Analysis of Washington Gas Light Company's Cost of Service and Tariffed Service Charges

Prepared testimony of
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Direct Testimony of William B. Marcus

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DIRECT TESTIMONY OF WILLIAM B. MARCUS
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I. Introduction and Summary

Q Please state your name, business affiliation and address.

A I am William B. Marcus. I am Principal Economist for JBS Energy, Inc., 311 D Street, West Sacramento, California 95605.

Q Please provide your qualifications.

A My qualifications are attached as Attachment A. I have 24 years experience with energy utility issues. I have testified or presented formal comments before about 40 federal, state, provincial, and local regulatory bodies on issues including utility restructuring, revenue requirements, resource planning, and cost-of-service and rate design. I previously testified before this Commission on electric cost of service and rate design in Case Nos. 8469 (Potomac Edison) and 8791 (Pepco). I also prepared draft testimony on the Generating Unit Performance Program in two cases (8703 and 8781) that were settled before the formal filing of testimony and filed formal comments on affiliate transaction rules in Case No. 8820.

Q On whose behalf are you appearing?

A I am appearing on behalf of the Maryland Office of People's Counsel (OPC).

Q What is the purpose of your testimony?

A My testimony analyzes the embedded cost of service study prepared by Washington Gas Light Company ("WG" or "the Company") and provides an alternative study. My testimony also provides some general comments on WG's marginal cost study (in addition to comments in other areas provided by Mr. Miller). Finally, I review WG's proposal to increase charges for service initiation, reconnection, field collection, and dishonored checks and provide alternative recommendations.

II. Embedded Cost of Service Analysis – Introductory Concepts

A. Issues in the Development of a Cost Study

Q How is an embedded cost of service study constructed?

A The costs contained in each plant and expense account from the FERC uniform system of accounts is directly assigned or allocated to jurisdictions. In the jurisdictional cost study, allocation factors are used for commodity gas, transmission, and storage. Most distribution costs are directly assigned based on their location.

The costs allocated or assigned to Maryland in the jurisdictional cost study are then allocated to customer classes in the cost of service study.

Allocation factors are often based on commodity, sales (or throughput), peak demand, number of customers, and revenue or margin, or some combination thereof. Allocation factors for expenses often follow those used to allocate the relevant plant. As the study is conducted, certain allocators are constructed internally as part of the study. For example, many cost of service studies allocate the preponderance of Administrative and General (A&G) Expenses in proportion to non-gas operation and maintenance (O&M) expenses. As a result, if the allocation factor used for one element of plant or O&M expense is changed, it will tend to cause the need to make consequential changes in other places in the study. Most of those consequential changes are made automatically by the computer models used to construct the study.

The end result of the cost of service study is a rate of return by customer class at present rates. The rate of return is calculated by assigning each class its present rate revenue, subtracting all the expenses allocated to them, calculating income taxes for each class, and finding the class's net income. This net income is expressed as a percentage of the rate base allocated to the class or a rate of return.

Q Where does the controversy arise between experts regarding the appropriateness of a particular cost of service study?

A Most of the controversy surrounding the construction of a cost of service study relates to the allocation factors used for certain accounts. In this case, to give one example, I will raise theoretical arguments regarding the appropriate basis for the construction of allocation factors for distribution mains. I will also raise arguments regarding the allocation of several other expense categories.

Occasionally, issues can arise if an analyst believes that it is important to disaggregate certain costs further beyond the level of FERC accounts to achieve a proper allocation. To quickly give one example of this type of issue (which will be addressed in detail later in my testimony), I will recommend breaking out the costs of administering gas purchases and transportation from other Administrative and General expenses and allocating them separately from the rest of the A&G expenses.

The treatment of Other Operating Revenue in an embedded cost study can also be controversial. Some analysts, (I among them), try to determine which customer classes pay tariffed charges for late payments, service establishment, reconnection and similar costs, just as they determine the amount of revenue which customer classes pay for gas and gas delivery services. Other analysts (including WG) will simply allocate other operating revenue in proportion either to total gross revenue or to non-gas margin without reference to the classes that are actually paying these charges.

B. Interpretation of the Cost Study's Results

Q Should a cost of service study be always followed to the letter?

A No. Even though it is prepared by a computer model and contains pages and pages of numbers stated down to the individual thousands of dollars for a utility with tens if not hundreds of millions of dollars of costs, a cost study should be viewed as a guideline, not as something that is absolutely accurate. There are four reasons:

1. recognition by the Commission that cost studies involve the application of judgment as well as, often, the use of load research data that may be imprecise;
2. recognition that a cost study is based on a specific revenue requirement, so that Commission decisions on revenue requirement issues may create further imprecision in the results of the cost of service study;
3. recognition that some differential in return among classes may be justified by risk;
4. balancing the cost study's results with other ratemaking and public policy goals of the Commission.

Q Does the Maryland Commission believe that the results of cost studies must be followed to the letter?

A No. It has expressed opinions that cost studies are guidelines and that the Commission has discretion to consider them together with other factors.

For example, in Order No. 77685, it rejected a request by AOBA to reject the Pepco-Conectiv merger settlement because it did not further equalize class rates of return, stating that "the Commission is not bound by cost-of-service studies in apportioning rate increases or decreases among customer classes,"[1] and citing a court decision to the effect that:

> The only statutory imperative is to construct and approve just and reasonable rates, and, as § 69(a) of article 78 makes clear, those are rates which, among other things, "fully consider and are consistent with the public good." That allows the Commission to consider and use factors other than pure cost of service. It does not require uniformity and does not require any specific formula or band of reasonableness. [2]

In Order No. 70875, involving the rehearing of a contested settlement in a Washington Gas rate case, the Commission found:

> However, as we explained in Order No. 70658, cost allocation and the assignment of additional revenue requirements in a given rate case is not a science but instead is based on judgment considering all factors which may impact on such a decision.[3]

In the underlying Order No. 70658, the Commission approvingly cited the following Staff testimony on past practice:

> At the hearing on June 30, 1993, Staff Counsel assured the Commission that Staff was indeed mindful of Commission precedent. Staff notes that for several decades the Commission has not supported an allocation of an entire increase to one class. Rather, the Commission supports gradual movement of the classes towards an overall rate of return. [4]

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[1] Order No. 77685, p. 20.

[2] *Building Owners and Managers Association of Metropolitan Baltimore, Inc. v. Public Service Commission of Maryland*, 93 Md. App. 741, 758-764 (1992) at 762, *cert. denied*, 329 Md. 479 (1993), as quoted in Order No. 77685, page 20. Citation omitted.

[3] *Re Washington Gas Light Company*, 84 Md PSC 401 at 407 (1993); MD PSC Case No. 8545, Order No. 70875.

[4] *Re Washington Gas Light Company*, 84 Md PSC 274 at 281 (1993); MD PSC Case No. 8545, Order No. 70658.

Q Will you explain how a Commission can recognize judgment when interpreting a cost of service study?

A A Commission can recognize the disagreements among analysts and the judgment that went into preparing the study when making a decision. For example, the Wisconsin Public Service Commission typically reviews several different electric cost of service studies, deliberately constructed with different theoretical underpinnings, when making a decision on electric cost allocation and rate design.

In this WG case, the single largest cost of service issue is the method of allocation of distribution mains, which I will discuss at some length below. While I certainly hope that I can convince the Commission to adopt my position instead of the Company's on that issue, it is clearly within the Commission's prerogative to look at both cost studies, not explicitly adopt either, but rely on both to reach a conclusion that is less extreme than the Company's position even while not adopting all of OPC's position.

Q Will you briefly discuss how changes in revenue requirements may affect the cost of service study?

A The cost study is prepared on the basis of a specific set of revenue requirements, in this case, the Company's revenue requirements. This means that the cost study cannot give precise results in the event that the Commission adopts a different revenue requirement. To give just one example of how such imprecision arises, Mr. Effron is proposing a significant ($2.7 million) reduction in uncollectible accounts expenses. My cost study allocates 82% of these expenses to residential customers. Thus, if Mr. Effron's adjustment in this area is adopted, my cost study will overstate the residential class revenue requirement relative to other classes. These types of imprecisions abound when the Commission is making a number of independent revenue requirement decisions.

Q Will you briefly explain why some differential in return among classes may be justified?

A Differentials in return are shown as the end result of a cost of service study. However, setting equal rates of return for all classes is not necessarily the right answer. As I will discuss in more detail below, the goal should **not** be to move all customer classes toward an equal rate of return because not all customer classes impose the same risk on the system.[5]

In particular, residential loads are less risky than larger commercial and industrial loads. While residential loads may be riskier with respect to weather-related fluctuations, OPC is recommending a weather normalization mechanism to reduce that particular shareholder risk. Residential loads are also not as greatly influenced by economic conditions as larger commercial and industrial customers. More importantly, residential and the smallest business customers do not cause one of the largest business risks facing the natural gas industry: bypass of the local distribution company (LDC) for service by a FERC-regulated pipeline, which has the potential in some cases to strand physical assets.

Q Will you discuss other ratemaking goals that must be balanced with cost of service considerations when designing rates?

A A critical ratemaking goal is continuity with past rates and avoiding rate and bill shocks. This goal is often recognized in Commission decisions that move classes toward more equality in rate of return without imposing

[5] Although the issue is more important for electricity than gas, not all functions (generation, transmission, distribution, retail) impose the same risks either.

very large increases. In Maryland, this principle has been generally recognized in recent electric rate cases. If a rate case results in a significant increase, no class has been given a decrease. This goal also can affect other rate design issues. For example, Mr. Miller's testimony supporting a weather normalization adjustment shows that it mitigates consumers' bill shock in a cold winter.

A second ratemaking goal is the promotion of universal service and recognition of ability to pay. This goal comes into play in this case in two key areas: (1) OPC's recommendation not to increase charges for service initiation and field collection to a level reflective of the full cost of service because it disproportionately impacts poor people and renters, and (2) in Mr. Colton's testimony which forms part of the basis for OPC's recommendation to reject the Company's large proposed increases in customer charges.

A third goal involves giving customers control over their bills and encouraging energy efficiency. High fixed charges reduce incentives for customers to conserve energy by reducing the payback on investments in efficient appliances. They also reduce the ability of customers to control their own bills through their own consumption decisions.

A final goal, affecting rate design rather than the allocation of costs among customer classes, involves recognition of differences in the cost of serving different customers within rate classes. The embedded cost study provides class average information. And those averages may not fit everyone in the class. If it is cheaper to serve residential customers living in individually metered apartments despite their lower energy usage, a one-size-fits-all customer charge together with declining block rates can result in smaller customers subsidizing large ones, contrary to conventional wisdom.[6] Similarly, if the small commercial class covers a wide variety of customers of different sizes, a customer charge based on class average costs will overcharge the smallest customers who, by and large, are similar to residential customers and would have cheaper meters and shorter service lines than the small commercial class average.

Q Will you provide a few more comments on the impact of rate design on investments in energy efficiency?

A High fixed charges reduce incentives for customers to conserve energy by reducing the payback on investments in efficient appliances. They also reduce the ability of customers to control their own bills through their own consumption decisions. Many economists assume that the world runs like a Swiss watch without market imperfections. If we just "get the prices right" consumers will "do the right thing." Under this view, there is allegedly no reason to encourage conservation unless one is concerned about global warming or depletion of natural resources. Whatever customers do in response to price is deemed to be economically rational.

However, this view overlooks significant institutional barriers that prevent cost-effective efficiency investments including, but not limited to:

- **split incentives (**where one party pays for the investment and the other pays the utility bill), such as between landlords and tenants and similarly between new home builders and the first owners;
- **tenure versus appliance life** (a residential customer may not believe that he or she can gain adequate benefits from an investment if the length of residency is short or uncertain), even though future customers who occupy the premises would receive benefits over the life of the investment;

[6] I found that lower costs of services and meters and higher load factors for apartment dwellers means that they were cheaper to serve on a unit cost basis in Southern California.

- **lack of information** by customers on investment choices with different energy use, their effectiveness, and their impact on energy costs;
- **lost opportunities** (conservation investments that must be made at a particular time, when a building is built or an appliance is replaced); and
- **lack of capital** to spend on efficiency investments.

In addition, current energy prices do not convey all necessary information to customers about future prices. It is difficult to make a good investment decision in a building that lasts 50 years or an appliance that will be around for 20 years. In 2000-2001 we learned the hard lesson that gas prices are uncertain and subject to unforeseen upward spikes for periods of time due to supply and demand imbalances. A consistent policy of encouraging conservation can reduce both the severity of price excursions to society as a whole (by reducing demand and thereby lessening imbalances that create high prices) and the impacts of these price excursions on individual consumers (who are less exposed to the high prices if they had previously invested in conservation).

These considerations have led to the development of appliance and building standards and to utility demand-side management (DSM) programs. It is clear that rate design cannot encourage conservation by itself, but it has at least some impact in increasing the amount of cost-effective conservation that is pursued. However, even if DSM is not being pursued, a Commission can avoid loading rates with extremely high fixed charges, so that customers see higher price signals that vary with usage, which may have the effect of overcoming some of the barriers to efficiency investments.

III. OPC's Cost of Service Study

Q Have you prepared a cost of service study on behalf of OPC?

A Yes. The study is included as OPC Exhibit WBM-1. The biggest single issue (in terms of monetary effect) is the allocation of mains, but there are a number of other disagreements between my analysis and WG's cost study.

Q Have you reviewed the Company's jurisdictional allocation study?

A Yes. I have no disagreement with the methodology used, since most distribution costs are directly assigned based on location, rather than allocated.

Q How have you organized the rest of your testimony on the cost of service study?

