Fed Exp.

STATE OF MARYLAND
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	*	
OF BALTIMORE GAS ELECTRIC COMPANY	*	CASE NO. 8697
FOR GAS RATE INCREASE	*	

Direct Testimony of
Paul Chernick
on behalf of
The Maryland Office of People's Counsel
Resource Insight, Inc.
July 7, 1995

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Exhibit ____ (PLC-1) Professional Qualificati ns of Paul Chernick

Exhibit ____ (PLC-2) Work Papers for Company's Proposed New-Customer Adjustment

Exhibit ____ (PLC-3) New Residential Construction Costs

Exhibit ____ (PLC-4) New Residential Customer Costs

Exhibit ____ (PLC-5) 1994 Average Rate Base, BG&E Estimates of New Customer Costs

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I. Identification and Qualifications

Q: State your name, occupation and business address.

A: I am Paul L. Chernick. I am President of Resource Insight, Inc., 18 Tremont Street, Suite 1000, Boston, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a Research Associate at Analysis and Inference, after 1986 as President of PLC, Inc., and in my current position at Resource Insight, I have advised a variety of clients on utility matters. My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions;

ratemaking for plant under construction; ratemaking for excess and/or uneconomical plant entering service; conservation program design; cost recovery for utility efficiency programs; and the valuation of environmental externalities from energy production and use. My resume is appended to this testimony as Exhibit ____ PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately eighty times on utility issues before various regulatory, legislative, and judicial bodies, including the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Council, the Vermont Public Service Board, the Texas Public Utilities Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities Commission, the Minnesota Public Utilities Commission, the South Carolina Public Service Commission, the Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume.

Q: Have you testified previously before this commission?

A: Yes. I testified in Case No. 8278 and Case No. 8241 on the least-cost planning efforts of Baltimore Gas and Electric Company (BG&E); in Case No. 8473 on the reasonableness of the proposed contract between BG&E and the AES Northside generation project; in Case No. 8487 on the electric cost allocation proposed by Baltimore Gas & Electric; and in Case No. 8179, on Potomac Edison's contract with AES Warrior Run.

Q: **Have you testified previously on cost-allocation and rate-design issues?**

A: Yes. I have testified about ten times on cost allocations and rate design, in addition to several related pieces of testimony on such related topics as the allocation of DSM program costs, and the derivation of marginal/avoided costs for evaluation of DSM, non-utility generation and utility supply options.

Q: **Are you the author of any publications on utility planning and ratemaking issues?**

A: Yes. I am the author of a number of publications on rate design, cost allocation, power-plant cost recovery, conservation program design and cost-benefit analysis, and other ratemaking issues. These publications are listed in my resume.

Q: **Are you engaged in any least-cost planning activities in Maryland?**

A: Yes. I am a consultant for the Maryland Office of People's Counsel to the DSM collaboratives for WGL and PEPCo, as well as more limited roles in collaboratives with BG&E, Delmarva Power, and Potomac Edison. I am generally responsible for issues concerning avoided costs, resource allocation, cost recovery and regulatory policy.

Q: On whose behalf are you testifying?

A: My testimony is being sponsored by the Maryland Office of People's Counsel.

II. Introduction and Summary

Q: Please describe the purpose of your testimony.

A: My testimony reviews aspects of BG&E's rate design (especially the New Customer Adjustment), cost-of-service study, and revenue allocation

Q: How is the remainder of your testimony organized?

A: The next section presents my review and critique of the proposed New Customer Adjustment. Section IV discusses other rate design issues, including the residential customer charge, the standby rate, and the allocation of the brokering margin. Section V discusses problems in BG&E's cost-of-service study. Section VI critiques BG&E's proposed allocation of the revenue increase from this case, and proposes an alternative allocation.

Q: Please summarize your conclusions and recommendations.

A: My major conclusions and recommendations include:

- There is no need or justification for the New Customer Adjustment, since new customers do not impose any excess cost on BG&E's shareholders, and the New Customer Adjustment should be rejected.

- Any future charge similar to the New Customer Adjustment should be structured very differently.
- The residential customer charge should not be increased.
- BG&E should explore alternative designs for the standby charge.
- The ratepayer share of the brokering margin should continue to be credited to firm sales customers through the PGA.
- BG&E's cost-of-service study is so poorly documented as to be unreviewable by the Commission or the parties to this case.
- BG&E's cost-of-service study appears to rely on incorrect data, outdated cost structures and erroneous computations.
- Of BG&E's cost allocations that are reviewable, several are conceptually flawed, resulting in inappropriate cost allocations, including excessive allocations to the residential class.
- The allocation of production and storage costs is inconsistent, and understates the costs imposed by interruptible customers.
- The Company's allocation of the Manor Line to Bethlehem Steel understates Bethlehem Steel's share of the line, as well as the cost of the line.
- The environmental cleanup costs of the Spring Garden

site should be allocated on the basis of the past and present use of the site, and therefore on NCP and throughput, rather than on firm coincident peak.

- Gas conservation costs should not be allocated on distribution plant.
- BG&E's allocation of Customer Accounts Expense and Administrative & General Expense should be updated to reflect the important role of customer size, gas supply, and dispatch in causation of these costs.
- Bethlehem Steel should not be exempted from the normal revenue increase procedure.
- The rate-of-return bandwidth should be increased to 20% from the usual 7%, to reflect the greater uncertainties and problems in the cost-of-service study.
- The residential percentage rate increase should be no more than twice the non-residential rate increase.

III. BG&E's Proposed New Customer Adjustment

Q: Please summarize BG&E's proposed New Customer Adjustment.

A: As described in Witness DeWitt's pre-filed testimony, BG&E proposes to impose a New Customer Adjustment (NCA) surcharge on the residential class consisting of $220 per year for each new residential customer added in new construction. This surcharge is intended to recover the difference between the annual carrying charges for mains and services embedded in BG&E's proposed rates, and the annual carrying costs for mains and services installed for residential new construction. BG&E estimates these annual costs to be $299 for residential new construction and $79 for embedded costs.

As explained by Witness DeWitt on the stand, the computation of the $220 cost differential in Exh. DDD-4 is based on engineering estimates, rather than any actual data (Tr. 160, IR OPC 5-3).[1] Witness DeWitt also specified that the NCA assumed that new customers would be heating customers (prefiled at 25), and that the costs of serving new customers were intended to be computed for single-family homes on 100' frontage, and 50' of main per customer.

Q: Is the NCA justified?

A: No. It is not clear that there is any need for any NCA, because BG&E has not:

- established that load growth, absent an NCA, is bad for shareholders.
- reconciled its position on the NCA with its desire for increased penetration in residential new construction.
- compared increased revenues from load growth in all sectors with increased costs from load growth in residential new construction.

If any NCA were required, it would be much lower than BG&E has estimated, because:

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[1] Indeed, BG&E was not able to produce any actual data on the costs of past or budgeted service extensions (IR OPC 5-5, 5-13, 5-14, 5-15, 5-17).

- BG&E's computation of the annual carrying costs for mains and services allocated to heating customers is understated.
- BG&E's computation of the annual carrying costs for mains and services constructed for new heating customers is overstated.
- BG&E ignores the fact that heating customers pay costs allocated to non-heating customers.
- BG&E has computed costs and revenues for two categories of costs that happen to rise quickly with new customer additions, while ignoring offsetting excess revenues from cost categories that rise slowly with new customer additions. (These computations also contain errors.)

If any NCA were required, it should be structured very differently, so as to

- avoid double-counting in test year;
- collect costs from all classes, not just residential; and
- be a part of a comprehensive change in rate regulation to correct adverse incentives and encourage efficiency.

<u>A.</u> <u>BG&E Has Not Demonstrated that It Needs Compensation for Load Growth</u>

Q: Has BG&E demonstrated that it needs the NCA to compensate it for adding new customers?

A: No. In arguing that new high-use residential customers impose excessive costs, BG&E is taking an odd position for a utility. Utilities generally seek new customers and new loads, and promote their services. Indeed, BG&E anticipates that it will be deluged by new gas heating customers precisely because it is aggressively marketing gas to residential new construction (Annual Report at 8-9; 1994 Gas Forecast at 17).[2] Thus, BG&E is requesting a special rate surcharge not for a cost it incurs reluctantly (such as DSM) or one that is beyond its control (such as purchased gas cost fluctuations), but for a cost that it has welcomed and sought.[3]

Second, BG&E has not demonstrated that the total revenues it receives from load growth is insufficient to offset the costs incurred for load growth, including such low-cost, high-profit new customers as industrial, commercial, residential on existing mains, and multi-family residential with single services, as well as load growth of

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[2]Witness DeWitt's projection of 11,000 new-construction customers and 5,000 conversions annually is much more aggressive than BG&E's most recent (1994) Gas Sales Peak, and Customer Forecast, which projects only 7,633 new customers, even with promotion; and IR OPC 5-19, which projects 8,322 meters installed in new construction and 1,825 installed in heating conversions for 1996.

[3]The 1994 Annual Report to Shareholders (at 3) asserts, "expansion of our gas business is a key element of our marketing strategy as well. We now serve about 30 percent of our electric service territory with gas, leaving significant room for growth." The Annual Report also reports (at 8, 9) that BG&E "[l]aunched aggressive expansion plan to increase gas sales" and plans to [e]xpand gas distribution system to areas of high residential growth [and] route gas mains to increase conversions from other fuels."

existing non-residential customers.[4] BG&E has only presented an argument for a portion of the costs and revenues of one component of load growth.[5]

B. New Customers Impose Little if Any Burden on BG&E

Q: How has BG&E overstated the burden of residential new construction?

A: BG&E overstates new customer-service and mains costs, overstates the depreciation rate on services and mains, understates depreciation in rates, treats 1994 costs as if they were test-year rates, understates sales to new heating customers, ignores customer costs recovered through commodity charges, and ignores all offsetting revenues recovered from new customers for costs that do not vary with addition of customers.

1. BG&E's Overestimate of New Customer Service and Mains Costs

Q: Has BG&E provided any documentation of its estimates of the costs of serving residential new construction?

A: Mr. DeWitt's testimony provides no source for the new-customer Mains and Service costs reported in Exh. DDD-4. Nor

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[4] Load-growth revenues may cover load-growth costs, even if they do not cover the increase in total costs for inflation. If BG&E wants to change to a California-style rate adjustment mechanism with regular inflation adjustments, it should request that treatment directly, rather than using residential load growth to justify a surcharge to help offset inflation.

[5] As I shall demonstrate below, even BG&E's limited argument is fatally flawed.

do the work papers for Exh. DDD-4 (provided to OPC by Mr. DeWitt on June 21) cite any source for the new-customer costs, even though those work papers do identify the source of most of the other inputs to Exh. DDD-4. Those work papers are attached as Exhibit ____ (PLC-2). The response to Staff request A-1 #7 provides Mains and Service estimates for 1991, 1993, and 1994 that are very similar to those in Exh. DDD-4, but also reports no source.[6]

Finally, in response to OPC 5-3, a follow-up to Staff request A-1 #7, BG&E provides the computation of engineering estimates for the Mains and Service costs for residential new construction.

Q: **Any there any problems with BG&E's estimates of the residential new construction costs?**

A: Yes. BG&E's estimate is inconsistent with the application of the NCA, contains an error in the computation of mains footage per customer, and uses fairly high-end estimates of frontage per customer.

Q: **How is BG&E's estimate inconsistent with the application of the NCA?**

A: BG&E's estimate, as Witness DeWitt conceded, is only valid for single-family residential development. The actual residential new construction will comprise a mix of the following:

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[6]The stability in BG&E's estimates suggest that its assumptions have not been changed much.

- single-family residential development;
- town-house development, with lower per-customer service costs (since several units will typically share a service drop), and lower per-customer mains costs (since units will tend to be clustered closer together);
- multi-family development, with still lower per-customer service costs and mains costs;
- addition of single-family, town-house, or multi-family residences along existing mains, with no incremental mains cost.

Since the NCA would be applied to all residential new construction, regardless of whether it imposed costs comparable to those of single-family residential developments, BG&E's use of only single-family costs overstates the NCA.

Q: **What mix of new residential customers does BG&E project?**

A: On discovery, BG&E was unable to provide any forecast of the mix of customers in residential new construction (IR OPC 5-19(b)). Exhibit _____ (PLC-3) provides BG&E's estimates of the mix of residential new construction for 1995 filed in July 1992: 50% single family, 30% townhouse, and 20% multi-family.

Q: **Please describe BG&E's error in the computation of mains footage per customer.**

A: Witness DeWitt testified that the NCA was based on an assumption of an average lot width of 100 feet, with each main covering two lots on opposite sides of the street, "so that you would be looking at 50 feet on the average." (Tr. at 161) But IR OPC 5-3 shows that BG&E used "an average lot frontage of 110 feet," and did not divide the cost by the two lots served. [7]

Q: How would correction of this error change the computation of the NCA for single-family houses?

A: Exhibit ____ (PLC-4) shows how correcting the frontage to be consistent with BG&E's assumptions and practice reduces the cost of mains. Using two customers per unit of frontage produces a capital cost that is 30% lower than the cost BG&E used.[8]

Q: What would the mix of residential new construction cost?

A: Since BG&E provided only estimates of the frontage and service length for single-family homes, I estimated these variables for townhouses and small multi-family buildings. I

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[7]It is not clear whether the 110' frontage is consistent with DeWitt's statement: "We have experienced over the past ten years a downsizing in lot size for new residential construction, substantial downsizing" (Tr. at 162). Since BG&E's tariffs provide for paying for as much as 130' of frontage, the 110' assumption is at the high end of the reasonable range for estimates of frontage per single-family customer. Any costs for longer frontage would be paid by the builders as contributions in aid of construction (CIAC), and would not be included in BG&E's carrying costs. BG&E has not provided any formulae or rules for computing CIAC for residential new construction, or the "economic test" for longer mains and services mentioned in the tariffs (IR OPC 5-18).

[8]I have assumed that Witness DeWitt's reference on the stand to 100' of frontage was intended to be a reference to 110'.

assumed wider frontage (implying longer mains) and greater set-backs (implying longer services) for a townhouse cluster or multi-family building than for a single-family development, but divided the main and service costs by more customers, and increased the cost of the service in proportion to the square root of customers served. The resulting costs are 72% and 91% lower than the value BG&E used for single-family development in Exh. DDD-4. The average new dwelling cost would be $620, 55% of the cost assumed by BG&E.

I have not included any residential new construction customers located along existing mains in this computation. Serving these customers would require only construction of new services, reducing costs by over 50%. Yet BG&E intends to impose the same NCA for residential new construction along existing mains as for construction requiring new mains.

Q: **Witness DeWitt (at 25, lines 21-22) asserts that providing new gas service to existing dwelling units is "generally more expensive" than serving residential new construction. Is this statement correct?**

A: No. The basis for the statement is provided in IR OPC 5-6(e), in which BG&E asserts

> Gas service extensions for existing dwelling units are generally more [expensive] due to restoration costs. Service extensions for existing units require restoration of roads, driveways, sidewalks, landscaping, etc.

In fact, "the cost of breaking and replacing paving, including sidewalks, and lawn repairs, if any, is not included in any economic test and is chargeable to the Customer" (Terms and Conditions 8.22). BG&E bears none of the restoration costs.

<u>2. BG&E's Errors in Estimating the Mains and Service Costs Allocated to and Imposed by New Customers</u>

Q: **How did BG&E err in estimating the annual mains and service costs allocated to and imposed by new customers?**

A: In addition to overstating the capital costs of the new installations, BG&E made six errors.

First, BG&E over-stated depreciation for both the embedded allocation and the new customers. Rather than multiply mains plant by the mains depreciation rate (2.1%) and service plant by the service depreciation rate (4.71%), BG&E multiplied both mains and service by the sum of the two depreciation rates (6.81%). I was initially surprised that BG&E, experienced as it is in computing its expenses, made such a glaring error, but that error is clearly documented in the work papers for Exh. DDD-4. This error overstated the annual depreciation expense for the new plant by $50 per customer. The correct value is $43, as reflected in Exhibit ____ (PLC-5) at 2, while Exh. DDD-4 computes $93.

Second, BG&E makes an equally surprising mistake in assuming that depreciation is a function of net, rather than gross, plant. BG&E is well aware that its depreciation expense is computed as a percentage (the depreciation rate) times its gross plant in service. Yet Exh. DDD-4 computes the embedded depreciation expense as the depreciation rate times net plant (where net plant is gross plant minus accumulated depreciation). Exh. DDD-4 provides only one plant value for embedded cost, and one for new customers; while gross and net investment are quite similar for brand-new plant, the difference is significant for the embedded costs, where accumulated depreciation is a quarter to a third of the gross investment. Correcting this error raises embedded costs.

Third, BG&E assumes that property taxes are 2% of net plant; the available evidence indicates that property taxes are 2% of gross plant. BG&E's marginal cost study assumes property taxes add 2% to the levelized carrying costs, implying that the taxes are levied on gross plant. In addition, BG&E's cost-of-service study reports distribution property taxes of $13,644,205 on gross plant of $646,607,999, or 2.1%.[9] Correcting this error also increases embedded costs.

Fourth, BG&E mixes and matches time frames in estimating the embedded net plant costs. As shown in Exhibit ____ (PLC-2), BG&E used average 1994 gross plant from the cost-of-service study, from which it subtracted the (later) year-end 1994 accumulated depreciation. To match the cost-

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[9]Since net distribution plant is $451,676,932, a 2% property tax rate on net plant would result in only about $9 million in taxes.

of-service study, the accumulated depreciation should be reduced by half a year's depreciation. To match the test year on which rates will actually be set in this case, the gross plant should be increased. Exh. RMB-4 shows that BG&E estimated utility plant in service for the test year to be about $683.1 million, or 10.7% more than the $616.8 million reported for year-end 1994 in the FERC Form 2.[10]

Fifth, BG&E ignores the accumulated depreciation of the new plant. This accumulated depreciation is small (about $21) in the first full year, but it reaches 10% of gross plant in about three years. Since return is computed on net plant, that portion of the cost serving new customers will fall over time.

