OCA Statement No. 3

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
v.	)	Docket No. R-2018-3006818
	)	
	)	
Peoples Natural Gas Company LLC	)	

PUBLIC

DIRECT TESTIMONY
OF
GLENN A. WATKINS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

APRIL 29, 2019

TABLE OF CONTENTS

PAGE

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 1503 Santa Rosa Road, Suite 130, Richmond, VA 23229.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am a President and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with offices in Richmond, Virginia. Except for a six month period during 1987 in which I was employed by Old Dominion Electric Cooperative, as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my career at Technical Associates, I have conducted marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities, and have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, Montana, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. A more complete description of my education and experience as well as a list of my prior testimonies is provided in my Schedule GAW-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. Over the last 20-plus years, I have provided testimony before this Commission on issues concerning cost allocations, rate design, cost of capital, and revenue requirement on more than 50 occasions.

Q. HAVE YOU PARTICIPATED IN OTHER EQUITABLE AND PEOPLES REGULATORY PROCEEDINGS?

A. Yes. I provided expert testimony in Equitable's last general rate case (Docket No. R-2008-2029325) which occurred before the merger with Peoples as well as the Peoples Service Expansion Tariff case (Docket No. R-2014-2429613).

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

A. Technical Associates, Inc. has been retained by the OCA to evaluate the level of discounted rates offered to certain Large Commercial and Industrial customers as well as the reasonableness of Peoples Natural Gas Company's ("Peoples" or "Company") natural gas class cost of service studies, proposed distribution of revenues by customer class and residential rate design. Finally, I will provide my recommendation regarding the Company's proposed consolidation of rates between its Peoples and Equitable Divisions. The purpose of my direct testimony is to provide comments regarding my analysis of the Company's proposals and to present my findings and recommendations based on the studies I have undertaken in this matter.

II. <u>CLASS COST OF SERVICE</u>

A. Concepts and Methods

Q. PLEASE BRIEFLY EXPLAIN THE CONCEPT OF A CLASS COST OF SERVICE STUDY ("CCOSS") AND ITS PURPOSE IN A RATE PROCEEDING.

A. Generally there are two types of cost of service studies used in public utility ratemaking: marginal cost studies and embedded, or fully allocated, cost studies. Consistent with the practices of this Commission, Peoples' has utilized a traditional embedded cost of service study for purposes of establishing the overall revenue requirement in this case, as well as for class cost of service purposes.

Embedded class cost of service studies are also referred to as fully allocated cost studies because the majority of a public utility's plant investment and expense is incurred to serve all customers in a joint manner. Accordingly, most costs cannot be specifically attributed to a particular customer or group of customers. To the extent that certain costs can be specifically attributed to a particular customer or group of customers, these costs are directly assigned in the CCOSS. The costs jointly incurred to serve all or most customers; therefore, must be allocated across specific customers or customer rate classes.

It is generally accepted that to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although the cost analyst strives to abide by this concept to the greatest extent practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors, and must be subjectively assigned or allocated to customer rate classes. With regard to those costs in which cost causation can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor; e.g., peak demand, energy or throughput usage, number of customers, etc.

Q. IN YOUR OPINION, HOW SHOULD THE RESULTS OF A CCOSS BE UTILIZED IN THE RATEMAKING PROCESS?

A. Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive individual costs. These disagreements can and do arise as a result of the quality of data and level of detail available from financial records. There are also fundamental differences in opinions regarding the cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned previously, cost causation factors cannot be realistically ascribed to some costs such that subjective decisions are required.

In these regards, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS only as a guide, with the results being used as one of many tools to assign class revenue responsibility.

Q. HAVE THE HIGHER COURTS OPINED ON THE USEFULNESS OF COST ALLOCATIONS FOR PURPOSES OF ESTABLISHING REVENUE RESPONSIBILITY AND RATES?

A. Yes. In an important regulatory case involving Colorado Interstate Gas Company and the Federal Power Commission (predecessor to FERC), the United States Supreme Court stated:

> "But where, as here, several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[1]"

Q. DOES YOUR OPINION, AND THE FINDINGS OF THE U.S. SUPREME COURT, IMPLY THAT COST ALLOCATIONS SHOULD PLAY NO ROLE IN THE RATEMAKING PROCESS?

A. Not at all. It simply means that regulators should consider the fact that cost allocation results are not surgically precise and that alternative, yet equally defensible, approaches may produce significantly different results. In this regard, when all cost allocation approaches consistently show that certain classes are over or under contributing to costs and/or profits, there is a strong rationale for assigning smaller or greater percentage rate increases to these classes. On the other hand, if one set of cost allocation approaches show dramatically different results than another approach, caution should be exercised in assigning disproportionately larger or smaller percentage increases to the classes in question.

Q. PLEASE EXPLAIN THE BASIC CONCEPTS OF COST ALLOCATION FOR PUBLIC UTILITIES AND NATURAL GAS LOCAL DISTRIBUTION COMPANIES ("LDCs").

A. As I mentioned earlier, the majority of a LDC's plant investment serves customers in a joint manner. In this regard, the LDC's infrastructure is a system benefiting all customers. If all customers were the same size and had identical usage characteristics, cost

[1] 324 U.S. 581, 589 (1945), 65 S. Ct. 829, 833 (1945).

allocation would be simple (even unnecessary). However, in reality, a utility's customer base is not so simple. Customers (or customer groups) tend to vary greatly in the amount of service required throughout the year such that there are small usage and large usage customers. Therefore, differences in usage should be considered. Because different groups of customers also utilize the system at varying degrees during the year, consideration should also be given to the demands placed on the system during peak usage periods.

Q. WITH REGARD TO NATURAL GAS LOCAL DISTRIBUTION COMPANIES, IS THERE ANY ASPECT OF CLASS COST ALLOCATIONS THAT TENDS TO OVERSHADOW OTHER ISSUES OR IS OFTEN CONTROVERSIAL?

A. Yes. For virtually every natural gas LDC, the largest single rate base item (account) is distribution Mains. Furthermore, several other rate base and operating income accounts are typically allocated to classes based on the previous assignment of distribution Mains. As such, the methods and approaches used to allocate distribution Mains to classes are usually by far the most important (in terms of class rate of return ["ROR"] results) and tend to be the most controversial.

Q. WHAT METHODS ARE COMMONLY USED TO ALLOCATE NATURAL GAS DISTRIBUTION MAINS?

A. While a myriad of cost allocation methods and approaches have been developed, three (3) methods predominate in the natural gas LDC industry: "peak responsibility," "Peak and Average" or "Demand/Commodity," and "Customer/Demand," which I will address shortly in more detail. These methods differ in the criteria used to allocate Mains, as cost allocation analysts do not universally agree on the cost causative factors or drivers influencing Mains investments. There are three (3) criteria generally considered when selecting a Mains cost allocation method: peak demand (whether coincident, non-coincident, actual or design day); annual (average day) usage; and number of customers. Because a LDC system must be capable of supplying gas to its firm customers during peak demand periods (i.e., on very cold days), relative class peak day demands are often considered a good proxy for measuring the cost causation of Mains investment.[2] Annual (or average day) throughput is also often used to allocate Mains as this factor reflects the utilization of a utility's Mains investment. Number of customers is also sometimes considered when allocating Mains. That is, customer counts by class serve as a basis for allocation Mains. Even though annual levels of usage and peak load requirements vary greatly between customer classes (residential versus large industrial), some analysts are of the opinion that customer counts should be considered because at least some infrastructure investment in Mains is required simply to "connect" every customer to the system. With these three criteria identified, various methods weight and utilize these criteria differently within the cost allocation process. In other words, some methods rely on only one criterion while others consider two or more criteria with varying weights given to each factor utilized.

The three most common natural gas LDC cost allocation methods are: the "peak responsibility" method (whether coincident or class non-coincident) in which peak day demands are the only factor utilized to allocate Mains; the "Peak and Average" or "Demand/Commodity" approach in which both peak day and annual (average day) throughput is reflected within the allocation of Mains;[3] and the Customer/Demand method that utilizes a combination of peak day demands and customer counts to assign Mains cost responsibility.

Under the Customer/Demand method, the weights given to class customer counts and peak day demands are determined from a separate analysis using one of two approaches: minimum-size and zero-intercept. The "minimum-size" approach prices the entire system footage of Mains at the cost per foot of the smallest diameter pipe installed. This "minimum-size" cost is then divided by the actual total investment in Mains to determine the weight given to customer counts. One (1) minus the customer percentage is

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[2] Embedded cost allocations are directly concerned only with relative, not absolute, criteria. That is, because embedded cost allocations reflect nothing more than dividing total system costs between classes, it is the relative (percentage) contributors to total system amounts that are relevant.

[3] Under the Peak and Average or Demand/Commodity approach, peak use and annual throughput are either weighted equally or based on system load factor, where load factor is ratio of average daily usage to peak day usage. When using a load factor approach to weight Peak and Average usage, the weighting of average day usage is that of the system load factor while the peak day weight is one minus the system load factor.

then given to the peak day demand within the allocation process. The second approach used to classify and allocate Mains based partially on customers and partially on peak demand is known as the "zero-intercept" method. Under this approach, statistical linear regression techniques are used to estimate the cost of a theoretical "zero size" Main. Similar to the minimum size approach, the cost of this estimated zero size pipe per foot is multiplied by the total system footage and is then divided by total Mains investment to arrive at a customer weighting.

Q. WHICH METHOD, OR METHODS, DID THE COMPANY USE TO ALLOCATE COSTS TO CUSTOMER CLASSES FOR THIS CASE?

A. Company witness Russell A. Feingold conducted his CCOSS utilizing two different Mains cost allocation approaches: one using the Customer/Demand method and another using the Peak and Average approach.

Q. WITH REGARD TO UTILITIES GENERALLY, AND NATURAL GAS LDCs SPECIFICALLY, ARE THERE A COMMON SET OF EXTERNAL FACTORS, OR DRIVERS, USED IN VIRTUALLY EVERY CCOSS?

A. Virtually every utility cost allocation study rests on the analysts' selection of three primary external (exogenous) allocation factors: number of customers; peak demand; and, annual (average day) usage.[4] From these three exogenous factors, a host of internally generated allocation factors are developed based on previously allocated plant and expenses. In this regard, it is important to understand that the relative relationship across classes between these external allocators can be dramatically different.

Q. WITH RESPECT TO PEOPLES, WHAT ARE THE RELATIVE CLASS RELATIONSHIPS OF THESE THREE PRIMARY ALLOCATION FACTORS?

A. The following table shows the relative amounts (percentages) of the three primary external allocation factors (customers, annual throughput, and design day demand) for the combined Peoples/Equitable Divisions:

[4] It should be noted that "weighted" customer counts are often used for certain plant and expense accounts.

TABLE 1

Relative Percentages of Primary Allocation Factors

Allocation Factor	Class			
	RES	SGS	MGS	LGS
Customers	92.59%	6.58%	0.79%	0.04%
Annual MCF	42.95%	8.43%	14.01%	34.61%
Peak Demand (Design Day)	55.87%	11.25%	16.62%	16.25%

As can be seen above, there is a vast difference in the relativities of these external allocation factors, such that the selection of a particular Mains allocation method will significantly affect the assignment of costs across the classes.

Q. IS THERE A PREFERRED METHOD TO ALLOCATE NATURAL GAS DISTRIBUTION MAINS COSTS?

A. Yes. The Peak and Average approach is the most fair and equitable method to assign natural gas distribution Mains costs to the various customer classes. This method recognizes each class's utilization of the Company's facilities throughout the year yet also recognizes that some classes rely upon the Company's facilities (Mains) more than others during peak periods.

Q. HAS THIS COMMISSION PROVIDED GUIDANCE AS TO A PREFERRED APPROACH TO BE USED IN NATURAL GAS LOCAL DISTRIBUTION COMPANY CLASS COST OF SERVICE STUDY?

A. Yes. Based on my experience in other natural gas distribution company rate cases before this Commission, as well as review of Commission Orders in similar cases in which I did not participate, this Commission has a long history of providing guidance as to the appropriate methods or approaches to allocate distribution Mains for natural gas local distribution companies. First, the notion of allocating a portion of Mains investment based on the number of customers has been consistently rejected by this Commission. Second, the Commission has consistently found that the allocation of Mains should consider both peak and annual (average) demands. For example, in its September 2007 Opinion & Order concerning a Philadelphia Gas Works rate case (Docket No. R-00061931),[5] the Commission stated in its Order:

> "Reviewing the record, we find that the allocation of distribution Mains investment costs should be done using both annual and peak demands."[6]

Q. NOTWITHSTANDING THIS COMMISSION'S PRACTICE TO NOT CONSIDER NUMBER OF CUSTOMERS WITHIN THE ALLOCATION OF MAINS, WHAT IS THE RATIONALE TO ALLOCATE MAINS INVESTMENT, AT LEAST PARTIALLY, BASED ON CUSTOMER COUNTS?

A. I am aware of two rationales, or arguments, used to advocate the allocation of natural gas distribution Mains based partially on number of customers. While the conceptual argument has no economic or practical logic in my opinion, the second rationale may produce reasonable results in some instances, but is rarely applicable to natural gas LDCs.

The first rationale used by some analysts is that, because every customer (regardless of size) must be physically connected to the utility's distribution network, there is some minimum level of investment required to simply connect customers to the distribution system. It is certainly true that, unless natural gas is delivered in a portable tank or cylinder, some form of a physical "plumbing" is required to deliver natural gas to each and every end-user.[7] Indeed, this is the very purpose of the distribution system. However, no customer connects to a LDC system simply to be connected but never utilize natural gas, nor do LDCs haphazardly install natural gas Mains where no usage is present or anticipated. Because there is no economic utility (benefit) derived from simply being connected to a system, there is no economic (or cost causative) basis for assigning some value of a LDC's distribution Mains required to simply connect customers.

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[5] This appears to be the most recent litigated natural gas distribution case in Pennsylvania concerning the proper allocation of distribution Mains-related costs.

[6] Pa. PUC v. Philadelphia Gas Works, Docket No. R-00061931, Order, at Page 80.

[7] If natural gas was delivered to end-users in tanks (such as done with propane), there would be no distribution system, or Mains to allocate.

The second rationale used to consider number of customers within the allocation of Mains relates to customer densities and differences in the mix of customers (by class) throughout a utility's service area. Possibly the best way to explain why customer densities may be relevant in the assignment of distribution costs to individual classes is by way of example. Consider two different utilities: a rural electric utility with urban, suburban, and rural service areas and another utility with only urban and suburban customers. With respect to the electric utility with a rural service area, many miles of conductors and associated plant must be installed in order to serve the demands of relatively few customers. Conversely, many more customers are served on a per mile basis for the urban/suburban utility. With respect to the utility with a rural service area, such an allocation based on usage or demand may be unfair if some classes are located mainly in urban or suburban areas, while other classes of customers are located in urban, suburban, and rural areas. As a result, some cost studies classify distribution plant as partially demand-related and partially customer-related.

Q. IN THE ABOVE EXAMPLE, YOU REFERRED TO ELECTRIC UTILITIES INSTEAD OF NATURAL GAS UTILITIES. IS THERE A REASON WHY YOU SELECTED THE ELECTRIC UTILITY INDUSTRY FOR YOUR EXAMPLE?

A. Yes. Although the concepts are the same between electric and natural gas distribution facilities (e.g., conductors are synonymous with Mains), electric utilities are required to serve rural (sparsely populated) areas. Such requirements, however, are **<u>not</u>** in place for natural gas LDCs. Moreover, electric utilities are required to connect all consumers regardless of density or usage. Such is not the case for natural gas LDCs, as their tariffs allow the utility to only connect those customers in areas with sufficient customer densities and usage.

As such, and as a general matter, a Customer/Demand classification of electric distribution facilities could be appropriate given the characteristics of a utility's service area, but are rarely appropriate for natural gas LDCs with more densely populated service areas that are not required to serve all potential residences and businesses.

Q. SHOULD PEAK DAY DEMANDS BE THE ONLY CONSIDERATION WHEN ALLOCATING NATURAL GAS DISTRIBUTION MAINS?

A. No. Perhaps the most fundamental aspect of cost allocation is the desire to reasonably assign costs (plant and expenses) based on cost causation. As indicated earlier, while it is appropriate to consider and reflect class peak demands when allocating distribution Mains, it should not be the only criteria. An LDC system is constructed and is in existence in order to serve the natural gas energy needs of its customers throughout the year. If Peoples' (or any natural gas LDC's) customers only required gas for one day of the year (the so-called peak day), the costs to deliver gas throughout the system would be prohibitively high such that a system would never exist. In other words, Peoples customers' demand and utilize natural gas every day of the year, not just one day out of 365 days. If by chance, a customer did require gas for only one day a year, it would be prohibitively expensive to the Company (and ultimately the customer) to provide service as the investment in Mains would therefore be required to be recovered from a very small amount of natural gas energy (usage) and would be economically unfeasible.

Q. IS PEOPLES' "MAINS EXTENSION" POLICY CONSISTENT WITH THE REALITY THAT CUSTOMERS UTILIZE NATURAL GAS THROUGHOUT THE YEAR AND NOT ON JUST A SINGLE DAY?

A. Yes. When Peoples evaluates a Main extension proposal or project, it considers the maximum load that will be placed on the extension in its determination of the required size of Main as well as the annual margin revenue that will be generated from the usage of natural gas along the extension.

Q. EVEN THOUGH MAINS ARE INSTALLED TO MEET THE NATURAL GAS ENERGY NEEDS OF CUSTOMERS THROUGHOUT THE YEAR AND IT WOULD BE PROHIBITIVELY EXPENSIVE TO SERVE A CUSTOMER FOR ONLY ONE DAY PER YEAR, DOES IT COST MORE TO INSTALL A MAIN WITH HIGHER PEAK DEMANDS PLACED UPON IT THAN ANOTHER SEGMENT WITH LOWER PEAK DAY DEMAND REQUIREMENTS?

A. While this is correct as a broadly general statement, there is not a direct and linear relationship between peak demands (capacity requirements) and costs. This is the most important concept. That is, if one were to consider allocating the cost of Mains based on the physical relationships of peak day demand (load), one must evaluate whether <u>costs</u> increase proportionally and in a linear manner with <u>peak load</u>. In reality, if the peak load on one line segment of Mains is double that of another line segment, the cost of Mains for a higher capacity pipe (to meet these additional costs) may be higher but is not double that of the lower capacity Main. This reality reflects the major shortcoming of the Peak Responsibility method (which allocates Mains entirely on peak day demand) because it is premised on the incorrect assumption that there is a direct and perfectly linear relationship between peak loads (demand), system capacity, and costs. With regard to system capacity, the amount of gas that can be delivered throughout a LDC system is not only a function of the size of pipe(s) but also pressurization of gas within these pipes, and, as well, the presence or absence of looping various segments of the distribution system. In very simple terms, and all else constant, the capacity of pipes increases by a factor of exactly 4 to 1 as the diameter of pipe increases.[8] Therefore, if the size of pipe is doubled, the capacity of the pipe increases by a factor of four. At the same time, the cost of this additional capacity is far less than four times as much.[9]

Additionally, and as important as the geometric capacity of pipe at a given pressure, the amount of gas required to be pushed through a distribution system can be met with larger pipes at lower pressures or smaller pipes at higher pressures. With increases in materials, technology, and pipe coupling improvements, we are seeing that LDCs are replacing their systems with smaller plastic pipes operated at higher pressures. Indeed, a 2-inch plastic pipe operating at 60 pounds per square inch gauge ("psig") has approximately 3.6 times the capacity of a 4-inch plastic line operating at low pressures

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[8] The volume of a cylinder (pipe) is equal to pi (3.14159) x Radius^2 x length. Therefore, it can be seen that as the diameter doubles, the area (volume) of the pipe increases by four times that of the smaller pipe.

