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DC PSC FC785

July 1982

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE
DISTRICT OF COLUMBIA
FORMAL CASE NO. 785

DIRECT TESTIMONY
OF
PAUL L. CHERNICK

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Paul L. Chernick. I am employed as a research associate by Analysis and Inference, Inc., 10 Post Office Square, Suite 970, Boston, Massachusetts, 02109.

Q. MR. CHERNICK, WOULD YOU PLEASE BRIEFLY 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 a S.M. degree from Massachusetts Institute of Technology in February, 1978, in Technology and Policy. I have been elected to membership in the engineering honorary society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi. I am the author of Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions, Report 77-1, Technology and Policy Program, Massachusetts Institute of Technology. During my graduate education, I was the teaching assistant for courses in systems analysis. I have served as a consultant to the National Consumer Law Center for two projects: teaching part of a short course in rate design and time-of-use rates, and assisting in preparation for an electric time-of-use rate design case. In my current position, I have advised a variety of clients on utility matters. My resume is attached to this testimony as Exhibit (H)-23.

Q. MR. CHERNICK, HAVE YOU TESTIFIED PREVIOUSLY IN UTILITY PROCEEDINGS?

A. Yes. I have testified approximately twenty times on utility issues before such agencies as the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Council, the Texas Public Utilities 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. Subjects I have testified on include cost allocation, rate design, long range energy and demand forecasts, costs of nuclear power, alternatives to nuclear power, electric generating and transmission system reliability, and fuel efficiency standards.

Q. HAVE YOU PUBLISHED ARTICLES ON COST ALLOCATION AND RATE DESIGN ISSUES?

A. Yes. My master's thesis, which deals largely with rate design issues, was published by M.I.T. In addition, I have co-authored one paper on cost allocation issues, which was published as an Institute Award Paper by the Institute for Public Utilities.

Q. BY WHOM HAVE YOU BEEN RETAINED IN THIS PROCEEDING?

A. I have been retained by the Office of the People's Counsel of the District of Columbia.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. First, I have been asked to examine the PEPCO generation, transmission, and distribution systems in order to provide Mr. Meyer, who is also testifying in this case, with recommendations concerning the engineering economic details of PEPCO's system. Second, I have been asked to review PEPCO's marginal cost estimation methodology and make recommendations for improvements in that methodology where appropriate.

Q. WHAT INFORMATION AND DATA SOURCES DID YOU USE IN PREPARING YOUR TESTIMONY?

A. The information and data I examined are listed in OPC Exhibit (H)-1.

Q. PLEASE DESCRIBE THE PRINCIPLES ON WHICH YOUR CLASSIFICATION RECOMMENDATIONS ARE BASED.

A. My classification approach is engineering-economic in nature. I do not rely on artificial or irrelevant distinctions, such as fixed/variable or capital/expenses. Instead, I examine each component of PEPCO's costs to determine what portion of that component would have been necessary to accommodate one allocator (such as a peak demand), with other possible allocators (such as energy use) set at or near zero. Thus, I define a minimum system for the first allocator.

I generally use a demand measure for the first allocator, so that energy is responsible for the remaining cost in excess of the minimum system. My reasons for this choice are both practical and philosophical. Practically, it is generally easier to define a system which would meet peak demand with little or no energy, than to define one which would carry the energy load with little or no peak demand. It is not even clear how the all-energy, no-demand situation would be defined: perhaps as a system with 100% load factor (although this would provide some reliability), or as a system which provides the present energy output over the year, but in no particular time pattern. Neither of these systems would be easy to model. Over all, the reliability-first or demand-first approach is simpler and less ambiguous.

My philosophical preference is also for considering peak demand (or reliability) before energy, following my perception of the utility planning process. In generation and transmission planning, utility planners generally appear to assign the first priority to providing acceptably reliable service and the second priority to minimizing energy costs and facilitating economic dispatch. In distribution planning, reliability also generally seems to be the primary concern; other factors, such as minimizing loss costs and maximizing equipment life, are matters of less urgency.

The division between reliability and energy is not really as clear-cut as the preceding discussion might imply. Energy use outside the peak period affects the reliability of all the major functional types of plant. In addition, the planning process is generally simultaneous, rather than sequential, regardless of the relative importance of reliability and total energy- related costs. Recent increases in energy prices may also have weakened or partially reversed the traditional order of priorities.

Q. ARE YOUR RECOMMENDED ALLOCATION METHODS BASED ON THE SAME CONSIDERATIONS AS ARE YOUR CLASSIFICATION RECOMMENDATIONS?

A. Yes. Again, I believe that the fundamental engineering and economic considerations which determine the cost of building and maintaining the utility's plant should be reflected in the choice of allocator. In principle, this would require different measures of demand and energy for each component of the system, to recognize diversity within and between classes, the influence of various time periods on thermal constraints, the differing costs of fuel and of line losses between periods, and similar considerations. Constraints of data and of time have prevented this sort of detailed analysis. In general, more sophisticated allocators would tend to shift revenue responsibility to classes with high use in the system peak period, such as the GT class. Since many of my other recommendations shift revenue responsibility onto the GT class, and off of the residential class, I expect that detailed allocators would further support our recommended allocation of the revenue increase.

I have recommended changes in allocators for a few distribution plant accounts, and for associated expenses. In most of these cases, I have simply recognized the diversity that is demonstrated by the several residential customers which may share one transformer, length of secondary, or (in the case of apartment buildings) services. In the case of services, I have also recognized that not every customer has a service drop. I also have credited each class's demand allocator with the load-carrying capacity of the services allocated to the class on the basis of customer number. Each of these recommendations is a straight forward and incremental refinement of PEPCO's approach; none is fundamentally different from PEPCO's allocation.

Q. DO YOU CONSIDER YOUR RECOMMENDATIONS TO REPRESENT THE ULTIMATE FORM OF COST ALLOCATION FOR PEPCO?

A. No. I consider my recomendations to be a preliminary, rough-cut attempt to define the energy-serving portion of

PEPCO's costs. With improved data, such as PEPCO's mix of equipment types, the effective load carrying capacity of each generator, and the number of customers which use each piece of equipment, the allocations can be improved.

Q. DO UTILITIES PLAN AND BUILD POWER PRODUCTION FACILITIES TO MEET RELIABILITY CONSTRAINTS OR TO PRODUCE ENERGY ECONOMICALLY, OR BOTH?

A. Power production facilities are built both in order to serve demand (i.e. to meet reliability constraints) and in order to produce energy economically (i.e. to minimize total generation costs over all 8760 hours of the load duration curve). Different facilities may be designed with different proportions of these two goals in mind. In other words, some facilities may be designed more to meet reliability constraints than to minimize total generation costs, the opposite may be true for some other facilities.

Q. PLEASE EXPLAIN WHY THIS IS TRUE.

A. The investment and fixed operating costs relating to generation are not caused solely, or even largely, by peak demands. Utilities attempt to minimize total generation costs, including both fixed and variable costs, over all 8760 hours of their annual load duration curve (LDC). If a utility wished to construct generation capacity just to serve its annual peak, it would construct far more capital-inexpensive, and fuel-expensive, capacity, like combustion turbines. However, PEPCO, like all other large utilities, finds it worthwhile to invest in far more capital-intensive generating facilities with lower fuel costs in order to serve all kwh's and all kw's (no matter where they appear on the LDC) more economically. As a result, a very substantial proportion of production power supply costs are in fact incurred to save energy rather than meet reliability constraints.

