. 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) residential heating customer's bill at 5, 10, 15, 20 and 25 dekatherms compared to current effective rates and compared to the rates in effect one year ago.

Q26. 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 2021?

A26. Table 4 shows the Monthly Benchmark Prices as established by NYMEX +/- basis as of March 18, 2021 by pipeline for June, July and August 2021 included in this filing.

TABLE 4

Benchmark Prices								
	Panhandle Eastern	Texas Gas	Midwestern Gas	Panhandle PrePay	PEAK B	Rockies Express East	PEAK A	TGT-REX
Jun. 2021	$2.4578	$2.5885	$2.4471	$2.1261	$2.4055	$2.3738	$2.2780	$2.4793
Jul. 2021	$2.6023	$2.6308	$2.5000	$2.2705	$2.4675	$2.4109	$2.3400	$2.5323
Aug. 2021	$2.6295	$2.6420	$2.5186	$2.2977	$2.4835	$2.3198	$2.3560	$2.5509

Q27. HAS PETITIONER PROPERLY APPLIED ITS GCA RATES SINCE ITS LAST GCA PROCEEDING IN CAUSE NO. 37399 GCA 149?

A27. Yes.

Q28. ARE PETITIONER'S BOOKS AND RECORDS UNDER REVIEW BEING KEPT ACCORDING TO THE UNIFORM SYSTEM OF ACCOUNTS, AS PRESCRIBED BY THE COMMISSION?

A28. Yes.

<u>GAS SUPPLY</u>

ASSET MANAGEMENT AGREEMENT

Q29. PLEASE DESCRIBE THE ASSET MANAGEMENT AGREEMENT ("AMA") BETWEEN EXELON GENERATION COMPANY, LLC ("EXELON") AND CITIZENS GAS.

A29. 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. The AMA was entered into on April 1, 2018 and the term will expire on March 31, 2021.

Q30. HAS CITIZENS GAS BEEN ABLE TO ESTABLISH A NEW AMA?

A30. Yes. Citizens Gas began working on the Request for Proposal (RFP) back in early August 2020 and has completed that process. Exelon exercised their Right of First Refusal in their current agreement and matched the selected bid. - The term of the new AMA contract will commence on April 1, 2021 and be effective through March 31, 2024.

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 the table 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. 2021	135,886	20,000	80,000	100,000	335,886
Jul. 2021	135,886	20,000	80,000	100,000	335,886
Aug. 2021	135,886	20,000	80,000	100,000	335,886

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 KLK-4, Schedules 2A, 2B, and 2C depict Citizens Gas' estimated throughput and retail sales volumes for the twelve months ending May 2022. 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, assuming normal weather, as reflected in Attachments KLK-4, 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 objective of Citizens Gas in utilizing hedging instruments is to minimize the risk of price volatility and exposure in the competitive natural gas market on behalf of its gas customers. However, Citizens Gas does not enter into hedging transactions without considering the current environment and anticipated future conditions. In order to provide greater price certainty for its customers, Citizens Gas utilizes hedging instruments to mitigate the inevitable market fluctuation in gas costs incurred to meet its system supply needs. All of the hedging transactions are tied to the projected physical volumes of natural gas required to serve Citizens Gas' system supply customers. I want to emphasize, however, that use of hedging instruments does not assure Citizens Gas that it will be able to lock-in 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 looking 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 during summer months, and financial hedges that collar or cap the cost of purchased gas.

On a monthly basis, Citizens Gas creates a plan that meets the projected demands of the system under normal weather. Each day, Citizens Gas will optimize swing purchases, as well as storage utilization, to meet the 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 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 hedges to establish ceilings or floors may be purchased as well. When a floor is purchased, and the price of the commodity falls below the strike price, the purchaser effectively pays the established floor price. When a ceiling is purchased, and the price of the commodity rises above the strike price, the purchase effectively is capped at the established ceiling price. Premiums always are necessary when floors and ceilings are purchased and they become part of the cost of the hedging strategy.

Historically, Citizens Gas has used physical hedges to mitigate price volatility as well. In Citizens Gas' case, physical hedges are transactions through which a purchase price is agreed upon with the counter-party and locked in.

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

A39. Financial hedges are utilized to hedge up to anticipated baseload sendout volumes. Withdrawals from storage hedge heat load, up to optimum withdrawal levels (assuming normal weather). When considered together, these two hedging tactics hedge each month's lowest historical sendout. Costless collars are put in place to hedge an increment of sendout greater than the lowest historical sendout, and financial caps are put in place to hedge an additional increment of sendout against extreme increases in gas prices.

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, margin calls may be made by the brokerage house. 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. Citizens Gas' hedging strategy will continue to focus on mitigating price volatility while at the same time the strategy will allow for 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, brokerage fees, commission fees, clearing fees, exchange fees, National Futures Association fees, and transaction fees. In addition, Citizens Gas recognizes gains and losses on the settlement of the contract. Attachment KLK-4, 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 fixed-price contracts and / or financial hedges. Initially, Citizens Gas used more fixed-priced contracts. However, as the dynamics of the market have changed, the mix between fixed-price and financial hedges has shifted to 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 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.

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 are call or put options, or a combination of the two. 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, in order to physically receive the gas, Petitioner would still need to purchase natural gas on the market. 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, they also allow Petitioner to take advantage of market prices in a declining market. This is in contrast 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 considered to be "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, plus 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 considered to be "out of the money." In that case, Petitioner would purchase the volumes and the market and the financial hedges would expire worthless. The combination of these two transactions results in a net acquisition price of the market price, plus 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 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 will always 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 in order 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 to implement the state's first-ever prepaid natural gas program. The IMGPA is an Indiana nonprofit corporation formed in 2007 as 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' 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 a 33.5 cent per Dth discount starting November 1, 2020 through October 31, 2023 and a 28 cent 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 20.75 cent per Dth discount 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.

Q53. DOES THIS CONCLUDE YOUR TESTIMONY?

A53. 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.

Korlon L. Kilpatrick II

Tab 2

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is J.P. Ghio. My business address is 2150 Dr. Martin Luther King, Jr. Street, Indianapolis, Indiana 46202.

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, which does business as Citizens Energy Group. I serve as Vice President of Energy Operations for Citizens Energy Group.

Q3. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AS CITIZENS ENERGY GROUP'S VICE PRESIDENT OF ENERGY OPERATIONS AS THEY RELATE TO THIS GCA PROCEEDING?

A3. Citizens Energy Group manages and controls a number of energy utilities, including the gas utility doing business as Citizens Gas, the Petitioner in this proceeding ("Citizens Gas" or "Petitioner"). I oversee and provide leadership for the employees responsible for providing gas utility services to Citizens Gas's customers, which includes procuring reliable gas supplies in order to provide firm service to our retail customers at the lowest gas cost reasonably possible.

Q4. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A4. I hold a Bachelor of Science degree with a concentration in Mechanical Engineering from Lehigh University and a Master of Business Administration degree from Saint Joseph's University.

Q5. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A5. I have over 25 years of experience in the energy industry spanning products such as natural gas, propane, power, oil, steam and chilled water. Approximately half of my career has been with state regulated utilities while the other half has been with federally regulated or unregulated businesses. I have held roles of increasing responsibility in departments from engineering, marketing, supply, trading, operations through executive roles such as Vice President of Gas & Electric Supply and Vice President of Gas Supply & Customer Operations with my former companies. I joined Citizens Energy Group in January 2020.

Q6. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR ANY OTHER STATE UTILITY COMMISSION?

A6. I have not previously testified before this Commission. I have testified as a witness before the Pennsylvania Public Utility Commission in a number of cases, including cases related to gas costs.

Q7. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A7. The purpose of my testimony is to describe certain weather-related events that occurred during February 2021, the steps Citizens Gas took to manage its gas supply while those events were ongoing and the corresponding effects on the gas cost adjustments that Citizens Gas proposes, as submitted in the prefiled direct testimony and attachments sponsored by Citizens Gas witness Korlon L. Kilpatrick II.

Q8. DO YOU HAVE ANY INTRODUCTORY REMARKS YOU WOULD LIKE TO MAKE?

A8. Yes. As has been widely reported, the weather events that occurred during February 2021 created significant challenges for electric and natural gas utilities across the country. Our employees rose to those challenges and reacted quickly to execute a strategy that took advantage of capital investments Citizens Gas has made and operational planning it has conducted over the years, such as interconnections to multiple interstate pipelines. As a result of those efforts by our employees, Citizens Gas safely and reliably met the natural gas needs of our customers in Indianapolis, realized significant financial benefits for our customers, and made available gas supplies to other parts of the country at a time of critical need.

Q9. PLEASE DESCRIBE THE WEATHER EVENTS THAT OCCURRED IN FEBRUARY 2021.

A9. Beginning on approximately February 12, 2021, a cold weather front began sweeping across a large portion of the United States. The colder weather spanned states as far north as the Canadian border to southern states including Oklahoma, Texas and Louisiana. The colder weather lasted for close to a week with more moderating temperatures returning by February 20, 2021.

Q10. WAS THIS WEATHER OUTSIDE OF THE PLANNING PARAMETERS FOR CITIZENS GAS?

A10. No. The mean temperatures in Indianapolis for the period February 12th through February 19th, 2021 were 16°F. The coldest day was February 17th. The high, low and mean temperatures for February 17th were 22°F, 2°F, and 12°F, respectively. For comparison, Citizens Gas plans for a design cold day or peak demand day with a mean temperature of ("negative") -17°F.

Q11. IF THE WEATHER WAS WITHIN CITIZENS GAS'S PLANNING PARAMETERS, WHY WERE THERE IMPACTS TO CITIZENS GAS?

A11. While the local weather conditions were within our planning parameters, the February cold weather front affected other parts of the country that disrupted natural gas supplies and caused severe wholesale spot market price volatility. For example, the colder weather reached certain gas production areas in the Oklahoma panhandle region. Due in part to the weather, an amount of natural gas production was shut in and not available. At the same time, the colder weather increased demand for natural gas in numerous states. As gas supplies decreased and demand increased, the spot price of natural gas in the wholesale market increased significantly for a period of time before returning to more normal levels.

Q12. CAN YOU DESCRIBE SOME OF THE CHANGES IN SPOT PRICES FOR NATURAL GAS OVER THIS PERIOD IN FEBRUARY?

A12. Yes. Gas prices in the Oklahoma panhandle region saw some of the greatest volatility. For example, spot prices for natural gas delivered into the Panhandle Eastern Pipeline on February 11th were just over $6 per dekatherm. By President's Day weekend, February 13-16, the same location was trading at approximately $225 per dekatherm, nearly 100 times higher than prices in the early part of February which were approximately $2.50 per dekatherm. By February 19th, the price had returned to just over $6 per dekatherm.

Prices in the Chicago area, as measured by spot prices on the Midwestern Pipeline, followed a similar pattern to prices in Oklahoma. Prices that were below $4 per dekatherm moved towards $130 per dekatherm before retreating to $6.

Prices in Louisiana for natural gas delivered into the Texas Gas pipeline stayed below $7 per dekatherm through the holiday weekend but peaked later, on February 17th, at roughly $40 per dekatherm. Two days later, the price was below $7 per dekatherm.

By comparison, natural gas produced in Western Pennsylvania had lower volatility. Prices in the range of $3 per dekatherm at the start of the week only rose to the mid-$8 per dekatherm range. Prices quickly declined from this point.

Q13. WAS CITIZENS GAS SUBJECT TO ANY OF THESE HIGHER THAN NORMAL MARKET-BASED PRICES?

A13. Yes. When actual temperatures fall below normal temperatures during a month, Citizens Gas plans to meet some of the incremental demand with incremental purchases. Citizens Gas contracts with four different interstate pipelines which access supplies in areas as diverse as Oklahoma, Chicago, Louisiana and Pennsylvania. This access to diverse supply basins has been a strategy to limit risk to a price spike in any one location. The direct access to production by contracting for interstate pipeline capacity is also intended to lower the risk of price exposures due to capacity constraints during peak demand periods. However, based on our plans, Citizens Gas was still purchasing some incremental supplies and as noted above, with price increases across large parts of the United States, Citizens Gas did have some exposure to the higher prices.

Q14. WAS CITIZENS GAS ABLE TO LIMIT THE AMOUNT OF INCREMENTAL PURCHASES IT HAD TO MAKE DURING THE PERIOD OF HIGHER PRICES?

A14. Yes. As part of Citizens Gas's normal planning, a portion of incremental demand can be met with the use of natural gas held in storage. Citizens Gas was able to use contracted storage from its supply plan to meet part of the incremental demand. In addition, Citizens Gas was able to take advantage of operating conditions in its own underground storage fields in Greene County to take quantities in excess of those quantities used in normal supply planning. We estimate the use of storage mitigated over $25 million of potential incremental costs.

Q15. DID CITIZENS GAS TAKE ANY ADDITIONAL ACTIONS TO LIMIT THE AMOUNT OF INCREMENTAL PURCHASES AND ITS EXPOSURE TO HIGHER GAS PRICES?

A15. Yes. Citizens Gas contacted third party transportation suppliers and posted a notice on its website reminding suppliers to deliver a quantity of natural gas that matched the aggregate amount of their customer demands. In effect, Citizens Gas was making sure transportation suppliers or marketers did not short the distribution system at a critical time.

Q16. DID CITIZENS GAS PREVENT ANY TRANSPORTATION CUSTOMERS FROM CONSUMING GAS THAT WAS DELIVERED ON THEIR BEHALF?

A16. No. Citizens Gas did not restrict transportation customers from consuming natural gas if their supplier had delivered a sufficient amount of supply, and all third-party transportation suppliers delivered enough supplies for their customers. In this regard, Citizens Gas honored all contractual obligations and even worked closely with specific power generators to support the reliability of the electric grid.

Q17. DID CITIZENS GAS ENGAGE IN ANY OTHER SUPPLY ACTIVITY TO SUPPORT THE DISTRIBUTION SYSTEM?

A17. Yes. For the gas day February 16, 2021, Citizens Gas entered into an arrangement with Citizens Thermal for the steam utility to shed approximately 3,400 dekatherms of natural gas load from the natural gas distribution system. To decrease demand, Citizens Gas requested the steam utility use heating oil instead of natural gas in two of its boilers for approximately half a day. Citizens Gas reimbursed the steam utility for the incremental cost associated with the use of heating oil which amounted to approximately $95,000.

Q18. ARE THE COSTS FOR THIS SERVICE INCLUDED IN THE GCA?

A18. Yes. In general, the decision to seek a load shedding service from the steam utility was based on economics. Reimbursing the steam utility the incremental cost to run the oil boilers was less than the costs of purchasing natural gas in the wholesale market. In addition, the gas supply gained from the steam utility was flexible because it was turned on during a single day, avoiding ratable purchases over a four-day holiday weekend. This type of interaction demonstrates the benefits of the different utilities working together under the Citizens Energy Group umbrella.

Q19. WERE THERE ANY OTHER SUPPLY ACTIVITIES THAT HAD AN IMPACT ON THE GCA?

A19. Yes. After planning to meet the demand projections of the entire system, including certain contingencies for errors in weather or demand forecasts, Citizens Gas searched for opportunities to optimize the use of supply assets to provide value to customers.

Q20. WAS CITIZENS GAS ABLE TO FIND ANY OPPORTUNITIES?

A20. Yes. In short, Citizens Gas was able to sell gas supplies in certain production areas with the highest price and replace these supplies from a different production area with a lower price. While the "lower" price was still considerable based on historical standards, the lower prices were significantly lower than the selling prices. These wholesale sales transactions directly contributed to the projected GCA variance of $10.6 million. Since these margins were generated with use of the interstate pipeline assets included in the GCA recovery mechanism, the associated margins are accordingly being credited to customers via the GCA.

Q21. TO WHOM DID CITIZENS GAS MAKE WHOLESALE SALES OF NATURAL GAS?

A21. Citizens Gas made sales of available gas to two counterparties, its current asset manager, Exelon Generation Company, LLC ("Exelon"), and Citizens Gas of Westfield.

Q22. HOW DID CITIZENS GAS DETERMINE THE SELLING PRICE?

A22. The sales prices were based on the market prices at the time of the transactions.

Q23. DID THE TRANSACTIONS BETWEEN CITIZENS GAS AND CITIZENS GAS OF WESTFIELD BENEFIT CITIZENS GAS OF WESTFIELD?

A23. Yes. While Citizens Gas of Westfield did have to pay higher than normal prices for natural gas due to the February winter event, the transactions between Citizens Gas and Citizens Gas of Westfield lowered the cost to the customers of Westfield when compared to the alternatives Citizens Gas of Westfield had at the time. In sum, the customers of Citizens Gas of Westfield saved approximately $600,000 as a result of the help and support Citizens

Gas provided. The benefits to Citizens Gas of Westfield and its customers are detailed in the GCA filing for Citizens Gas of Westfield (Cause No. 37389 GCA 126).

Q24. DID THOSE SALES RESULT IN CITIZENS GAS PROVIDING A SUBSIDY TO CITIZENS GAS OF WESTFIELD?

A24. No. Citizens Gas sold available gas to Citizens Gas of Westfield at the same price Citizens Gas sold gas to Exelon, an unaffiliated, independent, third-party marketer.

Q25. EARLIER, YOU MENTIONED THAT CITIZENS GAS WAS ABLE TO MAKE AVAILABLE GAS SUPPLIES TO OTHER PARTS OF THE COUNTRY AT A TIME OF CRITICAL NEED. PLEASE EXPLAIN HOW THE STEPS CITIZENS GAS TOOK BENEFITTED AREAS OUTSIDE OF MARION COUNTY AND WESTFIELD, INDIANA.

A25. In addition to lowering the costs to the customers of Citizens Gas, and providing support to and lowering costs for Citizens Gas of Westfield as described previously, Citizens Gas's sales to Exelon made gas supplies available to a portion of the country in short supply of natural gas at a time of critical need in those areas. Through the use of Citizens Gas's interconnected transmission system, we were able to transport supplies from a portion of the country with ample supply and divert supplies from an area already short on gas to customers in that geographic region. We estimate that Citizens Gas's actions in this regard supported the equivalent of approximately 20,000 residential customers in southwestern central states. In other words, up to 20,000 homes in other states may have been without heat for a period of several days in February, if Citizens Gas had not taken the steps we took to make natural gas supplies available in those areas.

Q26. DID ANY OF THE ACTIVITIES YOU HAVE DESCRIBED COMPROMISE THE INTEGRITY OF THE CITIZENS GAS DISTRIBUTION SYSTEM OR THE RELIABILITY OF SUPPLY TO CITIZENS GAS'S RETAIL CUSTOMERS?

A26. No. Our first priority was to ensure we could safely and reliably meet the demands of our customers in Indianapolis. Citizens Gas did not deviate from its prudent planning process and had sufficient supplies to meet all of the contract obligations and retail customer demands. Citizens Gas was able to achieve the benefits I have described without any threat of an impact to reliability by using contractual rights to firm assets, such as interstate pipeline storage and transportation capacity, as well as physical assets owned, operated and maintained by Citizens Gas, such as underground storage in Greene County. More broadly, we also used assets under the Citizens Energy Group umbrella, such as the Citizens Thermal steam utility's dual fuel boilers.

Q27. IN THE FUTURE, IS THERE AN OPPORTUNITY FOR CITIZENS GAS TO SUPPORT AND PROVIDE BENEFIT TO CITIZENS GAS OF WESTFIELD OR OTHER LOCAL INDIANA UTILITIES AND MUNICIPALITIES?

A27. Absolutely. Citizens Gas has the potential to further invest in its assets and operations to provide flexibility which could be used to support neighboring communities such as Citizens Gas of Westfield and other Indiana utilities or municipalities. Citizens Gas has the potential to reduce the impact of winter price volatility and ultimately lower costs for these potential customers. In response to events this winter and the benefit to nearby communities, Citizens Gas is contemplating providing additional wholesale services to the market. Depending on the type of wholesale service offered, Citizens Gas is considering filing a separate petition with the Commission related to those service offerings.

Q28. DOES THIS CONCLUDE YOUR TESTIMONY?

A28. Yes, it does.

VERIFICATION

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

J.P. Ghio

Tab 3

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF THE BOARD OF DIRECTORS FOR UTILITIES OF THE DEPARTMENT OF PUBLIC UTILITIES OF THE CITY OF INDIANAPOLIS, AS SUCCESSOR TRUSTEE OF A PUBLIC CHARITABLE TRUST, FOR APPROVAL OF GAS COST ADJUSTMENTS TO BE APPLICABLE IN THE MONTHS OF JUNE, JULY AND AUGUST 2021	**) CAUSE NO. 37399-GCA 150**

PETITION

TO THE INDIANA UTILITY REGULATORY COMMISSION:

The Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis, as Successor Trustee of a Public Charitable Trust, d/b/a Citizens Gas (hereinafter referred to as "Petitioner"), respectfully represents and shows the Commission:

Petitioner's Characteristics and Other Matters

1. Petitioner is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana, including certain sections of the Public Service Commission Act, as amended. Petitioner's rates and charges and terms and conditions for gas service are subject to the approval of this Commission by virtue of the provisions of IC 8-1-11.1-3(c)(9). Petitioner's principal office is at 2020 North Meridian Street, Indianapolis, Indiana 46202.

