STATE OF MARYLAND

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Application of	**)**	
Baltimore Gas and Electric Company	**)**	**Case No. 9230**
for Revisions in its Electric and Gas	**)**	
Base Rates	**)**	

REBUTTAL TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE OFFICE OF PEOPLES COUNSEL

Resource Insight, Inc.

AUGUST 20, 2010

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I. Introduction

Q: Are you the same Paul Chernick who filed direct testimony in this case?

A: Yes.

Q: What are the subjects of your rebuttal testimony?

A: I respond to the testimony of other parties on the following five subjects:

- new electric tariff riders,
- the electric cost of service,
- the proposed electric revenue allocation,
- the gas cost of service,
- the proposed gas revenue allocation.

II. Electric Riders

Q: What response do you have to the direct testimony of Staff Witness Phillip VanderHeyden?

A: Mr. VanderHeyden identified problems with the Diagnostic Service Fee that I had not previously noticed (VanderHeyden Direct, pp. 15–19). I agree with his critique of the fee, especially with the possibility that customers will decline to commit to paying the $80 fee, needlessly extending outages.

Q: How should the Commission proceed with regard to this fee?

A: The Commission should limit the applicability of the fee to customers who have previously reported an outage that turned out not to be due to problems on the Company's system. Even those customers should only be charged the fee if the customer is able to determine that the outage does not affect his entire premises and fails to do so.

The Company should be required to file with the Commission the script that BG&E's customer-service staff will talk callers through, to determine whether the outage is internal to the customer's premises and to determine whether the customer is physically and intellectually capable of assessing the cause of the outage.

Finally, as Mr. VanderHeyden suggests, the Company should record all outage reports, even if the caller does not request a BG&E staff visit for whatever reason.

III. Electric Cost-of-Service Study

Q: To which issues regarding BG&E's electric cost-of-service study will you respond?

A: I will comment on the following testimony and claims:

- Testimony of Staff Witness Gregory Campbell on the use of the sum of maximum demand (SMD) to allocate secondary lines and line transformers.
- Testimonies of Mr. Campbell and MEG Witness Richard Baudino on the classification of primary and secondary distribution plant and their assertions that some primary and secondary distribution plant should be classified as customer-related.

A. Demand Allocator for Line Transformers and Secondary

Q: What is Mr. Campbell's basis for suggesting that secondary lines and line transformers should be allocated on the sum of maximum demand?

A: He acknowledges that most of distribution investments, comprising substations and primary feeders, "typically have high levels of load diversity and consequently customer-class peaks (NCP method) are normally used for the allocation of these facilities." He then asserts that "The facilities closer to the customer, namely secondary feeders and line transformers, have a much lower level of diversity. They are usually allocated using a SMCD method" (Campbell Direct, p. 21).

By SMCD, Mr. Campbell refers to the sum of maximum customer demands, whenever those occur. One customer may experience its maximum load for the year at 7 AM on January 12th, another at 8 PM on October 6th, a third at 2 PM on July 3rd, and so on. The SMCD adds up all these loads, regardless of timing.

Q: Is Mr. Campbell correct that secondary feeders and line transformers are usually allocated on the sum of customer maximum demands?

A: That has not been my experience. Various utilities use a range of demand allocators for secondary distribution; I do not believe that any particular allocator is "usual."

Q: Are the costs of secondary lines and transformers driven largely by the maximum demands of individual customers?

A: No. Most transformers and most spans of secondary conductor serve more than one customer. The Company has about six customers per transformer.[1] For larger commercial, institutional, and industrial customers, each customer may be served by one or more dedicated transformers, but smaller customers typically share a transformer.

Assuming six residential customers per transformer on a radial suburban system, BG&E's distribution guidelines (excerpted in Exhibit PLC-R1) show

[1] I derived that ratio from BG&E's 2001 FERC Form 1, p. 429. That was the last year that the FERC Form included transformer number.

very large load diversity for residential customers, even when all the customers on the transformer are assumed to have the same air conditioning or heating equipment. A group of six houses each with 2½ hp air conditioning, for example, would have a coincidence factor of 57%, as shown in Table 1R.