Q. PLEASE GO INTO MORE DETAIL ON THE SUBJECT OF WHY UTILITIES INVEST IN DIFFERENT TYPES OF GENERATING FACILITIES.

A. There are two basic reasons for a utility investing in generating facilities. First, generators are built to maintain or increase system reliability, that is the probability that customer demand can be met by available generating capacity at any particular instant. Second, more expensive generating facilities are built to allow for more economical operation, that is, so that they can burn cheaper fuel and/or burn fuel more efficiently.

PEPCO's existing combustion turbines cost an average of $198/kw in 1981 dollars. The Morgantown, Dickerson, and Chalk Point steam units all cost substantially more than gas turbines. PEPCO is projecting the need for a 300 mw coal fired unit in 1993 which is estimated to cost $1100/kw in 1981 dollars (PEPCO Ex. C., p. 3). Obviously, PEPCO accepts higher capital cost as a tradeoff for lower heat rates and less expensive fuel.

Q. IS THE GENERATION CAPITAL COST WHICH IS RELATED TO RELIABILITY DETERMINED SOLELY BY PEAK DEMAND?

A. Absolutely not, for at least three reasons. First, most utility systems base their reliability requirements on a loss-of-load probability (LOLP) target, which requires that the expected number of hours of generation supply inadequacy over the course of a particular planning horizon (usually a year) be less than that target. Load shape affects the difficulty of maintaining system reliability. Stated another way, differences in the shape of the load duration curve will cause differences in the amount of reserve capacity required to meet a reliability constraint. Everything else being equal, higher reserve margins and hence more capacity are required for systems with high load factors and many hours per year with demand near the system peak than for systems with low load factors and with sharply spiked load curves. Let us define two systems, System 1 and System 2, which are both hypothetical extremes. For illustration purposes, I will assume an LOLP criteria of 1 day in 10 years. System 1 has a sharp peak and thus has only 100 hours which are vulnerable to supply inadequacy; if 10,000 mw of reasonably reliable capacity is installed, the probability of losing load in the low-demand hours is negligible. Therefore, for System 1, a "1 day in 10 years" LOLP criteria essentially means "24 hours of LOLP in 1000 hours (10 years x 100 hours/year) at or near full load." Therefore 2.4% of the high-load hours can result in load-shedding without violating the LOLP target.

By comparison, System 2 has a broad peak and thus has 1000 hours/year which are at risk, so the permissible rate of supply inadequacy is lowered to only 0.24% of the high-load hours, if the target LOLP is to be maintained. Therefore, System 2 will require a higher reserve margin to achieve a target LOLP than will System 1; this result is an effect of the off-peak hours' demand on additional capacity.