2. Petitioner is authorized to and is engaged in rendering gas utility service in Marion County, Indiana. It owns, operates, manages and controls plant and equipment, used and useful for the distribution and furnishing of service to the public. Petitioner takes delivery of its supplies of natural gas from Panhandle Eastern Pipe Line Company ("Panhandle"), Texas Gas Transmission Corporation ("Texas Gas"), Midwestern Gas Transmission ("Midwestern") and

Rockies Express Pipeline ("REX Pipeline").

3. The books and records of Petitioner supporting the data, calculations and allegations contained in this Petition are available for inspection and review by the Commission and the Indiana Office of Utility Consumer Counselor.

4. The names and addresses of the persons authorized to accept service of papers in this proceeding are:

Korlon L. Kilpatrick II
Director, Regulatory Affairs
Citizens Energy Group
2020 North Meridian Street
Indianapolis, Indiana 46202-1306

Michael E. Allen (Attorney No. 20768-49)
Citizens Energy Group
2020 North Meridian Street
Indianapolis, Indiana 46202-1306

Michael B. Cracraft (Attorney No. 3416-49)
Ice Miller LLP
One American Square, Suite 2900
Indianapolis, Indiana 46282-0200

Request for Approval of Gas Cost Adjustments
to be Applicable During the Months of June, July and August 2021

5. This Petition is an application under IC 8-1-2-42(g) for Commission approval of Petitioner's gas cost adjustments to be applicable for the June, July and August 2021 billing months. This Petition is filed in accordance with the Public Service Commission Act, as amended, and in compliance with the Commission's May 14, 1986 Order in Cause No. 37091, the Commission's December 11, 2002 Order in Cause No. 41605, the Order in Cause No. 37399-GCA75 and the Commission's August 27, 2014 Order in Cause No. 44374. Pursuant to the Stipulation and Settlement Agreement on Gas Cost Adjustment Modification Issue ("Stipulation"), approved by final Order of the Commission in Cause No. 37399-GCA75 on December 4, 2002, as such Stipulation has been thereafter amended; the resulting monthly GCA factors attached as Attachment KLK-2 are subject to change.

6. Copies of Petitioner's proposed monthly tariff sheets incorporating its gas cost adjustments in each Rider A, are attached as Attachment KLK-2. The bill impact statements are attached as Attachment KLK-3.

7. Petitioner's cost of gas, based upon the estimated average gas cost for the three months of June, July and August 2021, is estimated to total $5,888,015. Petitioner's requested gas cost adjustment rates, modified for the recovery of Indiana Utility Receipts Tax, are set forth in the following Rider A (One-Hundred Seventeenth Revised Page No. 501, One-Hundred Eighteenth Revised Page No. 501, and One-Hundred Nineteenth Revised Page No. 501) and will be applied to all bills rendered by Petitioner during its June, July and August 2021 billing months. Supporting schedules containing estimated cost data relating to the requested gas cost adjustment rates are set forth in Attachment KLK-4.

8. Petitioner 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. Changes in Petitioner's gas cost since its last base rate proceeding in Cause No. 43975 reflect changes in natural gas purchases and the rates of its pipeline suppliers, which have been filed with the Federal Energy Regulatory Commission.

WHEREFORE, Petitioner respectfully prays that the Indiana Utility Regulatory Commission, as provided for in Indiana Code §8-1-2-42(g)(1), conduct a summary hearing on the matters set forth herein and thereafter enter an Order in a timely manner in this Cause:

(a) approving Petitioner's proposed monthly tariff sheets, *i.e.*, Rider A One-Hundred Seventeenth Revised Page No. 501, One-Hundred Eighteenth Revised Page No. 501, and One-Hundred Nineteenth Revised Page No. 501, as are attached to this Petition;

(b) authorizing and approving the monthly gas cost adjustments set forth in each Rider A (identified as Attachment KLK-2), and in the supporting schedules attached to this Petition, to become effective for Petitioner's June, July and August 2021 billing months;

(c) making such further orders and providing such further relief as may be appropriate and proper.

DATED this 1st day of April 2021.

BOARD OF DIRECTORS FOR UTILITIES OF THE DEPARTMENT OF PUBLIC UTILITIES OF THE CITY OF INDIANAPOLIS, AS SUCCESSOR TRUSTEE OF A PUBLIC CHARITABLE TRUST

By: /s/LaTona S. Prentice
LaTona S. Prentice
Vice President, Regulatory & External Affairs
Citizens Energy Group
2020 North Meridian Street
Indianapolis, Indiana 46202
(317) 927-4529

ATTEST:

/s/Jennett M. Hill
Jennett M. Hill
Senior Vice President and
General Counsel

VERIFICATION

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

LaTona S. Prentice

CERTIFICATE OF SERVICE

I hereby certify that on the 1st day of April 2021, I served a copy of the foregoing Petition upon the Office of Utility Consumer Counselor by delivery or by depositing a copy in the United States mail, first class postage prepaid to the following addresses:

Office of Utility Consumer Counselor
115 West Washington Street
Suite 1500 South
Indianapolis IN 46204
infomgt@oucc.in.gov

Michael B. Cracraft (Attorney No. 3416-49) Ice Miller LLP
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Michael E. Allen, (Attorney No. 20768 -49) Citizens Energy Group
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E-Mail: mallen@citizensenergygroup.com

Attorneys for
Petitioner, Citizens Gas

Tab 4

Citizens Gas
2020 North Meridian Street
Indianapolis, IN 46202

One-Hundred Seventeenth Revised Page No. 501
Superseding Substitute One-Hundred Sixteenth 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, 2021

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

Gas Rate No. D1	Gas Supply Charge	**$**	**0.2664**
Gas Rate No. D2	Gas Supply Charge	**$**	**0.3842**
Gas Rate No. D3	Gas Supply Charge	**$**	**0.2269**
Gas Rate No. D4	Gas Supply Charge	**$**	**0.3295**
Gas Rate No. D5	Gas Supply Charge	**$**	**-**
Gas Rate No. D7	Gas Supply Charge	**$**	**0.2237**

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

Capacity	**$**	**0.0904**
Commodity	**$**	**0.2696**
Gas Supply Charge	**$**	**0.3600**

3. Balancing Charges: $ per Therm

Gas Rate No. D3	**$**	**0.0042**	**$**	**0.0002**	for Basic Delivery Service Option
Gas Rate No. D4	**$**	**0.0045**	**$**	**0.0002**	for Basic Delivery Service Option
Gas Rate No. D5	**$**	**0.0053**	**$**	**0.0003**	for Basic Delivery Service Option
Gas Rate No. D7	**$**	**0.0042**			
Gas Rate No. D9	**$**	**0.0356**	**$**	**0.0018**	for Basic Delivery Service Option

Citizens Gas
2020 North Meridian Street **One-Hundred Eighteenth Revised Page No. 501**
Indianapolis, IN 46202 **Superseding One-Hundred Seventeenth 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, 2021

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

Gas Rate No. D1	Gas Supply Charge	**$**	**0.2889**
Gas Rate No. D2	Gas Supply Charge	**$**	**0.4206**
Gas Rate No. D3	Gas Supply Charge	**$**	**0.2370**
Gas Rate No. D4	Gas Supply Charge	**$**	**0.3433**
Gas Rate No. D5	Gas Supply Charge	**$**	**-**
Gas Rate No. D7	Gas Supply Charge	**$**	**0.2337**

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

Capacity	**$**	**0.0915**
Commodity	**$**	**0.2804**
Gas Supply Charge	**$**	**0.3719**

3. Balancing Charges: $ per Therm

Gas Rate No. D3	**$**	**0.0047**	**$**	**0.0002**	for Basic Delivery Service Option
Gas Rate No. D4	**$**	**0.0050**	**$**	**0.0003**	for Basic Delivery Service Option
Gas Rate No. D5	**$**	**0.0058**	**$**	**0.0003**	for Basic Delivery Service Option
Gas Rate No. D7	**$**	**0.0047**			
Gas Rate No. D9	**$**	**0.0360**	**$**	**0.0018**	for Basic Delivery Service Option

Citizens Gas
2020 North Meridian Street
Indianapolis, IN 46202

One-Hundred Nineteenth Revised Page No. 501
Superseding One-Hundred Eighteenth 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 August 1, 2021

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

Gas Rate No. D1	Gas Supply Charge	**$**	**0.2875**
Gas Rate No. D2	Gas Supply Charge	**$**	**0.4191**
Gas Rate No. D3	Gas Supply Charge	**$**	**0.2362**
Gas Rate No. D4	Gas Supply Charge	**$**	**0.3406**
Gas Rate No. D5	Gas Supply Charge	**$**	**-**
Gas Rate No. D7	Gas Supply Charge	**$**	**0.2329**

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

Capacity	**$**	**0.0902**
Commodity	**$**	**0.2797**
Gas Supply Charge	**$**	**0.3699**

3. Balancing Charges: $ per Therm

Gas Rate No. D3	**$**	**0.0047**	**$**	**0.0002**	for Basic Delivery Service Option
Gas Rate No. D4	**$**	**0.0050**	**$**	**0.0003**	for Basic Delivery Service Option
Gas Rate No. D5	**$**	**0.0058**	**$**	**0.0003**	for Basic Delivery Service Option
Gas Rate No. D7	**$**	**0.0047**			
Gas Rate No. D9	**$**	**0.0361**	**$**	**0.0018**	for Basic Delivery Service Option

Current rates effective pursuant to
I.U.R.C. Order in Cause No. 43975

Effective: August 1, 2021

Tab 5

CITIZENS GAS

Impact Statement for Residential Heating Customers

Proposed GCA Factor June 2021
vs.
Currently Approved GCA Factor April 2021

Table No. 1

Consumption Dth	Bill At Proposed GCA Factor $3.8420	Bill At Current GCA Factor $2.9830	Dollar Increase (Decrease)	Percent Change
5	$47.37	$43.07	$4.30	9.98 %
10	$78.24	$69.65	$8.59	12.33 %
15	$109.11	$96.22	$12.89	13.40 %
20	$139.98	$122.80	$17.18	13.99 %
25	$170.85	$149.37	$21.48	14.38 %

Proposed GCA Factor June 2021
vs.
GCA Factor One Year Ago June 2020

Table No. 2

Consumption Dth	Bill At Proposed GCA Factor $3.8420	Bill At Prior Year's GCA Factor $3.3760	Dollar Increase (Decrease)	Percent Change
5	$47.37	$45.01	$2.36	5.24 %
10	$78.24	$73.52	$4.72	6.42 %
15	$109.11	$102.03	$7.08	6.94 %
20	$139.98	$130.54	$9.44	7.23 %
25	$170.85	$159.05	$11.80	7.42 %

CITIZENS GAS

Impact Statement for Residential Heating Customers

Proposed GCA Factor July 2021
vs.
Currently Approved GCA Factor April 2021

Table No. 1

Consumption Dth	Bill At Proposed GCA Factor $4.2060	Bill At Current GCA Factor $2.9830	Dollar Increase (Decrease)	Percent Change
5	$49.19	$43.07	$6.12	14.21 %
10	$81.88	$69.65	$12.23	17.56 %
15	$114.57	$96.22	$18.35	19.07 %
20	$147.26	$122.80	$24.46	19.92 %
25	$179.95	$149.37	$30.58	20.47 %

Proposed GCA Factor July 2021
vs.
GCA Factor One Year Ago July 2020

Table No. 2

Consumption Dth	Bill At Proposed GCA Factor $4.2060	Bill At Prior Year's GCA Factor $3.5750	Dollar Increase (Decrease)	Percent Change
5	$49.19	$46.00	$3.19	6.93 %
10	$81.88	$75.51	$6.37	8.44 %
15	$114.57	$105.01	$9.56	9.10 %
20	$147.26	$134.52	$12.74	9.47 %
25	$179.95	$164.02	$15.93	9.71 %

CITIZENS GAS

Impact Statement for Residential Heating Customers

Proposed GCA Factor August 2021
vs.
Currently Approved GCA Factor April 2021

Table No. 1

Consumption Dth	Bill At Proposed GCA Factor $4.1910	Bill At Current GCA Factor $2.9830	Dollar Increase (Decrease)	Percent Change
5	$49.11	$43.07	$6.04	14.02 %
10	$81.73	$69.65	$12.08	17.34 %
15	$114.34	$96.22	$18.12	18.83 %
20	$146.96	$122.80	$24.16	19.67 %
25	$179.57	$149.37	$30.20	20.22 %

Proposed GCA Factor August 2021
vs.
GCA Factor One Year Ago August 2020

Table No. 2

Consumption Dth	Bill At Proposed GCA Factor $4.1910	Bill At Prior Year's GCA Factor $3.7610	Dollar Increase (Decrease)	Percent Change
5	$49.11	$46.93	$2.18	4.65 %
10	$81.73	$77.37	$4.36	5.64 %
15	$114.34	$107.80	$6.54	6.07 %
20	$146.96	$138.24	$8.72	6.31 %
25	$179.57	$168.67	$10.90	6.46 %

Tab 6

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated For June 2021

Line No.		A Demand	B Commodity and Other	C Total
	Estimated Cost of Gas			
1	Purchased gas cost (Schedule 3, Page 1, ln 16)	$922,578	$6,165,228	$7,087,806
2	PEPL Unnominated Quantities cost (Schedule 4 pg 1, ln 16 col A + ln 23)	-	607,060	607,060
3	Gas (injected into) withdrawn from storage - net cost (Schedule 5, ln 3)	(701,860)	(4,690,720)	(5,392,580)
4	Total estimated gas cost (ln 1 through ln 3)	$220,718	$2,081,568	$2,302,286
5	Total Gas Supply variance (Sch 1, June, total of ln 17)	-	(301,101)	(301,101)
6	Total Balancing Demand variance (Sch 1 pg 2 ln 11 + Sch. 1, ln 28)	-	919	919
7	Dollars to be refunded (Schedule 12A, ln 16 * Sch 2B, ln 27, col. F)	-	14,259	14,259
8	Total cost to be recovered through GCA (ln 4 + ln 5 + ln 6 - ln 7)	$220,718	$1,767,127	$1,987,845
9	Net Write-Off Recovery Costs (ln 8 *1.10%)			$21,866
10	Total cost to be recovered through GCA (ln. 8 + ln 9)			$2,009,711

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated For June 2021
To Be Applied To June 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
	Calculation of Gas Supply Charge per Unit (Dth)					
11	Balancing Demand Cost Variance (Sch12B, pg. 2, ln 13 * Sch 2C, ln 22)	($19)	($1,410)	-	-	-
12	Throughput excluding Basic - Dth (Sch 2C, ln 1)	3,815	349,491	-	-	-
13	Total Balancing Demand Cost variance per unit of throughput (ln 11/ ln 12)	($0.005)	($0.004)	-	-	-
14	Retail demand cost per unit sales (Sch 1A, pg 1 ln 8)	0.190	0.463	0.040	0.348	-
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)	$0.185	$0.459	$0.040	$0.348	$0.000
17	Total Gas Supply variance (Sch 12B, pg 1, ln 15) * (Sch 2B, ln 27)	(2,553)	(182,383)	(21,271)	(94,894)	0
18	Dollars to be refunded ((ln 7) * Sch 2B, ln 23)	96	8,824	1,265	4,074	0
19	Other non-demand gas costs (ln 4, col B - ln 2, col B) * (Sch 2B, ln 23)	9,960	912,523	130,777	421,248	0
20	Total monthly non-demand costs to be recovered through Gas Supply Charge (ln 17 - ln 18 + ln 19)	$7,311	$721,316	$108,241	$322,280	$0
21	Sales subject to GCA - Dth (Schedule 2B, ln 1)	3,815	349,491	50,087	161,336	0
22	Total monthly non-demand costs per unit sales (ln 20 / ln 21)	$1.916	$2.064	$2.161	$1.998	$0.000
23	Net Write-Off Recovery Cost (Sch 1C, pg 1, ln 4)	0.024	0.057	0.001	0.011	0.000
24	PEPL Unnominated Quantites Retail Cost (Schedule 4, pg. 1 ln 8)	0.452	1.159	0.035	0.892	0.000
25	PEPL Balancing Cost for Gas Rates D1 & D2 only (Sch 4, pg 1, ln 15)	0.050	0.049	-	-	-
26	Gas Supply Charge to be recovered through GCA (ln 16 + ln 22 + ln 23 + ln 24 + ln 25)	$2.627	$3.788	$2.237	$3.249	$0.000
27	Gas Supply Charge modified for Indiana Utility Receipts Tax (ln 26 / (1 - 1.40%))	$2.664	$3.842	$2.269	$3.295	$0.000

Citizens Gas
Determination of Balancing Demand Charge per Unit (Dth)
Estimated for the Period June 2021
To Be Applied to the June 2021 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)	($1,592)	($1,623)	$472	$5,091
29	Throughput excluding Basic - Dth (Sch 2C, ln 1)	216,907	343,556	167,983	16,920
30	Total Balancing Demand Cost variance per unit of throughput (ln 28/ ln 29)	($0.0073)	($0.0047)	$0.0028	$0.3009
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	0.0500
33	Total balancing demand charge per unit of throughput (ln 30 + ln 31 + ln 32)	0.0417	$0.0443	$0.0518	$0.3509
34	Total balancing demand charge modified for Indiana Utilities Receipts Tax (ln 33 / (1-1.40%))	$0.042	$0.045	$0.053	$0.356

Citizens Gas
Determination of Basic Balancing Charge
Estimated for June 2021
To Be Applied to June 2021

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)	0.0021	0.0022	0.0026	0.0175
36	Basic balancing charge modified for Indiana Utilities Receipts Tax (ln 35/ (1-1.40%))	$0.002	$0.002	$0.003	$0.018

Citizens Gas
Determination of Back-up Gas Supply Charge
Estimated for June 2021
To Be Applied to June 2021

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)	58,182
39	Total retail demand costs for Gas Rates Nos. D3 & D4 (ln 37 + ln 38)	$188,461
40	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, line 1)	211,423
41	Back-up supply capacity charge per unit (ln 39 / ln 40)	$0.891
42	Back-up supply capacity charge modified for Indiana Utilities Receipts Tax (ln 41 / (1-1.40%))	$0.904
43	PEPL monthly variable costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 1, ln 5)	$15,346
44	Total monthly non-demand costs for Gas Rate Nos. D3 & D4 (Sch 1, ln 19 - ln 18)	546,686
45	Total retail non-demand costs for Gas Rates Nos. D3 & D4 (ln 43 + ln 44)	$562,032
46	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, ln 1)	211,423
47	Back-up supply commodity charge per unit (ln 45 / ln 46)	$2.658
48	Back-up supply commodity charge modified for Indiana Utilities Receipts Tax (ln 47 / (1-1.40%))	$2.696
49	Total Back-up Gas Supply Charge (ln 42 + ln 48)	$3.600

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for July 2021

Line No.		A Demand	B Commodity and Other	C Total
	Estimated Cost of Gas			
1	Purchased gas cost (Schedule 3, Page 2, ln 16)	$902,997	$6,252,562	$7,155,559
2	PEPL Unnominated Quantities cost (Schedule 4 pg 2, ln 16 col A + ln 23)	-	622,066	$622,066
3	Gas (injected into) withdrawn from storage - net cost (Schedule 5, ln 6)	(702,810)	(4,866,660)	($5,569,470)
4	Total estimated gas cost (ln 1 through ln 3)	$200,187	$2,007,968	$2,208,155
5	Total Gas Supply variance (Sch 1, July, total of ln 17)	-	(272,396)	($272,396)
6	Total Balancing Demand variance (Sch 1 pg 2 ln 11 + Sch. 1, ln 28)		1,158	$1,158
7	Dollars to be refunded (Schedule 12A, ln 16 * Sch 2B, ln 28, col. F)	-	12,895	$12,895
8	Total cost to be recovered through GCA (ln 4 + ln 5 + ln 6 - ln 7)	$200,187	$1,723,835	$1,924,022
9	Net Write-Off Recovery Costs (ln 8 * 1.10%)			$21,164
10	Total cost to be recovered through GCA (ln. 8 + ln 9)			$1,945,186