Table 1R: Coincidence Factors for Fossil-Heated Homes

	Air Conditioning Tons								
	0.5	*1.0*	*1.5*	*2.0*	*2.5*	*3.0*	*3.5*	*4.0*	*4.5*
1 House (kVA)	7.3	8.2	9.3	10.7	12.1	13.6	15.2	16.9	18.5
3 Houses (diversified kVA)	14.7	16.8	19.3	22.2	25.2	28.4	31.7	35.0	38.5
6 Houses (diversified kVA)	23.7	27.4	31.7	36.4	41.5	46.7	52.1	57.6	63.2
Coincidence Factor 6 Houses	54%	56%	57%	57%	57%	57%	57%	57%	57%

Source: Exhibit PLC-R1

A group of six houses each with 12 kW of electric heating, would have a coincidence factor of 54%, as shown in Table 2R.

Table 2R: Coincidence Factors for Electrically-Heated Homes

	Furnace kW								
	8.0	*10.0*	*12.0*	*14.0*	*16.0*	*18.0*	*20.0*	*22.0*	*24.0*
1 House (kVA)	13.0	15.4	17.9	20.5	23.0	25.6	28.2	30.8	33.4
3 Houses (diversified kVA)	26.5	31.3	36.3	41.3	46.3	51.4	56.5	61.6	66.8
6 Houses (diversified kVA)	43.0	50.7	58.5	66.4	74.4	82.5	90.6	98.7	107.0
Coincidence Factor 6 Houses	55%	55%	54%	54%	54%	54%	54%	53%	53%

Source: Exhibit PLC-R1.

Even identical houses may routinely peak at different times, depending on household composition, work and school schedules, and building orientation. The actual peak load for any particular house may occur not at typical peak conditions, but under special conditions not correlated with loads on other houses. For example, one house may experience its maximum load when the family returns from vacation to a hot house in the summer or a very cold one in the winter, even if neither temperatures nor time of day would otherwise be consistent with an annual maximum load. The house next door may experience its maximum load following a water leak or interior painting, when the windows are open and fans, dehumidifiers and the heating or cooling systems are working.

Taking into account diversity among different types of residential customers, the load coincidence factors would be even lower. A single transformer may serve some homes with electric heat, peaking in the winter, and some with fossil heat, peaking in the summer.

Q: Would you expect similar results for multi-family housing?

A: Yes. The same factors (household composition, work and school schedules, unit-specific events) apply in multi-family housing as well as in single-family housing. The effects of orientation are probably even stronger in multi-family housing than in single-family homes. Units on the east side of the building are likely to have summer peak loads in the morning, while those on the west side are likely to experience maximum loads in the evening and those on the south in the middle of the day. The units on the north side are most exposed to the late-afternoon sun in late June, while the noon sun will shine most strongly on the south side later in the summer, when it is lower.

Q: Can you compare this level of diversity among customers sharing a transformer to the level of diversity that would be represented by Mr. Campbell's proposed secondary-distribution demand allocator of 50% SMCD and 50% NCP?

A: Not exactly, since BG&E has not provided data on SMCD for residential customers. While Mr. Campbell says that "The Company data responses to Staff Data Request 25" would allow him "to complete the SMCD method calculations," the data on residential loads provided in Staff DR 25-02 Attachment 1 is described as "2009 Hourly kWh Load Profiles for Electric Subclasses Without Hourly Interval Metering." These data appear to represent average loads across the sampled customers, not MCD values.

In any case, it is unlikely that the diversity in the NCP will be large enough that the average of NCP and SMCD will be as diversified as the 53%–57% coincidence of similar single-family houses, let alone the higher diversity of different types of neighboring homes, multi-family housing, and buildings served from secondary networks.

Q: Would the factors you describe above apply to secondary lines?

A: Yes, although the average span of secondary probably serves fewer customers than the average transformer.

Q: Other than the sharing of transformers by residential and other small customers, are there other factors that reduce the effect of individual customer maximum demands on transformer sizing?

A: A portion of BG&E's distribution load is served by a secondary network, in which several transformers are connected in parallel to serve multiple buildings through a network of secondary lines, so failure of any one transformer will not result in loss of service to any customer. In secondary networks, the number of transformers and the investment in secondary lines are driven by the aggregate load of the entire network or large parts of the network.