A I first present information regarding the single largest difference between my proposal and WG's – the allocation of the cost of distribution mains. Second, I present information on another issue where I disagree significantly with WG – the allocation of a package of costs, revenues, and rate base including uncollectible accounts expenses, late payment charges, customer deposits, and other tariffed charges to customers. I then review other issues relating to the allocation of plant and finally review WG's allocation of expenses. Finally, I review the results of my cost study and the implications for allocation of costs to customer classes.

A. Allocation of Mains

Q How has the Company assigned costs to mains?

A It has divided the cost of each of these types of facilities between customer and demand, assigning 54% of costs as customer-related and 46% based on a 50-50 split of demand and commodity costs. The method used was based on assigning the cost of a hypothetical "minimum system" built with two-inch mains as a customer cost, while assigning all other main costs as demand / commodity related.

Q **Are you aware of any other Maryland gas utilities that do not use the minimum system method for the allocation of mains?**

A Yes. Baltimore Gas and Electric (BG&E) treats mains as 100% demand-related using a non-coincident peak method (other than a portion directly assigned to certain very large customers). It is my understanding that this method has been used since Case No. 8070.

Q **Do Maryland <u>electric</u> utilities use a minimum system method to allocate overhead and underground lines to customers?**

A By and large, they do not. Pepco, BG&E and Potomac Edison treat all lines and transformers as 100% demand-related. Only Conectiv (formerly Delmarva Power and Light), which has not filed a cost of service study since its 1992 rate case, which was settled, has used a minimum system.

Q **Will you evaluate WG's minimum system proposal further?**

A I believe that such a division is inappropriate in theory. Mains should be treated as common facilities without customer costs.

Mains are common facilities built to serve a large number of customers, and are generally not dedicated to an individual customer. This suggests the use of a common allocation method, such as demand or demand and commodity costs.

Assigning no customer component to mains is appropriate because it recognizes that the utility puts pipe in the ground not simply to serve customers or to deliver gas on a couple of peak days out of the year, but to provide gas service on a sustained basis to customers.[7]

The Company has proposed a minimum system method for the allocation of main costs between customer and demand. A minimum system method double-charges small customers when coupled with a full allocation of demand-related costs for the larger system, as proposed by WG. A significant portion of the demand of small customers could be met by the minimum system. More expensive components may be needed in many cases primarily to serve larger customers.

The cost of spanning the service area is not a customer cost for a gas utility, because a customer who is hooked up but uses no gas is an economic fiction. There are no such new customers in reality. Gas service is discretionary, and customers choose it because it is cheaper than an alternative fuel. If a customer needed the services provided by natural gas only on rare occasions, the customer would choose another fuel rather than paying for mains and services. Propane and heating oil do not require an infrastructure of pipes, and the wires infrastructure will be put in place for electricity regardless of the customer's choice of fuel to use for the energy services that can be provided by gas.

Moreover, because the infrastructure of mains is expensive, gas service is not available in many rural areas that do not have the requisite density to generate the revenue at existing rates that is required to support gas service (although in some jurisdictions, they can pay surcharges to receive gas). And if the usage of a group of customers is insufficient to support the cost of installing mains to reach them, the individual customers are, at

[7] Even large customers who may not use gas when alternate fuels are cheaper or on a peak day find it economic to install a main so that they can use large volumes of gas at times when it is available and cheaper.

least in principle, surcharged to enable gas service through the main extension allowance process.

In other words, mains are installed at ratepayer expense only in order to permit customers to consume significant quantities of gas on a sustained basis. Using the number of customers as an allocation component makes no sense.

Q Does a minimum system method have other analytical problems?

A Yes. The minimum system method double-counts the costs of serving low-use customers, both across customer classes for cost allocation and within customer classes if used for rate design.

In a nutshell, the analytical problem arises because the minimum system method develops a hypothetical utility system of mains (and other equipment under WG's proposal) that can carry a significant amount of demand. The minimum system is assigned to all customers on an equal-dollars-per-customer basis. If that is done, then it is wrong to allocate the remaining demand-related portion of the system by the total system demand. Analytically, if the minimum system is used as a customer cost, it would be necessary to use a demand allocator that would give each customer class credit for that portion of the demand (an equal number of peak day ccf per customer) that can be carried by the minimum system.

My critique of the minimum system method is not new. Professor Bonbright recognized the inaccuracies of treating minimum system costs as customer costs in his **<u>1961</u>** edition of <u>Principles of Public Utility Regulation</u>.[8] His preferred option was to recognize that minimum system

[8] The current edition, revised by others after Bonbright's death, omits this criticism.

costs were neither demand nor customer costs but were unallocable. He adds:

> "And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But the fully distributed cost analyst dare not avail himself of this solution, since he is the prisoner of his own assumption that "the sum of the parts equals the whole." He is therefore under impelling pressure to "fudge" his cost apportionment by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other cost categories."

A seminal Public Utilities Fortnightly article written nearly 20 years ago by George Sterzinger[9] provides a further clear exposition of the problems with the minimum system method. Dr. Sterzinger was the first to bring to the forefront the significant criticism that the minimum system method clearly overcharges small customers, because the minimum system can carry a significant portion of the residential class's demand.

Q If a minimum system were to be used to assign certain costs as customer-related, have you prepared any alternatives that the Commission should be aware of?

A Yes. A somewhat more economically defensible minimum system could be derived, in the event that the Commission does not choose to adopt my recommendation to assign none of the main costs as customer-related.

The minimum system as designed by WG assigns approximately 73 feet of main per customer.[10] I believe that the amount of main to connect a

[9] George J. Sterzinger, "The Customer Charge and Problems of Double Allocation of Costs," Public Utilities Fortnightly, July 2, 1981, pp. 30-32.

[10] Calculated as 24,667,937 feet of main from OPC DR 5-12 divided by 338,748 customers from WG's cost of service model. The minimum system is calculated based on feet of main (in OPC DR 5-12). The assignment of the same number of dollars per customer is mathematically to the assignment of the same number of feet of main per customer. Note that the Company denies that it assigns the same number of feet to each customer (in OPC DR 5-13a), but it provides no rationale for its denial, referencing a Staff DR 3-15 on an entirely different topic as supporting its argument.

minimum-sized customer to the system in an urban and suburban region can be conservatively estimated as 40 feet.[11] Beyond the main running down the street and connecting the customer to the system, other mains are required to span the system as a whole, to connect larger customers to the system, and to connect city gate sources of gas to customers (similar to electric transmission lines of lower than bulk system voltage – 69 or 138 kilovolts – and electric primary distribution feeder lines). All of these functions are either demand-related functions or functions of connecting non-residential customers to the system. Assigning 40 feet of two-inch main per customer (a minimum connection cost) as a customer cost yields to a customer component of 29.35% of the system.

This method still suffers from all of the other infirmities of the minimum system method and is not recommended but is more reasonable than WG's estimate that 54% of the system is customer-related.

Q **Do you agree with the 50-50 split between demand and commodity used by WG for the non-customer portion of costs?**

A Yes. It is clear that a main is not fully demand-related. The existence of the main is based on the economics of sustained gas usage, not on the existence of the customer, but the size of the pipe is based on peak day considerations. However, if a customer only needed gas for a few days a year, propane or fuel oil would be cheaper than building the entire infrastructure.

A method which is based entirely on numbers of coincident peak demand will also allocate virtually none of the costs of having the system in place

[11] With mains running down one side of the street, a figure of 25-30 feet taking single-family and multi-family customers both into account may be more appropriate, but 40 feet is conservative. Of course, larger commercial and industrial customers need longer mains. For example a hotel or office building spanning an entire block would need on the order of 150-300 feet of main to connect its premises, while continuing to serve other customers.

and available to an off-peak user. While an off-peak user should clearly be assigned less of the system costs than a peak user, it should not be given off-peak use of the system for nothing, because the market value of the system (relative to the alternative of using a more expensive fuel) is likely to be greater than zero.

To provide an example, the fixed-variable transmission rate design approved by FERC does not mean that off-peak transmission is costless. In most parts of the country, there is an active market for brokered firm and non-firm capacity on gas pipelines, often at prices less than the full as-billed rate calculated on a fixed-variable basis, but often at prices well above zero.

B. Allocation of Uncollectible Accounts Expenses, Late Charges, Customer Deposits, and Other Tariffed Charges

Q How has WG allocated uncollectible accounts expenses, late charge revenues, revenue from other tariffed charges, and the deduction from rate base associated with customer deposits?

A WG has allocated all of these costs in proportion to gas sales revenue excluding nonfirm sales.

Q Is this allocation method reasonable?

A No. None of these costs are related to sales revenues. I propose a more reasonable package of allocation factors for all of these cost and revenue sources. This package of factors in total reduces costs assigned to residential customers, but one individual item (uncollectible accounts expenses) increases the residential customer allocation.

Q What do you propose?

A I propose the following package of allocation factors.

- Allocate two items (a) uncollectible accounts expenses and (b) customer deposits (offset to rate base and interest expense) half by number of customers and half by revenues excluding nonfirm sales.
- Allocate late payment charges to the rate group that pays them from DR 4-27 (0.34% of residential revenue and 0.27% of other classes).
- Allocate five other tariffed charges based on number of customers. These include (a) service initiation; (b) reconnection; (c) field collection; (d) returned checks and (e) meter relocation.

Q Why do you propose to allocate uncollectible accounts expenses and customer deposits half by number of customers and half by revenues excluding nonfirm sales?

A While WG claims not to have information on uncollectible expenses by customer class or large write-offs from individual customers (OPC DRs 5-2 and 5-4), my experience in reviewing other utilities suggests that uncollectible accounts expenses tend to have an intermediate allocation between number of customers (about 92% residential in Maryland) and gross revenues (about 72% residential).

Similarly, WG claims to have no information on which customer classes pay customer deposits (OPC DR 5-5). A 50-50 customer / revenue allocation factor recognizes that residential customers are likely to be responsible for deposits more than in proportion of their share of revenues, but larger customers also have some responsibility.

Q Why do you propose to allocate late payment revenues by the classes that pay them?

A Allocating the revenues to the classes that pay them makes more sense than spreading them to all customer classes by sales. The Company is throwing away data that exist and demonstrate that residential customers pay a disproportionate share of late payment charges. Instead, the Company is proposing to use a cruder approximation that does not give residential customers credit for the charges that they pay.

Q Why do you propose to allocate tariffed service charges by number of customers?

A The allocation by number of customers reflects that the specific costs that are recovered through these special charges are customer-related costs. All of these costs have costs appearing in the areas of customer accounts (meter reading, records and collections, telephone center), meter O&M and services on customer premises (setting meters, disconnecting service, turning on appliances, etc.) WG's practice – to assign the costs by number of customers in the cost study and then assign the revenues which pay those costs in proportion to total sales revenues – is unreasonable. It creates a mismatch that overcharges residential customers. In addition, information from utilities which keep records on these costs by customer class find that residential customers actually pay service establishment and reconnection charges in equal if not greater proportion to their percentage of customers on the system.

Q Why does WG allocate these costs by sales?

A WG claims in response to OPC DR 5-7 that:

> Firm gas sales that are presented by customer class provide a good basis for allocation of this miscellaneous revenue. Late payment charges, reconnection charges and service application charges are all a function of gas sales.

We have requested the basis for these statements in OPC DR 11-10 but have not yet received the response.

Q Has WG always held this opinion that these charges are related to sales in all customer classes?

A No. WG has changed its opinion of who pays these service charges, to the strong detriment of the Residential class, between 1993 and its filing in Docket 8920.

In Docket 8545, when a number of these charges were first approved and others were increased as a result of a settlement agreement, WG's witness, Mr. Schepis, took a very different position than the Company is taking in this case. Mr. Schepis specifically testified:

> In addition, the Stipulation addresses the modification to or addition of <u>certain miscellaneous charges that will be borne almost entirely by residential customers</u> who drive the respective costs. This assignment of revenues provides further movement toward parity of system returns, increasing the percentage increase to the Residential class [from 3.93 percent] to 4.46 percent.[12]

The Commission's Order No. 70658 adopting the Settlement in this docket contains specific language to the effect that these miscellaneous costs (largely service establishment charges) should be considered as paid by residential customers when evaluating WG's rate design:

> Under the stipulated rates, the Residential class would see an increase in rates of 3.93 percent which with the addition of increases of certain miscellaneous charges will result in a combined increase to the Residential class of 4.46 percent (with a proportionately higher increase to the FGC Residential class).[13]

Q Should the Commission take any regulatory action to require WG to keep more complete records with respect to tariffed charges?

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[12] Case No. 8545, Supplemental Direct Testimony of Joseph M. Schepis in Support of Settlement Exhibit WG (2C), filed June 23, 1993, page 7. Emphasis added.

[13] *Re Washington Gas Light Company***,** 84 Md PSC 274 at 280 (1993); MD PSC Case No. 8545, Order No. 70658

A Yes. In its decision in this case, the Commission should order the Company to keep records of the total amount of money collected from each individual tariffed charge and the amount of money collected from each tariffed charge either by customer class or at least divided into residential and non-residential sub-accounts. These charges include but are not limited to late charges, and charges for service initiation, field collection, reconnection, returned checks, and meter relocation. When the company keeps incomplete records, it is impossible to quantify with precision the amount of these charges paid by each class – a relevant factor in cost allocation.

C. Other Issues Relating to Plant Cost Allocation

Q Do you agree with the Company's analysis of the costs of transmission and storage plant?

A Yes. I believe that a weather-gas-related allocation of storage costs and a 50-50 demand / commodity split for the allocation of transmission costs are both reasonable options. I specifically support the 50-50 split between demand and commodity allocation factors for transmission that reflects that a transmission system is built both to meet peak loads and to carry gas throughout the year.

Q Aside from mains, are you treating any elements of the distribution system differently than WG?