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for July 2021
To Be Applied to July 2021 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)	($1,215)	-	-	-
12	Throughput excluding Basic - Dth (Sch 2C, ln 2)	3,222	301,132	-	-	-
13	Total Balancing Demand Cost per unit of throughput (ln 11 /ln 12)	($0.005)	($0.004)	-	-	-
14	Retail demand cost per unit sales (Sch 1A, pg 2 ln 8)	0.204	0.487	0.036	0.327	-
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)	$0.199	$0.483	$0.036	$0.327	$0.000
17	Total Gas Supply variance (Sch 12B, pg 1, ln 15) * (Sch 2B, ln 28)	(2,156)	(157,147)	(21,523)	(91,570)	0
18	Dollars to be refunded ((ln 7) * Sch 2B, ln 24)	81	7,603	1,280	3,931	0
19	Other non-demand gas costs (ln 4, col B - ln 2, col B) * (Sch 2B, ln 24)	8,744	817,159	137,530	422,469	0
20	Total monthly non-demand costs to be recovered through Gas Supply Charge (ln 17 - ln 18 + ln 19)	$6,507	$652,409	$114,727	$326,968	$0
21	Sales subject to GCA - Dth (Schedule 2B, ln 2)	3,222	301,132	50,681	155,684	0
22	Total monthly non-demand costs per unit sales (ln 20 / ln 21)	$2.020	$2.167	$2.264	$2.100	$0.000
23	Net Write-Off Recovery Cost (Sch 1C, pg 2, ln 4)	0.028	0.064	0.001	$0.011	$0.000
24	PEPL Unnominated Quantites Retail Cost (Sch 4, pg 2 ln 8)	0.548	1.379	0.036	0.947	0.000
25	PEPL Balancing Cost for Gas Rates D1 & D2 only (Sch 4, pg 2, ln 15)	0.054	0.054	-	-	-
26	Gas Supply Charge to be recovered through GCA (ln 16 + ln 22 + ln 23 + ln 24 + ln 25)	$2.849	$4.147	$2.337	$3.385	$0.000
27	Gas Supply Charge modified for Indiana Utility Receipts Tax (ln 26 / (1 - 1.40%))	$2.889	$4.206	$2.370	$3.433	$0.000

Citizens Gas
Determination of Balancing Demand Charge per Unit (Dth)
Estimated for July 2021
To Be Applied to the July 2021 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 23)	($1,591)	($1,562)	$467	$5,074
29	Throughput excluding Basic - Dth (Sch 2C, ln 2)	216,757	330,648	166,353	16,864
30	Total Balancing Demand Cost variance per unit of throughput (ln 28/ ln 29)	($0.0073)	($0.0047)	$0.0028	$0.3009
31	Monthly balancing demand charge per unit of throughput (Sch 1A, pg 2, ln 11)	0.000	0.000	0.000	0.000
32	PEPL balancing demand charge per unit of throughput (Sch 4, pg 2, ln 15)	0.0540	0.0540	0.0540	0.0540
33	Total balancing demand charge per unit of throughput (ln 30 + ln 31 + ln 32)	$0.0467	$0.0493	$0.0568	$0.3549
34	Total balancing demand charge modified for Indiana Utilities Receipts Tax (ln 33 / (1-1.40%))	$0.047	$0.050	$0.058	$0.360

Citizens Gas
Determination of Basic Balancing Charge
Estimated for July 2021
To Be Applied to July 2021

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)	0.0023	0.0025	0.0028	0.0177
36	Basic balancing charge modified for Indiana Utilities Receipts Tax (ln 35/ (1-1.40%))	$0.002	$0.003	$0.003	$0.018

Citizens Gas
Determination of Back-up Gas Supply Charge
Estimated for July 2021
To Be Applied to July 2021

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 2, ln 2)	$133,440
38	Monthly retail demand costs for Gas Rate Nos. D3 & D4 (Sch 1A, pg 2, ln 6)	52,771
39	Total retail demand costs for Gas Rates Nos. D3 & D4 (ln 37 + ln 38)	$186,211
40	Estimated Monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, line 2)	206,365
41	Back-up supply capacity charge per unit (ln 39 / ln 40)	$0.902
42	Back-up supply capacity charge modified for Indiana Utilities Receipts Tax (ln 41 / (1-1.40%))	$0.915
43	PEPL monthly variable costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 2, ln 5)	$15,785
44	Total monthly non-demand costs for Gas Rate Nos. D3 & D4 (Sch 1, ln 19 - ln 18)	554,788
45	Total retail non-demand costs for Gas Rates Nos. D3 & D4 (ln 43 + ln 44)	$570,573
46	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, ln 2)	206,365
47	Back-up supply commodity charge per unit (ln 45 / ln 46)	$2.765
48	Back-up supply commodity charge modified for Indiana Utilities Receipts Tax (ln 47 / (1-1.40%))	$2.804
49	Total Back-up Gas Supply Charge (ln 42 + ln 48)	$3.719

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for August 2021

Line No.		A Demand	B Commodity and Other	C Total
	Estimated Cost of Gas			
1	Purchased gas cost (Schedule 3, Page 3, ln 16)	$872,207	$6,244,459	$7,116,666
2	PEPL Unnominated Quantities cost (Schedule 4 pg 3, ln 16 col A + ln 23)	-	621,786	621,786
3	Gas (injected into) withdrawn from storage - net cost (Schedule 5, ln 9)	(679,250)	(4,863,240)	(5,542,490)
4	Total estimated gas cost (ln 1 through ln 3)	$192,957	$2,003,005	$2,195,962
5	Total Gas Supply variance (Sch 1, August, total of ln 17)	-	(272,161)	(272,161)
6	Total Balancing Demand variance (total of Sch 1 pg 2 ln 11 + Sch. 1, ln 28)		1,163	1,163
7	Dollars to be refunded (Schedule 12A, ln 16 * Sch 2B, ln 29, col. F)	-	12,879	12,879
8	Total cost to be recovered through GCA (ln 4 + ln 5 + ln 6 - ln 7)	$192,957	$1,719,128	$1,912,085
9	Net Write-Off Recovery Costs (ln 8 * 1.10%)			$21,033
10	Total cost to be recovered through GCA (ln. 8 + ln 9)			$1,933,118

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for August 2021
To Be Applied to August 2021 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)	($17)	($1,209)	-	-	-
12	Throughput excluding Basic - Dth (Sch 2C, ln 3)	3,219	299,531	-	-	-
13	Total Balancing Demand Cost per unit of throughput (ln 11/ln 12)	($0.005)	($0.004)	-	-	-
14	Retail demand cost per unit sales (Sch 1A, pg 3 ln 8)	$0.197	$0.472	$0.034	$0.313	-
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)	$0.192	$0.468	$0.034	$0.313	$0.000
17	Total variance (Sch 12B, pg 1, ln 15) * (Sch 2B, ln 29)	(2,155)	(156,312)	(21,489)	(92,205)	0
18	Dollars to be refunded ((ln 7) * Sch 2B, ln 25)	81	7,562	1,278	3,958	0
19	Other non-demand gas costs (ln 4, col B - ln 2, col B) * (Sch 2B, ln 25)	8,715	811,027	137,016	424,461	0
20	Total monthly non-demand costs to be recovered through Gas Supply Charge (ln 17 - ln 18 + ln 19)	$6,479	$647,153	$114,249	$328,298	$0
21	Sales subject to GCA - Dth (Schedule 2B, ln 3)	3,219	299,531	50,603	156,763	0
22	Total monthly non-demand costs per unit sales (ln 20 / ln 21)	$2.013	$2.161	$2.258	$2.094	$0.000
23	Net Write-Off Recovery Cost (Sch 1C, pg 3 ln 4)	0.027	0.064	0.001	0.011	0.000
24	PEPL Unnominated Quantites Retail Cost (Sch 4, pg 3 ln 8)	0.549	1.385	0.036	0.940	0.000
25	PEPL Balancing Cost for Gas Rates D1 & D2 only (Sch 4, pg 3, ln 15)	0.054	0.054	-	-	-
26	Gas Supply Charge to be recovered through GCA (ln 16 + ln 22 + ln 23 + ln 24 + ln 25)	$2.835	$4.132	$2.329	$3.358	$0.000
27	Gas Supply Charge modified for Indiana Utility Receipts Tax (ln 26 / (1 - 1.40%))	$2.875	$4.191	$2.362	$3.406	$0.000

Citizens Gas
Determination of Balancing Demand Charge per Unit (Dth)
Estimated For the Period August 2021
To Be Applied to the August 2021 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 24)	($1,589)	($1,561)	$466	$5,073
29	Throughput excluding Basic - Dth (Sch 2C, ln 3)	216,493	330,363	166,105	16,864
30	Total Balancing Demand Cost variance per unit of throughput (ln 28/ ln 29)	($0.0073)	($0.0047)	$0.0028	$0.3008
31	Monthly balancing demand charge per unit of throughput (Sch 1A, pg 3, ln 11)	0.000	0.000	0.000	0.000
32	PEPL balancing demand charge per unit of throughput (Sch 4, pg 3, ln 15)	0.0540	0.0540	0.0540	0.0550
33	Total balancing demand charge per unit of throughput (ln 30 + ln 31 + ln 32)	$0.0467	$0.0493	$0.0568	$0.3558
34	Total balancing demand charge modified for Indiana Utilities Receipts Tax (ln 33 / (1-1.40%))	$0.047	$0.050	$0.058	$0.361

Citizens Gas
Determination of Basic Balancing Charge
Estimated for August 2021
To Be Applied to August 2021

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)	0.0023	0.0025	0.0028	0.0178
36	Basic Balancing Charge modified for Indiana Utilities Receipts Tax (ln 35/ (1-1.40%))	$0.002	$0.003	$0.003	$0.018

Citizens Gas
Determination of Back-up Gas Supply Charge
Estimated for August 2021
To Be Applied to August 2021

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 3, ln 2)	$133,440
38	Monthly retail demand costs for Gas Rate Nos. D3 & D4 (Sch 1A, pg 3, ln 6)	50,864
39	Total retail demand costs for Gas Rates Nos. D3 & D4 (ln 37 + ln 38)	$184,304
40	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, line 3)	207,366
41	Back-up supply capacity charge per unit (ln 39 / ln 40)	$0.889
42	Back-up supply capacity charge modified for Indiana Utilities Receipts Tax (ln 41 / (1-1.40%))	$0.902
43	PEPL monthly variable costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 3, ln 5)	$15,718
44	Total monthly non-demand costs for Gas Rate Nos. D3 & D4 (Sch 1, ln 19 - ln 18)	556,241
45	Total retail non-demand costs for Gas Rates Nos. D3 & D4 (ln 43 + ln 44)	$571,959
46	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, ln 3)	207,366
47	Back-up supply commodity charge per unit (ln 45 / ln 46)	$2.758
48	Back-up supply commodity charge modified for Indiana Utilities Receipts Tax (ln 47 / (1-1.40%))	$2.797
49	Total Back-up Gas Supply Charge (ln 42 + ln 48)	$3.699

Citizens Gas
Allocation of Monthly Demand Cost
June 2021

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)	$724	$161,812	$1,996	$56,186	-	-	$220,718
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)	$724	$161,812	$1,996	$56,186	-	-	$220,718
7	Estimated monthly retail sales- Dth (Sch 2B, ln 1)	3,815	349,491	50,087	161,336	-	-	564,729
8	Monthly retail demand cost per unit sales (ln 6 / ln 7)	$0.190	$0.463	$0.040	$0.348	-	-	$0.391
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)	3,815	349,491	216,907	343,556	167,983	16,920	1,098,672
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	$ 943,203
13	TGT Unnominated Demand Costs	$ -
14	IMGPA Prepay Demand Costs	$ 90,195
15	Demand Cost (Sch 3 ln 15 col G)	$ (110,820)
16	Demand Cost (Sch 5 ln 3 col G)	$ (701,860)
17	Monthly retail demand costs (ln 12 + sum(ln14 + ln15 + ln16))	$ 220,718
18	Unnominated Demand Costs (ln 13)	$0
19	Total monthly demand costs (ln 17 + ln 18)	$220,718

Citizens Gas
Allocation of Monthly Demand Cost
July 2021

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)	$656	$146,760	$1,811	$50,960	-	-	$200,187
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)	$656	$146,760	$1,811	$50,960	-	-	$200,187
7	Estimated monthly retail sales- Dth (Sch 2B, ln 2)	3,222	301,132	50,681	155,684	-	-	510,719
8	Monthly retail demand cost per unit sales (ln 6 / ln 7)	$0.204	$0.487	$0.036	$0.327	-	-	$0.392
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)	3,222	301,132	216,757	330,648	166,353	16,864	1,034,976
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	$ 957,755
13	TGT Unnominated Demand Costs	$ -
14	IMGPA Prepay Demand Costs	$ 93,202
15	Demand Cost (Sch 3 ln 15 col G)	$ (147,960)
16	Demand Cost (Sch 5 Ln 6 Col G)	$ (702,810)
17	Monthly retail demand costs (ln 12 + sum(ln 14 + ln15 + ln16))	$ 200,187
18	Unnominated Demand Costs (ln 13)	$0
19	Total Monthly demand costs (ln 17 + ln 18)	$ 200,187

Citizens Gas
Allocation of Monthly Demand Cost
August 2021

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)	$633	$141,460	$1,745	$49,119	-	-	$192,957
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)	$633	$141,460	$1,745	$49,119	-	-	$192,957
7	Estimated monthly retail sales- Dth (Sch 2B, ln 3)	3,219	299,531	50,603	156,763	-	-	510,116
8	Monthly retail demand cost per unit sales (ln 6 / ln 7)	$0.197	$0.472	$0.034	$0.313	-	-	$0.378
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)	3,219	299,531	216,493	330,363	166,105	16,864	1,032,575
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	Calculation of Monthly Demand Costs	Demand Cost
	Exelon Generation Company, LLC	
12	Nominated Demand Costs	$ 957,755
13	TGT Unnominated Demand Costs	$ -
14	IMGPA Prepay Demand Costs	$ 93,202
15	Demand Cost (Sch 3 ln 15 col G)	$ (178,750)
16	Demand Cost (Sch 5 Ln 9 Col G)	$ (679,250)
17	Monthly retail demand costs (ln 12 + sum(ln 14 + ln15 + ln16))	$ 192,957
18	Unnominated Demand Costs (ln 13)	$0
19	Total Monthly demand costs (ln 17 + ln 18)	$192,957

Citizens Gas
Determination of Gas Cost Adjustment (GCA)
Estimation Period June 1, 2021 through August 31, 2021
UAF Component in Rates ($/DTH)

Line No.		A June 2021	B July 2021	C August 2021	D Total
1	Volume of pipeline gas purchases (Sch. 3) - Dths	2,497,307	2,441,084	2,439,612	7,378,003
2	Volume of Gas (injected into) withdrawn from storage (See Schedule 3B) - Dths	(1,919,681)	(1,919,681)	(1,919,681)	(5,759,043)
3	Total volume supplied - Dths	577,626	521,403	519,931	1,618,960
4	Less: Gas Division usage - Dths	(5,147)	(3,688)	(2,839)	(11,674)
5	Total volume of gas available for sale - Dths (ln 3 + ln 4)	572,479	517,715	517,092	1,607,286
6	UAF Percentage 1.360%	1.360%	1.360%	1.360%	
7	UAF Volumes - Dths (ln 5 * ln 6)	7,786	7,041	7,032	21,859
8	Average Commodity Rate - Schedule 3A	$2.4688	$2.5614	$2.5596	
9	UAF Costs (ln7 * ln8)	$19,222	$18,035	$17,999	$55,256
10	Schedule 2B Retail sales volumes	564,729	510,719	510,116	1,585,564
11	UAF Component in rates - $ per Dth (ln9 / ln10) 1/	$0.0340	$0.0353	$0.0353	

1/ For informational purposes only.

Citizens Gas
Allocation of Net Write-Off Recovery Cost
June 2021

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	$92	$19,876	$56	$1,827	$15	$21,866
3	Estimated retail sales- Dth (Sch 2B, ln 1)	3,815	349,491	50,087	161,336	0	564,729
4	Net Write-Off Recovery cost per unit sales (ln 2 / ln 3)	$0.024	$0.057	$0.001	$0.011	$0.000	

Citizens Gas
Allocation of Net Write-Off Recovery Cost
July 2021

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	$89	$19,237	$55	$1,768	$15	$21,164
3	Estimated retail sales- Dth (Sch 2B, ln 2)	3,222	301,132	50,681	155,684	0	510,719
4	Net Write-Off Recovery cost per unit sales (ln 2 / ln 3)	$0.028	$0.064	$0.001	$0.011	$0.000	

Citizens Gas
Allocation of Net Write-Off Recovery Cost
August 2021

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	$88	$19,119	$54	$1,757	$15	$21,033
3	Estimated retail sales- Dth (Sch 2B, ln 3)	3,219	299,531	50,603	156,763	0	510,116
4	Net Write-Off Recovery cost per unit sales (ln 2 / ln 3)	$0.027	$0.064	$0.001	$0.011	$0.000	

Citizens Gas
Estimated Total Throughput for Twelve Months Ending May 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 Total Throughput Subject to GCA
	Estimated Total Throughput Volumes (Dth) for Twelve Months Ending May 2022							
1	June 2021	3,815	349,491	232,447	347,516	239,743	724,740	1,897,752
2	July 2021	3,222	301,132	232,257	334,554	237,343	504,184	1,612,692
3	August 2021	3,219	299,531	231,993	334,269	236,909	727,198	1,833,119
4	First Quarter	10,256	950,154	696,697	1,016,339	713,995	1,956,122	5,343,563
5	September 2021	4,333	355,340	234,167	408,924	252,043	717,720	1,972,527
6	October 2021	4,966	677,949	262,287	635,075	302,808	786,222	2,669,307
7	November 2021	9,461	1,886,703	275,265	1,171,871	371,100	540,480	4,254,880
8	Second Quarter	18,760	2,919,992	771,719	2,215,870	925,951	2,044,422	8,896,714
9	December 2021	17,126	3,713,462	309,699	2,110,096	456,196	582,490	7,189,069
10	January 2022	19,845	4,078,254	299,937	2,539,510	480,438	592,286	8,010,270
11	February 2022	18,221	4,047,734	272,934	2,353,362	432,096	548,856	7,673,203
12	Third Quarter	55,192	11,839,450	882,570	7,002,968	1,368,730	1,723,632	22,872,542
13	March 2022	11,818	2,815,490	253,428	1,672,188	385,206	541,694	5,679,824
14	April 2022	8,216	1,971,127	249,589	1,076,511	312,360	761,460	4,379,263
15	May 2022	5,359	904,305	248,156	579,178	262,632	771,652	2,771,282
16	Fourth Quarter	25,393	5,690,922	751,173	3,327,877	960,198	2,074,806	12,830,369
17	Total Throughput - Dth	109,601	21,400,518	3,102,159	13,563,054	3,968,874	7,798,982	49,943,188
	Quarterly Allocation Factor							
18	First Quarter (line 4/line 17)	0.093576	0.044399	0.224585	0.074935	0.179899	0.250818	0.106993
19	Second Quarter (line 8/line 17)	0.171166	0.136445	0.248768	0.163375	0.233303	0.262140	0.178137
20	Third Quarter (line 12/line 17)	0.503572	0.553232	0.284502	0.516327	0.344866	0.221007	0.457971
21	Fourth Quarter (line 16/line 17)	0.231686	0.265924	0.242145	0.245363	0.241932	0.266035	0.256899
	Current Throughput Allocation Factor							
22	Allocation of June 2021 Estimated Throughput (line 1/line 1, column G)	0.002010	0.184161	0.122485	0.183120	0.126330	0.381894	1.000000
23	Allocation of July 2021 Estimated Throughput (line 2/line 2, column G)	0.001998	0.186726	0.144018	0.207451	0.147172	0.312635	1.000000
24	Allocation of August 2021 Estimated Throughput (line 3/line 3, column G)	0.001756	0.163400	0.126556	0.182350	0.129238	0.396700	1.000000
25	Allocation of Quarter Estimated Throughput (line 4/line 4, column G)	0.001919	0.177812	0.130381	0.190199	0.133618	0.366071	1.000000
	Monthly Allocation Factors							
26	June 2021 (line 1/line 4)	0.371977	0.367825	0.333641	0.341929	0.335777	0.370498	0.355147
27	July 2021 (line 2/line 4)	0.314158	0.316930	0.333369	0.329176	0.332415	0.257747	0.301801
28	August 2021 (line 3/line 4)	0.313865	0.315245	0.332990	0.328895	0.331808	0.371755	0.343052
29	Total Throughput Allocation Factor (line 17/line 17, col. G)	0.002195	0.428496	0.062114	0.271570	0.079468	0.156157	1.000000