B. Classification of Distribution Plant

Q: What is the core of Mr. Baudino's argument regarding the classification of distribution plant?

A: He asserts that "there is a minimal level of distribution investment necessary to connect a customer to the distribution system that is independent of the level of demand of the customer. To the extent that this component of distribution cost is a function of the requirement to interconnect the customer, regardless of the customer's size, it is appropriate to assign the cost of these facilities to rate schedules on the basis of the number of customers" (Baudino Direct, pp. 7–8).[2]

Q: What is the "minimal level of distribution investment necessary to connect a customer to the distribution system"?

A: The connection to the system normally comprises the service drop and meter.

Q: How does BG&E allocate services and meters?

A: The Company tracks the investment in services and meters by customer class and directly assigns each class the costs of the equipment that serves it.

Q: Other than services and meters, is there a minimum primary and secondary system necessary to connect each customer to the distribution system?

A: No, for three reasons. First, much of the cost of a distribution system is required to cover an area, and is not really sensitive to either load or customer number. For example, serving many customers in one multi-family building is no more expensive than serving one commercial customer of the same size, other than metering. The distribution cost of serving a geographical area for a given load is roughly the same whether that load is from concentrated commercial or disbursed residential customers.

Second, load levels help determine the number of units, as well as their size. As load grows, utilities add distribution feeders and transformers in parallel with existing equipment, such as adding a transformer to serve one end of a block, as load grows beyond the capability of the transformer originally serving

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[2] Mr. Campbell's argument for the allocation of distribution costs on customer number (Campbell Direct, p. 21) is very similar to that of Mr. Baudino. The Commission Staff made a similar argument in Case No. 9192, through the testimony of Charles Ermer; the Commission rejected that argument (Order No. 83085, December 30, 2009, pp. 42–46).

the block. Indeed, large customers may be served by multiple transformers to increase reliability.

In general, more small electric customers than large customers can be served from one transformer. Greater loads require larger service drops and secondary wires, so more transformers are added to reduce the length of the wires. Increasing the number of transformers is expensive because (1) transformers show large economies of scale in dollars of investment per kVA of capacity, and (2) dispersed transformers have lower diversity than transformers serving many customers, increasing the total installed kVA required to meet customer load.

Third, load can determine the type of equipment installed, in addition to size and number. Electric distribution systems are often relocated from overhead to more expensive underground because the weight of lines required to meet load makes overhead service infeasible. Voltages may also be increased to carry more load, increasing the costs of equipment (e.g., insulation requirements for transformers and lines).

Q: Will minimum-system approaches produce a reasonable classification of costs?

A: No. As Bonbright, Danielsen & Kamerschen explain, these approaches attempt to classify costs that are fundamentally "unassignable":

> [T]he inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to us clearly indefensible…. [Cost analysts are] under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground….[3]

[3]Bonbright, James. Albert Danielsen, and David Kamerschen. 1988. *Principles of Public Utility Rates.* Arlington, Va.: Public Utilities Reports. 491–492.

Small customers are especially burdened when a high percentage of costs are assumed to be customer-related; allocations should not rely on these flawed methods.

Q: How is the cost of the minimum distribution system generally derived?

A: The most common methods used are the minimum-system method and the zero-intercept method.

Q: Please describe the minimum-system method.

A: A minimum-system analysis attempts to calculate the cost (in constant dollars) of the utility's installed units (transformers, poles, conductor-feet, etc.), were each of them the minimum-sized unit of that type of equipment that would ever be used on the system. The analysis asks, "How much would it have cost to install the same number of units (poles, conductor-feet, transformers), but with the size of the units installed limited to the current minimum unit normally installed?" This cost is assumed to be customer-related, and the remaining cost is treated as demand-related.[4]

The ratio of the costs of the minimum system to the actual system (in the same year's dollars) produces a percentage of plant that is claimed to be customer-related.

Q: Please describe the zero-intercept method.

A: The zero-intercept method attempts to extrapolate the cost of equipment below the size of the minimum system, to the cost of equipment that carries zero load,

[4] The customer-related portion (which is computed in constant dollars) must be compared to the actual installed cost of the entire account (in mixed dollars); translating actual mixed dollars into constant dollars can be difficult, especially under conditions of technical change and different inflation rates for large and small installations (e.g., small installations are often more related to labor costs than are large ones).

as in hypothetical 0-kVA transformers, or the smallest units legally allowed (as 25-foot poles), or the smallest units physically feasible (e.g., the thinnest conductors that will support their own weight in overhead spans). The idea is that this procedure identifies the amount of equipment required to connect existing customers, even if they had virtually no load.