A I have made some technical corrections to WG's allocation of the capital costs of meters. WG's intended to base its meter cost allocation percentages on the average cost of meters in each class, recognizing the different types of meters installed. However, WG's figures did not tie to the meter cost data provided on a separate spreadsheet of its cost of service model. In addition, most classes contain a few meters that WG cannot classify by type. WG assumes that these unclassified meters all have the average cost of the system. This assumption is likely to understate the cost of unclassified meters in large customer classes. I believe that it is more appropriate to assume that unclassified meters have the average cost of the other meters in each class. While this sounds like a small distinction, these corrections reduce the residential class allocation of meters by 1.47% (from 69.56% to 68.09%).

Q How have you treated service lines?

A I have reluctantly used WG's methodology.

Services are dedicated to the individual customers that they serve, and are therefore 100% customer-related (just as mains are common facilities and should be treated as zero percent customer-related). Nevertheless, the sizing and cost of service mains relates in part to the size of the customer, so that an equal number of dollars should not be charged to each class. I would have preferred it had the Company used the "weighted customer" method that it used for meters that that a number of other gas utilities use for services. Under this method, the cost of service mains is weighted based on the number of customers multiplied by the investment cost of a new service for members of the class.[14] The demand method used in this gas study appears to be a short cut.

However, WG did not have any data on the cost of service mains in the larger customer classes. Mr. Raab in his marginal cost study even made the unhelpful and counterfactual assumption that commercial and industrial customers have no service lines at all – a claim that I have never seen made by any other gas utility.

[14] This weighted customer method for services is similar to the method used to allocate meter plant costs in this case.

Q Have you treated all other distribution plant in the same way to WG?

A Yes, with one exception.

Q What is that exception?

A WG identified an $11.5 million pro forma adjustment to distribution plant.[15] This plant is not assigned to specific FERC plant accounts. WG allocated this plant by number of customers, allocating over 90% to the residential class. Absent information about what specific plant is being allocated, it is more appropriate to allocate the pro forma adjustment in proportion to all other distribution plant rather than assuming that it is customer-related.

Q How do you allocate general plant to customer classes?

A I use the same method as the Company, allocating it by the sum of storage, transmission, and distribution plant. My results are different from the Company, but only because my distribution property allocation factors are different.

Q What other rate base items must be allocated in the cost of service study?

A Allocations must be made for depreciation reserve, construction work in progress, materials and supplies, cash working capital, deferred taxes, and customer deposits.

Q Do you have any other differences with the Company in the allocation of these other rate base items?

[15] For information, Mr. Effron's testimony on revenue requirements has proposed to delete this pro forma adjustment.

A With the exception of customer deposits, no. I have used the same methods as the Company. My results are different, only because of differences in allocation of distribution property discussed above and (for cash working capital) differences in O&M expense allocation discussed below.

I have allocated the offset to rate base for customer deposits based one half on number of customers and one half on sales revenues, rather than based entirely on sales revenues. The reason for this difference was discussed in Section IIB above.

D. Other Issues Related to Expense Allocation

Q What other concerns do you have with WG's allocation of expenses?

A I believe that the Commission should allocate costs for two specific functions differently than WG has allocated them. These functions are major account executives and administration of gas purchases and transportation. Unfortunately, the Company has not answered OPC data requests 5-18, 11-8, 11-9, and 11-11 at the time my testimony was filed which would enable a more complete recommendation.

I have other relatively small differences with the Company in the treatment of customer accounting and sales and marketing expenses.

Q What are the issues associated with the allocation of costs for major account executives?

A Major account executives serve large customers. Their costs should be included in customer service and information accounts, although because the Uniform System of Accounts is not really uniform, many utilities include them in customer accounting or administrative and general accounts.

One of the most common errors made by utilities in electric and gas cost of service studies is to make small customers pay for the costs of these staffers whose job is to provide services to large customers.

Q Has the Company provided you with any information regarding the cost of major account executives?

A No. I requested the information in DR 5-18, issued in late April and was told, when the question was answered in May, that they would provide the information at a later time. WG has not done so to date. In addition, I requested information in DR 11-11 based on department organization charts that might provide another way of obtaining the same information. However, that question was also not answered at the time of filing.

Q What do you recommend conceptually regarding the treatment of major account executives?

I recommend that the Commission unbundle these costs from their FERC accounts and directly assign the cost of major account executives to large commercial and industrial customers (allocating among all customers using 3000 therms or more, half by customers and half by throughput, recognizing that the largest customers in these classes receive more of the services). However, I do not have the information to do that at this time.

Q How have you reflected the issue of major account representatives in your testimony at this time?

A As discussed below, I have proposed a lower allocation of customer service and information expenses (Accounts 907-910) to residential customers than WG has proposed. I would revise that allocation if more exact information on the level of these costs and where they are accounted for becomes available, and if that information is materially different from my proposal.

Q Will you discuss costs relating to the administration of gas purchases and transportation?

A It appears from the organization charts provided in response to DR 5-22 that WG may have assigned a significant amount of administrative costs relating to gas purchasing and transportation to the Administrative and General (A&G) accounts. A utility should assign costs relating to the administration of gas purchases to Account 813 (Other Gas Supply Expenses). As a result, costs that should be allocated on a commodity basis to all sales volumes are instead included as A&G expenses and allocated largely based on other non-gas O&M expenses. Such an allocation overcharges residential customers for this function.

Costs of administration of gas transportation should be allocated to transportation customers based on throughput.

Q Since WG has not yet provided information on the magnitude of these costs, have you been able to include them in your cost of service study?

A No I have not. As a result, my cost study is likely to overstate the residential class's revenue responsibility.

Q Do you have any differences with the Company on the allocation of transmission, storage, and distribution expenses?

A No. The expenses generally follow the allocation of plant. I fully agree with the Company's allocation method for storage and transmission. Differences between my proposed allocation of distribution expenses and the Company's proposal result from my different allocation of mains and other distribution plant, not from methodological issues.

Q Have you examined customer accounting costs?

A Yes. The Company allocates all customer accounting costs in equal dollars per customer. I believe that a weighted customer method should be used to reflect that it is more complex to read meters and provide service to larger customers. I asked for data on customer weighting information. WG claims to have no information in this area. (OPC DR 5-16) I therefore use weights developed by Southwest Gas for customer accounting based on its meter read times (weighting small commercial customers as 1.5 times residential customers and other larger commercial and industrial customers as twice residential customers.) This reduces the allocation of customer accounting costs to the residential class by about three percentage points.

Q Will you discuss the allocation of customer service and information expenses?

A The Company has requested $1,208,046 in customer service and information expenses (Maryland jurisdiction) for Accounts 907-910. About 88% of the costs (total company) are for Customer Assistance expenses (Account 908) and 12% for Information and Instructional Advertising (Account 909) with a nominal amount for supervision.

WG has proposed to allocate these expenses by number of customers, so that the residential class pays 92% of the costs.

Q Do you have any concerns with this allocation method?

A Yes. Expenditures contained in this area include a mixture of costs for most utilities. They are likely to include some marketing costs for all classes shown in response to DR 5-22 (for which additional information was requested in DR 11-11, which has also not yet been received). In addition, these accounts are the appropriate place to book the costs of major account representatives.

Q What is your recommendation for these accounts at this time?

A Pending the responses to DR 11-11 (activities of various sales and marketing departments) and the update of the response to DR 5-18 (major accounts representatives), I believe it reasonable to allocate these costs more broadly than based on number of customers. I recommend 50% customers and 50% throughput at this time. This reduces the residential allocation of these costs from 92% to 72%.

Q Will you discuss sales and marketing expenses in Accounts 911-915?

A Sales and marketing expenses in these accounts include demonstrating and selling expenses (Account 912), and advertising expenses (Account 913)[16] which constitute approximately 10% of costs in these accounts. A nominal number of dollars are included in Account 911 (supervision). The total amount which the Company assigns to the Maryland jurtisdiction is $964,294.

Sales and marketing expenses are a policy-related expense. The theoretical purpose of the Company's sales and marketing efforts is to encourage the use of gas. If successful, sales and marketing expenses will theoretically increase gas margin by more than their costs.

The Company allocates them by number of customers, again assigning about 92% to the residential class.

I disagree with that allocation for two reasons. First, as shown in the organization charts attached to OPC DR 5-22, a significant portion of sales and marketing expenses are aimed at commercial and other large customers. Second and more importantly, I believe that the costs should be allocated in proportion to the benefits (of higher margin revenues).

[16] Other advertising expenses are included in FERC Accounts 909 and 930.1.

Otherwise different customers will pay the cost than will receive the benefits of WG's marketing programs.

Q **How do you propose to allocate sales and marketing expenses?**

A I have allocated sales and marketing expenses by sales revenues excluding nonfirm. I have thus allocated the costs in proportion to the supposed benefits rather than based on equal dollars per customer. Residential customers are allocated about 73% of these costs under my proposal instead of the 92% allocation in WG's proposal.

Q **How has WG allocated Administrative and General Expenses?**

A Like most other utilities, WG has allocated A&G expenses using a series of allocation factors related to total labor costs, adjusted O&M expenses (O&M minus fuel, uncollectibles, and A&G), and total property.

Q **Will you evaluate WG's proposal?**

A It represents one reasonable way of cost allocation for ordinary A&G expenses, aside from the issues of major account representatives and administration of gas purchases and transportation discussed above. However, my results are different from the Company's study because of differences in the allocation of other expense and plant items.

Q **Will you discuss the allocation of general taxes other than income taxes?**

A Although I agree with WG's methodology, differences between my study and WG arise because of differences in the underlying allocation of other plant and expense items.

E. Allocation of Costs to Customer Classes

Q **How does one evaluate the output of a cost of service study?**

A There are two parameters of evaluation: class rates of return and class revenue-cost ratios. The revenue-cost ratio is the ratio of class revenue to class costs, including a return at the system average rate of return). The revenue-cost ratio is generally less volatile than the rate of return i.e., a revenue-cost differential is smaller on a percentage basis than the return differential).

Q Will you summarize the results of your cost of service study?

A Yes. I am providing the summary results in the table attached as OPC Exhibit WBM-1.[17] Broken down into the rate classes identified by WG, we find that the rates of return and revenue-cost ratios of all of the major classes (the residential, small commercial, and large commercial classes with space heating) are very close to the system average, with all of these classes differing from the system average revenue-cost ratio by less than 1.5%.

Adding together space heating and non-space heating customers, the residential class has a revenue-cost ratio of 99.4% while the sum of firm commercial and industrial customers are at 101.6%, and GMA customers are at 102.0%.

Q Are the results sensitive to the methodology used for the allocation of mains?

A Yes, to a limited extent. I have prepared sensitivity analyses of various recommended methods for allocating the cost of mains.

The chart below shows the return to each customer class at present rates and the revenue-cost ratio at present rates using all other elements of the OPC's Cost of Service Study and varying the allocation of mains. Exhibit

[17] The first page of this exhibit after the cover page is the summary table; the remaining three pages are the summary pages for rate base, revenues, and expenses.

(OPC) WBM-2 contains the summary page for each of the three alternative analyses.

Return	**System**	**Firm Loads**	**All Res**	**All C/I**	**All GMA**
OPC Recommended (0% customer)	6.26%	6.99%	6.56%	7.95%	7.80%
BG&E (0% customer, 100% demand)	6.26%	6.74%	6.18%	8.00%	7.97%
OPC Alternative (29.35% customer)	6.26%	6.86%	5.80%	9.48%	9.69%
Company (53.44% customer)	6.26%	6.75%	5.24%	10.99%	11.68%

Revenue-Cost Ratio (firm load return = 100%)					
OPC (0% customer)	98.86%	100.00%	99.40%	101.59%	101.97%
BG&E (0% customer, 100% demand)	99.25%	100.00%	99.19%	102.07%	102.98%
OPC Alternative (29.35% customer)	99.06%	100.00%	98.44%	103.97%	106.34%
Company (53.44% customer)	99.24%	100.00%	97.69%	105.98%	110.15%

Q What do you recommend?

A Based on the results of my cost-of-service study, the small differentials (particularly with residential rates only slightly below the system average) point to an across-the-board system average percentage rate increase or decrease as being the design of choice. Within these broad rate classes, the design of rates should give a slightly larger than average percentage increase (or smaller decrease) to residential customers not using space heating and a slightly smaller than average percentage increase (or larger decrease) to commercial and industrial and GMA customers that do not use space heating.

In the event that the Commission adopts a different allocation method for mains than I recommend, then a residential increase slightly above the system average (i.e., 1% more than the system average) would be consistent with such a decision.

If there is a significant rate increase, regardless of the cost study being adopted, I would recommend that the Commission follow provide no class with an actual rate decrease. With a significant decrease, all classes should share in the decrease.

Q Is the appropriate level of rate increase by customer class related in any way to WG's proposal to increase service charges?

A Yes.

My recommended rate spread is consistent with my recommendations regarding these service charges.

If the Commission rejects my recommendations and significantly increases service charges, then the Commission should adopt a smaller residential rate increase than I recommend. Just as I assumed that the existing level of the revenue from these charges should be allocated by the number of customers, the Commission should include the increased service charges as part of the rate changes it is adopting. To analyze the effect of those rate changes, it should assume (consistent with WG's testimony on the Settlement of Case No. 8545) that at least 90% of those increased service charges will be paid by residential customers when looking at the total impact on residential customers of its adopted rate changes.

IV. Review of Washington Gas' Marginal Cost Study

A. General Description of Marginal Cost Methods

Q Have you reviewed Mr. Raab's marginal cost study?

A Yes.

Q Have you previously been involved in the preparation and analysis of gas and electric marginal cost studies?

