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Table 10

STATE OF MARYLAND
PUBLIC SERVICE COMMISSION

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.	Case No. 8473

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF THE

MARYLAND OFFICE OF PEOPLE'S COUNSEL

November 16, 1992

RESOURCE INSIGHT, Inc.
18 Tremont Street
Boston MA 02108
(617)-723-1774

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I. IDENTIFICATION AND QUALIFICATIONS

Q: Please 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: Please summarize your professional education and experience.

A: I received an S.B. degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and an S.M. 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 over 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 need for, cost of, and 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 Attachment 1 to this testimony.

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 the Baltimore Gas and Electric Company (BG&E).

Q: Have you been involved in least-cost utility resource planning?

A: Yes. I have been involved in utility planning issues since 1978, including load forecasting, the economic evaluation of proposed and existing power plants, and the establishment of rate for qualifying facilities. Most recently, I have been a consultant to various energy conservation design collaboratives in New England, New York, and Maryland; to the Conservation Law Foundation's (CLF's) conservation design project in Jamaica; to CLF interventions in a number of New England rulemaking and adjudicatory proceedings; to the Boston Gas Company on avoided costs and conservation program design; to the City of Chicago in reviewing the Least Cost Plan of Commonwealth Edison; to the South Carolina Consumer Advocate on least-cost planning; to environmental groups in North Carolina, Florida, Ohio and Michigan on DSM planning; and to several parties on incorporating externalities in utility planning and resource acquisition. I also assisted the DC PSC in drafting order 8974 in Formal Case 834 Phase II, which established least-cost planning requirements for the electric and gas utilities serving the District.

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 allocations, 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 (MPC) to the DSM collaboratives for PEPCO, WGL and BG&E, as well as more limited roles in collaboratives with Delmarva Power and Potomac Edison. These collaboratives also include the Commission Staff, DNR, and various combinations of other parties. I am generally responsible for issues concerning avoided costs, resource allocation, cost recovery and regulatory policy. I have also been involved in similar collaborative undertakings involving electric and gas utilities in Vermont, New York, and Massachusetts.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING?

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

II. INTRODUCTION

Q: Please describe the purpose of your testimony.

A: This testimony addresses the reasonableness of the contract between Baltimore Gas and Electric (BG&E) and the AES Northside (AESN) generation project, and the validity of BG&E's analysis of that contract's effect on costs to its customers. The AESN project is scheduled to start producing power for BG&E in 1997, but the contract gives BG&E certain limited options to delay the commercial operation date (COD) until 2001.

Q: Please summarize your evaluation of the AESN purchase.

A: BG&E has performed several differential revenue requirement (DRR) analyses of the cost-effectiveness of the AESN contract, each of which compares the installation of AESN in 1997 or 2001 with a reference case without AESN. One set of analyses uses assumptions, such as load growth and fuel prices, from the 1991 Integrated Resource Plan (IRP). These assumptions were already outdated at the time the contract was initially signed, and are even more stale today. Moreover, they are not being used to screen DSM or any other resource. Hence, I do not consider these analyses to have any probative value.

BG&E has also performed a number of DRR analyses based on the assumptions in the 1992 IRP, including some variants on

BG&E's base-case planning assumptions, and various sensitivities for differing load growth, fuel prices, and Perryman performance. In each case, AESN delays the operation of various combinations of BG&E oil-fired combustion turbines (CTs) and gas-fired combined cycle plants, and then avoids the installation of 300 MW of the first BG&E coal-fired plant; in the base case, the first coal plant would be added in 2009.

I have used BG&E's base-case analysis from the testimony of Mr. Meyer as a starting point for my analysis. In BG&E's base-case analysis, the AESN project produces a net present value cost of $55.3 million (1991$) if the AESN project is installed in 1997 (IR DNR-4-1b, Enclosure 1) and a net savings of only $2.1 million with a 2001 in-service date (IR DNR-4-1b, Enclosure 2). Thus, even in BG&E's own evaluations, the proposed AESN agreement appears to be barely cost-effective.

As detailed below, following review of the available relevant information, I have concluded that BG&E's analysis of the AESN contract is seriously flawed and substantially overstates the benefits to ratepayers. Therefore, the Commission should reject the proposed contract. Since the contract should not be approved, it is unnecessary to take any position regarding the rate recovery BG&E may request.

Q: Please summarize the deficiencies in BG&E's analysis.

A: I have identified the following deficiencies:

- BG&E has not evaluated other supply and demand resources on an equal footing with AESN;
- BG&E's Differential Revenue Requirement (DRR) analysis employs unrealistic input assumptions and methods, exaggerating the economic benefits of the proposed AESN purchase; and
- BG&E overstates the value of additional benefits that are not quantified in its DRR analysis.

Q: How is the remainder of your testimony organized?

A: Section III discusses problems in BG&E's analysis of AESN, compared to other resource options. Section IV describes a number of errors in the AESN analysis that overstate the value of AESN. Section V presents my conclusions and recommendations.

III. DIFFERENCES BETWEEN BG&E'S EVALUATIONS OF AESN AND OF OTHER RESOURCES

Q: How is BG&E's treatment of AESN inconsistent with its treatment of other resources?

A: BG&E favors AESN in at least three ways:

- BG&E's analysis of AESN is not integrated with the evaluation of other alternatives. BG&E treats AESN as the only alternative to an uneconomical "straw man" expansion plan.
- BG&E asserts that AESN has a number of special non-price benefits, all of which are either illusory, overstated, or applicable to other resources.
- BG&E does not subject the AESN project to the non-price screening it proposes for other non-utility generation projects.

A. The AESN Project in an Integrated Planning Context

Q: How does BG&E's examination of the AESN purchase overlook other resources options?

A: In BG&E's DRR analysis, the AESN purchase competes only against BG&E-built generating facilities, delaying BG&E-installed Cts and gas-fired combined cycle units and eliminating a 300 MW pulverized coal plant addition in 2009. As discussed in Sections IV.C and IV.E, the BG&E's costs supposedly avoided by AESN are overstated. Thus, BG&E uses a special, high avoided cost for AESN, without allowing other resources to compete with the avoided costs or with AESN.

Under least-cost planning, the AESN purchase should be selected only if it is preferable to all competing resources, not just BG&E-built facilities. The costs avoided by AESN are not necessarily entirely those of BG&E capacity, but may include the costs of some combination of DSM and other non-utility generators (NUGs).

In order to determine whether the AESN project is part of a least-cost resource plan, BG&E could take some combination of the following approaches:

- screen all DSM and supply options under the avoided costs used for AESN, and compare those that pass the screen;
- screen AESN against a mix of BG&E supply, NUGs, and DSM; or
- directly compare AESN to other NUGs in the pending bidding process.

Since the AESN contract, as it is currently configured, is barely competitive with BG&E's own supply options, the current contract is unlikely to survive any of these processes. Of course, AESN would be free to participate in the bidding process which is underway. AESN would also be free to alter the terms of its proposed contract so that it might have a chance to become the successful bidding project.

Q: Would BG&E's commitment to the AESN purchase affect the amount of other resources BG&E will deploy?

A: Yes. If BG&E does not commit to AESN, the size of the supply bid block will be larger. The commitment to AESN would also tend to reduce avoided costs for DSM, potentially resulting in rejection of DSM that would be less expensive than AESN. As discussed in Section III.D, a large amount of cost-effective DSM is not included in BG&E's current plans; some of this potential may be precluded by the reduction in avoided costs and the increase in rates occasioned by BG&E's commitment to AESN.

B. Asserted Unquantified Benefits of AESN

Q: Please describe the additional unquantified benefits BG&E claims for AESN.

A: BG&E claims that the AESN contract will provide several additional benefits:

- It will avoid the need to acquire coal-fired capacity in the future at higher cost because of the "currently depressed market" for coal-fired generating equipment;
- The possibility of retirement of existing coal-fired units increases the value of the AESN purchase;
- The project has transmission benefits;
- The AESN project flexibility permits BG&E to modify timing to match future capacity and energy needs; and
- There are aspects of the proposed AESN purchase that will mitigate any effects on BG&E's cost of capital.

Q: What is your evaluation of these additional benefits?

A: These additional benefits are either illusory, overstated or applicable to other NUGs and to DSM.

Q: Does BG&E assess the current and long-term market in coal-fired generating equipment?

A: No. BG&E provides no detailed information of the current and long-term market conditions. It has not even estimated the duration of the depression or quantified its effect on equipment price (IR MPC-1-34 and 35):

> . . . BG&E did not intend to predict the duration of this current market, but anticipates an increase in orders as a result of Clean Air Act requirements as well as "normal" economic cycles that would tend to limit the time the current situation can prevail.

Q: What is the relevance of the duration of the market depression?

A: BG&E's current analysis of the AESN purchase assumes a 2001 commercial operation date. If the depression is of a short duration, it is unlikely that the purchase rates under the AESN agreement are set to reflect the current depressed market for coal plant. It is difficult to believe that AESN's suppliers would be willing to build a plant in 2001, based on prices driven by current market conditions.

On the other hand, if the depressed market conditions last through the decade, BG&E will have the opportunity to procure coal-fired generation at a later date at restrained prices.

Therefore, in the evaluation of the AESN purchase, current conditions in the market for coal equipment have little, if any, relevance.

Q: Why do you believe that consideration of the retirement of existing coal units is unlikely to improve the economics of the AESN purchase?

A: First of all, there is no reason to believe that Wagner 2&3 and Crane 1&2 will become obsolete or uneconomic within the first ten years of AESN's operation.[1], BG&E has not performed any retirement or cost improvement studies for these four coal units (IR MPC-1-39, 41, and 43) that would indicate otherwise. In fact, according to an October 1992 article in Electrical World, "Baltimore G&E's Crane station finds a new lease on life at 30," the Company has already invested in improvements to the Crane station that have "readied the station for another 15 to 20 years of reliable service."

[1] Unless due to CO_2 concerns.

In addition, if there were a valid concern about the retirement of existing coal plant, it would cut in favor of DSM and other NUGs, as well as the AESN purchase.

Q: Will the AESN purchase have transmission benefits that are unique to AESN?

A: No. BG&E has not performed any quantitative analysis of transmission benefits (IR MPC-1-44). But to the extent that such benefits exist, they apply to competing resources as well as to AESN. The most recent draft of BG&E's Request for Power Supply Proposals gives 70 points out of a possible total of 1000 to projects located in the northern part of the system. This would result in a NUG in the preferred supply area receiving $4/MWH more than an otherwise comparable competitor in the least desired area. BG&E is thus likely to receive a disproportionate number of bids from NUGs in its preferred supply areas.[2]

Q: How has BG&E overstated the flexibility benefits of the AESN agreement?

A: The AESN contract permits the Company to delay the commercial operation date from 1997 to 2001. But this flexibility has to be balanced against the substantial risks BG&E would incur by

[2]BG&E could also engage in more aggressive DSM addressed to the areas in which demand reductions would be most valuable. To date, BG&E has failed to do so (IR MPC-1-45).

committing to the AESN purchase. First, AESN has not established the siting, environmental, or financial feasibility of its project.[3] Waiting for AESN to fail imposes a large cost on BG&E.

Second, BG&E overlooks the reduced flexibility that results from a commitment to the AESN project. The contract provides at most a 4-year delay, which can only be exercised in two steps of up to two years each, at least 49 months prior to the scheduled in-service date (Filing Attachment 3, p. 3). Unlike BG&E-built plant, the AESN contract does not permit annual schedule revisions or any further delay after the start of construction. Since BG&E does not expect AESN to be cost-effective prior to 2001, the contract offers very little useful flexibility.

Third, the lead time on the AESN contract is very long. Even if AESN appeared to be economic in 2001, the contract would commit BG&E to a specific resource, far in advance of its construction start date. The longer the lead time of a resource, the higher the uncertainty about future load and costs, and the more likely it will be that the Company will invest in capacity that is not needed or economic.

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[3]AESN has a history of proposing plants, and even signing contracts, for plants that it cannot build.

Finally, BG&E's analysis of AESN with a 2001 COD indicates that the contract does not break even until 2028 (IR DNR 4-1b, Enclosure 2). This breakeven point occurs 7 years after the 70% reduction in the capacity payment, 27 years after the in-service date of the unit, and 2 years after the end of the initial 25-year term of the AESN contract. BG&E ignores the possibility that after 27 years, continuing operation under the contract payment schedule may no longer be economic for AESN.

Q: Does BG&E demonstrate any cost-of-capital benefits of AESN?

A: No. To the contrary, BG&E suggests that NUG purchases may be treated by rating agencies as debt, increasing BG&E's cost of capital, and reserves the right to request higher rates to cover the resulting costs (Bourquin Direct, p. 5; Filing Attachment 3, p. 13-15; IR MPC-1-49).

Filing Attachment 3 argues that the cost of "this particular contract should be mitigated by several other features" of the contract, including capacity charges that vary linearly with performance (and are thus the same as take-or-pay energy charges), and the fact that the AESN contract in 2001 would replace the "debt like" PP&L purchase.[4] The first

[4]Attachment 3 also argues (twice) that BG&E's cost of capital would not be adversely affected if the Commission gives BG&E more money through an undefined special rate adjustment. Of course,

argument does not hold together; take-or-pay energy charges are the norm in NUG contracts,[5] and BG&E has not even attempted to demonstrate that such charges would reduce the cost-of-capital effect (IR MPC-1-46).

Even BG&E cannot take the second argument seriously, and recants it on discovery, noting that "BG&E's credit rating has not been downgraded for the PP&L purchase" (IR MPC-1-48). In any case, DSM and other NUGs could also replace the PP&L purchase; any advantage given to AESN for entering service about 2001 should also be applied to other resources.

Q: How large a capital cost penalty might AESN impose?

A: BG&E estimates that AESN would add $70 million annually to BG&E's revenue requirements, if the rating agencies treat the entire purchase as take-or-pay, equivalent to debt (IR MPC-1-49). I do not know how BG&E computed this value, and cannot review it. If this value turns out to be correct, the present value of the cost to ratepayers would be $385 million (1991$) for a 1997 COD, or $257 million for a 2001 COD. Even if only 5% of the purchase is treated as debt, BG&E's estimate would

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this would be cold comfort to the ratepayers, who would pay either for higher return or for BG&E's special charges.

[5]If BG&E requested it, most NUG bidders would offer similar terms. However, BG&E does not give any points in its proposed bid evaluation for take-or-pay energy charges as opposed to fixed demand charges.

indicate a cost of $19 million for a 1997 COD and $13 million for a 2001 COD.

C. BG&E's Non-Price Scoring

Q: How would the AESN project fare in competitive bidding?

A: Based on the record in this proceeding, AESN would be disqualified from participating in BG&E's bidding process, or any reasonable bidding process, because AESN has not established the siting, environmental, or financial feasibility of its project.

Q: How does AESN compare to other resources on the non-price point scale BG&E has proposed in its pending RFP for supply resources?

A: AESN fares very poorly on that scale, partly because AESN has refused to provide the information necessary to evaluate the project. If AESN were as uncooperative in the proposed BG&E bidding process, or any reasonable bidding process, as it has been in this docket, it would be disqualified.

Table 1 lists the point score I believe BG&E's rating system would give to AESN, the Perryman combined-cycle plant, and DSM. AESN gets points for AES's experience,[6] transmission

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[6] I have assumed that the rest of the project team will be similarly experienced.

interconnection, reliability of technology, and viability of fuel supply and transmission. For most other categories, AESN gets no other points. As a result, AESN receives 210-230 fewer points than Perryman or DSM.[7]

Q: Can these points be converted to dollar terms?

A: Yes. BG&E also gives points to levelized resource prices. The point score is linear, with a difference of $35/kWh equivalent to 600 points. Thus, BG&E gives one point for each $0.0583/MWH decrease in price. Each one-point decrease in non-price points must be offset by a $0.0583/MWH decrease in price, if the resource is to remain competitive.

This price is nominally levelized over the period 1995-2015. The present value in 1991 of $0.0583/MWH in 1995-2015 is $0.42/MWH. Levelizing the same stream in real terms gives a present value of $0.44/MWH over 1998-2031 and $0.34/MWH over 2002-2035.[8] For a 300 MW unit operating at a 90% capacity factor, each point is worth $1.0 million for a 1997 COD and $0.8 million for a 2001 COD. A resource of the size of AESN, with its 210-point non-price disadvantage, would have to be $217 million less expensive than the alternatives to be

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[7]The BG&E system does not give full credit to DSM for load-following, short lead time, or other benefits.

[8]This value does not include costs in the first partial year of operation.

competitive for a 1997 COD, and $171 million less expensive to be competitive for a 2001 COD.

D. DSM and AESN

Q: Did BG&E screen AESN and DSM with comparable avoided costs?

Q: No. BG&E uses higher avoided costs for AESN than for DSM, even though the analyses were developed contemporaneously.[9] Most importantly, BG&E allows AESN to defer CTs and combined-cycle units and then back out a very expensive coal plant, but restricted DSM to avoiding the first stage of the Perryman combined cycle. DSM should also be assumed to displace the most expensive combinations of supply.

In addition, BG&E appears to have given a much larger environmental credit to AESN than to DSM.

Q: Is additional investment in energy efficiency a realistic alternative to AESN?

A: Yes. The amount of DSM reflected in BG&E's resource plan should be increased to reflect two types of programs. First, BG&E has filed with the Commission plans for programs for which it has not yet estimated impacts, including commercial

[9]DSM is credited with other types of avoided costs, such as transmission and distribution investment, line losses, and planning risk, which are not avoided by AESN or other central supply resources.

HVAC replacement, residential new construction, residential home improvement, and commercial operation and maintenance programs. These load reductions would be additive with those in the plan, to the extent they exceed the "placeholder" BG&E included for Phase II collaborative programs, amounting to 690 GWH and 210 MW by 2001.

Second, BG&E has not yet filed programs to address a number of DSM market segments. For example, BG&E has no program to address:

- residential new construction,
- residential lighting direct installation or mail order,
- commercial equipment replacement,
- small C/I direct installation retrofit,
- large commercial customer installed retrofit (for measures other than HVAC and lighting), and
- comprehensive industrial retrofits.

The load reductions from these programs would also be incremental to the specific programs included in the IRP. Together, these programs could produce savings much larger than BG&E's Phase 2 collaborative "placeholder" DSM.

Q: Is BG&E one of the leading utilities in energy conservation?

A: No. While BG&E has gotten off to a good start, it is still well behind the industry leaders. As shown in Table 2, other collaborative utilities, including PEPCo, are saving 50% to 200% more energy than BG&E, depending on the utility and the time period. BG&E is a couple of years behind the other collaborative utilities, and has lots of room for improvement in its DSM efforts. In addition, even the leading utilities could generally improve their programs.

Q: Dr. Yokell testified on behalf of AESN that BG&E's resource plan assumes an excessive level of demand reduction, 991 MW or a 14% reduction in total peak by 2000 (pp. 18, 20), that BG&E's DSM program is the second-most-aggressive plan in North America, after Duke Power, and that BG&E's plans are probably unrealistic in that context. Is Dr. Yokell correct?

A: No. Dr. Yokell relies on a study his firm "recently conducted" for "a large utility in North America." The study turns out to have been performed in 1989, for Ontario Hydro (IR MPC-4-8).[10] Dr. Yokell's reliance on this study is disingenuous, for at least three reasons. First, the 1989 study was based on the DSM programs planned in 1988 or early 1989, prior to the wave of collaboratives, DSM cost-recovery and incentive orders, and generally heighten expectations for

[10]Dr. Yokell also asserts that utilities only achieve only 60% to 70% of their DSM plans (IR MPC-4-7). He provides no support for that assertion, either in general or specifically for a utility, such as BG&E, that is still low on the DSM learning curve.

conservation. Second, while the 1989 study was intended to reassure Ontario Hydro that its DSM plans were at the leading edge of the industry, Hydro has increased its own program goals substantially since that time. Third, the study did not attempt to determine whether the utility programs were maximizing DSM potential.