Q: Does the minimum-system method exclude all demand-related investment?

A: No, for the following reasons:

- The typical definition of a minimum system includes equipment that would carry a large portion of the average customer's load. The load carried by the minimum system should be excluded from the allocator for the demand-classified portion of distribution; the resulting allocation of primary and secondary distribution may be very close to a simple demand-based allocation.
- The current minimum unit installed by the utility is sized to carry expected demand. Consequently, as demand has risen over time, so has the minimum size of equipment installed. In fact, utilities usually stop stocking some less-expensive small equipment because rising demand has resulted in very rare use of the small equipment and the cost of maintaining stock was no longer warranted.
- Minimum-system analyses usually ignore the effect of loads on the number of units installed, or the type of equipment installed. Hence, a portion of the costs allocated to customer number is really driven by demand.
- Minimum systems analyses fundamentally assume that all area-spanning investment is caused by the number of customers. As described above, this is not true.

Q: How should the number of units installed be categorized as customer or demand-related?

A: A type of equipment (e.g., transformer, conductor, pole, service drop, meter) should be considered dedicated investment and therefore customer-related only if the removal of one customer eliminates the unit. The number of meters and services (although not the size) are customer-related, while transformers, conductors and poles should be largely demand-related, especially in non-rural areas. Reducing the number of customers, without reducing the demand in an area, will have the following effects

- occasionally eliminate a transformer, for an isolated customer, whose transformer serves no other customers.
- sometimes eliminate a span of secondary conductor, if the customer is the furthest one from the transformer on that secondary.
- rarely eliminate a pole, if the customer is at the end of the primary line.

In many situations, additional transformers and conductors are added to increase capacity, rather than to reach an additional customer.

Q: Can the zero-intercept method be relied on to determine the customer-related portion of plant?

A: No. The determination of the number and size of units required for a zero-demand system are far from simple. A system designed to connect customers but provide zero load would look very different from the existing system. For example, a zero-capacity electric system would not use the overlapping primary and secondary systems and line transformers that the real system uses. Without the need for high voltages to carry power, poles could be shorter and cross-arms would be unnecessary; with no transformers and cross-arms, and lighter conductors, poles could be thinner as well. The labor and equipment costs of setting those short, light poles would be much lower than the costs of real utility poles of any size.

The zero-intercept method is so abstract that it is open to very wide range of interpretations, producing an extremely wide range of results. The concept of a zero-intercept system poses many opportunities for speculative fancy, but provides little if any useful information.

IV. Electric-Revenue Allocation

Q: Which witnesses propose different allocations of any electric rate increase from the across-the-board allocation proposed by BG&E?

A: Staff Witness VanderHeyden and Sparrows Point Witness Phillips both propose a two-step revenue-allocation method. They take very different approaches to that method.

Mr. Phillips would first bring all classes to within 10% of the system average return, as estimated in BG&E's electric cost-of-service study. This step would include an 8.2% increase in base rates for residential customers and a 34.3% decrease for Sparrows Point (Exhibit NP-20). Because of large decreases in the allocations to general service, Sparrows Point, and private lighting in the first step, Mr. Phillips's second step would require a 7% rate increase to achieve BG&E's requested overall 5.3% revenue increase. The final result is an increase of 14% for residential customers and a 21% decrease for Sparrows Point.

Mr. VanderHeyden proposes that half the allowed rate increase be allocated in proportion to base revenues to Schedules R, RL, and P, and the remaining half in proportion to base revenues, excluding the new Schedule T.[5] No class would receive a revenue decrease and no class would receive more than a 5% increase.

Q: Is Mr. Phillips's proposed revenue allocation reasonable?