Sixth, BG&E computed the contribution to mains and services for the average residential customer, even though Witness DeWitt's testimony (at 25) states that BG&E was attempting to perform this analysis for the average heating customer. The average heating customer pays a higher bill, paying for more equipment, particularly for mains.[11]

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[10] The average rate base in the COSS would be still smaller, on the order of $580 million.

[11] As Witness DeWitt testified, "the average embedded cost recovered for any customer is a function of the amount of gas that customer would use in relation to average" (Tr. at 158). Since heating customers use an average of 91 Dth annually (IR OPC 5-7), compared to only 48 Dth annually for non-heating customers (IR OPC 5-11). Some of the residential customers classified as non-heating have probably installed gas heat (1994 Gas Load Forecast at 18); the average consumption of customers without any gas heat is unknown, but certainly lower than 48 Dth.

Residential new construction with gas service appears to be nearly all gas heated; indeed, BG&E's non-heating residential customers are declining in number.

Q: **Have you corrected these errors?**

A: Yes. I computed two sets of corrections. Each properly computes depreciation from gross plant by function, property tax from gross plant, and return from mid-year net plant, aging the new plant from its first year to its six year in service.

- Exhibit _____ (PLC-5) estimates embedded average net plant in service for 1994, using the inflated investment per new customer used in Exh. DDD-4. The embedded costs allocated to heating customers rises to $83, and the first-year carrying costs on BG&E's assumed $1,370 investment for each new customer would be $246, compared to BG&E's estimate of $299, reducing the first-year differential to $163.
- Exhibit _____ (PLC-6) estimates embedded average net plant in service for the test year, using the inflated investment per new customer used in Exh. DDD-4. The cost of the embedded mains and services in the test year are about $654/customer gross and $455/customer net, compared to BG&E's single estimate of $363 for both net and gross plant. The annual carrying charge for this plant included in rates is $91, compared to

the $79 computed by BG&E.[12] The first-year differential is thus $155.

Thus, even limiting the comparison between embedded and new costs to the categories and methods selected by BG&E, the excess cost for an average new starts at $155/customer-year, not $220, and falls over time. As we shall see, this one-third drop in the differential is just the beginning of the corrections needed to BG&E's estimate.

Q: **What is the result of combining these corrections in BG&E's carrying charges with your previous correction in BG&E's estimates of capital costs?**

A: Exhibit ____ (PLC-7) estimates embedded average net plant in service for the test year, using the corrected estimate of single-family investment per new customer computed in Exhibit ____ (PLC-4). The first-year carrying charge for the $963 new-customer investment is $177, reducing the differential to $86.

Exhibit ____ (PLC-8) estimates embedded average net plant in service for the test year, using the corrected estimate of investment per average new customer computed in Exhibit ____ (PLC-4). The first-year carrying charge for the $614 new-customer investment is $114, reducing the differential to $23, just 10% of BG&E's estimate.

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[12] BG&E's over-estimate of depreciation rates is more than balanced by its underestimate of depreciable plant, failure to match costs to the test year, and use of average, rather than heating, customers.

3. Non-Heating Service Costs Collected through Heating Customer Bills

Q: Are all the costs allocated as customer-related collected through the customer charge?

A: No. Witness DeWitt testified that only part of the cost of services is recovered in the customer charge (Tr. at 154). BG&E allocated to each residential customer $15.46 in 1994 customer costs (Ex. DDD-3, sheet G-4). Including the proposed post-equalization rate increase, the customer costs would be $16.51.

Under the current $8 customer charge, $8.51 of customer costs would be recovered through the commodity charge; under BG&E's proposed $12 customer charge, $4.51 is in the commodity charge.

Q: How does the recovery of these customer costs through commodity charges affect the net cost of serving residential new construction?

A: As Witness DeWitt testified, "the average embedded cost recovered for any customer is a function of the amount of gas that customer would use in relation to average" (Tr. at 158). The average heating customer, including those in residential new construction, will pay its customer-allocated costs, plus a portion of the non-heating customers' customer-allocated costs. That portion to be about $15/year for the proposed customer charge and $28/year for the current customer charge; see Exhibit ____ (PLC-9).

These additional revenues help offset the costs of residential new construction customers. In effect, each new heating customer pays $91/year for its services and mains, plus another $15-$28 for non-heating customer services (or other customer-allocated costs).

4. Customer Costs that Do Not Increase Immediately for New Customers

Q: How has BG&E treated costs other than mains and services carrying charges in computing the proposed NCA?

A: BG&E has assumed that all costs other than mains and services are the same for new and existing customers.

Q: Is this a reasonable assumption?

A: No. It is not reasonable for a number of customer-allocated costs, for production and storage costs, or for maintenance of mains.

Q: What customer-allocated costs would not be expected to rise promptly and proportionally with residential new construction?

A: Meter and service maintenance should be minimal for newly installed meters and services. Meters are tested and replaced periodically, or when bills change radically, suggesting that the meter may be in error. Brand-new services and meters are not likely to require repair or testing.

Residential new construction is unlikely to contribute to uncollectables for some years. Revenues become uncollectable only after they have been billed, the customer has fallen into arrears, and then goes bankrupt, leaves the service territory, or disappears. This process takes time. New homes added in 1995 may contribute to uncollectables in 2000 (when they will be reflected in rate case computations), but not in 1995 or 1996.

Customer records and collections includes some costs that vary more-or-less directly with customer number (at least within a class): postage (perhaps 25¢/month), stationary, and so on. Some costs may vary as customer number rises; if enough customers are added, an additional clerical position may be added. However, since much of the records function is computerized, and since no new software or hardware is likely to be required for a few percent increase in customer number, most of the records costs will not change. Collection costs are likely to be very small for the first few years of new customers, for the same reasons that uncollectables are.

Exhibit ____ (PLC-10) estimates the fixed customer-allocated costs from BG&E's cost-of-service study, assuming that just one third of records and collections expense is fixed in the short term, and that all customer service and meter reading is variable. Administrative and general expenses are allocated in proportion to other customer-allocated costs. The resulting fixed costs are $71 for 1994, and $76 for the test year.

5. Production and Storage Costs

Q: Do production and storage costs vary significantly with residential new construction?

A: Not in the short run. The Company is not projecting the addition of any production or storage facilities on its system. Costs of off-system storage contracts are recovered through the PGA.

Q: How much do residential new-construction customers pay towards production and storage costs?

A: I estimate this cost as $38/customer year; see Exhibit ____ (PLC-11). This cost is not offset by any increase in production or storage expense.

6. Maintenance of Mains and Services

Q: Would the new mains and services require the same level of maintenance as the average main?

A: No. Compared to older pipes, which have had an opportunity to settle, corrode, and be damaged by subsequent excavations new steel and plastic pipes are less likely to leak, and require testing and repair.

BG&E has no information about the relative costs of maintaining old and new mains and services (IR OPC 5-20).

Q: How much does the average residential heating customer contribute to the costs of maintaining mains and services?

A: Dividing the main and service maintenance costs allocated to the residential heating customers in the cost-of-service study ($1,876,337 and $839,008) by the number of residential heating customers yields $7.07. Escalating for the proposed rate increase produces $7.55/year.

7. Summary of Corrections to the New Customer Adjustment

Q: Please summarize your corrections to BG&E's estimate of the costs collected from the average residential heating customer that can be applied to offset the carrying costs of service extensions to residential new construction.

A: Exhibit ____ (PLC-12) lists my estimates for the test year of the main and service costs allocated to the average residential heating customer ($91), the non-heating service costs recovered from the average heating customer ($15-28), and other costs recovered from heating customers that are fixed in the short run ($121). The average heating customer thus contributes about $226 to $239 annually that can be applied to the carrying costs of the mains and services.[13] The analysis in Exh. DDD-4 acknowledged only $79 for means and services.

Q: How do these contributions compare to the carrying costs of the mains and services installed for residential new construction?

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[13]This is the contribution of the average-size heating customer. The average new heating customer is more likely to use gas water heating (which BG&E is encouraging). New townhouses and multi-family buildings are more likely than existing inner-city homes to have dryers installed, which are likely to be gas-fired where the house is heated with gas. New single-family homes may also have more of the large uses of hot water, such as whirlpools and spas.

A: BG&E estimates the carrying costs of new single-family mains and services to be $279 annually. Simply correcting the errors in BG&E's estimate (overstating depreciation, overstating return, failing to divide the mains cost per unit of frontage by two) reduces this estimate to $177 (as derived in Exhibit ____ [PLC-7] at 2), less than the contribution estimated above. The cost would fall by $5/yr. thereafter (Exhibit ____ [PLC-8]).

Since BG&E would also apply the NCA to townhouses and multi-family dwellings, the correct comparison would be between the cost of serving a mix of building types and the revenues received. Based on the most-recent BG&E forecast of building type mix I was able to find, and my estimates of frontage and service length by building type, the annual cost would be $114 in the first year, declining $3/yr. thereafter.

Including customers added along existing mains would further decrease the cost of serving the average new residential customer.

C. Any Future NCA Should Be Structured Very Differently

Q: If the Commission were to consider some form of NCA in the future, what changes should be made in the approach to implementing such a rate adjustment?

A: BG&E's approach should be changed in four ways. First, all costs and revenues, not a narrow selection, should be considered in determining whether load growth or new customers are covering their costs. As I have demonstrated above, the accounts for which new customers pay more than their short-run incremental cost more than cover any shortfall between the embedded and incremental carrying costs of meters and services.

Second, this sort of adjustment should be considered only as part of a general decoupling of earnings from sales. The idea of allowing a utility a fixed amount of revenue per customer originated with David Moskovitz of the Regulatory Assistance Project, as an alternative to traditional sales-indexed ratemaking. BG&E's proposal would increase its revenues for increased sales, and increase its rates for increased customer number. Combining these two approaches to ratemaking is unnecessarily complicated and subject to abuse.

Third, any increase in allocated costs should be allocated among rate classes, not to one targeted class. BG&E claims that its NCA would "simply address the timing issue related to regulatory lag" and "have no effect on the embedded-cost principle" (DeWitt at 27) and "absent the adjustment, these costs would be captured in the revenue requirement of a future base rate proceeding, thus contributing to a change in rates applicable to all customers within the class" (DeWitt at 26). In fact, the NCA operates very differently than would a base rate proceeding, and is entirely inconsistent with the "embedded-cost principle" DeWitt describes for the NCA (DeWitt at 26-27) and for Bethlehem Steel (DeWitt at 10). In a rate case, all classes are charged for each type of plant as if it were the same age; hence, large additions of mains or services for one class will increase the average cost of mains or services, and hence the cost allocation to all classes. BG&E's NCA vintages residential plant, allocating all the new mains and services to residential customers. If any special excess cost were to be collected through a surcharge, that cost should be allocated as it would be in a rate case.

Fourth, any future adjustment must be carefully structured to avoid double-counting costs. The rider appears to contemplate a surcharge in March 1996, to recover $220 per residential new construction customer added in 1995. Yet the costs of the customers added in January to June 1995 are already in the test year, as are some costs for customers who do not take service until later in 1995 or into 1996. Thus, some costs would be included in both the base rates and the surcharge.

IV. Rate Design

Q: What rate-design issues do you discuss?

A: My testimony covers the residential customer charge and the standby charge for delivery service.

<u>A. Residential customer charge</u>

Q: What is BG&E's proposal on the residential customer charge?

A: BG&E proposes to increase the customer charge by 50%, from $8 to $12 per month. By way of comparison, BG&E is proposing to increase the residential commodity charge only 4.6%, and total residential rates 23.2%. The proposed increase in the customer charge would represent 88% of the increased revenues from the residential class.

Q: What is BG&E's rationale for this large percentage increase in the customer charge?

A: BG&E proposes the increase in the customer charge to "minimize weather-related fluctuations in total revenues and … provide a better match between cost and cost-causation" (DeWitt at 19).

Q: Is it appropriate to reduce the customer charge to minimize weather-related fluctuations in total revenues?

A: Reducing the variability of revenues may be worth something to BG&E's shareholders. The variability of revenues due to economic cycles of larger non-residential customers are probably more important for shareholders than weather-related variability (which would not be expected to correlate with other financial results). Unfortunately, reducing the variability of large customer revenues is likely to be very difficult.

If the small residential customers are to bear the cost of reducing weather-related risks to shareholders, the residential class should be compensated, such as by a reduction in the target rate of return.[14] BG&E has not estimated the value to the shareholders of the massive increase in the customer charge, or offered any compensation.

Q: **Is Witness DeWitt correct in stating that "distribution service primarily involves fixed costs which do not vary with throughput" at 18?**

A: That depends on what he means by "fixed" and "vary."[15] He is correct that most distribution costs do not vary with actual throughput, or peak demand, in any one year. However, most distribution costs do vary with the size of the customer. BG&E allocates many distribution costs (such as mains) on demand, and some costs on winter or annual commodity as well. Even for the BG&E classifies as customer-related, BG&E allocates virtually all of the costs between

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[14]BG&E proposes this sort of compensation for Bethlehem Steel, in proposing a reduction in revenues compared to normal practice of approximately $1 million in exchange for a reduction in revenue risk due to the transfer of $3.5 million from commodity to customer charges. Since BG&E proposes to shift another $24 million to residential customer charges, the same reasoning would result in a $7 million reduction in charges to residential customers.

[15]It might be easier to understand Witness DeWitt's testimony if he had adhered to the rules of grammar. In that case, he would have written "fixed costs <u>that</u> do not vary with throughput," which clearly refers to a portion of fixed costs, or "fixed costs<u>, which</u> do not vary with throughput," which clearly states that no fixed costs vary with throughput.

classes so that classes comprised of large customers pay more per customer than classes comprised of small customers. In addition, BG&E allocates different percentages of residential costs (ranging from about 15% to about 25%) to the non-heating customers for different accounts. While BG&E does not appear to have specified the customer numbers it used for allocations within classes, it is difficult to understand why non-heating customers would have higher costs in any category (other than CIAC) than heating customers. The variation in allocation percentages therefore suggests that even BG&E recognizes that small residential customers impose smaller customer-allocated costs than do large residential customers.

All costs that are demand- or commodity-related should be recovered through demand or commodity charges. Since residential customers can not be economically metered or billed for demand,[16] these costs must be recovered through the commodity charge. In addition, a portion of many customer-classified costs vary with the size of the customer (in revenues, sales, or demand), and should also be recovered through the commodity charge.

Q: Does increasing the residential customer charge "provide a better match between cost and cost-causation?"

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[16]Residential customer maximum demand would not provide much useful information, due to the diversity of customers on most parts of the system. Metering for contribution to class NCP or CP would be very expensive.

A: Not really. BG&E's argument on this point appears to be based on the relationship of the customer charge to the costs classified as customer-related. Even if BG&E's allocation of costs between classes were really based on cost causation--which I have not been able to verify, given BG&E's reluctance to provide the derivation of its allocators--the costs classified as customer-related may not be equal for all customers in the class. For example, even if BG&E has properly allocated services between classes, the service cost for small residential customers is likely to be lower than for large ones. Large residential customers are likely to be single-family homes, each using a fairly long service drop. Small customers are likely to share services in multi-family housing or townhouses, or perhaps in row houses with individual, but short, service lines.

Other costs that are classified as customer-related will also vary with the customer's use. For example, uncollectable accounts and collection expense are likely to be larger for large customers than for small customers (since the large customers have larger bills to become uncollectable). A large customer with a large bill is more likely to place demands on customer service to explain his bill, and on the meter department to test his meter.

Hence, BG&E has not demonstrated that cost causation would be better reflected by a larger customer charge.

Q: Is the shift to greater customer charges and smaller

commodity charges required by increased competition in the gas industry, as discussed by Witness DeWitt (at 6)?

A: No. Regardless of whether delivery services are collected on a customer basis or a commodity basis, the residential customers will not bypass BG&E's delivery system.

Q: Is there any reason to keep the customer charge at $8?

A: Yes. The smaller customer charge increases the costs recovered through the commodity charge of the larger new customers. As discussed above, the lower customer charge thus increases the funds available to pay for mains and services to reach the surge of new customers BG&E anticipates, reducing the need for the NCA.

Q: What is your recommendation regarding the residential customer charge?

A: The customer charge should be kept at $8/month, or, if the charge is increased, increased in proportion to the overall residential rate increase.

B. Standby Charge

Q: How does BG&E propose to set the standby charges?

A: As I understand BG&E's proposal, the standby charge would be set at the average system demand charge: the sum of all pipeline, production, and storage costs, divided by sales and standby service.

Q: What would BG&E charge for commodity actually delivered under the standby provisions?

A: BG&E does not seem to have specified the delivered commodity charge. It should do so.[17]

Q: Are there any problems in the design of the standby provisions?

A: I have identified two such problems. First, the standby service is not priced like standby. A normal standby resource, whether a standby electric generator, a standby line of credit, or a emergency service contract between utilities, would have a low fixed charge to reserve capacity, combined with a high charge when that capacity is used. BG&E's proposed standby charge includes too much baseload pipeline demand charge to be a normal standby charge.[18] Since standby customers would be paying BG&E for the full capacity charges of a sales customer, regardless of whether they used any BG&E commodity, customers with nearly firm gas supplies would be paying twice for baseload capacity. Standby customers, having paid BG&E for baseload capacity, will have an incentive to use that capacity, by purchasing only the lowest-cost, least-reliable supplies for

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[17] Witness DeWitt states (at 14), "Gas commodity transactions for firm service under Schedule DS are treated as standard purchases from the Company." This may mean that the rate for the standby service under the DS option in each rate is the same as the commodity charge in the normal rate. This point should be clarified in the tariff.

[18] On the other hand, the standby charge does not include any gas inventory, which should be reflected in this type of charge. One of BG&E's costs of being prepared to meet standby loads is the costs of keeping storage fields, LNG tanks, and propane tanks filled.

their delivery service.