Dr. Yokell's assertion that Duke Power's 1988/89 DSM program is the most aggressive in the country, and probably a more aggressive program than BG&E could hope to duplicate, is unfounded. The Duke plan Dr. Yokell presents as the alpha and omega of DSM was limited to programs that passed the rate impact measure (RIM). This spring, Duke filed its first DSM plan not strictly limited by the RIM test, and found much larger DSM potential. Duke has agreed to further accelerate its DSM program in stipulations with intervenors and Commission staff, and should be expanding its program further in the next couple of years.

Dr. Yokell also focusses on peak demand savings, rather than energy, in his comparison of utility programs. Since the AESN project would be base load, its economics are much more sensitive to BG&E's energy use than to peak loads. As shown in Table 2, BG&E's projected energy savings are still quite small.[11] A large portion of BG&E's projected demand reductions, about 30%, are due to load shifting and peak clipping (1992 IRP, Table V-3). These DSM measures are projected to have virtually no effect on sales. As shown in Table 2, BG&E's projections of annual DSM sales reductions due to DSM are much lower than its peak load reduction targets, only 4.7% of annual sales by 2001.

The multitude of errors in Dr. Yokell's DSM analysis are hardly surprising, given his apparent lack of familiarity with the quality of current utility DSM programs (IR MPC-4-11, 4-12).

Q: Have you estimated the potential for additional DSM in BG&E's resource plan?

A: Yes. I asked my staff to estimate the potential for a couple of the programs omitted or underestimated by BG&E. Attachment 3 contains the resulting analysis for just two programs. The first would be focussed on compressor replacement on small commercial HVAC equipment. When the compressor fails, lighting would be retrofit to reduce cooling loads, the entire packaged unit would be replaced with a more efficient and CFC-free unit, downsized to reflect the reduced load. The second

[11]Dr. Yokell proposes reducing BG&E's projected energy savings without any analysis at all (p. 18).

program would similarly intervene in the large commercial chiller market, as equipment fails or operators convert from R-22 to non-CFC refrigerants. Again, lighting loads would be reduced, HVAC equipment downsized, and efficient chilling systems installed; cooling loads would also be reduced by the addition of window film. These programs are not modelled as including other HVAC measures (distribution loss reduction, motor efficiency and sizing, cooling tower piping and pumping, etc.) or about 25% of large commercial space assumed to be served by non-chiller cooling (e.g., roof-top packaged units).

As documented in Attachment 3, the small commercial program would save about 600 GWH and 200 MW by 2001, and the large commercial program would save about 1600 GWH and 530 MW, for a total of over 2000 GWH and 700 MW. In contrast, the IRP's "unidentified" DSM, which must also cover all of the underestimates and omissions listed above, is only 690 GWH and 210 MW by 2001.

Clearly, DSM is a major potential alternative to AESN; BG&E does not examine this option in its analysis.

IV. BG&E's OVERSTATEMENT OF AESN BENEFITS

Q: What biases in the BG&E DRR analysis of AESN have you identified?

A: BG&E's DRR analysis biases the evaluation in favor of the AESN purchase in several ways, including:

- using DSM projections that are too low;
- understating the AESN energy charge;
- overstating the BG&E capital cost savings by crediting AESN with the elimination of coal plant capacity that should not be in the reference expansion plan, by assuming the least efficient type of coal capacity, and by ignoring end effects;
- exaggerating the value of the Maryland coal tax credit; and
- overstating the emission benefits of AESN project.

The subsequent subsections consider these problems in turn.

A. More Aggressive DSM

Q: Has BG&E evaluated the effect of increased DSM on the economics of the AESN purchase?

A: Yes. BG&E suggests that a low load-forecast sensitivity run is a reasonable substitute for a high DSM sensitivity run. BG&E's 1992 IRP includes a low load case that is 1457 GWH and 250 MW lower than the base case in 2001. With these loads, BG&E calculates a present value loss from the AESN project installed in 2001 of $105 million (IR DNR-1-1, Enclosure 3, p.

2). This is a $107 million decrease in net benefits from the base case. Losses would be even larger for the 1997 COD.

Even if some of the savings estimated in Attachment 3 overlap those in other programs, and even if some of the input assumptions were optimistic, sufficient DSM should be available to reduce load to roughly the level of BG&E's low load forecast, which would reduce the benefits of AESN by about $100 million for a 2001 COD (IR DNR-1-1, Enclosure 3).

B. Estimation of AESN Energy Charge

Q: What is BG&E's forecast of the AESN energy charge?

A: The proposed agreement specifies an energy rate of 16.7 mills per kWh (in 1990 dollars) adjusted each year by the preceding year's "escalation in the weighted average price per ton paid for all coal with sulfur content greater than 1.04%, but less than 2.25% which is delivered to all members of PJM from the North Appalachian Supply Region."[12]

According to the PROMOD outputs, BG&E projects an energy rate of 17.50 mills/kWh in 1997, equivalent to an average escalation rate between 1990 and 1997 of only 0.7%/year. For the period between its installation and 2021 (the last year of

[12]The computation is based on the year ended September 30.

the PROMOD simulation runs), the AESN energy rate is projected to escalate at about 3.5% per year.

Q: Why is BG&E's projected escalation rate for AESN so low prior to the 1997?

A: BG&E bases its projection of the AESN energy rate on its forecast of the delivered price for 2-3% sulfur coal to the Crane plant. As shown in Table 3, BG&E projects the cost of Crane coal to escalate at 3.53% annually over the period 1994 through 2023 (BG&E Long Term Fuel Price Forecast, 1992 IRP, Exh IV-B, p. 17). But between 1989 and 1991, the actual cost of Crane coal fell 9% (IRP Exh. IV-B, p. 5). BG&E projects that the cost of Crane coal will remain constant from 1991 to 1992, and rise only 2% annually between 1992 and 1994, leaving 1994 prices 5.5% below 1989 prices. With 2.9% escalation in 1995 and 1996, the 1996 price is equal to the 1989 price.[13] The result is virtually no net escalation for Crane coal or the AESN contract in the period before 1997.

Q: Is the Crane coal price a realistic predictor of escalation in the AESN energy charge?

A: No. In using Crane coal as the basis for its AESN energy charge forecast, BG&E makes two unrealistic assumptions:

[13]For reasons that are not clear, BG&E uses a 1997 price for AESN that is 4.8% higher than the 1990 contract price.

- BG&E assumes that the AESN energy price escalator was negative for 1991 and 1992;

- BG&E assumes that the weighted average price of coal with sulfur content between 1.04% and 2.25% will match Crane mid-sulfur coal price escalation throughout the forecast period.

Q: Why are these assumptions unrealistic?

A: According to the Agreement Analysis and Explanation (p. 4), the actual AESN energy price escalators for 1991 and 1992 are 3.62% and 2.04%, respectively. Attachment 4 provides BG&E's derivation of these figures. While BG&E has not provided data on specific plants or sulfur content, the data are useful, in that they indicate that the monthly data shows the same upward trend as do the annual data. The PROMOD production costing runs assume a cost of $17.50/MWH in 1997, when under the actual escalators, the AESN energy price has already reached $17.7/MWH by 1992 (p. 4).

In addition to its failure to follow the AESN price escalator in 1989-91, the price of Crane mid-sulfur coal is an unreliable predictor of future escalation in the AESN energy rate. It is reasonable to expect that the weighted average price of coal with sulfur content in the range 1.04% to 2.25% (as specified in the AESN contract proposal) would escalate at a greater rate than 2-3% Crane coal, for at least two reasons:

- Crane coal has a sulfur content at or above the high end of the range used in escalating the AESN energy price. In response to Clean Air Act, price for lower-sulfur coals should rise faster than prices for higher-sulfur coals.

- A growing proportion of the mix on the PJM system will be lower-sulfur, higher-priced coal. As a result, the higher-priced coals will be weighted more heavily in the calculation of the AESN energy rate.

Q: Does BG&E's analyses support your assertions?

A: Yes. BG&E's price forecast recognizes that low-sulfur coals will escalate faster than high-sulfur coals (IRP Exh. IV-B, pp. 12-17). BG&E's CAAA compliance plan also includes conversion of Crane from 2.5%S coal to low-sulfur coal at about 1%S.[14]

Q: Have you estimated the effect of more realistic escalation rates on the cost of the AESN contract?

A: Yes. As shown in Table 3, I escalated the contract price at the actual escalation rate reported by BG&E for 1990 and 1991; those rates are used to escalate the price for 1991 and 1992. To be generous to AESN, I assumed the 2% nominal escalation for 1991 continued through 1994, just prior to the Phase I requirements under Title I of the CAAA.

From 1994 on, I used BG&E's fuel price forecast. I assumed that the contract index (PJM 1.04% to 2.25% sulfur

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[14]BG&E reports different percentage sulfur contents in different documents, so all of these figures are approximate.

coal, from Northern Appalachia) would escalate with a mix of Crane 2.5%S and Wagner 1%S coal. I assumed that the mix would be equivalent to 75% Crane coal and 25% Wagner coal in 1994, shifting to 25% Crane coal and 75% Wagner coal by 2000, producing about 5% annual escalation of the index in this period. After 2000, I assumed that the index would escalate with Wagner coal prices.

Q: What was the result of your revision in the AESN energy price escalation rate?

A: For 2000, BG&E projects an AESN energy price of $19.4/MWH. My estimate is $24.4/MWH, 26% higher than BG&E's estimate. The difference in the 1991 present value of the energy charges is about $82 million for a 1997 COD, or $59 million for a 2001 COD.

C. The 2009 Coal Plant

1. Coal versus Gas

Q: Please explain why the BG&E analysis should not credit AESN with backing out a coal-plant addition in 2009.

A: BG&E's own resource evaluations indicate that its planned pulverized-coal plant addition in 2009 is not cost-effective and should not have been included in the reference expansion plan.

Q: Has BG&E performed any analysis of the cost-effectiveness of the coal plant addition in 2009?

A: No. The addition of a 414 MW pulverized coal plant in 2009 in the reference resource plan does not appear to be the result of any economic analysis. BG&E did not even screen alternative supply options for installation in 2009. The 1992 Integrated Resource Plan ends in 2006, and nothing in the 1992 IRP indicates that a coal plant will be an economic option for 2009, or at any other time.

Q: Does the 1992 IRP provide any evidence that indicates that the coal plant is *not* an economic option for 2009?

A: Yes. According to the IRP's PROVIEW screening of supply options, the coal plant is not a cost-effective option for 2001, the only in-service date analyzed. In comparison with a coal plant addition, the gas-fired combined cycle technology is overwhelmingly the preferred option, at least in 2001. With Base Case assumptions, the plan with a pulverized-coal plant is $288 million more expensive than that with a gas combined-cycle (IRP Table V-10). This conclusion is confirmed by the EMA analysis in Appendix 13 to Attachment 3 of the filing.

Q: Could the coal plant become the preferred option in 2009?

A: It appears unlikely. Table 4 extrapolates to 2009 the EMA busbar analysis of coal versus gas combined cycle (IR MPC-1-55). Table 4 shows that the coal plant would have to operate at an implausible capacity factor of 83% to achieve the same busbar cost as the gas plant. BG&E projects that the pulverized-coal plant could achieve a maximum capacity factor of just 79.5% (1992 IRP, Table IV-16).

Q: From your extrapolation of the EMA busbar analysis, can you determine when a coal plant could be the cost-effective option?

A: The coal plant could not be a cost-effective resource at least until 2011, when the breakeven capacity factor falls to 79%. However, the coal plant is unlikely to become the preferred option until much later. The coal plant does not replace gas plant energy on a kWh-for-kWh basis. In the off-peak period, the gas plant operates only about half the time; existing BG&E coal plants and economy energy purchases provide the rest of the off-peak energy. The coal plant thus replaces gas with a 50-60% capacity factor and either does not operate or backs out barely more expensive energy from other coal plants the other 19-29% of the hours that could operate.

In BG&E's base case, the combined-cycle plants operate at an average of 62% in 2008, the last year before the addition of a baseload plant. The coal plant is not cost-effective compared to gas at a 62% capacity factor until 2022. Crediting the coal plant to some extent for backing out slightly more expensive off-peak coal would justify using a higher capacity factor for the screening; at a 70% capacity factor, the coal plant is cost-effective in 2016.

Q: What is the additional cost penalty from adding a coal plant, rather than gas combined-cycle, in 2009?

A: Using the 70% equivalent capacity factor, the levelized cost of the coal plant in 2009 is $1,090/kW-yr, while that of the gas plant is $1,1012/kW-yr, or $78/kW-yr less. The present-value in 1991$ of $78/kW-yr over 30 years is $127/kW. For the 414 MW coal plant, the net cost is $53 million. This analysis is shown in Table 5.

Q: What is BG&E's basis for selecting a coal plant addition for 2009, even though the gas combined-cycle unit produces lower total costs?

A: BG&E's asserts that the pulverized coal plant would be added in 2009 to maintain a targeted optimal fuel mix, the "Opt-Mix" targets mentioned in the IRP, p. IV-20. BG&E asserts that the coal capacity would be added to maintain "a balanced fuel mix" as "the best hedge against [oil and gas price] uncertainties" (Attachment 3 to the filing, p. 12). However, the fuel mix target is not based on risk considerations, but on out-dated fuel price and load projections. In response to IR MPC-1-34, BG&E provided the basis for the fuel mix target, which turned out to be a simple economic analysis of the costs of various expansion plans, performed in 1989. Hence, BG&E's plan for a coal plant in 2009 is without any reasonable basis.

Q: How does BG&E's error in including the 2009 coal plant in its reference plan affect the apparent cost-effectiveness of AESN?

A: The extra cost of 300 MW of coal plant, over a comparable amount of gas capacity, is $38 million in 1991 present value dollars.

2. Pulverized Coal versus CGCC

Q: Would a pulverized-coal plant be the most attractive way for BG&E to reduce fuel price risks or increase fuel diversity?

A: No. There are lower-cost and more effective ways of maintaining fuel diversity and reducing fuel price risk. BG&E's 1992 IRP finds that coal-gasification combined-cycle (CGCC) is preferable to pulverized coal.[15]

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[15]DSM also helps to maintain a balanced system fuel mix by backing out a mix of coal and gas resources.

Q: What in the 1992 IRP indicates that the CGCC is superior to the pulverized coal option?

A: BG&E's IRP notes that as one of the benefits of its Perryman combined-cycle projects is the ability to add coal gasification with a short lead time, if there is a shift in relative fuel prices:

> The Perryman Project is designed with multiple fuel flexibility, to use either natural gas or No. 2 fuel oil, <u>but also, it is designed to allow the addition of a coal gasification plant if economics dictate</u>. (ES-13)

A CGCC is not only the more flexible option; it also appears to be lower cost option.

Q: What are the cost advantages of the CGCC?

A: The CGCC has an 18% higher capital cost (1992 IRP, Table IV-17), but the following cost advantages:

- a 22% lower heat rate (IRP Table IV-17);,
- an availability of 88%, compared to only 80% for pulverized coal (IRP Table IV-16); and
- lower emissions (IRP Exhibit IV-A, Figures 8-1 through 8-9).

In addition, gasification facilities can be added in small 40 MW increments, better matching resources to loads.

Q: Has BG&E performed any economic analysis which supports its choice of a pulverized coal technology over an CGCC?

A: No. In IR MPC 1-9, BG&E claims that "the PROVIEW [technology choice in the 1992 IRP] identified pulverized coal technology as being a lower cost option than coal gasification combined cycle technology." In making this assertion, BG&E misrepresents its IRP results. In 13 of the 15 cases in Table V-10, the PROVIEW analysis indicates that the CGCC is the preferred option for 2001. In the reference case, the system revenue requirements with an CGCC addition in 2001 are lower by $20 million (in NPV 1992 dollars).

Q: Would you expect the CGCC to remain the preferred option in 2009?

A: Yes. In later years, new coal facilities will become more valuable because a greater portion of the production they replace will be gas or oil-fired. Therefore, because the CGCC has a higher availability factor than the pulverized coal option, its cost advantage should improve over time.

Q: How much does BG&E overstate the benefits of AESN, by allowing it to back out the pulverized-coal plant, rather than the CGCC?

A: The net cost of the pulverized-coal plant in the IRP analysis is $695/kW, while that of the CGCC is $593/kW, for a difference of $102/kW. Converting from the 1992 present-value dollars of the IRP to the 1991 dollars used in BG&E's

analysis, and from a 2001 COD to 2009, adds eight years of inflation and removes nine years of discounting, for $57/kW. For the 300 MW of coal capacity BG&E assumes AESN would displace, the present-value savings would be $17 million.[16]

3. End Effects

Q: Has BG&E properly accounted for the costs of the avoided coal capacity?

A: No. In the AESN cases, BG&E removes the nominal ratemaking costs for 300 MW of coal, over the first 23 to 27 years of its life. The BG&E analysis credits AESN with avoiding the highest cost years of the BG&E-built coal plant's life.

Q: Why is this a problem?

A: The BG&E analysis assumes that the reference case and AESN case systems are identical at the end of the analysis period. This assumption is incorrect. In the reference case, without AESN installed in 2001, the system has an extra baseload coal plant that is only 23 to 27 years old at the end of the analysis period. This plant is likely to be an economic resource for many more years. On the other hand, if BG&E commits to the AESN purchase, it will need a new replacement

[16] Since the net loss from selecting the pulverized-coal plant over the gas combined-cycle is $38 million, the net loss of selecting the CGCC over gas would be $21 million.

resource when the contract is terminated. The AESN project does not eliminate the 2009 capacity addition, it just defers it.

BG&E's evaluation of the AESN purchase must be corrected take into account the differences between the reference case and the AESN case after the end of the analysis period, or "end effects."

Q: How can BG&E's analysis be corrected?

A: The simplest way to account for end effects is to restate the annual capital costs of the new coal plant in real-levelized terms, so that the annual cost of the unit in any particular year will be the same, regardless of the year in which it is installed. The analysis of the AESN contract would then properly credit the proposed agreement with the benefit of deferring a BG&E capacity addition, not with eliminating only the expensive early years of the plant.

Q: Have you determined a correction for end effects?

A: Yes. BG&E's overstates the 1991 net present value benefit of AESN in 1997 by $28 million and in 2001 by $16 million. My calculations are provided in Table 6.

D. Maryland Coal Tax Credit

Q: Why is BG&E's valuation of the Maryland coal tax credit excessive?

A: The contract provides that AESN will pass through to BG&E any portion of the $3/ton Maryland coal tax credit that AESN receives and can utilize. BG&E's analysis assumes that AESN will use Maryland coal, even though AESN will have no incentive to do so (IR MPC-1-26). Maryland coal is not cost-competitive for any of BG&E's own plants, either currently or after compliance with the CAAA (IR MPC-1-27),[17] and neither BG&E nor AESN has offered any reason to believe that it will be the lowest-cost coal for AESN. In addition:

- BG&E assumes that the current tax credit will continue indefinitely, without any basis (IR MPC-1-28).
- BG&E assumes that AESN will be able to reduce its Maryland tax bill by the mount of the coal tax credits earned, even though BG&E does not know when AESN is likely to be profitable for tax purposes, or whether the tax credit can be carried forward to profitable years (IR DNR-2-2).

Q: What is the effect of including the tax credits?

A: The tax credit reduces BG&E's estimate of the cost of the AESN case by $13 million for a 1997 COD and by $9 million

[17]BG&E does not know whether any other plants in Maryland use Maryland coal.

for a 2001 COD. The benefits of AESN should therefore be reduced by those amounts.

E. BG&E's Estimate of Avoided Environmental Costs

Q: How does BG&E value the environmental benefits of AESN?

A: BG&E gives AESN credit for reductions in BG&E's own emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_x). The credit ignores emissions of these pollutants from AESN. The credit is $500/ton SO_2 and $2500/ton NO_x in 1995, escalating at 4.25%.