A: No. Mr. Phillips ignores both the March 2008 settlement and Commission precedent. The Company (SP DR 1-79), MEG (Baudino Direct, pp. 3 and 5), Staff (VanderHeyden, pp. 3–4), and OPC all agree that the settlement was intended to limit rate increases to 5% by rate class, as well as overall. Mr. Phillips interprets the settlement provision that "any increase awarded…to the BGE electric distribution revenue…would be capped at 5%" to mean "the aggregate average increase would be capped at 5%." A more reasonable reading of "any increase" would be "the increase to any class."

Mr. Phillips proposed method would allocate 140% of BG&E's proposed rate increase ($66 million of the total $47 million increase) to residential customers.

Mr. Phillips recognizes that the Commission has previously taken a firm position that no class should experience a rate decrease in a proceeding that raises rates overall (Phillips Direct, p. 33). In the most recent PEPCo rate case, the Commission repeated its commitment to "*very gradually* continue to reduce the disparity between class rates of return and the overall rate of return" (Order No. 83516, Case No. 9217, p. 1, emphasis added). His approach would ignore the Commission's consistent policy of gradualism.

Q: Is Mr. VanderHeyden's proposed revenue allocation reasonable?

A: Mr. VanderHeyden's proposal is reasonable if the overall rate increase is close to BG&E's requested 5% increase, since it would be very similar to BG&E's

[5] I assume Mr. VanderHeyden intends that the allocations be proportional to revenues at current rates.

proposed equal-percentage increases. If the allowed increase is much smaller, Mr. VanderHeyden's proposal could result in rate increases twice as large for residential and Schedule-P customers than for other classes or the system average. For example, with a $30 million (3.6%) rate increase, Schedules R, RL, and P would experience rate increases of 4.9%, almost three times the 1.8% increase for other schedules' revenues.

I recommend that Mr. VanderHeyden's approach be modified to cap the revenue increase for the high-increase classes (R, RL, and P) at 150% of the increase of the low-increase classes (G, GS, GL, SL, PL, SP). That cap would result in about 22% of the increase being allocated in Mr. VanderHeyden's first step, rather than 50%.

Q: Is a cost-of-service study a strong guide to the appropriate allocation of the revenue increase?

A: No. Cost-of-service-study results are only as good as the inputs and assumptions. Inputs (including the composition of the utility's costs and estimates of class loads) inevitably vary from one rate case to another. As is clear from the discussion in Sections III and V, the assumptions about drivers for costs are controversial and many allocators (such as class non-coincident peaks) are only rough approximations of the actual drivers of customer costs. The Company's electric cost-of-service study, for example, does not recognize the effects of load factor and energy use on the sizing of distribution equipment, such as transformers and underground lines.

Hence, any cost-of-service study results should be taken as only a rough indication of the possible direction of equitable revenue allocation. No cost-of-service study is precise enough to support the reallocation methodology proposed by Mr. Phillips. Even Mr. VanderHeyden's more-reasonable revenue allocation places more reliance on the cost-of-service results than is really warranted.

V. Gas Cost-of-Service Study

Q: To which gas cost-of-service issues raised by parties in their direct testimony will you respond?

A: I will respond to the claims of Mr. Baudino regarding classification and allocation of gas mains and of Mr. Phillips that the SP schedule should be allocated only a portion of certain types of distribution lines.

Q: What are Mr. Baudino's key assertions in this part of his testimony?

A: Mr. Baudino argues that a portion of gas mains is customer-related and that interruptible service customers in the IS and ISS classes should receive a credit or reduction in their allocation of mains costs.

Q: Are gas mains customer-related?

A: No. Mr. Baudino's argument for classification of the costs of a hypothetical minimum mains system is essentially the same as his argument for a similar classification for electric distribution. In addition to the points I raised in rebuttal to Mr. Baudino's claims about the electrical system (Section III), it is important to recognize that mains are not extended to serve a very small load. The minimum gas-distribution system is a propane tank.

Q: Should the IS and ISS classes receive a discount on their allocation of mains costs?

A: No. The IS and ISS class loads are appropriately discounted for the purpose of allocating production plant (and all costs allocated on production plant), since that plant is driven by usage in the peak conditions in which IS and ISS loads are interrupted. Main costs, on the other hand, are driven by high usage levels in different places and at different times.