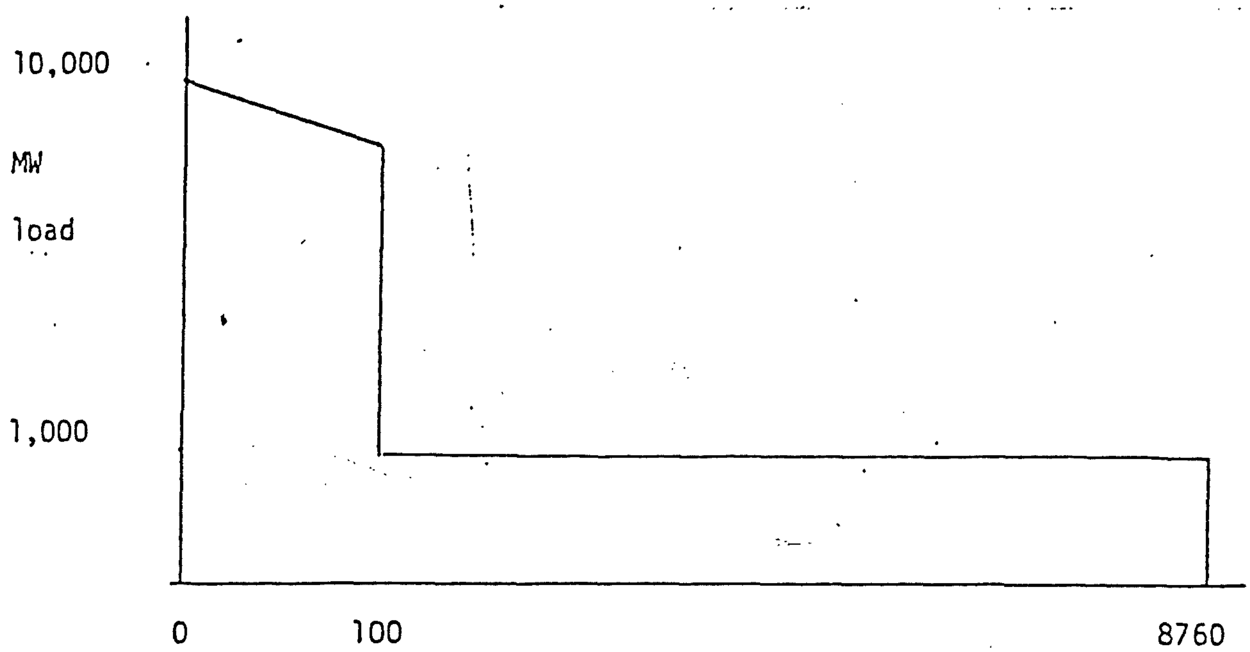

Figure 1: System 1's Load Duration Curve

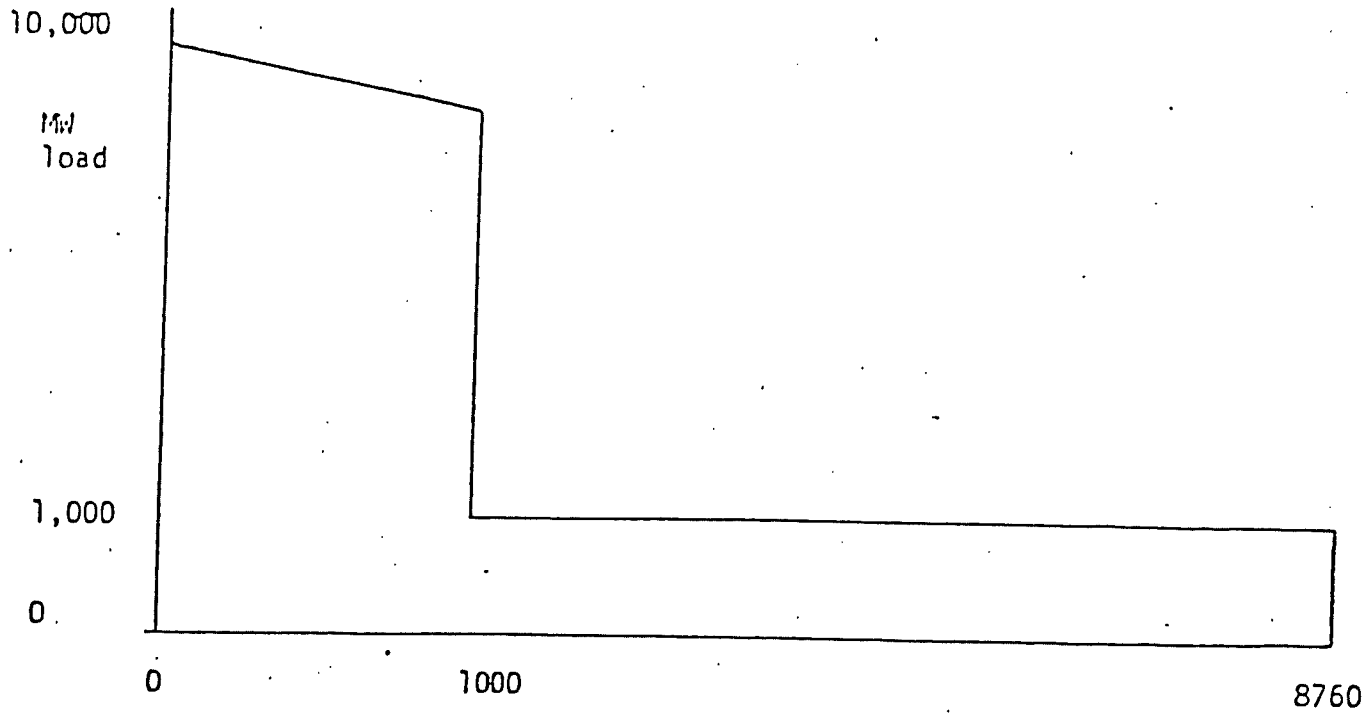

Figure 2: System 2's Load Duration Curve

Second, higher load factors require the installation of additional capacity to allow for maintenance of generating units. Let us define System 3 as hypothetical example of a system unconstrained by maintenance requirements. Monthly peaks in seven months (October - April) in System 3 are far below the annual peak. Even allowing for overruns, several large generators might be removed for maintenance during the offseason, without substantially impacting system reliability or the attainment of target LOLP.

By comparison, let us define hypothetical System 4 which does not have the same long, deep valley during the off-peak months. As a result, only a small number of generating units could be removed from service simultaneously for maintenance without increasing LOLP. Depending on the size, number and type of generators, it might not be possible to schedule them all for maintenance without appreciably increasing LOLP and therefore requiring additional capacity.

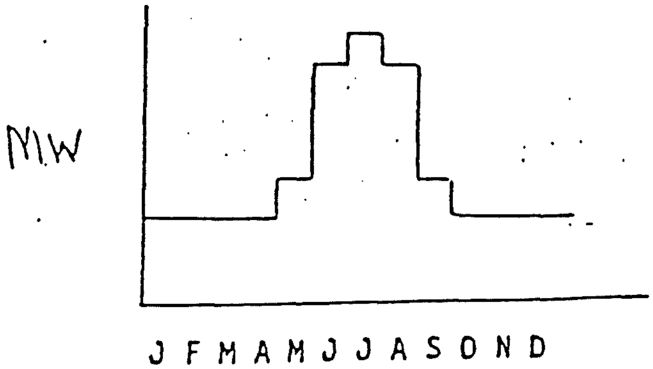

Figure 3: System 3's Annual Load Curve

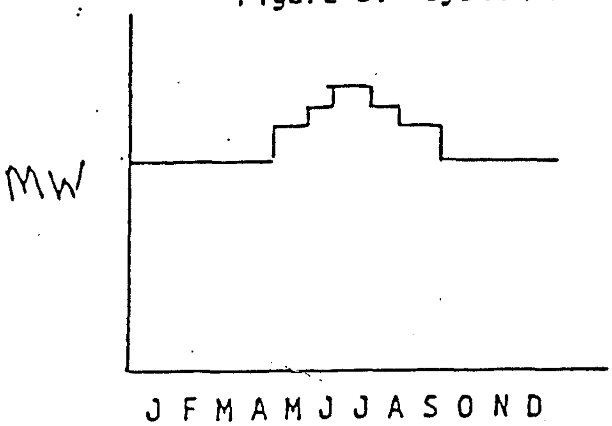

Figure 4: System 4's Annual Load Curve

A utility with a high load factor, and more specifically, consistently high monthly and weekly peaks, therefore requires a higher reserve margin than a low load-factor utility. This tendency extends to weekly load curves; a utility with consistently low demand on weekends (even in peak months) may be able to schedule some maintenance during those times without requiring additional capacity, while a utility with higher weekend demand might not be able to do so. Therefore, required reserves are also increased by demand in off-peak weeks and months, and by demand on weekends, even if these demands do not contribute substantially and directly to LOLP.

Third, capacity must be more durable if it is to meet demand throughout the year, rather than for just a few peak hours. Even peaking plants, such as combustion turbines, are typically expected to be able to function up to 1500 hours per year. While it is difficult to quantify the exact cost effect of this durability requirement, it is clear that providing reliable service outside a few peak hours must require some additional capital investment. Furthermore, a portion of O&M and capital additions are also due to the amount of use that a generating unit receives and of the resultant wear and stress on components.

Q. WHY DO COAL AND OIL STEAM PLANTS SUPPORT LESS FIRM DEMAND THAN WOULD BE SUPPORTED BY AN EQUIVALENT MW CAPACITY OF COMBUSTION TURBINES?

A. There are three basic reasons. First, large steam units tend to have higher forced outage rates than small peaking units. Second, large steam units have large maintenance requirements. The combined effect of these outages may be seen in the projections of capacity factors and related parameters for large units tabulated in Exhibit (H)-2. Third, independent of forced outage rates and scheduled maintenance requirements, the very size of large units reduces their contribution to system reliability. This effect can be illustrated by the following simple example. Consider a system with a 2000 mw system peak and with 3000 mw of installed capacity. If that capacity is composed of three 1000 mw plants, each with a 10% forced outage rate, the probability of not meeting peak demand (that is, the probability that 2 or 3 plants will be out) is 0.028:

LOLP = (3x.9x.1x.1) + (1x.1x.1x.1)

LOLP = 0.027 + 0.001

LOLP = 0.028

which is equivalent to 10.22 days/year, or 1 day in 0.0978 years. By contrast, if the 3000 mw of installed capacity is made up of 60 plants of 50 mw each, with each plant still having a 10% forced outage rate, the probability of not meeting peak (which now requires 21 or more (of 60) simultaneous outages) is only on the order of 1.57×10^{-7} which is equivalent to 0.0000573 days (about 5 seconds) per year, or 1 day in 17,452 years. This hypothetical example is somewhat extreme, but it illustrates the general point: Large generators require more reserve capacity than small generators, even if all other factors, such as their forced outage rates, are equal. Thus, a mw of capacity from a large generator has a smaller effective load carrying ability than a mw of capacity from a small generator, even if their forced outage rates are equal.

Q. CAN YOU QUANTIFY THE DIFFERENCE IN THE LOAD-CARRYING ABILITY OF DIFFERENT TYPES OF GENERATION FOR PEPCO?

A. Unfortunately, I have no estimate of the effective load-carrying capability (ELCC) of various types and sizes of generators on the PJM system of which PEPCO is a member. While the ELCC of generators differs from one utility system to another, the ELCC of large units can be estimated from studies done on other utilities, and the ELCC of small units can be estimated directly.

Effective Load Carrying Ratio (ELCR) is the ratio of MW of ELCC to MW of unit capacity. Exhibit (H)-3 tabulates sources of estimates for ELCR's of units with EFOR $\geq$ 10%. The values vary with the composition of the rest of the system (excluding the unit for which ELCR is to be estimated), but the pattern is clear. Units of 2.5-5.4% of system capacity and with 15-25% EFOR have ELCR's on the order of .45 to .60. Since PJM's current capacity is about 40,000 mw, a 1000 mw unit represents 2.5% of current capacity. As Exhibit (H)-2 demonstrates, the capacity factors of large plants are consistent with the EFOR at the top of the 15-25% range.

A small unit imposes no size penalty for its outages and its EFOR can be thought of as a deterministic constant derating. The small maintenance requirements can be scheduled off peak. Therefore, a small gas turbine with a 10% EFOR has an ELCR of .9. Therefore, the effective load carrying factor (ELCF), by which mw's of a 1000 mw steam unit may be converted to mw's of peakers, is on the order of .55 ÷ .9 = .6. For steam units smaller than 1000 mw, I have assumed a linear relationship between size and ELCF with ELCF = 1 at 50 mw and ELCF = .6 at 1000 mw.