A Yes, since the early 1980s. I have been involved in the preparation and review of electric and gas marginal cost studies in California and electric marginal cost studies in several other states.

Q What is the intent of a marginal cost study?

A Marginal costs are defined as changes in cost with respect to changes in output. Output can be defined as gas sales, peak demand, number of customers[18] or some combination thereof.

A marginal cost study is thus a study of how a utility's costs change when output changes. It is more future oriented than an "embedded cost study" or "cost of service study" which allocate a utility's existing and past costs to customer classes.

When such a marginal cost study is used to analyze class revenue requirements or rate design, it is necessary to compute the "marginal cost revenue responsibility" (which is simply the marginal costs associated with each type of output multiplied by the number of output units consumed in each class – for example peak demand costs multiplied by class peak demand, class customer costs multiplied by number of customers, etc.).

Because a marginal cost study is estimating future costs, it is only coincidental that such a study will bear any relationship to the existing embedded costs. The "marginal cost revenue responsibility" must be reconciled with the existing revenue requirement. Many analysts reconcile it by scaling the marginal costs to the embedded costs in equal proportion. In other words if the marginal cost revenue responsibility is $80 and the embedded cost is $100, then the marginal cost results are

[18] Subject to the caveats given below.

scaled up by $100/$80 or 125% to obtain embedded cost class allocation factors. A few analysts claim that "Ramsey pricing" should be used, which loads up differences between marginal and embedded costs on the least elastic rate components (often customer costs and charges), but Ramsey pricing has also been viewed as a form of price discrimination to be eschewed by regulatory commissions.

Q Will you provide a description of the general method used to conduct marginal cost studies of electric and gas transmission and distribution?

A A marginal cost study is usually divided between plant and O&M expenses, although Mr. Raab's analysis did not follow that distinction.

Capital plant is usually based on an analysis of the change in capital spending as related to the change in output. A regression analysis, which uses statistical techniques to relate plant and output by fitting the data to a line or curve, is one common method that is used.[19] When a regression is used, the slope of the line yields the incremental or marginal plant per unit of output. Capital plant is then multiplied by a real economic carrying charge (RECC) rate to obtain an annualized result.

General plant is usually treated either as a loader[20] on other tangible plant or (after multiplication by the RECC) a loader on expenses.

O&M expenses are generally computed based on averages of several years in real dollars or based on the last recorded year (if expenses have been trending down or up over time). Regression analysis is generally not used for O&M expenses, because factors such as productivity can be mixed into an incremental analysis.

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[19] Some analysts use a Total Investment Method, which is simpler than a regression. They add up total investments over a period of time and divide by the change in output.

[20] A "loader" is a percentage adder to either plant or expense items based on historical experience.

A&G expenses are generally treated as "loaders" applied either to O&M expenses or plant, depending on the type of cost, similar to an embedded cost study.

Q **To your knowledge, are there settled methodology for marginal cost analysis in Maryland?**

A No. It is my understanding that marginal cost studies have been presented, particularly for electric utilities, as a means of giving the Commission more information regarding rate design, but they have not been used extensively.

B. Critical Substantive Issues in Marginal Cost Analysis

Q **What are typical issues involved in the preparation of marginal cost studies?**

A There are a number of issues with respect to the definition of marginal expenses as well as issues with the appropriate definition of customer investment costs. There are also significant issues about the allocation of certain costs to customer classes that are similar to the issues raised in embedded cost analyses.

Q **Will you briefly describe the expense issues that have been raised?**

A Some analysts believe that certain O&M expenses are not legitimate marginal costs. These include expenses for DSM and energy efficiency programs (which are not related to the number of customers at all but to state energy policy and the cost-effectiveness of reducing the use of expensive gas or electricity), sales and marketing expenses (which are undertaken to encourage customers to use gas, again costs which are driven by policy and the desire to increase revenues, not costs necessary to serve customers), and uncollectible accounts expenses (which are arguably not marginal costs to bill-paying ratepayers).[21]

Some analysts also examine A&G costs in detail to determine whether costs are indeed marginal. Costs which are clearly not marginal are often excluded (for example transition obligations on OPEB, research and development costs). The extent to which non-marginal costs are excluded depends on the analyst. To give one example, SoCal Gas excludes a broad range of A&G costs including top executives' salaries as not constituting marginal costs.

Q Will you describe the theoretical issues associated with the definition of marginal customer costs?

The concept of a "marginal customer hookup cost" does not fit the typical marginal cost definition well. Ascribing the cost of new hookups as a rental cost applied to existing customers whose hookups have been in place for years, as Mr. Raab is suggesting, is problematic. Marginal customer costs are unlike other utility marginal costs of service. These costs are only avoidable at the time when the facility is being installed because a customer facility is dedicated to its location. The hookup cannot be used by another customer at another location. By contrast, transmission and distribution capacity are more common or fungible costs. If one customer reduces consumption by a decatherm or reduces his or her call on the electric generation system by one kilowatt of demand, other customers have the ability to use the space that is freed up. But a customer facility has no value apart from the location where it exists. It cannot be moved to serve another customer (aside from meters, where a

[21] For example, the California Commission, which is one of the few state Commissions to use marginal costs instead of embedded costs for rate design and thus has almost 20 years of experience in this area, has excluded all of these costs from marginal cost studies for both gas and electricity.

limited amount of salvage costs could be realized), and thus its future avoidable costs ("opportunity costs") are negligible. Customer access equipment is thus different both from other gas and electric plant and from the buildings to which it is attached (which could be rented or sold to someone else and thus have an opportunity value).

In a competitive market, the customer would pay the prevailing price of purchasing the customer hookup at the time that it was installed, which would approximate marginal cost. This is the way in which consumers purchase many durable goods which are affixed to their premises and have no other uses apart from the premises (curtains, ceiling insulation, etc.). Therefore, the economically efficient means of charging for customer hook-ups would be as a one-time charge when service is established. This charge would influence consumer behavior when the customer chooses to access the utility system--the only time when costs are avoidable.

Costs of services, regulators, and meters that Mr. Raab considers to be marginal are thus actually sunk costs except for the few customers installing new hookups in any given year.

Instead of assuming that each customer rents a customer hookup at the cost of a new hookup, a preferable method would calculate marginal customer hookup costs by multiplying the hookup cost by the number of new customers, plus the replacement costs multiplied by the number of replacement customers with an adjustment to include income and property taxes over the life of the investment.

Q Will you discuss the issues associated with cost allocation?

A The same issues of allocation of major account representatives, use of customer weighting factors for meters, services, and customer accounting costs, and treatment of tariffed service charges that I raised in my critique of WG's embedded cost of service analysis also arise whenever a marginal cost study is prepared.

Q Has Mr. Raab addressed these issues in preparing his marginal cost study?

A Only in a limited basis and not well. He has not addressed the possibility of non-marginal O&M costs or theoretical issues related to customer hookup costs. He ignores tariffed service charges. He has allocated hookup costs (but not customer accounting costs) differently by customer class, but to do so, he makes the incorrect assumption that large customers are not served through service mains and thus have no service line costs.

C. Specific Methodological Concerns with the Raab Study

Q What other concerns have you identified with Mr. Raab's study?

A I have identified several concerns, including his use of an incorrect definition for the "real economic carrying charge rate" (RECC) applied to capital investment and inappropriate and unquestioning use of a regression methodology, even when it produces strange results.

1. <u>Real Economic Carrying Charge Rate</u>

Q Why are you concerned regarding the real economic carrying charge rate calculation?

A The appropriate method for calculation of the real economic carrying charge rate is a very technical issue, but one which has a significant impact on Mr. Raab's results. Mr. Raab's incorrect calculation of the RECC yields a rate in the range of 16-17% depending on the type of property (OPC DR 4-55, 15th unnumbered page). I believe that an appropriate RECC is in the range of 10% for Maryland. By using an inflated RECC factor, Mr. Raab is overstating capital costs by about 60-70% in his marginal cost study.

Q What is the purpose of a real economic carrying charge rate?

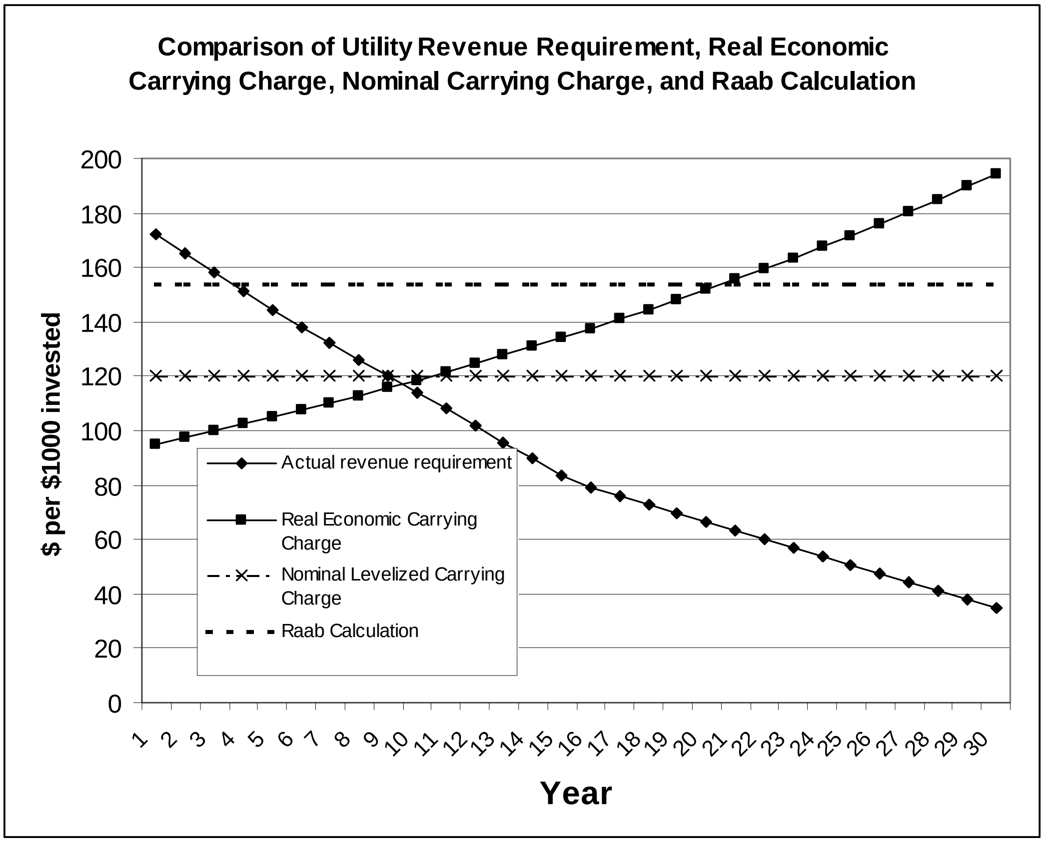
A A real economic carrying charge rate is designed to measure the economic return expected for an asset whose value increases at the rate of inflation every year. Since a marginal cost study is defined in real dollars, the carrying charge used must net out inflation. An economic carrying charge also has the property of measuring the value of deferring the construction of the asset from one year to the next.

Q How is an economic carrying charge rate calculated?

A One must look at the entire time stream of ownership of an asset and calculate a present value of revenue requirements over the life of the asset using utility accounting. The discount rate used is the utility rate of return. The present value of revenue requirements includes return, depreciation, and income and property taxes and may include certain other costs such as property insurance. From this present value of revenue requirements, one can then calculate two fixed charge rates, a levelized <u>nominal</u> fixed charge rate (the same number of dollars every year divided by the capital cost of the asset), and a real economic carrying charge rate (the number of dollars in the first year which, when increased at the rate of inflation every year, results in the same present value as the present value of revenue requirements).

Q Have you prepared an example of the relationship between utility revenue requirement, and the RECC?

A Yes. The chart below shows this information, using an asset with a 30-year life, a typical utility capital structure (45% equity, 50% debt, 5% preferred), an equity return of 10.5% and a debt return of 7.5%, Maryland-specific income and property taxes, and a 2.5% inflation rate. The end result is that for this example, the RECC is about 9.50%, and the levelized nominal fixed charge rate is 12.00%.



Q How does Mr. Raab calculate his supposed RECC?

A He calculates an after-tax return on utility property and adds the depreciation rate to it. He does not present-value the entire lifespan of the asset and does not account for inflation in any way. With the parameters in my example above, his calculation method would yield a figure of 15.35%.[22]

Q Do you believe that his calculation is right?

[22] The figures in Mr. Raab's testimony are higher because he uses a 12.5% return on equity.and a higher proportion of equity in his capital structure than in my illustrative example. The principle still holds that a

A No. His calculation greatly overstates the RECC and thus greatly overstates capital-related marginal costs.

2. Regression Methodology

Q Turning to the issue of regression methodology, are there significant pitfalls that an analyst must be concerned about?

A Yes. When one runs a regression of cumulative investments against total customers or total peak load, one must be worried about obtaining a spurious correlation that has little or no basis in fact. As the system grows, all of these numbers are rising. Investment base increases, the number of customers increases, and the peak demand increases. No wonder correlations in excess of 90% appear in Mr. Raab's regressions. Total customers are rising and total plant is rising. But correlation does not necessarily represent causation.

Let me give an example. Suppose I ran a regression of the total number of microwave ovens in the Pepco service area to the total number of Pepco customers from 1980-2000. I would expect to find a strong correlation, together with a finding based on the slope of the regression equation that every new Pepco customer purchased somewhere in the vicinity of two or three microwaves over the 20 year period covered by the regression. Because many existing customers did not own microwaves in 1980, the slope of the regression equation would assign all microwaves added after that date to the new customers.