Q: **How can these problems with the standby rate structure be corrected?**

A: BG&E should design a rate structure based on standby resources. The standby charge could be based on propane and LNG capacity costs, including inventory, with actual deliveries priced at the commodity cost of these peaking supplies. BG&E should attempt to ensure that the rate will always cover the costs standby customers impose on the system, without unnecessarily burdening low-use standby customers. This alternative rate structure should be provided to BG&E's consultative Round Table for review, and submitted to the Commission as a replacement for the current rate design, if it appears to be feasible.

Q: **Are the standby charges consistent with the purchased gas adjustment?**

A: The standby charges recover demand charges that would otherwise be recovered through the purchased gas adjustment (PGA). The standby charges should be applied as a credit to the PGA, to avoid double collection of the same costs. BG&E's proposed revisions to the rate tariffs (in Exh. DDD-1) do not appear to update the PGA computation from 1993 provided in IR OPC 4-13 (at. 48). It is my understanding that BG&E intends to credit the PGA with the demand charges collected from the standby customers; the tariffs should reflect this intention.

C. Brokering Service Credit

Q: **How does BG&E propose to allocate the ratepayer share of Brokering Service Credits?**

A: BG&E proposes to shift from the current method of flowing the credit through the PGA for sales, to making an annual adjustment to base rates for sales and delivery customers on an equal cent-per-therm basis.

Q: **What is BG&E's rationale for this change?**

A: Witnesses Hargest and DeWitt argue that, since the delivery customers pay for a portion of the $271,000 cost of the brokering expense and associated income taxes, the delivery customers should share in the margin, to match expenses and revenues.

Q: **Does this rationale lead to a therm allocation?**

A: No. Even if the Commission accepted BG&E's logic, the brokering service costs are applied as a test-year adjustment, which is allocated to all classes (or in BG&E's proposal, all classes except Bethlehem Steel) in proportion to base revenues. Thus, delivery customers will pay less of these costs per therm than sales customers, and industrial customers will pay less per therm than residential customers. If the brokering margin were to be allocated to match the allocation of the brokering service costs, the annual base-rate adjustment should be an equal percentage of base rates, not an equal value per therm.

Q: **Should the brokering margin be allocated in proportion to**

the allocation of the brokering service costs?

A: No. The brokering service costs are a small part of the total costs that make BG&E's brokering program possible. The vast majority of the costs underlying the brokering program are the demand charges that are paid by firm sales customers through the PGA. If the firm customers did not pay for the capacity, BG&E would not have it available to broker. If BG&E retains capacity that could have been released, or whose contract could have been allowed to expire, to be able to make brokering sales, it is the firm sales customers who pay the extra costs. Therefore, the brokering margins should be credited to the PGA, as they are at present.

Q: **How could BG&E deal with its concern about the allocation of brokering costs to delivery customers?**

A: The simplest solution is to allocate the brokering costs to the brokering service, and allow BG&E to recover these costs from its share of the brokering margin. Since the firm-sales customers pay for all of the capacity being resold under the brokering program, it seems fair that BG&E should spend a little shareholder money in exchange for its ample share of the resulting margins.

V. BG&E's Cost-of-Service Study

Q: **What is the purpose of the cost-allocation process?**

A: The cost allocation process assigns the utility's total revenue requirement to the various classes. The process is generally driven by some concept of fairness. It is a generally accepted principle that allocation based on cost causation results in an equitable sharing of costs.

Q: **What were the results of BG&E's cost-of-service study?**

A: According to the Company's COSS, the residential class earns less than the average Company rate of return. Based on these results, BG&E proposes a disproportionate increase to the residential class, more than three times the average increase in the base rates of all other customers (Exh. DDD-3, Sheet G-1).

Q: **Please summarize your evaluation of BG&E's COSS.**

A: Despite the OPC's requests for detailed documentation, the Company's allocation of many costs is largely unreviewable. This problem is especially true for the Company's allocation of customer-related costs, which is responsible in large part for the Company's proposal of a disproportionate increase in revenues allocated to the residential class and a 50% increase in the residential customer charge.

Where documentation exists, I have identified a number of problems with the Company's classification and allocation decisions.

Q: **What problems have you identified in BG&E's cost-allocation methodology?**

A: I have identified the following problems:

- Much of the load data BG&E has provided is contradictory and inconsistent with the allocation factors employed in the Company's cost-of-service study.

- The allocations of production and storage plant and production and storage expenses are internally inconsistent.
- The direct assignment of a portion of Manor Line to Bethlehem Steel Corporation results in an underallocation of costs to that customer,
- The services allocator is based, in some irreproducible way, on an out-of-date analysis that cannot be reproduced.
- The classification and allocation of energy conservation according to distribution plant does not reflect cost causation.
- The classification and allocation of environmental costs according to production plant has no connection to the cause of these costs,
- The allocation of customer accounts expenses fails to reflect the full extent of the variation in cost with the size and type of customer.
- BG&E's functionalization, classification, and allocation of administrative & general expenses adds unnecessary complexity to the Company's COSS and fails to reflect the commodity-related functions that these costs also serve.

Q: What is the effect of the Company's error on its costs?

A: Most, and probably all, of the errors overstate the allocation of costs to the residential class and understate the allocation to the commercial-and-industrial customers.

A. Data Problems

Q: Can you give us an example of the inconsistencies you have come across in your review of BG&E's COSS documentation?

A: Yes. The Company displays winter firm sales data and percentage factors in its Gas Cost of Service Study at 29 and 30. The Company implies that these data are the basis for the WFIRM allocator, for winter firm sales. However:

- Comparison of the two data sets "BGE Sales (Dth): Firm Winter" and "Winter Firm BGE & Firm DS Sales (Dth)" indicates that residential customers received 8.1 million Dth of delivery service gas under Schedule D, even though they are not eligible for delivery service;[19]
- The data indicate firm winter sales to Bethlehem Steel, but none are reflected in the WFIRM allocator;
- Comparison of the percentages at page 30 of the COSS documentation with the actual allocations indicates that the WFIRM allocator is not based on the data provided in this data set.

[19] I assume that the time period is the same for the two data sets, "Firm Winter Sales" and "Winter Firm BGE & Firm DS Sales," because the Dth for Schedule PLG is the same in both.

Despite a request for detailed documentation of all external allocators (IR OPC 4-24), BG&E has failed to provide a clear and consistent statement of the source of this allocator. The response to IR OPC 4-24 not only fails to specify the load data used, it also indicates that the WFIRM allocator is based on sales for <u>five</u> months--November through March--not the <u>three</u> months--January, February and December--suggested by the COSS documentation.

Q: **Did BG&E properly adjust the 1991 CP and NCP by class to 1994 conditions?**

A: No. BG&E increased the 1991 class CP and NCP by a ratio of 1991 customers to 1994 customers, as described in IR Staff RD-2-5. The use of customer number, rather than weather-adjusted throughput, to update the 1991 demands seems suspect, especially given the wide range of size in the non-residential customers. But even for the customer data BG&E chose to use for this analysis, the 1991 values used in the update are inconsistent with the 1991 values reported in IR Staff RD-2-3, as well as those in the 1991 cost-of-service study. The 1994 customer numbers are similarly inconsistent with the responses to IR OPC 5-6, 5-7, and 5-11, as well as the 1994 Gas Forecast. In particular, the 1994 customer number used in the update for residential heating customers (Schedule DH) appears to be the year-end customer number, and the 1994 customer number used in the update for non-heating customers (Schedule D) appears to be the year-end customer number with a pair of digits transposed (103,947 rather than 103,974).[20] Since IR OPC 5-7 and 5-11 imply that BG&E converted over 13,000 customers from Schedule D to Schedule DH in 1994, as well as adding about 6,000 new DH customers, the use of year-end data appears to overstate the residential loads. Since the 1994 Gas Forecast (prepared in mid-1994) estimated less than 1,700 heating conversions, the large shift from Schedule D to DH may just be the result of better identification of customers with gas heat.[21] Using customer numbers from earlier in 1994, prior to the transfer of the Schedule D customers to Schedule DH, would decrease the normalized residential loads by 2-3%.

B. Production and Storage Plant and Expenses

Q: How does BG&E allocate Production and Storage Plant and Expenses?

A: It classifies plant as demand-related and allocates it on coincident peak (PDAY). It classifies expenses as commodity-related and allocates them on winter firm sales (WFIRM).

Q: In what way are these allocations inconsistent?

A: The Schedule IS customers are assigned a share of this

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[20] IR OPC 5-7 also appears to contain a typographical error, since the number of heating customers is reported to have fallen by about 20,000 from January to February.

[21] The 1994 Gas Forecast (at 18) reports that the "upward trend in Schedule D usage is probably due to the installation of gas furnaces by Schedule D customers who are not re-classified into Schedule DH."

plant, presumably because Company uses peaking and LNG capacity to supply some of the demand from these customers. Yet these customers are allocated none of the O&M expenses associated with the use of these peaking facilities.

All customer classes, whether firm or interruptible, should be allocated a portion of these O&M expenses, depending upon their use of these facilities. At the very least, the schedule IS class should be allocated a share based on its critical load of 10,500 Dth per day over all days in the winter period.

C. Mains

Q: How does BG&E allocate mains?

A: BG&E's derivation of the Mains allocator consists of two components:

1. the direct assignment of Manor Line and Gate Station to the Bethlehem Steel, IS and AIS rate classes; and
2. the allocation of remaining gross plant according to an adjusted NCP allocator.

Q: How was the direct assignment of Manor Line and Gate Station performed?

A: BG&E directly assigns $22.48 million to Bethlehem Steel, based on an estimate of the cost of Manor Line and Manor Gate Station assuming it were installed nine years ago, where nine years approximates the average age of BG&E's distribution system. BG&E derived the assignment to

Bethlehem Steel as follows (MIG 1-3):

- First, BG&E estimated the current installed cost of the Manor Line and Manor Gate Station to be $41 million.
- Of this amount, the Company assigned 78% to Bethlehem Steel, or $33.57 million. The Company does not explain the basis for the 78%, but it appears to represent the relative capacity of the minimum facility needed to serve Bethlehem Steel's current load requirements (DeWitt at 10). In fact, 78% happens to be the ratio of (1) the average size of the minimum lines needed to serve Bethlehem Steel to (2) the average sizes actually installed.
- From the $33.57 million, BG&E removed $3.2 million of environmental costs included in the initial estimate of current installed cost of Manor Line.
- BG&E deflated the resulting $30.37 million to 1986 dollars using a factor of 0.7402, resulting in a figure of $22.48 million.

Q: **How is the remaining portion of the nine-year-old Manor Line and Gate Station assigned?**

A: In assigning the remainder of Manor Line and Gate Station, BG&E assumed that Bethlehem Steel should receive 89% of the total direct assignment. The Company does not specify the basis for this assumed percentage, but it happens to be the ratio of throughput to Bethlehem Steel, 17 million Dth, to the total throughput on the line, 19 million Dth. The

Schedule IS and AIS classes are responsible for the other 11%. Therefore, BG&E assigns to these classes 12.4% (=11%/89%) of the assignment to Bethlehem Steel (MIG 1-4).

As a result, BG&E directly assigned only ~~90.4%~~ 87 of the nine-year old facility, 78% to Bethlehem Steel and ~~12.4%~~ 10 to IS and AIS. The other ~~9.6%~~ 13 along with the rest of the amount in Account 378 is allocated to all classes based on non-Manor-Line NCP load.

Q: **How does BG&E allocate the remainder of Account 378?**

A: BG&E bases the allocation on an NCP allocator, adjusted to reflect an Bethlehem Steel demand on other distribution lines of just 245 MCF (Staff RD-2-9).

Q: **Is BG&E's assignment reasonable?**

A: No. BG&E's calculations understate the cost of a nine-year-old Manor Line and assign too little of the cost to Bethlehem Steel.

Q: **How has BG&E under-assigned costs to Bethlehem Steel?**

A: BG&E made the following two errors in its calculation:

- It excluded environmental costs;
- It assigned the reserve capacity of the Manor Line and Gate Station to other rate classes, not to Bethlehem Steel.

Q: **What is BG&E's rationale for excluding environmental costs?**

A: It appears that BG&E excluded these costs based on a belief that they would not have been incurred had the line been built nine years ago (MIG 1-3).

Q: **Why was BG&E incorrect in exclude environmental costs?**

A: For at least two reasons. First, BG&E does not provide any description of the environmental costs reflected in the estimate of installed cost, but they are likely to have been incurred nine years ago, when many of today's environmental regulations were in effect.[22] Second, BG&E has provided no reason why Bethlehem Steel should be the only customer not paying any of the environmental costs associated with constructing mains.

Q: **Please explain how BG&E assigned the reserve capacity of the Manor Line and Gate Station to all rate classes, not just to the Bethlehem Steel, IS and AIS classes.**

A: In the direct assignment, BG&E conceptualized a minimum-sized (in stock) main to deliver 3,708 Dth/hr. to Bethlehem Steel. In other words, BG&E allocates to Bethlehem Steel only a share equal to the cost of constructing a line with capacity equal to Bethlehem Steel's current use, essentially 78% of actual capacity. Similarly, BG&E assigned the cost of a minimum-sized line to the IS and AIS classes. In the case of these customers, their load is only 11% of the total delivered on the line or 12.4% of Bethlehem Steel's (=11%/89%). The IS and AIS receives a direct assignment that is 12.4% of Bethlehem Steel's. The remaining ~~9.6%~~ 13 of the cost of Manor Line--in other words, the reserve capacity--is

[22] For example, the Clean Water Act was in effect nine years ago.

allocated to all classes based on non-Manor-Line NCP.

Q: **Why is this approach inappropriate?**

A: Bethlehem Steel should pay for its full share of reserve capacity in the line, just as other classes receive an allocation of reserve capacity on all other lines in distribution system. As Witness DeWitt testified (Tr. at 178), Bethlehem Steel has put higher loads on the Manor Line in the past than it did in 1991.

<u>D. Services</u>

Q: **How does BG&E classify and allocate Services?**

A: BG&E classifies Services as customer-related and allocates them based on the allocation derived for the 1991 COSS adjusted for change in customer number.

Q: **Is BG&E's approach reliable?**

A: No, for two reasons. First, the 1994 allocation depends on a 1991 COSS analysis that in turn was derived from the 1990 COSS analysis. As a result, the unit costs per customer by rate class that were established in the 1990 COSS analysis (which is perhaps based on an even older study or studies) drives the current allocation. Since a large portion of the Services Account 380 accrued after 1990 (the services rate base increased by 15% between 1990 and 1991, and gross plant-in-service increased by 20% between 1991 and 1994), analyses from 1991 or earlier do not provide reliable bases for current assumptions about unit cost differentials.

Second, I have been unable to reproduce BG&E's derivation of the allocator from the 1991 SERV-RB allocator.

Q: Please describe your attempt to reproduce BG&E's calculation.

A: I adjusted the 1991 services rate-base allocation, which is provided in the 1991 COSS work papers (supplied in the preceding rate case), to reflect the 1991-to-1994 change in customer number. For this calculation, I used the same customer number data employed by BG&E in the derivation of its NCP allocator (as documented in IR Staff RD-2-5). According to my calculations, BG&E's allocator for the residential class should be 7~~4~~7.6%, not the 78.509% used in the Company's COSS.

<u>E.</u> <u>Environmental Costs</u>

Q: How does BG&E allocate environmental costs?

A: BG&E treats these costs as "Other Production Plant," classifies them as demand-related, and allocates them based on demand-related production plant--that is, according to the PDAY allocator.

Q: Does BG&E provide a rationale for this approach?

A: No. The Company's description of the cost-of-service study methodology merely reports the allocation without supplying any explanation.

Q: Is the Company's approach appropriate?

A: No. The allocation of environmental clean-up costs should be based on a consideration of the cause of the damage and the current use of the site. BG&E's allocation approach neither reflects the cause of the environmental contamination nor the current use of the Spring Gardens property.[23]

Q: How does BG&E's treatment of this cost fail to reflect the cause of the environmental contamination?

A: The environmental damage from manufactured gas is clearly a function of the amount of fuel produced, not of production plant. Furthermore, manufactured gas was not used solely as a peaking supply, but on a year-round basis. Therefore, to the extent that these costs are allocated according to the cause of the contamination, they should be allocated according to annual commodity, not according to use on a single peak day. Since there was no delivery service when Spring Gardens was manufacturing gas, the commodity measure should be throughput, not sales.

Q: How can the allocator be revised to reflect the current use of the site of the clean-up?

A: The Spring Gardens site is currently "a principal natural gas distribution and office facility for the Company." (OPC 1-3, Letter from BG&E to the PSC Staff at 2). Therefore, it is reasonable to allocate a portion of this cost in

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[23] The current use of the property is only relevant if BG&E could have avoided the environmental costs by ceasing to use the site, and selling it. Given the nature of Superfund liability, it is not clear that BG&E's environmental remediation costs are in any way related to the current use or ownership of the site.

proportion to some combination of Mains (which is allocated on NCP) and Distribution Load Dispatching (allocated on annual throughput).

Q: **What allocator might be used to combine these two considerations?**

A: An allocator that is two-thirds based on annual throughput and one-third based on NCP would reflect both the cause of the contamination and BG&E's current use of the site.

F. Conservation Expenses

Q: **How does BG&E treat energy-conservation costs?**

A: BG&E functionalizes energy-conservation costs as "Other Distribution Plant," and classifies it according to distribution plant excluding general plant. The 45% of the costs that are classified as customer-related are allocated in proportion to total customer-related distribution plant. The remaining 55%, classified as demand-related, is allocated according to total demand-related distribution plant. Overall, the residential class is allotted 60% of the conservation costs.

Q: **Is BG&E's approach a valid basis for allocating energy conservation costs?**

A: No. Distribution plant has nothing to do with rate class participation in DSM programs. I have not been able to determine what expenditures are included in this plant account, but whatever they are, they should not be allocated according to total distribution plant. Gas conservation influences expenditures on mains, but has very little effect on services and none on meter investment.

This cost would more appropriately be allocated on commodity or directly assigned to participating classes.

G. Customer Accounts Expense

Q: **How does BG&E classify and allocate customer accounts expenses?**

A: The Company classifies customer accounts expenses as customer-related. The Company has developed external allocators specifically for this category of expenses, CUSTACCTSO&M, which assigns 94.102% of these costs to residential customers.