Q. GIVEN THIS DISCUSSION, WHAT PORTION OF THE CAPITAL COSTS OF GENERATION IS PROPERLY ATTRIBUTABLE TO RELIABILITY?

A. The entire cost of peaking units plus the cost of hypothetical peaking capacity would provide the same ELCC as the existing non-peaking units. The difference in cost between the existing non-peaking units and hypothetical peaking capacity is attributable to energy. For PEPCO, the cost of hypothetical peaking capacity was estimated using combustion turbines. See Exhibit (H)-24 for a more comprehensive discussion of principles of production plant classification which have been developed by Mr. Meyer and myself.

Q. PLEASE SUMMARIZE HOW YOU APPLIED THESE PRINCIPLES TO PEPCO'S PRODUCTION PLANT?

A. I began by identifying the units that I considered to be completely reliability related. These included all combustion turbines, the Connemaugh Diesel, and all pre-1963 steam units. Prior to 1963, gas turbines were not widely available and units were not so specifically designed for peak or baseload service. (See Exhibit (H)-24, pp. 9-10, 12.) Next, I compared the cost of steam units added after 1963 with the cost of equivalent gas turbine capacity. The Benning steam units added in 1968 and 1972 were comparable in cost to gas turbines so these units were also considered completely reliability related. The units at Chalk Point, Connemaugh, and Morgantown were significantly more expensive than gas turbines; the portion of their cost in excess of equivalent gas turbine capacity was attributed to energy.

Q. WHAT WAS THE SOURCE OF YOUR DATA ON THE COST OF PEPCO'S STEAM PLANTS?

A. Annual total plant cost by station is reported in three publications: Steam-Electric Plant Construction Cost and Annual Production Expense, FERC Form 1, and the Annual

Report to the D.C. Public Service Commission. This data includes capital additions made after the plant is on line as well as construction cost. Data is aggregated by station but capital cost for each unit can be estimated by comparing total plant cost in the year including and the year prior to each unit's on-line date. The depreciation rate reported in the 1981 FERC Form 1 (p. 335) for Steam Production Plant, 4.08%, was applied to the total plant cost in each year to estimate accumulated depreciation. This method appears to overstate depreciation; however, this was a source of conservative bias in that an overstatement in depreciation reduces the portion of plant attributable to energy. Exhibit (H)-4 presents the cost data for the post-1963 PEPCO steam units a portion of whose cost is attributed to energy.

Q. HOW DID YOU ESTIMATE THE COST OF EQUIVALENT COMBUSTION TURBINE CAPACITY?

A. I used the average cost of existing PEPCO combustion turbines, adjusted for vintage and ELCF. The total plant cost for each combustion turbine plant reported in the 1980 Annual Report to the D.C. Public Service Commission was inflated to 1980 dollars using the Handy-Whitman Index. The average cost of all turbines was $178/kw in

1980 dollars. Then I used the Handy-Whitman Index to deflate this average cost to the on-line date of each of the energy-serving units. However, before I could derive the equivalent cost of peaking capacity, I had to adjust for the differing ELCC's of steam and combustion turbine units. As discussed <u>supra</u>, I have estimated the ELCF as .6 for a 1000 mw steam unit and 1.0 for a 50 mw unit. I assumed a linear relationship between size and ELCF, thus a 525 mw steam unit would have an ELCF of .8.

Thus, for each steam unit:

> Cost of equivalent combustion turbine capacity = (average cost of PEPCO's existing turbines deflating to the on-line date of the steam unit) x (MW of steam unit) x ELCF.

Exhibit (H)-5 summarizes the results.

Q. WHAT PORTION OF THE COST OF PEPCO'S STEAM UNITS IS ENERGY RELATED?

A. Exhibit (H)-6 shows the gross plant in service and accumulated depreciation for the three PEPCO steam units that are partially energy related and for the equivalent combustion turbine capacity. The equivalent combustion turbines represent the reliability related portion of the steam units. The energy related portion of the steam units is the remainder.

Q. WHAT PERCENTAGE OF PEPCO PRODUCTION PLANT IS ENERGY SERVING?

A. All production plant other than the Chalk Point, Connemaugh, and Morgantown steam unit was entirely classified to reliability. Thus, all PEPCO production plant other than the energy serving portion in Exhibit (H)-6 is reliability related. Energy serving production plant comprises 35.79% of the total. 47.72% of accumulated depreciation was classified to energy. Net plant was estimated as 31.93% energy. These figures appear in Exhibit (H)-7. As discussed <u>infra</u>, my methodology appears to overstate the energy serving portion of depreciation; however, this is conservative in that it lowers the portion of net plant classified to energy. For purposes of classifying the energy related 1981 depreciation expense, I will use the energy related percentage of production plant, 35.79%.

Q. WITHIN THE GENERATION AREA, HOW DOES PEPCO CLASSIFY FUEL AND DEFERRED FUEL EXPENSE?

A. PEPCO attributes a certain amount of fuel, a hypothetical "no load" amount which would be burned if the stations ran at no load, and produces a demand component of total fuel of 0.1084 (= no load cost of fuel of $37,296,549 ÷ total cost of fuel, Account 501, of $344,087,885) from a hypothetical calendar year 1979 no load simulation. This fraction of 0.1084 is derived on p. S-41 of PEPCO's July, 1980 Jurisdictional Cost Allocation, Calendar Year 1979. This fraction is then used (page S-120 of Ex. PEPCO G-1) to classify 10.5% of fuel and deferred fuel expense to demand and the remainder, 89.5% of fuel and deferred fuel expense, to energy.

Q. IN YOUR OPINION, DOES THIS REFLECT THE REALITY OF THE WAY IN WHICH PEPCO OPERATES ITS SYSTEM?

A. No. It is my opinion that 100% of both fuel and deferred fuel expense should be classified as energy related. I asked PEPCO if in fact PEPCO ever operated any of its units in a no-load status, which would have the effect of expending fuel without producing energy. PEPCO answered (Information Response OPC-9-45) that it did not operate or dispatch its units in this fashion. Accordingly, PEPCO never faced in the real world the hypothetical situation PEPCO is taking into account in making this classification. Furthermore, PEPCO has stated explicitly (Information Response OPC-9-31, Attachment A, p. 1) that "The amount of fuel consumed is directly proportional to the amount of energy used by customers." As 100% of fuel and deferred fuel expense in fact was and is used to produce energy, 100% should be considered to be energy-related.

Q. HOW DOES PEPCO CLASSIFY GENERATION O&M TO DEMAND AND ENERGY?

A. For steam units, all operation expenses (Accounts 500, 502-507) are classified to demand. All maintenance expenses (Accounts 510-514) are classified to energy. For peaking units, all O&M is classified to demand. See PEPCO Ex. G-1, p. S-116 and DR OPC-1-52(3) p. S-40.

Q. DOES THIS APPROACH FULLY ACCOUNT FOR THE ENERGY RELATED PORTION OF THESE COSTS?

A. PEPCO has built steam units with higher capital costs as a tradeoff to lower operation costs. The same contribution to reliability could be provided at less capital cost (in $/kW) by combustion turbines. Similarly, PEPCO's steam units at Chalk Point, Connemaugh, and Morgantown have significantly higher O&M costs than equivalent combustion turbine capacity. In 1981, the average non-fuel O&M for the three steam plants was $10.538/kw. For PEPCO's existing gas turbines, the 1981 cost was $1.332/kw.