Q: Is BG&E's treatment of environmental benefits appropriate?

A: BG&E's approach is too limited to reflect the environmental benefits to society in general, or even to its ratepayers and other residents of Maryland. BG&E includes only an estimate of the "market value" of reduced SO_2 and NO_x emissions by BG&E facilities, on the grounds that these pollutants are regulated under Title IV (the acid-rain section) of the 1990 Clean Air Act Amendments (CAAA). BG&E thus excludes

- any value of other regulated air pollutants, including particulates and heavy metals;
- any value of currently unregulated air emissions, including carbon dioxide (CO_2) and other greenhouse gases;
- any value of non-air environmental effects, including the generation of solid wastes, thermal and chemical pollution of water, and the consumption of water;

- the health, ecological and quality-of-life benefits of SO_2 and NO_x reductions, to the extent they exceed the "market value"; and

- the costs to BG&E, its ratepayers, and Maryland as a whole of meeting the stricter NO_x requirements under Title I (the ozone title) of the CAAA.

Q: Which aspects of the emissions analysis has BG&E treated properly?

A: Yes. BG&E assumed that a market value of SO_2 of $500/ton in 1995$, or roughly $400/ton in 1990$. This is a reasonable estimate of the market value of SO_2 allowances required under Title IV in 1995 for Conemaugh and Crane, and in 2000 for all BG&E steam plants. Every additional ton of SO_2 BG&E plants emit will force BG&E to buy one more allowance, or sell one less allowance.

Q: What are the problems with BG&E's calculation of environmental benefits for AESN?

A: There are at least five such problems.

- BG&E incorrectly assumes that Title IV of the CAAA will create a market value for NO_x.

- BG&E incorrectly assumes that all of its units will be covered by the SO_2 allowance requirements of CAAA Title IV by 1997.

- BG&E fails to reflect the increased costs to its ratepayers due to the NO_x emissions from AESN.

- BG&E overstates the emissions from its own plants in at least five ways.

- Perhaps most egregiously, BG&E includes emission benefits in its evaluation of AESN, but not for any other NUG (including Cogen Technologies and the proposed bidding) or for DSM.

Q: How has BG&E erred in assuming that Title IV of the CAAA will create a market value for NO_x?

A: Title IV requires reduction in NO_x emission rates for affected units, through the installation of low-NOx burners or comparable technology.[18] There is no allowance or trading system for NO_x.

Title I of the CAAA requires the State of Maryland to reduce NO_x emissions to meet ambient ozone limits. The Maryland Air Management Agency (MAMA) could create a trading system for major NOx emitters, as part of its compliance strategy; such trading systems are encouraged by the EPA. However, BG&E clearly believes that its \$2,500/ton NO_x value is based on Title IV, and that Title I requirements would impose additional costs (Filing Attachment 3, p. 8).

BG&E's treatment of NO_x does not really represent a realistic treatment of costs under Title I, either. As discussed below, any NO_x emissions from AESN will impose additional costs to BG&E, its customers, or other parts of the Maryland economy, to achieve the additional NO_x emission

[18]EPA has proposed to define "low-NO_x burners" to include other combustion modifications, such as over-fired air.

reductions required to offset AESN's emissions. In addition, $2,500/ton is an underestimate of the value to Maryland under Title I of the benefits of NO_x reductions. Achieving the CAAA ozone standard will probably require the installation of selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR), at costs of $6,000/ton or greater.[19]

Q: How has BG&E erred in assuming that all of its units will be covered by the SO_2 allowance requirements of CAAA Title IV by 1997?

A: As shown in IR DNR-4-2, BG&E has included SO_2 costs for all units starting in 1997, even though only Conemaugh and Crane are covered prior to 2000. Reductions of emissions from other units prior to that time have no market value.[20]

Q: How would the NO_x emissions from AESN increase costs to BG&E ratepayers?

A: Under the CAAA, all areas of the country are required to start making progress toward meeting the federal ozone standard of 0.12 ppm. The Baltimore area has been classified as a Severe Ozone Nonattainment Area, with an ozone design value is 0.19

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[19]New England Electric recently announced plans to install low-NO_x burners and SNCR on its Salem Harbor coal-fired plant in Massachusetts.

[20]In addition, BG&E includes allowance values for all of its CTs, even though several of its CTs are smaller than the 25 MW limit on coverage for the allowance program.

ppm.[21] Given this classification, Baltimore must comply with a number of requirements, including:[22]

- attaining the national ambient air quality standard (NAAQS) for ozone of 0.12 ppm within 17 years, or by 2007;
- reducing vehicle miles traveled, through government action and though mandatory employer vehicle occupancy reduction plans;
- installing gasoline vapor recovery (stage II);
- submitting to EPA a clean-fuel vehicle program for fleet vehicles;
- enhancing inspection and monitoring programs for motor vehicles;
- applying new source review requirements to new and modified major VOC and NO_x sources (i.e., those with the potential to emit over 25 tons/year), including
  - offsets of 120% of emissions if Best Available Control Technology (BACT) is required for existing sources, or else offsets of 130%;
  - 130% internal offsets for some modifications of existing facilities;
- requiring Reasonably Available Control Technology (RACT) on all existing major stationary VOC and NO_x sources;

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[21] The design value is the fourth highest reading of ozone concentration, taken over a 24-hour period.

[22] See National Research Council (1991), p.70; Sidley & Austin, (1991); US EPA (1990).

- reducing VOC emissions by 15% from 1990 levels by 1996, or the equivalent in combined VOC and NO_x reductions;[23]
- reducing VOC emissions (or the equivalent in NO_x and VOC) by another 3% annually until attainment; and
- demonstrating that the 3% reductions have been achieved on an average basis every three years.

The CAAA also includes Maryland in the Northeast Ozone Transport Region, which includes New England, New York, New Jersey, Pennsylvania, Delaware, DC, and part of Virginia. Since NO_x emissions in one state (such as in Maryland) may contribute to downwind ozone concentrations (as in New Jersey or New York), the Transport Region is expected to coordinate compliance strategies, and may recommend additional regional requirements to EPA if not all states meet their obligations.

The NO_x requirements can be waived by EPA if it determines that NO_x reductions would not be helpful in reducing ozone. Recent research indicates that NO_x is particularly important in ozone formation in the Northeast (National Research Council, 1991). Maryland's NO_x contributes to ozone formation in Maryland, and then blows northeastward to contribute to ozone formation in New Jersey and New York.

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[23]These reductions are in addition to those achieved through mandated controls, such as on motor vehicle tailpipe emissions and fuel volatility, and through compliance with regulations promulgated before 1990.

Exemptions from NO_x-reduction requirements are unlikely for Maryland.

Given this statutory structure, and the importance of NO_x in contributing to ozone problems in the Northeast, BG&E's treatment of AESN's NO_x emissions is clearly incorrect. If AESN is constructed and operated, it will emit NO_x.[24] The more NO_x AESN emits, the more NO_x reductions will be required of other Maryland emitters. BG&E or other utilities may be required to install expensive SCR and SNCR on their existing plants, or industries may be required to retrofit smaller boilers, or automobile traffic may be limited. One way or the other, Maryland will bear the burden of countering AESN's emissions.

Q: Would the costs to the state be reduced if AESN is required to obtain NO_x offsets?

A: Perhaps in part. AESN may use a low-cost offset, requiring some other facility to seek more expensive offsets. Any offsets that AESN is required to purchase will internalize

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[24]Recall that BG&E completely ignores AESN's NO_x emissions. AESN will emit more NO_x per kWh than DSM, BG&E combined-cycle plants (operating on gas or gasified coal), or combined-cycle NUGs. Even if AESN were displacing a higher-NO_x resource (such as BG&E's hypothetical and unlikely pulverized coal plant), BG&E's treatment understates AESN's costs. Since AESN has not provided either BG&E or the Commission with its own emissions, the Commission cannot find that AESN would have any environmental benefits.

some of the costs it will be imposing on Maryland, but not all of the costs. If offsets turn out to be priced at the marginal cost of compliance (which is likely to fall in the $6,000-$10,000/ton range), the financial viability of the AESN project may be threatened.[25]

Q: What is the basis for your estimates of the costs of complying with the ozone requirements of the CAAA?

A: I have not seen any Maryland-specific analysis. However, both New York and New Jersey have warned their utilities to prepare for retrofitting of SCR on existing power plants. NESCAUM also projects a need for SCR or SNCR on existing boilers.[26] The downwind states of the Northeast Ozone Transport Region are unlikely to impose these requirements on themselves without also insisting on application of similar measures in Maryland.

A number of high-ozone states require SCR on new combined-cycle and cogeneration plants. The Texas Air Control Board has required selective catalytic reduction (SCR) to

[25]Unfortunately, AESN has refused to provide any information on its financial viability or emissions, so the parties and the Commission cannot determine whether the threat to AESN's viability is significant.

[26]Massachusetts has just reached agreement with the New England Electric Company to require retrofit of low-NO_x burners and SNCR at the Salem harbor coal plant.

achieve 9 ppm NO_x on gas turbine cogenerators of more than 10 MW, unless they can reduce emissions less than 15 ppm without SCR (Hamilton, 1991).[27] TACB has estimated that the cost of SCR for a recent cogeneration application, reducing emissions from 25 ppm to 9 ppm, was \$6,627/T NO_x. The cost per ton would be higher for small units. Houston Lighting & Power expects that TACB will require future combined-cycle plants to use SCR, even with low-NO_x burners, reducing NO_x emissions from 15 ppm to 5 ppm. Assuming that the cost per kW-year is the same for the decrement from 15 to 5 ppm as for 25 to 9 ppm, the smaller reduction in emissions would increase the control cost to \$10,600/T.[28] The NO_x requirements for new units in Maryland and other northeastern states are comparable to the existing Texas standards; as part of their implementation plans, the Northeast will move towards the stricter limits.

This discussion has only considered controls on utility plants. The marginal cost of control for NO_x in the Baltimore area may well be higher than the marginal cost required for

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[27]The waiver of SCR on these low-NO_x units is based on both the cost of the SCR and on the inevitable "slip" of ammonia from the SCR system. TACB measures NO_x dry at 15% O_2.

[28]This estimate may be on the low side, even for the TACB example unit, since the lower concentrations may require more catalyst area to achieve the same percentage reduction. For small units, the cost would be even higher.

new utility plants or for retrofits to existing utility plants, and may include controls on industrial boilers, transportation controls, or other measures.

Q: How has BG&E overstated the emissions from its own plants?

A: BG&E has overstated the emissions from its own plants in at least five ways:

- SO_2 emission rates will fall as BG&E complies with CAAA Title IV,
- the NO_x emission rates for a new coal plant would be lower than assumed by BG&E,
- NO_x emission rates will fall as BG&E complies with CAAA Title IV,
- NO_x emissions will fall further as Maryland and BG&E comply with CAAA Title I, and
- BG&E will include market emission costs in its dispatch decisions, leading to lower total costs.

Q: How did BG&E overstate the future SO_2 emission rates for its power plants?

A: BG&E assumes that SO_2 emission rates remain at current levels throughout the period 1997-2035. Table 7 summarizes the emission rates BG&E assumes for each unit affected by Title IV. These emission rates are unrealistic beyond 1995 for Conemaugh and Crane, and beyond 2000 for all the other steam plants.

Title IV of the CAAA requires BG&E to use one allowance for each ton of sulfur emitted by affected units. BG&E's

affected units are Conemaugh and Crane in Phase I (1995), and all steam units in Phase II (2000). BG&E, like any other utility, can meet that requirement by any combination of reducing emissions and increasing supply of allowances.[29] According to BG&E's CAAA Compliance Plan (Exhibit IV-K to the 1992 IRP), BG&E is planning to comply by:

- scrubbing Conemaugh by 1995,
- switch Crane to low-sulfur Pocahontas coal by 1995,
- scrubbing Keystone by 2000, and
- switch Wagner 2&3 to compliance low-sulfur coal by 2000.[30]

Table 7 computes the percentage reductions and the controlled emission rates implied by the Compliance Plan. Depending on the plant, the reductions vary from 16% to 95%.

Q: Why do you believe the NO_x emission rates for a new coal plant would be lower than assumed by BG&E?

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[29]Allowances are obtained as allocations to existing units; bonuses for scrubbing, conservation, and other special compliance strategies; and as purchases from other utilities.

[30]In addition, BG&E is likely to find changes in the fuel used at its gas/oil plants will be cost-effective. While BG&E found that switching from 1% sulfur oil to 0.3% sulfur oil was not cost-effective, a more modest decrease (say, to 0.7% sulfur) is likely to be less expensive per ton of SO_2 avoided. Using gas may also remain cost-effective further into winter months.

A: BG&E assumes that, absent AESN, it would build a pulverized-coal plant in 2009 with NO_x emissions of 0.50 lb/MMBTU. This value is too high for a new pulverized-coal plant, and BG&E should not be planning a pulverized-coal plant in any case. Other recent coal-fired power plants have achieved NO_x emission rates in the range of 0.30-0.35 lb/MMBTU. For example, for its Cope coal-fired plant, South Carolina Electric and Gas has proposed a maximum hourly emission rate of 0.34 lb/MMBTU in an ozone attainment area. Houston Lighting and Power expects its future coal plants to emit 0.31 lb/MMBTU. Since existing boilers can (and generally will be required to) achieve emission rates of less than 0.50 lb/MMBTU with combustion retrofits, it is unlikely that BG&E would be allowed to build a new coal plant with these very high emission rates, in one of the country's worst ozone areas.

As discussed in Section IV.C, BG&E should not be planning on building a pulverized-coal plant in 2009. A gas-fired combined-cycle plant is likely to be less expensive than any coal plant; if coal is the preferred fuel, a gasification combined-cycle plant would be less expensive than pulverized coal. BG&E projects that its new gas-fired combined-cycle plants will produce 0.09 lb/MMBTU on gas, and 0.29 lb/MMBTU on oil,[31] and that coal-gasification combined-cycle plants will produce 0.15 lb/MMBTU NO_x.[32]

Q: How did BG&E overstate the future NO_x emission rates for its existing power plants?

A: BG&E assumes that NO_x emission rates remain at current levels throughout the period 1997-2035. Table 8 summarizes the emission rates BG&E assumes for each unit. These emission rates are unrealistic beyond the middle of this decade, given two provisions of the CAAA.

Title IV of the CAAA requires that each power plant covered by the SO_2 allowance system install low-NO_x burners by the time it is covered.[33] For BG&E, Conemaugh and Crane are covered in 1995, and all other fossil-fueled steam units are covered in the year 2000. As discussed above, NO_x emissions in Maryland will also have to be reduced to comply with Title I of the CAAA. Thus, BG&E's NO_x emissions will decline considerably, with or without AESN.

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[31]Houston Lighting and Power expects new gas-fired combined-cycle plants to produce just 0.06 lb/MMBTU without SCR.

[32]Destec, the manufacturer of one coal gasification process, claims emissions of 0.08 lb/MMBTU.

[33]EPA may define "low-NO_x burners" to include other combustion modifications.

Q: How much would you expect the emissions of BG&E's existing plants to decline as a result of CAAA Title IV implementation?

A: Table 8 lists my understanding of BG&E's estimates of its coal units' emission reductions under the requirements of Title IV.[34] Except for Brandon Shores, BG&E expects that NO_x emissions from its coal plants would decrease by 38% to 50%.

BG&E's estimated emission reductions are probably understated, since EPA has proposed to define "low-NO_x burners" to include other combustion modifications, such as over-fired air. With over-fired air, the emissions would be more like those in column 3 of Table 8, which are the based on MAMA's proposed RACT control requirements under Title I. Emissions from Brandon Shores would decrease 22%, while those from the older coal plants would fall 53%-67%, and emissions from the oil/gas steam plants would decrease 31%-50%.

Q: How much would you expect the emissions of BG&E's existing plants to decline as a result of CAAA Title I implementation?

A: MAMA has released draft regulations on RACT requirements for utility boilers. These regulations would require utility boilers to reduce emissions by May 15, 1995 to

- 0.25 lb/MMBTU for dual-fueled gas/oil steam units,

[34] The NO_x sections of BG&E's CAAA Compliance Plan are not very clear about BG&E's expectations for emission reductions at particular units.

- 0.38 lb/MMBTU for dry-bottom tangential- and wall-fired pulverized coal plants, and
- 0.55 lb/MMBTU for cyclone-boiler coal plants.[35]

BG&E's coal plants are all dry-bottom,[36] except for the Crane units, which have cyclone boilers. The emission limits are maxima for 24-hour periods, implying that the annual average emission rates would be somewhat lower.

In addition, the Northeast States for Coordinated Air Use Management (NESCAUM), which is composed of the eight downwind states of the Northeast Ozone Transport Region, has issued guidelines on NO_x RACT requirements for both utility boilers and utility combustion turbines. NESCAUM, most parts of which have lower ozone levels than Baltimore, has reached preliminary agreement to require Phase 1 combustion reductions by May 15, 1995 to

- 0.25 lb/MMBTU for dual-fueled gas/oil steam units,

[35]Alternatively, utilities may average emissions across units to achieve the same total reductions, or may demonstrate that a lower level of reduction is as much as is "reasonably achievable." Since MAMA has proposed to impose strict and expensive Lowest Achievable Emission Rate (LAER) requirements for new sources (IR MPC-1-38a), "reasonably achievable" controls for existing sources will also presumably be quite expensive.

[36]Wagner 3 uses 3-cell burners, but BG&E anticipates conversion of this unit to wall-firing for CAAA compliance (IRP Exhibit IV-K, Appendix G, p. 5).

- 0.33 lb/MMBTU for dry-bottom tangential- and wall-fired pulverized coal plants, and
- 0.55 lb/MMBTU for cyclone-boiler coal plants.

The NESCAUM emission limits are stricter than MAMA's proposal in two respects. First, they are maxima for one-hour periods, implying that daily average emission rates would be somewhat lower, and annual averages lower still. Second, the requirements for dry-bottom coal plants are tighter than MAMA's. NESCAUM's recommended RACT emission limits for existing combustion turbines, based on low-NO_x burners or steam/water injection, are equivalent to emission rates of 0.19 lb/MMBTU firing gas and 0.30 lb/MMBTU firing oil.

By May 15, 1999, NESCAUM is preparing to add Phase 2 post-combustion controls (either selective catalytic reduction, SCR, or selective non-catalytic reduction, SNCR) to bring gas and oil plant emissions down to 0.10 lb/MMBTU and coal plant emissions to 0.20 lb/MMBTU.

Table 8 summarizes three levels of emission reductions: BG&E Title IV projections, MAMA/NESCAUM Phase 1 proposals, and NESCAUM's Phase 2 proposals.

Q: Why should BG&E have included SO_2 and NO_x in the computation of dispatch order in its PROMOD production costing runs?

A: BG&E asserts that the SO_2 and NO_x values it assumes will vary with plant output. This will actually be the case for the SO_2 allowances; one allowance will be consumed with each ton of SO_2 emitted, just as limestone is used up in a scrubber. Therefore, these are variable O&M costs, which will be included in BG&E's dispatch.

Q: What is the effect of correcting BG&E's projection of its NO_x emission rates?

A: MPC asked BG&E to rerun PROMOD with the cost-effective and expected SO_2 and NO_x emission rate reductions, and with the residual cost of the SO_2 and NO_x emissions included in dispatch costs. Despite the fact that BG&E has performed multiple PROMOD runs for other parties, BG&E refused to perform these runs for MPC, asserting that it does not know what the market value of SO_2 and NO_x emissions will be (IR MPC-1-14). This is a peculiar response, since BG&E has selected SO_2 and NO_x values to use in justifying AESN.