Q: **What is the basis for this allocation?**

A: The allocation of customer accounts follows the 1991 COSS (OPC 4-24).

Q: **What have you been able to determine about the derivation of the customer-accounts allocator in the 1991 study?**

A: The 1991 work papers provides a breakdown by type of expense, including "Customer Accounts," "Credit & Collection," "Meter Reading," "Customer Records," "District Offices," "Customer Relations," and "Office Services" expenses. For the most part, the analysis assumes that the non-residential customer has the same cost as the residential customer. The major exception is customer relations. BG&E assigned this expense only to rate classes C and D and assumed that the cost of a residential customer was about 4 times that of any Schedule C customer.

Overall, the customer-accounts allocator assumes that the cost of a commercial-and-industrial customer on Schedule C is only 75% of the cost of a residential customer.

Q: **Is this allocation of customer accounts expense reasonable?**

A: No. First, these expenses are likely to vary with the size of the customer or its revenues. In general, larger customers (especially delivery-service and interruptible customers) should be expected to have more complicated installations, metering, and billing, and to warrant more time and attention from BG&E. It is difficult to believe that BG&E spends as much time and attention on each residential customer as on each large commercial-and-industrial customer, considering, for example, that a large Schedule C Customer uses 35 times as much gas and provides 17 times as much operating revenue as the average residential Schedule DH customer. It is implausible that BG&E spends <u>more</u> time and resources on the residential customer. Unless the Company can provide reasonable supporting evidence, this allocation should be rejected on its face.

Second, 1991 experience may not be representative of current cost patterns. As BG&E itself stresses, the post-636 world requires that it now provide a much-more-complex mix of services. For example, flexible rates for interruptible customers and combined delivery and sales services will undoubtedly add to the complexity and the cost of meter reading, billing and record-keeping.

Q: **What are your recommendations considering the allocation of these expenses?**

A: The Commission should require the Company to perform a detailed study of the effect of size and type of customer on these expenses. This study should consider, in particular, the resources required to provide complex services to large customers.

In the absence of a well-supported analysis of Customer Accounts expenses, I recommend that these expenses be allocated 50% on throughput and 50% on customer number.

H. Administrative and General Expenses

Q: **How did BG&E allocate Administrative and General expenses?**

A: According to IR OPC 4-19, BG&E functionalizes A&G into the three major expense categories as follows: 4.43% is considered production-related, 3.05% storage-related, and 92.52% distribution-related. Each of these three categories of A&G expenses is classified into plant and labor components. BG&E does not specify the basis for the functionalization and classification. But in general, it appears that most of the A&G expenses are considered labor-related and then allocated according to labor.

Q: Is this method reasonable?

A: No. Administrative & general expenses are general overhead expenses, i.e., a cost necessary to support other functions. First, the embedded-cost study treats A&G as if it were driven mainly by only one kind of expense, labor. Only Account 926, employee pensions and benefits, should be considered labor-related. The remaining A&G consists of such expenses as:

- salaries of executives, officers and other employees concerned with broad oversight of the Company's business, and associated supplies and expenses (Accounts 920 and 921);
- regulatory expenses,
- general advertising,
- industry association dues, other experimental and general research expenses, and costs of publishing information and reports to stockholders.

In addition, BG&E's approach fails to reflect the rapid changes taking place in the gas industry. A significant amount of corporate overhead must be associated with the relatively new and rapidly increasing cost component associated with planning for a more diverse mix of gas supplies (including potentially hundreds of contracts for commodity supplies, gathering, upstream pipelines, downstream pipelines, and storage), acquiring gas from that range of suppliers, managing the receipt of gas for delivery service, and otherwise accommodating the increasing complex post-636 gas market. These costs are not proportional to directly-allocated production, storage, distribution, and customer labor. They are more closely related to throughput.

VI. Allocation of the Rate Increase

Q: How does BG&E allocate the rate increase between classes?

A: Following its usual practice, BG&E starts by computed the change in revenues necessary to bring each class's earned return for 1994 costs, as estimated from the flawed cost-of-service study, into a 7% uncertainty band around the target return. Since the target return is 9.54%, the 7% band is 8.87% to 10.21%. BG&E does not believe that its cost-of-service study results are sufficiently detailed to support more precise revenue allocations. BG&E raises Schedules D and C, and PLG's estimated return, to 8.87%; lowers Schedule IS estimated return to 10.21%; and leaves Schedule AIS at 10.11%. BG&E departs from its usual approach, in lowering Bethlehem Steel's return to 9.54%, rather than the top of the uncertainty band.

The Company then computes the rest of the revenue increase (covering increases from 1994 to the test year, plus any under- or over-collection in the first phase of the allocation), and allocates that difference in proportion to test year billing determinants at 1994 rates. Again, BG&E

departs from its usual practice in exempting Bethlehem Steel from this increase.

Q: **What is BG&E's rationale for reducing Bethlehem Steel's revenue requirement below the top of the uncertainty band, and for exempting Bethlehem Steel from the second part of the rate increase?**

A: Witness DeWitt (at 24) argues that the change in rate design justifies this change in allocation method, which decreases Bethlehem Steel's revenue allocation by approximately $1 million. As discussed above, the change in rate design reduces costs to shareholders, not to other ratepayers. If Bethlehem Steel is entitled to a discount from anyone, it is from shareholders, not other ratepayers.

Q: **What is the effect of eliminating this special treatment of Bethlehem Steel?**

A: Exhibit ____ (PLC-13) at 1 reproduces the computations in Exh. DDD-3, Sheet G-2, without the special treatment of Bethlehem Steel. The revenue-requirements change for Bethlehem Steel would be an increase of $29,000, rather than the $644,000 decrease proposed by BG&E. Residential rates would rise $300,000 less without the special treatment of Bethlehem Steel.[24]

Q: **Do you propose any other changes in BG&E's allocation of the rate increase?**

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[24] These computations assume that BG&E is granted its full requested rate increase.

A: Yes. As discussed above, BG&E's cost-of-service study suffers from a number of problems, including

- BG&E's failure to provide any documentation of the connection between the allocators and the fundamental underlying data;
- reliance on allocators from the 1991 cost-of-service study, which was in turn an update of the 1990 cost-of-service study; and
- apparent failure to reflect the changes in the causality of supply planning expenses, supply acquisition expenses, customer dispatch expenses, and related administrative and general expenses and general plant related to post-636 changes in the natural gas industry, including the rise in delivery service and the increase in complexity of supply planning and acquisition.

Reliance on BG&E's undocumented efforts to develop properly allocators from the underlying data, and to properly update allocators, seems particularly unwarranted in light of the multiple egregious errors in BG&E's development of the NCA. If the documentation of the NCA were as sparse and as indirect as that of the cost-of-service study, the Commission would have never known that BG&E used the wrong depreciation rates, and confused gross plant with net plant, single family costs with average costs, and heating with non-heating revenues. For the cost-of-service study itself, we know that some of BG&E's allocators (e.g., services, winter sales, NCP, CP) are inconsistent with the data provided by BG&E, that the derivation of some allocators contain transposition errors, that BG&E allocates some costs (e.g., conservation, environmental costs) on irrelevant allocators, and that some of BG&E's allocators (e.g., customer accounts) are based on implausible assumptions. The costs allocated on incorrect or suspect allocators exceed the rate increase request; reallocation of these costs could have a significant effect on the indicated rate of return earned by various classes.

In addition, BG&E has used some allocators from 1990, without updating them for the changes in cost causation in the post-636 world. If BG&E is correct that its typical cost-of-service study, using data that are roughly one year out of date, cannot be relied on to distinguish differences in class rate of return of less than 7% of the target return (or roughly 70 basis points), then this five-year-old data should not be relied on within about 35% of the target return.

To reflect these greater uncertainties, I propose that BG&E's bandwidth be expanded for this case from the traditional 7% to 20%. Exhibit ____ (PLC-13) at 2-4 presents the results of using BG&E's revenue-allocation methodology with 10%, 15%, and 20% bandwidths. The 20% bandwidth results in no rate reductions for any class; that result is appropriate both due to the exceptional uncertainties in the reliability of BG&E's cost-of-service study and due to BG&E's proposed removal of the limit on the upward flex on the interruptible IS rate (which would otherwise have experienced a rate decrease). Reducing the interruptible rate for cost-allocation purposes would be inconsistent with simultaneously allowing BG&E to raise the rate for individual customers. The 20% bandwidth still results in twice as large a rate increase to the residential class (21.6%) as to the non-residential classes (10.2%), while more than doubling the PLG rate.

If BG&E receives a smaller rate increase than it has proposed, I recommend increasing residential revenue requirements no more than twice the percentage increase for other classes.

Q: **Does this conclude your testimony?**

A: Yes, at this time. A number of discovery responses are outstanding. I will update my testimony if those responses provide relevant information.

Qualifications of

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Summary of Professional Experience

1986–Present **President, Resource Insight, Inc.** Consults and testifies in utility and insurance economics. Reviews utility supply-planning processes and outcomes: assesses prudence of prior power planning investment decisions, identifies excess generating capacity, analyzes effects of power-pool-pricing rules on equity and utility incentives. Reviews electric-utility rate design. Estimates magnitude and cost of future load growth. Designs and evaluates conservation programs for electric, natural-gas, and water utilities, including hook-up charges and conservation cost recovery mechanisms. Determines avoided costs due to cogenerators. Evaluates cogeneration rate risk. Negotiates cogeneration contracts. Reviews management and pricing of district heating systems. Determines fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determines profitability of transportation services. Advises regulatory commissions in least-cost planning, rate design, and cost allocation.

1981–86 Research Associate, Analysis and Inference, Inc. (Consultant, 1980–81). Researched, advised, and testified in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions. Consulted on utility rate-design issues, including small-power-producer rates; retail natural-gas rates; public-agency electric rates, and comprehensive electric-rate design for a regional power agency. Developed electricity cost allocations between customer classes. Reviewed district-heating-system efficiency. Proposed power-plant performance standards. Analyzed auto-insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

1977–81 **Utility Rate Analyst, Massachusetts Attorney General.** Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies. Topics included demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power-pool operations, nuclear-power cost projections, power-plant cost-benefit analysis, energy conservation, and alternative-energy development.

Education

SM, Technology and Policy Program, Massachusetts Institute of Technology, February, 1978.

SB, Civil Engineering Department, Massachusetts Institute of Technology, June, 1974.

Publications

"The Allocation of DSM Costs to Rate Classes," *Proceedings of the Fifth National Conference on Integrated Resource Planning.* Washington: National Association of Regulatory Utility Commissioners. (May 15, 1994): p.328-344.

"Environmental Externalities: Highways and Byways" (with B. Biewald and W. Steinhurst), *Proceedings of the Fifth National Conference on Integrated Resource Planning.* Washington: National Association of Regulatory Utility Commissioners. (May 15, 1994): p.449-473.

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"Monetizing Externalities in Utility Regulations: The Role of Control Costs" (with E. Caverhill), in *Proceedings from the NARUC National Conference on Environmental Externalities*. (October 1990): p.41-62.

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"Conservation and Cost-Benefit Issues Involved in Least-Cost Planning for Gas Utilities," in *Least Cost Planning and Gas Utilities: Balancing Theories with Realities*, Seminar proceedings from the District of Columbia Natural Gas Seminar, (May 23, 1989): p.12-17.

"The Role of Revenue Losses in Evaluating Demand-Side Resources: An Economic Re-Appraisal" (with J. Plunkett), *Summer Study on Energy Efficiency in Buildings, 1988*, American Council for an Energy Efficient Economy 8 (1988): p.8.198-8.214.

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"Capital Minimization: Salvation or Suicide?," in I.C. Bupp, ed., *The New Electric Power Business*, Cambridge Energy Research Associates, (1987): pp. 63-72.

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"Capacity/Energy Classifications and Allocations for Generation and Transmission Plant" (with M. Meyer), *Award Papers in Public Utility Economics and Regulation*, p.46-65. Institute for Public Utilities, Michigan State University, 1982.

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"Cost Allocation for Utility Ratemaking." With Susan Geller. Day-long workshop for the staff of the Connecticut Department of Public Utility Control, October, 1993.

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"Cost-Effectiveness Analysis." Presentation as part of "Effective DSM Collaborative Processes," a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August, 1993.

"Environmental Externalities: Current Approaches and Potential Implications for District Heating and Cooling" (with R. Brailove), International District Heating and Cooling Association 84th Annual Conference; June 1993.

"Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making." Presentation at the American Planning Association 1992 National Planning Conference; presentation cosponsored by the Edison Electric Institute. May, 1992.

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Energy Planning Workshops; Columbia, S.C.; October 21, 1991; "Overview of Integrated Resources Planning Procedures in South Carolina and Critique of South Carolina Demand Side Management Programs."

Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28, 1991; "Least Cost Planning and Gas Utilities."

NARUC Forum on Gas Integrated Resource Planning; Washington, D.C., February 24, 1991; "Least-Cost Planning in a Multi-Fuel Context."

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"Quantifying and Valuing Environmental Externalities." Presentation at the Lawrence Berkeley Laboratory Training Program for Regulatory Staff, sponsored by the U.S. Department of Energy's Least-Cost Utility Planning Program; Berkeley, California, February 2, 1990;

District of Columbia Natural Gas Seminar; Washington, D.C., May 23, 1989; "Conservation in the Future of Natural Gas Local Distribution Companies."

Massachusetts Natural Gas Council; Newton, Massachusetts, April 3, 1989; "Conservation and Load Management for Natural Gas Utilities."

New England Conference of Public Utilities Commissioners, Environmental Externalities Workshop; Portsmouth, N.H., January 22-23, 1989; "Assessment and Valuation of External Environmental Damages."

New England Utility Rate Forum; Plymouth, Massachusetts, October 11, 1985; "Lessons from Massachusetts on Long Term Rates for QFs".

Massachusetts Energy Facilities Siting Council; Boston, Massachusetts, May 30, 1985; "Reviewing Utility Supply Plans".

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National Conference of State Legislatures; Boston, Massachusetts, August 6, 1984; "Utility Rate Shock".

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Connecticut Department of Public Utility Control, Docket No. 87-07-01, Phase 2; Rate design and cost allocations; March 1988 to June 1989.

Expert Testimony

1. MEFSC 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General; June 12, 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with S. C. Geller.

2. MEFSC 78-17; Northeast Utilities 1978 forecast; Massachusetts Attorney General; September 29, 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. MEFSC 78-33; Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General; November 27, 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. MDPU 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1, 1979.

   Review of numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with S.C. Geller.

5. MDPU 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1, 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. Atomic Safety and Licensing Board, Nuclear Regulatory Commission 50-471; Pilgrim Unit 2, Boston Edison Company; Commonwealth of Massachusetts; June 29, 1979.

Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with S.C. Geller.

7. MDPU 19845; Boston Edison Time-of-Use Rate Case; Massachusetts Attorney General; December 4, 1979.

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with S.C. Geller. Testimony eventually withdrawn due to delay in case.

8. MDPU 20055; Petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G. & E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General; January 23, 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. MDPU 20248; Petition of MMWEC to Purchase Additional Share of Seabrook Nuclear Plant; Massachusetts Attorney General; June 2, 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. MDPU 200; Massachusetts Electric Company Rate Case; Massachusetts Attorney General; June 16, 1980.

    Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. MEFSC 79-33; Eastern Utilities Associates 1979 Forecast; Massachusetts Attorney General; July 16, 1980.

    Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. MDPU 243; Eastern Edison Company Rate Case; Massachusetts Attorney General; August 19, 1980.

    Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. Texas PUC 3298; Gulf States Utilities Rate Case; East Texas Legal Services; August 25, 1980.

Inter-class revenue allocations, including production plant in-service, O&M, CWIP, nuclear fuel in progress, amortization of canceled plant residential rate design; interruptible rates; off-peak rates. Joint testimony with M.B. Meyer.

14. MEFSC 79-1; Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General; November 5, 1980.

    Cost comparison methodology; nuclear cost estimates; cost of conservation, cogeneration, and solar.

15. MDPU 472; Recovery of Residential Conservation Service Expenses; Massachusetts Attorney General; December 12, 1980.

    Conservation as an energy source; advantages of per-kWh allocation over per-customer-month allocation.

16. MDPU 535; Regulations to Carry Out Section 210 of PURPA; Massachusetts Attorney General; January 26, 1981 and February 13, 1981.

    Filing requirements, certification, qualifying facility (QF) status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of QFs in specific areas; wheeling; standardization of fees and charges.

17. MEFSC 80-17; Northeast Utilities 1980 Forecast; Massachusetts Attorney General; March 12, 1981 (not presented).

    Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecasts and wholesale forecast.

18. MDPU 558; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; May, 1981.

    Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. MDPU 1048; Boston Edison Plant Performance Standards; Massachusetts Attorney General; May 7, 1982.

    Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. DCPSC FC785; Potomac Electric Power Rate Case; DC People's Counsel; July 29, 1982.

    Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O&M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. NHPUC DE1-312; Public Service of New Hampshire-Supply and Demand; Conservation Law Foundation, et al.; October 8, 1982.

    Conservation program design, ratemaking, and effectiveness. Cost of power from Seabrook nuclear plant, including construction cost and duration, capacity factor, O&M, replacements, insurance, and decommissioning.

22. Massachusetts Division of Insurance; Hearing to Fix and Establish 1983 Automobile Insurance Rates; Massachusetts Attorney General; October, 1982.

    Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. Illinois Commerce Commission 82-0026; Commonwealth Edison Rate Case; Illinois Attorney General; October 15, 1982.

    Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful like, capacity factor), risks, discount rates, evaluation techniques.

24. New Mexico Public Service Commission 1794; Public Service of New Mexico Application for Certification; New Mexico Attorney General; May 10, 1983.

    Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking proposal.

25. Connecticut Public Utility Control Authority 830301; United Illuminating Rate Case; Connecticut Consumers Counsel; June 17, 1983.

    Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.