Citizens Gas
Estimated Retail Sales Volume for Twelve Months Ending May 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 Total Retail Sales Subject to GCA
	Estimated Retail Sales Volumes (Dth) for Twelve Months Ending May 2022						
1	June 2021	3,815	349,491	50,087	161,336	0	564,729
2	July 2021	3,222	301,132	50,681	155,684	0	510,719
3	August 2021	3,219	299,531	50,603	156,763	0	510,116
4	First Quarter	10,256	950,154	151,371	473,783	0	1,585,564
5	September 2021	4,333	355,340	47,787	184,824	0	592,284
6	October 2021	4,966	677,949	53,638	221,284	0	957,837
7	November 2021	9,461	1,886,703	44,029	538,133	0	2,478,326
8	Second Quarter	18,760	2,919,992	145,454	944,241	0	4,028,447
9	December 2021	17,126	3,713,462	50,283	1,202,698	0	4,983,569
10	January 2022	19,845	4,078,254	32,442	1,553,880	0	5,684,421
11	February 2022	18,221	4,047,734	21,497	1,523,445	0	5,610,897
12	Third Quarter	55,192	11,839,450	104,222	4,280,023	0	16,278,887
13	March 2022	11,818	2,815,490	17,424	993,046	0	3,837,778
14	April 2022	8,216	1,971,127	37,808	631,983	0	2,649,134
15	May 2022	5,359	904,305	52,866	294,517	0	1,257,047
16	Fourth Quarter	25,393	5,690,922	108,098	1,919,546	0	7,743,959
17	Total Retail Sales - Dth	109,601	21,400,518	509,145	7,617,593	0	29,636,857
	Quarterly Retail Allocation Factor						
18	First Quarter (line 4/line 17)	0.093576	0.044399	0.297304	0.062196	0.000000	0.053500
19	Second Quarter (line 8/line 17)	0.171166	0.136445	0.285683	0.123955	0.000000	0.135927
20	Third Quarter (line 12/line 17)	0.503572	0.553232	0.204700	0.561860	0.000000	0.549278
21	Fourth Quarter (line 16/line 17)	0.231686	0.265924	0.212313	0.251989	0.000000	0.261295
22	Annual (line 17 / line 17, Column F)	0.003698	0.722092	0.017179	0.257031	0.000000	1.000000
	Current Retail Sales Allocation Factor						
23	Allocation of June 2021 Estimated Throughput (line 1/line 1, column F)	0.006755	0.618866	0.088692	0.285687	0.000000	1.000000
24	Allocation of July 2021 Estimated Throughput (line 2/line 2, column F)	0.006309	0.589623	0.099235	0.304833	0.000000	1.000000
25	Allocation of August 2021 Estimated Throughput (line 3/line 3, column F)	0.006310	0.587182	0.099199	0.307309	0.000000	1.000000
26	Allocation of Quarter Estimated Retail Sales (line 4/line 4, column F)	0.006468	0.599254	0.095468	0.298810	0.000000	1.000000
	Monthly Retail Allocation Factors						
27	June 2021 (line 1/line 4)	0.371977	0.367825	0.330889	0.340527	0.000000	0.356169
28	July 2021 (line 2/line 4)	0.314158	0.316930	0.334813	0.328598	0.000000	0.322106
29	August 2021 (line 3/line 4)	0.313865	0.315245	0.334298	0.330875	0.000000	0.321725

Citizens Gas
Estimated Total Throughput Excluding Basic Volume (Dth) for Twelve Months Ending May 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 Total Throughput Subject to GCA
	Estimated Total Throughput Excluding Basic Volumes (Dth) for Twelve Months Ending May 2022							
1	June 2021	3,815	349,491	216,907	343,556	167,983	16,920	1,098,672
2	July 2021	3,222	301,132	216,757	330,648	166,353	16,864	1,034,976
3	August 2021	3,219	299,531	216,493	330,363	166,105	16,864	1,032,575
4	First Quarter	10,256	950,154	650,157	1,004,567	500,441	50,648	3,166,223
5	September 2021	4,333	355,340	218,567	404,784	176,143	17,280	1,176,447
6	October 2021	4,966	677,949	246,240	630,177	208,196	18,910	1,786,438
7	November 2021	9,461	1,886,703	258,944	1,165,991	253,560	20,880	3,595,539
8	Second Quarter	18,760	2,919,992	723,751	2,200,952	637,899	57,070	6,558,424
9	December 2021	17,126	3,713,462	293,023	2,102,966	310,062	23,312	6,459,951
10	January 2022	19,845	4,078,254	283,135	2,532,008	326,182	24,056	7,263,480
11	February 2022	18,221	4,047,734	256,337	2,346,586	294,056	22,624	6,985,558
12	Third Quarter	55,192	11,839,450	832,495	6,981,560	930,300	69,992	20,708,989
13	March 2022	11,818	2,815,490	237,003	1,666,050	262,942	21,266	5,014,569
14	April 2022	8,216	1,971,127	233,511	1,071,471	214,560	19,200	3,518,085
15	May 2022	5,359	904,305	232,298	574,838	181,536	17,732	1,916,068
16	Fourth Quarter	25,393	5,690,922	702,812	3,312,359	659,038	58,198	10,448,722
17	Total Throughput excl. Basic - Dth	109,601	21,400,518	2,909,215	13,499,438	2,727,678	235,908	40,882,358
	Current Throughput Excl. Basic Allocation Factor							
18	Allocation of June 2021 Estimated Throughput (line 1/line 1, column G)	0.003472	0.318104	0.197427	0.312701	0.152896	0.015400	1.000000
19	Allocation of July 2021 Estimated Throughput (line 2/line 2, column G)	0.003113	0.290956	0.209432	0.319474	0.160731	0.016294	1.000000
20	Allocation of August 2021 Estimated Throughput (line 3/line 3, column G)	0.003117	0.290082	0.209663	0.319941	0.160865	0.016332	1.000000
21	Total Throughput Excl. Basic Allocation Factor (line 17/line 17, col. G)	0.002681	0.523466	0.071161	0.330202	0.066720	0.005770	1.000000
	Monthly Total Throughput less Basic							
22	June 2021 (line 1/line 4)	0.371977	0.367825	0.333622	0.341994	0.335670	0.334070	0.346998
23	July 2021 (line 2/line 4)	0.314158	0.316930	0.333392	0.329145	0.332413	0.332965	0.326880
24	August 2021 (line 3/line 4)	0.313865	0.315245	0.332986	0.328861	0.331917	0.332965	0.326122

Citizens Gas
Purchased Gas Cost - Estimated
June 2021

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)
	June 2021										
	Exelon Generation Company, LLC										
1	Panhandle Eastern Pipeline - TOR			883,199		$2.4578			2,170,727		2,170,727
2	Texas Gas Transmission - TOR			355,898		2.5885			921,242		921,242
3	TGT-REX			165,947		2.4793			411,432		411,432
4	Indiana Municipal Gas Purchasing Authority - TOR			5,310		2.4578			13,051		13,051
5	Indiana Municipal Gas Purchasing Authority - Prepay			144,690		2.1261			307,625		307,625
6	PEAK B			300,000		2.4055			721,650		721,650
7	Rockies Express Pipeline - TOR			600,000		2.3738			1,424,280		1,424,280
8	PEAK A			300,000		2.2780			683,400		683,400
9	Midwestern Gas Transmission Purchases			-		2.4471			-		-
10	Fixed Price Purchases								-		-
11	Hedging Transaction Costs								141,998		141,998
12	Boil-off / Peaking purchase			42,263		2.6130			110,433		110,433
13	Net Demand Cost Charges - AMA							943,203	-		943,203
14	Demand Cost Charges -IMGPA - Prepay	5,000			18.0390			90,195	-		90,195
15	Texas Gas - NNS - (Injections)/Withdrawls			(300,000)	0.3694	2.4687		(110,820)	(740,610)		(851,430)
16	Total			2,497,307				$922,578	$6,165,228	-	$7,087,806

Citizens Gas
Purchased Gas Cost - Estimated
July 2021

		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 2021										
	Exelon Generation Company, LLC										
1	Panhandle Eastern Pipeline - TOR			851,977		$2.6023			2,217,100		2,217,100
2	Texas Gas Transmission - TOR			385,897		2.6308			1,015,218		1,015,218
3	TGT-REX			165,947		2.5323			420,228		420,228
4	Indiana Municipal Gas Purchasing Authority - TOR			5,487		2.6023			14,279		14,279
5	Indiana Municipal Gas Purchasing Authority - Prepay			149,513		2.2705			339,469		339,469
6	PEAK B			310,000		2.4675			764,925		764,925
7	Rockies Express Pipeline - TOR			620,000		2.4109			1,494,758		1,494,758
8	PEAK A			310,000		2.3400			725,400		725,400
9	Midwestern Gas Transmission Purchases			-		2.5000			-		-
10	Fixed Price Purchases								-		-
11	Hedging Transaction Costs								172,691		172,691
12	Boil-off / Peaking purchase			42,263		2.6750			113,054		113,054
13	Net Demand Cost Charges - AMA							957,755	-		957,755
14	Demand Cost Charges -IMGPA - Prepay	5,000			18.6404			93,202	-		93,202
15	Texas Gas - NNS - (Injections)/Withdrawls			(400,000)	0.3699	2.5614		(147,960)	(1,024,560)		(1,172,520)
16	Total			2,441,084				$902,997	$6,252,562	-	$7,155,559

Citizens Gas
Purchased Gas Cost - Estimated
August 2021

		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)
	August 2021										
	Exelon Generation Company, LLC										
1	Panhandle Eastern Pipeline - TOR			956,044		$2.6295			$2,513,918		$2,513,918
2	Texas Gas Transmission - TOR			380,358		2.6420			1,004,906		1,004,906
3	TGT-REX			165,947		2.5509			423,314		423,314
4	Indiana Municipal Gas Purchasing Authority - TOR			5,487		2.6295			14,428		14,428
5	Indiana Municipal Gas Purchasing Authority - Prepay			149,513		2.2977			343,536		343,536
6	PEAK B			310,000		2.4835			769,885		769,885
7	Rockies Express Pipeline - TOR			620,000		2.3198			1,438,276		1,438,276
8	PEAK A			310,000		2.3560			730,360		730,360
9	Midwestern Gas Transmission Purchases			-		2.5186			-		-
10	Fixed Price Purchases										
11	Hedging Transaction Costs								171,906		171,906
12	Boil-off / Peaking purchase			42,263		2.6910			113,730		113,730
13	Net Demand Cost Charges - AMA							957,755	-		957,755
14	Demand Cost Charges -IMGPA - Prepay	5,000			18.6404			93,202	-		93,202
15	Texas Gas - NNS - (Injections)/Withdrawls			(500,000)	0.3575	2.5596		(178,750)	(1,279,800)		(1,458,550)
16	Total			2,439,612				$872,207	$6,244,459	-	$7,116,666

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

Line No	Description	Jun 2021	Jul 2021	Aug 2021	Total
	Commodity Volumes (Dth)				
	Purchases for Retail:				
1	Panhandle TOR	883,199	851,977	956,044	2,691,220
2	IMGPA TOR	5,310	5,487	5,487	16,284
3	IMGPA Prepay	144,690	149,513	149,513	443,716
4	Midwestern Gas	0	0	0	0
5	Rockies Express TOR - Monthly	600,000	620,000	620,000	1,840,000
6	PEAK A	300,000	310,000	310,000	920,000
7	Fixed Price Purchases (Sch. 3)	0	0	0	0
8	Texas Gas TOR	355,898	385,897	380,358	1,122,153
9	TGT-Rex East	165,947	165,947	165,947	497,841
10	PEAK B	300,000	310,000	310,000	920,000
11	Texas Gas NNS	(300,000)	(400,000)	(500,000)	(1,200,000)
12	Boil-off/ Peaking purchases (Sch. 3)	42,263	42,263	42,263	126,789
13	Total Retail Volumes (Ln1 through Ln12)	2,497,307	2,441,084	2,439,612	7,378,003
	Demand Rate				
14	Total Demand Costs (Sch. 3)	$922,578	$902,997	$872,207	$2,697,782
15	Demand Cost per Dth (Line 14 / Line 13)	$0.3694	$0.3699	$0.3575	$0.3657
	Commodity Rate				
16	Panhandle TOR	$2.4578	$2.6023	$2.6295	
17	IMGPA TOR	2.4578	2.6023	2.6295	
18	IMGPA Prepay	2.1261	2.2705	2.2977	
19	Annual Delivery Service - Midwestern Gas	2.4471	2.5000	2.5186	
20	Rockies Express TOR - Monthly	2.3738	2.4109	2.3198	
21	PEAK A	2.2780	2.3400	2.3560	
22	Fixed Price Purchases (Sch. 3)	0.0000	0.0000	0.0000	
23	Texas Gas TOR	2.5885	2.6308	2.6420	
24	TGT-Rex East	2.4793	2.5323	2.5509	
25	Texas Gas NNS	2.4687	2.5614	2.5596	
26	Boil-off/ Peaking purchases (Sch. 3)	2.6130	2.6750	2.6910	
27	PEAK B	2.4055	2.4675	2.4835	
	Commodity Costs				
28	PEPL (Ln 1 x Ln 16)	$2,170,727	$2,217,100	$2,513,918	$6,901,745
29	IMGPA - TOR (Ln 2 x Ln 17)	13,051	14,279	14,428	41,758
30	IMGPA - Authority Prepay (Ln 3 x Ln 18)	307,625	339,469	343,536	990,630
31	Midwestern (Ln 4 x Ln 19)	0	0	0	0
32	Rockies Express TOR (Ln 5 X Ln 20)	1,424,280	1,494,758	1,438,276	4,357,314
33	PEAK A (Ln 6 X Ln 21)	683,400	725,400	730,360	2,139,160
34	Fixed Price Purchases (Ln 7 x Ln 22)	0	0	0	0
35	Texas Gas (Ln 8 x Ln 23)	921,242	1,015,218	1,004,906	2,941,366
36	TGT-Rex East (Ln 9 x Ln 24)	411,432	420,228	423,314	1,254,974
37	Texas Gas -Unnominated Gas (Ln 11 x Ln 25)	(740,610)	(1,024,560)	(1,279,800)	(3,044,970)
38	Boil-off/ Peaking purchases (Ln 12 x Ln 26)	110,433	113,054	113,730	337,217
39	PEAK B (Ln 10 x Ln 27)	721,650	764,925	769,885	2,256,460
40	Hedging Transaction Costs (Sch 3)	141,998	172,691	171,906	486,595
41	Subtotal(Ln 28 through Ln 40)	$6,165,228	$6,252,562	$6,244,459	$18,662,249
42	Commodity Cost per Dth (Line 41/Line 13)	$2.4688	$2.5614	$2.5596	$2.5294
43	Total Average Rate per Dth (Line 15 + Line 42)	$2.8382	$2.9313	$2.9171	$2.8951

Citizens Gas
Projected Information
For Three Months Ending August 31, 2021

Line No.	A	B		C	D	E
				Commodity		
Line No.	Jun 2021	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	2,755,044	$	2.4665	476.96%	Sch 3 pg 1 (line 16 - line 10 - line 12 - line 15)
3	Boil off/Peaking Purchases	42,263	$	2.6130	7.32%	Sch 3 pg 1 line 12
4	Unnominated Seasonal Gas Purchases	(300,000)	$	2.4687	-51.94%	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	(1,919,681)	$	2.4688	-332.34%	Sch 5 ln 3 col A - Sch 4 pg 1 ln 20 Col E
7	Total Net Purchases	577,626			100.00%	
				Commodity		
	Jul 2021	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	2,798,821	$	2.5597	536.79%	Sch 3 pg 2 (line 16 - line 10 - line 12 - line 15)
10	Boil off/Peaking Purchases	42,263	$	2.6750	8.11%	Sch 3 pg 2 line 12
11	Unnominated Seasonal Gas Purchases	(400,000)	$	2.5614	-76.72%	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	(1,919,681)	$	2.5614	-368.18%	Sch 5 line 6 col A - Sch 4 pg 2 ln 20 Col E
14	Total Net Purchases	521,403			100.00%	
				Commodity		
	Aug 2021	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	2,897,349	$	2.5577	557.26%	Sch 3 pg 3 (line 16 - line 10 - line 12 - line 15)
17	Boil off/Peaking Purchases	42,263	$	2.6910	8.13%	Sch 3 pg 3 line 12
18	Unnominated Seasonal Gas Purchases	(500,000)	$	2.5596	-96.17%	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	(1,919,681)	$	2.5596	-369.22%	Sch 5 line 9 col A - Sch 4 pg 3 ln 20 Col E
21	Total Net Purchases	519,931			100.00%	

Citizens Gas
Allocation of Panhandle Unnominated Quantities Cost
June 2021

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)	3,815	349,491	50,087	161,336	0	-	564,729
4	Fixed cost per unit retail sales (ln 2 / ln 3)	$0.404	$1.037	$0.031	$0.798	$0.000	-	
5	PEPL monthly retail variable costs (ln 24 * ln 1)	$182	$42,686	$184	$15,162	$0	-	$58,214
6	Estimated monthly retail sales- Dth (Sch 2B, ln 1)	3,815	349,491	50,087	161,336	0	-	564,729
7	Net monthly retail variable costs per unit sales (ln 5 / ln 6)	$0.048	$0.122	$0.004	$0.094	$0.000	-	
8	Total PEPL cost per unit retail sales (ln 4 + ln 7)	$0.452	$1.159	$0.035	$0.892	$0.000	-	
9	PEPL balancing demand costs (ln 18 * Sch 2C, ln 18)	$170	$15,548	$9,650	$15,284	$7,473	$753	$48,878
10	Est. monthly total throughput excl. Basic - Dth (Sch 2C, ln 1)	3,815	349,491	216,907	343,556	167,983	16,920	1,098,672
11	Fixed balancing cost per unit throughput (ln 9 / ln 10)	$0.045	$0.044	$0.044	$0.044	$0.044	$0.045	
12	PEPL monthly balancing variable costs (ln 25 * Sch 2C, ln 18)	$20	$1,831	$1,137	$1,800	$880	$89	$5,757
13	Estimated monthly total throughput excl Basic- Dth (Sch 2C, ln 1)	3,815	349,491	216,907	343,556	167,983	16,920	1,098,672
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)	$0.050	$0.049	$0.049	$0.049	$0.049	$0.050	

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 2021	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)	700,000		0.0020			$1,400			$1,400
20	(100 - day firm) (Midpoint)	714,067		0.0094		19,681	6,712		$55,859	62,571
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)						$8,112	$0	$55,859	$63,971
24	PEPL Retail Variable Costs (line 23 * 91%) 1/									$58,214
25	PEPL Balancing Variable Costs (line 23* 9%) 1/									$5,757

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

Citizens Gas
Allocation of Panhandle Unnominated Quantities Cost
July 2021

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)	3,222	301,132	50,681	155,684	0	-	510,719
4	Fixed cost per unit retail sales (ln 2 / ln 3)	$0.490	$1.233	$0.032	$0.847	$0.000	-	
5	PEPL monthly retail variable costs (ln 24 * ln 1)	$187	$43,909	$189	$15,596	$0	-	$59,881
6	Estimated monthly retail sales - Dth (Sch 2B, ln 2)	3,222	301,132	50,681	155,684	0	-	510,719
7	Net monthly retail variable costs per unit sales (ln 5 / ln 6)	$0.058	$0.146	$0.004	$0.100	$0.000	-	
8	Total PEPL cost per unit retail sales (ln 4 + ln 7)	$0.548	$1.379	$0.036	$0.947	$0.000	-	
9	PEPL balancing demand costs (ln 18 * Sch 2C, ln 19)	$156	$14,566	$10,485	$15,994	$8,047	$816	$50,064
10	Estimated monthly total throughput - Dth (Sch 2C, ln 2)	3,222	301,132	216,757	330,648	166,353	16,864	1,034,976
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)	$18	$1,724	$1,240	$1,892	$952	$96	$5,922
13	Estimated monthly total throughput excl Basic - Dth (Sch 2C, ln 2)	3,222	301,132	216,757	330,648	166,353	16,864	1,034,976
14	Net monthly balancing variable costs per unit throughput (ln 12 / ln 13)	$0.006	$0.006	$0.006	$0.006	$0.006	$0.006	
15	Total PEPL Balancing cost per unit throughput (ln 11 + ln 14)	$0.054	$0.054	$0.054	$0.054	$0.054	$0.054	

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 2021	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)	700,000		0.0020			$1,400			$1,400
20	(100 - day firm) (Midpoint)	714,067		0.0094		19,681	6,712		$57,691	64,403
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)						$8,112	$0	$57,691	$65,803
24	PEPL Retail Variable Costs (line 23 * 91%) 1/									$59,881
25	PEPL Balancing Variable Costs (line 23 * 9%) 1/									$5,922