If we ignored the intercept and multiplied the number of "marginal" microwaves by the number of existing customers to calculate the "marginal microwave oven saturation per customer "(like Mr. Raab

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correctly calculated RECC is about one-third less than Mr. Raab's method, regardless of the underlying capital structure and return.

multiplies the “marginal cost” that he calculates by the total number of customers to obtain the “marginal cost revenue responsibility”), we would be assuming that there are several microwaves in every kitchen.

Now my regression equation for microwaves sounds preposterous on its face, and no one would believe its results.

But Mr. Raab’s regression has the same problem, only the numbers are a little more subtle. The slope of his regression assigns all WG distribution investments, regardless of why they were made, to the number of new customers over the time period. These costs which the regression assigns to new customers are multiplied by the total number of customers.

While use of these cumulative regressions is common in marginal cost studies, it is also reasonable to run a check on the cumulative equations by running a regression to compare investments in each year to the number of customers or amount of load added in each year. This would show a better estimate of the real correlation between investments and customers or load.

Q Did you run such a test, Mr. Marcus?

A Yes. I prepared two separate regressions for the most recent historical period from 1990 to 2001, comparing annual distribution investments excluding SRM (in constant dollars) to number of customers and peak demand.[23] I included a dummy variable for the year 1996, when a large addition was recorded as a result of the merger that added the Frederick system to WG’s service area. I included this dummy variable because the Frederick addition was not a new investment but a consolidation of two

[23] The regressions are stated in thousands of dollars. Thus –0.0752 X customer additions is interpreted as negative $75.20 per customer. As the peak load is stated in thousands of therms, the $19.71 X Peak load change is interpreted as $19.71 per peak day therm.

existing embedded systems. Mr. Raab, by contrast, incorrectly treated the Frederick consolidation as if it were a new physical system investment.

<u>Equation 1 – Relation of Annual Investment to Changes in Peak Load</u>

Investment = 31,029 + 107,413 * dummy96 + 19.71 * Peak load change (8.16) (11.35) (2.68) Adjusted R^2 = 0.922

<u>Equation 2 – Relation of Annual Investment to Customer Additions</u>

Investment = 39,624 + 107,889 * dum96 – 0.0752 * Customer additions (4.18) (5.54) (0.17) Adjusted R^2 = 0.860

Q What do these regression equations show?

A The regressions show several important things. First, contrary to the spurious correlation obtained by Mr. Raab (obtained by regressing two steadily rising streams of numbers against each other), investment in the bulk portion of the distribution system may not be closely related to the number of customers. Average investments do not vary systematically with the number of customers, as shown in Equation 2, where customer additions have the wrong sign (negative) and are statistically insignificant.

The preponderance of non-SRM distribution investments are not closely related to <u>either</u> the number of customers or system demand. The largest terms are the constant term and the dummy variable for the addition of the Frederick system. In other words, most of the distribution system investments may not be marginal costs at all. However, there is a statistically significant although small <u>demand-related</u> component that would be appropriate for inclusion in a marginal cost calculation. Equation 1 shows that the average investment level (aside from the Frederick merger year) was $31 million plus $19.71 per peak day therm. The demand-related component is statistically significant at the 5% level.

In essence, then, my check of Mr. Raab's investment figures indicates that we have "number salad." A cumulative equation run using Mr. Raab's methodology, which is the basis for his large customer component in his marginal cost study, is a spurious correlation of two large numbers rising at the same time. The annual figures suggest that most costs are not marginal (ending up in the intercept term, not the slope), but there is a small demand-related component and most costs are not marginal. In essence, we must be cautious when using the figures.

Q If a cumulative equation were to be used, is there a better way to structure an investment equation than Mr. Raab's formulation?

A Yes. A relationship of cumulative investment to <u>both</u> the number of customers and peak load with a dummy variable for the Frederick merger provides a more robust equation for the period from 1990-2001.

Equation 3: Cumulative Investment vs. Customers, Loads, and Frederick merger

Cumulative investment = 25536 + 89446 * dummy96on
(3.27) (5.45)

+ 1.097 * Cumulative customers + $40.04 X cumulative peak day therms
(5.075) (3.125)
Adjusted R^2 = 0.996

This equation suggests that non-SRM marginal investments would be better measured as $1097 per customer plus $40.17 per peak day therm if a cumulative equation were to be used.

Q How does this compare to an analysis of investment costs using the Raab method?

A An investment cost regression over the period from 1984 to 2001, excluding any dummy variable for the Frederick merger and run only against number of customers, would yield a "marginal" customer investment of $2447.

<u>Equation 4: Simple (Raab) Form of Investment Equation 1984-2001</u>

Cumulative investment = -36980 + 2.447 X Cumulative customers
(3.27) (27.93)
Adjusted R^2 = .979

From 1990 to 2001, the same regression would show a "marginal" customer component of $2169.

<u>Equation 5: Simple (Raab) Form of Investment Equation 1990-2001</u>

Cumulative investment = 8656 + 2.169 X Cumulative customers
(0.59) (23.27)
Adjusted R^2 = .980

In other words, simply conducting the more careful analysis in equation 3 reduces the "customer" costs calculated using the Raab method by 50% or more, while uncovering some significant demand-related costs.

Q What other problems have you identified with Mr. Raab's equations?

A There are two problems.

First, he confuses productivity with marginal costs, most notably in his equation that produces a negative marginal cost for customer accounting. In the area of customer-related expenses, he found that as the number of customers rises, real expenditures were falling due to productivity.

However, his regression correlates the increase in the number of customers with the decline in expenses, so that costs per customer end up being negative. This is a nonsensical result. A better interpretation would be to look at the last five to ten years of customer accounts expenditures in constant dollars per customer; if they are declining over time, the last recorded year should be assumed to be the marginal cost; if not, the average should be used.

Second, he mixes annualized investment costs (annualized improperly and overstated because of his inaccurate RECC calculation) with O&M costs that do not belong in regressions at all, thereby creating further analytical problems.

Q What do you conclude from this information?

A I believe that the material provided by Mr. Raab is useless for regulatory purposes because of the flaws that Mr. Miller and I have identified.

If the Commission wishes to investigate marginal costs further, it should do so in a generic docket or a later phase of this proceeding that is not under the severe time constraints of a general rate case.

V. Evaluation of WG's Proposal to Increase Service Charges

Q Will you briefly describe WG's proposals with respect to service charges?

A WG's tariffs currently contain charges for service initiation, reconnection of service, field collection, and dishonored checks. WG is proposing significant increases to all of these charges with the alleged goal of covering 100% of the cost of each of these services through increased charges.

Residential customers pay the preponderance of these charges, as they are the customers who move most often and run into payment problems.

OPC has therefore evaluated both the cost basis and other policy arguments regarding these charges in more detail below.

Q Will you summarize OPC's recommendations?

A The table below compares existing charges, WG's proposals, and OPC's proposals for the most important charges. Figures shown are for the main system. Some of these charges are currently lower in the Frederick District. In all cases both WG and OPC propose the same charges for the entire WG system including Frederick. I have also included BG&E's charges for these same services for comparison. With the exception of field collection, BG&E's charges are lower than WG's charges.

	Existing	**WG**	**OPC**	**BG&E**
Service initiation (gas on)	$40	$57	$25	$20
Service initiation (gas off)	$40	$127	$40	$40
Dishonored check	$15	$30	$15	$15
Field collection	$8.50	$30	$8.50	$15
Reconnect delinquent (regular hours)	$50	$125	$70	$20[24]

A. Service Initiation Charge

Q What is the service initiation charge?

A It is a charge, currently set at $40, which is charged to customers who begin gas service at a new address.

[24] I cannot readily determine from BG&E's tariff whether the service initiation charge is added to the reconnection charge.

Q What is the Company's proposal for the service initiation charge?

A It proposes to increase the charge to $57 where the gas has not been turned off and to $120 where the gas has been turned off.

Q Why is the Company proposing to increase this charge to this extent?

A WG believes that users should pay the full cost of service initiation. In WG's view, this principle is the only factor that the Commission should consider. It overrides all other rate design principles including gradualism, avoiding rate shock, and ability to pay.

Q Did the company provide a detailed study to determine the cost basis of the service initiation charge?

A No. The sole information is provided on one page of the response to Staff DR 3-75 (page 19).[25]

The Company has not provided enough information to justify its existing charge, much less support an increase of 42% (with gas flowing) or 200% (with gas already turned off). The basis for $20 of "General Administrative Costs" is not provided. "Corporate Support is only 5% of the cost of estimating the cost for changing the location of a meter (Staff DR 3-75, page 16). However, "General Administrative Costs" are 35% of the cost of service initiation. The $31.60 cost of a field visit to read a meter is also not justified. A field visit to disconnect a customer or collect money has a cost of only $15. Why it costs $16.60 more to spend two minutes reading the meter is nowhere explained.

[25] OPC asked for detailed justification of the cost basis of this charge in its DR 4-12 and was referred to the response to Staff DR 3-79. That response in turn referred to Staff DR 3-75. It is therefore reasonable for the Commission to assume that no other documentation exists beyond Staff DR 3-75, because it should have been produced in response to the OPC data request.

For reconnection charges when the gas has been turned off, the Company has the same $20 of General Administrative Costs, and a $94.80 cost for appliance turn-ons. The $94.80 cost of appliance turn-ons appears twice in the data response (on pages 17 and 19) but there is not one scintilla of supporting documentation for it.

Q Does the Company have any information regarding who pays the service initiation charge?

A It claims not to have any information in response to several OPC data requests. The Company claims not to know which customer classes pay the charge (OPC DR 4-11). WG also claims to have no information on the incidence of the charge by income (OPC DR 4-17) and by ownership versus rental (OPC DR 4-16). However, WG clearly does not believe that low-income customers should be given a discount for this charge.

Q Does the Company believe that it is important to have any of this information?

A No. WG claims that it is unnecessary to have any such information when deciding to increase its charge, because one and only one rate design principle is important – to make the user pay the costs of this particular service regardless of any information regarding the characteristics of the "users" of this service. As stated in the response to OPC DR 11-5(a):

> The intent of the charge is to have those customers who utilize or require a service to pay for that service, at its cost, regardless of their ownership status or class of service. Therefore, such data was not required or needed to determine the cost of providing this service and was, therefore, not accumulated.

Q Were you able to obtain any information that would be helpful to the Commission regarding the incidence of this charge by income level and by ownership versus rental?

A Yes. While the Company itself collects no data internally on the incidence of the charge, there is a significant amount of census data related to the question of average length of time that someone lived in the same place and the characteristics of customers who moved in the previous year. The year 2000 census data is not available yet, so I reviewed information from the 1990 decennial census and from the *American Housing Survey for the Washington Metropolitan Statistical Area: 1998*.

The 1998 survey of housing[26] shows that 37% of renters but only 9% of homeowners moved in the previous year. Data from the 1990 census for the state of Maryland confirms this information, showing that 10% of homeowners and 37% of renters moved in the previous year.[27]

The information also shows that 29% of those with incomes under the poverty line, 33% of food stamp recipients, and 34% of recipients of welfare or Supplemental Security Income moved in the previous year. By comparison, only 18% of those with incomes above the poverty line moved in the previous year.

The chart belows shows more information on the results by income level:

	Moved in last year
Less than $25,000	24.0%
$25,000 to $50,000	25.6%
$50,000 to $100,000	17.1%

[26] US Census Bureau, *American Housing Survey for the Washington Metropolitan Statistical Area: 1998*, Tables 3-9 to 3-12 and 4-9 to 4-12, pp. 60-64, 103-107.

[27] From http://www.census.gov/hhes/www/housing/census/historic/movers.html

Over $100,000	12.5%

Q Could the Company have readily found this data at reasonable cost?

A Certainly. Finding and analyzing these data took me about an hour and 15 minutes of internet research and spreadsheet preparation. This fact suggests to me that would not have been difficult or costly for the Company to obtain this information if it wanted to obtain it.

Q What is your recommendation with respect to the appropriate level of the basic service initiation charge?

A I recommend that the service establishment charge where gas is flowing should be set at no more than $25 -- $15 for the field visit, $5 for telephone system costs, and $5 for other undefined system costs and overheads. This recommendation reflects that these charges must be set conservatively.

While the Company follows the "user pay" principle to justify large fees, the Commission should clearly base its decisions on a broader public interest perspective than WG has taken. It must also remember <u>who</u> pays these charges – disproportionately renters and poor people.

I simply do not believe that the Company should be allowed to burden renters and poor people with undefined charges for "General Administrative Costs." Ratepayers as a whole should pay for the administration of the Company through their gas rates, without those costs being disproportionately dumped on people having the gas turned on. The extremely high and unjustified and unitemized charges for field visits also should not be used as the basis of these costs.

I recognize that this is a decrease from current levels, but the flimsy documentation presented by the Company in this case leads me to I believe that the Company was previously allowed a fee that is too high.

Q What do you recommend for service initiation when the gas has been turned off?

A I recommend a charge of $40. This amount is the same as the current charge and 60% above my recommended charge where the gas remains on. I believe that it is more expensive to turn the gas on than not, but believe that the Company has not adequately documented or justified its request to increase the charge. My recommendation is the same as BG&E's current charge.

There are several reasons why I do not support the company's $120 figure. First, as discussed above, I do not believe that the costs have been adequately documented. Second, as also discussed above, this cost disproportionately affects renters.

Moreover, even if it were adequately documented, and even it its effects were not disproportionate, a 300% increase in the cost to $120 for this kind of service constitutes rate shock. By comparison, the telephone service initiation charges are in the range of $60. The rate shock is made worse by the fact that the Company never previously had a differential in the service initiation charge when gas was turned off or not. Customers have no knowledge that it is more expensive to turn off the gas than to change service while the gas is still running. The Company has no plans at this time to inform them of this fact in advance or to offer a grace period before the higher charge comes in. (OPC DRs 4-19, 4-20, and 4-21) Unsuspecting customers who do not understand what is happening to them will simply be gouged without being given any information on how to avoid the charge.