26. MDPU 1509; Boston Edison Plant Performance Standards; Massachusetts Attorney General; July 15, 1983.

    Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. Massachusetts Division of Insurance; Hearing to Fix and Establish 1984 Automobile Insurance Rates; Massachusetts Attorney General; October, 1983.

    Profit margin calculations, including methodology, interest rates.

28. Connecticut Public Utility Control Authority 83-07-15; Connecticut Light and Power Rate Case; Alloy Foundry; October 3, 1983.

    Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. MEFSC 83-24; New England Electric System Forecast of Electric Resources and Requirements; Massachusetts Attorney General; November 14, 1983, Rebuttal, February 2, 1984.

    Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. Michigan PSC U-7775; Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; February 21, 1984.

    Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. MDPU 84-25; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; April 6, 1984.

    Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. MDPU 84-49 and 84-50; Fitchburg Gas & Electric Financing Case; Massachusetts Attorney General; April 13, 1984.

    Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. Michigan PSC U-7785; Consumers Power Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; April 16, 1984.

    Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. FERC ER81-749-000 and ER82-325-000; Montaup Electric Rate Cases; Massachusetts Attorney General; April 27, 1984.

    Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. Maine PUC 84-113; Seabrook 1 Investigation; Maine Public Advocate; September 13, 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. MDPU 84-145; Fitchburg Gas and Electric Rate Case; Massachusetts Attorney General; November 6, 1984.

    Prudence of Fitchburg and Public Service of New Hampshire in decision regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. Pennsylvania PUC R-842651; Pennsylvania Power and Light Rate Case; Pennsylvania Consumer Advocate; November, 1984.

    Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. NHPUC 84-200; Seabrook Unit 1 Investigation; New Hampshire Public Advocate; November 15, 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. Massachusetts Division of Insurance; Hearing to Fix and Establish 1985 Automobile Insurance Rates; Massachusetts Attorney General; November, 1984.

    Profit margin calculations, including methodology and implementation.

40. MDPU 84-152; Seabrook Unit 1 Investigation; Massachusetts Attorney General; December 12, 1984.

    Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. Maine PUC 84-120; Central Maine Power Rate Case; Maine PUC Staff; December 11, 1984.

    Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. Maine PUC 84-113; Seabrook 2 Investigation; Maine PUC Staff; December 14, 1984.

Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. MDPU 1627; Massachusetts Municipal Wholesale Electric Company Financing Case; Massachusetts Executive Office of Energy Resources; January 14, 1985.

    Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. Vermont PSB 4936; Millstone 3; Costs and In-Service Date; Vermont Department of Public Service; January 21, 1985.

    Construction schedule and cost of completing Millstone Unit 3.

45. MDPU 84-276; Rules Governing Rates for Utility Purchases of Power from Qualifying Facilities; Massachusetts Attorney General; March 25, 1985, and October 18, 1985.

    Institutional and technological advantages of Qualifying Facilities. Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. MDPU 85-121; Investigation of the Reading Municipal Light Department; Wilmington (MA) Chamber of Commerce; November 12, 1985.

    Calculation on return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in street-lighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. Massachusetts Division of Insurance; Hearing to Fix and Establish 1986 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; November, 1985.

    Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

48. New Mexico Public Service Commission 1833, Phase II; El Paso Electric Rate Case; New Mexico Attorney General; December 23, 1985.

    Nuclear decommissioning fund design. Internal and external funds; risk and return; fund accumulation, recommendations. Interim performance standard for Palo Verde nuclear plant.

49. Pennsylvania PUC R-850152; Philadelphia Electric Rate Case; Utility Users Committee and University of Pennsylvania; January 14, 1986.

    Limerick 1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

50. MDPU 85-270; Western Massachusetts Electric Rate Case; Massachusetts Attorney General; March 19, 1986.

    Prudence of Northeast Utilities in generation planning related to Millstone 3 construction: decisions to start and continue construction, failure to reduce ownership share, failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

51. Pennsylvania PUC R-850290; Philadelphia Electric Auxiliary Service Rates; Albert Einstein Medical Center, University of Pennsylvania and AMTRAK; March 24, 1986.

    Review of utility proposals for supplementary and backup rates for small power producers and cogenerators. Load diversity, cost of peaking capacity, value of generation, price signals, and incentives. Formulation of alternative supplementary rate.

52. New Mexico Public Service Commission 2004; Public Service of New Mexico, Palo Verde Issues; New Mexico Attorney General; May 7, 1986.

    Recommendations for Power Plant Performance Standards for Palo Verde nuclear units 1, 2, and 3.

53. Illinois Commerce Commission 86-0325; Iowa-Illinois Gas and Electric Co. Rate Investigation; Illinois Office of Public Counsel; August 13, 1986.

    Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. New Mexico Public Service Commission 2009; El Paso Electric Rate Moderation Program; New Mexico Attorney General; August 18, 1986. (Not presented).

    Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

    Recommendation for rate-base treatment; proposal of power plant performance standards.

55. City of Boston, Public Improvements Commission; Transfer of Boston Edison District Heating Steam System to Boston Thermal Corporation; Boston Housing Authority; December 18, 1986.

    History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. Massachusetts Division of Insurance; Hearing to Fix and Establish 1987 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; December 1986 and January 1987.

    Profit margin calculations, including methodology, implementation, derivation of cash flows, installment income, income tax status, and return to shareholders.

57. MDPU 87-19; Petition for Adjudication of Development Facilitation Program; Hull (MA) Municipal Light Plant; January 21, 1987.

    Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. New Mexico Public Service Commission 2004; Public Service of New Mexico Nuclear Decommissioning Fund; New Mexico Attorney General; February 19, 1987.

    Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. MDPU 86-280; Western Massachusetts Electric Rate Case; Massachusetts Energy Office; March 9, 1987.

    Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

60. Massachusetts Division of Insurance 87-9; 1987 Workers' Compensation Rate Filing; State Rating Bureau; May 1987.

    Profit margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.

61. Texas PUC 6184; Economic Viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief; August 17, 1987.

STNP operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP 2 cost and schedule projections. Potential for conservation.

62. Minnesota PUC ER-015/GR-87-223; Minnesota Power Rate Case; Minnesota Department of Public Service; August 17, 1987.

    Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.

63. Massachusetts Division of Insurance 87-27; 1988 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; September 2, 1987. Rebuttal October 8, 1987.

    Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.

64. MDPU 88-19; Power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric; November 4, 1987.

    Comparison of risk from QF contract and utility avoided cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.

65. Massachusetts Division of Insurance 87-53; 1987 Workers' Compensation Rate Refiling; State Rating Bureau; December 14, 1987.

    Profit margin calculations, including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.

66. Massachusetts Division of Insurance; 1987 and 1988 Automobile Insurance Remand Rates; Massachusetts Attorney General and State Rating Bureau; February 5, 1988.

    Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. Massachusetts Department of Public Utilities 86-36; Investigation into the Pricing and Ratemaking Treatment to be Afforded New Electric Generating Facilities which are not Qualifying Facilities; Conservation Law Foundation; May 2, 1988.

    Cost recovery for utility conservation programs. Compensating for lost revenues. Utility incentive structures.

68. Massachusetts Department of Public Utilities 88-123; Petition of Riverside Steam & Electric Company; Riverside Steam and Electric Company; May 18, 1988, and November 8, 1988.

    Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. Massachusetts Department of Public Utilities 88-67; Boston Gas Company; Boston Housing Authority; June 17, 1988.

    Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. Rhode Island Public Utility Commission Docket 1900; Providence Water Supply Board Tariff Filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island; June 24, 1988.

    Estimation of avoidable water supply costs. Determination of costs of water conservation. Conservation cost-benefit analysis.

71. Massachusetts Division of Insurance 88-22; 1989 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; Profit Issues August 12, 1988, supplemented August 19, 1988; Losses and Expenses September 16, 1988.

    Underwriting profit margins. Effects of 1986 Tax Reform Act. Taxation of common stocks. Lag in tax payments. Modeling risk and return over time. Treatment of finance charges. Comparison of projected and achieved investment returns.

72. Vermont Public Service Board Docket No. 5270, Module 6; Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and the Management of Demand for Energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group; September 26, 1988.

    Cost recovery for utility conservation programs. Compensation of utilities for revenue losses and timing differences. Incentive for utility participation.

73. Vermont House of Representatives, Natural Resources Committee; House Act 130; "Economic Analysis of Vermont Yankee Retirement"; Vermont Public Interest Research Group; February 21, 1989.

    Projection of capacity factors, operating and maintenance expense, capital additions, overhead, replacement power costs, and net costs of Vermont Yankee.

74. MDPU 88-67, Phase II; Boston Gas Company Conservation Program and Rate Design; Boston Gas Company; March 6, 1989.

    Estimation of avoided gas cost; treatment of non-price factors; estimation of externalities; identification of cost-effective conservation.

75. Vermont Public Service Board Docket No. 5270; Status Conference on Conservation and Load Management Policy Settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service; May 1, 1989.

    Cost-benefit test for utility conservation programs. Role of externalities. Cost recovery concepts and mechanisms. Resource allocations, cost allocations, and equity considerations. Guidelines for conservation preapproval mechanisms. Incentive mechanisms and recovery of lost revenues.

76. Boston Housing Authority Court 05099; Gallivan Boulevard Task Force vs. Boston Housing Authority, et al.; Boston Housing Authority; June 16, 1989.

    Effect of master-metering on consumption of natural gas and electricity. Legislative and regulatory mandates regarding conservation.

77. MDPU 89-100; Boston Edison Rate Case; Massachusetts Energy Office; June 30, 1989.

    Prudence of BECo's decision of spend $400 million from 1986-88 on returning the Pilgrim nuclear power plant to service. Projections of nuclear capacity factors, O&M, capital additions, and overhead. Review of decommissioning cost, tax effect of abandonment, replacement power cost, and plant useful life estimates. Requirements for prudence and used-and-useful analyses.

78. MDPU 88-123; Petition of Riverside Steam and Electric Company; Riverside Steam and Electric; July 24, 1989. Rebuttal, October 3, 1989.

    Reasonableness of Northeast Utilities' 1987 avoided cost estimates. Projections of nuclear capacity factors, economy purchases, and power plant operating life. Treatment of avoidable energy and capacity costs and of off-system sales. Expected versus reference fuel prices.

79. MDPU 89-72; Statewide Towing Association, Police-Ordered Towing Rates; Massachusetts Automobile Rating Bureau; September 13, 1989.

    Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison to competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing. Joint testimony with I. Goodman.

80. Vermont Public Service Board Docket 5330; Application of Vermont Utilities for Approval of a Firm Power and Energy Contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group; December 19, 1989. Surrebuttal February 6, 1990.

    Analysis of a proposed 450-MW, 20 year purchase of Hydro-Quebec power by twenty-four Vermont utilities. Comparison to efficiency investment in Vermont, including potential for efficiency savings. Analysis of Vermont electric energy supply. Identification of possible improvements to proposed contract.

    Critique of conservation potential analysis. Planning risk of large supply additions. Valuation of environmental externalities.

81. Mass DPU 89-239; Inclusion of Externalities in Energy Supply Planning, Acquisition and Dispatch for Massachusetts Utilities; December, 1989; April, 1990; May, 1990.

    Critique of Division of Energy Resources report on externalities. Methodology for evaluating external costs. Proposed values for environmental and economic externalities of fuel supply and use.

82. California Public Utilities Commission; Incorporation of Environmental Externalities in Utility Planning and Pricing; Coalition of Energy Efficient and Renewable Technologies; February 21, 1990.

    Approaches for valuing externalities for inclusion in setting power purchase rates. Effect of uncertainty on assessing externality values.

83. Illinois Commerce Commission Docket 90-0038; Proceeding to Adopt a Least Cost Electric Energy Plan for Commonwealth Edison Company; City of Chicago; May 25, 1990. Joint rebuttal testimony with David Birr, August 14, 1990.

    Problems in Commonwealth Edison's approach to demand-side management. Potential for cost-effective conservation. Valuing externalities in least-cost planning.

84. Maryland Public Service Commission Case No. 8278; Adequacy of Baltimore Gas & Electric's Integrated Resource Plan; Maryland Office of People's Counsel; September 18, 1990.

    Rationale for demand-side management, and BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

85. Indiana Utility Regulatory Commission; Integrated Resource Planning Docket; Indiana Office of Utility Consumer Counselor; November 1, 1990.

Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

86. Mass DPU Dockets 89-141, 90-73, 90-141, 90-194, and 90-270; Preliminary Review of Utility Treatment of Environmental Externalities in October QF Filings; Boston Gas Company; November 5, 1990.

    Generic and specific problems in Massachusetts utilities' RFPs with regard to externality valuation requirements. Recommendations for corrections.

87. Mass EFSC 90-12/90-12A; Adequacy of Boston Edison Proposal to Build Combined-Cycle Plant; Conservation Law Foundation; December 14, 1990.

    Problems in Boston Edison's treatment of demand-side management, supply option analysis, and resource planning. Recommendations of mitigation options.

88. Maine PUC Docket No. 90-286; Adequacy of Conservation Program of Bangor Hydro Electric; Penobscot River Coalition; February 19, 1991.

    Role of utility-sponsored DSM in least-cost planning. Bangor Hydro's potential for cost-effective conservation. Problems with Bangor Hydro's assumptions about customer investment in energy efficiency measures.

89. Commonwealth of Virginia State Corporation Commission Case No. PUE900070; Order Establishing Commission Investigation; Southern Environmental Law Center; March 6, 1991.

    Role of utilities in promoting energy efficiency. Least-cost planning objectives of and resource acquisition guidelines for DSM. Ratemaking considerations for DSM investments.

90. Massachusetts DPU Docket No. 90-261-A; Economics and Role of Fuel-Switching in the DSM Program of the Massachusetts Electric Company; Boston Gas Company; April 17, 1991.

    Role of fuel-switching in utility DSM programs and specifically in Massachusetts Electric's. Establishing comparable avoided costs and comparison of electric and gas system costs. Updated externality values.

91. Commonwealth of Massachusetts; Massachusetts Refusetech Contractual Request for Adjustment to Service Fee; Massachusetts Refusetech; May 13, 1991.

    NEPCo rates for power purchases from the NESWC plant. Fuel price and avoided cost projections vs. realities.

92. Vermont PSB Docket No. 5491; Cost-Effectiveness of Central Vermont's Commitment to Hydro Quebec Purchases; Conservation Law Foundation; July 19, 1991.

Changes in load forecasts and resale markets since approval of HQ purchases. Effect of HQ purchase on DSM.

93. South Carolina Public Service Commission Docket No. 91-216-E; Cost Recovery of Duke Power's DSM Expenditures; South Carolina Department of Consumer Affairs; September 13, 1991. Surrebuttal October 2, 1991.

    Problems with conservation plans of Duke Power, including load building, cream skimming, and inappropriate rate designs.

94. Maryland Public Service Commission Case No. 8241, Phase II; Review of Baltimore Gas & Electric's Avoided Costs; Maryland Office of People's Counsel; September 19, 1991.

    Development of direct avoided costs for DSM. Problems with BG&E's avoided costs and DSM screening. Incorporation of environmental externalities.

95. Bucksport Planning Board; AES/Harriman Cove Shoreland Zoning Application; Conservation Law Foundation and Natural Resources Council of Maine; October 1, 1991.

    New England's power surplus. Costs of bringing AES/Harriman Cove on line to back out existing generation. Alternatives to AES.

96. Massachusetts DPU Docket No. 91-131; Update of Externalities Values Adopted in Docket 89-239; Boston Gas Company; October 4, 1991. Rebuttal December 13, 1991.

    Updates on pollutant externality values. Addition of values for chlorofluorocarbons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

97. Florida PSC Docket No. 910759; Petition of Florida Power Corporation for Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 21, 1991.

    Florida Power's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

98. Florida PSC Docket No. 910833-EI; Petition of Tampa Electric Company for a Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 31, 1991.

    Tampa Electric's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

99. Pennsylvania PUC Dockets I-900005, R-901880; Investigation into Demand Side Management by Electric Utilities; Pennsylvania Energy Office; January 10, 1992.

    Appropriate cost recovery mechanism for Pennsylvania utilities. Purpose and scope of direct cost recovery, lost revenue recovery, and incentives.

100. South Carolina PSC Docket No. 91-606-E; Petition of South Carolina Electric and Gas for a Certificate of Public Convenience and Necessity for a Coal-Fired Plant; South Carolina Department of Consumer Affairs; January 20, 1992.

    Justification of plant certification under integrated resource planning. Failures in SCE&G's DSM planning and company potential for demand-side savings.

101. Massachusetts DPU Docket No. 92-92; Adequacy of Boston Edison's Street-Lighting Options; Town of Lexington; June 22, 1992.

    Efficiency and quality of street-lighting options. Boston Edison's treatment of high-quality street lighting. Corrected rate proposal for the Daylux lamp. Ownership of public street lighting.

102. South Carolina PSC Docket No. 92-208-E; Integrated Resource Plan of Duke Power Company; South Carolina Department of Consumer Affairs; August 4, 1992.

    Problems with Duke Power's DSM screening process, estimation of avoided cost, DSM program design, and integration of demand-side and supply-side planning.

103. North Carolina Utilities Commission Docket No. E-100, Sub 64; Integrated Resource Planning Docket; Southern Environmental Law Center; September 29, 1992.

    General principles of integrated resource planning, DSM screening, and program design. Review of the IRPs of Duke Power Company, Carolina Power & Light Company, and North Carolina Power.

104. Ontario Environmental Assessment Board–Ontario Hydro Demand/Supply Plan Hearings; *Environmental Externalities Valuation and Ontario Hydro's Resource Planning* (3 vols.); October, 1992.

105. Public Utility Commission of Texas Docket No. 110000; Application of Houston Lighting and Power Company for a Certificate of Convenience and Necessity for the DuPont Project; Destec Energy, Inc.; September 28, 1992.

106. Maine Board of Environmental Protection; In the Matter of the Basin Mills Hydroelectric Project Application; on behalf of Conservation Intervenors; November 16, 1992.