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

Citizens Gas
Allocation of Panhandle Unnominated Quantities Cost
August 2021

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)	3,219	299,531	50,603	156,763	0	-	510,116
4	Fixed cost per unit retail sales (ln 2 / ln 3)	$0.491	$1.239	$0.032	$0.841	$0.000	-	
5	PEPL monthly retail variable costs (ln 24 * ln 1)	$186	$43,722	$189	$15,529	$0	-	$59,626
6	Estimated monthly retail sales- Dth (Sch 2B, ln 3)	3,219	299,531	50,603	156,763	0	-	510,116
7	Net monthly retail variable costs per unit sales (ln 5 / ln 6)	$0.058	$0.146	$0.004	$0.099	$0.000	-	
8	Total PEPL cost per unit retail sales (ln 4 + ln 7)	$0.549	$1.385	$0.036	$0.940	$0.000	-	
9	PEPL balancing demand costs (ln 18* Sch 2C, ln 20)	$156	$14,521	$10,497	$16,018	$8,054	$818	$50,064
10	Estimated monthly total throughput - Dth (Sch 2C, ln 3)	3,219	299,531	216,493	330,363	166,105	16,864	1,032,575
11	Fixed balancing cost per unit throughput (ln 9 / ln 10)	$0.048	$0.048	$0.048	$0.048	$0.048	$0.049	
12	PEPL monthly balancing variable costs (ln 25 * Sch 2C, ln 20)	$18	$1,711	$1,236	$1,887	$949	$96	$5,897
13	Estimated monthly total throughput excl Basic - Dth (Sch 2C, ln 3)	3,219	299,531	216,493	330,363	166,105	16,864	1,032,575
14	Net monthly balancing variable costs per unit throughput (ln 12 / ln 13)	$0.006	$0.006	$0.006	$0.006	$0.006	$0.006	
15	Total PEPL Balancing cost per unit sales (ln 11 + ln 14)	$0.054	$0.054	$0.054	$0.054	$0.054	$0.055	

	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

	Calculation of Monthly Variable Costs	A	B	C	D	E	F	G	H	I
		Volumes		Storage Rates			Costs			
	August 2021	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)	700,000		0.0020			$1,400			$1,400
20	(100 - day firm) (Midpoint)	714,067		0.0094		19,681	6,712		$57,411	64,123
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)						$8,112	$0	$57,411	$65,523
24	PEPL Retail Variable Costs (line 23 * 91%) 1/									$59,626
25	PEPL & 3 Balancing Variable Costs (line 23 * 9%) 1/									$5,897

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, 2021

		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 2021									
1	Greene Co.	1,200,000	0	$443,280	$2,962,560	$0	$0	($443,280)	($2,962,560)	($3,405,840)
2	PEPL WSS	700,000	0	258,580	1,728,160	0	0	(258,580)	(1,728,160)	(1,986,740)
3	Subtotal	1,900,000	0	701,860	4,690,720	0	0	(701,860)	(4,690,720)	(5,392,580)
	July 2021									
4	Greene Co.	1,200,000	0	443,880	3,073,680	0	0	(443,880)	(3,073,680)	(3,517,560)
5	PEPL WSS	700,000	0	258,930	1,792,980	0	0	(258,930)	(1,792,980)	(2,051,910)
6	Subtotal	1,900,000	0	702,810	4,866,660	0	0	(702,810)	(4,866,660)	(5,569,470)
	August 2021									
7	Greene Co.	1,200,000	0	429,000	3,071,520	0	0	(429,000)	(3,071,520)	(3,500,520)
8	PEPL WSS	700,000	0	250,250	1,791,720	0	0	(250,250)	(1,791,720)	(2,041,970)
9	Subtotal	1,900,000	0	679,250	4,863,240	0	0	(679,250)	(4,863,240)	(5,542,490)
10	Grand Total	5,700,000	0	$2,083,920	$14,420,620	$0	$0	($2,083,920)	($14,420,620)	($16,504,540)

Citizens Gas
Demand Allocation of Injections and Withdrawals
Greene Co.
For Three Months Ending August 31, 2021

Line No.		A Volume DTH	B Demand Cost	C Commodity Cost	D Total Cost	E Total $/DTH	F Comm $/DTH
1	Beginning Balance @ June 2021	3,061,510	$1,258,816	$6,670,776	$7,929,592	$2.5901	$2.1789
2	Add: Net injections at cost	1,200,000	443,280	2,962,560	3,405,840	2.8382	2.4688
3	Less: Gross withdrawals - avg. unit cost	0	0	0	0	0.0000	0.0000
4	Beginning Balance @ July 2021	4,261,510	1,702,096	9,633,336	11,335,432	2.6600	2.2605
5	Add: Net injections at cost	1,200,000	443,880	3,073,680	3,517,560	2.9313	2.5614
6	Less: Gross withdrawals - avg. unit cost	0	0	0	0	0.0000	0.0000
7	Beginning Balance @ August 2021	5,461,510	2,145,976	12,707,016	14,852,992	2.7196	2.3266
8	Add: Net injections at cost	1,200,000	429,000	3,071,520	3,500,520	2.9171	2.5596
9	Less: Gross withdrawals - avg. unit cost	0	0	0	0	0.0000	0.0000
10	Ending balance @ August 31, 2021	6,661,510	$2,574,976	$15,778,536	$18,353,512	$2.7552	$2.3686

Citizens Gas
Demand Allocation of Injections and Withdrawals
From PEPL FS
For Three Months Ending August 31, 2021

Line No.		A Volume DTH	B Demand Cost	C Commodity Cost	D Total Cost	E Total $/DTH	F Comm $/DTH
1	Beginning Balance @ June 2021	3,173,935	$1,552,105	$5,622,487	$7,174,592	$2.2605	$1.7715
2	Add: Net injections at cost	700,000	258,580	1,728,160	1,986,740	2.8382	2.4688
3	Less: Gross withdrawals - avg. unit cost	0	0	0	0	0.0000	0.0000
4	Beginning Balance @ July 2021	3,873,935	1,810,685	7,350,647	9,161,332	2.3649	1.8975
5	Add: Net injections at cost	700,000	258,930	1,792,980	2,051,910	2.9313	2.5614
6	Less: Gross withdrawals - avg. unit cost	0	0	0	0	0.0000	0.0000
7	Beginning Balance @ August 2021	4,573,935	2,069,615	9,143,627	11,213,242	2.4516	1.9991
8	Add: Net injections at cost	700,000	250,250	1,791,720	2,041,970	2.9171	2.5596
9	Less: Gross withdrawals - avg. unit cost	0	0	0	0	0.0000	0.0000
10	Ending balance @ August 31, 2021	5,273,935	$2,319,865	$10,935,347	$13,255,212	$2.5133	$2.0735

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
December 2020

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)	$7,365	$1,646,576	$20,315	$571,744	$0	$2,246,000
6	Allocated other demand costs (ln 2 * (Schedule 7, pg. 1, ln 4 Col A)	2,865	538,596	14,807	207,035	0	763,303
7	Allocated contracted storage costs (ln 4 * Schedule 7 pg. 1, ln 3 Col B))	2,024	475,451	2,052	168,873	0	$648,400
8	Actual other non-demand gas costs (Sch. 7 pg. 1, Col B, ln 2 + ln 4) * (Sch. 6A, ln 30))	46,581	8,072,253	119,630	2,609,371	0	10,847,835
9	Total actual cost of gas incurred (ln 5 + ln 6 + ln 7 + ln 8)	$58,835	$10,732,876	$156,804	$3,557,023	$0	$14,505,538
10	Actual cost of gas billed including Utility Gross Receipts Tax (Sch. 6A, ln 33)	$57,209	$10,401,713	$142,821	$3,238,227	$0	$13,839,970
11	Actual cost of gas billed excluding Utility Gross Receipts Tax (ln 10 * (1 - 1.4%))	56,408	10,256,088	140,822	3,192,892	0	13,646,210
12	Net - Write Off Recovered (Sch 12 C ln 3)	787	136,392	372	11,602	0	149,153
13	Variance from Cause No. 37399-GCA 148 Filing (Sch. 1, pg. 2 Dec., 2020 ln 17)	(5,095)	(724,418)	(8,789)	(377,500)	0	(1,115,802)
14	Refund from cause No. 37399- GCA 148 Filing (Sch. 1, pg. 2 Dec., 2020 ln 18)	0	0	0	0	0	0
15	Gas cost recovered to be reconciled with actual cost of gas incurred (ln 11 - ln 12 - ln 13 + ln 14)	60,716	10,844,114	149,239	3,558,790	0	14,612,859
16	Gas cost variance (over)/underrecovery (ln 9 - ln 15)	($1,881)	($111,238)	$7,565	($1,767)	$0	($107,321)

Citizens Gas
Calculation of Actual Gas Cost Variance
December 2020

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)	$117	$20,346	$1,738	$11,302	$2,233	$4,424	$40,160
18	Allocated PEPL Balancing Demand & variable cost (Sch. 7, pg. 2, Col A ln 2 * ln 31)	188	32,487	2,775	18,047	3,566	7,064	64,127
19	Total actual Balancing Demand cost incurred (ln 17 + ln 18)	305	52,833	4,513	29,349	5,799	11,488	104,287
20	Actual Balancing Demand Cost Billed including Utility Gross Receipts Tax (Sch. 6A, ln 38)	$228	$46,661	$3,023	$23,854	$5,313	$15,174	$94,253
21	Actual Balancing Demand Cost Billed excluding Utility Gross Receipts Tax (ln 20 * (1-1.4%))	225	46,008	2,981	23,520	5,239	14,962	92,935
22	Balancing Demand Cost Variance from Cause No. 37399 - GCA 148 (Sch. 1, pg. 2 Dec., 2020 ln 11)	(96)	(14,632)					(14,728)
23	Balancing Demand Cost Variance from Cause No. 37399 - GCA 148 (Sch. 1, pg. 3 Dec., 2020 ln 28)			(2,125)	(10,591)	862	5,246	(6,608)
24	Balancing Demand cost recovered to be reconciled with actual Balancing Demand Cost Incurred (ln21 - ln22 - ln23)	$321	$60,640	$5,106	$34,111	$4,377	$9,716	$114,271
25	Balancing Demand cost variance (over)/underrecovery (ln 19 - ln 24)	($16)	($7,807)	($593)	($4,762)	$1,422	$1,772	($9,984)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
December 2020

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	20,713	3,589,273	53,192	1,160,239	-		4,823,417
27	Standard Delivery - Dths			248,568	826,970	258,902	24,925	1,359,365
28	Basic Delivery - Dths			4,795	6,672	135,118	755,574	902,159
29	Total Throughput - Dths (ln 26+ ln 27 + ln 28)	20,713	3,589,273	306,555	1,993,881	394,020	780,499	7,084,941
30	Retail sales allocation factor (ln 26 / ln 26, col. G)	0.004294	0.744135	0.011028	0.240543	0.000000	0.000000	1.000000
31	Throughput subject to Balancing GCA allocation factor (ln 29/ln 29, column G)	0.002924	0.506605	0.043269	0.281425	0.055614	0.110163	1.000000
	Calculation of Gas Supply Charge Recovery							
32	Gas Supply Charge Cause No. 37399 - GCA 148 (D1 & D2 excludes balancing charges) per Dth	$2.762	$2.898	$2.685	$2.791	$0.000	$0.000	
33	Gas Supply Charge Recovery (ln 26 * ln 32)	$57,209	$10,401,713	$142,821	$3,238,227	$0	-	$13,839,970
	Calculation of Balancing Charge Recovery							
34	Balancing GCA Charge Cause No. 37399 - GCA 148 Standard & Retail Customers (per Dth)	$0.011	$0.013	$0.010	$0.012	$0.020	$0.245	
35	Balancing GCA Charge Cause No. 37399 - GCA 148 Basic Delivery Customers (per Dth)			$0.001	$0.001	$0.001	$0.012	
36	Balancing Charge Recovery - Standard & Retail (ln 26 + ln 27) * (ln 34)	$228	$46,661	$3,018	$23,847	$5,178	$6,107	$85,039
37	Balancing Charge Recovery - Basic (ln 28 * ln 35)			$5	$7	$135	$9,067	$9,214
38	Total Balancing Charge Recovery (ln 36 + ln 37)	$228	$46,661	$3,023	$23,854	$5,313	$15,174	$94,253

1/ Line 36 Column C calculation is (259,642 * 0.01) + (42,118 * 0.01)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
January 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,Col C ln 1)	$7,150	$1,598,526	$19,722	$555,059	$0	$2,180,457
6	Allocated other demand costs (ln 2 * ((Schedule 7 pg. 1, Col C ln 4))	4,420	830,706	22,838	319,323	0	1,177,287
7	Allocated contracted storage costs (ln 4 * Schedule 7 pg. 1, Col D ln 3))	2,100	493,305	2,129	175,215	0	672,749
8	Actual other non-demand gas costs (Sch. 7 pg. 1, Col D, ln 2 + ln 4) * (Sch. 6B, ln 30))	47,665	8,350,222	91,139	2,990,884	0	11,479,910
9	Total actual cost of gas incurred (lns 5+6+7+8)	$61,335	$11,272,759	$135,828	$4,040,481	$0	$15,510,403
10	Actual cost of gas billed including Utility Gross Receipts Tax (Sch. 6B, ln 33)	$61,683	$11,533,707	$133,552	$3,792,097	$0	$15,521,039
11	Actual cost of gas billed excluding Utility Gross Receipts Tax (ln 10 * (1 - 1.4%))	60,819	11,372,235	131,682	3,739,008	0	15,303,744
12	Net - Write Off Recovered (Sch 12 C ln 9)	835	154,379	532	13,096	0	168,842
13	Variance from Cause No. 37399-GCA 148 Filing (Sch. 1, pg. 2 Jan., 2021 ln 17)	(5,903)	(795,604)	(5,990)	(485,061)	0	(1,292,558)
14	Refund from cause No. 37399- GCA 148 Filing (Sch. 1, pg. 2 Jan., 2021 ln 18)	0	0	0	0	0	0
15	Gas cost recovered to be reconciled with actual cost of gas incurred (ln 11 - ln 12 - ln 13 + ln 14)	$65,887	$12,013,460	$137,140	$4,210,973	$0	$16,427,460
16	Gas cost variance (over)/underrecovery (ln 9 - ln 15)	($4,552)	($740,701)	($1,312)	($170,492)	$0	($917,057)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
January 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 B ln 1 *) *ln 31)	$121	$21,144	$1,354	$11,785	$2,026	$3,730	$40,160
18	Allocated ADS2 Balancing Demand & variable cost ((Sch. 7, pg. 2, Col B ln 2) * ln 31)	200	35,032	2,243	19,525	3,357	6,179	66,536
19	Total actual Balancing Demand cost incurred (ln17 + ln 18)	$321	$56,176	$3,597	$31,310	$5,383	$9,909	$106,696
20	Actual Balancing Demand Cost Billed including Utility Gross Receipts Tax (Sch. 6B, ln 38)	$232	$48,751	$2,301	$24,833	$4,928	$15,193	$96,238
21	Actual Balancing Demand Cost Billed excluding Utility Gross Receipts Tax (ln 20 * (1-1.4%))	229	48,068	2,269	24,485	4,859	14,980	94,890
22	Balancing Demand Cost Variance from Cause No. 37399 - GCA 148 (Sch. 1, pg. 2 Jan., 2021 ln 11)	(111)	(16,070)	-	-	-	-	(16,181)
23	Balancing Demand Cost Variance from Cause No. 37399 - GCA 148 (Sch. 1, pg. 3 Jan., 2021 ln 28)	-	-	(2,054)	(12,751)	907	5,414	(8,484)
24	Balancing Demand cost recovered to be reconciled with actual Balancing Demand Cost Incurred (ln 21 - ln 22 - ln 23)	$340	$64,138	$4,323	$37,236	$3,952	$9,566	$119,555
25	Balancing Demand cost variance (over)/underrecovery (ln 19 - ln 24)	($19)	($7,962)	($726)	($5,926)	$1,431	$343	($12,859)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
January 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	23,189	4,062,595	44,340	1,455,141	0	0	5,585,265
27	Standard Delivery - Dths		-	211,357	801,790	252,137	28,301	1,293,585
28	Basic Delivery - Dths	-	-	4,369	7,320	137,161	688,272	837,122
29	Total Throughput - Dths (ln 26 + ln 27 + ln 28)	23,189	4,062,595	260,066	2,264,251	389,298	716,573	7,715,972
30	Retail sales allocation factor (ln 26 / ln 26, col. G)	0.004152	0.727377	0.007939	0.260532	0.000000	0.000000	1.000000
31	Throughput subject to Balancing GCA allocation factor (ln 29 / ln 29, column G)	0.003005	0.526517	0.033705	0.293450	0.050454	0.092869	1.000000
	Calculation of Gas Supply Charge Recovery							
32	Gas Supply Charge Cause No. 37399 - GCA 148 (D1 & D2 excludes balancing charges) per Dth	$2.660	$2.839	$3.012	$2.606	$0.000	$0.000	
33	Gas Supply Charge Recovery (ln 26* ln 32)	$61,683	$11,533,707	$ 133,552	$3,792,097	$0	$0	$15,521,039
	Calculation of Balancing Charge Recovery							
34	Balancing GCA Charge Cause No. 37399 - GCA 148 Standard & Retail Customers (per Dth)	$0.010	$0.012	$0.009	$0.011	$0.019	$0.245	
35	Balancing GCA Charge Cause No. 37399 - GCA 148 Basic Delivery Customers (per Dth)	-	-	$0.000	$0.001	$0.001	$0.012	
36	Balancing Charge Recovery - Standard & Retail (ln 26 + ln 27) * (ln 34)	$232	$48,751	$2,301	$24,826	$4,791	$6,934	$87,835
37	Balancing Charge Recovery - Basic (ln 28 * ln 35)	-	-	$0	$7	$137	$8,259	$8,403
38	Total Balancing Charge Recovery (ln 36 + ln 37)	$232	$48,751	$2,301	$24,833	$4,928	$15,193	$96,238

1/ Line 36 Column C calculation is (219,264 * 0.009) + (36,433 * 0.009)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
February 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, Col E ln 1)	$7,044	$1,574,859	$19,430	$546,841	$0	$2,148,174
6	Allocated other demand costs (ln 2 * (Schedule 7 pg. 1, Col E, ln 4))	5,556	1,044,275	28,710	401,418	0	1,479,959
7	Allocated contracted storage costs (ln 4 * Schedule 7 pg. 1,Col F ln 3)	2,073	486,945	2,101	172,956	0	664,075
8	Actual other non-demand gas costs ((Sch. 7 pg. 1, ln 2 + ln 4) * (Sch. 6C, ln 30))	8,784	1,622,773	21,412	624,440	0	2,277,409
9	Total actual cost of gas incurred (ln 5 + ln 6 + ln 7 + ln 8)	$23,457	$4,728,852	$71,653	$1,745,655	$0	$6,569,617
10	Actual cost of gas billed including Utility Gross Receipts Tax (Sch. 6C, ln 33)	$61,622	$11,861,674	$190,750	$4,205,704	$0	$16,319,750
11	Actual cost of gas billed excluding Utility Gross Receipts Tax (ln 10 * (1 - 1.4%))	60,759	11,695,611	188,080	4,146,824	0	16,091,274
12	Net - Write Off Recovered (Sch 12 C ln 15)	889	160,126	921	14,219	0	176,155
13	Variance from Cause No. 37399-GCA 148 Filing (Sch. 1, pg. 2 Feb, 2021, ln 17)	($5,420)	($789,652)	($4,184)	($473,596)	$0	(1,272,852)
14	Refund from cause No. 37399- GCA 148 Filing (Sch. 1, pg. 2 Feb, 2021, ln 18)	0	0	0	0	0	0
15	Gas cost recovered to be reconciled with actual cost of gas incurred (ln 11 - ln 12 - ln 13 + ln 14)	$65,290	$12,325,137	$191,343	$4,606,201	$0	$17,187,971
16	Gas cost variance (over)/underrecovery (ln 9 - ln 15)	($41,833)	($7,596,285)	($119,690)	($2,860,546)	$0	($10,618,354)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
February 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, ln 1 * ln 31)	$102	$18,908	$1,199	$11,718	$1,877	$2,470	$36,274
18	Allocated ADS2 Balancing Demand cost (Sch. 7, pg. 2, ln 2 * ln 31)	$185	$34,235	$2,170	$21,216	$3,399	$4,473	$65,678
19	Total actual Balancing Demand cost incurred (ln 17 + ln 18)	$287	$53,143	$3,369	$32,934	$5,276	$6,943	$101,952
20	Actual Balancing Demand Cost Billed including Utility Gross Receipts Tax (ln 38)	$178	$41,058	$1,793	$22,847	$4,741	$12,655	$83,272
21	Actual Balancing Demand Cost Billed excluding Utility Gross Receipts Tax (ln 20 * (1-1.4%))	176	40,483	1,768	22,527	4,675	12,478	82,107
22	Balancing Demand Cost Variance from Cause No. 37399 - GCA 148 (Sch. 1, pg. 2 Feb, 2021 ln 11)	(103)	(15,949)	-	-	-	-	(16,052)
23	Balancing Demand Cost Variance from Cause No. 37399 - GCA 148 (Sch. 1, pg. 3 Feb, 2021 ln 28)	-	-	(1,859)	(11,817)	818	5,091	(7,767)
24	Balancing Demand cost recovered to be reconciled with actual Balancing Demand Cost Incurred (ln21 - ln22 - ln23)	$279	$56,432	$3,627	$34,344	$3,857	$7,387	$105,926
25	Balancing Demand cost variance (over)/underrecovery (ln 19 - ln 24)	$8	($3,289)	($258)	($1,410)	$1,419	($444)	($3,974)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
February 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 - Dth	22,222	4,105,806	54,175	1,579,904	-	-	5,762,107
27	Standard Delivery - Dths	-	-	202,025	957,916	270,806	27,032	1,457,779
28	Basic Delivery - Dths	-	-	4,098	6,757	136,860	509,414	657,129
29	Total Throughput - Dths (ln 26 + ln 27 + ln 28)	22,222	4,105,806	260,298	2,544,577	407,666	536,446	7,877,015
30	Retail sales allocation factor (ln 26 / ln 26, col. G)	0.003857	0.712552	0.009402	0.274189	0.000000	0.000000	1.000000
31	Throughput subject to Balancing GCA allocation factor (ln 29 / 29, column G)	0.002821	0.521239	0.033045	0.323038	0.051754	0.068103	1.000000
	Calculation of Gas Supply Charge Recovery							
32	Gas Supply Charge Cause No. 37399 - GCA 148 (D1 & D2 excludes balancing charges) per Dth	$2.773	$2.889	$3.521	$2.662	$0.000	$0.000	
33	Gas Supply Charge Recovery (ln 26 * ln 32)	$61,622	$11,861,674	$190,750	$4,205,704	-	-	$16,319,750
	Calculation of Balancing Charge Recovery							
34	Balancing GCA Charge Cause No. 37399 - GCA 148 Standard & Retail Customers (per Dth)	$0.008	$0.010	$0.007	$0.009	$0.017	$0.242	
35	Balancing GCA Charge Cause No. 37399 - GCA 148 Basic Delivery Customers (per Dth)	-	-	$0.000	$0.001	$0.001	$0.012	
36	Balancing Charge Recovery - Standard & Retail (ln 26 + ln 27) * (ln 34)	$178	$41,058	$1,793	$22,840	$4,604	$6,542	$77,015
37	Balancing Charge Recovery - Basic (ln 28 * ln 35)	-	-	$0	$7	$137	$6,113	$6,257
38	Total Balancing Charge Recovery (ln 36 + ln 37)	$178	$41,058	$1,793	$22,847	$4,741	$12,655	$83,272