Q. HOW DID YOU CLASSIFY O&M COSTS OF THE CHALK POINT, CONNEMAUGH, AND MORGANTOWN PLANTS?

A. Basically, I followed the same approach as for capital costs. The O&M costs of equivalent combustion turbine capacity were classified to reliability. The remainder of steam plant costs were classified to energy. As Exhibit (H)-8 shows, approximately 90% of the O&M cost for the three steam plants are energy serving.

Q. HOW DID YOU CLASSIFY O&M COSTS FOR THE REST OF PEPCO'S PRODUCTION PLANT?

A. I used the same methodology as PEPCO. For steam units all operation expenses were classified to reliability and all maintenance expenses to energy. All peaking unit O&M expenses were classified to reliability.

Q. WHAT IS THE RESULT OF YOUR CLASSIFICATION OF NON-FUEL O&M EXPENSES TO DEMAND AND ENERGY?

A. 76.034% of 1981 O&M expenses were assigned to energy and 23.966% to demand. See Exhibit (H)-9. This compares with PEPCO's classification of 58.32% energy and 41.68% demand. See PEPCO Ex. G-1 p. S-116.

Q. THEORETICALLY, HOW CAN YOU DETERMINE THE PORTION OF THE COSTS OF PEPCO'S TRANSMISSION SYSTEM THAT IS RELIABILITY-SERVING AND THE PORTION THAT IS ENERGY-SERVING?

A. The most precise solution would involve designing a transmission system to interconnect the minimum-cost reliability-serving generation alternative to the load centers. The cost of this "minimum" transmission system would be considered reliability related. The difference between the actual cost of PEPCO's transmission network and the cost of the minimum system would be energy related. In the case of PEPCO, a minimum system would consist of gas turbines dispersed through the service territory with transmission lines to move power into the distribution system and to interconnect generation and load centers for reliability purposes.

Q. PLEASE EXPLAIN HOW THE ACTUAL PEPCO TRANSMISSION NETWORK DIFFERS FROM THE MINIMUM SYSTEM DESCRIBED ABOVE AND WHY IT IS MORE EXPENSIVE?

A. A number of factors can be identified. PEPCO's generation is concentrated in several large stations outside of the service territory. If generation were dispersed through the service area (as in the minimum system), the long, expensive transmission lines out to Dickerson, Chalk Point, Connemaugh, and Morgantown would not be required (and transmission losses would be smaller). PEPCO accepts this increase in transmission costs as part of the tradeoff for the lower operating costs at large coal and oil steam plants. As discussed above, PEPCO's decision to build these large units rather than combustion turbines is energy, rather than reliability related. It is these large steam units that require remote siting. (See Exhibit (H)-24, p. 18).

PEPCO's transmission system is also more expensive because it is designed to allow for large transfers of energy with neighboring utilities. PEPCO participates in the PJM Interconnection and it is involved in a variety of transactions including the interchange energy (economy power), installed capacity, operating capacity, short term power, and extended emergency (See 1981 FERC Form 1, pp. 328(a) - (f); DR OPC-9-53). Tie lines with other utilities are generally energy related unless they displace a utility's need for generating capacity. (See Exhibit (H)-24, p. 19). In the case of PEPCO, economy power transactions dominate all others; these transactions are related to minimization of energy cost, rather than reliability.

PEPCO's transmission system is designed to minimize energy losses and to function over extended hours of high loadings (DR OPC-9-13). If the system were designed only to meet peak demands a less costly system would be necessary; in some cases lines or circuits would not be required, voltage levels could be lower, and less or smaller transformers would be needed. The effect of load factor on underground transmission lines and transformers will be discussed below. Thus, much of the cost of PEPCO's transmission system is related to energy rather than reliability.

Q. CAN THE THEORETICAL SOLUTION OF DESIGNING A MINIMUM TRANSMISSION SYSTEM BE APPROXIMATED BY DIVIDING THE EXISTING PEPCO TRANSMISSION SYSTEM INTO RELIABILITY AND ENERGY RELATED COMPONENTS?

A. Yes. The configuration of the PEPCO network allows a fairly straight-forward identification of specific transmission lines that are energy related. Many of PEPCO's transmission lines are required solely to connect generation outside of the service territory and to connect with neighboring utilities. The lines I consider to be energy related are on the periphery of the system and comprise most of the above ground network. The transmission lines in the center of the network, which are within the the service area and primarily underground, can be considered as reliability related.

Q. HOW WELL DOES THE CLASSIFICATION SCHEME DESCRIBED IN THE PREVIOUS RESPONSE APPROXIMATE THE THEORETICAL MINIMUM TRANSMISSION NETWORK?

A. On balance, I believe it is reasonably accurate. The portion of the transmission network I have classified to reliability related provides access to all substations which connect with subtransmission and distribution. I have considered almost all of the radial lines into D.C. as reliability related even though a portion of their capacity is required to move power in from the remote generating units. In a minimum system with dispersed generation, some of these radial lines would either be unnecessary or would operate at lower voltage levels. It is possible that in a minimum system, some transmission would be required that is not included in the portion of the existing system we have classed as load related. These lines might be needed on the periphery of the service area and to connect the dispersed generation into the network. Also, some portion of the tie lines to other utilities might be reliability related. For classification purposes, I have assumed that the cost of any lines left out of the minimum system is balanced by the cost of lines included that would not be necessary. The effect of load factor on transmission system cost will be evaluated infra.

Q. DESCRIBE THE RESULTS OF YOUR CLASSIFICATION OF THE EXISTING PEPCO TRANSMISSION SYSTEM INTO ENERGY AND RELIABILITY RELATED COMPONENTS?

A. The transmission lines classified as energy serving fall into several broad groups. First, transmission lines connecting remote generation (Dickerson, Chalk Point, Morgantown, and Connemaugh) with the service area are energy related. Second, interties with neighboring utilities are energy related. Third, the circumferential "beltway" of transmission that skirts the service area from the Quince Orchard Substation (No. 118) in the northwest to Talbert Substation (No. 166) in the southeast is energy related. Fourth, some portions of the radial transmission lines that are clearly not area serving are energy related. For example, the transmission lines from Talbert Substation (No. 160) through Burches Hill Substation (No. 202) to Palmers Corner Substation (No. 84) which move power from remote generation to load centers are energy related.

It should be noted that only 230 and 550 kv transmission lines were classified as energy related; all transmission at voltages below 230 kv were classified as reliability related. In general, all of the circuits between a pair of substations were considered to be either energy or reliability related. However, one circuit from Quince Orchard Substation (No. 118) through Mt. Zion Substation (No. 165) to Norbeck Substation (No. 158) was classified as reliability related so as not to isolate the Norbeck Substation which connects with substransmission. Similarly, two of the circuits from Bells Mill Road Substation (No. 210) to Quince Orchard Substation (No. 118) were classified as reliability related since the Quince Orchard and Norbeck Substations connect with substransmission.

Q. ON A COST BASIS, HOW MUCH OF PEPCO'S EXISTING TRANSMISSION SYSTEM IS ENERGY RELATED?

A. Utilizing the 1981 FERC Form 1, the energy related lines comprise 73.7% of the total cost. The remaining 26.3% is reliability related. 89.6% of the cost of reliability related transmission is attributable to underground lines.