Since BG&E refused to run PROMOD with realistic emission rates, I have estimated the effect of such rates. Attachment 2 to this testimony summarizes the NO_x reductions BG&E attributes to operation of AESN, and corrects them to reflect realistic emission rates for existing and future plants.[37] Table 9 summarizes the resulting system NOx emission reductions. BG&E estimated that AESN's effect on its systems SO_2 and NO_x emissions would be have a 1991 present value of $70 million for a 1997 COD and $58 million for a 2001 COD. With BG&E's expected Title IV emissions reductions, the AESN NO_x benefit would be reduced by $3.7 million in 1991 present-value dollars for a 1997 COD and $0.4 million for a 2001 COD. With BG&E's expected Title IV emissions reductions and realistic emission rates for a new pulverized-coal plant without selective reduction, benefits fall by $19.2 million for a 1997 COD and $17.0 million for a 2001 COD. With the Maryland Title I combustion controls on boilers, NESCAUM Phase 1 combustion controls on CTs, and realistic emission rates for a new pulverized-coal plant, the AESN NO_x benefits would be reduced by $21.3 million for a 1997 COD and $17.4 million for a 2001 COD. With the Phase 2 controls and the more realistic gasified coal technology, the NO_x benefit would fall by $39.7 million for a 1997 COD and $37.1 million for a 2001 COD.

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[37]BG&E's emission summaries do not list emissions from the combined-cycle plants, which are apparently incorporated in some other way. I have therefore implicitly accepted BG&E's treatment of combined-cycle emissions, and computed a correction to the emissions of other units.

This revision does not include AESN's NO_x emissions, which AESN has refused to provide; reduced SO_2 emissions due to Title IV compliance; or any reduction in emissions due to BG&E dispatch. Even so, this one correction eliminates BG&E's estimate of the net benefits of AESN, by a factor to 8-18 times.

Q: Why is it improper for BG&E to include emission benefits in its evaluation of AESN, but not for any other NUG (including Cogen Technologies and the proposed bidding) or for DSM?

A: If BG&E's approach were correct, all these resources should be credited with emission reductions. By selecting a high-cost resource and selectively giving that resource a special credit for emission reduction, BG&E has failed to properly follow least-cost planning principles.

F. AESN's Claimed Offsetting Understatements of Benefits

Q: In Dr. Yokell's testimony, AESN has asserted that BG&E's computations of benefits for AESN are understated. Do any of his points have merit?

A: Perhaps. I have previously discussed the weaknesses of Dr. Yokell's claim that BG&E's DSM plans are too optimistic. The remainder of his points can be divided into two groups: the price of Perryman fuel and the performance of the Perryman plant. On the latter issue, I would agree with Dr. Yokell that realistic capacity and heat rate values should be used for Perryman. If his complaints are correct, the avoided costs for DSM and for the bidding analysis should be increased.

I am not sure whether Dr. Yokell is testifying that there is some risk of higher gas prices, as on page 15 of his testimony, or whether he is testifying that gas prices will be higher, as implied by his recommendation that the Commission use higher prices in evaluating the AESN contract. In any case, he has not accounted for BG&E's ability to convert its combined-cycle plants to coal, should the need arise.

While I do not generally get involved in the thankless task of forecasting fuel prices, I find some of Dr. Yokell's arguments to be nonsensical or disingenuous. For example, on page 25 he asserts that

> Gas DSM programs may increase the load factor of firm gas customers . . . Firm gas customers may shift load from peak to "shoulder-peak" periods, thereby increasing pipeline capacity utilization.

These are odd suggestions. Most DSM programs do not change end-use load factors; weatherization programs decrease load factor, since they have a larger percentage effect on shoulder loads than peak loads. Dr. Yokell's explanation of his testimony does little to strengthen his argument:

> The statement is based on a logical proposition. By their very nature, DSM programs are designed to alter load factors. Depending on the utility's needs, a DSM program may raise or lower the load factor of a particular customer. (IR MPC-4-18)

Changing load factors is not a primary objective of most gas DSM. In any case, the discovery response appears to recant Dr. Yokell's suggestion that gas DSM will tend to reduce interruptible gas availability, and retreats to a position that gas DSM could either increase or decrease interruptible gas availability.

Few firm gas customers can shift loads by weeks or months to move from peak periods to shoulder periods. Dr. Yokell is unable to provide any example of how this load shifting could occur, and defends his testimony as "a logical proposition regarding how firm gas customers <u>may</u> behave" (IR MPC-4-19).

Dr. Yokell's discussion (pages 26 and 27) of the pipeline interruptions in the winter of 1989-90 is more obviously misleading. Dr. Yokell describes this as "a reasonably typical winter" (p. 27, line 8). In fact, 1989-90 was one of the least typical winters in history. December 1989 was the coldest December on record in much of North America, resulting in rapid depletion of gas storage. For Baltimore, December 1989 was colder than all but one month in the last thirty years (IR MPC-4-22). Interruptions continued after the cold wave, as storage was refilled.

As shown in IR MPC-4-35, interruptions were much lower in 1991-92, despite load growth and almost perfectly normal weather (at least in Baltimore). Columbia interrupted ITS service on 18 days, versus 46 in 1989-90; Transco interrupted service on 83 days, versus 106 in 1989-90.

V. CONCLUSIONS AND RECOMMENDATIONS

Q: Please summarize the results of the adjustments you describe above.

A: Table 10 summarize those results. The eight adjustments I am able to quantify total nearly $400 million for a 2001 COD, and more for a 1997 COD. Clearly, the $2 million benefit BG&E estimates for the 2001 COD would be swamped by these adjustments; the AESN contract is just not beneficial.

Q: What is your recommendation to the Commission?

A: I recommend that the Commission reject the proposed contract, but allow AESN to participate in BG&E's bidding.

Q: Does this conclude your testimony?

A: Yes.

Table 1: Comparison of Resource Scores under BG&E Proposed Non-Price

	Non-Price Category	Maximum Points		AESN	Perryman	DSM
A	Environmental Permitting Certainty	50		0	50	50
B	Financeability	50			50	50
	1 Financing Experience		10	10		
	2-6 Coverages and Other Criteria		40	0		
C	Commercial Operation Date Certainty	50			50	50
	1 Environmental Permits		7	0		
	2 Zoning and Land Use		7	0		
	3 Construction		7	0		
	4 Engineering		7	0		
	5 Financing		7	0		
	6 Fuel Supply		7	7		
	7 Transmission Viability		8	8		
D	Level of Project Development	70		0	70	70
E	Reliability of Technology	30		28	30	30
F	Project Experience	40			40	40
	1 Generation		12	12		
	Transmission		10	0		
	Financing		8	8		
	2 Engineering		3	3		
	Environmental		3	3		
	Financial		3	3		
	Fuel Acquisition		1	1		
G	Electric Interconnection Point	70		70	70	35
H	Fuel Supply Certainty	20		0	0	20
I	Project Reliabilty	20		0	20	20
	TOTAL	400		153	380	365

TABLE 2

Comparison of Baltimore Gas & Electric Conservation Goals to Those of Leading Utilities

	Projected sales (GWh) [1]	Projected sales growth (GWh) [2]	Planned energy savings (GWh) [3]	Energy savings growth (GWh) [4]	Growth in GWh savings as % of sales growth [5]	GWh savings as % of sales [6]
1992-1996						
Potomac Electric - Maryland	15,227	1,621	892	892	55.0%	5.9%
Baltimore Gas & Electric	28,922	3,810	685	685	18.0%	2.4%
1992-2001						
Northeast Utilities, including newly acquired PSNH	39,453	8,051	2,894	2,894	35.9%	7.3%
Northeast Utilities, w/o PSNH	30,493	5,876	2,419	2,419	41.2%	7.9%
Baltimore Gas & Electric	31,960	6,848	1,516	1,516	22.1%	4.7%
1993-2003						
Pacific Gas & Electric	94,587	13,854	7,451	7,451	53.8%	7.9%
Baltimore Gas & Electric	33,272	7,528	1,806	1,736	23.1%	5.2%
1992-2007						
United Illuminating	6,983	1,749	654	654	37.4%	9.4%
New England Electric System	31,011	7,713	2,692	2,136	27.7%	6.9%
Sacramento Municipal Utility District	13,740	4,710	2,766	2,726	57.9%	19.8%
Baltimore Gas & Electric	35,838	10,726	2,258	2,258	21.1%	6.3%
1993-2007						
New York State Electric and Gas	19,405	4,145	1,559	1,328	32.0%	6.8%
Baltimore Gas & Electric	35,838	10,094	2,258	2,188	21.7%	6.1%

TABLE 2

Notes:

[1]:	Sales figures are for the final year of the interval indicated, and are pre-DSM forecasts; that is, they do not take into account reductions due to DSM.
[2]:	[1] minus the sales of the year preceding the first year of the specified interval.
[3]:	Energy savings are for the final year of the interval indicated.
[4]:	[3] minus the savings of the year preceding the first year of the specified interval.
[5]:	[4]/[2]
[6]:	[4]/[1]

Sources:
Baltimore Gas & Electric from 1992 Integrated Resource Plan. The 1991 load forecast and DSM impacts f
Integrated Resource Plan.

NEES, "Integrated Resource Management Draft Initial Filing: Technical Volumes," May 20, 1991, pp. I-8, I

NYSEG figures from NYSEG's 1992 DSM filing.

Northeast Utilities data from Northeast Utilities, "1991 Forecast of Loads and Resources for 1992-2011," (March 1,1992).

United Illuminating data from UI's "Report to the Connecticut Siting Council," (3/1/92).

SMUD data from their "1991 Load Forecast," April 30, 1991.

PG & E data from "Form R-6.6," page 4 and CEC's "Electricity Report," Table 2-4, September 1992.

Potomac Electric Power Company "Fall 1990 Long-Term Forecast"
Potomac Electric Power Company, Conservation Program Designs, Phase 1 (8/91) and Phase 2 (12/91).

Table 3: Escalation of Coal Costs and AESN Energy Charges

Year	Crane Coal Price Lagged One Year	Escalation	BG&E Estimate of AESN Energy Price	Escalation	Corrected Estimate	Corrected Escalator	
1990	163		16.7		16.7	1.0362	BG&E
1991	154				17.3	1.0204	BG&E
1992	148				17.7	1.0204	continue 91
1993	145				18.0	1.0204	continue 91
1994	149				18.4	1.0204	continue 91
1995	154				18.8	1.0541	esc from 75%
1996	157				19.8	1.0541	Crane in 94
1997	163	1.000	17.5	1.048	20.8	1.0541	to 75%
1998	169	1.034	18.11	1.035	22.0	1.0541	Wagner in
1999	174	1.034	18.72	1.034	23.2	1.0541	2000
2000	180	1.034	19.37	1.035	24.4	1.0541	
2001	186	1.034	20.01	1.033	25.7	1.0355	Wagner esc
2002	193	1.036	20.73	1.036	26.6	1.0355	
2003	200	1.036	21.47	1.036	27.6	1.0355	
2004	207	1.036	22.24	1.036	28.6	1.0355	
2005	214	1.036	23.04	1.036	29.6	1.0355	
2006	222	1.035	23.85	1.035	30.6	1.0362	
2007	230	1.036	24.71	1.036	31.7	1.0362	
2008	238	1.036	25.6	1.036	32.9	1.0362	
2009	247	1.036	26.52	1.036	34.1	1.0362	
2010	256	1.036	27.47	1.036	35.3	1.0362	
2011	265	1.035	28.44	1.035	36.6	1.0368	
2012			29.47	1.036	37.9	1.0368	
2013			30.54	1.036	39.3	1.0368	
2014			31.64	1.036	40.8	1.0368	
2015			32.79	1.036	42.3	1.0368	
2016			33.98	1.036	43.8	1.0368	
2017			35.21	1.036	45.4	1.0368	
2018			36.49	1.036	47.1	1.0368	
2019			37.81	1.036	48.9	1.0368	
2020			39.19	1.036	50.7	1.0368	
2021			40.61	1.036	52.5	1.0368	
2022			42.1	1.036	54.5	1.0368	
2023			43.6	1.036	56.5	1.0368	
2024			45.2	1.036	58.5	1.0368	
2025			46.8	1.036	60.7	1.0368	
2026			48.5	1.036	62.9	1.0368	
2027			50.3	1.036	65.2	1.0368	
2028			52.1	1.036	67.6	1.0368	
2029			54.0	1.036	70.1	1.0368	
2030			55.9	1.036	72.7	1.0368	
2031			58.0	1.036	75.4	1.0368	

Table 3: Escalation of Coal Costs and AESN Energy Charges

Year	Crane Coal Price Lagged One Year	Escalation	BG&E Estimate of AESN Energy Price	Escalation	Corrected Estimate	Corrected Escalator		
2032			60.1	1.036	78.2	1.0368		
2033			62.2	1.036	81.0	1.0368		
2034			64.5	1.036	84.0	1.0368		
2035			66.8	1.036	87.1	1.0368	difference	
PV 1998-2031			$124 /MWH		$159 /MWH		$34 /MWH	$82 million
PV 2002-2031			$86 /MWH		$111 /MWH		$25 /MWH	$59 million

TABLE 4: BREAKEVEN CAPACITY FACTOR FOR COAL AND GAS

	Coal	Gas
1997		
fixed $/kW−yr	$407.47	$142.94
fixed O&M $/kW−yr	$48.81	$16.49
capital $/kW−yr	$358.66	$126.45
Variable $/MWH	$34.78	$60.04
Variable O&M	$8.51	$4.06
Fuel	$26.27	$55.98

Escalation Rates	coal	gas
fuel	4.10%	6.25%
capital	5.25%	5.25%
fixed O&M	4.25%	4.25%
variable O&M	4.25%	4.25%

year	1997		1998		1999		2000		2001		2002		2003		2004		2005		2006	
fixed $/kW−yr	$407.47	$142.94	$428	$150	$450	$158	$473	$166	$498	$175	$523	$184	$550	$193	$578	$203	$608	$213	$639	$224
fixed O&M $/kW−yr	$48.81	$16.49	$51	$17	$53	$18	$55	$19	$58	$19	$60	$20	$63	$21	$65	$22	$68	$23	$71	$24
capital $/kW−yr	$358.66	$126.45	$377	$133	$397	$140	$418	$147	$440	$155	$463	$163	$488	$172	$513	$181	$540	$190	$568	$200
Variable $/MWH	$34.78	$60.04	$36	$64	$38	$68	$39	$72	$41	$76	$43	$81	$44	$86	$46	$91	$48	$97	$50	$103
Variable O&M	$8.51	$4.06	$9	$4	$9	$4	$10	$5	$10	$5	$10	$5	$11	$5	$11	$5	$12	$6	$12	$6
Fuel	$26.27	$55.98	$27	$59	$28	$63	$30	$67	$31	$71	$32	$76	$33	$81	$35	$86	$36	$91	$38	$97
Breakeven Cap Factor	120%		115%		112%		108%		105%		101%		98%		96%		93%		90%	

year	2007		2008		2009		2010		2011		2012		2013		2014		2015		2016	
fixed $/kW−yr	$672	$236	$707	$248	$743	$261	$781	$274	$822	$288	$864	$303	$908	$319	$955	$335	$1,004	$353	$1,056	$371
fixed O&M $/kW−yr	$74	$25	$77	$26	$80	$27	$84	$28	$87	$30	$91	$31	$95	$32	$99	$33	$103	$35	$108	$36
capital $/kW−yr	$598	$211	$630	$222	$663	$234	$698	$246	$734	$259	$773	$272	$813	$287	$856	$302	$901	$318	$948	$334
Variable $/MWH	$52	$109	$54	$115	$57	$123	$59	$130	$61	$138	$64	$147	$67	$156	$69	$165	$72	$175	$75	$186
Variable O&M	$13	$6	$13	$6	$14	$7	$15	$7	$15	$7	$16	$8	$17	$8	$17	$8	$18	$9	$19	$9
Fuel	$39	$103	$41	$109	$43	$116	$44	$123	$46	$131	$48	$139	$50	$148	$52	$157	$54	$167	$56	$177
Breakeven Cap Factor	88%		86%		83%		81%		79%		77%		76%		74%		72%		70%	

year	2017		2018		2019		2020		2021		2022		2023		2024		2025		2026	
fixed $/kW−yr	$1,110	$390	$1,167	$410	$1,227	$431	$1,291	$453	$1,357	$477	$1,427	$501	$1,501	$527	$1,578	$554	$1,659	$583	$1,745	$613
fixed O&M $/kW−yr	$112	$38	$117	$40	$122	$41	$127	$43	$133	$45	$138	$47	$144	$49	$150	$51	$157	$53	$163	$55
capital $/kW−yr	$998	$352	$1,050	$370	$1,106	$390	$1,164	$410	$1,225	$432	$1,289	$454	$1,357	$478	$1,428	$503	$1,503	$530	$1,582	$558
Variable $/MWH	$78	$198	$81	$210	$85	$223	$88	$236	$92	$251	$96	$266	$100	$283	$104	$300	$108	$319	$113	$338
Variable O&M	$20	$9	$20	$10	$21	$10	$22	$11	$23	$11	$24	$11	$25	$12	$26	$12	$27	$13	$28	$14
Fuel	$59	$188	$61	$200	$64	$212	$66	$226	$69	$240	$72	$255	$75	$271	$78	$288	$81	$306	$84	$325
Breakeven Cap Factor	69%		67%		66%		65%		63%		62%		61%		60%		58%		57%	

Table 5: Comparison of Coal and Gas Plant Cost, 2009 COD

	Coal	Gas	Net
fixed $/kW-yr	$743	$261	
fixed O&M $/kW-yr	$80	$27	
capital $/kW-yr	$663	$234	
Variable $/MWH	$57	$123	
Variable O&M	$14	$7	
Fuel	$43	$116	
$/kW-yr @ capacity factor = 70%	$1,090	$1,012	$78
Present Value 1991$, 35 year life			$127 /kW
Present Value for 300 MW			$38 million

Table 6: End Effects Analysis

YEAR	414 MW COAL PLANT REV REQ (a)	PV FACTOR (b)	PV	INFL FACTOR	PV OF $1 (c)	LEVELIZED	PV	DIFFERENCE (e)	DIFFERENCE DISCOUNTED TO 1991 (f)	DIFFERENCE FOR 300 MW OF COAL PLANT CAPACITY (g)
2009	133624	1.00	133624	1.00	0.50	65076	65076			
2010	252299	0.90	228015	1.04	0.94	135358	122329			
2011	244069	0.82	199347	1.08	0.88	140772	114977			
2012	235792	0.74	174050	1.12	0.83	146403	108067			
2013	227807	0.67	151971	1.17	0.78	152259	101573			
2014	220091	0.60	132692	1.22	0.73	158349	95468			
2015	212624	0.54	115852	1.27	0.69	164683	89731			
2016	205388	0.49	101138	1.32	0.65	171270	84338			
2017	198282	0.45	88241	1.37	0.61	178121	79269			
2018	191196	0.40	76898	1.42	0.57	185246	74505			
2019	184113	0.36	66922	1.48	0.54	192656	70027			
2020	177032	0.33	58155	1.54	0.51	200362	65819			
2021	169954	0.30	50456	1.60	0.48	208377	61863			
2022	162879	0.27	43702	1.67	0.45	216712	58145			
2023	155806	0.24	37780	1.73	0.42	225380	54651			
2024	148736	0.22	32595	1.80	0.39	234395	51366			
2025	141670	0.20	28058	1.87	0.37	243771	48279			
2026	134606	0.18	24093	1.95	0.35	253522	45378			
2027	127546	0.16	20632	2.03	0.33	263663	42650			
2028	120489	0.15	17615	2.11	0.31	274209	40087			
2029	114104	0.13	15076	2.19	0.29	285178	37678			
2030	109060	0.12	13022	2.28	0.27	296585	35414			
2031	104689	0.11	11297	2.37	0.26	308448	33285			
2032	100321	0.10	9784	2.46	0.24	320786	31285			
2033	95958	0.09	8458	2.56	0.23	333618	29405			
2034	91599	0.08	7296	2.67	0.21	346962	27637			
2035	87245	0.07	6281	2.77	0.20	360841	25976			
2036	82895	0.07	5393	2.88	0.19	375275	24415			
2037	78550	0.06	4619	3.00	0.18	390286	22948			
2038	74210	0.05	3943	3.12	0.17	405897	21569			
2039	69875	0.05	3356	3.24	0.16	422133	20272			
2040	65546	0.04	2845	3.37	0.15	439018	19054			
2041	61221	0.04	2401	3.51	0.14	456579	17909			
2042	56901	0.04	2017	3.65	0.13	474842	16833			
2043	52586	0.03	1685	3.79	0.12	493836	15821			
2044	48276	0.03	1398	3.95	0.11	513589	14870			
2045	47413	0.03	1241	4.10	0.11	534133	13976			
TOTAL			1881947		14		1881947			
TOTAL FOR 1997 COD			1821232 (c)				1579976 (d)	241255	39026	28280
TOTAL FOR 2001 COD			1858443 (c)				1718695 (d)	139749	22606	16381

Notes to Table 6:

(a) IR Staff 1-4, Enclosure 1

(b) Discount rate = 10.65%

(c) For 1997 COD, sum of PV revenue requirements over the period 2009 through 2031. For 2001 COD, sum over the period 2009 through 2036.