1/ Line 36 Column C calculation is (223,193 * 0.007) + (33,007 * 0.007)

Citizens Gas
Trailing Twelve Month Variance
For January 2020 through February 2021

Line No.			A January 2020	B February 2020	C March 2020	D April 2020	E May 2020	F June 2020	G July 2020	H August 2020	I September 2020	J October 2020	K November 2020	L December 2020	M January 2021	N February 2021
1	Actual Cost of Gas	Total Sch 6 pg 1 ln 9 + Sch 6 pg 2 ln 19	$12,791,023	$12,620,659	$7,383,182	$4,317,200	$2,906,287	$1,331,877	$1,368,247	$1,630,453	$2,062,291	$5,105,853	$8,250,758	$14,609,825	$15,617,099	$6,671,569
2	Variance	Total Sch 6 pg 1 ln 16 + Sch 6 pg 2 ln 25	($1,500,513)	($779,086)	($464,555)	($442,851)	$179,518	($668,512)	($334,647)	($98,921)	($118,959)	($856,549)	($1,466,980)	($117,305)	($929,916)	($10,622,328)
3										Gas Cost Trailing Twelve Months (ln 1, col A-L)				$74,377,655		
4										Variance Trailing Twelve Months (ln 2, col A-L)				($6,669,360)		
5										Total Trailing Twelve Months % Variance (ln 4 / ln 3)				-8.97%		
6										Gas Cost Trailing Twelve Months (ln 1, col B-M)					$77,203,731	
7										Variance Trailing Twelve Months (ln 2, col B-M)					($6,098,763)	
8										Total Trailing Twelve Months % Variance (ln 7 / ln 6)					-7.90%	
9										Gas Cost Trailing Twelve Months (ln 1, col C-N)						$71,254,641
10										Variance Trailing Twelve Months (ln 2, col C-N)						($15,942,005)
11										Total Trailing Twelve Months % Variance (ln 10 / ln 9)						-22.37%

Citizens Gas
Determination of Actual Retail Gas Costs
For Three Months Ending February 28, 2021

Line No.		A	B	C	D	E	F
		December 2020		January 2021		February 2021	
		Demand	Non-Demand	Demand	Non-Demand	Demand	Non-Demand
1	Demand gas costs (Sch. 8)	$2,246,000	-	$2,180,457	-	$2,148,174	-
2	Pipeline non-demand gas costs (Schedule 8)	-	7,856,405	-	6,978,726	-	(3,404,612)
3	PEPL Contracted storage and related transportation costs (Sch. 9)	-	648,400	-	672,749	-	664,075
4	Net cost of gas (injected into) withdrawn from storage (Schedule 10)	763,303	2,991,430	1,177,287	4,501,184	1,479,959	5,682,021
5	Total gas costs	$3,009,303	$11,496,235	$3,357,744	$12,152,659	$3,628,133	$2,941,484

Citizens Gas
Determination of Actual Balancing Costs
For Three Months Ending February 28, 2021

Line No.		A December 2020	B January 2021	C February 2021
1	Balancing Demand Costs (Schedule 8)	$40,160	$40,160	$36,274
2	PEPL Balancing Demand Costs (Sch. 9)	64,127	66,536	65,678
3	Total Balancing Costs	$104,287	$106,696	$101,952

Citizens Gas
Purchased Gas Cost - Per Books
December 2020

		A	B	C	D	E	F	G	H	I
Line No.		Demand - Dth	Commodity Dth	Demand $/Unit	Commodity $/Dth	Other $/Unit	Demand (A x C)	Commodity (B x D)	Other	Total (F + G + H)
	Accrual -November, 2020									
	Exelon Generation Company									
1	Panhandle Eastern Pipeline - TOR	33,463	-	$ 13.2172	$ -		$ 442,288	$ -		$ 442,288
2	MGT Pipeline -	1,350,000	-	0.0641	-		86,504	260		86,764
3	Indiana Municipal Gas Purchasing Authority - TOR		17,940	-	2.8347			50,854		50,854
4	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	494,760	18.0374	2.5016		308,260	1,237,710		1,545,970
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	(58,787)	(58,787)	0.7574	2.1870		(44,525)	(128,567)		(173,092)
9	Texas Gas Transmission - Unnominated Withdrawal	281,601	281,601	0.3802	2.6980		107,065	759,760		866,825
10	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
11	Rockies Express - Delivered Supply - (BP PEAK B)		294,118	-	2.7885		-	820,148		820,148
12	Rockies Express - Delivered Supply - (BP PEAK A)		299,888	-	2.6620		-	798,300		798,300
13	Rockies Express - EAST	20,000	-	16.7292	-		334,583	-		334,583
14	Intraday Purchases		-	-	-			-		-
15	Fuel Retention Volumes		-	-	-					-
16	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		693,259	-	1.6577		-	1,149,182		1,149,182
17	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
18	Hedging Transaction Cost			-	-			(54,911)		(54,911)
19	Imbalance		(2,656)	-	2.2428			(5,957)		(5,957)
20	Utilization Fee			-	-		(243,750)	-		(243,750)
21	Net Demand Cost Charges - AMA			-	-		-			-
22	REX Winter 2021	16,000	257,563	11.4799	1.8589		183,678	478,780		662,458
23	Third Party Supplier Balancing Gas Costs		299,368	-			-	663,679		663,679
24	Boil-off / Peaking purchase		40,121	-	2.9960		-	120,203		120,203
25	MGT Cash Out Imbalance		-	-	-			-		-
26	NSS Injection fuel loss	-	(17)	-	-		-			-
27	Backup Supply Sales		(49,261)		2.3211			(114,341)		(114,341)
28	Subtotal		2,567,897				$2,024,423	$5,775,100	$0	$7,799,523
	Actual -November, 2020									
	Exelon Generation Company									
29	Panhandle Eastern Pipeline - TOR	33,463	-	$ 13.2172	$ -		$ 442,288	$ -		$ 442,288
30	MGT Pipeline -	1,350,000	-	0.0641	-		86,504	260		86,764
31	Indiana Municipal Gas Purchasing Authority - TOR		17,940	-	2.8347			50,854		50,854
32	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	494,760	18.1425	2.5016		310,056	1,237,710		1,547,766
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	(58,787)	(58,787)	0.8341	2.1977		(49,034)	(129,196)		(178,230)
37	Texas Gas Transmission - Unnominated Withdrawal	281,601	281,601	0.3802	2.6980		107,065	759,760		866,825
38	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
39	Rockies Express - Delivered Supply - (BP PEAK B)		300,000	-	2.7885		-	836,550		836,550
40	Rockies Express - Delivered Supply - (BP PEAK A)		299,888	-	2.6620		-	798,300		798,300
41	Rockies Express - EAST	20,000	-	16.7292	-		334,583	-		334,583
42	Intraday Purchases		-	-	-			-		-
43	Fuel Retention Volumes		-	-	-					-
44	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		693,259	-	1.6577		-	1,149,182		1,149,182
45	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
46	Hedging Transaction Cost			-	-			(54,911)		(54,911)
47	Imbalance		(2,656)	-	2.2523			(5,982)		(5,982)
48	Utilization Fee			-	-		(243,750)	-		(243,750)
49	Net Demand Cost Charges - AMA			-	-		-			-
50	REX Winter 2021	16,000	257,563	11.4799	1.8832		183,678	485,046		668,724
51	Third Party Supplier Balancing Gas Costs		299,368	-				663,679		663,679
52	Boil-off / Peaking purchase		40,121	-	2.9960			120,203		120,203
53	MGT Cash Out Imbalance		480	-	2.5479			1,223		1,223
54	NSS Injection fuel loss	-	(17)							-
55	Backup Supply Sales		(49,261)	-	2.3211		-	(114,341)		(114,341)
56	Subtotal		2,574,259				$2,021,710	$5,798,337	$0	$7,820,047

Citizens Gas
Purchased Gas Cost - Per Books
December 2020

Line	Description	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, 2020									
	Exelon Generation Company									
57	Panhandle Eastern Pipeline - TOR	33,463	-	$ 13.3194	$ -		$ 445,707	$ -		$ 445,707
58	MGT Gas Pipeline -	1,395,000	-	0.0620	-		86,504	-		86,504
59	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
60	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	511,252	18.6272	2.3773		318,338	1,215,392		1,533,730
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	(388)	(388)	0.7577	2.3840		(294)	(925)		(1,219)
65	Texas Gas Transmission - Unnominated Withdrawal	483,858	483,858	0.3764	2.5610		182,124	1,239,160		1,421,284
66	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
67	Rockies Express - Delivered Supply - (BP PEAK B)		310,000	-	2.6885			833,435		833,435
68	Rockies Express - Delivered Supply - (BP PEAK A)		310,000	-	2.5610			793,910		793,910
69	Rockies Express - EAST	20,000	310,000	16.7292	1.7450		334,583	540,960		875,543
70	Intraday Purchases		-	-	-			-		-
71	Fuel Retention Volumes		-	-	-					-
72	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		820,848	-	2.4668			2,024,853		2,024,853
73	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
74	Hedging Transaction Cost			-	-			147,363		147,363
75	Imbalance		(13,087)	-	2.4097			(31,536)		(31,536)
76	Utilization Fee			-	-		(243,750)	-		(243,750)
77	Net Demand Cost Charges - AMA			-	-		-			-
78	REX Winter 2021	25,000	702,951	11.4799	2.3523		286,997	1,653,531		1,940,528
79	Third Party Supplier Balancing Gas Costs		(125,960)	-				(458,094)		(458,094)
80	Boil-off / Peaking purchase		57,639	-	2.8960			166,923		166,923
81	MGT Cash Out Imbalance		-	-	-			-		-
82	NSS Injection fuel loss		-	-	-		-			-
83	Backup Supply Sales		(116,445)		2.5059			(291,804)		(291,804)
84	Subtotal		3,250,668				$ 2,288,873	$ 7,833,168	$ -	$ 10,122,041
85	Total Purchased Costs (line 84 + line 56 - line 28)		3,257,030				$ 2,286,160	$ 7,856,405	$ -	$ 10,142,565
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)		3,257,030				$ 1,884,556			
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 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 - December, 2020									
	Exelon Generation Company									
1	Panhandle Eastern Pipeline - TOR	33,463	-	$ 13.3194	$ -		$ 445,707	$ -		$ 445,707
2	MGT Gas Pipeline -	1,395,000	-	0.0620	-		86,504	-		86,504
3	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
4	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	511,252	18.6272	2.3773		318,338	1,215,392		1,533,730
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	(388)	(388)	0.7577	2.3840		(294)	(925)		(1,219)
9	Texas Gas Transmission - Unnominated Withdrawal	483,858	483,858	0.3764	2.5610		182,124	1,239,160		1,421,284
10	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
11	Rockies Express - Delivered Supply - (BP PEAK B)		310,000	-	2.6885			833,435		833,435
12	Rockies Express - Delivered Supply - (BP PEAK A)		310,000	-	2.5610			793,910		793,910
13	Rockies Express - EAST	20,000	310,000	16.7292	1.7450		334,583	540,960		875,543
14	Intraday Purchases		-	-	-			-		-
15	Fuel Retention Volumes		-	-	-					-
16	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		820,848	-	2.4668			2,024,853		2,024,853
17	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
18	Hedging Transaction Cost			-	-			147,363		147,363
19	Imbalance		(13,087)	-	2.4097			(31,536)		(31,536)
20	Utilization Fee			-	-		(243,750)	-		(243,750)
21	Net Demand Cost Charges - AMA			-	-		-			-
22	REX Winter 2021	25,000	702,951	11.4799	2.3523		286,997	1,653,531		1,940,528
23	Third Party Supplier Balancing Gas Costs		(125,960)	-				(458,094)		(458,094)
24	Boil-off / Peaking purchase		57,639	-	2.8960			166,923		166,923
25	MGT Cash Out Imbalance		-	-	-			-		-
26	NSS Injection fuel loss		-	-	-		-			-
27	Backup Supply Sales		(116,445)		2.5059			(291,804)		(291,804)
28	Subtotal		3,250,668				$ 2,288,873	$ 7,833,168	$ -	$ 10,122,041
	Actual - December, 2020									
29	Panhandle Eastern Pipeline - TOR	33,463	-	$ 13.3194	-		$ 445,707	$ -		$ 445,707
30	MGT Gas Pipeline -	1,395,000	-	0.0620	-		86,504	-		86,504
31	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
32	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	511,252	18.6272	2.3773		318,338	1,215,392		1,533,730
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	(388)	(388)	0.7577	2.3918		(294)	(928)		(1,222)
37	Texas Gas Transmission - Unnominated Withdrawal	483,858	483,858	0.3764	2.5610		182,124	1,239,160		1,421,284
38	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
39	Rockies Express - Delivered Supply - (BP PEAK B)		310,000	-	2.6885			833,435		833,435
40	Rockies Express - Delivered Supply - (BP PEAK A)		310,000	-	2.5610			793,910		793,910
41	Rockies Express - EAST	20,000	310,000	16.7292	1.7450		334,583	540,960		875,543
42	Intraday Purchases		-	-	-		-	-		-
43	Fuel Retention Volumes		-	-	-					-
44	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		820,848	-	2.4668			2,024,853		2,024,853
45	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)		-	-	-					-
46	Hedging Transaction Cost			-	-			147,363		147,363
47	Imbalance		(10,998)	-	2.4178			(26,591)		(26,591)
48	Utilization Fee		-	-	-		(243,750)	-		(243,750)
49	Net Demand Cost Charges - AMA			-	-		-	-		-
50	REX Winter 2021	25,000	697,069	11.4799	2.3891		286,997	$1,665,356		1,952,353
51	Third Party Supplier Balancing Gas Costs		(125,960)	-			-	(458,094)		(458,094)
52	Boil-off / Peaking purchase		57,639	-	2.8960		-	166,923		166,923
53	MGT Cash Out Imbalance		2,766	-	2.5000		-	6,915		6,915
54	NSS Injection fuel loss		-	-	-					-
55	Backup Supply Sales		(116,445)		2.5059			(291,804)		(291,804)
56	Subtotal		3,249,641				$ 2,288,873	$ 7,856,850	$0	$ 10,145,723

Citizens Gas

Purchased Gas Cost - Per Books

January 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 - January, 2021									
	Exelon Generation Company									
57	Panhandle Eastern Pipeline - TOR	33,463	-	$ 13.3194	$ -		$ 445,707	$ -		$ 445,707
58	MGT Pipeline	1,395,000	-	0.0620	-		86,504	-		86,504
59	Indiana Municipal Gas Purchasing Authority - TOR		18,538	-	2.4199			44,861		44,861
60	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	511,252	18.6122	2.0871		318,082	1,067,050		1,385,132
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	(1,236)	(1,236)	0.7330	2.1537		(906)	(2,662)		(3,568)
65	Texas Gas Transmission - Unnominated Withdrawal	296,323	296,323	0.3872	2.5947		114,736	768,869		883,605
66	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
67	Rockies Express - Delivered Supply - (BP PEAK B)	-	310,000	-	2.2595		-	700,445		700,445
68	Rockies Express - Delivered Supply - (BP PEAK)		310,000	-	2.1320			660,920		660,920
69	Rockies Express - EAST	20,000	620,000	16.7292	2.0866		334,583	1,293,692		1,628,275
70	Intraday Purchases		-	-	-			-		-
71	Fuel Retention Volumes		-	-	-					-
72	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		231,441	-	2.6174			605,765		605,765
73	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
74	Hedging Transaction Cost			-	-			82,303		82,303
75	Imbalance		49	-	2.2041			108		108
76	Utilization Fee			-	-		(243,750)			(243,750)
77	Net Demand Cost Charges - AMA			-	-		-			-
78	REX Winter 2021	25,000	775,000	11.4799	2.0145		286,997	$1,561,218		1,848,215
79	Third Party Supplier Balancing Gas Costs		86,856	-				142,553		142,553
80	Boil-off / Peaking purchase		60,360	-	2.4670			148,908		148,908
81	MGT Cash Out Imbalance		-	-	-			-		-
82	NSS Injection fuel loss		-							-
83	Backup Supply Sales		(49,622)		2.3978			(118,986)		(118,986)
84	Subtotal		3,168,961				$ 2,220,617	$ 6,955,044	$0	$9,175,661
85	Total Purchased Costs (line 84 + line 56 - line 28.)		3,167,934				$2,220,617	$6,978,726	$0	$9,199,343
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)		3,167,934				$1,819,013			
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 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 - January, 2021									
	Exelon Generation Company									
1	Panhandle Eastern Pipeline - TOR	33,463	-	$ 13.3194	$ -		$ 445,707	$ -		$ 445,707
2	MGT Pipeline	1,395,000	-	$ 0.0620	-		86,504	-		86,504
3	Indiana Municipal Gas Purchasing Authority - TOR	-	18,538	-	2.4199		-	44,861		44,861
4	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	511,252	18.6122	2.0871		318,082	1,067,050		1,385,132
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	(1,236)	(1,236)	0.7330	2.1537		(906)	(2,662)		(3,568)
9	Texas Gas Transmission - Unnominated Withdrawal	296,323	296,323	0.3872	2.5947		114,736	768,869		883,605
10	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill	-	-	-	-		-	-		-
11	Rockies Express - Delivered Supply - (BP PEAK B)	-	310,000	-	2.2595		-	700,445		700,445
12	Rockies Express - Delivered Supply - (BP PEAK)		310,000	-	2.1320		-	660,920		660,920
13	Rockies Express - EAST	20,000	620,000	16.7292	2.0866		334,583	1,293,692		1,628,275
14	Intraday Purchases	-	-	-	-			-		-
15	Fuel Retention Volumes	-	-	-	-		-	-		-
16	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)	-	231,441	-	2.6174		-	605,765		605,765
17	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)	-	-	-	-		-	-		-
18	Hedging Transaction Cost	-		-	-			82,303		82,303
19	Imbalance		49	-	2.2041			108		108
20	Utilization Fee	-	-	-	-		(243,750)	-		(243,750)
21	Net Demand Cost Charges - AMA	-	-	-	-		-			-
22	REX Winter 2021	25,000	775,000	11.4799	2.0145		286,997	1,561,218		1,848,215
23	Third Party Supplier Balancing Gas Costs	-	86,856	-				142,553		142,553
24	Boil-off / Peaking purchase	-	60,360	-	2.4670		-	148,908		148,908
25	MGT Cash Out Imbalance	-	-	-	-		-	-		-
26	NSS Injection fuel loss		-							
27	Backup Supply Sales		(49,622)		2.3978		-	(118,986)		(118,986)
28	Sub-total		3,168,961				$2,220,617	$6,955,044	$0	$9,175,661
	Actual - January, 2021									
	Exelon Generation Company									
29	Panhandle Eastern Pipeline - TOR	33,463	-	$ 13.3194	$ -		$ 445,707	$ -		$ 445,707
30	MGT Pipeline	1,395,000	-	0.0620	-		86,504	-		86,504
31	Indiana Municipal Gas Purchasing Authority - TOR		18,538	-	2.4199			44,861		44,861
32	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	511,252	18.6122	2.0871		318,082	1,067,051		1,385,133
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	(1,236)	(1,236)	0.7330	2.2144		(906)	(2,737)		(3,643)
37	Texas Gas Transmission - Unnominated Withdrawal	296,323	296,323	0.3764	2.5610		111,536	758,883		870,419
38	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
39	Rockies Express - Delivered Supply - (BP PEAK B)	-	310,000	-	2.2595		-	700,445		700,445
40	Rockies Express - Delivered Supply - (BP PEAK)	-	310,000	-	2.1320		-	660,920		660,920
41	Rockies Express - EAST	20,000	620,000	16.7292	2.0866		334,583	1,293,692		1,628,275
42	Intraday Purchases		-	-	-			$0		-
43	Fuel Retention Volumes		-	-	-					-
44	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		231,441	-	2.6174			605,765		605,765
45	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
46	Hedging Transaction Cost			-	-			82,303		82,303
47	Imbalance		49	-	2.2449			110		110
48	Utilization Fee			-	-		(243,750)			(243,750)
49	Net Demand Cost Charges - AMA			-	-		-			-
50	REX Winter 2021	25,000	775,000	11.4799	2.2412		286,997	1,736,937		2,023,934
51	Third Party Supplier Balancing Gas Costs		86,856	-				142,553		142,553
52	Boil-off / Peaking purchase		60,360	-	2.4670			148,908		148,908
53	MGT Cash Out Imbalance		(216)	-	2.5926			(560)		(560)
54	NSS Injection fuel loss		-							
55	Backup Supply Sales		(49,622)		2.3978			(118,986)		(118,986)
56	Sub-total		3,168,745				$ 2,217,417	$ 7,120,145	$ -	$ 9,337,562