Q. HOW DID YOU ESTIMATE THE EFFECT OF LOAD FACTOR ON UNDERGROUND TRANSMISSION LINE SIZING?

A. I used data for 138kv 1250kcm cable in pipe, from EEI (1957), p. 10-51. This is a common installation on PEPCO's system. Exhibit (H)-10 shows how I extrapolated the data to a zero load factor. The ampacity at zero load factor is estimated at 1.569 times that at 100% load factor for one pipe, and 1.711 for two pipes. I assumed that transmission lines are designed for 100% load factors. The average mile of PEPCO underground transmission line has 1.44 circuits, in some cases with four or five circuits, so I averaged the two-pipe and one-pipe ratios. The average ratio is 1.640, indicating that only 61.0% of transmission capacity is necessary to meet peak.

Q. WHAT PORTION OF TOTAL TRANSMISSION LINE PLANT DID YOU CLASSIFY AS ENERGY-RELATED?

A. As derived above, 73.7% of gross transmission plant is related to remote generation and economic dispatch, and is thus energy-related. Of the remaining 26.3% of transmission plant, 89.6% is underground (1981 FERC Form 1, p. 422-423). The underground load-related lines are 39.0% energy-related, due to load factor effects. Thus, a total of 0.737 + (.263 x .896 x .39) = 82.9% of transmission plant is energy related.

Q. HOW DOES ENERGY USE IN HOURS OTHER THAN THE PEAK HOUR AFFECT THE INSTALLED COST OF TRANSFORMERS?

A. There are four ways in which energy use determines the sizing, and hence the cost, of transformers. The first two factors are closely related to one another: the length of the peak period and the load factor on the transformer. The third factor is the cost of the energy lost in the transformer. The fourth factor is the effect of periodic overloads on useful transformer life.

Q. HOW DO THE LOAD FACTOR AND LENGTH OF THE PEAK PERIOD INFLUENCE TRANSFORMER SIZING?

A. PEPCO has indicated that it sizes transformers on the radial underground system so that they are 100% loaded at peak. Transformers on the networks are sized so as to be 120% loaded at peak under a first contingency (i.e., the failure of one of the feeders to the network). (DR OPC-9-54. These loadings are consistent with normal practice for high load factors and long peak periods (see Fink, 1978, p. 17-4).

But lower daily load factors and shorter peak periods permit higher loadings, as illustrated in Westinghouse (1964, Ch. 5) and Fink (1978, Ch. 17). Short peaks and low off-peak currents allow the transformer to cool between peaks, so that it can tolerate a higher peak current. The limit for very short-duration load is generally stated as 200% of rated capacity (Fink, 1978, p. 17-40).

Thus, for every kva of peak load, PEPCO installs 1 kva of transformer on the underground radial system. For the networks, 0.83 kva of transformer is installed per kva of first-contingency load. But in either case, only 0.5 kva of transformer would be necessary to meet the brief load (apparently 30 minutes) which is the basis for PEPCO's demand allocator, were it not for the neighboring hours of high utilization and the relatively high off-peak loads on peak days. Thus, even considering only system reliability, only 50% of the UG radial transformer capacity, and 60% of the network transformer capacity, can be attributed to the single-hour peak load.

Q. OTHER THAN THE SYSTEM RELIABILITY ISSUES WHICH YOU HAVE DISCUSSED, ARE THERE OTHER FACTORS WHICH MAY INFLUENCE THE SIZING OF TRANSFORMERS?

A. Yes. Transformers may also be sized to reduce internal losses, both of energy and of peak demand. A utility would generally estimate the cost of peak demand losses per kw lost in line transformers on system peak as the sum of the annualized marginal cost per kw of peaking generation, transmission, and primary capacity. The energy loss cost per kw of peak losses is

$$¢/\text{kwh} \times 8760 \times LSF$$

where LSF is the loss factor (Fink, 1978, p. 18-103). The loss factor is itself a function of load factor (LF):

$$LSF = a \times LF + (1-a) \times LF^2.$$

The value of a is variously estimated at 0.15 to 0.30 (Op. cit.; EEI, 1957, p. 10-13).

From DR OPC 12-13, PEPCO estimates primary, transmission and production marginal demand costs at about $100/kw-year. The average marginal energy cost for the GT class is estimated by PEPCO as 4.293¢/kwh (PEPCO GG-6), with the higher costs occuring at higher load levels. At a 50% load factor, LSF is .2875 to .325, and the value of energy losses is $108 to $122 per kw of peak losses. Most PEPCO transformers do not experience load factors quite as high as 50% but the correlation between hourly energy cost and hourly losses balances any over-statement of load factor. Thus, energy losses and demand losses should be about equally important in PEPCO's decisions to upgrade line transformers for loss reduction, given PEPCO's own estimates of loss costs.

Q. HOW IS ENERGY USE REFLECTED IN SERVICE LIFE CONSIDERATIONS?

A. The 120% first-contingency loading of network transformers accepts a "reasonable" reduction of service life for each such incident (DR OPC-9-43, item 3, p. 10). It appears that the reasonable reduction is about 0.25%, from the values in Table 17-12 to Fink (1978), and on p. 114 of Westinghouse (1964), which approximate 120% loading for eight hours.

Since there are many hours of the year when the network is at or near full loads, first contingencies will frequently cause overloading. Thus, only a very small loss of service life is acceptable per overload.

If the only high-demand hours were the one on which the peak allocation is based, the chances of a first contingency coinciding with the peak would be small, and most transformers would be retired for other reasons before they experienced many overloads. In this situation, larger losses of service life per overload would be acceptable, and the short peak would allow greater overloads for the same loss of service life. Thus, to the extent that transformers are sized to prolong their useful lives, energy use plays are important role in these decisions.

Q. WHAT PORTION OF TRANSFORMER PLANT HAVE YOU CLASSIFIED AS ENERGY-SERVING?

A. I have classified 45% of line transformer plant investment as energy-serving. The reliability analysis suggests that 40-55% is energy serving, while the cost of losses suggests a 50-55% classification to energy. My classification probably understates the energy-related portion of line transformer investment.

Substation transformers will generally experience higher load factors than line transformers, due to load diversity and economic dispatch. In addition, I do not believe the substation transformers are sized in expectation of over loads, as are network transformers. Substation transformer demand losses (as assessed in general utility practice) are also lower, since they are above the primary system (and in some cases above part of the transmission system). Hence, I have classified 50% of substation plant to energy.

Q. HOW DID YOU ESTIMATE THE EFFECT OF LOAD FACTOR ON UNDERGROUND SUBTRANSMISSION LINE SIZING?

A. I do not have design information on PEPCO's substransmission lines, so I examined the effects of load factor on UG transmission line (as described above) and on UG primary distribution (as described below). I took the larger demand-related portion, which is 65.4% for UG primary, as the demand-related portion of UG subtransmission. I assumed that the underground fraction of the subtransmission investment was the same as the underground portion of non-generation-related transmission investment, 89.6%. Thus, the energy-related portion of subtransmission investment is estimated to be (1-.654) (.896) = 31.0%.

Q. HOW DID YOU CLASSIFY DISTRIBUTION SUBSTATIONS?

A. For the same reasons discussed previously for transmission substations, I classified distribution substations 50% to energy and 50% to demand.