Determining exactly how the sizing of each piece of the distribution system is driven by each class is very difficult. While not ideal, the class non-coincident peak allocator is often used to recognize that the maximum loads in a residential area may occur at a different hour than the maximum loads in a commercial area.[6] The highest loads on the mains serving a commercial area with a concentration of IS and ISS customers may well occur when those customers are not interrupted and specifically *because* they are not interrupted.

In addition, IS and ISS customers appear to be free to convert to firm service when that is convenient or economic for them. Many IS and ISS customers were probably firm customers in the past. Hence, the installed mains capacity is likely to be driven by past firm loads from currently interruptible customers, and BG&E must be prepared to meet their distribution loads if they choose to return to firm service.

Q: What are Mr. Phillips' key assertions regarding allocation of gas mains?

A: Mr. Phillips, in his direct testimony makes the following assertions:

- "BGE's proposed gas rates to Sparrows Point erroneously assume that BGE's entire gas distribution system is used to provide natural gas delivery service to Sparrows Point" (p. 4).
- "BGE's service to Sparrows Point is accomplished using discrete, readily identifiable facilities…" (p. 4).

[6]This approach is widely used for allocating both electricity and gas distribution costs.

- “BGE’s service to Sparrows Point...does not involve the majority of BGE’s distribution facilities.…only a small portion of BGE’s distribution system actually can be used to serve Sparrows Point” (4).
- “…21.9%...of BGE’s main investment is for pipe that is 12″ in diameter and larger. Therefore, $497.6 million, or fully 78.1%, of BGE’s distribution main investment is for pipe that is smaller than 12″ in diameter and is not or cannot be used to serve Sparrows Point (p. 11).

Q: Is it true that BGE’s service to Sparrows Point does not involve the majority of BGE’s distribution facilities?

A: Yes. The same is true for any customer. For example:

- The customers in Manchester, Hampstead and Westminster are served exclusively by lines 12 inches in diameter or smaller, from the Holbrook Gate Station, and are not served by any other mains.
- Customers in Perryville are served only by an 8-inch OHP line from the Conowingo Gate Station, and are not otherwise connected to the BG&E gas system.
- Customers in Baltimore are not served by the lines in the prior two areas, or by HP and OHP lines that run to Annapolis.

Hence, while Mr. Phillips is correct that not all BG&E mains serve Sparrows Point, that observation has no relevance to cost allocation.

Q: Is it true that no pipe smaller than 12 inches in diameter is used to serve Sparrows Point?

A: No. As I pointed out in my Direct Testimony, of Sparrows Point’s nineteen connection points, seven are from mains less than 12-inch diameter, with one connection as small as ¾ inch (OPC DR 5-11, Attachment 2).

Q: Is the Sparrows Point facility served only by the OHP line from the Manor Gate Station?

A: No. While Mr. Phillips seems to rely on the contractual arrangements for gas supply to Sparrows Point (Phillips Direct, p. 9), gas molecules do not read contracts. The Company considers Sparrows Point to be served through "several interconnected Over High Pressure (OHP) Systems specifically the Manor, Linden Church, ASC, and Tuscarora Systems depending on the weather, gas supply scenarios, and operating conditions," as well as a portion of the HP system (SP DR 1-37). The portions of the OHP system identified by BG&E as serving Sparrows Point are also supplied or supported by OHP lines from the Dublin, Sharon, Beaver Dam, Owings Mills, and Granite Gate Stations. Most of the OHP system seems to provide direct or indirect support to Sparrows Point.

In addition to the OHP system, gas is supplied to Sparrows Point over roughly eight miles of HP mains, which are paralleled and reinforced by a medium-pressure main.

Q: What is the significance of Mr. Phillips' observation (Phillips Direct, p. 18) that "the minimum size pipe that would be installed to serve Sparrows Point" would be 20 inches or 12 inches, depending on the assumptions made in the hypothetical?

A: Not much. Mr. Phillips appears to believe that the size of a single hypothetical line serving Sparrows Point is relevant to determining the size of mains that should be allocated to Sparrows Point. This perspective is incorrect, for at least the following four reasons:

- Smaller mains are less-expensive substitutes for larger mains. If not for the Company's smaller mains, BG&E would have installed many more feet of 12-inch lines, at higher cost.