[9] The cost of Mains investment reflects the cost of capitalized labor to install the Main plus the cost of materials (the piping). Although the labor cost of installing pipe increases somewhat with larger size pipe, these additional labor costs tend to be much smaller than the capacity added. Similarly, the materials cost of the pipe also increases but by a much smaller percentage than the capacity added.

(less than 1psig). Because the allocation of Mains only concerns the assignment of the pipes costs, there is not a clear relationship between a main segment's capacity (peak load ability) and the cost of that pipe. The relevance of this is that an allocation method that only considers peak load by definition assumes there is a direct and perfectly linear relationship between load (capacity) and the cost of Mains. This assumption is clearly not accurate.

Q. SINCE THERE IS NOT A DIRECT AND LINEAR RELATIONSHIP BETWEEN PEAK LOAD REQUIREMENTS AND THE COST OF MAINS, IS THERE A COST ALLOCATION METHOD THAT REASONABLY REFLECTS THE COST CAUSATION OF MAINS?

A. Yes. When properly applied, the Peak and Average (Demand/Commodity) method reasonably and fairly models the economies of scale reflected in Mains investment. If all customers (and classes) demanded and utilized natural gas at a consistent rate throughout the year, the Peoples/Equitable LDC systems would be comprised of smaller size Mains. Obviously, such is not the case in that the Company's peak (design day) demands are about 3.82 times that of its average day firm service demands.[10] Even though the increased capacity required to serve design day peak loads is almost four times that required for average day loads, the actual cost of Mains is much smaller than this almost 4 to 1 relationship. In fact, it is apparent that the diameters of the Company's Mains are about twice as large as would be required under constant load conditions. However, the incremental cost of this additional capacity (to serve design day loads versus average day loads) is less than a factor of two. This indicates that a cost allocation method which allocates about half of the Company's Mains costs based on average demand and the remaining half on peak demand serves as a reasonable proxy for cost causation and fairly assigns class cost responsibility. To summarize, the allocation of Mains solely on peak demands does not reflect cost causation due to the economies of scale present in meeting

[10] Company CCOSS (Exhibit No. 11). Total design day demand is 1,221,001 MCF, whereas average day demand is 319,267 MCF.

the capacity (design day) needs of the company's distribution system; i.e., as peak demand increases, costs increase at a decreasing rate.

B. Peoples Class Cost of Service Studies

1. Minor Adjustments to Peoples' Peak & Average CCOSS

Q. PLEASE PROVIDE A SUMMARY OF THE COMPANY'S CLASS COST OF SERVICE STUDIES SPONSORED BY WITNESS FEINGOLD.

A. The following table presents a summary of consolidated (Peoples plus Equitable) class rates of return at current rates as calculated by Mr. Feingold:

TABLE 2
Russell Feingold Calculated RORs at Current Rates
(Consolidated Basis)

	Rates of Return		Indexed RORs	
Class	Customer/Demand	P&A	Customer/Demand	P&A
Residential	3.40%	4.96%	74%	108%
Small Gen'l Service	4.60%	3.91%	100%	85%
Med. Gen'l Service	8.80%	4.83%	191%	105%
Large Gen'l Service	10.33%	3.14%	224%	68%
Total Company	4.61%	4.61%	100%	100%

Q. HAVE YOU EXAMINED MR. FEINGOLD'S DETAILED ELECTRONIC CCOSS MODEL?

A. Yes. In response to I&E-RS-14-D, the Company provided electronic copies of the Black & Veatch cost allocation models that incorporate both Mr. Feingold's Customer/Demand and Peak & Average studies.

Q. DO YOU HAVE ANY DISAGREEMENTS WITH THE METHODS IN WHICH MR. FEINGOLD ALLOCATED COSTS TO INDIVIDUAL CLASSES?

A. Yes. As noted earlier, I disagree with Mr. Feingold's Customer/Demand method in which distribution Mains are allocated partially on number of customers and partially on peak (design) day demands. Notwithstanding this disagreement, Mr. Feingold has bifurcated distribution Mains investment between low pressure and regulated pressure pipes. In this regard, Mr. Feingold allocated regulated pressure Mains to all customer classes while he exempted the Large General Service class from any cost responsibility associated with low pressure Mains. I will discuss this significant disagreement in detail later in my testimony.

In addition, I have several minor disagreements with Mr. Feingold's CCOSS model and discovered a couple of minor errors. As noted, these errors and disagreements are relatively minor in nature such that I normally do not identify or discuss such small disagreements. However, because I will recommend a substantive change to Mr. Feingold's P&A approach later in my testimony, I note these disagreements for clarity.

The Black & Veatch CCOSS model is exceptionally complex in that every rate base, revenue, and expense FERC account is first functionalized, then classified, and finally allocated, to individual classes. That is, every FERC account is first placed into multiple "functional" cost categories[11] then each "functional" cost category (by FERC account) is then classified into separate "classification" categories.[12] Finally, each FERC account's "classified" amount (by function) is allocated to individual classes. As a result, the Black & Veatch model separates every FERC account into fifteen separate cost "buckets" before the FERC account is ultimately allocated to individual classes. While this approach of functionalization, classification, and then allocation is not uncommon, in my opinion, Mr. Feingold's shuffling of costs adds unnecessary complexity to the cost allocation process and often results in inconsistencies and/or oversights within the ultimate allocation of costs to individual classes.

With regard to the minor errors discovered in Mr. Feingold's CCOSS model, I observed a minor error in the amount of current non-gas rate revenues assigned to the individual classes. That is, while the total Company non-gas (margin) revenues in Mr. Feingold's CCOSS match the Company's pro forma non-gas (margin) revenues at current

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[11] The Black & Veatch model classifies each FERC account between: gas supply; gathering; storage; transmission; and, distribution.

[12] Each functional category is functionalized between demand, commodity, and customer.

rates as per Filing Exhibit No. 3, Schedule 15, class margin revenues are not the same. While these revenues are known by individual class and can be directly assigned, Mr. Feingold functionalized, classified, and allocated these revenues to rate classes. Somewhere along the way, there is a slight error. A comparison of class margin revenues between the Company's revenue proof and those allocated by Mr. Feingold is presented in the table below:

TABLE 3
Comparison of Non-Gas (Margin) Revenues
(Consolidated Basis)

Class	Company Revenue Proof Exhibit ____	Feingold CCOSS	Difference
Residential	$265,681,853	$265,809,639	$127,786
Small Gen'l Service	$32,006,975	$31,970,304	-$36,671
Med. Gen'l	$42,777,457	$42,728,445	-$49,012
Large Gen'l Service	$36,747,373	$36,705,270	-$42,103
Total Company	$377,213,659	$377,213,659	$0

The second error relates to Mr. Feingold's ultimate allocation of distribution Mains and Services expense (Account 874) that totals $12.199 million. Mr. Feingold attempted to allocate this expense item based on distribution Mains plus Services plant investment. However, it was determined that within his classification routine, Mr. Feingold only included low pressure Mains within the demand classification (i.e., cost related to Mains) and then included the total cost of Services investment. This error resulted in Mr. Feingold not recognizing regulated Mains within his classification and allocation process.[13] This error results in under-allocation of costs to the large volume classes and an over-allocation of costs to the small volume classes.

I also have a few disagreements with the manner in which Mr. Feingold ultimately allocated certain rate base and expense accounts. A description of these disagreements are provided in my Schedule GAW-2. My corrections and minor modifications to Mr.

[13] Specifically, Mr. Feingold's exclusion of regulated Mains resulted in a classification of 52.62% demand-related and 47.38% customer-related when these percentages should be 72.10% demand-related and 27.90% customer-related [($702.395 plus $931.935)/(702.395 + 931.935 + 632.414)].

Feingold's P&A study (before other adjustments) produce similar, but not identical, class rates of return at current rates as shown in the table below:

TABLE 4
Comparison of P&A Rates of Return at Current Rates
Combined Basis
(Before OCA's Other Adjustments)

Class	Feingold	OCA
Residential	4.96%	4.97%
Small Gen'l Service	3.91%	3.82%
Med. Gen'l Service	4.83%	4.65%
Large Gen'l Service	3.14%	3.29%
Total Company	4.61%	4.61%

2. Bifurcation of Distribution Mains

Q. PLEASE EXPLAIN MR. FEINGOLD'S RATIONALE FOR BIFURCATING DISTRIBUTION MAINS BETWEEN LOW PRESSURE AND REGULATED PRESSURE PIPES.

A. According to Mr. Feingold, this bifurcation:

> "treatment reflects the fact that larger customers (primarily industrial customers) included in the Company's Large General Service rate case do not require Peoples' low pressure distribution mains to receive gas utility service. The nature of their gas loads and higher gas delivery pressure requirements dictate that they be served from Peoples' regulated pressure gas distribution system. In fact, because of such gas demand requirements, the customers are not connected to Peoples' low pressure gas distribution system, nor can they be served indirectly through a back-feeding of gas from such facilities."[14]

Q. PLEASE EXPLAIN WHY YOU DISAGREE WITH MR. FEINGOLD'S BIFURCATION OF DISTRIBUTION MAINS BETWEEN LOW PRESSURE AND REGULATED PRESSURE PIPE INVESTMENTS.

A. First, and foremost, the Peoples' and Equitable distribution systems are a conglomeration of various sizes of pipe operated at varying pressures installed at various times over the last 100-plus years. Historically, most of the Company's smaller Mains (2-

[14] Direct Testimony of Russell A. Feingold, page 28, line 20 through page 29, line 4.

inches and less) and many of its larger Mains were operated at low pressure due to the safety rating of the pipes and couplings. However, as materials and coupling methods improved and as pipes have been replaced, the Company began operating more and more of its systems at higher pressures with smaller pipes since this is more cost effective.

In response to OCA-V-2, the Company provided a database of its distribution Mains property records that provided investments and footages by vintage year, size, type, and a separation between low pressure and regulated pressure pipes. I analyzed these detailed property records and observed that 78.6% of the footage of small (2-inch) pipes are operated at the higher regulated pressure and only 21.4% of 2-inch pipes are operated at low pressure. Similarly, I observed that approximately half of the larger (6-inch) pipes (49%) are operated at regulated pressure and the other half (51%) are operated at low pressure. Furthermore, 30.5% of the footage of 8-inch pipes are operated at low pressure. Because small diameter pipes (2-inch) tend to serve low volume customers (Residential and Small General Service), we can see that a large percentage of these small diameter pipes are served under higher, regulated, pressure. At the same time, large volume users (Industrials) are typically served with larger diameter pipes and a large percentage of the larger diameter Mains are operated at low pressure. Furthermore, the vast majority of the higher pressure regulated pipes have been installed in more recent years such that the low pressure pipes tend to be of older vintage years. A summary of the Company's Mains installed footages separated between low pressure and regulated pressure, by pipe size, is presented in my Schedule GAW-3.

It is apparent that the Company's investments and operation of low pressure versus regulated pressure Mains are not a function of the type of customer served (i.e., Large General Service versus all other customer classes), but rather, an evolution of the Company moving more and more to regulated pressure Mains. As a result, Peoples' network of distribution of Mains is a system of commonly-used facilities.

Mr. Feingold's proposal to skeletonize its distribution Mains between low pressure and regulated pressure pipes would result in nothing more than enabling the Large General Service class to skim the cream of the top of cost responsibility. That is, for the LGS class, Mr. Feingold's approach would reflect the advantages of being part of a network, or system of commonly-used facilities, but then not share in a reasonable proportion of the costs associated with this system. Each and every customer served by Peoples enjoys a significant savings as a result of the economies of scale made possible with a large commonly-used distribution system. Each customer's savings are brought about not only as a result of not having to build their own facilities to deliver gas to their individual facility from a transmission pipeline, but also due to the sharing of investment and operational costs of a joint-use distribution system. Under Mr. Feingold's approach, the LGS class would enjoy the economies of scale benefits associated with being part of this system, but nonetheless, share only a small portion of the Company's jointly-incurred costs. Therefore, Mr. Feingold's proposed bifurcation of distribution Mains between low pressure and regulated pressure should be rejected such that all distribution Mains should be allocated on a joint-use basis.

Q. HAS A COST ALLOCATION APPROACH TO BIFURCATE COMMON USE MAINS PREVIOUSLY BEEN ADDRESSED BY THIS COMMISSION?

A. Yes. In 1994, National Fuel Gas Distribution Corporation ("NFGD") proposed a cost allocation methodology similar to that proposed by Peoples in this case (Docket No. R-00942991). In that case, the Commission flatly rejected NFGD's proposal on several grounds, and stated:

> After a review of the record, we find that the arguments opined by OCA are most persuasive. We conclude that we should retain our historic practice of allocating total [*319] distribution main costs based on each class' contribution to peak and annual requirements. NFG's proposed small mains adjustment suffers from the same weaknesses that we have previously found required the rejection of other alternatives to a Peak and Average cost of service study.
>
> Specifically, we have previously rejected proposals for a zero-intercept or minimum system method of cost of service. See, *Pennsylvania P.U.C. v. National Fuel gas Distribution Corp., 73 Pa. P.U.C. 552, 617 (1990); Pennsylvania P.U.C. v. Peoples Natural Gas Co., 63 Pa. PUC 6 (1986)*. In those cases we rejected these methods, agreeing with the OCA's position that such methods are not consistent with cost causation.
>
> There is little on this record to distinguish NFGD's proposed small main adjustment in the instant proceeding from the "minimum system" approach

> which we have previously rejected. Like the minimal system approach, the small mains adjustment would allocate the costs of smaller mains primarily to customers with smaller throughput. At the same time, NFGD did not propose an equally skewed allocation of larger distribution mains to customers with larger throughput based on any analysis of the [*320] use of such larger-size distribution mains by smaller customers. Instead, the focus of NFG's study was clearly to relieve large customers of the burden of paying for smaller distribution mains, without any consideration of whether small customers should be paying for larger distribution mains.
>
> NFGD's current system embodies numerous past and on-going augmentations to meet the continually changing requirements of its customers, and it is simply improper to look at the distribution system at a particular point in time and attempts to identify particular sizes of mains to particular customer classes. The Company's analysis focuses only upon the use of small mains by large customers and does not consider small customers' use of large mains. The size of mains directly connected to a customer is only a small factor in determining the cost of system augmentation necessary to serve a particular customer or customer class. Main line extensions are made based upon the particular economics of each extension in terms of the load generated and the number of customers served.
>
> For all the reasons discussed above, we find that NFGD's separate treatment of small and large mains for cost allocation [*321] purposes should be rejected. The Peak and Average method that allocates mains equally is a sound and reasonable method of cost allocation and should remain intact.[15]

Q. HAVE YOU CONDUCTED A CCOSS UTILIZING THE PEAK & AVERAGE METHOD WITH NO BIFURCATION OF DISTRIBUTION MAINS?

A. Yes. The following table provides a comparison of my recommended CCOSS utilizing the P&A method with no bifurcation of Mains to those obtained by Mr. Feingold reflecting a bifurcation of Mains:

[15] Pa. PUC v. Nat'l Fuel Gas Distribution, 83 Pa. PUC 262, 318-321 (1994).

TABLE 5
Comparison of Peoples' and OCA's P&A CCOSS Results at Current Rates
(Consolidated Basis)

Class	Rates of Return OCA	Rates of Return Peoples	Indexed RORs OCA	Indexed RORs Peoples
Residential	5.85%	4.96%	127%	108%
Small Gen'l Service	4.86%	3.91%	105%	85%
Med. Gen'l Service	6.00%	4.83%	130%	105%
Large Gen'l Service	-0.36%	3.14%	-8%	68%
Total Company	4.61%	4.61%	100%	100%

As can be seen in the table above, the Residential and Medium General Service classes' RORs are considerably higher than the system average ROR (127% and 130%, respectively) while the Small General Service class' ROR is about the same as the system average ROR (105%) and the Large General Service Class is contributing virtually no profits to the system (-8% indexed ROR). The details of my recommended CCOSS are provided in my Schedule GAW-4.

Q. ALTHOUGH YOU HAVE CONCEPTUAL DISAGREEMENTS WITH MR. FEINGOLD AS TO HOW DISTRIBUTION MAINS SHOULD BE ALLOCATED AS WELL AS MINOR CORRECTIONS TO HIS CCOSS, ARE THERE ANY INACCURACIES OR BIASES INHERENT WITHIN BOTH MR. FEINGOLD'S AND YOUR CCOSS?

A. Yes. Both the Peoples Division and Equitable Division engage in discounted, negotiated, rates for certain Commercial and Large Industrial customers; i.e., certain customers pay significantly less than full tariff rates. On a consolidated basis, these discounts equate to an excess of [**BEGIN HIGHLY CONFIDENTIAL**] [redacted]. [**END HIGHLY CONFIDENTIAL**].[16] While the vast majority of these discounted rates are attributable to the LGS class, there are some discounted rates attributable to the MGS class and a miniscule amount to the SGS class. The current revenues in both Mr. Feingold's

[16] Per response to I&E-RS-9D.

and my CCOSS reflect these discounted rates. At the same time, the Commercial and Industrial classes (SGS, MGS, and LGS) are fully allocated costs (rate base and expenses). The problem and bias that results is that we have no way of knowing the relative contributions to profitability (ROR) for the full tariff customers in these classes. Indeed, 72.4% of the LGS throughput (MCF) is delivered at discounted rates while only 27.6% of the LGS MCF is priced at full tariff rates.[17] As a result, the calculated rates of return for the MGS and LGS classes are understated as it relates to the full tariff customers within these two classes.

Q. HAVE YOU BEEN ABLE TO ESTIMATE THE PROFIT CONTRIBUTIONS (RORs) FOR THE FULL TARIFF CUSTOMERS WITHIN THE MGS AND LGS CLASSES?

A. No. In order to do so, I would need a separation of the specific load and usage characteristics of the full tariff and discounted rate customers within these two classes, which I do not have. Furthermore, while I attempted to impute the revenue for these classes as if all customers within these classes pay full tariff rates, the data provided in discovery is inconsistent relating to those customers that receive discounted rates and those that pay full tariff rates. To illustrate, in the Company's revenue proof which is provided in Filing Exhibit No. 3, Schedule 15, the total discounted MCF (total Company) is 29,585,502 MCF, while its response to Highly Confidential OCA-IV-5h and OCA-IV-6h indicates discounted volumes of [**BEGIN HIGHLY CONFIDENTIAL**] [redacted] [**END HIGHLY CONFIDENTIAL**]. Similarly, Non-Confidential Filing Exhibit No. 3, Schedule 15 indicates discounted delivery revenues of $11,733,665, while Highly Confidential responses referenced above total [**BEGIN HIGHLY CONFIDENTIAL**] [redacted] [**END HIGHLY CONFIDENTIAL**]. Furthermore, the Highly Confidential responses to OCA-IV-5h and OCA-IV-6h provides an itemization by rate schedule wherein the amounts by rate schedule (MGS and LGS) are not even close to the amounts shown in Filing Exhibit No. 3, Schedule 15 for negotiated rate customers.