Q. HOW DID YOU ESTIMATE THE EFFECT OF LOAD FACTORS ON PRIMARY CONDUCTOR SIZING?

A. I used two methods. First, I found from DR OPC-9-54 that the standard PEPCO network feeder cables are PILC three conductor copper 15kv shielded cables, ranging in size from #2 to 600kcm ("Low Voltage AC Network System Design", p. 2). From Figure 10-28 in EEI (1957), pp. 10-31, I found that similar cables (350 and 5000kcm, 12kv, 3 conductor, paper-insulated) reach about 35% of their steady-state temperature in 30 minutes, and essentially 100% of steady-state temperature in 8 hours. Hence, all other things being equal, an eight-hour peak load would cause about 2.86 times (1/.35) as much cable heating as a half hour needle load at the same wattage loss rate in the same cable. Alternatively, the wattage loss rate could be 2.86 times as great in the half-hour peak, and yet cause no more heating than is experienced in the eight hour peak. Since losses are proportional to the square of the current, the half-hour peak would allow 1.69 times

(= $2.86^{1/2}$) the current for the same peak temperature. Hence, only about 59.2% (1/1.69) of the cable capacity would be required to accommodate a half-hour peak.

The second method utilized Table XXXVIII, p. 10-47 of EEI (1957), which gives the ampacities for comparable cables from #4 to 750 kcm, at 50% to 100% load factor, and with one to twelve cables per duct bank. I extrapolated the load factor effect back to zero, and found the ratio of ampacities at zero load factor and 75% load factor (PEPCO's standard assumption: see "Consumer Engineering Definities Design" in DR OPC-9-54). These calculations are presented in Exhibit (H)-11. The simple average of the four ratios is 1.395. (I do not know the actual mix of primary lines on PEPCO's system.) Thus, the existing cables could carry about 40% higher peak if the peak was the only load on the line. Equivalently, 71.7% of the physical capacity would carry the peak, if not for the loads in other hours.

The linear extrapolation in the second method may be quite conservative. However, I averaged the two results and classified 65.4% of primary line capacity as demand related, and the remaining 34.6% as energy related.

Q. HOW DID YOU CLASSIFY THE TRANSFORMERS?

A. As discussed above in the transmission substation section, I classified 45% of line transformer plant as energy and 55% as demand.

Q. ARE THE DEMAND PORTIONS OF ALL DISTRIBUTION PLANT PROPERLY ALLOCATED BY PEPCO?

A. No. The effects of customer diversity are under-stated for transformers, and neglected for secondary distribution and for services. As a result, PEPCO overstates the portion of the distribution system for which the residential class is responsible.

Q. HOW DID YOU ESTIMATE THE EFFECTS OF DIVERSITY ON TRANSFORMER SIZING?

A. I estimated diversity, $D(n)$, as a function of number of customers, n, by the equation

$$D(n) = (1-D)/n + D$$

where D is the coincidence factor for the class. The form of the equation is from Hazelrigg, _et_ _al_. (1982). The value of D for the residential class can be determined from DR OPC-9-50 as

$$340321 \div 920698 = .369634.$$

I assume that half the residential load is in multifamily dwellings with an average of 40 customers per transformer, and that the other half is in single-family homes with an average of eight homes per transformer. The coincidence factor for 40 residential customers is .3854 while that for eight customers is .4484. The average transformer coincidence factor for the residential class is thus 0.4169; multiplied by the sum of customer peaks (920698 kw), this produces a transformer demand of 383849 kw at the sales level, or 398555 kw at the input to transformers (with 3.83% losses, from DR OPC-9-2).

Q. WHY IS PEPCO'S PROCEDURE OF AVERAGING CLASS PEAK AND THE SUM OF CUSTOMER PEAKS NOT AN ADEQUATE MEASURE OF DIVERSITY?

A. Averaging class peak with customer peak produces an estimate of residential class transformer demand coincidence of 0.6848. For all but the largest electric-heating customers, PEPCO assumes at least that much diversity for 3 or 4 residential customers, even when only group diversity is considered (see "Total Peak Demand (KVA)" in item 1, DR OPC-9-54). Including diversity between types of residential customers, the coincidence at the transformer would be even lower. The number of residential customers per transformer is almost certainly greater than 3 or 4, especially on PEPCO's dense system, with much multi-family housing. Even on the PEPCO's less-dense overhead system in D.C., including some commercial customers, there are five services per transformer, and there may be many customers per service, as I will discuss below. Hence, PEPCO's methodology understates diversity for the residential class.

Q. DID YOU MAKE SIMILAR ADJUSTMENTS FOR THE OTHER CLASSES?

A. No. Diversity is much lower for other classes, the size of the customers is larger, and demands for those customers found in groups (retail stores, or offices) are probably more highly coincident than the class as a whole. Thus, I used PEPCO's methodology for estimating demand on transformers. This probably overstates the contribution of non-demand GS customers (a small part of the class), and may understate the contribution of the GT class, each member of which is large enough to fully utilize one or more large transformers.

Q. HOW DOES THIS CHANGE THE PERCENTAGE OF ALLOCATION OF TRANSFORMERS?

A. Exhibit (H)-12 derives an improved line transformer allocator. PEPCO allocates almost 40% more line transformer cost to the residential class than I do.

Q. HOW DID YOU ESTIMATE THE EFFECT OF LOAD FACTOR ON UNDERGROUND SECONDARY LINES?

A. Item 3 in DR OPC-9-54 indicates that underground network mainline is 250 and 500 kcm; Item 1 indicates that URD uses secondary mainlines as small as #2/0. The network mains are rated at 50% load factor and the URD is rated at 75% load factor.

I used the only data available to me on load factor effcts on 1600V cable, from p. 10-50 of EEI, 1957, and extrapolated zero load factor ampacities for one conductor set at 1/0 and 500 kcm for the URD system, and for 3 sets of 250 kcm and 500 kcm for the network. I took the ratio of ampacities at zero load factor and the load factor PEPCO uses in rating each system, and averaged the four results, as shown in Exhibit (H)-13. The average ratio was 1.212; hence, I assumed that 85.1% of the secondary capacity is needed for peak demand.

It appears that the sizing of secondary cable is significantly affected by considerations of loss minimization (Anderson and Thiemann, 1960). As discussed above, line losses are 50-55% energy related, even by traditional utility reasoning. Hence, I may have significantly understated the energy component of all secondary lines.

Q. HAVE YOU MADE SIMILAR IMPROVEMENTS IN THE SECONDARY DEMAND ALLOCATOR?

A. Yes. The analysis was identical, except that I assumed that half the secondary serving residential demand experiences four-customer diversity and that the rest experiences 40-customer diversity. Four residential customers have a coincidence factor of .5272; averaged with the coincidence factor for 40 customers, this yields a sales level residential coincidence for secondary lines of .4563. Multiplying by the sum-of-customer-demands (920698 kw) and by secondary losses (1.01789) yields 427630 kw for residential class load on secondary lines. Exhibit (H)-14 recalculates the allocation of secondary lines with this improvement.

Q. WHAT PORTION OF DISTRIBUTION PLANT DOES PEPCO CLASSIFY AS CUSTOMER-RELATED?

A. PEPCO classifies meters, portions of services, and portions of poles, secondary conductors, and line transformers as customer-related.

Q. ON WHAT BASIS IS THIS CLASSIFICATION MADE?

A. PEPCO uses a "minimum system" approach: it employs existing components, which are the smallest such components PEPCO uses (or uses in large amounts). Thus, PEPCO designs a system with considerable reliability and energy-serving ability, which is not truly minimal.

Q. DO YOU BELIEVE THAT PEPCO'S ESTIMATE OF THE MINIMUM SYSTEM ACCURATELY REFLECTS THE COST OF SERVING THE TERRITORY, WITH SMALL, IF NOT MINIMAL AMOUNTS OF ENERGY AND DEMAND PER CUSTOMER?