Citizens Gas
Purchased Gas Cost - Per Books
February 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 -February, 2021									
	Exelon Generation Company									
57	Panhandle Eastern Pipeline - TOR	33,463	-	$ 13.0129	$ -		$ 435,449	$ -		$ 435,449
58	MGT Pipeline	1,260,000	-	0.0687	-		86,504	-		86,504
59	Indiana Municipal Gas Purchasing Authority - TOR		12,558	-	3.5569			44,668		44,668
60	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	460,975	16.8096	2.3332		287,276	1,075,545		1,362,821
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	(225)	(225)	0.9244	(2.3200)		(208)	522		314
65	Texas Gas Transmission - Unnominated Withdrawal	508,756	508,756	0.4072	2.7660		207,165	1,407,219		1,614,384
66	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
67	Rockies Express - Delivered Supply - (BP PEAK B)		280,000	-	2.5525		-	714,700		714,700
68	Rockies Express - Delivered Supply - (BP PEAK A)		280,000	-	2.4250		-	679,000		679,000
69	Rockies Express - EAST	20,000	-	16.7292	-		334,583	-		334,583
70	Intraday Purchases		88,367	-	11.3441			1,002,446		1,002,446
71	Fuel Retention Volumes		-	-	-					-
72	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		880,356	-	(10.4604)			(9,208,909)		(9,208,909)
73	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
74	Hedging Transaction Cost			-	-			289,115		289,115
75	Imbalance		8,569	-	(1.3431)			(11,509)		(11,509)
76	Utilization Fee			-	-		(243,750)			(243,750)
77	Net Demand Cost Charges - AMA			-	-		-			-
78	REX Winter Purchases	25,000	85,000	11.4799	5.1171		286,997	434,952		721,949
79	Third Party Supplier Balancing Gas Costs		3	-				(132,425)		(132,425)
80	Boil-off / Peaking purchase		136,635	-	2.7600			377,113		377,113
81	MGT Cash Out Imbalance		-	-	-			-		-
82	NSS Injection fuel loss		-							-
83	Backup Supply Sales		(83,164)		2.9117			(242,150)		(242,150)
84	Sub-total		2,657,830				2,187,648	(3,569,713)	$ -	(1,382,065)
85	Total Purchased Costs (line 56 + line 84 - line 28)		2,657,614				$2,184,448	($3,404,612)	$0	($1,220,164)
86	Total TGT Unnominated Demand Cost (line 62+ line 34 - line 6)						362,739			
87	Total Purchase Cost excluding TGT Demand Unnom. (ln 85 - ln 86)		2,657,614				$1,821,709			
88	TGT Unnominated Demand Cost - Retail (line 86 * 90%)						$326,465			
89	Balancing Demand Cost (line 86 * 10%)						$36,274			

Citizens Gas
Actual Information
For Three Months Ending February 28, 2021

	A	B		C	D	E
		Volumes in		Commodity		
Line No.	December 2020	Dths		Cost per Dth	% of Total	Reference
1	Intraday Purchases	-	$	-	0.00%	Sch8A, lns 14, 42, 70
2	Index Purchases / Spot	1,447,134	$	2.3495	51.51%	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	820,848	$	2.4668	29.22%	Sch8A, lns 16, 44, 72
4	Boil off/Peaking Purchases	57,639	$	2.8960	2.05%	Sch8A, lns 24, 52, 80
5	Unnominated Seasonal Gas Purchases	-			0.00%	
6	Storage Withdrawal	483,858	$	2.5610	17.22%	Sch8A, lns 9, 37, 65
7	Total Purchases	2,809,479			100.00%	
8	REX Winter Purchases	702,951				Sch8A, lns 22,50,78
9	Third Party	(125,960)				Sch8A, lns 23, 51, 79
10	Imbalance	(13,087)				Sch8A, lns 19, 47, 75
11	Fuel Retention	-				Sch8A, lns 15, 43, 71
12	MGT Cash Out Imbalance	480				Sch8A, lns 25, 53, 81
13	Unnominated Seasonal Gas Payback	-				
14	NNS Injection Loss	-				Sch8A, lns 26, 54, 82
15	Backup Supply Sales	(116,445)				Sch8A, lns 27, 55, 83
16	Storage Injection	(388)	$	4.0052		Sch8A, lns 8, 36, 64
17	Net Purchases	3,257,030				
		Volumes in		Commodity		
	January 2021	Dths		Cost per Dth	% of Total	
18	Intraday Purchases	-	$	-	0.00%	Sch8B, lns 14, 42, 70
19	Index Purchases	1,769,790	$	2.1285	75.05%	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	231,441	$	2.6174	9.82%	Sch8B, lns 16, 44, 72
21	Boil off/Peaking Purchases	60,360	$	2.4670	2.56%	Sch8B, lns 24, 52, 80
22	Unnominated Seasonal Gas Purchases	-			0.00%	
23	Storage Withdrawal	296,323	$	2.5947	12.57%	Sch8B, lns 9, 37, 65
24	Total Purchases	2,357,914			100.00%	
25	REX Winter Purchases	769,118				Sch8B, lns 22,50,78
26	Third Party	86,856				Sch8B, lns 23, 51, 79
27	Imbalance	2,138				Sch8B, lns 19, 47, 75
28	Fuel Retention	-				Sch8B, lns 15, 43, 71
29	MGT Cash Out Imbalance	2,766				Sch8B, lns 25, 53, 81
30	Unnominated Seasonal Gas Payback	-				
31	NNS Injection Loss	-				Sch8B, lns 26, 54, 82
32	Backup Supply Sales	(49,622)				Sch8B, lns 27, 55, 83
33	Storage Injection	(1,236)	$	2.1561		Sch8B, lns 8, 36, 64
34	Net Purchases	3,167,934				
		Volumes in		Commodity		
	February 2021	Dths		Cost per Dth	% of Total	
35	Intraday Purchases	88,367	$	11.3441	3.34%	Sch8C, lns 14, 42, 70
36	Index Purchases	1,033,533	$	2.4324	39.03%	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	880,356	$	(10.4604)	33.25%	Sch8C, lns 16, 44, 72
38	Boil off/Peaking Purchases	136,635	$	2.7600	5.16%	Sch8C, lns 24, 52, 80
39	Unnominated Seasonal Gas Purchases	-			0.00%	
40	Storage Withdrawal	508,756	$	2.7464	19.22%	Sch8C, lns 9, 37, 65
41	Total Purchases	2,647,647			100.00%	
42	REX Winter Purchases	85,000				Sch8C, lns 22,50,78
43	Third Party	3				Sch8C, lns 23, 51, 79
44	Imbalance	8,569				Sch8C, lns 19, 47, 75
45	Fuel Retention	-				Sch8C, lns 15, 43, 71
46	MGT Cash Out Imbalance	(216)				Sch8C, lns 25, 53, 81
47	Unnominated Seasonal Gas Payback					
48	NNS Injection Loss	-				Sch8C, lns 26, 54, 82
49	Backup Supply Sales	(83,164)				Sch8C, lns 27, 55, 83
50	Storage Injection	(225)	$	(1.9867)		Sch8C, lns 8, 36, 64
51	Net Purchases	2,657,614				

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

Line No.	Description	December 2020 Dth	December 2020 Rate	December 2020 Amount	January 2021 Dth	January 2021 Rate	January 2021 Amount	February 2021 Dth	February 2021 Rate	February 2021 Amount
1	Panhandle Eastern Pipeline - Demand	33,463	$ 13.3194	$ 445,707	33,463	$ 13.3194	$ 445,707	33,463	$ 13.0129	$ 435,449
2	MGT Pipeline - Demand	1,395,000	0.0620	86,504	1,395,000	0.0620	86,504	1,260,000	0.0687	86,504
3	Indiana Municipal Gas Purchasing Authority - Demand	17,090	18.6272	318,338	17,090	18.6122	318,082	17,090	16.8096	287,276
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	(388)	0.7577	(294)	(1,236)	0.7330	(906)	(225)	0.9244	(208)
7	Texas Gas Transmission - Unnominated Withdrawal	483,858	0.3764	182,124	296,323	0.3872	114,736	508,756	0.4072	207,165
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	-	-	(243,750)	-	-	(243,750)	-	-	(243,750)
12	REX Winter Purchases	25,000	11.4799	286,997	25,000	11.4799	286,997	25,000	11.4799	286,997
13	Panhandle Eastern/MGT Pipeline/Rockies Express East- Commodity	310,000	1.7450	540,960	620,000	2.0866	1,293,692	-	-	-
14	Indiana Municipal Gas Purchasing Authority - Commodity	-	-	-	18,538	2.4199	44,861	12,558	3.5569	44,668
15	Indiana Municipal Gas Purchasing Authority - Prepay Commodity	511,252	2.3773	1,215,392	511,252	2.0871	1,067,050	460,975	2.3332	1,075,545
16	Texas Gas Transmission - Commodity	-	-	-	-	-	-	-	-	-
17	Texas Gas Transmission - Unnominated Injection - Commodity	(388)	2.3840	(925)	(1,236)	2.1537	(2,662)	(225)	(2.3200)	522
18	Texas Gas Transmission - Unnominated Withdrawal - Commodity	483,858	2.5610	1,239,160	296,323	2.5947	768,869	508,756	2.7660	1,407,219
19	Rockies Express - Delivered Supply - (BP PEAK B)	310,000	2.6885	833,435	310,000	2.2595	700,445	280,000	2.5525	714,700
20	Rockies Express - Delivered Supply - (BP PEAK A)	310,000	2.5610	793,910	310,000	2.1320	660,920	280,000	2.4250	679,000
21	Intra-DayPurchases	-	-	-	-	-	-	88,367	11.3441	1,002,446
22	TGT-PEPL-MGT-REX- Swing Gas (Commodity)	820,848	2.4668	2,024,853	231,441	2.6174	605,765	880,356	(10.4604)	(9,208,909)
23	Hedging Transaction Cost	-	-	147,363	-	-	82,303	-	-	289,115
24	Imbalance	(13,087)	2.4097	(31,536)	49	2.2041	108	8,569	(1.3431)	(11,509)
25	REX Winter Purchases	702,951	2.3523	1,653,531	775,000	2.0145	1,561,218	85,000	5.1171	434,952
26	Third Party Supplier Balancing Gas Costs	(125,960)		(458,094)	86,856		142,553	3		(132,425)
27	Boil-off / Peaking purchase	57,639	2.8960	166,923	60,360	2.4670	148,908	136,635	2.7600	377,113
28	MGT Cash Out Imbalance	-	-	-	-	-	-	-	-	-
29	Fuel Retention Volumes	-	-		-	-		-	-	-
30	NSS Injection fuel loss	-		-	-			-		-
31	Backup Supply Sales	(116,445)	2.5059	(291,804)	(49,622)	2.3978	(118,986)	(83,164)	2.9117	(242,150)
32	Current Pipeline Rate Per Dth	3,250,668	$3.1138	$ 10,122,041	3,168,961	$2.8955	$ 9,175,661	2,657,830	($0.5200)	$ (1,382,065)
33	Current Commodity Rate Per Dth	3,250,668	$2.4097	$7,833,168	3,168,961	$2.1947	$6,955,044	2,657,830	($1.3431)	(3,569,713)

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

Line No.	Description	November 2020 Dth	November 2020 Rate	November 2020 Amount	December 2020 Dth	December 2020 Rate	December 2020 Amount	January 2021 Dth	January 2021 Rate	January 2021 Amount
1	Panhandle Eastern Pipeline - Demand	33,463	$ 13.2172	$ 442,288	33,463	$ 13.3194	$ 445,707	33,463	$ 13.3194	$ 445,707
2	MGT Pipeline - Demand	1,350,000	0.0641	86,504	1,395,000	0.0620	86,504	1,395,000	0.0620	86,504
3	Indiana Municipal Gas Purchasing Authority - Demand	17,090	18.1425	310,056	17,090	18.6272	318,338	17,090	18.6122	318,082
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	0.3543	401,604
6	Texas Gas Transmission - Unnominated Injections	(58,787)	0.8341	(49,034)	(388)	0.7577	(294)	(1,236)	0.7330	(906)
7	Texas Gas Transmission - Unnominated Withdrawal	281,601	0.3802	107,065	483,858	0.3764	182,124	296,323	0.3764	111,536
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	-	-	(243,750)	-	-	(243,750)	-	-	(243,750)
12	REX Winter Purchases	16,000	11.4799	183,678	25,000	11.4799	286,997	25,000	11.4799	286,997
13	Panhandle Eastern/MGT Pipeline/Rockies Express East- Commodity	-	-	260	310,000	1.7450	540,960	620,000	2.0866	1,293,692
14	Indiana Municipal Gas Purchasing Authority - Commodity	17,940	2.8347	50,854	-	-	-	18,538	2.4199	44,861
15	Indiana Municipal Gas Purchasing Authority - Prepay Commodity	494,760	2.5016	1,237,710	511,252	2.3773	1,215,392	511,252	2.0871	1,067,051
16	Texas Gas Transmission - Commodity	-	-	-	-	-	-	-	-	-
17	Texas Gas Transmission - Unnominated Injection - Commodity	(58,787)	2.1977	(129,196)	(388)	2.3918	(928)	(1,236)	2.2144	(2,737)
18	Texas Gas Transmission - Unnominated Withdrawal - Commodity	281,601	2.6980	759,760	483,858	2.5610	1,239,160	296,323	2.5610	758,883
19	Rockies Express - Delivered Supply - (BP PEAK B)	300,000	2.7885	836,550	310,000	2.6885	833,435	310,000	2.2595	700,445
20	Rockies Express - Delivered Supply - (BP PEAK A)	299,888	2.6620	798,300	310,000	2.5610	793,910	310,000	2.1320	660,920
21	Intra-DayPurchases	-	-	-	-	-	-	-	-	-
22	TGT-PEPL-MGT-REX- Swing Gas (Commodity)	693,259	1.6577	1,149,182	820,848	2.4668	2,024,853	231,441	2.6174	605,765
23	Hedging Transaction Cost	-	-	(54,911)	-	-	147,363	-	-	82,303
24	Imbalance	(2,656)	2.2523	(5,982)	(10,998)	2.4178	(26,591)	49	2.2449	110
25	REX Winter Purchases	257,563	1.8832	485,046	697,069	2.3891	1,665,356	775,000	2.2412	1,736,937
26	Third Party Supplier Balancing Gas Costs	299,368		663,679	(125,960)		(458,094)	86,856		142,553
27	Boil-off / Peaking purchase	40,121	2.9960	120,203	57,639	2.8960	166,923	60,360	2.4670	148,908
28	MGT Cash Out Imbalance	480	2.5479	1,223	2,766	2.5000	6,915	(216)	2.5926	(560)
29	Fuel Retention Volumes	-	-	-	-	-	-	-	-	-
30	NSS Injection fuel loss	(17)	-	-	-	-	-	-	-	-
31	Backup Supply Sales	(49,261)	2.3211	(114,341)	(116,445)	2.5059	(291,804)	(49,622)	2.3978	(118,986)
32	Current Pipeline Rate Per Dth	2,574,259	$3.0378	$ 7,820,047	3,249,641	$3.1221	$ 10,145,723	3,168,745	$2.9468	$ 9,337,562
33	Current Commodity Rate Per Dth	2,574,259	$2.2524	5,798,337	3,249,641	$2.4178	7,856,850	3,168,745	$2.2470	7,120,145

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

Citizens Gas
PEPL Unnominated Quantities Cost
December 2020

Line No.		A Compres. Fuel-Dth	B Demand Costs	C Volumes	D Storage Rates	E Compres. Fuel	F Total
	Accrual -November, 2020						
	PEPL						
1	Demand Cost		$674,143				$674,143
2	PEPL Injection fuel cost	157				477	477
3	PEPL Injection (Net)			5,659	$0.0020		11
4	(100-day Firm) (Midpoint)			5,769	0.0094		54
5	PEPL Withdrawal fuel cost	4,624				9,923	9,923
6	PEPL Withdrawal (Midpoint)			201,673	0.0020		403
7	(100-day Firm) (Net)			200,059	0.0094		1,881
8	PEPL - Sub Total		$674,143			$10,400	$686,892
	Actual -November, 2020						
	PEPL						
9	Demand Cost		$674,143				$674,143
10	PEPL Injection fuel cost	157				477	477
11	PEPL Injection (Net)			5,659	0.0020		11
12	(100-day Firm) (Midpoint)			5,769	0.0094		54
13	PEPL Withdrawal fuel cost	4,624				9,923	9,923
14	PEPL Withdrawal (Midpoint)			201,673	0.0020		403
15	(100-day Firm) (Net)			200,059	0.0094		1,881
16	PEPL - Sub Total		$674,143			$10,400	$686,892
	Accrual - December, 2020						
	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	9,546				20,494	20,494
22	PEPL Withdrawal (Midpoint)			416,390	0.0020		833
23	(100-day Firm) (Net)			413,056	0.0094		3,883
24	PEPL - Sub Total		$687,317			$20,494	$712,527
25	Total (line 24 + line 16 - line 8)		$687,317			$20,494	$712,527
26	PEPL - Balancing Costs (ln 25 * 9%)						$64,127
27	PEPL - Retail Costs (ln 25 * 91%)						$648,400

Citizens Gas
PEPL Unnominated Quantities Cost
January 2021

Line No.		A Compres. Fuel-Dth	B Demand Costs	C Volumes	D Storage Rates	E Compres. Fuel	F Total
	Accrual - December, 2020						
	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	9,546				20,494	20,494
6	PEPL Withdrawal (Midpoint)			416,390	0.0020		833
7	(100-day Firm) (Net)			413,056	0.0094		3,883
8	PEPL - Sub Total		$687,317			$20,494	$712,527
	Actual - December, 2020						
	PEPL						
9	Demand Cost		$687,317				$687,317
10	PEPL Injection fuel cost	-				-	-
11	PEPL Injection (Net)			-	0.0020		-
12	(100-day Firm) (Midpoint)			-	0.0094		-
13	PEPL Withdrawal fuel cost	9,546				20,494	20,494
14	PEPL Withdrawal (Midpoint)			416,390	0.0020		833
15	(100-day Firm) (Net)			413,056	0.0094		3,883
16	PEPL - Sub Total		$687,317			$20,494	$712,527
	Accrual - January, 2021						
	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	19,677				42,245	42,245
22	PEPL Withdrawal (Midpoint)			858,623	0.0020		1,717
23	(100-day Firm) (Net)			851,755	0.0094		8,006
24	PEPL - Sub Total		$687,317			$42,245	$739,285
25	Total (line 24+ line 16 - line 8)		$687,317			$42,245	$739,285
26	PEPL Balancing Costs (ln 25 * 9%)						$66,536
27	PEPL Retail Costs (ln 25 * 91%)						$672,749