- Customers can be served entirely by smaller mains, from the pipeline gate station to the service drop. For example, 6-inch HP lines from the Owings Mill and Holbrook Gate Stations serve large areas of the northwest suburbs.[7]
- Smaller mains, such as the 8-inch OHP lines from the Dublin and Sharon Gate Stations to Notchcliff, can feed gas into the lines from Manor to Sparrows Point.
- Smaller mains parallel and reinforce larger mains, and vice versa.

Q: Is Mr. Phillips (Phillips Direct, p. 9) correct that "BGE delivers…gas over a relatively short distance to the Sparrows Point mill?"

A: No. Even the shortest set of mains that the gas might travel from the Manor Gate Station to Sparrows Point comes to something like 25 miles. Almost all of BG&E's gas service territory (except for Annapolis) is within 25 miles of the closest pipeline gate station. Hence, Mr. Phillips description should read "BGE delivers gas over a relatively *long* distance to the Sparrows Point mill."

Q: Is the segregation of electric delivery costs into transmission, primary and secondary voltage levels a good analogy to the treatment of various main sizes and pressures in gas delivery, as Mr. Phillips suggests on page 22 of his direct?

A: No.

VI. Gas Revenue Allocation

Q: What testimony on gas revenue allocation will you be rebutting?

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[7] Most of these lines are reinforced and backed up by other lines, some of which happen to be larger or operate at higher pressure.

A: I rebut Mr. Baudino's testimony on pages 18–21 of his direct, in which he argues that the percentage increases in the gas delivery rate for the IS, ISS, and SP rates are excessive.

Q: Do the percentage revenue increases that Mr. Baudino presents in his Table 2 represent percentage increases in gas costs for the various classes?

A: No. Mr. Baudino presents only the delivery costs. As shown in the following table, the proposed increases for Schedules ISS, IS and SP are smaller than those for Schedules D and C in $/Dth and in percentage of total gas costs.

Table 3R: Proposed Rate Increases

Schedule	Gas Delivery Revenues	Annual Through-put (Dth)	Average Delivery Rate ($/Dth)	Proposed Increase	Proposed Increase ($/Dth)	Total Gas Price ($/Dth)	Increase in Total Gas Cost
D	$213,626,355	42,152,389	$5.07	$27,883,351	$0.66	$11.07	6.0%
C	$75,247,853	28,490,638	$2.64	$9,649,417	$0.34	$8.64	3.9%
ISS	$1,270,690	1,116,250	$1.14	$247,362	$0.22	$7.14	3.1%
IS	$11,642,789	19,733,019	$0.59	$2,653,829	$0.13	$6.59	2.0%
PLG	$44,219	9,220	$4.80		$0.00	$10.80	0.0%
SP	$4,790,255	9,230,896	$0.52	$1,902,470	$0.21	$6.52	3.2%

Note: Assumes $6/Dth supply

I assumed for the purpose of this table that supply costs $6/Dth for all classes. In fact, gas costs are likely to be $0.25 or $0.50/Dth greater for Schedules D and C than for Schedules IS, ISS and SP, which would slightly narrow the range of percentage changes in total costs. Gas prices lower than $6/Dth would also reduce the range of percentage changes, but the increase for Schedule D is still the highest of any class down to gas prices of about $1.60/Dth.

If BG&E is granted a smaller overall increase in delivery rates, the percentage changes in total gas cost will diverge further.

Q: What do you conclude from this analysis?

A: Considering the absolute increases in rates and the overall cost of gas, the Company's proposed allocation of the revenue increase is more burdensome for Schedule D than for the other classes. If the Company's approach to revenue allocation is modified, it should be in the direction of reducing, not increasing, the residential burden.

Q: Do the economic considerations raised by Mr. Baudino on page 19 of his testimony support higher rate increases to residential customers and lower rate increases to business customers?

A: No. The financial stresses on households are as real as those on businesses. As Mr. Baudino notes, the unemployment rate in Maryland is still high. Mr. Baudino cites a 7.1% Maryland unemployment rate for June 2010, while the Bureau of Labor Statistics reports 7.4%.[8] The unemployment rates in much of BG&E's gas territory are even higher: 11% in Baltimore City, 7.9% in Baltimore County. This is not a time to push additional gas costs onto households.

Q: Does this conclude your testimony?

A: Yes.

[8] http://www.bls.gov/ro3/mdlaus.htm