(d) For 1997 COD, sum of levelized revenue stream over the period 2009 through 2031. For 2001 COD, sum over the period 2009 through 2031.

(e) (c) - (d)

(f) (e)/(1.1065^18)

(g) (f)*300/414

Table 7: BG&E's Proposed SO2 Emission Reductions

	Uncontrolled Emissions (T/yr) [1]	Controlled Emissions (T/yr) [2]	Emission Reduction (T/yr) [3]	Percent Reduction [4]	Uncontrolled SO2 emission (lb/MMBTU) [5]	Controlled Emissions (lb/MMBTU) [6]
Conemaugh	20,782	1,028	19,754	95%	3.54	0.17
Crane	37,827	12,592	25,235	67%	3.14	1.04
KeyStone	26,127	1,307	24,820	95%	2.30	0.12
Wagner 2&3	18,751	15,668	3,083	16%	1.28	1.07
Phase I total			44,989			
Phase II total			72,892			

Notes:

1 [2] + [3]
2 IRP Exhibit IV-K, Table IV-2.
3 IRP Exhibit IV-K, Table IV-2.
4 [3]/[2]
5 IR DNR 4-2
6 [5] * (1 - [4])

Table 8: NOx Emission Rates (lb/MMBTU)

Plant	Unit	Used by BG&E	Estimated by BG&E for CAAA Title IV	Title I MD/ NESCAUM Targets	Title I NESCAUM Targets Phase II	reductions: Estimated by BG&E for CAAA Title IV	reductions: NESCAUM Targets for Ph 1, Title I	reductions: NESCAUM Targets for Ph 1, Title I
Keystone	1	0.85	0.50	0.38	0.20	41%	55%	76%
Keystone	2	0.85	0.50	0.38	0.20	41%	55%	76%
Conemaugh	1	0.81	0.50	0.38	0.20	38%	53%	75%
Conemaugh	2	0.89	0.50	0.38	0.20	44%	57%	78%
Bran Shor	1	0.49		0.38	0.20		22%	59%
Bran Shor	2	0.49		0.38	0.20		22%	59%
Crane	1	1.39	0.70	0.55	0.20	50%	60%	86%
Crane	2	1.69	0.85	0.55	0.20	50%	67%	88%
Wagner	2	0.80	0.50	0.38	0.20	38%	53%	75%
Wagner	3	0.80	0.50	0.38	0.20	38%	53%	75%
Gould St	3	0.43		0.25	0.10		42%	77%
Riverside	4	0.36		0.25	0.10		31%	72%
Wagner	1	0.50		0.25	0.10		50%	80%
Wagner	4	0.37		0.25	0.10		32%	73%
Wagner CT	1 oil	0.48		0.30			38%	
Crane CT	1 oil	0.48		0.30			38%	
Wport CT	5 gas	0.50		0.19			62%	
River CT	6 gas	0.50		0.19			62%	
River CT	78 oil	0.49		0.30			39%	
Notch CL	14 gas	0.40		0.19			53%	
Notch CL	58 gas	0.40		0.19			53%	
Phila Rd	14 oil	0.48		0.30			38%	
Perryman	12 oil	0.48		0.30			38%	
Perryman	34 oil	0.48		0.30			38%	
Conema P	3 oil	--						
Keyston P	3 oil	--						
New CTs	var oil	0.29						
New CTs	var gas	0.09						
Perry CC	5-7 gas	0.09			0.02			78%
CoalBC	var	0.50		0.34	0.17		32%	66%

Table 9: Summary of Effect of Reduced BG&E NOx Emission Rates of On Benefits of AES Northside

Emission Rates for	From:				
Existing Coal	BG&E Title IV Compliance Plan	BG&E Title IV Compliance Plan	Maryland AMA Proposed RACT	Maryland AMA Proposed RACT	NESCAUM Phase 2
Other Existing Boilers	no change	no change	Maryland AMA Proposed RACT	Maryland AMA Proposed RACT	NESCAUM Phase 2
Existing CTs	no change	no change	NESCAUM Phase 1	NESCAUM Phase 1	NESCAUM Phase 2
New Coal	no change	New Pulverized Coal	New Pulverized Coal	New Gasified Coal	New Gasified Coal
Emission Rate (lb/MMBTU)	0.5	0.34	0.34	0.15	0.15
Reductions in AESN Benefit 1991PV$ millions					
1997 COD	$3.7	$19.2	$21.3	$39.7	$43.9
2001 COD	$0.4	$17.0	$17.4	$37.1	$37.9

TABLE 10: SUMMARY OF CORRECTION

Category of correction		Reduction in AESN Benefits (1991 PV $million) 1997 COD	2001 COD
Overstated NOx emissions (Title I, Phase 1, w/ CGCC)		$40	$37
BG&E Non–price points		$217	$171
Excess cost of pulverized coal over CGCC		$17	$17
Excess cost of 2009 CGCC over gas CC		$21	$21
Coal plant end effects		$28	$16
Cost of capital	up to	$385	$257
	if 5%	$19	$13
Coal tax credit		$13	$9
Additional DSM		$108 +	$108 +
TOTAL		$463	$392

Unquantified

Additional DSM

Overstated SO2 emissions

Failure to reflect AESN NOx emissions

Failure to use economic dispatch

Effect of NUG, DSM in A.C.

ATTACHMENT 2

BG&E NOx NOx EMISSIONS:

Plant	Unit	Emission Rate	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Keystone	1	0.85	4458.3	5319.6	4679.2	5336.5	4679.9	5322.2	4505.6	5336.7	4709.8	5322.2	4709.8	5336.8	4505.6	5322.2	4709.8	5336.7
Keystone	2	0.85	4933.6	4358.7	4957.5	4374.8	4958.8	4198.6	4959.5	4402.4	4959.5	4388.9	4959.5	4212.2	4959.5	4388.9	4959.5	4402.4
Conemaugh	1	0.81	2470.4	2175.3	2474.1	2183.6	2475.4	2191	2476	2197.7	2476	2191.1	2476	2197.8	2476	2191.1	2476	2197.8
Conemaugh	2	0.89	2476.1	2818.9	2479.3	2828.1	2480.3	2820.8	2496.2	2828.4	2496.2	2820.8	2496.2	2828.5	2496.2	2820.8	2496.2	2828.5
Bran Shor	1	0.49	10214.2	10370.9	10494.2	10617.3	10834.4	10981.6	10895	11013	11014.1	10993.4	10982.6	10992.2	10959.2	10955.4	10955.8	10954.7
Bran Shor	2	0.49	9659.7	9799.8	9874.6	9907	10068.9	10190.3	10025.7	10200.9	10112	10104.3	10163.8	10114.3	10081.8	10069.6	10079.6	10064.9
Crane	1	1.39	6760	7481.2	7767.1	7904.3	8205.5	8265.7	8327.9	8366.5	8371.9	8366.6	8350.9	8383.8	8366.5	8345.5	8358.1	8355
Crane	2	1.69	8483.5	9574.7	9872.9	10037.3	10151.6	10235.1	10238.5	10282.7	10269.2	10263.6	10258.1	10293.9	10269.6	10255.2	10265.4	10268.6
Wagner	2	0.8	2924.2	3001.1	3081.5	3189.4	3424.4	3568.1	3588	3762.9	3768.1	3767.3	3744.2	3728.6	3725.6	3714.3	3717.1	3681.2
Wagner	3	0.8	7129.9	7381.2	7709	7769.4	7974.6	8094.9	8106.8	8155.7	8149.4	8150.9	8140.7	8166.9	8152	8137	8146	8141.7
Gould St	3	0.43	408.8	363.2	364.7	387.9	399.9	410.4	387.3	345	341.4	342	341.5	339.8	331.8	311.8	344.3	351
Riverside	4	0.36	426.9	380.5	379	391.8	405.4	399.3	374.6	339.7	317.7	286	302.5	296.2	274.2	248.1	273.8	291.7
Wagner	1	0.5	1351.5	1265.6	1227.9	1266	1289.5	1290.3	1322.9	1149.2	1086.5	1021.4	1059.5	1038.1	1028.7	961.5	1014.7	1022.8
Wagner	4	0.37	1812.5	1642.2	1586.9	1692.7	1670.3	1648.3	1667.5	1462.5	1372.2	1332	1371.8	1342.8	1343.9	1298.6	1353.1	1415.6
Wagner CT	1	0.48	10.2	14.8	15.2	13.5	12.6	9.3	8.1	11.1	11.2	8	5.4	4.7	4.6	4.4	4.6	4.9
Crane CT	1	0.48	10.8	15.7	16.4	14.7	13.8	10.2	8.9	12.3	12.3	8.8	6	5.2	5.1	4.9	5.1	5.4
Wport CT	5	0.5	297.9	273.4	257.6	227.1	211	159.8	141.1	185.2	194.1	182.1	179.8	170.9	163.4	156.1	167.6	173.1
River CT	6	0.5	398	360.9	339.6	295.3	277.7	216.4	194.1	250.3	261.7	246.4	242.9	233.6	225.2	212.2	228.2	235.3
River CT	78	0.49	30.2	43.8	45.4	40.5	37.9	27.8	24.1	33.5	33.5	23.7	16	13.8	13.5	13	13.7	14.3
Notch CL	14	0.4	224.3	200	192	169.8	154.8	118.3	103.1	129.7	137.2	128.7	128.4	122	116.7	111	117.9	121.3
Notch CL	58	0.4	196	174.9	164.7	147.9	135.4	102.8	89.6	114.1	120.3	112.5	111.1	106.3	101.9	97	103	106.2
Phila Rd	14	0.48	49.3	69.5	72.6	65	60.7	44.6	38.7	53.2	53.5	38.5	26.4	22.6	22.2	21.3	22.5	23.5
Perryman	12	0.48	123	161.4	171.3	155	143	104.8	90.4	119.8	122.7	91.2	64.7	54.7	54.2	51.5	54.4	56.9
Perryman	34	0.48	97.5	131	137.2	124.8	115.5	84.2	72.7	97.8	99.5	72.8	51.1	43.4	42.8	40.8	43.1	45.2
Conema P	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Keyston P	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Newperry	51	0.29	146.5	54.9														
Newperry	52	0.29	64.1	36.9														
Perry CC	5	0	146	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Perry CC	1	0			0	0	0	0	0	0	0	0	0	0	0	0	0	0
Perry CC	6	0					0	0	0	0	0	0	0	0	0	0	0	0
Perry CC	2	0						0	0	0	0	0	0	0	0	0	0	0
Perry CC	7	0									0	0	0	0	0	0	0	0
Perry CC	3	0										0	0	0	0	0	0	0
Newperry	61	0.09				56.8	41.3											

BG&E NOx NOx EMISSIONS:

Plant	Unit	Emission Rate	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Newperry	62																	
Newperry	71	0.1					54.2	82.8	80.5	27.3								
Newperry	72	0.09						42.7	58.6	18.3								
CTBC	1	0.29										61.2	78.1	73.3	72.1	68	72.9	74.9
CTBC	2	0.29											41.6	51.7	50.7	48.1	50.9	53.1
CoalBC	1	0.5													4567.1	7034.9	7036.3	7057
CTBC	7	0.29																
CombCycl	5	0																
CombCycl	1	0																
CTBC	3	0.29																
CoalBC	2	0.5																
CTBC	9	0.29																
CTBC	10	0.29																
CombCycl	6	0																
TOTAL		48	65303.4	67470.1	68359.9	69196.5	70276.8	70620.3	70281.4	70895.9	70490	70324.4	70308.6	70174.1	74410.1	76883.2	77069.6	77283.7

BASE CASE WITH AES (1997)

BG&E NOx NOx EMISSIONS:

Plant	Unit	Emission Rate	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Keystone	1	0.85	4457.8	5321.3	4678.5	5335.5	4679.5	5322.2	4505.6	5336.7	4709.8	5322.2	4709.8	5336.8	4505.6	5322.2	4709.8	5336.7
Keystone	2	0.85	4933.6	4359.5	4956.5	4373.3	4958.2	4198.6	4959.5	4402.4	4959.5	4388.9	4959.5	4212.2	4959.5	4388.9	4959.5	4402.4
Conemaugh	1	0.81	2470.7	2177.2	2475.3	2184.2	2475.8	2191	2476	2197.8	2476	2191.1	2476	2197.8	2476	2191.1	2476	2197.8
Conemaugh	2	0.89	2476.3	2820.5	2480.4	2828.5	2480.7	2820.8	2496.2	2828.5	2496.2	2820.8	2496.2	2828.5	2496.2	2820.8	2496.2	2828.5
Bran Shor	1	0.49	10229.4	10067	9920.6	10019.1	10432.3	10859.7	10881.6	10929.8	10864.9	10854.3	10934.6	11022.4	10964.9	10964.6	10972.6	10971.9
Bran Shor	2	0.49	9660.8	9476.2	9397.4	9391.8	9787.9	10119	10022.1	10137.2	10014.8	10009.6	10136.7	10127.4	10083.3	10078.9	10092.4	10087.6
Crane	1	1.39	6781.4	7178	7263.8	7332.6	7927.2	8200	8326.8	8326.2	8317	8316.4	8321.4	8385.6	8361.7	8356.2	8376.4	8380.1
Crane	2	1.69	8502.3	9265.8	9344.7	9532.4	9896.3	10176.1	10247.7	10256.5	10238.9	10223.6	10222.9	10296.1	10261.2	10271.8	10281.7	10292.9
Wagner	2	0.8	2935.3	2789.5	2762.4	2790.3	3188.6	3500.6	3595.2	3659.2	3615	3631	3717	3772.4	3733.8	3721.1	3733.7	3706.9
Wagner	3	0.8	7199.1	7064.2	7104.4	7181	7649.8	8017.5	8105.4	8132.2	8114.9	8107.9	8103.9	8165.9	8143.2	8153.9	8166.3	8169.5
Gould St	3	0.43	391.5	366.6	379	377.4	413.5	355.2	334.3	362.2	344.4	338.8	340	326	328.4	309.9	340.4	346.8

BG&E NOx NOx EMISSIONS:

Plant	Unit	Emission Rate	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Riverside	4	0.37	395.6	371.9	376.5	384.2	407.2	368.4	336.4	342.1	340.8	326.1	324.8	273.5	256.2	242	255.5	277
Wagner	1	0.48	1331.8	1249.8	1285.1	1313.2	1351.1	1232.7	1161	1185.4	1177.5	1185.8	1084.2	1002.8	975.1	963.3	993.1	1016.8
Wagner	4	0.37	1774.3	1631.2	1613.7	1697.5	1790.3	1552.5	1454.2	1472.5	1473.8	1509.3	1369.9	1303.5	1299	1255.7	1345.8	1395.7
Wagner CT	1	0.48	13.2	12.8	12.2	9.5	10.5	13.2	13.4	10.8	9.5	7.5	10.1	10.2	5.4	4.2	4.5	4.6
Crane CT	1	0.48	14	13.6	13.1	10.4	11.5	14.5	14.7	11.8	10.5	8.4	11	11.2	5.9	4.7	5	5.1
Wport CT	5	0.5	299.6	288.5	283.1	283.3	214	216.7	226.3	186.5	166.9	135	169.9	174.6	160.7	152.3	163.4	165.5
River CT	6	0.5	390.9	375.3	377.2	375.1	282.2	289.8	305.9	251.9	225.5	183.1	229.9	235.3	221	207.8	223.1	228.9
River CT	78	0.49	39	37.9	36.3	28.5	31.4	39.7	40.1	32.4	28.4	22.5	30	30.3	16	12.4	13.2	13.7
Notch CL	14	0.4	219.4	210.9	211.4	216.7	160.1	152.6	160.5	135.6	120	98.3	118.2	121.7	115.2	108.9	115.5	118.4
Notch CL	58	0.4	191.9	184.6	185	185.2	139.2	134.4	140.8	118.4	104.7	85.2	103.9	106.7	100.5	93.8	100.8	103.5
Phila Rd	14	0.48	63	61	58.7	46.7	50.6	62.8	63.9	52.4	45.9	36.7	47.9	48.6	26.5	20.4	21.7	22.5
Perryman	12	0.48	152.2	147.4	143.4	117.7	122	142.7	146.4	121.7	107.2	87.6	109.4	111.7	66.1	49.4	52.8	54.6
Perryman	34	0.48	121.9	118.2	113.9	92.9	97.8	116.4	118.9	98	86.3	70	89	90.6	51.9	39.1	41.8	43.2
Conema P	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Keyston P	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Newperry	51	0.29	147.8	143	139.5	140.4	62										0	
Newperry	52	0.29				63.5	42.3											
Perry CC	5	0					0	0	0	0	0	0	0	0	0	0	0	0
Perry CC	1	0						0	0	0	0	0	0	0	0	0	0	0
Perry CC	6	0						0	0	0	0	0	0	0	0	0	0	0
Perry CC	2	0							0	0	0	0	0	0	0	0	0	0
Perry CC	7	0											0	0	0	0	0	0
Perry CC	3	0												0	0	0	0	0
Newperry	61	0.14					62.6	35.2									0	
Newperry	62	0.13					47.2	23.8										
Newperry	71	0.09								48.5	75.6	75.3	25.4					
Newperry	72	0.09										38	17.4					
CTBC	1	0.29													52.8	65.4	70.9	72.4
CTBC	2	0.29													38.3	46.2	49.4	51.1
CoalBC	1	0.5													1258.6	1929.5	1926.2	1929.7
CTBC	7	0.29																
CombCycl	5	0																
CombCycl	1	0																
CTBC	3	0.29																
CoalBC	2	0.5																
CTBC	9	0.29																

BG&E NOx NOx EMISSIONS:

Plant	Unit	Emission Rate	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
CTBC	10	0.29																
CombCycl	6	0																
TOTAL			65192.8	65731.9	65612.1	66310.9	68771.8	70156.1	70132.9	70636.7	70124	70073.4	70159	70191.8	70963	71774.5	71987.7	72223.8
		DIFFERENCES																
Keystone	1		-0.5	1.7	-0.7	-1	-0.4	0	0	0	0	0	0	0	0	0	0	0
Keystone	2		0	0.8	-1	-1.5	-0.6	0	0	0	0	0	0	0	0	0	0	0
Conemaugh	1		0.3	1.9	1.2	0.6	0.4	0	0	0.1	0	0	0	0	0	0	0	0
Conemaugh	2		0.2	1.6	1.1	0.4	0.4	0	0	0.1	0	0	0	0	0	0	0	0
Bran Shor	1		15.2	-303.9	-573.6	-598.2	-402.1	-121.9	-13.4	-83.2	-149.2	-139.1	-48	30.2	5.7	9.2	16.8	17.2
Bran Shor	2		1.1	-323.6	-477.2	-515.2	-281	-71.3	-3.6	-63.7	-97.2	-94.7	-27.1	13.1	1.5	9.3	12.8	22.7
Crane	1		21.4	-303.2	-503.3	-571.7	-278.3	-65.7	-1.1	-40.3	-54.9	-50.2	-29.5	1.8	-4.8	10.7	18.3	25.1
Crane	2		18.8	-308.9	-528.2	-504.9	-255.3	-59	9.2	-26.2	-30.3	-40	-35.2	2.2	-8.4	16.6	16.3	24.3
Wagner	2		11.1	-211.6	-319.1	-399.1	-235.8	-67.5	7.2	-103.7	-153.1	-136.3	-27.2	43.8	8.2	6.8	16.6	25.7
Wagner	3		69.2	-317	-604.6	-588.4	-324.8	-77.4	-1.4	-23.5	-34.5	-43	-36.8	-1	-8.8	16.9	20.3	27.8
Gould St	3		-17.3	3.4	14.3	-10.5	13.6	-55.2	-53	17.2	3	-3.2	-1.5	-13.8	-3.4	-1.9	-3.9	-4.2
Riverside	4		-31.3	-8.6	-2.5	-7.6	1.8	-30.9	-38.2	2.4	23.1	40.1	22.3	-22.7	-18	-6.1	-18.3	-14.7
Wagner	1		-19.7	-15.8	57.2	47.2	61.6	-57.6	-161.9	36.2	91	164.4	24.7	-35.3	-53.6	1.8	-21.6	-6
Wagner	4		-38.2	-11	26.8	4.8	120	-95.8	-213.3	10	101.6	177.3	-1.9	-39.3	-44.9	-42.9	-7.3	-19.9
Wagner CT	1		3	-2	-3	-4	-2.1	3.9	5.3	-0.3	-1.7	-0.5	4.7	5.5	0.8	-0.2	-0.1	-0.3
Crane CT	1		3.2	-2.1	-3.3	-4.3	-2.3	4.3	5.8	-0.5	-1.8	-0.4	5	6	0.8	-0.2	-0.1	-0.3
Wport CT	5		1.7	15.1	25.5	56.2	3	56.9	85.2	1.3	-27.2	-47.1	-9.9	3.7	-2.7	-3.8	-4.2	-7.6
River CT	6		-7.1	14.4	37.6	79.8	4.5	73.4	111.8	1.6	-36.2	-63.3	-13	1.7	-4.2	-4.4	-5.1	-6.4
River CT	78		8.8	-5.9	-9.1	-12	-6.5	11.9	16	-1.1	-5.1	-1.2	14	16.5	2.5	-0.6	-0.5	-0.6
Notch CL	14		-4.9	10.9	19.4	46.9	5.3	34.3	57.4	5.9	-17.2	-30.4	-10.2	-0.3	-1.5	-2.1	-2.4	-2.9
Notch CL	58		-4.1	9.7	20.3	37.3	3.8	31.6	51.2	4.3	-15.6	-27.3	-7.2	0.4	-1.4	-3.2	-2.2	-2.7
Phila Rd	14		13.7	-8.5	-13.9	-18.3	-10.1	18.2	25.2	-0.8	-7.6	-1.8	21.5	26	4.3	-0.9	-0.8	-1
Perryman	12		29.2	-14	-27.9	-37.3	-21	37.9	56	1.9	-15.5	-3.6	44.7	57	11.9	-2.1	-1.6	-2.3
Perryman	34		24.4	-12.8	-23.3	-31.9	-17.7	32.2	46.2	0.2	-13.2	-2.8	37.9	47.2	9.1	-1.7	-1.3	-2
Conema P	3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Keyston P	3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Newperry	51		1.3	88.1	139.5	140.4	62	0	0	0	0	0	0	0	0	0	0	0
Newperry	52		-64.1	-36.9	0	63.5	42.3	0	0	0	0	0	0	0	0	0	0	0
Perry CC	5		-146	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

BG&E NOx NOx EMISSIONS:

Plant	Unit	Emission Rate	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Perry CC	1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Perry CC	6		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Perry CC	2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Perry CC	7		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Perry CC	3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Newperry	61		0	0	0	-56.8	21.3	35.2	0	0	0	0	0	0	0	0	0	0
Newperry	62		0	0	0	0	47.2	23.8	0	0	0	0	0	0	0	0	0	0
Newperry	71		0	0	0	0	-54.2	-82.8	-80.5	21.2	75.6	75.3	25.4	0	0	0	0	0
Newperry	72		0	0	0	0	0	-42.7	-58.6	-18.3	0	38	17.4	0	0	0	0	0
CTBC	1		0	0	0	0	0	0	0	0	0	-61.2	-78.1	-73.3	-19.3	-2.6	-2	-2.5
CTBC	2		0	0	0	0	0	0	0	0	0	0	-41.6	-51.7	-12.4	-1.9	-1.5	-2
CoalBC	1		0	0	0	0	0	0	0	0	0	0	0	0	-3308.5	-5105.4	-5110.1	-5127.3
CTBC	7		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CombCycl	5		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CombCycl	1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTBC	3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CoalBC	2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTBC	9		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTBC	10		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CombCycl	6		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL																		
DIFFERENCES			-110.6	-1738.2	-2747.8	-2885.6	-1505	-464.2	-148.5	-259.2	-366	-251	-149.6	17.7	-3447.1	-5108.7	-5081.9	-5059.9
		1000 T	0.1	1.7	2.7	2.9	1.5	0.5	0.1	0.3	0.4	0.3	0.1	0.0	3.4	5.1	5.1	5.1
		$/T	$2,717	$2,839	$2,967	$3,101	$3,240	$3,386	$3,538	$3,697	$3,864	$4,038	$4,219	$4,409	$4,608	$4,815	$5,032	$5,258
PV 1991	$47.9	$M	$0.3	$4.9	$8.2	$8.9	$4.9	$1.6	$0.5	$1.0	$1.4	$1.0	$0.6	($0.1)	$15.9	$24.6	$25.6	$26.6
		ADJUSTS																
Keystone	1	41%	-0.2	0.7	-0.3	-0.4	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Keystone	2	41%	0.0	0.3	-0.4	-0.6	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Conemaugh	1	38%	0.1	0.7	0.5	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

BG&E NOx NOx EMISSIONS:

Plant	Unit	Emission Rate	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Conemaugh	2	44%	0.1	0.7	0.5	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bran Shor	1	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bran Shor	2	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Crane	1	50%	10.7	-151.6	-251.7	-285.8	-139.2	-32.9	-0.6	-20.1	-27.4	-25.1	-14.8	0.9	-2.4	5.4	9.1	12.6
Crane	2	50%	9.4	-154.5	-264.1	-252.4	-127.7	-29.5	4.6	-13.1	-15.2	-20.0	-17.6	1.1	-4.2	8.3	8.2	12.1
Wagner	2	38%	4.2	-79.3	-119.7	-149.7	-88.4	-25.3	2.7	-38.9	-57.4	-51.1	-10.2	16.4	3.1	2.5	6.2	9.6
Wagner	3	38%	26.0	-118.9	-226.7	-220.6	-121.8	-29.0	-0.5	-8.8	-12.9	-16.1	-13.8	-0.4	-3.3	6.3	7.6	10.4
Gould St	3	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Riverside	4	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wagner	1	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wagner	4	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wagner CT	1	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Crane CT	1	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wport CT	5	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
River CT	6	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
River CT	78	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Notch CL	14	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Notch CL	58	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Phila Rd	14	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perryman	12	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perryman	34	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Conema P	3	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Keyston P	3	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Newperry	51	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Newperry	52	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perry CC	5	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perry CC	1	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perry CC	6	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perry CC	2	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perry CC	7	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perry CC	3	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Newperry	61	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Newperry	62	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Newperry	71	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Newperry	72	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CTBC	1	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

BG&E NOx NOx EMISSIONS:

Plant	Unit	Emission Rate	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
CTBC	2	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CoalBC	1	32%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1058.7	-1633.7	-1635.2	-1640.7
CTBC	7	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CombCycl	5	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CombCycl	1	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CTBC	3	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CoalBC	2	32%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CTBC	9	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CTBC	10	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CombCycl	6	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reduction		TOTAL	50.2	-501.8	-861.9	-909.2	-477.1	-116.7	6.2	-80.9	-113.0	-112.3	-56.4	18.1	-1065.5	-1611.2	-1604.1	-1596.0
in Savings		1000 T	-0.1	0.5	0.9	0.9	0.5	0.1	0.0	0.1	0.1	0.1	0.1	0.0	1.1	1.6	1.6	1.6
PV 1991	$19.2	$M	($0.1)	$1.4	$2.6	$2.8	$1.5	$0.4	($0.0)	$0.3	$0.4	$0.5	$0.2	($0.1)	$4.9	$7.8	$8.1	$8.4
2001 on	$17.0																	
w/25% of 2001																		
		NET	-160.809	-1236.38	-1885.90	-1976.36	-1027.89	-347.512	-154.725	-178.332	-253.05	-138.662	-93.25	-0.35	-2381.55	-3497.50	-3477.80	-3463.92
		1000 T	0.2	1.2	1.9	2.0	1.0	0.3	0.2	0.2	0.3	0.1	0.1	0.0	2.4	3.5	3.5	3.5
		$/T	$2,717	$2,832	$2,953	$3,078	$3,209	$3,346	$3,488	$3,636	$3,791	$3,952	$4,120	$4,295	$4,477	$4,667	$4,866	$5,073
PV 1991	$32.0	$M	$0.4	$3.5	$5.6	$6.1	$3.3	$1.2	$0.5	$0.6	$1.0	$0.5	$0.4	$0.0	$10.7	$16.3	$16.9	$17.6
'97-'01	$7.8																	
01 on	$24.3																	

Plant	Unit	BG&E NOx Emission Rate	2013	2014	2015	2016	2017	2018	2019	2020	2021
Keystone	1	0.85	4709.8	5322.2	4505.6	5336.8	4709.8	5322.2	4709.8	5336.8	4505.6
Keystone	2	0.85	4959.5	4198.6	4959.5	4402.4	4959.5	4388.9	4959.5	4212.2	4959.6
Conemaugh	1	0.81	2476	2191.1	2476	2197.8	2476	2191.1	2476	2197.8	2476
Conemaugh	2	0.89	2496.2	2820.8	2496.2	2828.5	2496.2	2820.8	2496.2	2828.5	2496.2
Bran Shor	1	0.49	10916.3	10881.2	10956.9	11021.2	10975.4	10969.9	10954.8	10972.7	10991.6
Bran Shor	2	0.49	10052.4	10013.1	10097	10125.4	10080.3	10060.8	10068.1	10082.5	10109.5
Crane	1	1.39	8340.8	8315.6	8360.9	8380	8350.3	8322.6	8334.1	8325.4	8352
Crane	2	1.69	10253.7	10235.7	10261	10301.8	10258.3	10233.8	10246.1	10252.7	10251.8
Wagner	2	0.8	3681.5	3632.4	3735.3	3767.1	3749.4	3727.2	3726.6	3761	3771.5
Wagner	3	0.8	8130.8	8110.6	8138.3	8179.8	8139.5	8129.6	8121.2	8134.1	8128.4
Gould St	3	0.43	387.2	374.8	347.8	339	342.7	351.3	373.5	374.9	367.9
Riverside	4	0.36	290.4	271	254	246.9	231.4	232.8	239	232.1	205.8
Wagner	1	0.5	1080.6	1066.9	1008.9	963.5	942.7	903.6	930.2	938	855.9
Wagner	4	0.37	1504.2	1459.3	1434.4	1315.8	1366.6	1272.8	1418.6	1390.2	1364.6
Wagner CT	1	0.48	4.8	3.5	4.1	2.9	2.8	2.8	1.9	1.2	2.3
Crane CT	1	0.48	5.3	3.9	4.5	3.2	3.1	3.1	2.2	1.4	2.6
Wport CT	5	0.5	171.4	171.9	153.2	143.3	143.9	143.8	141.4	139.9	127.9
River CT	6	0.5	233.2	234.4	208.4	197.5	197.8	194.8	192.3	190.3	173.5
River CT	78	0.49	14.2	10.3	12	8.6	8.3	8.2	5.7	3.6	6.8
Notch CL	14	0.4	123.7	121.8	107.7	101.7	101.3	99.4	100.2	97.3	88.3
Notch CL	58	0.4	105.6	106.4	94.2	88.9	88.8	87.2	86.4	85.3	77.5
Phila Rd	14	0.48	23.4	17.3	19.6	14.2	13.7	13.5	9.6	6.2	11
Perryman	12	0.48	57.4	44.1	47.8	35.6	33.5	32.8	24.2	16	26.3
Perryman	34	0.48	45.4	34.3	37.9	27.9	26.5	26	18.9	12.4	21
Conema P	3	0	0	0	0	0	0	0	0	0	0
Keyston P	3	0	0	0	0	0	0	0	0	0	0
Newperry	51	0.29									
Newperry	52	0.29									
Perry CC	5	0	0	0	0	0	0	0	0	0	0
Perry CC	1	0	0	0	0	0	0	0	0	0	0
Perry CC	6	0	0	0	0	0	0	0	0	0	0
Perry CC	2	0	0	0	0	0	0	0	0	0	0
Perry CC	7	0	0	0	0	0	0	0	0	0	0
Perry CC	3	0	0	0	0	0	0	0	0	0	0
Newperry	61	0.09									

Plant	Unit	BG&E NOx Emission Rate	2013	2014	2015	2016	2017	2018	2019	2020	2021
Newperry	62										
Newperry	71	0.1									
Newperry	72	0.09									
CTBC	1	0.29	76.5	77	70.7	61.9	63.5	62.1	61.4	61	56
CTBC	2	0.29	53.8	53.6	49.8	43.8	45	43.7	43.4	43.2	39.8
CoalBC	1	0.5	7035.5	7037.4	7036.5	7057.8	7037.4	7039.4	7041.3	7060	7040.3
CTBC	7	0.29		29.5	9						
CombCycl	5	0			0	0	0	0	0	0	0
CombCycl	1	0				0	0	0	0	0	0
CTBC	3	0.29				25.8	31.6	30.8	30.4	30.2	28
CoalBC	2	0.5					4565.9	7031.7	7034.9	7051.8	7033.5
CTBC	9	0.29							17.4	20.9	3.4
CTBC	10	0.29								12.5	2.1
CombCycl	6	0									0
TOTAL		48	77229.6	76838.7	76887.2	77219.1	81441.2	83746.7	83865.3	83872.1	83576.7

BASE CASE WITH AES (1997

Plant	Unit	BG&E NOx Emission Rate	2013	2014	2015	2016	2017	2018	2019	2020	2021
Keystone	1	0.85	4709.8	5322.2	4505.6	5336.8	4709.8	5322.2	4709.8	5336.8	4505.6
Keystone	2	0.85	4959.5	4198.6	4959.5	4402.4	4959.5	4388.9	4959.5	4212.2	4959.5
Conemaugh	1	0.81	2476	2191.1	2476	2197.8	2476	2191.1	2476	2197.8	2476
Conemaugh	2	0.89	2496.2	2820.8	2496.2	2828.5	2496.2	2820.8	2496.2	2828.5	2496.2
Bran Shor	1	0.49	10925.1	10893.9	10967.6	11029	10985.4	10977	10959.2	10976	10995.2
Bran Shor	2	0.49	10064.4	10031.1	10107.8	10136	10091.8	10076.8	10073.6	10085.8	10114.2
Crane	1	1.39	8352.7	8336	8371.3	8390.6	8362.9	8339.5	8342.2	8333.6	8360.1
Crane	2	1.69	10262.3	10252.7	10271.4	10311.1	10269.6	10250.4	10252.6	10261.4	10259.5
Wagner	2	0.8	3693.7	3649.4	3745.7	3776.2	3758.9	3741.7	3731.3	3762.8	3776.6
Wagner	3	0.8	8142.1	8131.2	8150.5	8190.6	8151.3	8140	8131.6	8144.7	8138.3
Gould St	3	0.43	366.7	354.8	325.9	335.2	330.5	329.6	371.6	354.3	326

Plant	Unit	BG&E NOx Emission Rate	2013	2014	2015	2016	2017	2018	2019	2020	2021
Riverside	4	0.37	277.4	269.3	241.5	231.4	217.1	231.2	221.6	231.8	190.1
Wagner	1	0.48	1080.2	1050.1	1010.3	965.1	946.1	893.3	930.2	939.6	857.6
Wagner	4	0.37	1485.2	1453.1	1387.1	1268.5	1298.2	1269.3	1384.6	1327.2	1366
Wagner CT	1	0.48	4.6	3.4	3.9	2.8	2.7	2.7	1.9	1.2	2.2
Crane CT	1	0.48	5.1	3.7	4.3	3.1	3	3	2.1	1.3	2.5
Wport CT	5	0.5	166.5	167.8	150	139.1	139.2	138.4	138.6	138.6	125.4
River CT	6	0.5	227.3	229.4	204.7	189.8	192	190.8	188.9	188.8	170.5
River CT	78	0.49	13.6	9.9	11.5	8.2	7.9	7.9	5.5	3.5	6.5
Notch CL	14	0.4	120.2	119.6	106.2	97.9	98.6	97.5	97.1	96.8	87
Notch CL	58	0.4	103.2	104.3	92.7	85.6	86.3	85.5	84.9	84.7	76.3
Phila Rd	14	0.48	22.4	16.6	18.8	13.6	13.1	13	9.2	5.9	10.7
Perryman	12	0.48	55.3	42.6	46	34.2	32.1	31.6	23.4	15.4	25.6
Perryman	34	0.48	43.6	33.1	36.4	26.7	25.3	25	18.2	11.9	20.4
Conema P	3	0	0	0	0	0	0	0	0	0	0
Keyston P	3	0	0	0	0	0	0	0	0	0	0
Newperry	51	0.29			0				0	0	
Newperry	52	0.29									
Perry CC	5	0	0	0	0	0	0	0	0	0	0
Perry CC	1	0	0	0	0	0	0	0	0	0	0
Perry CC	6	0	0	0	0	0	0	0	0	0	0
Perry CC	2	0	0	0	0	0	0	0	0	0	0
Perry CC	7	0	0	0	0	0	0	0	0	0	0
Perry CC	3	0	0	0	0	0	0	0	0	0	0
Newperry	61	0.14									
Newperry	62	0.13									
Newperry	71	0.09									
Newperry	72	0.09									
CTBC	1	0.29	74.1	75	69.1	59.9	61.3	59.6	60	60.2	54.8
CTBC	2	0.29	52	52	48	42.3	43.3	42.4	42.3	42	38.8
CoalBC	1	0.5	1937.9	1939	1937.9	1944.7	1939	1939.9	1940.2	1945.4	1939.9
CTBC	7	0.29		28.7	8.6						
CombCycl	5	0			0	0	0	0	0	0	0
CombCycl	1	0				0	0	0	0	0	0
CTBC	3	0.29				24.9	30.3	29.8	29.5	29.3	27.2
CoalBC	2	0.5					4566.2	7033.9	7035.9	7053	7034.7
CTBC	9	0.29							16.9	20.3	3.2