[17] Calculated per Filing Exhibit No. 3, Schedule 15.

Q. WITH THIS BEING SAID, DO THE COST ALLOCATION STUDIES CONDUCTED BY EITHER MR. FEINGOLD OR YOU PROVIDE ANY MEANINGFUL INSIGHT AS TO RELATIVE CLASS PROFITABILITY OR CLASS REVENUE RESPONSIBILITY?

A. Only in a very limited fashion. That is, given the shortcomings discussed above, I have determined that the Residential and MGS classes are contributing somewhat more than the system average rate of return, while the SGS class' indexed rate of return is somewhat lower but about equal to the system average rate of return. With regard to the LGS class, it is impossible to determine the relative profitability of full tariff customers while the same is true to a lesser extent for the MGS class.

Q. GIVEN THE SHORTCOMINGS OF THE DATA AND INFORMATION REQUIRED TO CONDUCT A PROPER CLASS COST ALLOCATION STUDY FOR THIS CASE, DO YOU HAVE ANY RECOMMENDATIONS FOR FUTURE PEOPLES RATE CASES?

A. Yes. To the extent that Peoples continues to engage in negotiated, discounted rates to certain customers, these customers should be separated from full tariff rate customers by class within any CCOSS analysis and effectively treated as a separate class (or classes).

III. <u>CLASS REVENUE ALLOCATION</u>

Q. HOW DOES THE COMPANY PROPOSE TO ASSIGN ITS REQUESTED $94.848 MILLION OVERALL REVENUE INCREASE TO INDIVIDUAL CLASSES?

A. Company witness Feingold claims that he first considered two options in assigning the Company's proposed overall increase to individual classes. Under Mr. Feingold's first option, he calculated each class's required increase (i.e., equal 8.0% ROR) based on the average of: (a) his Customer/Demand CCOSS; and, (b) the average of his Customer/Demand and P&A CCOSS. In other words, under this option, Mr. Feingold gave

75% weight to his Customer/Demand CCOSS and 25% weight to his P&A CCOSS.[18] Under Mr. Feingold's second option, he simply assigned equal percentage increases to each class. Then, "after further discussions with the Company," Mr. Feingold concludes and proposes to assign greater than average increases to the rate classes that exhibit the greatest revenue deficiencies as derived in the Company's cost of service studies. In this regard, Mr. Feingold states that the:

> Residential Service rate class exhibited a relative rate of return on net rate base below 1.00 at present rates under both the cost of service study based on the design day method with a customer component of distribution mains and a combination (midpoint) of Peoples' two cost of service studies. For rate classes that exhibited revenue surpluses or a relative rate of return on net rate base above 1.00, the Medium General Service and Large Volume Service rate classes, I determined that a smaller than average increase in non-gas revenues was warranted. Finally, I assigned the average increase in non-gas revenues (i.e., 23.9%) to the rate class whose relative rates of return on net rate base was closer to 1.00 (Small General Service) compared to the other rate classes.[19]

What is most important to understand is that Mr. Feingold's evaluation and ultimate recommendations are effectively based upon a 75% weighting and consideration of his Customer/Demand method and 25% weighting of his P&A method.

As noted earlier, Mr. Feingold discussed these options with the Company and adjusted his final (and recommended) class revenue allocations somewhat to arrive at his recommended class revenue increases as shown in the table below:[20]

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[18] Calculated as: (50% weight to Customer/Demand with 100% Customer/Demand, and 0% P&A) plus (50% weight to Customer/Demand and 50% weight to P&A) = 75% weight to Customer/Demand and 25% weight to P&A.

[19] Direct Testimony of Russell A. Feingold, page 43, lines 13 through 21.

[20] Per Exhibit RAF-4, page 3. It should be noted that Mr. Feingold's proposed increases shown in this Exhibit reflect not only the increases in base rates but also an allocation of other non-rate revenue.

TABLE 6
Company Proposed Class Revenue Allocation

Class	Non-Gas Revenue at Current Rates	Revenue Increase	Percent Increase
Residential	$273,991,108	$79,862,244	29.1%
Small Gen'l Service	$33,951,754	$8,742,577	25.8%
Med. Gen'l Service	$45,000,023	$4,950,003	11.0%
Large Gen'l Service	$43,112,951	$1,293,389	3.0%
TOTAL	$396,055,837	$94,848,212	23.9%

Q. DID MR. FEINGOLD SHOW WHAT THE REQUIRED CLASS INCREASES WOULD BE UNDER HIS PEAK & AVERAGE CCOSS?

A. No. As explained earlier, Mr. Feingold presented the required class increases (at equal rates of return) in his Exhibit RAF-4, page 3 under his Customer/Demand study (his Table 1) as well as under the mid-point of his Customer/Demand and P&A CCOSS results (his Table 2). Mr. Feingold did not present the required class increases under his P&A study.

Q. HAVE YOU CALCULATED THE REQUIRED CLASS INCREASES OR DECREASES UTILIZING YOUR PEAK & AVERAGE CCOSS?

A. Yes. The calculations showing the development of class required increases (decreases) under my P&A CCOSS are shown on page 1 of Schedule GAW-4 and are summarized below:

TABLE 7
Required Increases Under OCA P&A CCOSS[21]

Class	Non-Gas Revenue at Current Rates	Required Revenue Increase	Percent Increase
Residential	$273,909,059	$36,004,227	13.1%
Small Gen'l Service	$33,949,700	$8,025,371	23.6%
Med. Gen'l Service	$45,010,829	$6,746,298	15.0%
Large Gen'l Service	$43,186,248	$44,072,315	102.1%
TOTAL	$396,055,837	$94,848,211	23.9%

Q. IS MR. FEINGOLD'S PROPOSED CLASS REVENUE ALLOCATION REASONABLE AND APPROPRIATE?

A. No. This Commission has a decade's long and consistent policy of not considering CCOSS that allocate natural gas distribution Mains partially on number of customers. However, and as discussed above, Mr. Feingold's proposed revenue allocation is, by and large, based upon a 75% weighting of his Customer/Demand CCOSS and a 25% weighting of his Peak & Average CCOSS. Therefore, the vast majority of Mr. Feingold's class revenue allocation recommendation is based on a CCOSS methodology that has been consistently rejected by this Commission.

Q. FOR CLARIFICATION, CAN YOU PROVIDE A COMPARISON OF THE REQUIRED CLASS INCREASES UNDER MR. FEINGOLD'S METHODOLOGY TO HIS ULTIMATE PROPOSED CLASS INCREASES?

A. Yes. Remembering that Mr. Feingold considered the average of: (a) his Customer/Demand CCOSS; and, (b) the mid-point of his Customer/Demand CCOSS and P&A CCOSS (which gives 75% weight to his Customer/Demand CCOSS), the table below provides a comparison of Mr. Feingold's averaging methodology to his final recommended class revenue increases:

21 Includes other (non-rate) revenue.

TABLE 8
Comparison of Feingold Weighted Average of His CCOSS
Results and His Final Recommended Class Increases

	Pct. Increase in Non-Gas Revenue	
Class	Feingold Wgtd. Avg. Method	Feingold Proposed
Residential	29.7%	29.1%
Small Gen'l Service	27.3%	25.8%
Med. Gen'l Service	5.7%	11.0%
Large Gen'l Service	3.9%	3.0%
TOTAL	23.9%	23.9%

Q. GIVEN THE SHORTCOMINGS IN THE COMPANY'S AND YOUR CCOSS ANALYSES AS WELL AS THE IMPROPER REVENUE ALLOCATION PROPOSED BY MR. FEINGOLD, DO YOU RECOMMEND AN ALTERNATIVE ALLOCATION OF ANY OVERALL INCREASE RECOMMENDED BY THE COMMISSION?

A. Yes. Given the shortcomings and inaccuracies of our CCOSS analyses, as well as my recommended ratemaking treatment of the Company's discounted rates to selected Commercial and Large Industrial customers, the only fair and equitable apportionment of any overall increase authorized by the Commission in this case is to allocate that increase on an equal percentage basis across all classes.

Q. UNDER YOUR EQUAL PERCENTAGE REVENUE INCREASE ALLOCATION RECOMMENDATION, WILL THE FULL TARIFF CUSTOMERS IN THE LGS CLASS, AND TO A LESSER EXTENT, THE MGS CLASS, BE UNFAIRLY DISADVANTAGED?

A. No. First, and as will be discussed later in my testimony, I am recommending the imputation of additional rate revenue associated with discounted rates applicable to these classes. Second, it should be remembered that this Commission has ruled that the Residential class should be totally responsible for the discounts offered under Customer Assistance Programs ("CAP") because such CAP programs are only available to

Residential customers. The same is true for the availability of discounted rates. That is, discounted rates are not available to Residential customers such that this class should not be burdened with both CAP costs and discounts as well as discounted rates offered only to Commercial and Large Industrial customers.

IV. CONSOLIDATION OF PEOPLES' AND EQUITABLE'S RATES

Q. HAVE YOU EVALUATED THE COMPANY'S PROPOSAL TO CONSOLIDATE THE PEOPLES DIVISION AND EQUITABLE DIVISION RATES INTO A SINGLE STATE-WIDE RATE?

A. Yes. As part of my investigation, I evaluated the bill impacts on current Peoples' and Equitable Residential customers separately. I conducted my analyses on both an all-in (all rates including gas costs) as well as on a non-gas cost basis. While the impact on the Equitable Division's Residential ratepayers will be somewhat greater than for Residential Peoples Division, I have determined that this impact is not large enough to warrant a gradual consolidation over several cases. Furthermore, and to the extent the Commission authorizes an increase less than the $94.8 million increase requested by the Company, this somewhat larger impact on Equitable's Residential customers will be less. The details of my Residential impact analysis using the Company's proposed increase is presented in my Schedule GAW-5.

V. RESIDENTIAL RATE DESIGN

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT AND PROPOSED RESIDENTIAL RATE STRUCTURES.

A. The following table presents a comparison of current and Company-proposed rates for the Residential class:

TABLE 9
Comparison of Current and Proposed Residential Rates

	Current		Proposed
	Peoples	Equitable	Consolidated
Base Customer Charge	$13.95	$13.25	$20.00
Fixed DSIC Charge	$0.6975	$0.6625	--
Fixed Supplier Choice Rider	$0.0115	$0.0001	$0.0067
Fixed TCJA Rider	-$0.6728	-$0.9508	--
Base Delivery Charge	$3.1330/MCF	$3.1687/MCF	$3.8753/MCF
Universal Service Rider	$0.4667/MCF	$0.2040/MCF	$0.4094/MCF
Volumetric DSIC Rider	$0.1904/MCF [22]	$0.1790/MCF [23]	--
Volumetric TCJA Rider	-$0.1511/MCF	-$0.2274/MCF	--
STAS	-$0.0072/MCF	-$0.0304/MCF	--
Gas Procurement Charge (Sales only)	$0.1055/MCF	$0.1055/MCF	$0.0801/MCF
Merchant Function Charge	$0.1024/MCF [24]	$0.1024/MCF [25]	$0.0982/MCF [26]

Q. DO YOU HAVE ANY COMMENTS OR CONCERNS REGARDING THE STRUCTURE OF THE COMPANY'S CURRENT AND PROPOSED FIXED CHARGES?

A. Yes. Fixed charges are imposed on customers on a monthly basis. Under current rates, the Peoples' Residential fixed charges total $13.9862 per customer per month while the current Equitable fixed charges total $12.9618. Similarly, under the Company's proposal, the Residential fixed charges would total $20.0067 per customer per month. It is illogical to have a fixed monthly charge in fractions of a penny. Furthermore, I do not understand how the Company can even bill fractions of a penny. While I understand that certain riders may be established outside of the context of a general rate case, it makes no

[22] The DSIC rate for sales customers is $0.1904/MCF while the same charge for transportation customers is $0.1813/MCF.

[23] The DSIC rate for sales customers is $0.1790/MCF while the same charge for transportation customers is $0.1700/MCF.

[24] The MFC for sales customers is $0.1024/MCF while the same charge for transportation customers is $0.0270/MCF.

[25] The MFC for sales customers is $0.1024/MCF while the same charge for transportation customers is $0.0270/MCF.

[26] The MFC for sales customers is $0.0982/MCF while the same charge for transportation customers is $0.0259/MCF.

sense to establish a fixed rate billed on a monthly customer basis that is a fraction of a penny. While this may result in a miniscule over- or under-collection of revenues, the reality is, this type of fixed monthly rates is simply illogical.

Q. IS THE COMPANY PROPOSING ANY SIGNIFICANT INCREASES TO THE BASIC FIXED MONTHLY CHARGE?

A. Yes. As shown in the table above, Peoples' witness Feingold proposes to increase the Peoples' basic monthly customer charge by $6.05 (43%) and increase Equitable's basic monthly customer charge by $6.75 (51%).

Q. HOW DOES MR. FEINGOLD ATTEMPT TO SUPPORT HIS PROPOSED LARGE INCREASES TO THE BASIC RESIDENTIAL MONTHLY CUSTOMER CHARGES?

A. Mr. Feingold first calculated a Residential "customer" cost of $24.41 per customer per month based on his understanding of a Commission Decision in an Aqua Pennsylvania rate case (Docket No. R-00038805).[27] He then opined that "it is appropriate to recover customer costs through the customer charge because these costs do not change with usage and it provides more levelized annual revenues for the Company and reduces winter bills for customers when gas consumption charges are greatest."[28]

Q. BEFORE WE DISCUSS ANY SPECIFIC DISAGREEMENTS YOU MAY HAVE WITH MR. FEINGOLD'S ANALYSIS AND RECOMMENDATION AS IT RELATES TO THE BASIC RESIDENTIAL CUSTOMER CHARGE, DO YOU HAVE ANY GENERAL COMMENTS CONCERNING THE ESTABLISHMENT OF SUCH CHARGES?

A. Yes. Several Commissions in the Country have a policy of maintaining relatively low fixed monthly customer charges primarily due to the reasoning that customers should have greater flexibility in controlling their energy bills with revenues collected primarily

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[27] Direct Testimony of Russell A. Feingold, page 36.

[28] Direct Testimony of Russell A. Feingold, page 46.

through volumetric rates as well as concerns over the affordability of energy by low income and low usage customers. Examples of States with this policy include: Maryland, Washington State, Virginia, Montana, Oregon, and South Carolina. Other State Commissions have allowed and established very high fixed monthly customer charges primarily due to the reasoning that fixed costs should be recovered from fixed charges and that fixed charges promote a greater level of revenue stability to utilities. Examples of this high customer charge policy States include: Ohio and New York.

My philosophy and opinions align with those States that have a policy of maintaining relatively low fixed monthly customer charges. As I will explain later in my testimony, Peoples is in the business of distributing natural gas to its customers such that the most equitable method of collecting revenues from its customers should be based upon the varying utilization of the Company's facilities and resources. Furthermore, as a matter of conservation as well as equity, the establishment of relatively low fixed charges enables customers to more easily control their natural gas and energy bills. In these regards, the ratemaking process is such that rates are developed with the best expectation that the company will have an opportunity to recover its costs and collect its authorized revenue requirement. This is true even with relatively low customer charges.

My philosophy and opinion is particularly relevant within Pennsylvania's ratemaking process given the fact that Peoples is entitled to use a fully projected future test year for ratemaking as well as the numerous guaranteed cost recovery riders that are in place within Peoples tariff.

Q. DO YOU AGREE WITH MR. FEINGOLD'S CALCULATED RESIDENTIAL CUSTOMER COST OF $24.41 PER MONTH?

A. No. While I am well aware of the Aqua Decision referenced by Mr. Feingold, it is uncertain if the Commission's Decision in the Aqua case represented a distinct change in policy or if it was based on the facts and circumstances unique to that case. Specifically, while the Commission allowed recognition of "portions of indirect costs" in its Final Order in the referenced Aqua case, the Commission clearly stated in its Final Order:

> We caution that these are costs which may be considered for inclusion in the customer charge, but such claims are subject to scrutiny on a case-by-case basis. [Final Order, p. 72]

For decades, this Commission has had a prescribed method in determining customer costs. For example, in its Order in National Fuel Gas Distribution Company's 1994 base rate proceeding (Docket No. R-00942991), the Commission stated:

> Commission precedent is clear that indirect customer costs are not properly included in the customer charge. Only those costs which represent items that the utility must have in place each month for each customer are "basic customer costs" which are properly recovered in the customer charge.

Moreover, the Commission has clearly defined the costs to be included in a Residential customer charge as being limited to those costs which directly relate to the meter and service drop, and customer service expenses associated with meter reading and billing.[29]

Q. PLEASE IDENTIFY THOSE COSTS THAT MR. FEINGOLD INCLUDED IN HIS CUSTOMER ANALYSIS THAT IN YOUR OPINION ARE NOT APPROPRIATE WITHIN THE DETERMINATION OF REASONABLE CUSTOMER CHARGES.

A. While it is appropriate to incorporate the costs required to connect and maintain a customer's account (i.e., the cost of meters, service drops, and billing and collecting), Mr. Feingold has included a host of overhead costs within his "customer" cost analysis. The following table provides a list of those overhead and indirect costs that Mr. Feingold inappropriately included within his calculated customer cost of $24.41 per month.

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[29] See Pa. PUC v. Metropolitan Edison, 60 Pa. PUC 349 (1985); Pa. PUC v. West Penn Power Co., 59 Pa. PUC 552 (1985); 69 PUR 4th 470 (1985).

TABLE 10
Feingold Inappropriate Inclusion of Residential "Customer" Costs
($000)

		Total Residential	Residential Customer	Percent Customer
Rate Base (Net Plant):				
303	Misc. Intangible Plant	$51,871.0	$39,869.6	76.9%
389-399	Total General Plant	$58,287.5	$6,997.3	12.0%
	Total Rate Base	$110,158.5	$46,866.9	42.5%
Expenses:				
874	Mains & Services-Operations	$9,035.8	$3,961.1	43.8%
904	Uncollectibles	$15,121.5	$15,121.5	100.0%
908	Customer Assistance	$2,884.8	$2,884.8	100.0%
909	Info. & Instructional Advertising	$2,970.2	$2,970.2	100.0%
910	Misc. Customer Service & Info.	$4.0	$4.0	100.0%
912, 913	Demonstrating & Selling	$431.8	$431.8	100.0%
920-932	Administrative & General	$43,728.0	$27,711.5	63.4%
403	Intangible Depreciation	$12,085.7	$9,288.8	76.9%
403.14	General Plant	$6,627.4	$795.6	12.0%
	Total Expenses	$92,889.2	$63,169.3	68.0%

Q. PLEASE EXPLAIN WHY THE COSTS IDENTIFIED IN THE TABLE ABOVE ARE NOT APPROPRIATELY CONSIDERED IN DETERMINING A REASONABLE FIXED RESIDENTIAL CUSTOMER CHARGE.