Finally, there is clear no economic nexus for this cost. In many cases, a customer requesting a service turn-on has no idea whether the previous customer turned the service off and has no ability to influence that customer in many cases. Charges like this one are designed to send price signals to influence behavior, but this particular price signal is likely to be unusable in many cases.

Q If the Company is allowed to charge more for service initiation when the gas is turned off, should it be required to provide information to customers?

A Yes. The Company should be ordered to provide information to customers through bill inserts, a program of outreach to landlords, and specific scripts designed for customer service representatives taking calls regarding a change of service to encourage departing customers to leave the gas on. It is my understanding that the Company has not yet planned whether to do these things, based on its response to OPC DRs 4-19, 4-20, and 4-21. If the Commission considers a charge higher than OPC's recommendation, it should also consider adopting a grace period of several months to enable customer education to precede the implementation of the new charge.

B. Dishonored Check Charge

Q What is the dishonored check charge?

A The dishonored check charge, charged when the Company receives a check that is returned by the bank, is currently $15 except in the Frederick district, where it is $13.50. WG proposes to increase this charge to $30 ($25 in costs plus a $5 penalty).

Q **Do you have any comments on the cost basis of the dishonored check charge?**

A Yes. The Company's request is again inflated. The response to Staff DR 3-75 (page 18 of 78) shows that a field collection visit is included in the cost of the returned check charge. There is no evidence that all, or even most, of the customers with returned checks end up with a field collection visit. Moreover, the cost of a field visit is included in both the separate field collection charge (if OPC's recommendation not to increase the a charge is rejected) and in the reconnection charge for delinquent customers. It may therefore also be double-counted when included as part of the returned check charge. The Company's own data indicate that without this field visit, the cost of a returned check would be only $10.18.

Q **What is your recommendation for the dishonored check charge?**

A The existing $15 charge covers the Company's real costs (about $10 excluding the field visit) plus a penalty in the Company's range (approximately $5.00). I therefore recommend that the charge remain at the current level of $15 for the WG system. The charge in the Frederick district should also be increased from $13.50 to $15. The Commission should reject WG's proposed increase to $30.

C. Reconnection Charge

Q **What is the reconnection charge?**

A It is a charge assessed when the gas is reconnected, either after a delinquency or after the customer requests a disconnection for some other reason. The current charge (for service from 8am to 5pm weekdays and

Saturdays) is $50 on the WG system except $37.50 in Frederick. An additional $20 is charged for service outside of the 8 to 5 pm time period or on Sundays and holidays. The Company is proposing to increase the reconnection charge to $125 for delinquent customers and $95 for non-delinquent customers.

Q Do you have any concerns regarding the cost basis for the charge?

A Yes. My specific cost concern relates to the $94.80 figure for appliance relighting. This figure is used both here and as part of the calculation of the service initiation charge with the gas turned off. The figure is nowhere itemized and documented, as I discussed above.

Q What do you recommend?

A I recommend setting the charge at of $40 during business hours (equal to my service initiation fee recommendation with gas turned off) and $70 during other hours for non-delinquent customers and $70 during business hours and $100 during other hours for delinquent customers. This recommendation is based on the current charge for service establishment, given the undocumented nature of the $94.80 cost, plus $30 for delinquent customers to reflect the costs of the collection process, and an increase from $20 to $30 for premium service. The total increase for business-day service to a delinquent customer is $20 or 40%. I also believe that, even if the actual costs are somewhat higher than my recommendation, it is reasonable to moderate this charge for reasons of reducing rate shock, even for customers who have been disconnected. It serves the public interest of restoring gas service, recognizing that the customer whose service is restored is paying its full arrearage plus a deposit.

D. Field Collection Charge

Q What is the field collection charge?

A It is a charge that is assessed when a gas service person comes to disconnect service and instead accepts a payment from the customer. The current charge is $8.50. WG is proposing to increase the charge to $30.00. WG's recommendation (like those for other service charges) is based entirely on cost incurrence with no consideration of other policy factors.

Q What is your position regarding this charge?

A I recommend no increase to the charge.

While I do not have a significant disagreement with the utility's cost analysis of this charge (as contrasted to the other charges discussed above), there are three key policy reasons that warrant keeping this charge at a level below cost.

First, disconnections are not cost-effective to the Company (by extending the time until the Company is paid, thus increasing its need for working capital, and by increasing the risk of uncollectibles). Thus, to the extent that increasing the field collection charge from $8.50 to $30 makes it haarder for customers to pay and creates additional disconnections, it may actually cost the company more than the revenue it raises. By being penny-wise and raising this charge to reflect "costs", the Company may be being pound-foolish.

In sum, the Company should work with the customer to avoid disconnection, because disconnection is bad for both the customer and the Company. Working with the customer to avoid disconnection includes not making the customer come up with large amounts of money above and beyond their past-due gas bill, like this proposed field collection charge.

Second, even if this particular charge for field collections does not reflect cost, the Commission should remember that the late payment charge (which is assessed against all customers receiving a field collection call) exceeds the company's cost of capital and thus generates surplus money that can be considered to fund a portion of the Company's collection activities.

Third and finally, Ms. Schilberg's analysis of the telephone and payment process indicates that the payment arrangement process is unclear and problematic. The company handbook cited by Ms. Schilberg specifically states that there is no place to pay a bill anywhere in the state of Maryland where it will be received in time to avoid disconnection once the customer receives a five-day notice, although customer service representatives may suggest different payment options. In other words, the Company's own practices with respect to payment processing may be increasing the number of field collections that are required.

OPC therefore recommends leaving this charge at $8.50 at the present time.

Q Does this complete your testimony, Mr. Marcus?

A Yes, it does. Thank you.

OPC EXHIBIT WBM-1
SUMMARY PAGES FROM OPC'S EMBEDDED COST OF SERVICE STUDY

Washington Gas Light Company
Maryland Division Pro Forma Class Cost of Service Study
Prepared by Maryland Office of People's Counsel
Income Statement Summary

Twelve Months Ended December 31, 2001 - Average

	Description	Maryland Total	Maryland Firm Load	Res Heating/ Cooling	Res Non Heating, Non Cooling	C&I Heating/ Cooling <3000	C&I Heating/ Cooling >3000	C&I Non Heating Non Cooling	GMA Heating/ Cooling	GMA Non Heating Non Cooling	Non Firm
	A	D	D1	E	F	G	H	I	J	K	L
1	**Operating Revenues**	$ 336,055,222	$336,039,236	$ 244,136,791	$ 1,046,108	$ 16,898,497	$ 49,571,564	$ 5,064,871	$ 16,575,014	$ 3,746,391	$ 15,986
2	Operating Expenses										
3	Operation	$ 218,870,669	$216,661,607	$ 164,662,679	$ 724,669	$ 10,755,910	$ 29,403,966	$ 2,490,422	$ 7,480,699	$ 1,143,262	$ 2,209,062
4	Maintenance	18,136,047	17,208,773	11,714,535	70,084	886,927	2,764,441	228,092	1,393,164	151,531	927,274
5	Depreciation	23,509,457	22,319,618	15,116,320	89,790	1,173,140	3,827,842	294,314	1,830,564	187,648	1,189,840
6	Amortization of Capital Leases	14,266	13,745	10,290	74	676	1,842	142	806	116	520
7	Amortization of Capitalized Software	2,677,944	2,580,293	1,931,702	13,844	126,841	308,168	26,694	151,266	21,777	97,651
8	Amort. Pepco/ MD Post 1989 Interruptibles	-	-								-
9	Interest on Customer Deposits	69,635	69,607	57,242	488	3,032	5,752	692	1,917	484	28
10	Interest on Supplier Refunds	-	-	-	-	-	-	-	-	-	-
11	General Taxes	26,211,656	25,401,713	17,466,344	90,694	1,429,476	4,271,391	377,704	1,575,275	190,828	809,942
12	Other Income Taxes	1,124,478	1,066,183	722,662	4,243	54,982	173,374	14,095	87,755	9,073	58,295
13	Expenses Before Federal Income Taxes	$ 290,614,151	$285,321,539	$ 211,681,774	$ 993,886	$ 14,430,984	$ 40,556,575	$ 3,432,155	$ 12,521,445	$ 1,704,720	$ 5,292,611
14	Federal Income Taxes	5,228,824	$ 8,820,838	5,050,254	(37,515)	375,461	1,808,763	581,544	672,031	370,299	(3,592,014)
15	Investment Tax Credit Adjustments	(325,065)	$ (314,773)	(235,566)	(1,802)	(14,881)	(38,352)	(2,662)	(19,142)	(2,368)	(10,292)
16	Deferred Income Taxes	6,966,714	$ 6,703,984	4,975,331	36,392	308,764	846,238	59,717	425,889	51,633	262,750
17	Total Operating Expenses	$ 302,484,624	$300,531,588	$ 221,471,793	$ 990,961	$ 15,100,328	$ 43,173,224	$ 4,070,754	$ 13,600,222	$ 2,124,285	$ 1,953,056
18	Net Operating Income	$ 33,570,598	$ 35,507,668	$ 22,664,997	$ 55,147	$ 1,798,169	$ 6,398,340	$ 994,117	$ 2,974,791	$ 622,107	$ (1,937,070)
19	Net Income Adjustments										
20	AFUDC	(9,778)	(9,253)	(6,260)	(34)	(461)	(1,523)	(119)	(779)	(77)	(525)
21	Net Operating Income - Adjusted	$ 33,560,820	$ 35,498,415	$ 22,658,738	$ 55,113	$ 1,797,708	$ 6,396,817	$ 993,998	$ 2,974,012	$ 622,030	$ (1,937,595)
22	Net Rate Base	535,719,921	507,947,211	344,288,254	2,021,354	26,194,119	82,598,080	6,714,941	41,807,791	4,322,673	27,772,709
23	Return Earned	6.26%	6.99%	6.58%	2.73%	6.86%	7.74%	14.80%	7.11%	14.39%	-6.98%
24	Revenue-Cost Ratio	98.86%	100.00%	99.43%	92.39%	99.81%	101.28%	111.56%	100.32%	113.19%	0.41%
	Income change for equalization			1,402,202	86,151	32,895	(624,365)	(524,717)	(52,232)	(319,935)	

Washington Gas Light Company
Maryland Division Pro Forma Class Cost of Service Study
Prepared by Maryland Office of People's Counsel
Rate Base Summary

Twelve Months Ended December 31, 2001
Average Rate Base

	Description	----- Reference ----- Sh-Pg-Ln	Allocator	Maryland Total	Residential Heat/Cool	Residential Non Heat/Non Cool	C&I Heating/ Cooling <3000	C&I Heating/ Cooling >3000	C&I Non Heating Non Cooling	GMA Heating/ Cooling	GMA Non Heating Non Cooling	Non Firm
	A	B	C	D	E	F	G	H	I	J	K	L
1	Gas Plant in Service Study	RB 2:50		$ 880,379,254	$ 565,506,147	$ 3,317,786	$ 43,294,682	$ 136,079,949	$ 11,007,368	$ 68,838,778	$ 7,047,258	$ 45,216,285
2	Gas Plant Held for Future Use	RB 4:12		265,588	156,411	319	11,781	45,593	3,883	23,834	2,235	21,724
3	Construction Work in Progress	RB 5:15		11,492,386	7,367,227	39,893	542,228	1,799,828	140,346	915,746	90,412	616,826
4	Materials & Supplies	RB 6:12		5,221,878	3,167,039	11,895	238,867	857,369	73,188	439,575	44,895	389,569
5	Sub-Total		=1+4	$ 897,357,739	$ 576,266,825	$ 3,369,783	$ 44,077,488	$ 138,772,739	$ 11,224,785	$ 70,217,726	$ 7,183,888	$ 46,244,404
6	Cash Working Capital	AL 8:38	O&M Adjusted	16,143,319	11,644,787	83,457	764,632	1,867,713	160,918	911,871	131,279	588,662
7	Total Rate Base Additions		=5+6	$ 913,501,058	$ 587,911,612	$ 3,453,239	$ 44,842,120	$ 140,630,452	$ 11,385,703	$ 71,129,597	$ 7,315,268	$ 46,833,066
8	LESS:											
9	Reserve for Depreciation	RB 7:27		$ 302,314,726	$ 194,818,701	$ 1,146,719	$ 14,824,248	$ 46,568,757	$ 3,719,215	$ 23,591,334	$ 2,394,886	$ 15,260,895
10	Deferred - Investment Tax Credit (1962 Act)	RB 8:13		-	-	-	-	-	-	-	-	-
11	Accumulated Deferred Income Taxes											
12	Liberalized Depreciation	RB 9:19		6,177,144	3,960,353	22,818	294,851	956,312	76,087	408,828	49,235	322,962
13	ACRS	RB 10:17		15,143,345	9,780,390	58,859	726,778	2,326,297	185,898	1,180,783	121,388	763,194
14	MACRS	RB 11:21		48,390,563	30,942,467	177,727	2,546,128	7,475,488	621,287	3,737,871	383,326	2,507,080
15	Construction Overheads	RB 12:16		1,024,671	661,053	3,935	49,218	157,402	12,468	80,843	8,148	51,530
16	Gains/Losses On Reacquired Debt											
17	Federal	AL 5:3	Net_Rate_Base	0	-	-	-	-	-	-	-	-
18	Other			0								
19	Customer Advances for Construction	AL 4:28	Dist_Mains_Plnt	1,878,821	1,105,673	2,254	82,713	322,297	27,448	167,878	15,888	153,068
20	Customer Deposits	RV 1:8	1/2 cust 1/2 GSNF	2,853,877	2,345,862	19,983	126,273	235,739	28,251	79,588	16,848	1,150
21	Supplier Refunds	AL 1:5	Annual_Firm_NW	-	-	-	-	-	-	-	-	-
22	Pro Forma Adjustment to Rate Base			0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total Rate Base Deductions		=9:22	$ 377,781,138	$ 243,623,358	$ 1,431,886	$ 18,648,881	$ 58,032,372	$ 4,670,762	$ 29,321,886	$ 2,992,586	$ 19,060,357
24	Net Rate Base		=7-23	$ 535,719,821	$ 344,288,254	$ 2,021,354	$ 26,194,118	$ 82,598,080	$ 6,714,941	$ 41,807,791	$ 4,322,673	$ 27,772,709