Plant	Unit	BG&E NOx Emission Rate	2013	2014	2015	2016	2017	2018	2019	2020	2021
CTBC	10	0.29								12.2	2
CombCycl	6	0									0
TOTAL			72117.1	71779.4	71754.5	72072	76293.6	78672.8	78734.6	78703	78448.6
		DIFFERENC									
Keystone	1		0	0	0	0	0	0	0	0	0
Keystone	2		0	0	0	0	0	0	0	0	-0.1
Conemaugh	1		0	0	0	0	0	0	0	0	0
Conemaugh	2		0	0	0	0	0	0	0	0	0
Bran Shor	1		8.8	12.7	10.7	7.8	10	7.1	4.4	3.3	3.6
Bran Shor	2		12	18	10.8	10.6	11.5	16	5.5	3.3	4.7
Crane	1		11.9	20.4	10.4	10.6	12.6	16.9	8.1	8.2	8.1
Crane	2		8.6	17	10.4	9.3	11.3	16.6	6.5	8.7	7.7
Wagner	2		12.2	17	10.4	9.1	9.5	14.5	4.7	1.8	5.1
Wagner	3		11.3	20.6	12.2	10.8	11.8	10.4	10.4	10.6	9.9
Gould St	3		-20.5	-20	-21.9	-3.8	-12.2	-21.7	-1.9	-20.6	-41.9
Riverside	4		-13	-1.7	-12.5	-15.5	-14.3	-1.6	-17.4	-0.3	-15.7
Wagner	1		-0.4	-16.8	1.4	1.6	3.4	-10.3	0	1.6	1.7
Wagner	4		-19	-6.2	-47.3	-47.3	-68.4	-3.5	-34	-63	1.4
Wagner CT	1		-0.2	-0.1	-0.2	-0.1	-0.1	-0.1	0	0	-0.1
Crane CT	1		-0.2	-0.2	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Wport CT	5		-4.9	-4.1	-3.2	-4.2	-4.7	-5.4	-2.8	-1.3	-2.5
River CT	6		-5.9	-5	-3.7	-7.7	-5.8	-4	-3.4	-1.5	-3
River CT	78		-0.6	-0.4	-0.5	-0.4	-0.4	-0.3	-0.2	-0.1	-0.3
Notch CL	14		-3.5	-2.2	-1.5	-3.8	-2.7	-1.9	-3.1	-0.5	-1.3
Notch CL	58		-2.4	-2.1	-1.5	-3.3	-2.5	-1.7	-1.5	-0.6	-1.2
Phila Rd	14		-1	-0.7	-0.8	-0.6	-0.6	-0.5	-0.4	-0.3	-0.3
Perryman	12		-2.1	-1.5	-1.8	-1.4	-1.4	-1.2	-0.8	-0.6	-0.7
Perryman	34		-1.8	-1.2	-1.5	-1.2	-1.2	-1	-0.7	-0.5	-0.6
Conema P	3		0	0	0	0	0	0	0	0	0
Keyston P	3		0	0	0	0	0	0	0	0	0
Newperry	51		0	0	0	0	0	0	0	0	0
Newperry	52		0	0	0	0	0	0	0	0	0
Perry CC	5		0	0	0	0	0	0	0	0	0

Plant	Unit	BG&E NOx Emission Rate	2013	2014	2015	2016	2017	2018	2019	2020	2021
Perry CC	1		0	0	0	0	0	0	0	0	0
Perry CC	6		0	0	0	0	0	0	0	0	0
Perry CC	2		0	0	0	0	0	0	0	0	0
Perry CC	7		0	0	0	0	0	0	0	0	0
Perry CC	3		0	0	0	0	0	0	0	0	0
Newperry	61		0	0	0	0	0	0	0	0	0
Newperry	62		0	0	0	0	0	0	0	0	0
Newperry	71		0	0	0	0	0	0	0	0	0
Newperry	72		0	0	0	0	0	0	0	0	0
CTBC	1		-2.4	-2	-1.6	-2	-2.2	-2.5	-1.4	-0.8	-1.2
CTBC	2		-1.8	-1.6	-1.8	-1.5	-1.7	-1.3	-1.1	-1.2	-1
CoalBC	1		-5097.6	-5098.4	-5098.6	-5113.1	-5098.4	-5099.5	-5101.1	-5114.6	-5100.4
CTBC	7		0	-0.8	-0.4	0	0	0	0	0	0
CombCycl	5		0	0	0	0	0	0	0	0	0
CombCycl	1		0	0	0	0	0	0	0	0	0
CTBC	3		0	0	0	-0.9	-1.3	-1	-0.9	-0.9	-0.8
CoalBC	2		0	0	0	0	0.3	2.2	1	1.2	1.2
CTBC	9		0	0	0	0	0	0	-0.5	-0.6	-0.2
CTBC	10		0	0	0	0	0	0	0	-0.3	-0.1
CombCycl	6		0	0	0	0	0	0	0	0	0
			0	0	0	0	0	0	0	0	0
TOTAL											
DIFFERENCES			-5112.5	-5059.3	-5132.7	-5147.1	-5147.6	-5073.9	-5130.7	-5169.1	-5128.1
		1000 T	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.2	5.1
		$/T	$5,495	$5,742	$6,000	$6,270	$6,553	$6,848	$7,156	$7,478	$7,814
PV 1991	$47.9	$M	$28.1	$29.1	$30.8	$32.3	$33.7	$34.7	$36.7	$38.7	$40.1
		ADJUSTS									
Keystone	1	41%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Keystone	2	41%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Conemaugh	1	38%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Plant	Unit	BG&E NOx Emission Rate	2013	2014	2015	2016	2017	2018	2019	2020	2021
Conemaugh	2	44%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bran Shor	1	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bran Shor	2	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Crane	1	50%	6.0	10.2	5.2	5.3	6.3	8.4	4.1	4.1	4.1
Crane	2	50%	4.3	8.5	5.2	4.7	5.7	8.3	3.3	4.3	3.9
Wagner	2	38%	4.6	6.4	3.9	3.4	3.6	5.4	1.8	0.7	1.9
Wagner	3	38%	4.2	7.7	4.6	4.1	4.4	3.9	3.9	4.0	3.7
Gould St	3	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Riverside	4	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wagner	1	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wagner	4	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wagner CT	1	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Crane CT	1	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wport CT	5	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
River CT	6	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
River CT	78	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Notch CL	14	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Notch CL	58	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Phila Rd	14	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perryman	12	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perryman	34	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Conema P	3	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Keyston P	3	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Newperry	51	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Newperry	52	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perry CC	5	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perry CC	1	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perry CC	6	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perry CC	2	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perry CC	7	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perry CC	3	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Newperry	61	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Newperry	62	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Newperry	71	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Newperry	72	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CTBC	1	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Plant	Unit	BG&E NOx Emission Rate	2013	2014	2015	2016	2017	2018	2019	2020	2021
CTBC	2	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CoalBC	1	32%	-1631.2	-1631.5	-1631.6	-1636.2	-1631.5	-1631.8	-1632.4	-1636.7	-1632.1
CTBC	7	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CombCycl	5	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CombCycl	1	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CTBC	3	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CoalBC	2	32%	0.0	0.0	0.0	0.0	0.1	0.7	0.3	0.4	0.4
CTBC	9	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CTBC	10	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CombCycl	6	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reduction		TOTAL	-1612.2	-1598.7	-1612.7	-1618.8	-1611.5	-1605.0	-1619.1	-1623.2	-1618.3
in Savings		1000 T	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
PV 1991	$19.2	$M	$8.9	$9.2	$9.7	$10.2	$10.6	$11.0	$11.6	$12.1	$12.6
2001 on	$17.0										2021
w/25% of 2001											
		NET	-3500.33	-3460.61	-3520.02	-3528.32	-3536.14	-3468.85	-3511.63	-3545.91	-3509.83
		1000 T	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
		$/T	$5,288	$5,513	$5,747	$5,992	$6,246	$6,512	$6,788	$7,077	$7,378
PV 1991	$32.0	$M	$18.5	$19.1	$20.2	$21.1	$22.1	$22.6	$23.8	$25.1	$25.9
'97-'01	$7.8										
01 on	$24.3										

Small Commercial HVAC Retirement
Pro Forma Program Budgets/Impacts for 1993 - 2001 (6):

Key Annual Data:	1993	1994	1995	1996	1997
Market Penetration	25%	50%	75%	75%	75%
Participants per year	956	1,913	2,869	2,869	2,869
Rebates	$11,617,191	$23,234,382	$34,851,573	$34,851,573	$34,851,573
Customer contribution	$1,636,434	$3,272,868	$4,909,302	$4,909,302	$4,909,302
New Saved MWH	24,863	49,725	74,588	74,588	74,588
New Saved MW	16	31	47	47	47

These next 4 pages of tables belong in ~~Att~~ 3

1998	1999	2000	2001	Cumulative
75%	75%	75%	75%	
2,869	2,869	2,869	2,869	22,950
$34,851,573	$34,851,573	$34,851,573	$34,851,573	$278,812,588
$4,909,302	$4,909,302	$4,909,302	$4,909,302	$39,274,412
74,588	74,588	74,588	74,588	596,700
47	47	47	47	376

Large Commercial Planned HVAC Retirement
Chiller Program Component
Pro Forma Program Budgets/Impacts for 1993 - 2001

Key Annual Data:	1993	1994	1995	1996	1997
Market Penetration	25%	50%	75%	75%	75%
Participants per year	69	139	208	208	208
Rebates	$11,890,757	$23,781,515	$35,672,272	$35,672,272	$35,672,272
Customer contribution	$7,859,743	$15,719,485	$23,579,228	$23,579,228	$23,579,228
New Saved MWH	64,966	129,932	194,898	194,898	194,898
New Saved MW	24	49	73	73	73

1998	1999	2000	2001	Cumulative
75%	75%	75%	75%	
208	208	208	208	1,663
$35,672,272	$35,672,272	$35,672,272	$35,672,272	$285,378,176
$23,579,228	$23,579,228	$23,579,228	$23,579,228	$188,633,824
194,898	194,898	194,898	194,898	1,559,183
73	73	73	73	586

ATTACHMENT 3

Analysis of Achievable Potential of Two Possible BG&E DSM Programs

RII assessed two DSM program concepts that address market opportunites which are currently not addressed by filed programs but which are under development by BG&E. BG&E is developing these concept under the the name of "Planned HVAC Retirement Program". Recently, BG&E filed a status report[1] on its program development effort with the Commission.

The program concepts assessed by RII are as follows:

1. A Small Commercial HVAC Retirement program component which addresses HVAC and lighting equipment of existing General Service (GS) class customers. This program concept is based on the energy efficiency opportunities presented when air conditioning systems (typically packaged roof-top and through-the-wall units) fail. At this time the customer faces considerable expense to replace or rebuild the unit. If a comprehensive high efficiency lighting retrofit is introduced at this time, the lighting based cooling load can be reduced. This results in a reduced capacity requirement for the new higher efficiency equipment and substantial energy and demand savings for the life of the new equipment. The customer would pay an amount equal to the cost of rebuilding the air conditioning unit (typically replacing the compressor), and BG&E would pay the rest of the cost.

2. A Large Commercial Planned HVAC Retirement program component which addresses HVAC and lighting equipment of existing Large General Service (GL) class customers. This program concept is also based on the energy efficiency opportunities presented when air conditioning systems (in this case chillers) fail. At this time the customer faces considerable expense to replace or rebuild the unit. Again, if a comprehensive high efficiency lighting retrofit is introduced at this time, the lighting based cooling load can be reduced. In addition, low-E window film is retrofited to the building's windows. Both actions result in a reduced capacity requirement for the new higher efficiency equipment and substantial energy and demand savings for the life of the new equipment. The customer would pay an amount equal to the cost of rebuilding the chiller (i.e., the rebuilding required to adapt the chiller to

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[1] Letter to Mr. Ronald E. Hawkins, Executive Secretary, Public Service Commission fo Maryland, "Baltimore Gas and Electric Company Collaborative Process, Status Report", October 30, 1992.

non-CFC refrigerant and/or repair it for continued operation), and BG&E would pay the rest of the cost.

Other similar program concepts such as Planned HVAC Retirement for existing Large General Service (GL) class customers with packaged roof-top units and Planned HVAC Retirement for existing Industrial category (Schedule P) customers were not assessed by RII. These program concepts can be expected to perform similarly to the concepts which RII has assessed.

Small Commercial HVAC Retirement

RII's assessment of the Small Commercial HVAC Retirement program component begins with an estimate of the costs and energy saving performance of the program concept as applied to a typical small commercial customer's building. The basic assumptions about this typical existing building are as follows:

Building square feet:	4,000 sqft
Square feet per ton A/C:	400 sqft
Lighting load:	2.5 W/sqft
Lighting System kW:	10.0 kW
EER of roof-top unit:	6.0 EER
A/C capacity:	10.0 ton unit
Cooling and lighting peak kW	30.0 kW
Cooling and lighting kWh	46,000 kWh

The basic assumptions about this typical existing building after completion of the lighting retrofit and installation of the new smaller more efficient roof-top unit are as follows:

Building square feet:	4,000 sqft
Square feet per ton A/C:	500 sqft
Lighting load:	1.0 W/sqft
Lighting System kW:	4.0 kW
EER of roof-top unit:	10.0 EER
A/C capacity:	8.0 ton unit
Cooling and lighting peak kW	13.6 kW
Cooling and lighting kWh	20,000 kWh

The cost-effectiveness of this typical project was assessed using estimates of project cost and demand and energy savings valued at BG&E's avoided costs.[2] The project was found to be cost-effective from a societal prespective (benefit-cost ratio of 2.21).

The impacts of this cost-effective program component were estimated by applying the impacts of the typical project to

[2] As per BG&E memo dated June 23, 1992 by J. Rudolph.

applicable BG&E GS class customers. It was assumed that there are 81,000 small commercial and industrial customers[3] and the saturation of air conditioning equipment is 60%.[4] It was also assumed that 8.33% of this air conditioning equipment would become eligible for program participation each year and that of these eligible participants 956 (25%) would participate in 1993, 1,913 (50%) would participate in 1994, and 2,869 (75%) would participate in each year 1995-2001.

The result is an estimate of 301 MW savings through 2001 derived from implementing this program concept assuming an 80% load diversity factor.

Large Commercial HVAC Retirement

RII's assessment of the Large Commercial HVAC Retirement program component begins with an estimate of the costs and energy saving performance of the program concept as applied to a typical large commercial customer's building with a chiller based system. The basic assumptions about this typical existing building[5] are as follows:

Building square feet:	100,000	sqft
Window film:	no	
Square feet per ton A/C:	400	sqft
Lighting load:	2.5	W/sqft
Lighting System kW:	250.0	kW
Chiller peak kW/ton:	.85	kW/ton
System capacity:	250.0	tons
Cooling and lighting peak kW	630.0	kW
Cooling and lighting kWh	1,402,500	kWh

The basic assumptions about this typical existing building after completion of the lighting retrofit and installation of the new smaller more efficient chiller are as follows:

Building square feet:	100,000	sqft
Window film:	yes	
Square feet per ton A/C:	625	sqft
Lighting load:	.85	W/sqft
Lighting System kW:	85.0	kW
Chiller peak kW/ton:	.60	kW/ton

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[3] BG&E 1992 IRP, Exhibit II-D, pg. 7-12

[4] BG&E 1992 IRP, Exhibit II-C, pg. 3-18.

[5] Based on the case presented in David J. Houghton, etal., The State of the Art: Space Cooling and Air Handling, COMPETITEK, Boulder, CO, August 1992, pg. 18.

System capacity:	160.0 tons
Cooling and lighting peak kW	227.4 kW
Cooling and lighting kWh	390,040 kWh

The cost-effectiveness of this typical project was assessed using estimates of project cost and demand and energy savings valued at BG&E's avoided costs.[6] The project was found to be cost-effective from a societal prespective (benefit-cost ratio of 2.99).

The impacts of this cost-effective program component were estimated by applying the impacts of the typical project to applicable BG&E GL class customers. It was assumed that there are 7,700 large commercial and light industrial customers[7] and the saturation of air conditioning equipment is 60%.[8] Further, it was assumed that 60% of this air conditioning equipment consists of chiller based systems. It was also assumed that 10% of this air conditioning equipment would become eligible for program participation each year as a result of equipment failure or retrofit for non-CFC refrigerant. It was estimated that of these eligible participants 58 (25%) would participate in 1993, 116 (50%) would participate in 1994, and 173 (75%) would participate in each year 1995-2001.

The result is an estimate of 528 MW savings through 2001 derived from implementing this program concept assuming a 90% load diversity factor.

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[6] As per BG&E memo dated June 23, 1992 by J. Rudolph.

[7] BG&E 1992 IRP, Exhibit II-D, pg. 7-12

[8] BG&E 1992 IRP, Exhibit II-C, pg. 3-18.

ATTACHMENT 4

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	09-Nov-92														
2						Appalacian Coal Escalator Data									
3															
4	Date			Tons			Price			Total Cost					
5							($/ton)			($)					
6															
7	Oct 88			2,624,975			37.03			97,202,624					
8	Nov 88			2,511,815			38.12			95,750,388					
9	Dec 88			2,497,768			38.63			96,488,701					
10	Jan 89			2,609,100			36.66			95,649,606					
11	Feb 89			2,437,200			37.69			91,858,068					
12	Mar 89			2,771,700			35.37			98,035,029					
13	Apr 89			2,697,500			36.12			97,433,700					
14	May 89			2,608,900			36.6			95,485,740					
15	June 89			2,218,500			40.85			90,647,575					
16	July 89			1,923,600			39.44			75,866,784					
17	Aug 89			2,850,500			37.69			107,435,345					
18	Sept 89			2,436,000			37.66			91,739,760					
19															
20		TOTAL		30,187,556			37.55831			1,133,790,520					
21															
22	Oct 89			2,714,900			36.99			100,424,151					
23	Nov 89			2,573,700			37.25			95,870,325			1992 index =		1.020529
24	Dec 89			2,350,200			38.58			90,670,716			1991 index =		1.036175
25	Jan 90			5,254,012			39.97			210,002,860					
26	Feb 90			2,592,148			38.94			100,938,243					
27	Mar 90			2,944,327			38.93			114,622,650			0.0167	$/kwh	1990
28	Apr 90			2,652,294			38.82			102,962,053			0.017304	$/kwh	1991
29	May 90			2,497,708			38.48			96,111,604			0.017659	$/kwh	1992
30	June 90			2,495,508			39.44			98,422,836					
31	July 90			2,213,666			40.43			89,498,516					
32	Aug 90			2,452,083			39.3			96,366,862					
33	Sept 90			2,534,548			39.09			99,075,481					
34															
35		TOTAL		33,275,094			38.91699			1,294,966,497					
36															
37	Oct 90			2,913,326			39.27			114,406,312					
38	Nov 90			2,277,534			40.77			92,855,061					
39	Dec 90			2,345,144			39.34			92,257,965					
40	Jan 91			2,460,579			41.05			101,006,768					
41	Feb 91			2,418,959			39.45			95,349,033					
42	Mar 91			2,515,904			39.31			98,900,186					
43	Apr 91			2,230,929			39.49			88,099,386					
44	May 91			2,279,447			38.9			88,670,488					
45	June 91			1,972,053			39.33			77,560,844					
46	July 91			2,032,274			39.31			79,888,691					
47	Aug 91			2,203,694			40.19			88,566,482					
48	Sept 91			2,035,765			40.24			81,919,184					
49															
50		TOTAL		27,683,608			39.71594			1,099,480,380					
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The Potomac Edison Company
Part of the Allegheny Power System

LEGAL DEPARTMENT

Downsville Pike, Hagerstown, MD 21740 (301) 790-3400

November 13, 1992

RECEIVED

NOV 16 1992

Ronald E. Hawkins
Executive Secretary
Public Service Commission
of Maryland
American Building
231 E. Baltimore Street
Baltimore, MD 21202

Re: Application of The Potomac Edison Company for Approval of an Electric Energy Purchase Agreement with AES Warrior Run, Inc. - PSC of Maryland Case No. 8179

Dear Mr. Hawkins:

On July 22, 1988, The Potomac Edison Company (PE) filed with the Commission for approval an Electric Energy Purchase Agreement with AES, Petrolia, Inc. (the EEPA). The EEPA was subsequently amended and in January of 1989 PE requested Commission approval of Amendment No. 1 to the EEPA. The EEPA, as amended, was approved by the Commission's Order No. 68345 in this case dated February 13, 1989.