A. First, while most, if not all, of the costs identified in the table above are sunk, or fixed costs in the short-run, these costs are overhead costs and simply the cost of doing business for any business enterprise. Simply because these costs do not vary with usage does not mean that they should be collected in a fixed monthly customer charge. Indeed, many of Peoples' costs are sunk, or fixed in nature, but this in no way implies that they should be collected in a non-avoidable fixed monthly charge.

Q. HAVE YOU CONDUCTED A CUSTOMER COST ANALYSIS THAT COMPORTS WITH THIS COMMISSION'S DECADES OLD PRACTICE AND POLICY OF ONLY INCLUDING THOSE COSTS REQUIRED TO CONNECT AND MAINTAIN A CUSTOMER'S ACCOUNT?

A. Yes. I have conducted a direct customer cost analysis that only reflects the direct costs associated with meters, service drops, meter reading, customer records and collections, and billing. As shown in my Schedule GAW-6, I have determined that the appropriate Residential customer cost is $13.98. In this regard, it should be noted that I have utilized OCA's recommended cost of equity of 8.75%. However, the risk associated with fixed monthly customer charges is virtually zero (considering that I have also included a provision for Uncollectibles) as customer charges are unavoidable and represent guaranteed revenue recovery for Peoples. As a result, my calculated customer cost of $13.98 per month is somewhat overstated.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING RESIDENTIAL CUSTOMER CHARGES?

A. I recommend increasing both the current Peoples' basic Residential customer charge of $13.95 per month and Equitable's basic Residential customer charge of $13.25 per month to $14.00 per month.

VI. NEGOTIATED (DISCOUNTED) RATES

Q. EARLIER IN YOUR TESTIMONY YOU INDICATED THAT BOTH PEOPLES' DIVISION AND EQUITABLE'S DIVISION ENGAGE IN DISCOUNTED NEGOTIATED RATES FOR CERTAIN COMMERCIAL AND LARGE INDUSTRIAL CUSTOMERS. CAN YOU GENERALLY EXPLAIN THE REASONS FOR OFFERING SELECTED CUSTOMERS' DISTRIBUTION RATES LOWER THAN THE FULL TARIFF RATES APPROVED BY THE COMMISSION?

A. Yes. In general, there are three categories of, or reasons for, negotiated, discounted rates below full tariff rates. These include what is known as: (1) Gas-on-Gas competition between competing NGDCs; (2) the potential threat of a customer by-passing Peoples' distribution system and procuring their gas directly from an interstate pipeline; and, (3) the ability of a customer to use an alternative fuel or energy source to meet their energy needs (e.g., electricity, coal, oil, or propane).

Q. HAS THE ISSUE OF NEGOTIATED, DISCOUNTED RATES HISTORICALLY BEEN CONTROVERSIAL OR CONTENTIOUS IN PENNSYLVANIA?

A. Yes. For many years, various parties have voiced concerns over the legitimacy and magnitude of certain discounted rates to selected customers. As will be discussed in more detail later, there is no doubt that discounted rates are appropriate and benefit all stakeholders under certain circumstances. However, there have been disagreements as to the level and preponderance of such discounted rates offered to selected customers.

Q. PLEASE PROVIDE A HISTORICAL PERSPECTIVE OF THE ISSUES CONCERNING GAS-ON-GAS COMPETITION.

A. With regard to Gas-on-Gas competition, the Commission initiated a generic investigation or rulemaking relating to this issue in Docket Nos. P-2011-2277868 and I-2012-2320323. On May 4, 2017, the Commission issued an Opinion and Order that set forth certain ground rules relating to Gas-on-Gas competition including an absolute floor on the discounted rates that NGDCs may offer to selected customers. In this Order, the Commission required that NGDC tariff provisions which pertain to Gas-on-Gas discounted rates, be amended to include a floor equal to the lowest tariffed rate under which a customer is capable of receiving service from a competing NGDC(s).[30]

With regard to existing long-term contracts resulting from Gas-on-Gas competition, the Commission also stated:

> the NGDCs have been fully aware that there may be changes in Gas-on-Gas discounts since at least 2012. Consequently, NGDCs knew there may be some risk in entering into *long-term* contracts once this proceeding began. Therefore, we concur with the ALJ that December 31, 2018, may be a reasonable date to end ratepayer subsidies of Gas-on-Gas discounts that exceed applicable rates of competing NGDCs. Accordingly, the NGDCs are placed on notice that they may not be able to recover any foregone revenue beyond December 31, 2018, in future rate proceedings. [Order, page 57].

[30] Order, page 54.

In its May 4, 2017 Order in these dockets, the Commission also sought comments from the various parties relating to uniform tariff provisions. The various parties met several times and developed a consensus on several of the questions posed by the Commission in this Order including what customer classes should be offered Gas-on-Gas flex rates and what should be the criteria and associated documentation for customers to demonstrate they are capable of receiving service from another NGDC. With regard to which customer classes should be offered Gas-on-Gas flex rates, all parties agreed that such rates should be limited to non-Residential customer classes. With regard to the criteria and documentation for customers to demonstrate they are capable of receiving service from another NGDC, all parties agreed that:

> A G-O-G flex rate must be supported by a sworn G-O-G Customer affidavit. An existing G-O-G Customer's affidavit must attest that the G-O-G Customer meets one or more of the eligibility criteria listed above. A new G-O-G Customer's affidavit must attest that (i) the G-O-G Customer has been offered service from a Competing NGDC with a lower tariffed rate and (ii) the Competing NGDC is physically able to connect the G-O-G Customer and has sufficient capacity to serve. All affidavits must include all relevant terms, conditions, rates, and customer contributions and advances associated with the competitive service offering. The G-O-G Customer affidavit shall be treated as confidential and disclosed in a Commission proceeding only pursuant to a protective agreement or order.[31]

Q. PLEASE PROVIDE A HISTORICAL PERSPECTIVE OF DISCOUNTED RATES RELATING TO THREATS OF BY-PASS AND ALTERNATIVE FUEL OPTIONS.

A. Some Large Industrial and Commercial customers are located in close proximity to an interstate pipeline such that it may be economically feasible for a customer to by-pass a NGDC by building and installing their own natural gas main spur and connecting directly to an interstate pipeline. This is commonly known as a potential threat of by-pass. As such, all stakeholders are better served if such customers contribute some revenue (above variable cost as well as above the dedicated capital cost required to serve that customer) to the NGDC rather than leaving the NGDC system entirely.

---

31 Reply Comments of OCA, Appendix A, Consensus Positions of Commenting Parties, September 21, 2017.

With regard to discounted rates associated with customers that have alternative fuel or energy options, there is no doubt that the use of natural gas for industrial purposes sometimes competes with alternative fuel or energy sources such as coal, oil, electricity, or propane. Although natural gas tends to have a distinct price advantage over most alternative energy sources, situations do exist wherein such alternative fuels do effectively compete with natural gas. As such, and similar to the benefits accruing to all stakeholders resulting from threats of by-pass, negotiated, discounted rates may be appropriate.

In Equitable's last general rate case (Docket No. R-2008-2029325), the issue of discounted rates was a contentious issue particularly as it relates to the Company's documentation and verification as to the legitimacy, need for, and level of specific discounted rates. In that case, the parties ultimately reached a Settlement Agreement which was approved by the Commission that states:

> B.3. Equitable will agree to maintain a highly confidential log of negotiated delivery service agreements available for review by the OTS, the OCA and the OSBA. The log will contain the following information related to negotiated agreements:
>
> Customer number, effective date of the agreement, the reason(s) for offering a negotiated delivery agreement, supporting work papers relied upon to substantiate the negotiated agreement, and an analysis which evaluates the contribution to overall fixed costs provided by each customer.

Q. ALTHOUGH YOU AGREE THAT THERE ARE SITUATIONS IN WHICH NEGOTIATED, DISCOUNTED RATES MAY BE APPROPRIATE, WHY HAS THIS ISSUE BEEN CONTROVERSIAL?

A. With respect to Gas-on-Gas competition, the vast majority of discounted rates associated with Gas-on-Gas competition were effectively eliminated with the Equitable/Peoples merger. Furthermore, the Commission set forth various ground rules relating to Gas-on-Gas competition as discussed above such that any controversy relating to this issue is pretty much limited to verification of the standards set forth in the Commission's May 4, 2017 Order as well as the agreement of all parties relating to the questions posed in that Commission Order.

With regard to negotiated, discounted rates associated with threats of by-pass and/or alternative energy sources, the concerns and controversies tend to revolve around the legitimacy of claimed threats of by-pass and/or use of alternative energy sources. For example, it has been observed that some customers that receive discounted rates could not realistically by-pass Peoples' distribution system due to factors such as the distance to an interstate pipeline, physical and permitting hurdles that would be required to by-pass the system such as river and public road crossings, and the fact that private enterprises do not have eminent domain such that several private property owner's lands would need to be traversed in order to build a stand-alone main to connect to a transmission system.

With regard to the claim of competition with alternative energy sources, natural gas tends to have a competitive advantage over most other energy or fuel sources and a customer that might consider an alternative energy source would require the capability to economically use such alternative energy sources as well as store inventory for certain types of alternative fuel sources such as coal. In addition, and particularly relevant for claimed alternative energy sources involving coal and oil, environmental permitting standards may inhibit these sources as a viable alternative to natural gas.

Q. SO THAT IT IS CLEAR, WHEN PEOPLES ENGAGES IN DISCOUNTED RATES TO SELECTED COMMERCIAL AND INDUSTRIAL CUSTOMERS, WHAT STAKEHOLDERS ARE RESPONSIBLE FOR THE COST IMPACTS OF THESE DISCOUNTED RATES?

A. The cost impact of rate discounts falls squarely on captive ratepayers. That is, in this application, the Company is asking all captive ratepayers to pay the difference between full tariff rates and its discounted rates offered to selected Commercial and Industrial customers. As a result, these selected Commercial and Industrial customers enjoy lower distribution rates than other Commercial and Industrial customers that pay full tariff rates and shareholders are made whole as a result of captive ratepayers paying for the difference between full tariff and discounted rates.

Q. WHAT STANDARDS SHOULD APPLY TO PEOPLES AS THEY RELATE TO WHETHER CAPTIVE RATEPAYERS SHOULD OR SHOULD NOT BE

REQUIRED TO FOOT THE BILL FOR DISCOUNTED RATES OFFERED TO SELECTED COMMERCIAL AND INDUSTRIAL CUSTOMERS?

A. Considering that Peoples is requesting that captive ratepayers fully fund the discount offered to a selected few Commercial and Industrial customers, reasonable and best industry practices require that Peoples diligently ensure that such discounts are required with detailed analyses conducted concerning an individual customer's ability to purchase its natural gas from a competing NGDC, by-pass the Peoples' distribution system or utilize an alternative energy source. Furthermore, it is important that proper records be kept to verify the legitimacy of such negotiated rates on a customer-by-customer basis.

Q. HAVE YOU AND OTHER PARTIES TO THIS CASE ATTEMPTED TO INVESTIGATE THE EXTENT TO WHICH DISCOUNTED RATES ARE OFFERED BY PEOPLES AS WELL AS VERIFICATION OF THE LEGITIMACY OF SUCH DISCOUNTED RATES TO SELECTED CUSTOMERS?

A. Yes. There has been a host of discovery requests by OCA, I&E, and OSBA on the issues concerning discounted rates. I will discuss the specifics of OCA's data requests that have been very detailed in nature later in my testimony.

Q. HAS THE COMPANY PROVIDED AN ITEMIZATION OF THOSE CUSTOMERS THAT RECEIVE DISCOUNTED RATES ALONG WITH THE ALLEGED REASON FOR OFFERING A DISCOUNTED RATE?

A. Yes. In response to various data requests, the Company provided an itemization of its customers that are offered discounted rates separated between the three reasons identified above.[32] Furthermore, the Company's itemization has included information as to each customer's usage (MCF), fully projected future test year revenue contained in its application, and the amount of revenue that would be generated under full tariff rates.

Q. EARLIER IN YOUR TESTIMONY YOU INDICATED THAT THE TOTAL LEVEL OF DISCOUNTS OFFERED TO SELECTED COMMERCIAL AND

[32] For example, OCA-IV-5, OCA-IV-6, I&E-RS-9D, I&E-RS-10D, and OSBA-I-7.

INDUSTRIAL CUSTOMERS IS SIGNIFICANT AND THAT THE VAST MAJORITY OF THE DISCOUNTS ARE ASSOCIATED WITH RATE LGS CUSTOMERS. IN TERMS OF MAGNITUDE, WHAT IS THE AVERAGE NON-GAS RATE PAID BY LGS CUSTOMERS WITH DISCOUNTED RATES COMPARED TO THOSE PAID BY FULL TARIFF LGS RATE CUSTOMERS?

A. On a consolidated (Peoples plus Equitable) basis, LGS customers that are served under discounted rates pay an average delivery rate of $0.367/MCF, while full tariff LGS customers pay, on average, $1.863/MCF in base rate delivery charges. In other words, LGS customers with negotiated rates receive on average an 80% discount over full tariff delivery rates.[33]

Q. AS PART OF YOUR INVESTIGATION, HAVE YOU ATTEMPTED TO VERIFY THE NECESSITY OR LEGITIMACY OF THESE DISCOUNTED RATES ON A CUSTOMER-BY-CUSTOMER BASIS?

A. Yes. In OCA-IV-5 and OCA-IV-6, detailed and specific information was requested on a customer-by-customer basis regarding documentation in support of the need to offer individual customer's discounted rates. OCA-IV-5 pertained to discounts associated with Gas-on-Gas competition while OCA-IV-6 pertained to discounts other than Gas-on-Gas competition. A complete copy of these data request questions are provided in my Schedule GAW-7 and requested the following information:

(a) account number;
(b) customer name;
(c) division (Peoples or Equitable);
(d) current rates charged by rate element;
(e) competing natural gas distribution company ("NGDC") and competing rate schedule;
(f) historic test year billing determinants and revenue by rate element;
(g) fully projected future test year billing determinants and revenue by rate element;
(h) identification of which rate schedule the volumes and revenues are contained within Exhibit No. 3, Schedule No. 15, Attachment D sponsored by Ms. Scanlon;
(i) firm contract demand;
(j) current contract;

33 Calculated per Filing Exhibit No. 3, Schedule No. 15.

(k) all documents and records supporting the customer's ability to purchase from a competing NGDC; and,

(l) all analyses which evaluate the contribution to overall fixed costs.

These data requests were served on the Company on March 13, 2019. A narrative response to OCA-IV-5 and OCA-IV-6 that referred to various attachments was received on April 4 and April 5, 2019, respectively. However, the attachments were not received until April 9, 2019. On April 9, 2019, OCA counsel wrote to the Company's counsel that the responses and attachments were not complete and not fully responsive to the items requested in OCA-IV-5 and OCA-IV-6 and requested the Company to supplement its responses. Finally, on the afternoon of April 24, 2019, the Company provided its supplemental responses.

Q. DO THE COMPANY'S INITIAL AND SUPPLEMENTAL RESPONSES FULLY RESPOND TO YOUR REQUESTS?

A. I cannot say with certainty. That is, at this point, I do not know if the Company has provided all documents in its possession relating to these requests. However, the data and information provided for many discounted rate customers is lacking in detail. For example, for several discounted rate customers, the Company simply provided an extremely undetailed map showing the customer's location relative to the nearest pipeline. For other customers, the Company's responses simply indicate that there is a competing fuel with no reference to what the competing fuel is, let alone, any analysis relating to either the need for, or level of, the discounted rate offered by Peoples. A complete copy of all documents provided by the Company in response to these two data requests are provided in my Highly Confidential Schedule No. GAW-8 and Highly Confidential Schedule No. GAW-9.

Q. WITH THE DOCUMENTS THAT YOU HAVE AVAILABLE AS OF THE WRITING OF THIS TESTIMONY, HAVE YOU BEEN ABLE TO VERIFY THE NEED FOR, AND LEGITIMACY OF, THE DISCOUNTS OFFERED TO EACH DISCOUNTED RATE CUSTOMER?

A. No. Many questions still remain in that there are a total of 41 customers (some with multiple accounts and locations) that receive discounted rates. While there is no analytical support regarding the need to offer these customers a discounted rate, the information provided by the Company thus far indicates that a few customers' discounted rates are likely justified and appropriate. However, for the vast majority of these 41 customers, the Company has provided virtually no support justifying the need for a discounted rate. Furthermore, I have observed that many of the negotiated rate customers are located a considerable distance from an interstate pipeline and that numerous rivers, public roads and highways, and landowners' properties would need to be traversed in order for the customer to build their own spur to the closest transmission line.

As an illustration, consider [**BEGIN HIGHLY CONFIDENTIAL**] [redacted] [**END HIGHLY CONFIDENTIAL**]. With this distance and various constraints, there is absolutely no doubt that it would impossible for this Customer to construct its own natural gas main and connect directly to the transmission pipeline.

While the data and information provided thus far does substantiate the need for a discounted rate for a few customers and the fact that several other customers are located in very close proximity to an interstate transmission pipeline, there is a strong probability that these close proximity customers are legitimately offered a discounted rate. However, for many others, I have been able to determine that it is either virtually impossible for a customer to build their own pipe and by-pass Peoples' distribution system or that I do not have enough information available to determine if the discounted rate is, or is not, warranted. Furthermore, for several of the alleged alternative fuel customers, there is no documentation at all concerning the viability of using an alternate fuel or even identifying what the alternative fuel might be.

In summary, as of the writing of this testimony (April 25, 2019), I have not yet been able to verify the need for, or legitimacy of, the level of discounts to Peoples' negotiated rate customers. The Company's supplemental responses were received only yesterday afternoon (April 24, 2019) and I simply have not had time to fully evaluate these documents. However, my review thus far has revealed that the documentation provided for several customers is still lacking. Therefore, I am unable to provide a recommendation in terms of the revenue impact associated with those discounted rates that are, and are not, justified. As such, I will continue my investigation as expeditiously as possible and will provide supplemental testimony as soon as my investigation is complete.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2018-3006818
Peoples Natural Gas Company LLC	:	

VERIFICATION

I, Glenn Watkins, hereby state that the facts above set forth in my Direct Testimony OCA Statement No. 3 are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: ______________________________

Glenn Watkins
Technical Associates, Inc.
1503 Santa Rosa Road
Suite 130
Richmond, VA 23229
watkinsg@tai-econ.com

DATED: April 29, 2019
*270933

OCA Statement No. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2018-3006818
	:	
Peoples Natural Gas Company, LLC	:	

EXHIBITS ACCOMPANYING
Direct Testimony of
Glenn A. Watkins
On Behalf of:
Office of Consumer Advocate

BACKGROUND & EXPERIENCE PROFILE
GLENN A. WATKINS
PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Jan. 2017-Present	President/Senior Economist, Technical Associates, Inc.
Mar. 1993-Dec. 2016	Vice President/Senior Economist, Technical Associates, Inc. (Mar. 1993-June 1995 Traded as C. W. Amos of Virginia)
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. Public Utility Regulation

A. Costing Studies -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. Rate Design Studies -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

GLENN A. WATKINS

C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers' compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI's administrative assigned risk plan and pool expenses.