107. Maryland Public Service Commission Case No. 8473; In the Matter of the Application of the Baltimore Gas and Electric Company for the Review and Approval of the Power Sales Agreement Between the Baltimore Gas and Electric Company and AES Northside, Inc.; Maryland Office of People's Counsel; November 16, 1992.

108. North Carolina Utilities Commission Docket No. E-100, Sub 64; In the Matter of Analysis and Investigation of Least Cost Integrated Resource Planning in North Carolina—1992; Southern Environmental Law Center, on Demand-Side Management Cost Recovery and Incentive Mechanisms; November 18, 1992.

109. South Carolina Public Service Commission Docket No. 92-209-E; In Re Carolina Power & Light Company; South Carolina Department of Consumer Affairs; November 24, 1992.

110 Florida Department of Environmental Regulation hearings on the Power Plant Siting Act; Legal Environmental Assistance Foundation, December, 1992.

111. Maryland Public Service Commission Case No. 8487; Application of the Baltimore Gas and Electric Company for an Increase in Electric Rates; January 13, 1993. Rebuttal Testimony: February 4, 1993.

1121 . Maryland Public Service Commission Case No. 8179; Petition of Potomac Edison for Approval of Amendment No. 2 to the Electric Energy Purchase Agreement with AES Warrior Run, Inc.; Maryland Office of People's Counsel; January 29, 1993.

113. Michigan Public Service Commission Case No. U-10102; In the Matter of the Application of the Detroit Edison Company for Authority to Amend its Rate Schedules Governing the Supply of Electric Energy; Michigan United Conservation Clubs; February 17, 1993.

114. Public Utilities Commission of Ohio Dockets No. 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP; City of Cincinnati, April, 1993

115. Michigan Public Service Commission Case No. U-10335; In the Matter of the Application of Consumers Power Company for Authority to Increase Its Rates; Michigan United Conservation Clubs; October 1993.

116. Illinois Commerce Commission 92-0268, Electric-Energy Plan for Commonwealth Edison ; City of Chicago. Direct, February 1, 1994; rebuttal, September 1994.

   Cost-effectiveness screening of demand-side management programs and measures; estimates by Commonwealth Edison of costs avoided by DSM and of future cost, capacity, and performance of supply resources.

117. Federal Energy Regulatory Commission Projects Nos. 2422 et al., Application of James River–New Hampshire Electric, Public Service of New Hampshire, for Licensing of Hydro Power; Conservation Law Foundation; 1993.

     Cost-effective energy conservation available to the Public Service of New Hampshire; power-supply options; affidavit.

118. Vermont Public Service Board Dockets No. 5270-CV-1,-3, and 5686; Central Vermont Public Service Fuel-Switching, DSM, and Program Design, on behalf of the Vermont Department of Public Service. Direct, April 1994; rebuttal, June 1994.

     Avoided costs and screening of controlled water-heating measures; risk, rate impacts, participant costs, externalities, space-and water-heating load, benefit-cost tests.

119. Florida Public Service Commission, Dockets 930548-EG–930551–EG, on behalf of the Legal Environmental Assistance Foundation, Inc. April 1994.

     Integrated resource planning, avoided costs, rate impacts, analysis of conservation goals of Florida electric utilities.

120. Vermont Public Service Board Docket No. 5724, on behalf of the Vermont Department of Public Service. Joint surrebuttal testimony with John Plunkett. August 1994.

121. Massachusetts Department of Public Utilities in DPU 94-49 on behalf of the Massachusetts Office of Attorney General. August 1994.

     Analysis of Boston Edison's treatment of the effects of planning decision on customer bills, especially the company's its modeling and treatment of risk.

122. Michigan Public Service Commission in MPSC Case No. U-10554, Consumers Power Company DSM Program and Incentive; on behalf of the Michigan Conservation Clubs. November 1994.

     Proposal to scale back DSM spending. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

123. Michigan Public Service Commission in MPSC Case No. U-10702, Detroit Edison Company Cost Recovery, on behalf of the Residential Ratepayers Consortium. December 1994.

     Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

124. New Jersey Board of Regulatory Commissioners in Docket No. EM92030359; on behalf of Freehold Cogeneration Associates. November 1994.

Comparison of potential externalities from the Freehold cogeneration project with that from three coal technologies; support for the study "The Externalities of Four Power Plants."

125. Michigan Public Service Commission in Case No. U-10671, Detroit Edison Company DSM Programs; on behalf of the Michigan United Conservation Clubs. January 1995.

Critique of proposal to scale back DSM efforts in light of potential for competition. Loss of savings, increase of customer costs, and decrease of competitiveness. Discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

126. Michigan Public Service Commission in Case No. U-10710; on behalf of the Residential Ratepayers Consortium. January 1995.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

127. Federal Energy Regulatory Commission in Projects Nos. 2458 and 2572; on behalf of the Conservation Law Foundation. February 1995.

Comments on draft environmental impact statement relating to new licenses for two hydropower projects in Maine. Applicant has not adequately considered how energy conservation can replace energy lost due to habitat-protection or -enhancement measures.

128. North Carolina Utilities Commission in Docket No. E-100, Sub 74; on behalf of the Hydro-Electric–Power Producer's Group. February, 1995.

Critique and proposed revision of avoided costs offered to small hydro-power producers by Duke Power and Carolina Power and Light.

129. New Orleans City Council in Docket No. UD-92-2A and -2B; on behalf of the Alliance for Affordable Energy. February, 1995; Rebuttal, April, 1995.

Critique of proposal to scale back DSM efforts in light of potential competition.

130. Public Service Commision of the District of Columbia in Formal Case No. 917,II; on behalf of the Potomac Electric Power Company. February, 1995.

Prudence of utility DSM investment; prudence standards for DSM programs of Potomac Electric Power Company.

131. Ontario Energy Board in EBRO 490; on behalf of the Green Energy Coalition. April, 1995.

DSM cost recovery. Lost-revenue adjustment mechanism for Consumers Gas Company.

Exhibit ____(PLC-2)

Workpapers
for

Company's Proposed
New Customer Adjustment

JUN 21 '95 08:19PM GAS PLANNING BGE

BALTIMORE GAS AND ELECTRIC COMPANY
New Customer Adjustment Worksheet

Post-it™ brand fax transmittal memo 7671	# of pages ▸ 9
To Ms. Czarski	From D. DeWitt
Co. OPC	Co. BGE
Dept.	Phone # 291-4718
Fax # 333-3616	Fax #

I. Embedded Cost Per Customer Derivation

Step #1 - Distribution Plant Levels

A/C 376	Mains	$271,381,544
A/C 380	Services	$155,828,480

13 month average levels (1994) referenced in the Functionalization of Accounts sheet of the COSS - Section E (Distribution Plant).

Step #2 - Accumulated Depreciation

Mains	$71,544,768
Services	$68,931,981

Accumulated depreciation amounts from Plant Accounting as of December 31, 1994

Step #3 - Adjust Plant Levels For Accumulated Depreciation

Mains		Services	
Mains	$271,381,544	Services	$155,828,480
Accum. Depr.	$71,544,768	Accum. Depr.	$68,931,981
	$199,836,776		$86,896,499

Step #4 - Residential Class Allocators

	COSS	D	DH	Total %
Mains	NCP	0.068	0.492	56%
Services	Service - Rate Base	0.195	0.590	79%

D and DH percentages represent the residential portion of total customer class allocators for Mains and Services.

Step #5 - Calculate Residential Portion of Mains and Services

Mains		Services	
	$199,836,776		$86,896,499
x	56%	x	79%
	$111,908,595		$68,648,234

Step #6 - Total Mains and Services and Divide by Number of Residential Customers

Total	$180,556,829
# of Res.	498,152

Cost/Cust.	$ 363

BALTIMORE GAS AND ELECTRIC COMPANY
New Customer Adjustment Worksheet

II. Depreciation Rates - Plant Accounting

Mains	2.10%
Services	4.71%

Standard Accounting Depreciation Rates.

III. Pre-Tax Incremental Weighted Cost of Capital - 13.04%

Gross-up BGE's after-tax incremental weighted cost of capital for federal tax, gross receipts tax, and PSC Assessment to arrive at a pre-tax rate. Divide BGE's current after-tax Incremental weighted cost of capital by the conversion factor in Witness Bange's testimony (Exhibit RMB-1).

After-Tax Incremental Weighted Cost of Capital	8.29%
Conversion Factor	0.6359
Pre-tax Incremental Weighted Cost of Capital	**13.04%**

IV. Current Residential Customer Level - 498,152

Represents year-ended 1994 Residential Customer Level.
Addition of Residential Heating and Non-Heating columns in the allocation table of the COSS.

V. Carrying Cost Calculations

	Embedded	New
Depreciation	$363	$1,370
	x (2.10%+4.71%)	x (2.10%+4.71%)
	$25	$93
Prop. Tax	$363	$1,370
	x 2.00%	x 2.00%
	$7	$27
Pre-Tax ICC	$363	$1,370
	x 13.04%	x 13.04%
	$47	$179
Total Carrying Costs	**$79**	**$299**

PHASE III: ALLOCATION

	Allocation Factor	Total	Residential		General Service			Automatic		Outdoor	
			Non-Heating	Heating	Non-Heating	Heating	Large	Interruptible	Interruptible	Lighting	BSC
p	DISTL&CUSTL-DEM	4,509,655	273,594	1,994,589	70,431	279,912	749,844	68,276	630,503	594	441,911
n	DISTO&M-DEM	32,418,584	1,966,794	14,338,538	506,311	2,012,208	5,390,418	490,819	4,532,509	4,272	3,176,716
ɔ	DISTPT-DEM	36,787,717	2,231,867	16,271,008	574,549	2,283,402	6,116,909	556,968	5,143,375	4,848	3,604,791
ɔ	DISTPTXL-DEM	(107,376,773)	(6,514,422)	(47,492,166)	(1,677,007)	(6,664,842)	(17,854,166)	(1,625,891)	(15,012,593)	(14,150)	(10,521,738)
ɔ	D-MAINS,SERV-DEM	(192,772)	(11,695)	(85,262)	(3,011)	(11,865)	(32,053)	(2,919)	(26,952)	(25)	(18,889)
p	NCP	271,381,544	16,464,401	120,030,622	4,238,429	16,844,571	45,124,213	4,108,734	37,942,486	35,762	26,592,327
		237,527,955	14,410,539	105,057,329	3,709,702	14,743,286	39,495,165	3,596,187	33,209,328	31,301	23,275,118
	CUST	7,228	1,398	5,300	141	304	80	1	2	-	-
	DISTL&CUSTL-CUS	3,677,142	722,519	2,352,171	84,405	212,455	262,294	8,330	30,109	1,867	2,892
	DISTO&M-CUS	46,041,746	8,061,803	27,522,816	1,156,874	3,384,988	5,055,820	177,461	573,712	37,405	71,768
	DISTPT-CUS	11,690,228	1,877,654	6,485,117	248,198	878,934	1,812,008	72,557	271,225	19,125	25,409
	DISTPTXL-CUS	(87,554,295)	(14,059,128)	(48,559,731)	(1,857,922)	(6,583,215)	(13,582,362)	(544,002)	(2,034,030)	(143,448)	(190,457)
rv-rb	D-MAINS,SERV-CUS	(627,245)	(122,239)	(370,204)	(15,671)	(41,910)	(57,106)	(3,084)	(14,945)	(1,528)	(556)
	INSTALL IVST	43,172,525	3,892,541	20,227,716	538,387	3,944,464	12,697,338	387,370	1,213,717	22,512	248,479
	MTRS-CUS	33,567,079	2,742,929	15,548,104	414,403	3,520,781	10,021,594	335,693	844,474	-	139,101
	REG IVST	7,013,594	926,067	3,521,980	93,175	199,461	1,949,889	87,171	198,267	21,169	18,414
	SERV-RB	155,828,480	30,368,333	91,970,912	3,893,305	10,411,919	14,187,103	766,287	3,712,845	379,623	138,154
		212,816,480	34,411,877	118,704,281	4,554,295	15,928,181	32,346,658	1,287,784	4,793,376	336,727	453,304
.thrpl	DISTO&M-COM	1,404,805	71,852	460,540	27,284	66,741	250,356	22,850	289,416	458	215,309
	DIST.RATE BASE	451,749,240	48,894,268	224,222,150	8,291,281	30,738,208	72,092,179	4,906,821	38,292,120	368,486	23,943,731
	PDAY	38,872,592	2,467,104	22,221,077	563,352	3,031,435	9,784,000	0	796,071	9,553	0
	PRODO&M-XCC-DEM	725,715	46,059	414,847	10,517	56,594	182,658	0	14,862	178	0
	PRODPT-DEM	12,635,285	801,916	7,222,817	183,114	985,348	3,180,226	0	258,758	3,105	0
	PRODPTXL-DEM	2,491,384	158,119	1,424,171	36,106	194,288	627,066	0	51,021	612	0
	STORPT-DEM	1,728,168	109,681	987,887	25,045	134,769	434,969	0	35,391	425	0
	STORPTXL-DEM	(14,539,030)	(922,740)	(8,311,072)	(210,704)	(1,133,810)	(3,659,387)	0	(297,745)	(3,573)	0
		41,814,114	2,660,139	23,959,727	607,430	3,268,624	10,549,532	0	858,358	10,300	0
firm	PRODO&MXGC-COM	2,344,949	180,629	1,310,352	60,268	201,088	592,074	0	0	538	0
firm	STORO&ML-COM	1,983,241	152,767	1,108,230	50,971	170,071	500,746	0	0	455	0
		4,328,190	333,396	2,418,582	111,239	371,159	1,092,820	0	0	993	0
	CITY GATE RATE BASE	46,242,304	2,993,535	26,378,309	718,669	3,639,783	11,642,352	0	858,358	11,293	0
	TOTAL RATE BASE	497,991,544	51,887,803	250,600,459	9,009,950	34,377,991	83,734,531	4,906,821	39,150,478	379,779	23,943,731

PHASE III: ALLOCATION

	Allocation Factor	Total	Residential Non-Heating	Residential Heating	General Service Non-Heating	General Service Heating	Large	Automatic Interruptible	Interruptible	Outdoor Lighting	BSC
p	DISTL&CUSTL-DEM	5,531,210	335,571	2,446,415	86,386	343,319	919,703	83,743	773,329	729	542,015
p	DISTL/P-DEM	709,705	43,057	313,897	11,084	44,051	118,006	10,745	99,225	94	69,546
p	DISTO&M-DEM	5,025,285	304,878	2,222,652	78,485	311,917	835,582	76,083	702,595	662	492,431
p	DISTO&ML-DEM	2,719,284	164,975	1,202,720	42,470	168,785	452,150	41,170	380,188	358	266,469
p	DISTPT-DEM	9,157,271	555,561	4,050,211	143,018	568,389	1,522,633	138,642	1,280,299	1,207	897,312
p	DISTPTXL-DEM	12,011,241	728,708	5,312,507	187,591	745,534	1,997,180	181,851	1,679,319	1,583	1,176,969
p	D-MAINS-DEM	4,201,597	254,906	1,858,344	65,620	260,792	698,624	63,612	587,435	554	411,709
p	D-MAINS,SERV-DEM	1,224,747	74,304	541,699	19,128	76,020	203,646	18,543	171,235	161	120,011
p	D-STRUCT-DEM	79,317	4,812	35,082	1,239	4,923	13,189	1,201	11,090	10	7,772
p	M&RGCGPT-DEM	317,236	19,246	140,312	4,955	19,691	52,749	4,803	44,353	42	31,086
p	M&RGENPT-DEM	1,425,967	86,512	630,698	22,271	88,509	237,104	21,589	199,368	188	139,729
		42,402,860	2,572,530	18,754,537	662,247	2,631,930	7,050,566	641,982	5,928,436	5,568	4,155,049
	874	1,492,502	241,684	916,254	89,564	192,427	50,664	861	1,040	0	9
	878	2,606,799	613,137	1,806,287	54,785	108,145	21,535	390	454	1,988	77
-lo&m	CS&IEXP-CUS	440,577	69,310	241,927	17,752	37,414	71,665	662	1,840	0	7
	CUST	8,828,989	1,708,207	6,476,019	172,605	370,839	97,639	1,859	2,004	0	16
	CUSTACCTSO&M	13,601,122	3,242,846	9,563,380	233,023	455,522	66,073	5,129	41,098	2,050	2,001
accto&m	CUSTACCTXUA-CUS	362,854	83,536	256,927	6,377	12,716	2,173	124	911	45	44
	CUSTS&IO&M	3,459,097	544,169	1,899,442	139,379	293,750	562,663	5,198	14,445	0	51
	DISTL&CUSTL-CUS	19,789,137	3,888,354	12,658,591	454,240	1,143,363	1,411,577	44,827	162,035	10,048	16,101
	DISTL/P-CUS	2,186,240	425,836	1,389,634	50,004	128,128	164,662	5,363	19,465	1,228	1,820
	DISTO&M-CUS	6,970,372	1,220,496	4,166,761	174,991	512,462	765,413	26,866	86,856	5,663	10,865
	DISTO&ML-CUS	6,118,307	1,061,705	3,617,805	151,109	451,554	708,627	25,821	87,856	5,926	9,903
	DISTPT-CUS	9,910,633	1,591,820	5,497,893	210,415	745,134	1,536,167	61,511	229,937	16,214	21,541
	DISTPTXL-CUS	10,574,493	1,698,011	5,864,870	224,393	795,097	1,840,429	65,703	245,863	17,325	23,003
	D-STRUCT-CUS	64,675	10,388	35,878	1,373	4,863	10,025	401	1,501	106	141
	METER,REGPT-CUS	1,892,794	170,888	888,117	23,638	173,220	557,507	18,311	50,950	987	9,175
	M&RCGPT-CUS	5,408	869	3,000	115	407	838	34	125	9	12
	M&RGENPT-CUS	20,353	3,269	11,291	432	1,530	3,155	126	472	33	44
	SERVMAINTEXP	1,209,293	282,007	839,008	25,274	49,944	12,577	242	242	0	0
		89,533,845	16,856,532	56,123,084	2,029,469	5,476,515	7,681,389	263,228	946,894	61,622	94,910
mpt	COM1	315,139	16,119	103,313	6,121	14,972	56,162	5,126	64,925	103	48,300
mpt	DISTL&CUSTL-COM	343,679	17,578	112,669	6,675	16,328	61,248	5,590	70,804	112	52,674
xpt	DISTL/P-COM	36,159	1,849	11,854	702	1,718	6,444	588	7,450	12	5,542
xpt	DISTO&M-COM	227,376	11,630	74,541	4,416	10,802	40,522	3,698	46,844	74	34,849
xpt	DISTO&ML-COM	168,961	8,642	55,391	3,282	8,027	30,111	2,748	34,809	55	25,896
mpt	DISTPTXL-COM	51,520	2,635	16,890	1,001	2,448	9,182	838	10,614	17	7,896
		1,142,834	58,453	374,658	22,197	54,295	203,669	18,588	235,446	373	175,157