Washington Gas Light Company
Maryland Division Pro Forma Class Cost of Service Study
Prepared by Maryland Office of People's Counsel
Revenues

Twelve Month Ended December 31, 2001 - Average

RV1		Description (A)	Sch-Pg-Ln (B)	Allocator (C)	Maryland Total (D)	Residential Heat/Cool (E)	Residential Non Heat/Non Cool (F)	C&I Heating/Cooling <3080 (G)	C&I Heating/Cooling >3080 (H)	C&I Non Heating Non Cooling (I)	GMA Heating/Cooling (J)	GMA Non Heating Non Cooling (K)	Non Firm (L)
RV1.1	1	**Operating Revenues**											
RV1:													
RV1:													
RV1.2	2	Sales of Gas to Customers			$ 333,194,856	$ 242,831,588	$ 1,830,119	$ 16,280,835	$ 40,725,348	$ 4,978,959	$ 16,482,818	$ 2,823,632	$ 13,963
RV1.3	3	Payne			-								0
RV1.4	4	City Gate Service			-	0	0	0	0	0	0	0	0
RV1.5	5	Total Heating/Cooling and Other Uses	=2:4		$ 333,194,856	$ 242,831,588	$ 1,830,119	$ 16,280,835	$ 40,725,348	$ 4,978,959	$ 16,482,818	$ 2,823,632	$ 13,963
RV1.6	6			Gas_Sales_Ex_Non_Firm	**1.0000**	**0.7298**	**0.0031**	**0.0487**	**0.1163**	**0.0139**	**0.0495**	**0.0085**	**0.0000**
RV1:													
RV1.7	7	Total Gas Sales Revenue excluding Non Firm	=5*6		$ 333,080,892	242,831,588	1,830,119	16,280,835	40,725,348	4,978,959	16,482,818	2,823,632	
RV1:													
RV1.8	8			Gas_Sales_Ex_Non_Firm	**1.0000**	**0.7298**	**0.0031**	**0.0487**	**0.1163**	**0.0139**	**0.0495**	**0.0085**	
RV1:													
RV1.9	9	Market Conservation Revenue Adjustment		Direct Assignment	$ (1,835,536)	(2,335,418)	(17,974)	115,388	404,332			(102,552)	
RV1:													
RV1.10	10	Rate Adjustment Due Customers	RV1:6	Gas_Sales_Ex_Non_Firm	0	-	-	-	-	-	-	-	-
RV1.11	11	Unbilled Gas Accrual/Reversal	RV1:6	Gas_Sales_Ex_Non_Firm	0	-	-	-	-	-	-	-	-
RV1.12	12	Provision for Rate Refunds	RV1:6	Gas_Sales_Ex_Non_Firm	0	-	-	-	-	-	-	-	-
RV1.13	13	Total Gas Sales	(7+9+10+11+12		$ 331,169,321	$ 240,496,170	$ 1,812,145	$ 16,396,223	$ 41,129,672	$ 4,978,959	$ 16,482,818	$ 2,720,478	$ 13,963
RV1:													
RV1.14	14	Other Operating Revenues											
RV1.15	15	Forfeited Discounts	RV1:6	**Late Charge Revenue**	1,457,848	1,124,687	4,711	50,815	179,211	18,313	60,860	18,350	-
RV1.16	16	Rent from Gas Property - Direct	RV1:6	Gas_Sales_Ex_Non_Firm	31,132	22,698	96	1,515	4,654	485	1,541	264	-
RV1.17	17	Rental Income from WGCC		Gas_Sales_Ex_Non_Firm	43,805	31,788	135	2,132	6,378	652	2,158	378	-
RV1.18	18	Miscellaneous Service Revenues	MRV1:17		2,819,140	2,545,253	29,316	110,227	79,858	16,723	23,795	15,894	2,122
RV1.19	19	Other Gas Revenues											
RV1.20	20	CNG Sales for Natural Gas Vehicles	AL:5.10	Meter_Count_CIS_Only	650,606	-	-	406,410	191,706	52,485	-	-	-
RV1.21	21	Revenue Net of Gas Cost - Off System Sales	RV1:6	Gas_Sales_Ex_Non_Firm	0	-	-	-	-	-	-	-	-
RV1.22	22	Transportation Sales			-	0	0	0	0	0	0	0	0
RV1.23	23	Sale of 2 P000 Parts		Gas_Sales_Ex_Non_Firm	2,475	1,804	8	120	362	37	122	21	-
RV1.24	24	Other Allocable - SPSI	RV1:6	Gas_Sales_Ex_Non_Firm	(118,168)	(86,143)	(365)	(5,750)	(17,208)	(1,766)	(5,851)	(1,007)	-
RV1.25	25	Third Party Balancing Charges	RV1:6	Gas_Sales_Ex_Non_Firm	0	-	-	-	-	-	-	-	-
RV1.26	26	Third Party Balancing Charges - Allocable	RV1:6	Gas_Sales_Ex_Non_Firm	0	-	-	-	-	-	-	-	-
RV1.27	27	Other (SOCP credit for non-tariff treatment)	RV1:6	Gas_Sales_Ex_Non_Firm	0	-	-	-	-	-	-	-	-
RV1.28	28	Make a Wave Cost	RV1:6	Gas_Sales_Ex_Non_Firm	163	133	1	9	27	3	9	2	-
RV1.29	29	Other Gas Revenues Miscellaneous	RV1:6	Gas_Sales_Ex_Non_Firm	0	-	-	-	-	-	-	-	-
RV1.30	30	Total Other Operating Revenues			$ 4,886,701	$ 3,648,220	$ 33,960	$ 574,274	$ 441,891	$ 86,912	$ 82,396	$ 25,921	$ 2,122
RV1:													
RV1.31	31	Total Operating Revenues	=13+30		$ 336,055,222	$ 244,138,791	$ 1,846,106	$ 16,980,497	$ 40,571,564	$ 5,064,071	$ 16,576,814	$ 2,746,391	$ 15,085

Schedule RV Page 1
Maryland Division Pro Forma Class Cost of Service Study
Miscellaneous Service Revenues
Prepared by Maryland Office of People's Counsel
Twelve Month Ended December 31, 2001 - Average

MRV1		Description (A)	Sch-Pg-Ln (B)	Allocator (C)	Maryland Total (D)	Residential Heat/Cool (E)	Residential Non Heat/Non Cool (F)	C&I Heating/Cooling <3080 (G)	C&I Heating/Cooling >3080 (H)	C&I Non Heating Non Cooling (I)	GMA Heating/Cooling (J)	GMA Non Heating Non Cooling (K)	Non Firm (L)
	1	**Miscellaneous Service Revenues**											
MRV1.2	2	Reconnect Revenues	RV1:6	**Ave_Customer_Bill**	$ 393,615	$ 308,351	$ 4,307	$ 10,134	$ 7,453	$ 1,939	$ 2,165	$ 2,148	$ 317
MRV1.3	3	Reconnect Revenues - Premium	RV1:6	**Ave_Customer_Bill**	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MRV1.4	4	Moving Gas Service	RV1:6	Gas_Sales_Ex_Non_Firm	184,831	134,612	572	8,869	27,851	2,184	9,166	1,507	-
MRV1.5	5	Changing Location of Meters	RV1:6	**Ave_Customer_Bill**	20,870	$ 18,385	$ 219	$ 771	$ 306	$ 89	$ 111	$ 109	$ 16
MRV1.6	6	Meter Relocation Estimating Fee	RV1:6	**Ave_Customer_Bill**	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MRV1.7	7	Dishonored Check Charge	RV1:6	**Ave_Customer_Bill**	145,863	$ 139,232	$ 1,825	$ 5,721	$ 2,817	$ 133	$ 835	$ 609	$ 130
MRV1.8	8	Service Initiation Charge	RV1:6	**Ave_Customer_Bill**	2,023,169	$ 1,859,244	$ 22,879	$ 77,749	$ 39,306	$ 8,085	$ 11,223	$ 18,896	$ 1,630
MRV1.9	9	Field Collection Charge	RV1:6	**Ave_Customer_Bill**	45,629	$ 44,499	$ 531	$ 1,060	$ 826	$ 239	$ 270	$ 354	$ 39
MRV1.10	10	Field Lights & Turn offs	RV1:6	Gas_Sales_Ex_Non_Firm	0	-	-	-	-	-	-	-	-
MRV1.11	11	Services on Customer Premises (SOCP)	AL:8.7	SOCP_Expense	0	-	-	-	-	-	-	-	-
MRV1.12	12	Welding for Contractors	RV1:6	Gas_Sales_Ex_Non_Firm	(1,039)	(756)	(3)	(50)	(151)	(15)	(51)	(9)	-
MRV1.13	13	Propane Conversions	RV1:6	Gas_Sales_Ex_Non_Firm	709	518	2	34	102	10	35	6	-
MRV1.14	14	Facilities Mapping Sales	RV1:6	Gas_Sales_Ex_Non_Firm	0	-	-	-	-	-	-	-	-
MRV1.15	15	Other	RV1:6	Gas_Sales_Ex_Non_Firm	0	-	-	-	-	-	-	-	-
MRV1.17	17	Total Miscellaneous Service Revenues	=2:16		$ 2,819,140	$ 2,545,253	$ 29,316	$ 110,227	$ 79,858	$ 16,723	$ 23,795	$ 15,894	$ 2,122

Washington Gas Light Company
Maryland Division Pro Forma Class Cost of Service Study
Prepared by Maryland Office of People's Counsel
Operating Expense Summary

Twelve Month Ended December 31, 2001 - Average

	Description	Reference Sc-Pg-Ln	Reference Allocator	Maryland Total	Residential Heat/Cool	Residential Non Heat/Non Cool	C&I Heating/ Cooling <3000	C&I Heating/ Cooling >3000	C&I Non Heating Non Cooling	GMA Heating/ Cooling	GMA Non Heating Non Cooling	Non Firm
	A	B	C	D	E	F	G	H	I	J	K	L
1	**Operating Expenses**											
2	Operation	EX:2:40		$ 218,870,669	$ 164,062,879	$ 724,669	$ 10,755,318	$ 29,483,966	$ 2,490,422	$ 7,488,800	$ 1,143,282	$ 2,208,062
3	Maintenance	EX:4:28		18,138,047	11,714,535	70,084	898,827	2,784,441	228,093	1,383,164	151,531	827,274
4	Depreciation	EX:6:22		23,509,457	15,118,328	89,790	1,173,148	3,827,842	294,314	1,838,564	187,848	1,188,840
5	Amortization			0								0
6	Interest on Customer Deposits	RV:1:8	1/2 customer 1/2 revenue	68,635	57,242	488	3,832	5,752	982	1,817	484	28
7	Interest on Supplier Refunds	AL:1:5	Annual_Firm_NRV	0	-	-	-	-	-	-	-	-
8	General Taxes	EX:8:15		28,211,698	17,466,344	90,694	1,429,478	4,271,391	377,704	1,575,275	190,828	809,942
9	Other Income Taxes	AL:5:3	Net_Rate_Base	1,124,479	722,882	4,243	54,982	173,374	14,095	87,756	9,873	58,295
10	Expenses Before Federal Income Taxes		=2÷9	$ 287,921,941	$ 209,739,782	$ 879,908	$ 14,303,467	$ 40,248,766	$ 3,405,319	$ 12,399,273	$ 1,682,837	$ 5,194,441
11	Federal Income Taxes			5,229,824	5,050,254	(37,516)	376,481	1,888,763	591,544	672,031	370,288	(3,592,014)
12	Investment Tax Credit Adjustment	EX:18:13		(325,005)	(210,842)	(1,263)	(15,838)	(48,905)	(3,988)	(25,224)	(2,881)	(18,308)
13	Deferred Income Taxes -											
14	Liberalized Depreciation	EX:11:19		(116,299)	(71,771)	(234)	(5,388)	(19,069)	(1,451)	(8,923)	(888)	(7,642)
15	ACRS Depreciation	EX:12:22		(706,109)	(461,828)	(2,700)	(34,371)	(109,558)	(8,748)	(55,501)	(5,717)	(27,707)
16	MACRS Depreciation	EX:13:26		7,857,237	5,049,873	28,995	387,858	1,216,701	97,171	619,701	63,423	415,054
17	Construction Overheads	EX:14:16		(67,979)	(47,588)	(268)	(3,541)	(11,534)	(919)	(5,876)	(582)	2,320
18	Other	WEX:4:41		0	-	2	4	6	8	10	12	14
19	Total Deferred Income Taxes		=14÷18	$ 6,966,714	4,468,883	25,710	324,652	1,075,627	86,059	548,410	56,258	381,960
20	Total Operating Expenses		=10+11+12+19	$ 299,792,415	$ 219,258,128	$ 988,163	$ 15,003,588	$ 43,131,156	$ 4,072,922	$ 13,599,814	$ 2,109,385	$ 1,884,387