GLENN A. WATKINS

IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

OCA Statement No. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2018-3006818
	:	
Peoples Natural Gas Company, LLC	:	

Schedule GAW-2

PEOPLES NATURAL GAS COMPANY
OCA Minor Disagreements and Adjustments to Feingold's CCOSS

<u>Account 303 (Miscellaneous Intangible Plant)</u>

Mr. Feingold utilized an 8-factor approach for this account that included a weighting of:

Calculated Revenue Requirement	40.08%
T&D Mains	4.54%
Plant	19.06%
O&M	7.90%
Customers	18.73%
Meter Reading	1.94%
Labor	6.70%
Gathering Volumes	0.05%

It is unknown how Mr. Feingold developed these weights, however, OCA accepted the weighting mechanisms used by Mr. Feingold with the exception of excluding "revenue requirement." This is because the exercise would be circular and that the intent is to evaluate class revenue contributions at current rates, not intertwined with the Company's proposed rates.

<u>Account 374 (Distribution Land), Account 375 (Structures & Improvements), and Account 387 (Other Equipment</u>

Mr. Feingold classifies a portion of these accounts as commodity-related which is a result of his classification based on total plant. However, the vast majority of the commodity-related total plant is a function of Intangible Account 303, which then would be circular.

OCA allocated these accounts on total distribution plant (excluding these accounts).

<u>Account 930 (Miscellaneous General Expenses)</u>

Mr. Feingold's ultimate allocation of costs to classes for this account is inconsistent in that he functionalized this account based on PSTD/LP Plant but then allocated distribution demand based on A&G labor plus A&G plant-related while the customer classification is allocated based on number of customers and gathering classification is allocated on gathering volumes.

OCA allocated this expense on PSTD Plant.

<u>Income Taxes</u>

Mr. Feingold ignored the tax deductibility of interest expense.

OCA has reflected interest expense as a deduction from taxable income.

OCA Statement No. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2018-3006818
	:	
Peoples Natural Gas Company, LLC	:	

Schedule GAW-3

PEOPLES NATURAL GAS COMPANY
Mains Footage By Size and Pressurization
Combined (Peoples + Equitable)

	Steel Footage			Plastic Footage			Total Footage		
Diameter	Low Pressure	Regulated Pressure	Pct Low Pressure	Low Pressure	Regulated Pressure	Pct Low Pressure	Low Pressure	Regulated Pressure	Pct Low Pressure
2	1,416,319	2,381,607	37.3%	825,568	5,837,723	12.4%	2,241,887	8,219,330	21.4%
3	2,454,125	2,421,209	50.3%	1,416,817	4,133,662	25.5%	3,870,942	6,554,871	37.1%
4	5,704,232	2,752,783	67.4%	2,861,787	4,003,655	41.7%	8,566,019	6,756,438	55.9%
5	439,170	184,100	70.5%	4	1	80.0%	439,174	184,101	70.5%
6	2,978,907	2,037,258	59.4%	1,440,318	2,210,078	39.5%	4,419,225	4,247,336	51.0%
7	77,860	44,278	63.7%	358	10	97.3%	78,218	44,288	63.8%
8	935,955	1,929,818	32.7%	331,937	960,447	25.7%	1,267,892	2,890,265	30.5%
9	20	2,570	0.8%	-	-		20	2,570	0.8%
10	211,813	601,437	26.0%	5,508	45,547	10.8%	217,321	646,984	25.1%
11	27	-	100.0%	-	-		27	-	100.0%
12	159,667	890,583	15.2%	26,443	129,530	17.0%	186,110	1,020,113	15.4%
13	-	110	0.0%	-	-		-	110	0.0%
14	4,898	52,139	8.6%	-	-		4,898	52,139	8.6%
16	30,752	491,790	5.9%	-	-		30,752	491,790	5.9%
18	-	448	0.0%	-	-		-	448	0.0%
19	700	200	77.8%	-	-		700	200	77.8%
20	4,464	419,844	1.1%	-	-		4,464	419,844	1.1%
24	2,717	132,121	2.0%	-	-		2,717	132,121	2.0%
30	986	57,145	1.7%	-	-		986	57,145	1.7%
36	642	1,501	30.0%	-	-		642	1,501	30.0%

OCA Statement No. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2018-3006818
	:	
Peoples Natural Gas Company, LLC	:	

Schedule GAW-4

PEOPLES NATURAL GAS COMPANY LLC
OCA CLASS COST OF SERVICE STUDY (CONSOLIDATED BASIS)
(SUMMARY)

		Total Combined	Residential Service	Small General Service	Medium General Service	Large General Service
Operating Income (At Current Rates):						
Non-Gas Rate Revenue		$ 377,213,659	$ 265,681,853	$ 32,006,975	$ 42,777,457	$ 36,747,373
Gas Revenue		$ 270,963,554	$ 203,033,014	$ 30,944,442	$ 24,410,131	$ 12,575,967
Other Revenue		$ 18,842,178	$ 8,227,205	$ 1,942,725	$ 2,233,372	$ 6,438,875
Total Revenue		$ 667,019,391	$ 476,942,073	$ 64,894,142	$ 69,420,960	$ 55,762,215
O&M Expenses		$ 462,991,184	$ 330,954,788	$ 46,061,312	$ 42,264,732	$ 43,710,352
Depreciation		$ 86,626,149	$ 56,588,179	$ 7,584,951	$ 8,865,710	$ 13,587,309
Taxes Other Than Income		$ 10,431,213	$ 6,487,859	$ 905,103	$ 1,132,965	$ 1,905,287
Income Taxes		$ 12,445,156	$ 10,964,333	$ 1,243,546	$ 2,293,701	$ (2,056,424)
Total Expenses		$ 572,493,702	$ 404,995,159	$ 55,794,912	$ 54,557,107	$ 57,146,524
Net Operating Income		$ 94,525,689	$ 71,946,914	$ 9,099,230	$ 14,863,853	$ (1,384,308)
Rate Base:						
Gross Plant In Service		$ 3,244,481,313	$ 1,989,262,830	$ 290,908,758	$ 375,912,664	$ 588,397,061
Depreciation Reserve		$ (1,057,114,518)	$ (674,905,993)	$ (91,913,236)	$ (113,674,782)	$ (176,620,508)
Net Plant		$ 2,187,366,795	$ 1,314,356,837	$ 198,995,523	$ 262,237,881	$ 411,776,553
Other Rate Base Items		$ (135,055,728)	$ (84,376,759)	$ (11,575,986)	$ (14,481,009)	$ (24,621,974)
Total Rate Base		$ 2,052,311,067	$ 1,229,980,078	$ 187,419,537	$ 247,756,873	$ 387,154,579
ROR At Current Rates		4.61%	5.85%	4.86%	6.00%	-0.36%
Required Increase @ Equal RORs:						
Required Income @ Company Requested ROR		$ 164,144,039	$ 98,373,926	$ 14,989,833	$ 19,815,619	$ 30,964,661
Income Deficiency (Excess) @ Equal ROR		$ 69,618,350	$ 26,427,013	$ 5,890,602	$ 4,951,766	$ 32,348,969
Revenue Conversion Factor	1.3624025					
Required Revenue Increase @ Equal ROR		$ 94,848,211	$ 36,004,227	$ 8,025,371	$ 6,746,298	$ 44,072,315
Pct Increase in Non-gas Revenue (Includes Other Revenue)		23.9%	13.1%	23.6%	15.0%	102.1%

PEOPLES NATURAL GAS COMPANY LLC
OCA CLASS COST OF SERVICE STUDY (CONSOLIDATED BASIS)
(RATE BASE)

	Account	Company Alloc	TAI Alloc	Total Combined	Residential Service	Small General Service	Medium General Service	Large General Service
RATE BASE								
I. GAS PLANT IN SERVICE								
A. INTANGIBLE PLANT								
Organization	301	PSTDPLT	43	$ 49,770	$ 30,261	$ 4,475	$ 5,851	$ 9,183
Franchise and Consents	302			$ -				
Miscellaneous Intangible Plant	303	IntangibleAcct303	69	$ 138,206,266	$ 100,578,679	$ 11,627,142	$ 10,708,806	$ 15,291,639
Subtotal - INTANGIBLE PLANT	301-303			$ 138,256,036	$ 100,608,940	$ 11,631,616	$ 10,714,658	$ 15,300,822
B. PRODUCTION PLANT								
Other Land & Land Rights-Land	325	GatherVolumes	6	$ 1,836,261	$ 326,558	$ 129,920	$ 331,457	$ 1,048,327
Gas Well Structures	326	GatherVolumes	6	$ -	$ -	$ -	$ -	$ -
Field Compressor Station Structures	327	GatherVolumes	6	$ 11,355,557	$ 2,019,455	$ 803,432	$ 2,049,749	$ 6,482,921
Field M&R Station Structures	328	GatherVolumes	6	$ 62,778	$ 11,164	$ 4,442	$ 11,332	$ 35,840
Other Structures	329	GatherVolumes	6	$ 1,923,583	$ 342,087	$ 136,098	$ 347,219	$ 1,098,179
Producing Gas Wells-Well Construction	330, 331	GatherVolumes	6	$ 12,205	$ 2,171	$ 864	$ 2,203	$ 6,968
Field Lines	332	GatherVolumes	6	$ 66,458,743	$ 11,818,922	$ 4,702,112	$ 11,996,220	$ 37,941,490
Field Compressor Station Equipment	333	GatherVolumes	6	$ 36,129,141	$ 6,425,152	$ 2,556,221	$ 6,521,536	$ 20,626,232
Field M&R Station Equip-Company	334	GatherVolumes	6	$ 6,256,209	$ 1,112,595	$ 442,641	$ 1,129,285	$ 3,571,688
Drilling & Cleaning Equipment	335	GatherVolumes	6	$ 18,642	$ 3,315	$ 1,319	$ 3,365	$ 10,643
Other Equipment-Other	337	GatherVolumes	6	$ 107,840	$ 19,178	$ 7,630	$ 19,466	$ 61,566
Subtotal - PRODUCTION PLANT	325-337			$ 124,160,959	$ 22,080,596	$ 8,784,679	$ 22,411,831	$ 70,883,852
C. NATURAL GAS STORAGE & PROCESSING PLANT								
Land and Land Rights	350	STORPT	40	$ 63,624	$ 34,221	$ 6,873	$ 10,293	$ 12,237
Structures and Improvements	351	STORPT	40	$ 1,733,972	$ 932,635	$ 187,318	$ 280,524	$ 333,495
Wells-Well Equipment	352	DesignDay	7	$ 1,868,356	$ 1,043,932	$ 210,276	$ 310,549	$ 303,598
Lines	353	Winter6	13	$ 2,134,447	$ 957,957	$ 189,460	$ 304,956	$ 682,075
Compressor Station Equipment - Other	354	DesignDay	7	$ 7,556,584	$ 4,222,195	$ 850,464	$ 1,256,019	$ 1,227,907
M&R Equipment-Meters & Gauges	355	Winter6	13	$ 75,749	$ 33,997	$ 6,724	$ 10,823	$ 24,206
Other Equipment	357	STORPT	40	$ 30,184	$ 16,235	$ 3,261	$ 4,883	$ 5,805
Subtotal - STORAGE PLANT	350-363			$ 13,462,916	$ 7,241,172	$ 1,454,375	$ 2,178,046	$ 2,589,323
D. TRANSMISSION PLANT								
Land & Land Rights	365	TRANPT	41	$ 3,036,718	$ 1,696,747	$ 341,771	$ 504,749	$ 493,451
Structures & Improvements	366	TRANPT	41	$ 2,931,326	$ 1,637,860	$ 329,909	$ 487,231	$ 476,326

PEOPLES NATURAL GAS COMPANY LLC
OCA CLASS COST OF SERVICE STUDY (CONSOLIDATED BASIS)
(RATE BASE)

	Account	Company Alloc	TAI Alloc	Total Combined	Residential Service	Small General Service	Medium General Service	Large General Service
Mains	367	DesignDay	7	$ 148,893,346	$ 83,193,237	$ 16,757,362	$ 24,748,331	$ 24,194,417
Compressor Station Equipment	368	DesignDay	7	$ 11,366,542	$ 6,350,985	$ 1,279,260	$ 1,889,292	$ 1,847,006
M&R Station Equipment	369	DesignDay	7	$ 33,706,719	$ 18,833,421	$ 3,793,559	$ 5,602,568	$ 5,477,172
Other Equipment	371	TRANPT	41	$ 2,464,382	$ 1,376,958	$ 277,357	$ 409,618	$ 400,450
Subtotal - TRANSMISSION PLANT	365-371			$ 202,399,033	$ 113,089,208	$ 22,779,217	$ 33,641,787	$ 32,888,821
E. DISTRIBUTION PLANT								
Land and Land Rights	374	DISTPT	42	$ 6,930,561	$ 4,383,915	$ 616,653	$ 766,588	$ 1,163,405
Structures and Improvements	375	DISTPT	42	$ 31,452,099	$ 19,894,975	$ 2,798,477	$ 3,478,911	$ 5,279,736
Low Pressure Mains	376	Peak & Average	28	$ 702,395,077	$ 347,075,355	$ 69,115,381	$ 107,570,614	$ 178,633,728
Regulated Pressure Mains	376	Peak & Average	28	$ 931,934,664	$ 460,498,036	$ 91,701,979	$ 142,724,213	$ 237,010,435
M & R Station Equipment	378	DesignDay	7	$ 67,674,628	$ 37,812,780	$ 7,616,514	$ 11,248,549	$ 10,996,785
Services	380	Service_Invest	15	$ 632,413,944	$ 590,954,989	$ 33,668,295	$ 7,462,456	$ 328,204
Meters	381	Meter_Invest	16	$ 126,828,614	$ 105,952,549	$ 14,515,233	$ 5,992,268	$ 368,564
Meter Installations	382	Meter_Invest	16	$ 90,344,063	$ 75,473,377	$ 10,339,663	$ 4,268,483	$ 262,540
Industrial M & R Station Equipment	385	M&R Equipment	17	$ 10,644,190	$ -	$ 646,956	$ 5,069,737	$ 4,927,497
Other Property on Customers Premise	386	Meter_Invest	16	$ 14,644,532	$ 12,234,033	$ 1,676,032	$ 691,910	$ 42,557
Other Equipment	387	DISTPT	42	$ 7,666,771	$ 4,849,604	$ 682,157	$ 848,020	$ 1,286,990
Subtotal - DISTRIBUTION PLANT	374-387			$ 2,622,929,143	$ 1,659,129,613	$ 233,377,340	$ 290,121,749	$ 440,300,440
F. GENERAL PLANT								
Land and Land Rights	389	PSTDPLT	43	$ 239,065	$ 145,357	$ 21,494	$ 28,107	$ 44,107
Structures and Improvements	390	PSTDPLT	43	$ 14,752,383	$ 8,969,776	$ 1,326,370	$ 1,734,433	$ 2,721,804
Office Furniture and Equipment	391	PSTDPLT	43	$ 10,087,950	$ 6,133,697	$ 906,996	$ 1,186,037	$ 1,861,219
Transportation Equipment	392	PSTDPLT	43	$ 64,888,326	$ 39,453,542	$ 5,834,035	$ 7,628,902	$ 11,971,848
Stores Equipment	393	PSTDPLT	43	$ -	$ -	$ -	$ -	$ -
Tools, Shop and Garage Equipment	394	PSTDPLT	43	$ 7,472,455	$ 4,543,418	$ 671,840	$ 878,534	$ 1,378,662
Laboratory Equipment	395	PSTDPLT	43	$ -	$ -	$ -	$ -	$ -
Power Operated Equipment	396	PSTDPLT	43	$ 8,956,064	$ 5,445,486	$ 805,229	$ 1,052,962	$ 1,652,387
Communication Equipment	397	PSTDPLT	43	$ 36,638,721	$ 22,277,155	$ 3,294,145	$ 4,307,604	$ 6,759,817
Miscellaneous Equipment	398	PSTDPLT	43	$ 238,262	$ 144,869	$ 21,422	$ 28,012	$ 43,959
Other Tangible Plant	399	PSTDPLT	43	$ -	$ -	$ -	$ -	$ -
Subtotal - GENERAL PLANT	389-399			$ 143,273,226	$ 87,113,300	$ 12,881,531	$ 16,844,592	$ 26,433,803
TOTAL PLANT IN SERVICE				$ 3,244,481,313	$ 1,989,262,830	$ 290,908,758	$ 375,912,664	$ 588,397,061

PEOPLES NATURAL GAS COMPANY LLC
OCA CLASS COST OF SERVICE STUDY (CONSOLIDATED BASIS)
(RATE BASE)

	Account	Company Alloc	TAI Alloc	Total Combined	Residential Service	Small General Service	Medium General Service	Large General Service
G. UTILITY PLANT	105			$ -				
TOTAL UTILITY PLANT				$ 3,244,481,313	$ 1,989,262,830	$ 290,908,758	$ 375,912,664	$ 588,397,061
II. DEPRECIATION RESERVE								
Intangible Plant	303	303	44	$ 65,311,840	$ 47,530,251	$ 5,494,614	$ 5,060,638	$ 7,226,337
Production Plant	325-337	325 - 337	45	$ 53,322,074	$ 9,482,717	$ 3,772,662	$ 9,624,969	$ 30,441,727
Local Storage Plant	350-357	350 - 357	46	$ 6,429,466	$ 3,458,156	$ 694,564	$ 1,040,167	$ 1,236,579
Transmission	365-371	365 - 371	47	$ 73,881,343	$ 41,280,744	$ 8,315,055	$ 12,280,199	$ 12,005,345
Distribution Land Structures & Improvements	374-375	374 - 375	48	$ 21,661,764	$ 13,702,114	$ 1,927,374	$ 2,396,004	$ 3,636,272
Distribution Mains	376	376	49	$ 412,081,098	$ 203,622,146	$ 40,548,607	$ 63,109,521	$ 104,800,824
Distribution M&R General	378	378	50	$ 27,099,121	$ 15,141,466	$ 3,049,900	$ 4,504,285	$ 4,403,470
Distribution Services	380	380	51	$ 257,018,152	$ 240,168,897	$ 13,683,068	$ 3,032,802	$ 133,385
Distribution - Meters	381	381	52	$ 28,466,508	$ 23,780,904	$ 3,257,924	$ 1,344,956	$ 82,724
Distribution - Meters Installations	382	382	53	$ 37,863,819	$ 31,631,412	$ 4,333,424	$ 1,788,951	$ 110,032
Industrial M & R Station Equipment - Other	385	385	54	$ 4,876,879	$ -	$ 296,418	$ 2,322,816	$ 2,257,645
Other Property on Customers Premises	386	386	55	$ 13,387,293	$ 11,183,737	$ 1,532,144	$ 632,509	$ 38,903
Other Equipment	387	387	56	$ 1,932,405	$ 1,222,340	$ 171,937	$ 213,743	$ 324,385
General Plant	389-399	389 - 399	57	$ 53,782,756	$ 32,701,109	$ 4,835,546	$ 6,323,223	$ 9,922,878
TOTAL DEPRECIATION RESERVE (PLANT IN SERVICE)				$ 1,057,114,518	$ 674,905,993	$ 91,913,236	$ 113,674,782	$ 176,620,508
Retirement Obligation								
TOTAL - DEPRECIATION RESERVE				$ 1,057,114,518	$ 674,905,993	$ 91,913,236	$ 113,674,782	$ 176,620,508
III. OTHER RATE BASE ITEMS								
Gas Storage Underground - NonCurrent		STORPT	40	$ -	$ -	$ -	$ -	$ -
Gas Stored Underground - Current		STORPT	40	$ 31,115,826	$ 16,735,976	$ 3,361,388	$ 5,033,955	$ 5,984,507
Materials and Supplies		PSTDPLT	43	$ 3,202,304	$ 1,947,072	$ 287,915	$ 376,494	$ 590,823
Prepayments		PSTDPLT	43	$ 6,409,880	$ 3,897,350	$ 576,305	$ 753,608	$ 1,182,618
Cash Working Capital		PSTDPLT	43	$ 35,194,786	$ 21,399,211	$ 3,164,323	$ 4,137,841	$ 6,493,412
Deferred Income Taxes		PSTDPLT	43	$ (207,849,485)	$ (126,377,099)	$ (18,687,508)	$ (24,436,804)	$ (38,348,075)
Customer Advances and Deposits		DISTPT	42	$ (3,129,038)	$ (1,979,268)	$ (278,409)	$ (346,102)	$ (525,259)
Total - OTHER RATE BASE ITEMS				$ (135,055,728)	$ (84,376,759)	$ (11,575,986)	$ (14,481,009)	$ (24,621,974)