PHASE III: ALLOCATION

Allocation Factor	Total	Residential Non-Heating	Residential Heating	General Service Non-Heating	General Service Heating	Large	Automatic Interruptible	Interruptible	Outdoor Lighting	BSC
DIST. EXPENSE	133,079,339	19,487,515	76,252,279	2,713,913	8,162,740	14,935,624	923,798	7,110,776	67,583	4,425,116
PDAY	374,720	23,782	214,204	5,431	29,222	94,315	0	7,674	92	0
PRODLP-DEM	38,401	2,437	21,952	557	2,995	9,665	0	786	9	0
PRODO&ML-DEM	460,294	29,213	263,122	6,671	35,896	115,853	0	9,426	113	0
PRODPT-DEM	466,371	29,599	266,596	6,759	36,369	117,383	0	9,551	115	0
PRODPTXL-DEM	5,362,956	340,368	3,065,673	77,721	418,224	1,349,824	0	109,828	1,318	0
STORLP-DEM	10,377	659	5,932	150	809	2,612	0	213	3	0
STORPT-DEM	709,148	45,007	405,376	10,277	55,302	178,488	0	14,523	174	0
STORPTXL-DEM	3,405,949	216,163	1,946,972	49,360	265,609	857,257	0	69,750	837	0
	10,828,216	687,228	6,189,827	156,926	844,426	2,725,397	0	221,751	2,661	0
PRODLP-COM	102,032	7,859	57,015	2,622	8,750	25,762	0	0	23	0
PRODO&ML-COM	1,487,315	114,566	831,108	38,225	127,543	375,531	0	0	341	0
PRODO&MXGC-COM	140,031	10,786	78,249	3,599	12,008	35,356	0	0	32	0
PRODPT-COM	717,434	55,263	400,900	18,439	61,523	181,144	0	0	165	0
PRODPTXL-COM	790,313	60,877	441,625	20,312	67,772	199,545	0	0	181	0
STORLP-COM	86,294	6,647	48,221	2,218	7,400	21,788	0	0	20	0
STORO&ML-COM	940,890	72,476	525,767	24,182	80,685	237,564	0	0	216	0
STORPT-COM	943,816	72,701	527,402	24,257	80,936	238,303	0	0	217	0
STORPTXL-COM	281,626	21,693	157,372	7,238	24,151	71,107	0	0	65	0
WFIRM	1,959,388	150,930	1,094,902	50,358	168,025	494,724	0	0	450	0
	7,449,139	573,798	4,162,561	191,450	638,793	1,880,824	0	0	1,710	0
CITY GATE EXPENSE	18,277,355	1,261,026	10,352,388	348,376	1,483,219	4,606,221	0	221,751	4,371	0
NET INCOME	1,863,022	2,926	875,708	107,774	116,156	350,517	28,588	259,575	(649)	122,427
RATEBASE	3,046,006	317,376	1,532,818	55,110	210,276	512,169	30,013	239,467	2,323	146,454
REVENUE	4,608,592	439,203	2,484,956	135,406	331,862	929,979	46,918	197,005	1,850	41,414
UNCLASS.EXPENSE	9,517,620	759,505	4,893,482	298,290	658,294	1,792,665	105,519	696,047	3,524	310,295
TOTAL EXPENSE	160,874,314	21,508,046	90,498,149	3,360,579	10,304,253	21,334,510	1,029,317	8,028,574	75,478	4,735,411

Notes to Allocation Summary:

1) On this report, Rate Base Allocator #376" includes the direct assignment of $27 million to AIS, IS and BSC

2) Unclassified Expense is Gross Receipts Taxes and Federal Income Taxes which are neither Functionalized nor Classified.

G-4 TRACE

Item 1

Summation of customer component of Distribution O&M expenses (accounts 870-894 except for account 879, which is itemized separately in Item 5.). These totals are allocated to each customer class, divided by number of customers in each respective class and then divided by 12 to get associated expenses per customer per month.

A/C	Amount
870	2,784,086
874	1,492,502
875	16,649
877	2,767
878	2,606,799
880	6,970,121
881	251
885	421,733
886	64,675
889	3,704
891	2,641
892	1,209,293
893	1,892,794
894	348,358
	17,816,373

Item 2

Summation of customer component of Distribution Customer Account Expenses (accounts 901-905). These totals are allocated to each customer class, divided by number of customers in each respective class and then divided by 12 to get associated expenses per customer per month.

A/C	Amount
901	190,228
902	3,037,450
903	13,601,122
904	5,791,539
905	172,626
	22,792,965

Item 3

Summation of customer component of Distribution Customer Service and Information Expenses (accounts 908-910). These totals are allocated to each customer class, divided by number of customers in each class and then divided by 12 to derive associated expenses per customer per month.

A/C	Amount
908	3,459,097
909	246,571
910	194,006
	3,899,674

Item 4

Summation of customer component of Distribution A&G expenses (accounts 920-935). These totals are allocated to each customer class, divided by number of customers in each class and then divided by 12 to derive associated expenses per customer per month.

A/C	Amount
920-926	19,789,137
924-925, 932	990,053
928	9,472
930	955,968
931	411,559
935	809,241
	22,965,430

Item 5

Customer component of account 879 within Distribution. This total is allocated to each customer class, divided by number of customers in each respective class and then divided by 12 to get associated expenses per customer per month.

A/C	Amount
879	2,443,897

Item 6

Customer component of account 403 within Distribution plant. This total is allocated to each customer class, divided by number of customers in each respective class and then divided by 12 to get associated expenses per customer per month.

A/C	Amount
403	10,574,493

Item 7

Summation of customer components of General Taxes, which includes Payroll Tax (408.15) and Real Estate and Other Taxes (408.17, 408.18). Added to this total is After Tax Return minus Before Tax Return which is multiplied by 0.02. Added to these customer class totals are the differentials between adjusted total expenses, grossed up by the expense gross up factor of 1.024, and total expenses associated with the customer component of Distribution O&M (870-894, 901-905, 907-910, 920-935), Depreciation (403) and General Taxes (408.15, 408.17, 408.18). This result is divided by number of customers in class and divided by 12 to get monthly totals for each customer class.

A/C	Amount
Other O&M	69,918,299
Depreciation	10,574,493
General Taxes	9,040,854
Payroll Tax (408.15)	2,912,488
Real Estate & Other Tax (408.17, 408.18)	6,128,365

Example (IS)

General Taxes		184,006.00
After Tax Ret - Bef. Tax Return	(585,961 - 445,341) x .02 =	2,812.40
(Total exp. x 1.024) - (Total Exp)	(1,001,325 - 977,714)=	23,611.00
		210,429.40

210,429 / (122 x 12) = 143.74/month

Item 8

Obtained by taking the differential between After Tax Return and Before Tax Return and multiplying that value by .98. After Tax Return obtained by taking total rate base and multiplying by the adjusted authorized rate of return of 9.29%. The Before Tax Return is calculated by taking the after tax return and grossing up by the tax gross up factor of 1.285 and the expense gross up factor of 1.024.

Example IS

Rate Base	4,794,364	Before Tax Return	585,961
ROR	x 0.09289	After Tax Return	445,341
After Tax Ret.	445,341		140,620
Tax Gross up Factor	x 1.285		x .98
Expense Gross-Up Factor	x 1.024		137,807
Before Tax Ret.	585,961		

137,807/ (122x 12) = \$94.13/month

Item 9

Obtained by taking total rate base and multiplying that value by 9.29%.

IS	
Rate Base	4,794,364
	x .09289
	445,348

445,348/ (122 x 12) = \$304.19

Item 11

External input for SAC charges.

Exhibit____(PLC-3)
New Residential Construction Costs

	New Residential Construction 1995 (# of units)	Share of New Residential Construction	Cost per Customer	Weighted Average Cost
Single-family	8,803	50.0%	$963	$482
Town-house	5,282	30.0%	$378	$113
Multi-family	3,521	20.0%	$126	$25
TOTAL	17,606	100.0%		$620

Source: Projections from BG&E Residential New Construction Program, 7/1/92.

Exhibit____(PLC-4)
New Residential Customer Costs

		Exhibit DDD-4		Two Single-Family per 110'		Townhouses		Multi-Family		
Mains	Cost per Foot ($)	Feet per Customer	Cost ($)	Feet per Customer	Cost ($)	Feet per Customer	Cost ($)	Feet per Customer	Cost ($)	**Weighted Average ($)**
Frontage		110		110		150		200		
Customers per Frontage		1		2		8		20		
Service Length		60		60		100		150		
Customers per Service		1		1		4		20		
Pipe	$3.63	110	$399	55	$200	18.75	$68	10	$36	**$128**
Trench	$3.40	110	374	55	187	18.75	64	10	34	**119**
Connections	$0.35	110	39	55	19	18.75	7	10	4	**12**
Total			$812		$406		$138		$74	**$259**
Services										
Pipe	$1.90	60	$114	60	$114	25	$95	7.5	$14	**$88**
Trench	$3.40	60	204	60	204	25	85	7.5	26	**133**
Tap	$239	1	239	1	239	0.25	60	0.05	12	**140**
Total			$557		$557		$240		$52	**$361**
TOTAL			$1,369		$963		$378		$126	**$620**
Percentage Reduction from Costs in Exhibit DDD-4					30%		72%		91%	**55%**

Notes: Townhouses include two four-unit clusters with 150' frontage and 100' service.
Multi-family includes one twenty-unit building with 200' of frontage and 150' service.

Exhibit___(PLC-5)
1994 Average Rate Base, BG&E Estimates of New Customer Costs

I. Data		1994 Ave. Gross Plant in Service ($)	1994 Year-end Accumulated Depreciation	Ave. Accumulated Depreciation	Net Plant in Service	Costs per Customer: Gross Plant	Net Plant	Depreciation
Embedded Cost/Cust.		$588			$399			
New Cost/Cust.		1,370			1,370			
Residential DH Cust. (1994)	383,927							
Est. of New Residentials	11,000							
Depr. Rate (Mains)	2.10%							
Depr. Rate (Services)	4.70%							
Property Tax Rate	2.00%							
Pre-Tax ICC	13.04%							
Embedded Cost (Mains)		$271,381,544	$71,544,768	$68,695,262	$202,686,282			
Residential DH %					49%			
Emb. Res. Portion of Mains		$133,519,720			$99,721,651	$348	$260	$7
Embedded Cost (Services)		$155,828,480	$68,931,981	$65,270,012	$90,558,468			
Residential DH %					59%			
Emb. Res. Portion of Services		$91,938,803			$53,429,496	$239	$139	$11
Total						$587	$399	

New Residential Customer Costs	Gross Plant	Depreciation
Mains		
Pipe	$399	
Trench	375	
Connections	39	
Total	$813	$17
Services		
Pipe	$114	
Trench	204	
Tap	239	
Total	$557	$26

Exhibit____(PLC-5)
1994 Average Rate Base, BG&E Estimates of New Customer Costs

II. Annual Adjustment to Rate Base
($/Customer)

	Embedded Costs (Gross)	New Customer Costs Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Investment: Gross	$588	$1,370	$1,370	$1,370	$1,370	$1,370	$1,370
Net	399	1,348	1,305	1,262	1,219	1,175	1,132
Carrying Costs							
Depreciation	19	43	43	43	43	43	43
Property Tax	12	27	27	27	27	27	27
Pre-Tax ICC	52	176	170	165	159	153	148
Allocated Costs	$82	$246	$240	$235	$229	$223	$218
Differential (per customer)		$164	$158	$152	$147	$141	$135
Annual Adjustment		$1,800,695	$1,738,654	$1,676,614	$1,614,573	$1,552,532	$1,490,492

Notes:

Embedded Net Mains and Services calculated as the difference between Gross and Accumulated Depreciation (adjusted).
Accumulated Depreciation adjusted to account for the timing difference in data collection.
Number of customers adjusted to reflect the number of space heating customers.
Embedded Mains and Services allocators adjusted to reflect portions due to space heating customers.
Depreciation adjusted to reflect appropriate allocations for Mains and Services.
Depreciation and Property Tax calculated from gross plant costs, Pre-Tax ICC calculated from net plant costs.

Exhibit____(PLC-6)

Test Year Rate Base, BG&E Estimate of New Customer Costs

		Ave. Gross Plant in Service				Costs per Customer		
I. Data		1994	Test Year	1994 Year-end Accumulated Depreciation	Test Year Net Plant in Service	Gross Plant	Net Plant	Depreciation
Embedded Cost/Cust.		$651			$453			
New Cost/Cust.		$1,370			$1,348			
Residential DH Cust. (1994)	383,927							
Est. of New Residentials	11,000							
Depr. Rate (Mains)	2.10%							
Depr. Rate (Services)	4.70%							
Property Tax Rate	2.00%							
Pre-Tax ICC	13.04%							
Embedded Cost (Mains)		$271,381,544	$300,508,422	$71,544,768	$228,963,654			
Residential DH %					49%			
Emb. Res. Portion of Mains		$133,519,720	$147,850,144		$112,650,118	$385	$293	$8
Embedded Cost (Services)		$155,828,480	$172,553,262	$68,931,981	$103,621,281			
Residential DH %					59%			
Emb. Res. Portion of Services		$91,938,803	$101,806,424		$61,136,556	$265	$159	$12
Total Gross Plant		$ 616,800,000	$ 683,000,000			$650	$453	
New Residential Customer Costs								
Mains								
Pipe						$399		
Trench						375		
Connections						39		
Total						$813		$17
Services								
Pipe						$114		
Trench						204		
Tap						239		
Total						$557		$26

Exhibit____(PLC-6)
Test Year Rate Base, BG&E Estimate of New Customer Costs

II. Annual Adjustment to Rate Base
($/Customer)

	Embedded Costs (Gross)	New Customer Costs Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Investment: Gross	$651	$1,370	$1,348	$1,348	$1,348	$1,348	$1,348
Net	$453	$1,348	$1,305	$1,262	$1,219	$1,175	$1,132
Carrying Costs							
Depreciation	$19	$43	$43	$43	$43	$43	$43
Property Tax	13	27	27	27	27	27	27
Pre-Tax ICC	59	176	170	165	159	153	148
Allocated Costs	$91	$246	$240	$235	$229	$223	$218
Differential (per customer)		$155	$150	$144	$139	$133	$127
Annual Adjustment		$1,709,871	$1,647,831	$1,585,790	$1,523,749	$1,461,709	$1,399,668

Notes:

Embedded Net Mains and Services calculated as the difference between Gross and Accumulated Depreciation (adjusted).
Test year gross plant in service by account based on 1994 plant multiplied by increase in total plant from 1994 to test year.
Number of customers adjusted to reflect the number of space heating customers.
Embedded Mains and Services allocators adjusted to reflect portions due to space heating customers.
Depreciation adjusted to reflect appropriate allocations for Mains and Services.
Depreciation and Property Tax calculated from gross plant costs, Pre-Tax ICC calculated from net plant costs.

Exhibit____(PLC-7)
Test Year Rate Base, Corrected Single-family Costs

		Ave. Gross Plant in Service				Costs per Customer		
I. Data		1994	Test Year	1994 Year-end Accumulated Depreciation	Test Year Net Plant in Service	Gross Plant	Net Plant	Depreciation
Embedded Cost/Cust.		$651			$453			
New Cost/Cust.		$963			$946			
Residential DH Cust. (1994)	383,927							
Est. of New Residentials	11,000							
Depr. Rate (Mains)	2.10%							
Depr. Rate (Services)	4.70%							
Property Tax Rate	2.00%							
Pre-Tax ICC	13.04%							
Embedded Cost (Mains)		$271,381,544	$300,508,422	$71,544,768	$228,963,654			
Residential DH %					49%			
Emb. Res. Portion of Mains		$133,519,720	$147,850,144		$112,650,118	$385	$293	$8
Embedded Cost (Services)		$155,828,480	$172,553,262	$68,931,981	$103,621,281			
Residential DH %					59%			
Emb. Res. Portion of Services		$91,938,803	$101,806,424		$61,136,556	$265	$159	$12
Total Gross Plant		$616,800,000	$683,000,000			$650	$453	
New Residential Customer Costs								
Mains								
Pipe						$200		
Trench						187		
Connections						19		
Total						$406		$9
Services								
Pipe						$114		
Trench						204		
Tap						239		
Total						$557		$26

Exhibit____(PLC-7)
Test Year Rate Base, Corrected Single-family Costs

II. Annual Adjustment to Rate Base
($/Customer)

	Embedded Costs (Gross)	New Customer Costs					
		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Investment: Gross	$651	$963	$946	$946	$946	$946	$946
Net	$453	$946	$911	$876	$842	$807	$772
Carrying Costs							
Depreciation	$19	$35	$35	$35	$35	$35	$35
Property Tax	13	19	19	19	19	19	19
Pre-Tax ICC	59	123	119	114	110	105	101
Allocated Costs	$91	$177	$172	$168	$163	$159	$154
Differential (per customer)		$86	$82	$77	$73	$68	$64
Annual Adjustment		$949,654	$899,872	$850,090	$800,308	$750,526	$700,744

Notes:
Embedded Net Mains and Services calculated as the difference between Gross and Accumulated Depreciation (adjusted).
Test year gross plant in service by account based on 1994 plant multiplied by increase in total plant from 1994 to test year.
Number of customers adjusted to reflect the number of space heating customers.
Embedded Mains and Services allocators adjusted to reflect portions due to space heating customers.
Depreciation adjusted to reflect appropriate allocations for Mains and Services.
Depreciation and Property Tax calculated from gross plant costs, Pre-Tax ICC calculated from net plant costs.