Citizens Gas
PEPL Unnominated Quantities Cost
February 2021

Line No.		A Compres. Fuel-Dth	B Demand Costs	C Volumes	D Storage Rates	E Compres. Fuel	F Total
	Accrual - January, 2021						
	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	19,677				42,245	42,245
6	PEPL Withdrawal (Midpoint)			858,623	0.0020		1,717
7	(100-day Firm) (Net)			851,755	0.0094		8,006
8	PEPL Total		$687,317			$42,245	$739,285
	Actual - January, 2021						
	PEPL						
9	Demand Cost		$687,317				$687,317
10	PEPL Injection Fuel Cost	-				-	-
11	PEPL Injection (Net)			-	$0.0020		-
12	(100-day Firm) (Midpoint)			-	0.0094		-
13	PEPL Withdrawal Fuel Cost	19,677				42,245	42,245
14	PEPL Withdrawal (Midpoint)			858,623	0.0020		1,717
15	(100-day Firm) (Net)			851,755	0.0094		8,006
16	PEPL Total		$687,317			$42,245	$739,285
	Accrual -February, 2021						
	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	31,033				66,625	66,625
22	PEPL Withdrawal (Midpoint)			1,354,006	0.0020		2,708
23	(100-day Firm) (Net)			1,343,175	0.0094		12,626
24	PEPL Total		$647,794			$66,625	$729,753
25	Total (line 24 + line 16 - line 8)		$647,794			$66,625	$729,753
26	PEPL Balancing Costs (ln 25 * 9%)						$65,678
27	PEPL Retail Costs (ln 25 * 91%)						$664,075

Citizens Gas
Cost of Gas Injections and Withdrawals
For the period December 1, 2020 - February 28, 2021

		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 2020									
1	UGS	26,108	1,243,332	$17,990	$63,372	$573,798	$2,375,510	$555,808	$2,312,138	$2,867,946
2	PEPL	-	413,056	(17)	20	207,478	679,312	207,495	679,292	886,787
3	Subtotal	26,108	1,656,388	$17,973	$63,392	$781,276	$3,054,822	$763,303	$2,991,430	$3,754,733
	January 2021									
4	UGS	-	1,621,144	$5	$212	$749,455	$3,100,600	$749,450	$3,100,388	$3,849,838
5	PEPL	-	851,755	-	-	427,837	1,400,796	427,837	1,400,796	1,828,633
6	Subtotal	-	2,472,899	5	212	1,177,292	4,501,396	1,177,287	4,501,184	5,678,471
	February 2021									
7	UGS	30,144	1,794,797	$24,811	($40,486)	$830,094	$3,432,549	$805,283	$3,473,035	$4,278,318
8	PEPL	-	1,343,175	-	-	674,676	2,208,986	674,676	2,208,986	2,883,662
9	Subtotal	30,144	3,137,972	24,811	(40,486)	1,504,770	5,641,535	1,479,959	5,682,021	7,161,980
10	Grand Total	56,252	7,267,259	$42,789	$23,118	$3,463,338	$13,197,753	$ 3,420,549	$ 13,174,635	$ 16,595,184

Citizens Gas
Demand Allocation of Injections and Withdrawals
From PEPL
For Three Months Ending February 28, 2021

		A	B	C	D	E	F
Line No.		Volume DTH	Demand Cost	Commodity Cost	Total Cost	Total $/DTH	Commodity $/DTH
1	Beginning balance @ December 2020	5,892,177	$2,959,259	$9,690,479	$12,649,738	$2.1469	$1.6446
2	Less: Net W/D @ avg. unit cost						
3	Prior mo. accrual reversal	200,059	100,410	328,917	429,327	2.1460	1.6441
4	Prior mo. actual	(200,059)	(100,410)	(328,917)	(429,327)	2.1460	1.6441
5	Current mo. accrual	(413,056)	(207,478)	(679,312)	(886,790)	2.1469	1.6446
6	Add: Gross Injections						
7	Prior mo. accrual reversal	(5,816)	(4,585)	(13,080)	(17,665)	3.0373	2.2490
8	Prior mo. actual	5,816	4,568	13,100	17,668	3.0378	2.2524
9	Current mo. accrual	-	-	-	-	-	-
10	Less: Compressor Fuel						
11	Prior mo. accrual reversal - W/D	4,624	2,321	7,602	9,923	2.1460	1.6441
12	Prior mo. accrual reversal - Injections	157	124	353	477	3.0373	2.2490
13	Prior mo. Actual - W/D	(4,624)	(2,321)	(7,602)	(9,923)	2.1460	1.6441
14	Prior mo. Actual - Injections	(157)	(123)	(354)	(477)	3.0378	2.2524
15	Current mo. Accrual -Inj	-	-	-	-	-	-
16	Current mo. Accrual-W/D	(9,546)	(4,795)	(15,699)	(20,494)	2.1469	1.6446
17	Beginning balance @ January 2021	5,469,575	2,746,970	8,995,487	11,742,457	2.1469	1.6446
18	Less: Net W/D @ avg. unit cost						
19	Prior mo. accrual reversal	413,056	207,478	679,312	886,790	2.1469	1.6446
20	Prior mo. actual	(413,056)	(207,478)	(679,312)	(886,790)	2.1469	1.6446
21	Current mo. accrual	(851,755)	(427,837)	(1,400,796)	(1,828,633)	2.1469	1.6446
22	Add: Gross Injections						
23	Prior mo. accrual reversal	-	-	-	-	-	-
24	Prior mo. actual	-	-	-	-	-	-
25	Current mo. accrual	-	-	-	-	-	-
26	Less: Compressor Fuel						
27	Prior mo. accrual reversal - W/D	9,546	4,795	15,699	20,494	2.1469	1.6446
28	Prior mo. accrual reversal - Inj	-	-	-	-	-	-
29	Prior mo. Actual - W/D	(9,546)	(4,795)	(15,699)	(20,494)	2.1469	1.6446
30	Prior mo. Actual - Injections	-	-	-	-	-	-
31	Current mo. accrual - Inj	-	-	-	-	-	-
32	Current mo. Accrual-W/D	(19,677)	(9,884)	(32,361)	(42,245)	2.1469	1.6446
33	Beginning balance @ February 2021	4,598,143	2,309,249	7,562,330	9,871,579	2.1469	1.6446
34	Less: Net W/D @ avg. unit cost						
35	Prior mo. accrual reversal	851,755	427,837	1,400,796	1,828,633	2.1469	1.6446
36	Prior mo. actual	(851,755)	(427,837)	(1,400,796)	(1,828,633)	2.1469	1.6446
37	Current mo. accrual	(1,343,175)	(674,676)	(2,208,986)	(2,883,662)	2.1469	1.6446
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	19,677	9,884	32,361	42,245	2.1469	1.6446
44	Prior mo. accrual reversal - Inj	-	-	-	-	-	-
45	Prior mo. Actual - W/D	(19,677)	(9,884)	(32,361)	(42,245)	2.1469	1.6446
46	Prior mo. Actual - Injections	-	-	-	-	-	-
47	Current mo. accrual -Inj	-	-	-	-	-	-
48	Current mo. Accrual-W/D	(31,033)	(15,588)	(51,037)	(66,625)	2.1469	1.6446
49	Ending balance @ February 28, 2021	3,223,935	1,618,985	5,302,307	6,921,292	$2.1468	$1.6447

Citizens Gas
Demand Allocation of Injections and Withdrawals
From UGS
For Three Months Ending February 28, 2021

		A	B	C	D	E	F
Line No.		Volume	Demand Cost	Commodity Cost	Total Cost	Total $/Unit	Commodity $/Unit
1	Beginning balance @ December 2020	8,087,547	$3,732,614	$15,451,765	$19,184,379	$2.3721	$1.9106
2	Add: Gross Injections						
3	Less: Prior mo. accrual	(135,082)	(106,486)	(303,799)	(410,285)	3.0373	2.2490
4	Add: Prior mo. actual	135,082	106,093	304,259	410,352	3.0378	2.2524
5	Add: Current mo. accrual	26,108	18,383	62,912	81,295	3.1138	2.4097
6	Less: Net Withdrawals						
7	Prior mo. accrual reversal	104,727	47,756	199,484	247,240	2.3608	1.9048
8	Prior mo. Actual	(104,727)	(47,756)	(199,484)	(247,240)	2.3608	1.9048
9	Current mo. accrual	(1,243,332)	(573,798)	(2,375,510)	(2,949,308)	2.3721	1.9106
10	Less: Blowoff						
11	Current mo. Blowoff	(6,087)	(2,809)	(11,630)	(14,439)	2.3721	1.9106
12	Beginning balance @ January 2021	6,864,236	3,173,997	13,127,997	16,301,994	2.3749	1.9125
13	Add: Gross Injections						
14	Less: Prior mo. accrual	(26,108)	(18,383)	(62,912)	(81,295)	3.1138	2.4097
15	Add: Prior mo. actual	26,108	18,388	63,124	81,512	3.1221	2.4178
16	Add: Current mo. accrual	-	-	-	-	-	-
17	Less: Net Withdrawals						
18	Prior mo. accrual reversal	1,243,332	573,798	2,375,510	2,949,308	2.3721	1.9106
19	Prior mo. actual	(1,243,332)	(573,798)	(2,375,510)	(2,949,308)	2.3721	1.9106
20	Current mo. accrual	(1,621,144)	(749,455)	(3,100,600)	(3,850,055)	2.3749	1.9126
21	Less: Blowoff						
22	Current mo. Blowoff	(8,106)	(3,747)	(15,504)	(19,251)	2.3749	1.9126
23	Beginning balance @ February 2021	5,234,986	2,420,800	10,012,105	12,432,905	2.3750	1.9125
24	Add: Injections						
25	Less: Prior mo. accrual	-	-	-	-	-	-
26	Prior mo. actual	-	-	-	-	-	-
27	Current mo. accrual	30,144	24,811	(40,486)	(15,675)	(0.5200)	(1.3431)
28	Less: Withdrawals						
29	Prior mo. accrual reversal	1,621,144	749,455	3,100,600	3,850,055	2.3749	1.9126
30	Prior mo. actual	(1,621,144)	(749,455)	(3,100,600)	(3,850,055)	2.3749	1.9126
31	Current mo. Accrual	(1,794,797)	(830,094)	(3,432,549)	(4,262,643)	2.3750	1.9125
32	Less: Blowoff						
33	Current mo. Blowoff	(8,823)	(4,081)	(16,874)	(20,955)	2.3750	1.9125
34	Ending balance @ February 28, 2021	3,461,510	1,611,436	6,522,196	8,133,632	$2.3497	$1.8842

Citizens Gas
Determination of "Unaccounted For" Percentage and Manufacturing / Steam Division Costs
For Three Months Ending February 28, 2021

Line No.		A December 2020	B January 2021	C February 2021	D Total
1	Volume of pipeline gas purchases - Dths (See Schedule 8)	3,257,030	3,167,934	2,657,614	9,082,578
2	Gas (injected into) withdrawn from storage (See Schedule 10)	1,630,280	2,472,899	3,107,828	7,211,007
3	Transported gas received	2,183,463	2,300,820	2,057,269	6,541,552
4	Transported gas (injected into) withdrawn from storage	0	0	0	0
5	Reverse transport imbalance already on Sch 8	125,960	(86,856)	(3)	39,101
6	Total volume supplied	7,196,733	7,854,797	7,822,708	22,874,238
7	Less: Gas Division usage	(11,665)	(12,647)	(14,928)	(39,240)
8	Total volume available for sale	7,185,068	7,842,150	7,807,780	22,834,998
9	Retail Volume of gas sold - Dths (Schedule 6, Page 3, ln 26)	4,823,417	5,585,265	5,762,107	16,170,789
10	Total Transport Usage (Sch 6 , Page 3, ln 27 + ln 28)	2,261,524	2,130,707	2,114,908	6,507,139
11	"Unaccounted for" gas (ln 8- ln 9 - ln 10)	100,127	126,178	(69,235)	157,070
12	Percentage of "unaccounted for" gas (line 11 / line 8)	1.39%	1.61%	-0.89%	0.69%

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

	Quarter	A Sales % (All GCA Classes)	B Refund (line 6 * column A)
7	June 2021 - August 2021	5.3500% (Sch. 2B, ln 18)	$0
8	Sept., 2021 - Nov., 2021	13.5927% (Sch. 2B, ln 19)	$0
9	Dec., 2021- Feb., 2022	54.9278% (Sch. 2B, ln 20)	$0
10	March 2022 - May 2022	26.1295% (Sch. 2B, ln 21)	$0
11	Total		$0

Calculation of Refund to be Returned in this GCA

12	Refund from Cause No. 37399-GCA 147	$0
13	Refund from Cause No. 37399-GCA 148	0
14	Refund from Cause No. 37399-GCA 149	40,033
15	Refund from this Cause (line 7)	0
16	Total to be refunded in this Cause (Sum of lines 12 through 15)	$40,033

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., 2020 Total Gas Supply Variance (Sch 6A, pg. 1,ln 16)	(1,881)	(111,238)	7,565	(1,767)	0	(107,321)
2	Jan., 2021 Total Gas Supply Variance (Sch 6B, pg. 1, ln 16)	(4,552)	(740,701)	(1,312)	(170,492)	0	(917,057)
3	Feb, 2021 Total Gas Supply Variance (Sch 6C, pg. 1, ln 16)	(41,833)	(7,596,285)	(119,690)	(2,860,546)	0	(10,618,354)
4	Total Net Write Off Gas Cost Variance (over)/under recover (Sch 12C, ln19)	(820)	(85,083)	(788)	(5,298)	280	(91,709)
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)	($49,086)	($8,533,307)	($114,225)	($3,038,103)	$280	(11,734,441)
	Distribution of variances to quarters by rate class						
7	First quarter Total Gas Supply Variance (ln 6 * Sch 2B, ln 18)	($4,593)	($378,871)	($33,960)	($188,957)	$0	($606,381)
8	Second quarter Total Gas Supply Variance (ln 6 * Sch 2B, ln 19)	(8,402)	(1,164,327)	(32,632)	(376,588)	0	(1,581,949)
9	Third quarter Total Gas Supply Variance (ln 6 * Sch 2B, ln 20)	(24,718)	(4,720,898)	(23,382)	(1,706,989)	0	(6,475,987)
10	Fourth quarter Total Gas Supply Variance (ln 6 * Sch 2B, ln 21)	(11,373)	(2,269,211)	(24,251)	(765,569)	0	(3,070,404)
	Calculation of variances for this Cause						
11	Cause No. 37399 - GCA 147 Total Gas Supply Variance (Sch 12B pg 1, ln 10)	(691)	(19,640)	(9,947)	(15,965)	0	(46,243)
12	Cause No. 37399 - GCA 148 Total Gas Supply Variance (Sch 12B pg 1, ln 9)	(699)	(27,980)	(13,011)	(24,116)	0	(65,806)
13	Cause No. 37399 - GCA 149 Total Gas Supply Variance (Sch 12B pg 1, ln 8)	(881)	(69,351)	(7,365)	(49,631)	0	(127,228)
14	This Cause Total Gas Supply Variance (line 7)	(4,593)	(378,871)	(33,960)	(188,957)	0	($606,381)
15	Total Gas Supply Variance to be included in GCA (Over)/Underrecovery (ln 11 + ln 12 + ln 13 + ln 14)	($6,864)	($495,842)	($64,283)	($278,669)	$0	($845,658)

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., 2020 Total Balancing Demand Cost Variance (Sch 6A, pg. 2, ln 25)	($16)	($7,807)	($593)	($4,762)	$1,422	$1,772	($9,984)
2	Jan., 2021 Total Balancing Demand Cost Variance (Sch 6B, pg. 2, ln 25)	($19)	($7,962)	($726)	($5,926)	$1,431	$343	($12,859)
3	Feb, 2021 Total Balancing Demand Cost Variance (Sch 6C, pg. 2, ln 25)	$8	($3,289)	($258)	($1,410)	$1,419	($444)	($3,974)
4	Balancing Demand Cost Variance (Line 1 + Line 2 + Line 3)	($27)	($19,058)	($1,577)	($12,098)	$4,272	$1,671	($26,817)
	Distribution of variances to quarters by rate class							
5	First quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 18)	($2)	($847)	($354)	($906)	$768	$419	($922)
6	Second quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 19)	($5)	($2,600)	($392)	($1,977)	$997	$438	($3,539)
7	Third quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 20)	($14)	($10,543)	($449)	($6,247)	$1,473	$369	($15,411)
8	Fourth quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 21)	($6)	($5,068)	($382)	($2,968)	$1,034	$445	($6,945)
	Calculation of variances for this Cause							
9	Cause No. 37399 - GCA 147 Total Balancing Demand Cost Variance (Sch 12B, pg. 2, ln 8)	($2)	($429)	$24	($367)	$972	$6,023	$6,221
10	Cause No. 37399 - GCA 148 Total Balancing Demand Cost Variance (Sch 12B, pg. 2, ln 7)	($21)	($904)	($2,473)	($1,546)	($403)	$5,645	$298
11	Cause No. 37399 - GCA 149 Total Balancing Demand Cost Variance (Sch 12B, pg. 2, ln 6)	($26)	($1,654)	($1,969)	($1,927)	$68	$3,151	($2,357)
12	This Cause Total Current Balancing Demand Cost Variance (line 5)	($2)	($847)	($354)	($906)	$768	$419	($922)
13	Total Balancing Demand Cost Variance to be included in GCA (Over)/Underrecovery (ln 9 + ln 10 + ln 11 + ln 12)	($51)	($3,834)	($4,772)	($4,746)	$1,405	$15,238	$3,240

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

Line No.		A	B	C	D	E	F
	December 2020						
		D1	**D2**	**D3**	**D4**	**D5**	**Total**
1	Actual Retail Sales in Dth (Sch 6A, line 26)	20,713	3,589,273	53,192	1,160,239	-	4,823,417
2	Net Write-Off Gas Cost Component per Dth Cause No. 37399-GCA 148, MPU Sch 1 pg 2, ln 23	$0.0380	$0.0380	$0.0070	$0.0100	$0.0000	
3	Actual Net Write Off Gas Cost Recovery (ln 1 * ln 2)	$787	$136,392	$372	$11,602	$0	$149,153
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)	$670	$145,040	$411	$13,329	$111	$159,561
6	Net Write Off Gas Cost Variance (over)/under recovery (ln 5 - ln 3)	**($117)**	**$8,648**	**$39**	**$1,727**	**$111**	**$10,408**
	January 2021						
7	Actual Retail Sales in Dth (Sch 6B, line 26)	23,189	4,062,595	44,340	1,455,141	-	5,585,265
8	Net Write-Off Gas Cost Component per Dth Cause No. 37399-GCA 148, MPU Sch 1 pg 2, ln 23	$0.0360	$0.0380	$0.0120	$0.0090	$0.0000	
9	Actual Net Write Off Gas Cost Recovery (ln 7 * ln 8)	$835	$154,379	$532	$13,096	$0	$168,842
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)	$717	$155,085	$440	$14,253	$119	$170,614
12	Net Write Off Gas Cost Variance (over)/under recovery (ln 11 - ln 9)	**($118)**	**$706**	**($92)**	**$1,157**	**$119**	**$1,772**
	February 2021						
13	Actual Retail Sales in Dth (Sch 6C, line 26)	22,222	4,105,806	54,175	1,579,904	-	5,762,107
14	Net Write-Off Gas Cost Component per Dth Cause No. 37399-GCA 148, MPU Sch 1 pg 2, ln 23	$0.0400	$0.0390	$0.0170	$0.0090	$0.0000	
15	Actual Net Write Off Gas Cost Recovery (ln 13 * ln 14)	$889	$160,126	$921	$14,219	$0	$176,155
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)	$304	$65,689	$186	$6,037	$50	$72,266
18	Net Write Off Gas Cost Variance (over)/under recovery (ln 17 - ln 15)	**($585)**	**($94,437)**	**($735)**	**($8,182)**	**$50**	**($103,889)**
19	Total Net Write Off Gas Cost Variance (over)/under recovery (ln 6 + ln 12 + ln 18)	($820)	($85,083)	($788)	($5,298)	280	($91,709)