PEOPLES NATURAL GAS COMPANY LLC
OCA CLASS COST OF SERVICE STUDY (CONSOLIDATED BASIS)
(RATE BASE)

	Account	Company Alloc	TAI Alloc	Total Combined	Residential Service	Small General Service	Medium General Service	Large General Service
TOTAL RATE BASE (Excl. Working Capital)				$ 2,052,311,067	$ 1,229,980,078	$ 187,419,537	$ 247,756,873	$ 387,154,579
Gas Purchases Cash Working Capital			31	$ -				
TOTAL RATE BASE				$ 2,052,311,067	$ 1,229,980,078	$ 187,419,537	$ 247,756,873	$ 387,154,579

PEOPLES NATURAL GAS COMPANY LLC
OCA CLASS COST OF SERVICE STUDY (CONSOLIDATED BASIS)
(EXPENSES)

	Account	Company Alloc	TAI Alloc	Total Combined	Residential Service	Small General Service	Medium General Service	Large General Service
EXPENSES								
I. OPERATION & MAINTENANCE EXPENSE								
A. NATURAL GAS PRODUCTION EXPENSES								
1. Natural Gas Production and Gathering								
a. Operations Accounts								
Operation Supervision & Engineering	750	GatherVolumes	6	$ 35	$ 6	$ 2	$ 6	$ 20
Production Maps	751	GatherVolumes	6	$ 1,885	$ 335	$ 133	$ 340	$ 1,076
Gas Wells Expense	752	GatherVolumes	6	$ 542	$ 96	$ 38	$ 98	$ 309
Field Lines Expense	753	GatherVolumes	6	$ 1,365,473	$ 242,834	$ 96,610	$ 246,476	$ 779,552
Field Compressor Station Expense	754756	GatherVolumes	6	$ 2,518,612	$ 447,906	$ 178,198	$ 454,625	$ 1,437,883
Other Expense	759	GatherVolumes	6	$ 60,043	$ 10,678	$ 4,248	$ 10,838	$ 34,278
Rents	760	GatherVolumes	6	$ 14,440	$ 2,568	$ 1,022	$ 2,606	$ 8,244
Subtotal - Operation Accounts	751-760			$ 3,961,029	$ 704,423	$ 280,252	$ 714,991	$ 2,261,363
b. Maintenance Accounts								
Maint Supervision & Engineering	762	GatherVolumes	6	$ 12,148	$ 2,160	$ 859	$ 2,193	$ 6,935
Producing Gas Wells Maintenance	763	GatherVolumes	6	$ 10,037	$ 1,785	$ 710	$ 1,812	$ 5,730
Field Lines	764, 787	GatherVolumes	6	$ 3,683,864	$ 655,133	$ 260,642	$ 664,961	$ 2,103,129
Field Meas/Reg	765, 766	GatherVolumes	6	$ 2,077,359	$ 369,434	$ 146,978	$ 374,976	$ 1,185,971
Other Equipment	769	GatherVolumes	6	$ 47,400	$ 8,429	$ 3,354	$ 8,556	$ 27,061
Subtotal - Maintenance Accounts	762-787			$ 5,830,808	$ 1,036,942	$ 412,543	$ 1,052,497	$ 3,328,825
Subtotal - Production and Gathering	751-787			$ 9,791,837	$ 1,741,365	$ 692,795	$ 1,767,488	$ 5,590,188
2. Other Gas Supply Expenses								
Nat Gas Well Head Purchases	800	Gas Cost Revenues	9	$ 270,963,554	$ 203,033,014	$ 30,944,442	$ 24,410,131	$ 12,575,967
Gas used for Compressor Station Fuel - Credit	810	Sales_Firm	5	$ (2,119,878)	$ (1,720,296)	$ (252,180)	$ (140,666)	$ (6,736)
Gas used for Other Util Ops-Credit	812755	Sales_Firm	5	$ 1,581,500	$ 1,283,399	$ 188,134	$ 104,942	$ 5,025
Other Gas Supply Expenses	813	Sales_Firm	5	$ 597,166	$ 484,605	$ 71,039	$ 39,625	$ 1,897
Subtotal - Other Gas Supply Expenses	801-813			$ 271,022,343	$ 203,080,721	$ 30,951,435	$ 24,414,032	$ 12,576,154
Subtotal - PRODUCTION EXPENSES	751-813			$ 280,814,180	$ 204,822,087	$ 31,644,231	$ 26,181,520	$ 18,166,342

PEOPLES NATURAL GAS COMPANY LLC
OCA CLASS COST OF SERVICE STUDY (CONSOLIDATED BASIS)
(EXPENSES)

	Account	Company Alloc	TAI Alloc	Total Combined	Residential Service	Small General Service	Medium General Service	Large General Service
B. STORAGE, TERMINALING & PROCESSING EXPENSES								
a. Operations Accounts								
Wells Expense	816	STORPT	40	$ 6,546	$ 3,521	$ 707	$ 1,059	$ 1,259
Lines Expenses	817	STORPT	40	$ 1,567	$ 843	$ 169	$ 254	$ 301
Compressor Station Expenses	818	STORPT	40	$ 625,975	$ 336,687	$ 67,623	$ 101,271	$ 120,394
Compressor Station Fuel	819	Sales_Firm	5	$ 96,499	$ 78,309	$ 11,479	$ 6,403	$ 307
Meas/Reg Station Expenses	820	STORPT	40	$ 664	$ 357	$ 72	$ 107	$ 128
Gas Losses	823	Sales_Firm	5	$ 245,946	$ 199,587	$ 29,258	$ 16,320	$ 781
Other Expenses	824	STORPT	40	$ 167	$ 90	$ 18	$ 27	$ 32
Storage Well Royalties	825	STORPT	40	$ 7,550	$ 4,061	$ 816	$ 1,221	$ 1,452
Subtotal - Operations Accounts	816-825			$ 984,914	$ 623,455	$ 110,142	$ 126,663	$ 124,654
b. Maintenance Accounts								
Maint. of Structures & Improvements	831	STORPT	40	$ 112	$ 60	$ 12	$ 18	$ 22
Maint. of Reservoirs and Wells	832	STORPT	40	$ 2,182	$ 1,174	$ 236	$ 353	$ 420
Maint. of Lines	833	STORPT	40	$ 22,434	$ 12,066	$ 2,424	$ 3,629	$ 4,315
Maint. of Compressor Station Equipment	834	STORPT	40	$ 303,536	$ 163,260	$ 32,790	$ 49,106	$ 58,379
Maint. of Meas/Reg Station Equipment	835	STORPT	40	$ 188	$ 101	$ 20	$ 30	$ 36
Maint. Of Other Equipment	837	STORPT	40	$ 165	$ 89	$ 18	$ 27	$ 32
Subtotal - Maintenance Accounts	831-837			$ 328,617	$ 176,750	$ 35,500	$ 53,164	$ 63,203
Subtotal - STORAGE EXPENSES	816-837			$ 1,313,530	$ 800,205	$ 145,642	$ 179,827	$ 187,857
C. TRANSMISSION EXPENSES								
a. Operations Accounts								
Supvervision/Engineering	850	TRANPT	41	$ 546	$ 305	$ 61	$ 91	$ 89
Compressor Station Labor & Expenses	853			$ -				
Mains Expense	856	TRANPT	41	$ 734,628	$ 410,469	$ 82,679	$ 122,106	$ 119,373
Meas/Reg Station Expenses	857	TRANPT	41	$ 177,805	$ 99,348	$ 20,011	$ 29,554	$ 28,892
Transmission/Compressor Ga	858			$ -				
Other Expenses	859	TRANPT	41	$ 8,640	$ 4,827	$ 972	$ 1,436	$ 1,404
Rents	860	TRANPT	41	$ 37,769	$ 21,103	$ 4,251	$ 6,278	$ 6,137
Subtotal - Operation Accounts	856-860			$ 959,388	$ 536,052	$ 107,975	$ 159,465	$ 155,896

PEOPLES NATURAL GAS COMPANY LLC
OCA CLASS COST OF SERVICE STUDY (CONSOLIDATED BASIS)
(EXPENSES)

	Account	Company Alloc	TAI Alloc	Total Combined	Residential Service	Small General Service	Medium General Service	Large General Service
b. Maintenance Accounts								
Maint. of Structures & Improvements	862	TRANPT	41	$ 9,340	$ 5,219	$ 1,051	$ 1,552	$ 1,518
Maint. of Mains	863	TRANPT	41	$ 2,128,764	$ 1,189,434	$ 239,584	$ 353,833	$ 345,913
Maint. Of Compressor Station	864	TRANPT	41	$ 726	$ 405	$ 82	$ 121	$ 118
Maint. Of Meas/Reg Station Equipment	865	TRANPT	41	$ 1,267,317	$ 708,105	$ 142,632	$ 210,647	$ 205,933
Maint. of Communication Equipment	866	TRANPT	41	$ 183,491	$ 102,525	$ 20,651	$ 30,499	$ 29,816
Maint of Other Equipment	867	TRANPT	41	$ 9,696	$ 5,418	$ 1,091	$ 1,612	$ 1,576
Subtotal - Maintenance Accounts	863-867			$ 3,599,334	$ 2,011,106	$ 405,091	$ 598,264	$ 584,874
Subtotal - TRANSMISSION EXPENSES	850-865			$ 4,558,722	$ 2,547,158	$ 513,066	$ 757,729	$ 740,769
D. DISTRIBUTION EXPENSES								
Operation Supervision & Engineering	870	DISTO&M_LABOR	60	$ (1,180,735)	$ (858,617)	$ (104,598)	$ (98,521)	$ (118,998)
Distribution Load Dispatching	871	Thruput	4	$ 1,545	$ 664	$ 130	$ 216	$ 535
Mains and Services Expenses	874	DISTMAIN-SERVICE	58	$ 12,198,679	$ 7,526,302	$ 1,046,642	$ 1,387,143	$ 2,238,592
Meas. & Reg. Station Expenses	875	DesignDay	7	$ 3,282,135	$ 1,833,873	$ 369,391	$ 545,541	$ 533,330
Meas. & Reg. Station Expenses - City Gate	877	DesignDay	7	$ 47,258	$ 26,405	$ 5,319	$ 7,855	$ 7,679
Meter & House Regulator Expenses	878	DISTMETER-REG	61	$ 5,800,677	$ 4,845,882	$ 663,874	$ 274,064	$ 16,857
Customer Installations Expenses	879	Service_Invest	15	$ 5,354,119	$ 5,003,121	$ 285,041	$ 63,178	$ 2,779
Other Expenses	880	DISTO&M	62	$ 2,695,806	$ 1,634,964	$ 252,396	$ 323,849	$ 484,597
Rents	881	DISTO&M	62	$ 390,129	$ 236,607	$ 36,526	$ 46,866	$ 70,129
Maint. of Structures & Improvements	886	DISTPT	42	$ 3,850,598	$ 2,435,690	$ 342,610	$ 425,914	$ 646,384
Maint. of Mains	887	MAINSPT	59	$ 29,797,704	$ 14,723,977	$ 2,932,082	$ 4,563,468	$ 7,578,178
Maint. of Compressor Station Equip.	888	DesignDay	7	$ 128,833	$ 71,984	$ 14,500	$ 21,414	$ 20,935
Maint. of Meas. & Reg. Station Expenses-General	889	DesignDay	7	$ 1,430,816	$ 799,460	$ 161,033	$ 237,823	$ 232,500
Maint. of Meas. & Reg. Station Expenses-Indust.	890	M&R Equipment	17	$ 1,555	$ -	$ 95	$ 741	$ 720
Maint. of Services	892	Service_Invest	15	$ 987,954	$ 923,187	$ 52,596	$ 11,658	$ 513
Maint. of Meters & House Regulators	893	DISTMETER-REG	61	$ 388,121	$ 324,236	$ 44,420	$ 18,338	$ 1,128
Maint. of Other Equipment	894	DISTO&M	62	$ 598,328	$ 362,877	$ 56,019	$ 71,878	$ 107,555
Subtotal - DISTRIBUTION EXPENSES	870-894			$ 65,773,523	$ 39,890,611	$ 6,158,074	$ 7,901,425	$ 11,823,412
Total - OPERATION & MAINTENANCE EXPENSES				$ 352,459,955	$ 248,060,061	$ 38,461,013	$ 35,020,501	$ 30,918,380
II. CUSTOMER ACCOUNTS EXPENSES								
Supervision	901			$ -				
Meter Reading Expenses	902	CUST-902	20	$ 4,799,922	$ 4,107,589	$ 368,596	$ 195,411	$ 128,327
Customer Records & Collection Expense	903	CUST-903	21	$ 17,132,673	$ 15,993,032	$ 1,020,735	$ 111,593	$ 7,313
Uncollectible Accounts	904	Write-Offs	19	$ 15,502,183	$ 15,121,513	$ 355,028	$ 23,433	$ 2,210
Subtotal - CUSTOMER ACCOUNTS EXPENSES	902-904			$ 37,434,779	$ 35,222,133	$ 1,744,360	$ 330,436	$ 137,851

PEOPLES NATURAL GAS COMPANY LLC
OCA CLASS COST OF SERVICE STUDY (CONSOLIDATED BASIS)
(EXPENSES)

	Account	Company Alloc	TAI Alloc	Total Combined	Residential Service	Small General Service	Medium General Service	Large General Service
III. CUSTOMER SERVICE & INFORMATIONAL EXPENSES								
Supervision	907	CUST-908-910	63	$ 437,767	$ 420,250	$ 15,698	$ 1,819	$ 0
Customer Assistance Expenses	908	CUST-908	22	$ 2,892,225	$ 2,884,801	$ 7,424	$ -	$ -
Info. & Instructional Advertising Expnese	909	CUST_AVG_XLGS	64	$ 3,206,633	$ 2,970,162	$ 211,151	$ 25,320	$ -
Misc. Customer Serv. & Inform. Expen.	910	Cust_Avg	1	$ 4,280	$ 3,963	$ 282	$ 34	$ 2
Subtotal - CUSTOMER SERVICE	907-910			$ 6,540,906	$ 6,279,177	$ 234,555	$ 27,173	$ 2
IV. SALES EXPENSES (C-8)								
Supervision	911			$ -				
Demonstrating & Selling Expenses	912, 913	CUST-912	23	$ 1,371,405	$ 431,769	$ 19,663	$ 5,574	$ 914,398
Miscellaneous Sales Expenses	916			$ -				
Subtotal - SALES EXPENSES	911-916			$ 1,371,405	$ 431,769	$ 19,663	$ 5,574	$ 914,398
Total-CUSTOMER ACCOUNTS, SERVICES & SALES EXPENSES	901-916			$ 45,347,090	$ 41,933,079	$ 1,998,577	$ 363,183	$ 1,052,251
V. ADMINISTRATIVE & GENERAL EXPENSES								
A. Labor-Related:								
Administrative & General Salaries	920	LABOR	65	$ 23,893,169	$ 15,143,843	$ 2,009,424	$ 2,413,253	$ 4,326,650
Office Supplies & Expenses	921	LABOR	65	$ 8,757,941	$ 5,550,912	$ 736,546	$ 884,568	$ 1,585,915
Admin. Expenses Transferred-Credit	922	LABOR	65	$ (23,185,277)	$ (14,695,171)	$ (1,949,890)	$ (2,341,754)	$ (4,198,462)
Outside Services Employed	923	LABOR	65	$ 15,787,796	$ 10,006,538	$ 1,327,759	$ 1,594,595	$ 2,858,903
Employee Pensions and Benefits	926	LABOR	65	$ 20,943,808	$ 13,274,494	$ 1,761,382	$ 2,115,362	$ 3,792,570
Subtotal - A&G Labor-Related	920-923, 926			$ 46,197,437	$ 29,280,617	$ 3,885,221	$ 4,666,023	$ 8,365,576
B. Plant-Related:								
Property Insurance	924	PSTDPLT	43	$ 293,432	$ 178,413	$ 26,382	$ 34,499	$ 54,138
Injuries and Damages	925	PSTDPLT	43	$ 8,174,163	$ 4,970,072	$ 734,930	$ 961,034	$ 1,508,127
Maintenance of General Plant	932	PSTDPLT	43	$ 176,258	$ 107,169	$ 15,847	$ 20,723	$ 32,520
Subtotal - A&G Plant-Related	924-925, 932			$ 8,643,854	$ 5,255,655	$ 777,159	$ 1,016,255	$ 1,594,785
C. Other-Related:								
Franchise Requirements	927			$ -				
Regulatory Commission Expenses	928	OPERREV	66	$ 1,277,369	$ 913,363	$ 124,275	$ 132,944	$ 106,787
Duplicate Charges - Credit	929			$ -				
Misc. Gen'l Expenses	930	PSTDPLT	43	$ 5,822,580	$ 3,540,258	$ 523,501	$ 684,559	$ 1,074,262
Rents	931	PSTDPLT	43	$ 3,242,900	$ 1,971,755	$ 291,565	$ 381,267	$ 598,313
Subtotal - A&G Other-Related	927-931			$ 10,342,849	$ 6,425,376	$ 939,342	$ 1,198,770	$ 1,779,361

PEOPLES NATURAL GAS COMPANY LLC
OCA CLASS COST OF SERVICE STUDY (CONSOLIDATED BASIS)
(EXPENSES)