Exhibit____(PLC-8)

Test Year Rate Base, Mix of Building Types

I. Data		Ave. Gross Plant in Service: 1994	Ave. Gross Plant in Service: Test Year	1994 Year-end Accumulated Depreciation	Test Year Net Plant in Service	Costs per Customer: Gross Plant	Costs per Customer: Net Plant	Costs per Customer: Depreciation
Embedded Cost/Cust.		$651			$453			
New Cost/Cust.		$620			$609			
Residential DH Cust. (1994)	383,927							
Est. of New Residentials	11,000							
Depr. Rate (Mains)	2.10%							
Depr. Rate (Services)	4.70%							
Property Tax Rate	2.00%							
Pre-Tax ICC	13.04%							
Embedded Cost (Mains)		$271,381,544	$300,508,422	$71,544,768	$228,963,654			
Residential DH %					49%			
Emb. Res. Portion of Mains		$133,519,720	$147,850,144		$112,650,118	$385	$293	$8
Embedded Cost (Services)		$155,828,480	$172,553,262	$68,931,981	$103,621,281			
Residential DH %					59%			
Emb. Res. Portion of Services		$91,938,803	$101,806,424		$61,136,556	$265	$159	$12
Total Gross Plant		$616,800,000	$683,000,000			$650	$453	
New Residential Customer Costs								
Mains								
Pipe						$128		
Trench						119		
Connections						12		
Total						$259		$5
Services								
Pipe						$88		
Trench						133		
Tap						140		
Total						$361		$17

Exhibit___(PLC-8)
Test Year Rate Base, Mix of Building Types

II. Annual Adjustment to Rate Base
($/Customer)

	Embedded Costs (Gross)	New Customer Costs					
		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Investment: Gross	$651	$620	$609	$609	$609	$609	$609
Net	$453	$609	$586	$564	$542	$519	$497
Carrying Costs							
Depreciation	$19	$22	$22	$22	$22	$22	$22
Property Tax	13	12	12	12	12	12	12
Pre-Tax ICC	59	79	76	74	71	68	65
Allocated Costs	$91	$114	$111	$108	$105	$102	$99
Differential (per customer)		$23	$20	$18	$15	$12	$9
Annual Adjustment		$257,088	$224,955	$192,822	$160,690	$128,557	$96,424

Notes:
Embedded Net Mains and Services calculated as the difference between Gross and Accumulated Depreciation (adjusted).
Test year gross plant in service by account based on 1994 plant multiplied by increase in total plant from 1994 to test year.
Number of customers adjusted to reflect the number of space heating customers.
Embedded Mains and Services allocators adjusted to reflect portions due to space heating customers.
Depreciation adjusted to reflect appropriate allocations for Mains and Services.
Depreciation and Property Tax calculated from gross plant costs, Pre-Tax ICC calculated from net plant costs.

Exhibit____(PLC-9)

Exhibit____(PLC-9)

Additional Service Costs Recovered Through Commodity Rate

	Description			Source
[1]	Customer-allocated Costs for 1994 ($/Cust.)	$15.46		Exh. DDD-3, Sheet G-4
[2]	Post-equalization Rate Increase	6.8%		Exh. DDD-3, Sheet G-2
[3]	Customer-allocated Costs in Proposed Rates ($/Cust.)	$16.51		[1]*(1+[2])

		Present	Proposed	
[4]	Customer Charge ($/Cust.)	$8.00	$12.00	Exh. DDD-3, Sheet G-5
[5]	Customer Costs in Commodity ($/Cust.)	$8.51	$4.51	[3]-[4]
[6]	Number of Residential Customers w/o Heating	114,225		Calculated from Exh. DDD-4 and IR OPC 5-6.
[7]	Non-heating Customer Costs in Commodity	$11,668,122	$6,185,322	[5]*[6]*12
[8]	Commodity (Dkth)	38,426,439		Exh. DDD-3, Sheet G-5
[9]	Recovery per Dkth ($/DKth)	$0.304	$0.161	[7]/[8]
[10]	Sales per Heating Customer 1995 (Dkth/Cust.)	91.06		1994 Forecast of Sales
[11]	Cost Recovered per Heating Customer ($/Cust.)	$27.65	$14.66	[9]*[10]

Exhibit____(PLC-10)

Exhibit____(PLC-10)

Customer Costs Not Immediately Increased by New Customers

	$/Month	$/Year
Meter and Service Maintenance	$2.32	$27.84
Uncollectibles	0.93	11.21
Records and Collections [1]	0.73	8.78
A&G [2]	1.91	22.98
TOTAL 1994		$70.80
Post-equalization Rate Increase	6.8%	
TOTAL Test Year		$75.62

Notes: [1] Assumes 1/3 fixed
[2] Allocated

Exhibit___(PLC-11)

Exhibit___(PLC-11)

Allocation of Test Year Production and Storage Costs to Residential Heating Customers

	Rate Base	Expenses
Production	$19,147,241	$6,040,700
Storage	$6,122,792	$4,311,605
Total	$25,270,033	$10,352,305
Return @ 13.04%		$3,295,212
Total P&S		$13,647,517
Number of DH customers		383,927
Customer Costs ($/Cust.)		$35.55
Customer Costs with Rate Increase ($/Cus		**$37.97**

Exhibit____(PLC-12)
Test Year Costs to DH Customers

Exhibit____(PLC-12)

Description	Costs ($/Year)	
Services and Mains Carrying Costs Allocated to DH		$90.60
Rate D Service Costs in Commodity	14.66 to	27.65
Production and Storage Costs		37.97
Fixed Customer Costs		75.62
Maintenance of Mains and Services		7.55
TOTAL	$226.41 to	$239.40

Exhibit ____ (PLC-13)
Revenue Increase Allocation

PART 1 - ALLOCATION TO MOVE TO WITHIN THE BANDWIDTH

7% Bandwidth

FROM 1994 COST OF SERVICE STUDY

	RATE BASE (1)	RATE OF RETURN (2)	RELATIVE ROR (3)	ROR Relative to Target	Relation to Band	TARGET RATE OF RETURN RELATIVE (4)	TARGET RATE OF RETURN PERCENT (5)	CHANGE IN RATE OF RETURN (6)	REVENUE ALLOCATION (7)
1. SCHEDULE D	$303,638,393	4.82%	0.75	0.51	below	0.93	8.87%	4.05%	$19,349,009
2. SCHEDULE C	$127,670,282	7.85%	1.22	0.82	below	0.93	8.87%	1.02%	$2,052,281
3. SCHEDULE PLG	$380,200	-3.84%	-0.59	-0.40	below	0.93	8.87%	12.71%	$76,005
4. SCHEDULE IS	$39,456,997	11.45%	1.77	1.20	above	1.07	10.21%	-1.24%	($770,773)
5. SCHEDULE AIS	$4,938,559	10.11%	1.57	1.06	within	1.06	10.11%	0.00%	($0)
6. BETHLEHEM STEEL	$21,907,108	11.41%	1.77	1.20	above	1.07	10.21%	-1.20%	($414,165)
7. TOTAL	$497,991,539	6.46%	1.00	0.68		1.00	9.54%	3.08%	$20,292,358

PART 2 - ALLOCATION BASED ON TEST YEAR REVENUES

8. REQUIRED CHANGE IN BASE REVENUE		$29,984,000
9. DEPRECIATION IMPACT FROM CASE NO. 8485		$2,274,000
10. TOTAL INCREASE IN BASE REVENUE		$32,258,000
11. LESS:	REVENUE CHANGE FROM PART 1	$20,292,358
12.	LATE PAYMENT CHARGE CHANGE	$199,887
13.	BALANCING SERVICE BASE REVENUE	$ 346,185
14.	TOTAL ADJUSTMENTS	$20,838,430
15. REMAINING REVENUE TO BE ALLOCATED		$11,419,570

	BASE REVENUE (1)	PERCENT OF TOTAL (2)	REVENUE ALLOCATION (3)	TOTAL REVENUE ALLOCATION (4)	Percentage Rate Increase
16. SCHEDULE D	$116,450,589	65.41%	$7,469,788	$26,818,797	23.0%
17. SCHEDULE C	$42,247,210	23.73%	$2,709,971	$4,762,252	11.3%
18. SCHEDULE PLG	$57,093	0.03%	$3,662	$79,667	139.5%
19. SCHEDULE IS	$10,984,743	6.17%	$704,622	($66,151)	-0.6%
20. SCHEDULE AIS	$1,380,741	0.78%	$88,568	$88,568	6.4%
21. BETHLEHEM STEEL	$6,905,523	3.88%	$442,959	$28,794	0.4%
22. TOTAL	$178,025,899	100.00%	$11,419,570	$31,711,928	17.8%

Exhibit ____ (PLC-13)
Revenue Increase Allocation

PART 1 - ALLOCATION TO MOVE TO WITHIN THE BANDWIDTH — 10% Bandwidth

	FROM 1994 COST OF SERVICE STUDY RATE BASE (1)	RATE OF RETURN (2)	RELATIVE ROR (3)	ROR Relative to Target	Relation to Band	TARGET RATE OF RETURN RELATIVE (4)	PERCENT (5)	CHANGE IN RATE OF RETURN (6)	REVENUE ALLOCATION (7)
1. SCHEDULE D	$303,638,393	4.82%	0.75	0.51	below	0.90	8.59%	3.77%	$17,982,422
2. SCHEDULE C	$127,670,282	7.85%	1.22	0.82	below	0.90	8.59%	0.74%	$1,477,675
3. SCHEDULE PLG	$380,200	-3.84%	-0.59	-0.40	below	0.90	8.59%	12.43%	$74,294
4. SCHEDULE IS	$39,456,997	11.45%	1.77	1.20	above	1.10	10.49%	-0.96%	($593,189)
5. SCHEDULE AIS	$4,938,559	10.11%	1.57	1.06	within	1.06	10.11%	0.00%	($0)
6. BETHLEHEM STEEL	$21,907,108	11.41%	1.77	1.20	above	1.10	10.49%	-0.92%	($315,567)
7. TOTAL	$497,991,539	6.46%	1.00	0.68		1.00	9.54%	3.08%	$18,625,634

PART 2 - ALLOCATION BASED ON TEST YEAR REVENUES

8. REQUIRED CHANGE IN BASE REVENUE		$29,984,000
9. DEPRECIATION IMPACT FROM CASE NO. 8485		$2,274,000
10. TOTAL INCREASE IN BASE REVENUE		$32,258,000
11. LESS:	REVENUE CHANGE FROM PART 1	$18,625,634
12.	LATE PAYMENT CHARGE CHANGE	$199,887
13.	BALANCING SERVICE BASE REVENUE	$ 346,185
14.	TOTAL ADJUSTMENTS	$19,171,706
15. REMAINING REVENUE TO BE ALLOCATED		$13,086,294

	BASE REVENUE (1)	PERCENT OF TOTAL (2)	REVENUE ALLOCATION (3)	TOTAL REVENUE ALLOCATION (4)	Percentage Rate Increase
16. SCHEDULE D	$116,450,589	65.41%	$8,560,028	$26,542,450	22.8%
17. SCHEDULE C	$42,247,210	23.73%	$3,105,500	$4,583,175	10.8%
18. SCHEDULE PLG	$57,093	0.03%	$4,197	$78,491	137.5%
19. SCHEDULE IS	$10,984,743	6.17%	$807,464	$214,275	2.0%
20. SCHEDULE AIS	$1,380,741	0.78%	$101,495	$101,495	7.4%
21. BETHLEHEM STEEL	$6,905,523	3.88%	$507,610	$192,043	2.8%
22. TOTAL	$178,025,899	100.00%	$13,086,294	$31,711,928	17.8%

Exhibit ____ (PLC-13)
Revenue Increase Allocation

PART 1 - ALLOCATION TO MOVE TO WITHIN THE BANDWIDTH — 15% Bandwidth

FROM 1994 COST OF SERVICE STUDY

	RATE BASE (1)	RATE OF RETURN (2)	RELATIVE ROR (3)	ROR Relative to Target	Relation to Band	TARGET RATE OF RETURN RELATIVE (4)	TARGET RATE OF RETURN PERCENT (5)	CHANGE IN RATE OF RETURN (6)	REVENUE ALLOCATION (7)
1. SCHEDULE D	$303,638,393	4.82%	0.75	0.51	below	0.85	8.11%	3.29%	$15,704,776
2. SCHEDULE C	$127,670,282	7.85%	1.22	0.82	below	0.85	8.11%	0.26%	$519,997
3. SCHEDULE PLG	$380,200	-3.84%	-0.59	-0.40	below	0.85	8.11%	11.95%	$71,442
4. SCHEDULE IS	$39,456,997	11.45%	1.77	1.20	above	1.15	10.97%	-0.48%	($297,215)
5. SCHEDULE AIS	$4,938,559	10.11%	1.57	1.06	within	1.06	10.11%	0.00%	($0)
6. BETHLEHEM STEEL	$21,907,108	11.41%	1.77	1.20	above	1.15	10.97%	-0.44%	($151,238)
7. TOTAL	$497,991,539	6.46%	1.00	0.68		1.00	9.54%	3.08%	$15,847,762

PART 2 - ALLOCATION BASED ON TEST YEAR REVENUES

8. REQUIRED CHANGE IN BASE REVENUE		$29,984,000
9. DEPRECIATION IMPACT FROM CASE NO. 8485		$2,274,000
10. TOTAL INCREASE IN BASE REVENUE		$32,258,000
11. LESS:	REVENUE CHANGE FROM PART 1	$15,847,762
12.	LATE PAYMENT CHARGE CHANGE	$199,887
13.	BALANCING SERVICE BASE REVENUE	$ 346,185
14.	TOTAL ADJUSTMENTS	$16,393,833
15. REMAINING REVENUE TO BE ALLOCATED		$15,864,167

	BASE REVENUE (1)	PERCENT OF TOTAL (2)	REVENUE ALLOCATION (3)	TOTAL REVENUE ALLOCATION (4)	Percentage Rate Increase
16. SCHEDULE D	$116,450,589	65.41%	$10,377,094	$26,081,870	22.4%
17. SCHEDULE C	$42,247,210	23.73%	$3,764,715	$4,284,712	10.1%
18. SCHEDULE PLG	$57,093	0.03%	$5,088	$76,530	134.0%
19. SCHEDULE IS	$10,984,743	6.17%	$978,868	$681,653	6.2%
20. SCHEDULE AIS	$1,380,741	0.78%	$123,040	$123,040	8.9%
21. BETHLEHEM STEEL	$6,905,523	3.88%	$615,362	$464,124	6.7%
22. TOTAL	$178,025,899	100.00%	$15,864,167	$31,711,929	17.8%

Exhibit ____ (PLC-13)
Revenue Increase Allocation

PART 1 - ALLOCATION TO MOVE TO WITHIN THE BANDWIDTH — 20% Bandwidth

FROM 1994 COST OF SERVICE STUDY

	RATE BASE (1)	RATE OF RETURN (2)	RELATIVE ROR (3)	ROR Relative to Target	Relation to Band	TARGET RATE OF RETURN RELATIVE (4)	TARGET RATE OF RETURN PERCENT (5)	CHANGE IN RATE OF RETURN (6)	REVENUE ALLOCATION (7)
1. SCHEDULE D	$303,638,393	4.82%	0.75	0.51	below	0.80	7.63%	2.81%	$13,427,129
2. SCHEDULE C	$127,670,282	7.85%	1.22	0.82	within	0.82	7.85%	0.00%	$0
3. SCHEDULE PLG	$380,200	-3.84%	-0.59	-0.40	below	0.80	7.63%	11.47%	$68,590
4. SCHEDULE IS	$39,456,997	11.45%	1.77	1.20	above	1.20	11.45%	0.00%	($1,241)
5. SCHEDULE AIS	$4,938,559	10.11%	1.57	1.06	within	1.06	10.11%	0.00%	($0)
6. BETHLEHEM STEEL	$21,907,108	11.41%	1.77	1.20	within	1.20	11.41%	0.00%	$0
7. TOTAL	$497,991,539	6.46%	1.00	0.68		1.00	9.54%	3.08%	$13,494,479

PART 2 - ALLOCATION BASED ON TEST YEAR REVENUES

8. REQUIRED CHANGE IN BASE REVENUE		$29,984,000
9. DEPRECIATION IMPACT FROM CASE NO. 8485		$2,274,000
10. TOTAL INCREASE IN BASE REVENUE		$32,258,000
11. LESS:	REVENUE CHANGE FROM PART 1	$13,494,479
12.	LATE PAYMENT CHARGE CHANGE	$199,887
13.	BALANCING SERVICE BASE REVENUE	$ 346,185
14.	TOTAL ADJUSTMENTS	$14,040,551
15. REMAINING REVENUE TO BE ALLOCATED		$18,217,449

	BASE REVENUE (1)	PERCENT OF TOTAL (2)	REVENUE ALLOCATION (3)	TOTAL REVENUE ALLOCATION (4)	Percentage Rate Increase
16. SCHEDULE D	$116,450,589	65.41%	$11,916,428	$25,343,557	21.8%
17. SCHEDULE C	$42,247,210	23.73%	$4,323,171	$4,323,171	10.2%
18. SCHEDULE PLG	$57,093	0.03%	$5,842	$74,432	130.4%
19. SCHEDULE IS	$10,984,743	6.17%	$1,124,072	$1,122,831	10.2%
20. SCHEDULE AIS	$1,380,741	0.78%	$141,292	$141,292	10.2%
21. BETHLEHEM STEEL	$6,905,523	3.88%	$706,644	$706,644	10.2%
22. TOTAL	$178,025,899	100.00%	$18,217,449	$31,711,928	17.8%