OPC EXHIBIT WBM-2
SUMMARY OF THREE MAIN ALLOCATION ALTERNATIVES

BG&E METHOD (0% CUSTOMER, 100% DEMAND)

Washington Gas Light Company
Maryland Division Pro Forma Class Cost of Service Study
Prepared by Maryland Office of People's Counsel
Income Statement Summary

Twelve Months Ended December 31, 2001 - Average

	Description	Maryland Total	Maryland Firm Load	Res Heating/ Cooling	Res Non Heating Non Cooling	C&I Heating/ Cooling <3000	C&I Heating/ Cooling >3000	C&I Non Heating Non Cooling	GMA Heating/ Cooling	GMA Non Heating Non Cooling	Non Firm
	A	D	D1	E	F	G	H	I	J	K	L
1	**Operating Revenues**	$ 336,055,222	$336,039,236	$ 244,136,791	$ 1,046,108	$ 16,898,497	$ 49,571,564	$ 5,064,871	$ 16,575,014	$ 2,746,391	$ 15,986
2	Operating Expenses										
3	Operation	$ 218,870,669	$217,275,184	$ 165,336,827	$ 721,803	$ 10,824,246	$ 29,374,954	$ 2,428,314	$ 7,487,944	$ 1,101,095	$ 1,595,485
4	Maintenance	18,136,047	17,578,857	12,121,153	68,356	928,144	2,746,942	190,631	1,397,534	126,097	557,190
5	Depreciation	23,509,457	22,761,175	15,601,487	87,728	1,222,317	3,606,964	249,619	1,835,778	157,303	748,283
6	Amortization of Capital Leases	14,266	13,912	10,473	73	694	1,634	125	808	105	354
7	Amortization of Capitalized Software	2,677,944	2,611,495	1,965,984	13,699	130,317	306,692	23,536	151,635	19,633	66,449
8	Amort. Pepco/ MD Post 1989 Interruptibles	-	-								-
9	Interest on Customer Deposits	69,635	69,607	57,242	488	3,032	5,752	692	1,917	484	28
10	Interest on Supplier Refunds	-	-	-	-	-	-	-	-	-	-
11	General Taxes	26,211,656	25,674,119	17,766,642	89,422	1,459,814	4,258,511	350,131	1,578,491	172,107	537,536
12	Other Income Taxes	1,124,478	1,086,672	745,174	4,147	57,263	172,405	12,021	87,997	7,665	37,806
13	Expenses Before Federal Income Taxes	$ 290,614,151	$287,071,020	$ 213,603,962	$ 985,715	$ 14,625,829	$ 40,473,854	$ 3,255,069	$ 12,542,103	$ 1,584,489	$ 3,543,130
14	Federal Income Taxes	5,228,824	$ 7,671,142	3,787,062	(32,146)	247,416	1,863,124	697,919	658,455	449,311	(2,442,318)
15	Investment Tax Credit Adjustments	(325,065)	$ (314,773)	(236,586)	(1,802)	(14,881)	(38,352)	(2,662)	(19,142)	(2,368)	(10,292)
16	Deferred Income Taxes	6,966,714	$ 6,703,984	4,976,331	36,392	308,764	846,238	59,717	425,889	51,633	262,750
17	Total Operating Expenses	$ 302,484,624	$301,131,354	$ 222,130,789	$ 988,160	$ 15,167,128	$ 43,144,864	$ 4,010,042	$ 13,607,305	$ 2,083,065	$ 1,353,270
18	Net Operating Income	$ 33,570,598	$ 34,907,883	$ 22,006,002	$ 57,948	$ 1,731,369	$ 6,426,700	$ 1,054,829	$ 2,967,709	$ 663,326	$ (1,337,285)
19	Net Income Adjustments										
20	AFUDC	(9,778)	(9,412)	(6,435)	(33)	(479)	(1,516)	(103)	(781)	(66)	(366)
21	Net Operating Income - Adjusted	$ 33,560,820	$ 34,898,471	$ 21,999,567	$ 57,915	$ 1,730,890	$ 6,425,184	$ 1,054,726	$ 2,966,928	$ 663,260	$ (1,337,650)
22	Net Rate Base	535,719,921	517,708,577	355,013,249	1,975,765	27,281,270	82,136,531	5,726,871	41,923,055	3,651,835	18,011,344
23	Return Earned	6.26%	6.74%	6.20%	2.93%	6.34%	7.82%	18.42%	7.08%	18.16%	-7.43%
24	Revenue-Cost Ratio	99.25%	100.00%	99.22%	93.29%	99.37%	101.83%	115.21%	100.86%	117.91%	0.62%
	Income change for equalization			1,931,694	76,270	108,126	(888,403)	(668,680)	(140,916)	(417,092)	

OPC'S ALTERNATIVE MINIMUM SYSTEM (29.35% CUSTOMER, REMAINDER 50/50 DEMAND-COMMODITY)

Washington Gas Light Company
Maryland Division Pro Forma Class Cost of Service Study
Prepared by Maryland Office of People's Counsel
Income Statement Summary

Twelve Months Ended December 31, 2001 - Average

	Description	Maryland Total	Maryland Firm Load	Res Heating/ Cooling	Res Non Heating Non Cooling	C&I Heating/ Cooling <3000	C&I Heating/ Cooling >3000	C&I Non Heating Non Cooling	GMA Heating/ Cooling	GMA Non Heating Non Cooling	Non Firm
	A	D	D1	E	F	G	H	I	J	K	L
1	**Operating Revenues**	$ 336,055,222	$336,039,236	$ 244,136,791	$ 1,046,108	$ 16,898,497	$ 49,571,564	$ 5,064,871	$ 16,575,014	$ 2,746,391	$ 15,986
2	Operating Expenses										
3	Operation	$ 218,870,669	$216,986,771	$ 166,013,105	$ 753,385	$ 10,715,619	$ 28,783,630	$ 2,444,247	$ 7,146,538	$ 1,130,247	$ 1,883,898
4	Maintenance	18,136,047	17,404,899	12,529,056	87,405	862,626	2,390,280	200,241	1,191,611	143,681	731,149
5	Depreciation	23,509,457	22,553,620	16,088,146	110,456	1,144,145	3,181,421	261,084	1,590,086	178,282	955,837
6	Amortization of Capital Leases	14,266	13,834	10,656	82	665	1,474	130	715	112	432
7	Amortization of Capitalized Software	2,677,944	2,596,828	2,000,374	15,305	124,793	276,622	24,346	134,273	21,115	81,115
8	Amort. Pepco/ MD Post 1989 Interruptibles	-	-								-
9	Interest on Customer Deposits	69,635	69,607	57,242	488	3,032	5,752	692	1,917	484	28
10	Interest on Supplier Refunds	-	-	-	-	-	-	-	-	-	-
11	General Taxes	26,211,656	25,546,074	18,066,884	103,444	1,411,588	3,995,985	357,204	1,426,919	185,050	665,581
12	Other Income Taxes	1,124,478	1,077,041	767,757	5,202	53,636	152,659	12,553	76,596	8,639	47,437
13	Expenses Before Federal Income Taxes	$ 290,614,151	$286,248,673	$ 215,532,221	$ 1,075,764	$ 14,316,103	$ 38,787,821	$ 3,300,496	$ 11,568,656	$ 1,667,611	$ 4,365,478
14	Federal Income Taxes	5,228,824	$ 8,211,559	2,519,880	(91,323)	450,957	2,971,124	668,066	1,298,169	394,686	(2,982,735)
15	Investment Tax Credit Adjustments	(325,065)	$ (314,773)	(236,566)	(1,802)	(14,881)	(38,352)	(2,662)	(19,142)	(2,368)	(10,292)
16	Deferred Income Taxes	6,966,714	$ 6,703,984	4,976,331	36,392	308,764	846,238	59,717	425,889	51,633	262,750
17	Total Operating Expenses	$ 302,484,624	$300,849,423	$ 222,791,865	$ 1,019,032	$ 15,060,943	$ 42,566,831	$ 4,025,617	$ 13,273,572	$ 2,111,562	$ 1,635,201
18	Net Operating Income	$ 33,570,598	$ 35,189,813	$ 21,344,925	$ 27,076	$ 1,837,554	$ 7,004,733	$ 1,039,254	$ 3,301,442	$ 634,829	$ (1,619,215)
19	Net Income Adjustments										
20	AFUDC	(9,778)	(9,337)	(6,610)	(41)	(451)	(1,362)	(107)	(692)	(74)	(440)
21	Net Operating Income - Adjusted	$ 33,560,820	$ 35,180,476	$ 21,338,315	$ 27,035	$ 1,837,103	$ 7,003,371	$ 1,039,147	$ 3,300,749	$ 634,756	$ (1,619,656)
22	Net Rate Base	535,719,921	513,120,225	365,772,119	2,478,202	25,553,134	72,729,180	5,980,340	36,491,632	4,115,618	22,599,695
23	Return Earned	6.26%	6.86%	5.83%	1.09%	7.19%	9.63%	17.38%	9.05%	15.42%	-7.17%
24	Revenue-Cost Ratio	99.07%	100.00%	98.49%	87.99%	100.51%	104.24%	114.19%	105.07%	114.73%	0.50%
	Income change for equalization			3,739,701	142,876	(85,133)	(2,016,923)	(629,124)	(798,816)	(352,681)	

COMPANY'S METHOD OF COST ALLOCATION FOR MAINS

Washington Gas Light Company
Maryland Division Pro Forma Class Cost of Service Study
Prepared by Maryland Office of People's Counsel
Income Statement Summary

Twelve Months Ended December 31, 2001 - Average

	Description	Maryland Total	Maryland Firm Load	Res Heating/ Cooling	Res Non Heating, Non Cooling	C&I Heating/ Cooling <3000	C&I Heating/ Cooling >3000	C&I Non Heating Non Cooling	OMA Heating/ Cooling	OMA Non Heating Non Cooling	Non Firm
	A	D	D1	E	F	G	H	I	J	K	L
1	**Operating Revenues**	$ 336,055,222	$336,039,236	$ 244,136,791	$ 1,046,108	$ 16,898,497	$ 49,571,564	$ 5,064,871	$ 16,575,014	$ 2,746,391	$ 15,986
2	Operating Expenses										
3	Operation	$ 218,870,669	$217,253,640	$ 167,121,430	$ 776,953	$ 10,682,552	$ 28,274,506	$ 2,406,349	$ 6,872,284	$ 1,119,566	$ 1,617,029
4	Maintenance	18,136,047	17,565,863	13,197,552	101,620	842,680	2,083,197	177,383	1,026,193	137,238	570,184
5	Depreciation	23,509,457	22,745,671	16,885,746	127,417	1,120,348	2,815,032	233,812	1,392,721	170,595	763,787
6	Amortization of Capital Leases	14,266	13,906	10,956	88	656	1,336	119	641	110	360
7	Amortization of Capitalized Software	2,677,944	2,610,399	2,056,735	16,503	123,111	250,732	22,419	120,327	20,572	67,544
8	Amort. Pepco/ MD Post 1989 Interruptibles	-	-								-
9	Interest on Customer Deposits	69,635	69,607	57,242	488	3,032	5,752	692	1,917	484	28
10	Interest on Supplier Refunds	-	-	-	-	-	-	-	-	-	-
11	General Taxes	26,211,656	25,664,554	18,557,940	113,907	1,396,907	3,769,952	340,379	1,305,161	180,308	547,101
12	Other Income Taxes	1,124,478	1,085,952	804,767	5,989	52,532	135,658	11,287	67,438	8,282	38,525
13	Expenses Before Federal Income Taxes	$ 290,614,151	$287,009,592	$ 218,692,368	$ 1,142,964	$ 14,221,818	$ 37,336,165	$ 3,192,440	$ 10,786,881	$ 1,637,154	$ 3,604,558
14	Federal Income Taxes	5,228,824	$ 7,711,511	443,145	(135,484)	512,917	3,925,100	739,076	1,812,055	414,701	(2,482,686)
15	Investment Tax Credit Adjustments	(325,065)	$ (314,773)	(236,566)	(1,802)	(14,881)	(38,352)	(2,662)	(19,142)	(2,368)	(10,292)
16	Deferred Income Taxes	6,966,714	$ 6,703,964	4,976,331	36,392	308,764	846,238	69,717	425,889	51,633	262,750
17	Total Operating Expenses	$ 302,484,624	$301,110,294	$ 223,875,278	$ 1,042,071	$ 15,028,619	$ 42,069,151	$ 3,988,571	$ 13,005,483	$ 2,101,121	$ 1,374,330
18	Net Operating Income	$ 33,570,598	$ 34,928,943	$ 20,261,512	$ 4,037	$ 1,869,879	$ 7,502,413	$ 1,076,300	$ 3,569,531	$ 645,271	$ (1,358,345)
19	Net Income Adjustments										
20	AFUDC	(9,778)	(9,407)	(6,897)	(47)	(442)	(1,230)	(98)	(621)	(71)	(371)
21	Net Operating Income - Adjusted	$ 33,560,820	$ 34,919,536	$ 20,254,615	$ 3,990	$ 1,869,436	$ 7,501,183	$ 1,076,202	$ 3,568,910	$ 645,200	$ (1,358,716)
22	Net Rate Base	535,719,921	517,365,833	383,404,407	2,853,148	25,027,063	64,629,554	5,377,436	32,128,542	3,945,682	18,354,088
23	Return Earned	6.26%	6.75%	5.28%	0.14%	7.47%	11.61%	20.01%	11.11%	16.35%	-7.40%
24	Revenue-Cost Ratio	99.24%	100.00%	97.75%	84.73%	101.08%	106.76%	116.39%	109.23%	116.01%	0.61%
	Income change for equalization			5,623,213	188,583	(180,238)	(3,139,020)	(713,253)	(1,400,398)	(378,887)	