	Account	Company Alloc	TAI Alloc	Total Combined	Residential Service	Small General Service	Medium General Service	Large General Service
Total - ADMINISTRATIVE & GENERAL EXPENSES	920-932			$ 65,184,139	$ 40,961,648	$ 5,601,721	$ 6,881,048	$ 11,739,722
TOTAL - OPERATING EXPENSES (Excl. Depr., Taxes, and Gas Supply Expense)				$ 182,177,004	$ 126,132,701	$ 14,417,081	$ 16,083,212	$ 25,544,010
VI. DEPRECIATION EXPENSE								
Intangible Plant	403.01	IntangPlt	67	$ 16,985,001	$ 12,359,988	$ 1,428,965	$ 1,316,315	$ 1,879,733
Production Plant	403.02	ProdPlt	68	$ 2,725,264	$ 484,657	$ 192,819	$ 491,927	$ 1,555,861
Storage Plant	403.03	STORPT	40	$ 296,238	$ 159,335	$ 32,002	$ 47,926	$ 56,975
Transmission	403.04	TRANPT	41	$ 3,162,820	$ 1,767,206	$ 355,963	$ 525,709	$ 513,942
Distribution Land Structures & Improvements	403.05	DISTPT	42	$ 1,262,031	$ 798,296	$ 112,290	$ 139,593	$ 211,852
Distribution Mains	403.06	MAINSPT	59	$ 27,818,560	$ 13,746,020	$ 2,737,335	$ 4,260,365	$ 7,074,840
Distribution M&R General	403.07	DesignDay	7	$ 1,426,582	$ 797,094	$ 160,556	$ 237,120	$ 231,812
Distribution Services	403.08	Service_Invest	15	$ 15,295,585	$ 14,292,857	$ 814,303	$ 180,487	$ 7,938
Distribution - Meters	403.09	Meter_Invest	16	$ 4,930,443	$ 4,118,889	$ 564,277	$ 232,948	$ 14,328
Distribution - Meters Installations	403.10	Meter_Invest	16	$ 1,741,537	$ 1,454,879	$ 199,315	$ 82,282	$ 5,061
Industrial M & R Station Equipment - Other	403.11	M&R Equipment	17	$ 225,744	$ -	$ 13,721	$ 107,520	$ 104,503
Other Property on Customers Premises	403.12	Meter_Invest	16	$ 269,216	$ 224,903	$ 30,811	$ 12,720	$ 782
Other Equipment	403.13	DISTPT	42	$ 311,886	$ 197,283	$ 27,750	$ 34,498	$ 52,355
General Plant	403.14	PSTDPLT	43	$ 10,175,242	$ 6,186,773	$ 914,844	$ 1,196,300	$ 1,877,325
Total - DEPRECIATION EXPENSE	403			$ 86,626,149	$ 56,588,179	$ 7,584,951	$ 8,865,710	$ 13,587,309
VII. TAXES OTHER THAN INCOME TAXES								
A. General Taxes								
Payroll Taxes	408.15	LABOR	65	$ 5,639,213	$ 3,574,217	$ 474,260	$ 569,571	$ 1,021,166
Plant Related Taxes	408.17	PSTDPLT	43	$ 4,792,000	$ 2,913,642	$ 430,843	$ 563,394	$ 884,120
Gas Related	408.18			$ -				
Subtotal - General Taxes				$ 10,431,213	$ 6,487,859	$ 905,103	$ 1,132,965	$ 1,905,287
				$ -	$ -	$ -	$ -	$ -
TOTAL EXPENSES (excl. GRT & Gas Purchases)	408.1			$ 279,234,366	$ 189,208,739	$ 22,907,135	$ 26,081,886	$ 41,036,606
B. Revenue Taxes: (GRT)								
State Gross Earnings	408.11			$ -				
Municipal Tax	408.12			$ -				
Subtotal - Revenue Taxes (GRT)				$ -				$ 2

PEOPLES NATURAL GAS COMPANY LLC
OCA CLASS COST OF SERVICE STUDY (CONSOLIDATED BASIS)
(EXPENSES)

	Account	Company Alloc	TAI Alloc	Total Combined	Residential Service	Small General Service	Medium General Service	Large General Service
Calculation of Taxable Income								
Total Revenue				$ 667,019,391	$ 476,942,073	$ 64,894,142	$ 69,420,960	$ 55,762,215
Total O&M Expenses				$ 462,991,184	$ 330,954,788	$ 46,061,312	$ 42,264,732	$ 43,710,352
Depreciation				$ 86,626,149	$ 56,588,179	$ 7,584,951	$ 8,865,710	$ 13,587,309
Taxes Other Than Income				$ 10,431,213	$ 6,487,859	$ 905,103	$ 1,132,965	$ 1,905,287
EBIT				$ 106,970,845	$ 82,911,247	$ 10,342,776	$ 17,157,554	$ (3,440,733)
Interest @ 1.96% Weighted Cost of Debt				$ 40,225,297	$ 24,107,610	$ 3,673,423	$ 4,856,035	$ 7,588,230
Taxable Income				$ 66,745,548	$ 58,803,637	$ 6,669,353	$ 12,301,519	$ (11,028,962)
Income Taxes				$ 12,445,156	$ 10,964,333	$ 1,243,546	$ 2,293,701	$ (2,056,424)
Net Operating Income				$ 94,525,689	$ 71,946,914	$ 9,099,230	$ 14,863,853	$ (1,384,308)
Rate Base				$ 2,052,311,067	$ 1,229,980,078	$ 187,419,537	$ 247,756,873	$ 387,154,579
Rate of Return @ Present Rates				4.61%	5.85%	4.86%	6.00%	-0.36%

PEOPLES NATURAL GAS COMPANY LLC
OCA CLASS COST OF SERVICE STUDY (CONSOLIDATED BASIS)
(LABOR)

	Account	Company Alloc	TAI Alloc	Total Combined	Residential Service	Small General Service	Medium General Service	Large General Service
LABOR SUBREPORT: FUNCTIONALIZATION PHASE								
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1. PRODUCTION:								
	751-766	GatherVolumes	6	$ 5,115,264	$ 909,691	$ 361,917	$ 923,337	$ 2,920,319
	801-813	GatherVolumes	6	$ 514,073	$ 91,422	$ 36,372	$ 92,793	$ 293,486
Sub Production				$ 5,629,337	$ 1,001,113	$ 398,289	$ 1,016,131	$ 3,213,805
2. STORAGE:								
	816-825	STORPT	40	$ 515,980	$ 277,525	$ 55,740	$ 83,476	$ 99,238
	831-835	STORPT	40	$ 170,027	$ 91,451	$ 18,368	$ 27,507	$ 32,701
Sub Storage				$ 686,007	$ 368,976	$ 74,108	$ 110,983	$ 131,940
3. TRANSMISSION:								
	856-860	TRANPT	41	$ 590,111	$ 329,721	$ 66,415	$ 98,085	$ 95,890
	863-866	TRANPT	41	$ 2,022,548	$ 1,130,086	$ 227,630	$ 336,178	$ 328,654
Sub Transmission				$ 2,612,659	$ 1,459,807	$ 294,045	$ 434,264	$ 424,544
4. DISTRIBUTION, Customer Accounting & Sales ETC								
	870	DISTO&M_LABOR	60	$ (1,216,023)	$ (884,279)	$ (107,724)	$ (101,466)	$ (122,555)
	871	Thruput	4	$ 1,139	$ 489	$ 96	$ 160	$ 394
	874	DISTMAIN-SERVICE	58	$ 9,131,486	$ 5,633,916	$ 783,478	$ 1,038,365	$ 1,675,728
	875	DesignDay	7	$ 2,642,455	$ 1,476,455	$ 297,398	$ 439,216	$ 429,386
	877	DesignDay	7	$ 36,535	$ 20,414	$ 4,112	$ 6,073	$ 5,937
	878	DISTMETER-REG	61	$ 4,737,480	$ 3,957,688	$ 542,193	$ 223,832	$ 13,767
	879	Service_Invest	15	$ 4,561,360	$ 4,262,333	$ 242,837	$ 53,824	$ 2,367
	880	DISTO&M	62	$ 2,205,472	$ 1,337,584	$ 206,488	$ 264,945	$ 396,454
	886	DISTPT	42	$ 814,487	$ 515,202	$ 72,470	$ 90,090	$ 136,725
	887	MAINSPT	59	$ 16,054,262	$ 7,932,912	$ 1,579,733	$ 2,458,683	$ 4,082,934
	888	DesignDay	7	$ 124,437	$ 69,528	$ 14,005	$ 20,683	$ 20,220
	889	DesignDay	7	$ 988,673	$ 552,415	$ 111,271	$ 164,332	$ 160,654
	890	M&R Equipment	17	$ 1,145	$ -	$ 70	$ 545	$ 530
	892	Service_Invest	15	$ 1,125,777	$ 1,051,975	$ 59,934	$ 13,284	$ 584
	893	DISTMETER-REG	61	$ 316,722	$ 264,590	$ 36,248	$ 14,964	$ 920
	894	DISTO&M	62	$ 434,662	$ 263,616	$ 40,695	$ 52,216	$ 78,135
	901			$ -				
	902	CUST-902	20	$ 2,275,681	$ 1,947,440	$ 174,754	$ 92,646	$ 60,841
	903	CUST-903	21	$ 8,647,282	$ 8,072,077	$ 515,190	$ 56,324	$ 3,691
	907	CUST-908-910	63	$ 495,796	$ 475,957	$ 17,779	$ 2,060	$ 0
	908	CUST-908	22	$ 336,449	$ 335,585	$ 864	$ -	$ -
	910	Cust_Avg	1	$ (13)	$ (12)	$ (1)	$ (0)	$ (0)
	912	CUST-912	23	$ 1,290,232	$ 406,213	$ 18,499	$ 5,244	$ 860,276
	916		31	$ -				
Sub Distribution				$ 55,005,497	$ 37,692,099	$ 4,610,388	$ 4,896,020	$ 7,806,989
				$ -				
5. TOTAL: LABOR allocator				$ 63,933,500	$ 40,521,995	$ 5,376,830	$ 6,457,397	$ 11,577,277

PEOPLES NATURAL GAS COMPANY LLC
OCA CLASS COST OF SERVICE STUDY (CONSOLIDATED BASIS)
(REVENUE)

	Account	Company Alloc	TAI Alloc	Total Combined	Residential Service	Small General Service	Medium General Service	Large General Service
OPERATING REVENUES								
Sales & Transportation Operating Revenues	480-485	Margin	10	$ 377,213,659	$ 265,681,853	$ 32,006,975	$ 42,777,457	$ 36,747,373
Gas Revenues		Gas Cost Revenues	9	$ 270,963,554	$ 203,033,014	$ 30,944,442	$ 24,410,131	$ 12,575,967
Forfeited Discounts	487	Collections	24	$ 4,405,264	$ 4,165,298	$ 133,614	$ 76,631	$ 29,722
Miscellaneous Service Revenues		ConnectionFee	25	$ 3,254,481	$ 2,087,364	$ 1,042,267	$ 122,067	$ 2,783
Gathering		GatherVolumes	6	$ 8,929,271	$ 1,587,968	$ 631,767	$ 1,611,789	$ 5,097,747
Intercompany Software License Fees		GatherVolumes	6	$ 119,962	$ 21,334	$ 8,488	$ 21,654	$ 68,486
Pooling		TRANSPORT_Thru	29	$ 1,931,541	$ 259,015	$ 110,894	$ 380,705	$ 1,180,927
Direct Customer Cashouts		LGSDirect	30	$ 27,049	$ -	$ -	$ -	$ 27,049
Royalties		Margin	10	$ 328	$ 231	$ 28	$ 37	$ 32
Tax Discount		Margin	10	$ 300	$ 211	$ 25	$ 34	$ 29
Rent from Gas Property		PSTDPLT	43	$ 173,982	$ 105,785	$ 15,643	$ 20,455	$ 32,100
Total - OPERATING REVENUES				$ 667,019,391	$ 476,942,073	$ 64,894,142	$ 69,420,960	$ 55,762,215

PEOPLES NATURAL GAS COMPANY LLC
OCA CLASS COST OF SERVICE STUDY (CONSOLIDATED BASIS)
(ALLOCATION AMOUNT)

	Account	Company Alloc	TAI Alloc	Total Combined	Residential Service	Small General Service	Medium General Service	Large General Service
Cust_Avg			1	$ 627,488	$ 580,997	$ 41,304	$ 4,953	$ 235
SmCust_Avg			2	$ 622,300	$ 580,997	$ 41,304	$ -	$ -
LGCust_Avg			3	$ 5,188	$ -	$ -	$ 4,953	$ 235
Thruput			4	$ 116,532,613	$ 50,052,933	$ 9,818,232	$ 16,324,057	$ 40,337,390
Sales_Firm			5	$ 50,820,315	$ 41,241,059	$ 6,045,557	$ 3,372,216	$ 161,482
GatherVolumes			6	$ 42,004,925	$ 7,470,092	$ 2,971,947	$ 7,582,152	$ 23,980,734
DesignDay			7	$ 1,221,001	$ 682,227	$ 137,419	$ 202,949	$ 198,406
Revenues			8	$ 648,177,213	$ 468,714,867	$ 62,951,417	$ 67,187,588	$ 49,323,340
Gas Cost Revenues			9	$ 270,963,554	$ 203,033,014	$ 30,944,442	$ 24,410,131	$ 12,575,967
Margin			10	$ 377,213,659	$ 265,681,853	$ 32,006,975	$ 42,777,457	$ 36,747,373
Sales_Rev			11	$ 479,765,179	$ 406,018,600	$ 48,182,088	$ 24,410,097	$ 1,154,394
Transport_Rev			12	$ 168,412,033	$ 62,696,267	$ 14,769,330	$ 42,777,491	$ 48,168,946
Winter6			13	$ 1	$ 0	$ 0	$ 0	$ 0
WinterSales			14	$ 37,182,291	$ 30,199,289	$ 4,467,888	$ 2,397,548	$ 117,566
Service_Invest			15	$ 930,188,979	$ 869,208,883	$ 49,521,168	$ 10,976,187	$ 482,741
Meter_Invest			16	$ 135,317,363	$ 113,044,045	$ 15,486,750	$ 6,393,335	$ 393,232
M&R Equipment			17	$ 1,305	$ -	$ 79	$ 622	$ 604
Account 879			18	$ 289,350	$ 267,488	$ 19,435	$ 2,323	$ 104
Write-offs			19	$ 11,465,479	$ 11,183,933	$ 262,580	$ 17,331	$ 1,635
CUST-902			20	$ 4,584,075	$ 3,922,875	$ 352,021	$ 186,623	$ 122,556
CUST-903			21	$ 13,233,301	$ 12,353,041	$ 788,417	$ 86,194	$ 5,649
CUST-908			22	$ 9,522,982	$ 9,498,538	$ 24,444	$ -	$ -
CUST-912			23	$ 1,550,255	$ 488,078	$ 22,227	$ 6,301	$ 1,033,649
Collections			24	$ 61,370,509	$ 58,027,491	$ 1,861,406	$ 1,067,554	$ 414,058
ConnectionFee			25	$ 5,300,901	$ 3,399,900	$ 1,697,645	$ 198,823	$ 4,534
Cust_Deposit			26	$ (22,847,791)	$ (15,313,754)	$ (4,396,413)	$ (1,959,019)	$ (1,178,605)
Peak & Average - LP			27	100.00000%	66.20283%	13.16194%	20.63523%	0.00000%
Peak & Average			28	100.00000%	49.41312%	9.83996%	15.31483%	25.43209%
TRANSPORT_Thru			29	$ 65,712,299	$ 8,811,874	$ 3,772,675	$ 12,951,841	$ 40,175,909
LGSDirect			30	$ 27,049	$ -	$ -	$ -	$ 27,049
STORPT			40	$ 11,635,136	$ 6,258,081	$ 1,256,923	$ 1,882,346	$ 2,237,786
TRANPT			41	$ 193,966,607	$ 108,377,643	$ 21,830,180	$ 32,240,190	$ 31,518,594
DISTPT			42	$ 2,576,879,712	$ 1,630,001,120	$ 229,280,053	$ 285,028,230	$ 432,570,310
PSTDPLT			43	$ 2,962,952,051	$ 1,801,540,590	$ 266,395,611	$ 348,353,414	$ 546,662,436
303			44	$ 138,206,266	$ 100,578,679	$ 11,627,142	$ 10,708,806	$ 15,291,639
325 - 337			45	$ 124,160,959	$ 22,080,596	$ 8,784,679	$ 22,411,831	$ 70,883,852
350 - 357			46	$ 13,462,916	$ 7,241,172	$ 1,454,375	$ 2,178,046	$ 2,589,323
365 - 371			47	$ 202,399,033	$ 113,089,208	$ 22,779,217	$ 33,641,787	$ 32,888,821
374 - 375			48	$ 38,382,660	$ 24,278,890	$ 3,415,130	$ 4,245,500	$ 6,443,141
376			49	$ 1,634,329,741	$ 807,573,391	$ 160,817,360	$ 250,294,827	$ 415,644,163
378			50	$ 67,674,628	$ 37,812,780	$ 7,616,514	$ 11,248,549	$ 10,996,785
380			51	$ 632,413,944	$ 590,954,989	$ 33,668,295	$ 7,462,456	$ 328,204
381			52	$ 126,828,614	$ 105,952,549	$ 14,515,233	$ 5,992,268	$ 368,564
382			53	$ 90,344,063	$ 75,473,377	$ 10,339,663	$ 4,268,483	$ 262,540
385			54	$ 10,644,190	$ -	$ 646,956	$ 5,069,737	$ 4,927,497
386			55	$ 14,644,532	$ 12,234,033	$ 1,676,032	$ 691,910	$ 42,557
387			56	$ 7,666,771	$ 4,849,604	$ 682,157	$ 848,020	$ 1,286,990
389 - 399			57	$ 143,273,226	$ 87,113,300	$ 12,881,531	$ 16,844,592	$ 26,433,803
DISTMAIN-SERVICE			58	$ 2,266,743,685	$ 1,398,528,380	$ 194,485,655	$ 257,757,283	$ 415,972,367
MAINSPT			59	$ 1,634,329,741	$ 807,573,391	$ 160,817,360	$ 250,294,827	$ 415,644,163
DISTO&M_LABOR			60	$ 21,110,457	$ 15,351,295	$ 1,870,113	$ 1,761,469	$ 2,127,579
DISTMETER-REG			61	$ 217,172,677	$ 181,425,926	$ 24,854,896	$ 10,260,751	$ 631,103
DISTO&M			62	$ 62,089,260	$ 37,656,163	$ 5,813,134	$ 7,458,832	$ 11,161,131
CUST-908-910			63	$ 6,103,139	$ 5,858,926	$ 218,857	$ 25,354	$ 2
CUST_AVG_XLGS			64	$ 627,253	$ 580,997	$ 41,304	$ 4,953	$ -
LABOR			65	$ 63,933,500	$ 40,521,995	$ 5,376,830	$ 6,457,397	$ 11,577,277
OPERREV			66	$ 667,019,391	$ 476,942,073	$ 64,894,142	$ 69,420,960	$ 55,762,215
IntangPlt			67	$ 138,256,036	$ 100,608,940	$ 11,631,616	$ 10,714,658	$ 15,300,822
ProdPlt			68	$ 124,160,959	$ 22,080,596	$ 8,784,679	$ 22,411,831	$ 70,883,852
IntangibleAcct303			69	100.00000%	72.77433%	8.41289%	7.74842%	11.06436%