On January 4, 1991, PE and AES Warrior Run, Inc. (successor by change of name to AES Petrola, Inc., hereinafter AES WR) filed a Joint Petition for Modification and Clarification of Order No. 68345. For the AES Warrior Run Project, the parties requested the Commission to grant an exception to its general policy that the capacity payments for purchases from qualifying facilities be recovered in base rates. On February 22, 1991, the Commission issued Order No. 69129 which permits PE to apply to recover the capacity payments for purchases from the AES Warrior Run project currently through a surcharge.

Since that time, AES WR has requested a change in the location of the project from the presently approved Celanese site to a new site located at Mexico Farms in Allegany County, Maryland. In consideration for agreeing to a change in project site, PE negotiated for the benefit of its customers a delay of one year in the project's earliest in-service date from October 1, 1995 to October 1, 1996. This delay would be accomplished with no increase in the capacity price to be charged PE by the project. This change was accepted by AES WR, and the new site and the one year's delay in the earliest in-service date are reflected in Amendment No. 2 to the EEPA enclosed herewith.

Consistent with the Commission's policy concerning purchase contracts between electric utilities and larger qualifying facilities, PE respectfully requests Commission approval of Amendment No. 2 to the EEPA in this matter. Approval of this Amendment would not affect the cost recovery mechanism authorized by the Commission's Order No. 69129 in this case.

AES WR supports and concurs with PE'S request for approval of Amendment No. 2 to the EEPA.

Fifteen copies of this letter and Amendment No. 2 are included for distribution to interested Commission personnel. Copies of this transmittal letter and the Amendment are being served on those parties who traditionally appear in PE's Maryland fuel and rate cases.

I also enclose a computer disk containing this filing together with a description of the files on the disk.

Should you have any questions concerning the Company's request, please contact me.

Very truly yours,

Philip J. Bray

Philip J. Bray

Enclosure

cc: John J. Carrara, Esq., Westvaco
Allen M. Freifeld, Esq., Staff
Lynne E. Gedanken, Esq. - AES WR
John M. Glynn, Esq., OPC
M. Brent Hare, Esq., DNR
Edward F. Shea, Jr., Esq., Eastalco

PJB:lmf/wd-8179PA.ltr

AMENDMENT NO. 2 TO ELECTRIC ENERGY PURCHASE AGREEMENT

AMENDMENT dated as of September 30, 1992 to ELECTRIC ENERGY PURCHASE AGREEMENT dated as of January 15, 1988, as amended by the AMENDMENT TO ELECTRIC ENERGY PURCHASE AGREEMENT dated as of November 1, 1988 (the "Agreement") between AES WARRIOR RUN, INC. (successor by change of name to AES Petrolia, Inc., formerly known as AES Cumberland, Inc.), a Delaware corporation having its principal place of business at 1001 North 19th Street, Arlington, Virginia 22209 (the "Seller") and THE POTOMAC EDISON COMPANY, a Maryland and Virginia corporation having its principal place of business at Downsville Pike, Hagerstown, Maryland 21740 (the "Buyer").

Seller and Buyer are parties to the Agreement, which provides for the sale by Seller and the purchase by Buyer of electric energy generated by a coal-fired cogeneration plant consisting of one or two circulating fluidized bed boilers or one or two pulverized coal-fired boilers, one steam turbine generator and related facilities having a gross design capacity of approximately 200 megawatts.

Seller and Buyer desire to amend the Agreement in certain respects. Accordingly, Seller and Buyer, intending to be legally bound, hereby agree as follows:

1. All references to the location of the Project at "Cresaptown, Allegany County, Maryland, approximately 4.5 miles southwest from Cumberland, Maryland" shall be deleted wherever appearing and replaced with the words "Allegany County Industrial Park, Allegany County, Maryland, approximately 4.5 miles southeast from Cumberland, Maryland".

2. All references to "AES Cumberland, Inc." and the "Cumberland Project" shall be deleted and replaced wherever appearing with the words "AES Warrior Run, Inc." or the "Warrior Run Project", as the case may be.

3. Section 1.2(a) shall be amended by the deletion of the date "September 30, 1995" and substituting the date "September 30, 1996" therefor.

4. Section 2.1(a) shall be amended by the deletion of the date "October 1, 1994" and substituting the date "October 1, 1995" therefor.

5. Section 2.1(a) shall be further amended by the deletion of the date "October 1, 1995" and substituting the date "October 1, 1996" therefor.

6. Section 5.7 shall be amended by the deletion of the date "December 31, 1992" and substituting the date "December 31, 1993" therefor.

7. Section 6.1(a) shall be amended by the deletion of the date "October 1, 1996" and substituting the date "October 1, 1997" therefor.

8. Section 6.2(b)(i) shall be amended by the deletion of the date "October 1, 1995" and substituting the date "October 1, 1996" therefor.

9. Section 9.1 Definitions shall be amended as follows:

(a) By deleting the date "October 1, 1995" in the terms "APS Proxy Units", "Avoided Energy Cost Rate", "Commencement Date", and "Dispatch Rate" and substituting the date "October 1, 1996" therefor.

(b) By deleting the date "October 1, 1994" in the term "Interconnection Date" and substituting the date "October 1, 1995" therefor.

(c) By deleting the date "December 31, 1995" in the term "Minimum Reserve Fund Requirement" and substituting the date "December 31, 1996" therefor.

10. The first paragraph of Section 10.2 shall be amended by the deletion of the dates "October 1, 1995", "September 30, 1995" and "October 1, 1996" and substituting the dates "October 1, 1996", "September 30, 1996" and "October 1, 1997" respectively therefor.

11. Section 10.2(c)(iii) shall be amended by the deletion of the date "January 1, 1993" and substituting the date "January 1, 1994" therefor.

12. The "QS" factor specified under the Assumptions section on Pages 1 and 2 of Exhibit C shall be amended by the deletion of the date "01-Oct-95" and substituting the date "01-Oct-96" therefor, as shown on the revised Pages 1 and 2 of Exhibit C, which are attached hereto and made a part hereof.

13. The "QE" factor specified under the Assumptions section on Pages 1 and 2 of Exhibit C shall be amended by the deletion of the date "01-Oct-2025" and substituting the date "01-Oct-2026" therefor, as shown on the revised Pages 1 and 2 of Exhibit C, which are attached hereto and made a part hereof.

14. The "PS" term in the Definitions section on Pages 1 and 2 of Exhibit C shall be amended by the deletion of the date "01-Oct-95" and substituting the date "01-Oct-96" therefor, as shown on the revised Pages 1 and 2 of Exhibit C, which are attached hereto and made a part hereof.

15. Exhibit D of the Agreement shall be amended by the deletion of all references to "AES Cumberland, Inc." and substituting the phrase "AES Warrior Run, Inc." therefor and by the deletion in the first paragraph of Exhibit D of the words "1925 North Lynn Street" and substituting the phrase "1001 North 19th Street" therefor.

16. The first recital in Exhibit D to the Agreement shall be amended by the deletion of the phrase "near Cresaptown, Allegany County, Maryland, approximately 4.5 miles southwest" and substituting the phrase "in the Allegany County Industrial Park, Allegany County, Maryland, approximately 4.5 miles southeast" therefor.

17. Exhibit E to the Agreement shall be amended by the deletion of all references to "AES Cumberland, Inc." and substituting the phrase "AES Warrior Run, Inc." therefor and by the deletion in the first paragraph of Exhibit E of the words "1925 North Lynn Street" and substituting the phrase "1001 North 19th Street" therefor.

18. The first recital in Exhibit E to the Agreement shall be amended by the deletion of the phrase "near Cresaptown, Allegany County, Maryland, approximately 4.5 miles southwest" and substituting the phrase "in the Allegany County Industrial Park, Allegany County, Maryland, approximately 4.5 miles southeast" therefor.

19. All references to the years "1993", "1994", "1995", and "1996" as they may appear in Schedule I to the Agreement shall be deleted and replaced with the years "1994", "1995", "1996", and "1997", respectively.

20. All references to the years "1993", "1994", "1995", and "1996" as they may appear in Schedule II to the Agreement shall be deleted and replaced with the years "1994", "1995", "1996", and "1997", respectively.

21. Each reference in the Agreement to "this Agreement", "hereto", "hereof", "hereby", or words of similar import shall be deemed to refer to the Agreement, as amended hereby.

22. This Amendment shall become effective upon the approval of the Agreement, as amended hereby, by the Public Service Commission of Maryland.

23. As amended hereby, the Agreement is hereby ratified and confirmed in all respects.

IN WITNESS WHEREOF, the parties hereto have duly executed this Amendment as of the date and year first above written.

AES WARRIOR RUN, INC.

By: ______________________

Title: Vice President

THE POTOMAC EDISON COMPANY

By: ______________________

Title: President

Sample Calculation #1, (hypothetical determination after 25 months): $49,910,498 is the capacity termination cost. 28-Aug-92

Assumptions:
CO = Contract Output = 180.0 MWh/h
QS = QF start date = 01-Oct-96 = 23,962 months
QE = QF contract expiration date = 01-Oct-2026 = 24,322 months
Column 4 = The assumed scheduled output of the QF in MWh per month
Column 2 = Capacity Rate (mills/kWh)

Definitions:
Expected contract term = 360 months
d = Annual discount rate = 12.70%
md = Monthly discount rate = 1.001307%
e = Annual Escalation rate = 6.00%
me = Monthly escalation rate = 0.486755%
PS = APS plant start date = 01-Oct-96 = 23,962 months
PL = APS plant life = 396 months
US = PV factor of uniform series = (1-(1+md)^-PL)/md = 97.9378
ES = PV factor of uniform escalating series to infinity = 1/(1-((1+me)/(1+md))^PL) = 1.1525
LF = Levelizing Factor = md/(1-(1+md)^-360) = 0.0103
RF = Replacement Factor = 1-((1+me)/(1+md))^(QS+360-PS) if QS+360>PS else 0 = 0.8410 [Factor for overlap with APS capacity need]
CTA = LF * RF * US * ES = 0.9775 [Contract Term Adjust. for 360 month term]
LF1 = Levelizing Factor = md/(1-(1+md)^-25) = 0.0454
RF1 = Replacement Factor = 1-((1+me)/(1+md))^(QS+25-PS) if QS+25>PS else 0 = 0.1199 [Factor for overlap with APS capacity need]
CTA1 = LF1 * RF1 * US * ES = 0.6145 [Contract Term Adjust. for 25 month term]
Column 3 = Column 2 * (1 - (CTA1 / CTA))
75% Output = CO * 0.75 * 8766 / 12 = 98,618 MWh / month
Column 5 = For each month of the operating year (12 month period beginning with the Billing Period in which the most recent anniversary of the Commencement Date occurs), the cumulative value of Column 5 should equal the greater of the cumulative value Scheduled Monthly MWH Output or the cumulative value 75% Output. Cumulative value means for this purpose the sum of the monthly values since the beginning of the operating year.
Column 6 = Column 3 * Column 5
Column 7 = sum of the previous values in Columns 6 and 7 * md
Column 8 = sum of all values in Columns 6 and 7

	------ mills/kWh ------						
Months ---(1)---	Capacity Rate ---(2)---	Monthly Levelized Cost-Value Difference ----(3)----	Scheduled Monthly MWH Output ----(4)----	Scheduled MWH Output or 75% Output ----(5)----	Monthly Cost-Value Difference -----(6)-----	Interest -----(7)-----	Capacity Termination Costs - after 25 months (current $) -----(8)-----
1	47.20	17.5308	131,490	131,490	$2,305,128		
2	47.20	17.5308	131,490	131,490	$2,305,128	$23,081	
3	47.20	17.5308	131,490	131,490	$2,305,128	$46,394	
4	47.20	17.5308	131,490	131,490	$2,305,128	$69,940	
5	47.20	17.5308	131,490	131,490	$2,305,128	$93,722	
6	47.20	17.5308	131,490	131,490	$2,305,128	$117,741	
7	47.20	17.5308	131,490	131,490	$2,305,128	$142,002	
8	47.20	17.5308	131,490	131,490	$2,305,128	$166,505	
9	47.20	17.5308	131,490	131,490	$2,305,128	$191,254	
10	47.20	17.5308	0	0	$0	$216,250	
11	47.20	17.5308	0	0	$0	$218,415	
12	47.20	17.5308	0	0	$0	$220,602	
13	48.50	18.0137	0	98,618	$1,776,463	$222,811	
14	48.50	18.0137	0	98,618	$1,776,463	$242,830	
15	48.50	18.0137	0	98,618	$1,776,463	$263,050	
16	48.50	18.0137	131,490	98,618	$1,776,463	$283,471	
17	48.50	18.0137	131,490	98,618	$1,776,463	$304,098	
18	48.50	18.0137	131,490	98,618	$1,776,463	$324,930	
19	48.50	18.0137	131,490	98,618	$1,776,463	$345,972	
20	48.50	18.0137	131,490	98,618	$1,776,463	$367,224	
21	48.50	18.0137	131,490	98,618	$1,776,463	$388,689	
22	48.50	18.0137	131,490	98,618	$1,776,463	$410,369	
23	48.50	18.0137	131,490	98,618	$1,776,463	$432,265	
24	48.50	18.0137	131,490	98,618	$1,776,463	$454,382	
25	49.80	18.4965	98,618	98,618	$1,824,079	$476,719	$49,910,498

Notes: "*" indicates multiplication, "/" indicates division, "^" indicates exponentiation, ">" indicates greater than, "PV" means Present Value, "QF" refers to this project. For this purpose scheduled output is the MWh's for which capacity payments were made. Special adjustments may have to be made for the first and last months of the contract. The actual escalation of the capacity rate is a separate calculation which is not related with the escalation rate "e" used here.

Sample Calculation #2, showing approximations for each possible year. Assumes 98,618 MWh / month scheduled for all months.

Assumptions: 28-Aug-92

```
   CO = Contract Output                 = 180.0 MWh/h
   QS = QF start date                   =   01-Oct-96 = 23,962 months
   QE = QF contract expiration date     = 01-Oct-2026 = 24,322 months
        Column 6    = Capacity Rate (mills/kWh)
```

Definitions:

```
        Expected contract term          = 360 months
    d = Annual discount rate            =    12.70%
   md = Monthly discount rate           = 1.001307%
    e = Annual escalation rate          = 6.000000%
   me = Monthly escalation rate         = 0.486755%
   PS = APS plant start date            =   01-Oct-96 = 23,962 months
   PL = APS plant life                  = 396 months
   US = PV factor of uniform series     = (1-(1+md)^-PL)/md   = 97.9378
   ES = PV factor of uniform escalating series to infinity    = 1/(1-((1+me)/(1+md))^PL) = 1.1525
  CTA = Contract Term Adjustment (for expected contract term) = 0.9775
    T = Column 1    = Actual contract term in months (up to the time of computation)
        Column 2    = md/(1-(1+md)^-T)                       [Levelizing factor over QF term]
        Column 3    = 1-((1+me)/(1+md))^(QS+T-PS) if QS+T>PS else 0  [Factor for overlap with APS capacity need]
        Column 4    = Column 2 * Column 3 * US * ES          [Actual Contract Term Adjustment]
        Column 5    = Column 4 / CTA                         [Percent of value received]
        Column 7    = the levelized equivalent of capacity payments to date
        Column 8    = Column 5 * Column 7
        Column 9    = Column 7 - Column 8
        75% Output  = CO * 0.75 * 8766 / 12                  = 98,618 MWh / month
   SO = Scheduled Output                                     = 98,618 MWh / month
        Column 10   = the greater of 0 or (Column 9 * the greater of SO or 75% Output)
        Column 11   = the future value of Column 10 for Column 1 months
```

Actual Contract Term (months)	Levelizing Factor	Replacement Factor	Actual Contract Term Adjustment	Capacity Value Factor	Capacity Rate (mills/kWh)	Levelized Capacity Rate to Date (mills/kWh)	Monthly Levelized Capacity Value (mills/kWh)	Monthly Levelized Cost-Value Difference (mills/kWh)	Monthly Cost-Value Difference	Capacity Termination Costs (current $)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
12	0.0889	0.0594	0.5962	61.0%	47.20	47.20	28.7895	18.4105	$1,815,594	$23,027,956
24	0.0471	0.1154	0.6131	62.7%	48.50	47.81	29.9850	17.8262	$1,757,978	$47,426,119
36	0.0332	0.1680	0.6298	64.4%	49.80	48.40	31.1810	17.2156	$1,697,760	$73,151,783
48	0.0263	0.2174	0.6464	66.1%	51.20	48.98	32.3886	16.5886	$1,635,926	$100,188,568
60	0.0223	0.2639	0.6629	67.8%	52.60	49.54	33.5968	15.9428	$1,572,238	$128,458,107
72	0.0196	0.3077	0.6793	69.5%	54.00	50.08	34.8001	15.2795	$1,506,824	$157,860,620
84	0.0177	0.3489	0.6954	71.1%	55.40	50.60	35.9947	14.6010	$1,439,913	$188,271,828
96	0.0163	0.3876	0.7114	72.8%	56.80	51.09	37.1774	13.9100	$1,371,768	$219,539,436
108	0.0152	0.4240	0.7271	74.4%	58.20	51.55	38.3454	13.2093	$1,302,664	$251,479,128
120	0.0144	0.4582	0.7425	76.0%	59.70	52.00	39.5005	12.5029	$1,233,005	$283,900,081
132	0.0137	0.4904	0.7577	77.5%	61.20	52.43	40.6390	11.7929	$1,162,988	$316,537,385
144	0.0131	0.5207	0.7725	79.0%	62.80	52.84	41.7613	11.0823	$1,092,913	$349,104,363
156	0.0127	0.5492	0.7871	80.5%	64.40	53.24	42.8640	10.3730	$1,022,955	$381,230,879
168	0.0123	0.5760	0.8013	82.0%	66.00	53.61	43.9444	9.6667	$953,303	$412,484,062
180	0.0120	0.6012	0.8151	83.4%	67.70	53.97	45.0024	8.9658	$884,187	$442,380,328
192	0.0117	0.6249	0.8286	84.8%	69.40	54.31	46.0356	8.2721	$815,769	$470,331,102
204	0.0115	0.6472	0.8418	86.1%	71.20	54.63	47.0439	7.5873	$748,236	$495,672,127
216	0.0113	0.6682	0.8545	87.4%	73.00	54.94	48.0251	6.9128	$681,725	$517,612,950
228	0.0112	0.6879	0.8669	88.7%	74.90	55.23	48.9793	6.2503	$616,385	$535,256,461
240	0.0110	0.7065	0.8789	89.9%	76.80	55.51	49.9048	5.6007	$552,330	$547,550,988
252	0.0109	0.7239	0.8905	91.1%	78.80	55.77	50.8016	4.9654	$489,675	$553,299,492
264	0.0108	0.7403	0.9017	92.2%	64.60	55.85	51.5213	4.3328	$427,287	$549,541,005
276	0.0107	0.7558	0.9125	93.3%	66.20	55.94	52.2231	3.7207	$366,929	$536,499,968
288	0.0106	0.7703	0.9229	94.4%	67.90	56.04	52.9060	3.1291	$308,588	$512,414,520
300	0.0105	0.7840	0.9330	95.4%	69.60	56.13	53.5686	2.5579	$252,250	$475,258,605
312	0.0105	0.7968	0.9426	96.4%	71.40	56.22	54.2104	2.0067	$197,900	$422,722,110
324	0.0104	0.8089	0.9519	97.4%	73.20	56.31	54.8306	1.4756	$145,521	$352,160,101
336	0.0104	0.8202	0.9608	98.3%	75.10	56.39	55.4289	0.9643	$95,093	$260,558,564
348	0.0103	0.8309	0.9694	99.2%	77.00	56.48	56.0050	0.4725	$46,595	$144,477,495
360	0.0103	0.8410	0.9775	100.0%	79.00	56.56	56.5589	0.0000	$0	$0

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