PEOPLES NATURAL GAS COMPANY LLC
OCA CLASS COST OF SERVICE STUDY (CONSOLIDATED BASIS)
(ALLOCATION PERCENTS)

Account	Company Alloc	TAI Alloc	Total Combined	Residential Service	Small General Service	Medium General Service	Large General Service
Cust_Avg		1	100.0000%	92.5909%	6.5824%	0.7893%	0.0374%
SmCust_Avg		2	100.0000%	93.3628%	6.6372%	0.0000%	0.0000%
LGCust_Avg		3	100.0000%	0.0000%	0.0000%	95.4749%	4.5251%
Thruput		4	100.0000%	42.9519%	8.4253%	14.0081%	34.6147%
Sales_Firm		5	100.0000%	81.1507%	11.8959%	6.6356%	0.3178%
GatherVolumes		6	100.0000%	17.7838%	7.0752%	18.0506%	57.0903%
DesignDay		7	100.0000%	55.8744%	11.2546%	16.6215%	16.2495%
Revenues		8	100.0000%	72.3128%	9.7121%	10.3656%	7.6095%
Gas Cost Revenues		9	100.0000%	74.9300%	11.4201%	9.0086%	4.6412%
Margin		10	100.0000%	70.4327%	8.4851%	11.3404%	9.7418%
Sales_Rev		11	100.0000%	84.6286%	10.0428%	5.0879%	0.2406%
Transport_Rev		12	100.0000%	37.2279%	8.7698%	25.4005%	28.6018%
Winter6		13	100.0000%	44.8808%	8.8763%	14.2873%	31.9556%
WinterSales		14	100.0000%	81.2196%	12.0162%	6.4481%	0.3162%
Service_Invest		15	100.0000%	93.4443%	5.3238%	1.1800%	0.0519%
Meter_Invest		16	100.0000%	83.5399%	11.4448%	4.7247%	0.2906%
M&R Equipment		17	100.0000%	0.0000%	6.0780%	47.6292%	46.2928%
Account 879		18	100.0000%	92.4445%	6.7166%	0.8028%	0.0361%
Write-offs		19	100.0000%	97.5444%	2.2902%	0.1512%	0.0143%
CUST-902		20	100.0000%	85.5761%	7.6792%	4.0711%	2.6735%
CUST-903		21	100.0000%	93.3481%	5.9578%	0.6513%	0.0427%
CUST-908		22	100.0000%	99.7433%	0.2567%	0.0000%	0.0000%
CUST-912		23	100.0000%	31.4837%	1.4338%	0.4065%	66.6760%
Collections		24	100.0000%	94.5527%	3.0331%	1.7395%	0.6747%
ConnectionFee		25	100.0000%	64.1381%	32.0256%	3.7507%	0.0855%
Cust_Deposit		26	100.0000%	67.0251%	19.2422%	8.5742%	5.1585%
Peak & Average - LP		27	100.0000%	66.2028%	13.1619%	20.6352%	0.0000%
Peak & Average		28	100.0000%	49.4131%	9.8400%	15.3148%	25.4321%
TRANSPORT_Thru		29	100.0000%	13.4098%	5.7412%	19.7099%	61.1391%
LGSDirect		30	100.0000%	0.0000%	0.0000%	0.0000%	100.0000%
STORPT		40	100.0000%	53.7861%	10.8028%	16.1781%	19.2330%
TRANPT		41	100.0000%	55.8744%	11.2546%	16.6215%	16.2495%
DISTPT		42	100.0000%	63.2548%	8.8976%	11.0610%	16.7866%
PSTDPLT		43	100.0000%	60.8022%	8.9909%	11.7570%	18.4499%
303		44	100.0000%	72.7743%	8.4129%	7.7484%	11.0644%
325 - 337		45	100.0000%	17.7838%	7.0752%	18.0506%	57.0903%
350 - 357		46	100.0000%	53.7861%	10.8028%	16.1781%	19.2330%
365 - 371		47	100.0000%	55.8744%	11.2546%	16.6215%	16.2495%
374 - 375		48	100.0000%	63.2548%	8.8976%	11.0610%	16.7866%
376		49	100.0000%	49.4131%	9.8400%	15.3148%	25.4321%
378		50	100.0000%	55.8744%	11.2546%	16.6215%	16.2495%
380		51	100.0000%	93.4443%	5.3238%	1.1800%	0.0519%
381		52	100.0000%	83.5399%	11.4448%	4.7247%	0.2906%
382		53	100.0000%	83.5399%	11.4448%	4.7247%	0.2906%
385		54	100.0000%	0.0000%	6.0780%	47.6292%	46.2928%
386		55	100.0000%	83.5399%	11.4448%	4.7247%	0.2906%
387		56	100.0000%	63.2548%	8.8976%	11.0610%	16.7866%
389 - 399		57	100.0000%	60.8022%	8.9909%	11.7570%	18.4499%
DISTMAIN-SERVICE		58	100.0000%	61.6977%	8.5800%	11.3713%	18.3511%
MAINSPT		59	100.0000%	49.4131%	9.8400%	15.3148%	25.4321%
DISTO&M_LABOR		60	100.0000%	72.7189%	8.8587%	8.3441%	10.0783%
DISTMETER-REG		61	100.0000%	83.5399%	11.4448%	4.7247%	0.2906%
DISTO&M		62	100.0000%	60.6484%	9.3625%	12.0131%	17.9759%
CUST-908-910		63	100.0000%	95.9986%	3.5860%	0.4154%	0.0000%
CUST_AVG_XLGS		64	100.0000%	92.6255%	6.5848%	0.7896%	0.0000%
LABOR		65	100.0000%	63.3815%	8.4100%	10.1002%	18.1083%
OPERREV		66	100.0000%	71.5035%	9.7290%	10.4076%	8.3599%
IntangPlt		67	100.0000%	72.7700%	8.4131%	7.7499%	11.0670%
ProdPlt		68	100.0000%	17.7838%	7.0752%	18.0506%	57.0903%
IntangibleAcct303		69	100.0000%	72.7743%	8.4129%	7.7484%	11.0644%

OCA Statement No. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2018-3006818
	:	
Peoples Natural Gas Company, LLC	:	

Schedule GAW-5

PEOPLES NATURAL GAS COMPANY
Peoples Proposed Rate Consolidation
Residential Impact Analysis

	Current			Change		Percent Change	
	Peoples	Equitable	Proposed	Peoples	Equitable	Peoples	Equitable
Base Rates:							
Cust.	$ 13.95	$ 13.25	$ 20.00	$ 6.05	$ 6.75		
Base Delivery	$ 3.1330	$ 3.1687	$ 3.8753	$ 0.7423	$ 0.7066		
Gas Cost:							
Capacity	$ 0.9953	$ 0.9953	$ 0.9953	$ -	$ -		
AVC Capacity	$ 0.6225	$ 0.6225	$ 0.6225	$ -	$ -		
GCA	$ (0.0372)	$ (0.0372)	$ (0.0372)	$ -	$ -		
Commodity	$ 3.8865	$ 3.8865	$ 3.8865	$ -	$ -		
STAS	$ (0.0072)	$ (0.0304)	$ -	$ 0.0072	$ 0.0304		
MFC	$ 0.1257	$ 0.1257	$ 0.1207	$ (0.0050)	$ (0.0050)		
Universal Svc.	$ 0.5479	$ 0.2904	$ 0.4094	$ (0.1385)	$ 0.1190		
GPC	$ 0.1055	$ 0.1055	$ 0.0801	$ (0.0254)	$ (0.0254)		
Supplier Choice-Cust.	$ 0.0115	$ 0.0001	$ 0.0067	$ (0.0048)	$ 0.0066		
DSIC:							
Cust.	$ 0.6975	$ 0.6625	$ -	$ (0.6975)	$ (0.6625)		
Delivery	$ 0.1956	$ 0.1845	$ -	$ (0.1956)	$ (0.1845)		
TCJA							
Cust.	$ (0.7294)	$ (0.9928)	$ -	$ 0.7294	$ 0.9928		
Delivery	$ (0.1638)	$ (0.2374)	$ -	$ 0.1638	$ 0.2374		
TOTAL CUST.	$ 13.9296	$ 12.9198	$ 20.0067	$ 6.0771	$ 7.0869	43.6%	54.9%
TOTAL DELIVERY	$ 9.4038	$ 9.0741	$ 9.9526	$ 0.5488	$ 0.8785	5.8%	9.7%
Non-Gas Cust.	$ 13.9296	$ 12.9198	$ 20.0067	$ 6.0771	$ 7.0869	43.6%	54.9%
Non-Gas Delivery	$ 3.9367	$ 3.6070	$ 4.4855	$ 0.5488	$ 0.8785	13.9%	24.4%
Typical Bills - Total Bill							
0	$ 13.93	$ 12.92	$ 20.01	$ 6.0771	$ 7.0869	43.6%	54.9%
5	$ 60.95	$ 58.29	$ 69.77	$ 8.8211	$ 11.4794	14.5%	19.7%
10	$ 107.97	$ 103.66	$ 119.53	$ 11.5651	$ 15.8719	10.7%	15.3%
20	$ 202.01	$ 194.40	$ 219.06	$ 17.0531	$ 24.6569	8.4%	12.7%
30	$ 296.04	$ 285.14	$ 318.58	$ 22.5411	$ 33.4419	7.6%	11.7%
50	$ 484.12	$ 466.62	$ 517.64	$ 33.5171	$ 51.0119	6.9%	10.9%
75	$ 719.21	$ 693.48	$ 766.45	$ 47.2371	$ 72.9744	6.6%	10.5%
100	$ 954.31	$ 920.33	$ 1,015.27	$ 60.9571	$ 94.9369	6.4%	10.3%
150	$ 1,424.50	$ 1,374.03	$ 1,512.90	$ 88.3971	$ 138.8619	6.2%	10.1%
Typical Bills - Non-Gas Charges							
0	$ 13.9296	$ 12.9198	$ 20.0067	$ 6.0771	$ 7.0869	43.6%	54.9%
5	$ 33.6131	$ 30.9548	$ 42.4342	$ 8.8211	$ 11.4794	26.2%	37.1%
10	$ 53.2966	$ 48.9898	$ 64.8617	$ 11.5651	$ 15.8719	21.7%	32.4%
20	$ 92.6636	$ 85.0598	$ 109.7167	$ 17.0531	$ 24.6569	18.4%	29.0%
30	$ 132.0306	$ 121.1298	$ 154.5717	$ 22.5411	$ 33.4419	17.1%	27.6%
50	$ 210.7646	$ 193.2698	$ 244.2817	$ 33.5171	$ 51.0119	15.9%	26.4%
75	$ 309.1821	$ 283.4448	$ 356.4192	$ 47.2371	$ 72.9744	15.3%	25.7%
100	$ 407.5996	$ 373.6198	$ 468.5567	$ 60.9571	$ 94.9369	15.0%	25.4%
150	$ 604.4346	$ 553.9698	$ 692.8317	$ 88.3971	$ 138.8619	14.6%	25.1%

OCA Statement No. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2018-3006818
	:	
Peoples Natural Gas Company, LLC	:	

Schedule GAW-6

PEOPLES NATURAL GAS COMPANY
Residential Customer Cost Analysis

	OCA COC
Gross Plant	
Services	$590,954,989
Meters	$105,952,549
Meter Installations	$75,473,377
Other Property on Customer Premises	$12,234,033
Total Gross Plant	**$784,614,948**
Accum. Depreciation Reserve	
Services	$240,168,897
Meters	$23,780,904
Meter Installations	$31,631,412
Other Property on Customer Premises	$11,183,737
Total Depr. Reserve	**$306,764,950**
Total Rate Base	**$477,849,998**
Operation & Maintenance Expenses	
Oper Meter & House Reg.	$4,845,882
Oper Customer Install Exp	$5,003,121
Services Maintenance	$923,187
Maint Meter & House Reg	$324,236
Meter Reading	$4,107,589
903 Records & Collections	$15,993,032
Total O&M Expenses	**$31,197,047**
Depreciation Expense	
Services	$14,292,857
Meters	$4,118,889
Meter Installations	$1,454,879
Other Property on Customer Premises	$224,903
Total Depreciation Expense	**$20,091,528**
Revenue Requirement	
Interest	$9,388,873
Equity Return	$22,436,252
Income Tax	$9,116,152
Total	**$40,941,277**
Revenue For Return	$40,941,277
O&M Expenses	$31,197,047
Depreciation Expense	$20,091,528
Subtotal Customer Revenue Requirement	$92,229,852
Plus: Uncollectible @ 5.692% 1/	$5,249,723
Total Customer Revenue Requirement	$97,479,576
Number of Bills	6,971,964
Monthly Cost	**$13.98**

1/ Calculated per CCOSS of $15,121,513 (Residential uncollectible) divided by $265,681,853 (Residential rate revenue).

OCA Statement No. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2018-3006818
	:	
Peoples Natural Gas Company, LLC	:	

Schedule GAW-7

Pennsylvania Public Utility Commission
v.
Peoples Natural Gas Company, LLC.
Docket No. R-2018-3006818

Interrogatories of the Office of Consumer Advocate
Set IV

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(1) Please provide a copy of Exhibit No. 3, Schedule No. 15 (all attachments) in executable Excel format with all formulae and links intact.

(2) With regard to Exhibit No. 3, Schedule No. 15, Attachment D, please explain in detail what the gas costs included for transportation customers represents.

(3) Please identify each current Peoples and Equitable rate schedule that has an interruptible provision.

(4) For each current Peoples and Equitable rate schedule that has an interruptible provision, please provide the following amounts consistent with the fully projected future test year:

(a) total firm contract demand;
(b) total firm MCF or Dth;
(c) total non-firm MCF or Dth; and,
(d) number of accounts with a non-firm provision.

(5) With regard to each account with negotiated rates resulting from Gas-on-Gas competition, please provide the following for each account:

(a) account number;
(b) customer name;
(c) division (Peoples or Equitable);
(d) current rates charged by rate element;
(e) competing natural gas distribution company ("NGDC") and competing rate schedule;
(f) historic test year billing determinants and revenue by rate element;
(g) fully projected future test year billing determinants and revenue by rate element;
(h) identification of which rate schedule the volumes and revenues are contained within Exhibit No. 3, Schedule No. 15, Attachment D sponsored by Ms. Scanlon;
(i) firm contract demand;
(j) current contract;
(k) all documents and records supporting the customer's ability to purchase from a competing NGDC; and,
(l) all analyses which evaluate the contribution to overall fixed costs.

In this response, please provide sub-items (a) through (i) in a single executable electronic file (preferably Excel). Please note that the actual customer names are not required, however, if the same customer has multiple negotiated rate accounts, please provide information that will enable the identification of customers with multiple accounts.

(6) With regard to each account with negotiated rates that are not the result of Gas-on-Gas competition, please provide the following for each account:

(a) account number;
(b) customer name;
(c) division (Peoples or Equitable);
(d) current rates charged by rate element;
(e) reason(s) for a negotiated rate; e.g., threat of by-pass, alternative fuels, etc.;
(f) historic test year billing determinants and revenue by rate element;
(g) fully projected future test year billing determinants and revenue by rate element;
(h) identification of which rate schedule the volumes and revenues are contained within Exhibit No. 3, Schedule No. 15, Attachment D sponsored by Ms. Scanlon;
(i) firm contract demand;
(j) current contract;
(k) supporting workpapers relied upon to substantiate the negotiated agreement; and,
(l) all analyses which evaluates the contribution to overall fixed costs

In this response, please provide sub-items (a) through (i) in a single executable electronic file (preferably Excel). Please note that the actual customer names are not required, however, if the same customer has multiple negotiated rate accounts, please provide information that will enable the identification of customers with multiple accounts.

(7) With regard to Ms. Scanlon's direct testimony, page 13, lines 12 through 14, please provide all workpapers and analyses showing each individual customer's (account) number of bills, volumes, and revenues that are embedded within each rate schedule in Exhibit No. 3, Schedule No. 15, Attachment D. Please provide in executable Excel format.

(8) With regard to the proposed transitional industrial rate class discussed in Ms. Scanlon's direct testimony, page 17, line 18 through page 18, line 6, please provide a side-by-side comparison of number of customers, volumes, delivery rates, and delivery rate revenues under current and proposed rates separated by division and current rate schedule. Provide in executable Excel format.

(9) For each requested interruption or curtailment during the last five years, please provide the following by rate schedule:

(a) date and duration of requested interruption or curtailment;
(b) reason for requested interruption or curtailment;
(c) amount of requested interruption or curtailment;

(d) actual amount curtailed; and,
(e) number of customers requested to curtail.

(10) With regard to Rate MLX, the OCA cannot find any billing determinants or revenues associated with this pilot rate schedule in Exhibit No. 3, Schedule No. 15, Attachment D. Please explain and quantify where Rate MLX billing determinants and revenues are contained within this Exhibit for the historical and fully projected forecasted test year under current and proposed rates. In this response, please also itemize the amounts associated with Rate MLX by tier. Please provide in executable Excel format.

(11) With regard to the Company's mainline extension programs subject to Rate MLX, please provide the following annual amounts since the inception of Rate MLX by Rate MLX tier:

(a) total footage of mains installed;
(b) total cost of mains installed;
(c) CIAC collected (not included Rate MLX revenues);
(d) accumulated number of customers and bills;
(e) annual throughput;
(f) annual MLX revenue; and,
(g) annual delivery revenue (excluding MLX revenue).

Please provide in executable Excel format.

(12) Please provide all workpapers and analyses utilized to develop the Company's (Peoples and Equitable) design day demands by rate schedule (class). Please provide in executable Excel format.

(13) For each zip code in Peoples' service area, please provide the number of customers by rate schedule. Provide in executable Excel format.

(14) For each zip code in Equitable's service area, please provide the number of customers by rate schedule. Provide in executable Excel format.

(15) For the most recent 12-month period, please provide an electronic database of every Equitable and Peoples residential customers' billed usage. In this response, provide a unique customer identification number, identification of whether the customer is in the Equitable service area or Peoples service area, the date of each meter read, usage (CCF or therms), and number of days included in bill. Please provide in Microsoft Excel or Access if possible or in the alternative, provide in ASCII, comma-delimited format with all fields defined.

(16) With regard to multiple customers served by a single service line, please provide the following by rate schedule (Equitable and Peoples separately):

(a) number of multiple customers served by a single service line; and,
(b) number of service lines that serve multiple customers.

(17) Please provide a copy of Mr. Feingold's Exhibits RAF-2 through RAF-10 in executable Excel format.

(18) Please provide a copy of all workpapers and analyses supporting Mr. Feingold's Exhibits RAF-2 through RAF-10 in executable Excel format.

(19) Please provide a copy of Mr. Feingold's class cost of service studies in executable electronic (Excel) format with all links and formulae intact.

268139.doc

OCA Statement No. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2018-3006818
	:	
Peoples Natural Gas Company, LLC	:	

HIGHLY CONFIDENTIAL
Schedule GAW-8

OCA Statement No. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2018-3006818
	:	
Peoples Natural Gas Company, LLC	:	

HIGHLY CONFIDENTIAL
Schedule GAW-9