A. No. PEPCO's procedure is inconsistent in several ways. First, poles are allocated between primary and secondary lines on the basis of conductor miles, which assumes that they use entirely separate sets of poles; in fact, the converse is true (DR OPC-9-10). Primary poles are classified by PEPCO as entirely demand-serving; since much of the secondary system shares poles with the primary system, the additional poles due to secondary (part of which is classified to customers) must be much fewer than PEPCO assumes.

Second, PEPCO assumes that the number of line transformers is independent of load. This is clearly not correct. High load densities results in fewer customers per transformer, due to maximum transformer sizing (see DR PC-9-54), and due to secondary line economics.

Third, PEPCO constructs a curious and inconsistent "minimum" system in the area currently served by underground distribution. This system includes overhead transformers (but no poles on which to put them), and no primary or secondary, and underground services. The "minimum" services are each several times the size of the "minimum" transformers: a system on which the latter are sufficient would not need nearly as large services as PEPCO assumes.

Finally, PEPCO's methodology has a counter-intuitive effect, as noted by PEPCO in DR OPC-9-31, p. 5, "As the average energy use per customers [sic] increase over the years, the minimum size facilities will also increase." Thus, the minimum system is, in PEPCO's view, energy related, as well as customer related.

Q. DO YOU AGREE WITH PEPCO THAT THE COST OF THE MINIMUM AREA-SERVING SYSTEM (PROPERLY ESTIMATED) IS DETERMINED BY THE NUMBER OF CUSTOMERS?

A. No. The cost of minimal equipment above the level of service drops is determined by the area to be served and the homogeneity of customers within the area, not by the number of customers. PEPCO acknowledges as much with respect to poles and conductors (OPC-9-31, p. 2). With respect to transformers PEPCO states that:

> A transformer must be installed for a customer no matter how small the load, the number of transformers is proportional to the number of customers.

Since PEPCO has many more customers than transformers, this statement cannot be true: in a dense area, such as an apartment building, a hundred customers may be served by a single line transformer.

Q. HOW WOULD YOU RECOMMEND ALLOCATING TRULY AREA-SERVING DISTRIBUTION COSTS?

A. These costs are undertaken to permit the delivery of energy and demand to all customers. On systems for which the density of energy, demand and customer charges do not justify extensions of the distribution system to all potential customers, the utility usually requires an advance payment or guarantee before the distribution system is extended. This counter example indicates that it is the total value of service to (or the revenue from) the customers served at secondary which causes the true minimum area-spanning distribution system (however defined) to be built.

Q. WHAT PORTION OF DISTRIBUTION COSTS HAVE YOU CLASSIFIED AS AREA-SERVING, AND HOW HAVE YOU ALLOCATED THAT PORTION?

A. I have accepted PEPCO's estimate of the total cost of the area-serving system, from PEPCO's customer classification of OH secondary and transformers, and have allocated them with other general expenses, in proportion to total allocable costs.

Q. HOW HAVE YOU CLASSIFIED AND ALLOCATED SERVICE LINES?

A. I have accepted PEPCO's classification of services between demand and customer number. In allocating the customer component, I recognize the difference between the number of customers and the number of services. In allocating the demand component, I recognize both the diversity in residential customers on a single service, and the demand-serving capability of the "minimum" services on which the customer classification is based.

Q. PLEASE EXPLAIN HOW YOU ALLOCATED THE CUSTOMER COMPONENT OF SERVICES.

A. From DR OPC-9-31, I found that the DC jurisdiction has a total of 117805 services: 57206 overhead, 1066 URD, and 59533 other underground. The total number of DC customers in the classes and voltage levels which would have services, is given as 196874 in allocator C13 of the Class of Business Cost Allocation Study. Thus, there are 79069 more customers than services. The next problem to determine which classes contain the customers without services.

I have assumed that the percentage of service less customers in each class is inversely proportional to the average maximum customer demand in each class. The calculation of the number of services per class and the resultant allocator is shown in Exhibit (H)-15.

Q. HOW DID YOU ALLOCATE THE DEMAND-RELATED PORTION OF SERVICES?

A. First, I recognized that the customers in an apartment building share a single service drop, and that the service therefore benefits from the diversity in customer demands. I assumed a coincidence factor for residential service of 0.7, which is equivalent to half the load on services coming from apartments of twenty units.

Second, I subtracted the load-carrying capacity of the minimum services from each class sum of customer demand. See Sterzinger (1981). Exhibit (H)-16 shows the calculation of the services. Exhibit (H)-17 derives the demand on services net of minimum service capacity. Note that the minimum service capacity of the residential class has been reduced by 50% to recognize the likelihood that services to small residential customers are oversized.

Q. HOW DID PEPCO ALLOCATE GENERAL PLANT?

A. PEPCO allocates general plant in proportion to all other plant, various portions of which are allocated to various measures of demand and customer number.

Q. DO YOU BELIEVE THAT PEPCO'S ALLOCATION OF GENERAL PLANT IS REASONABLE?

A. No. General plant includes (primarily) PEPCO's office building and equipment, which exist to support all the activities of the company, including fuel purchasing (as discussed in Mr. Nicolson's testimony); dealing with customers; preparing rate cases, fuel clause filings, and other legal proceedings; hiring employees, and dealing with labor unions; maintaining records of all sorts; and much more. The need for office space, equipment, and associated expenses would be less if any aspect of the company's business were simpler and cheaper. If fuel were cheaper, for example, fuel purchasing, customer relations, and regulatory activities would probably all be simpler and less expensive.

Q. HOW DO YOU ALLOCATE GENERAL PLANT?

A. I allocate general plant (as well as general expenses, and general materials and supplies) in proportion to all costs.

Q. PLEASE DESCRIBE THE SCOPE OF YOUR TESTIMONY ON PEPCO'S MARGINAL COST STUDY FOR THE GT AND SL RATES.

A. I will discuss certain errors in PEPCO's application of the methodology approved by the Commission in F.C. 680.

The basic methodology includes the following points:

1. energy charges are to be based on PEPCO's marginal running costs, not the PJM's costs;

2. the marginal distribution cost is to be recovered by an equal monthly demand charge, and based on the cost of new facilities per kw of new load; and

3. marginal generation and transmission costs are to be recovered from a seasonal demand charge, and determined to meet the revenue requirement (so long as the charge exceeds the PJM deficiency charge).

My analysis will focus on three errors in the estimation of marginal energy charges. First, PEPCO uses average, rather than marginal losses. Second, PEPCO assumes that percentage losses are the same in all periods. Third, the "other energy costs" are calculated erroneously at the generation level, and are not increased to reflect losses at the sales level.

Q. HOW DOES PEPCO DERIVE ITS MARGINAL COSTS FOR RATES GT AND SL?

A. PEPCO's documentation of its marginal cost study is contained in OPC Data Request 12-13, which includes PEPCO's response in Staff Data Request 3-21. GT marginal energy costs are estimated by PEPCO as the sum of:

(1) average period PEPCO running rates for the year ended April 30, 1982 (summer and winter off-peak rates are averaged together)

(2) PEPCO's estimates of other marginal energy costs (averaged over all kWh's) for the year ended December 31, 1981.

Marginal distribution investment is estimated from 1979-1981 investments (in 1981 dollars) per kW of 1979-1981 load growth. Marginal distribution O&M is assumed to equal average 1981 O&M per kW. Marginal production and transmission costs were taken from PEPCO's estimates in Formal Case No. 758, but were not used in PEPCO's rate design since the production and transmission charge is set to satisfy the revenue requirement. Customer charges were taken from the average cost allocation study. Average loss ratios (for energy or demand) and the GRT were applied to each cost component.

The SL energy rates are derived by weighting period marginal energy rates by SL use per period, and applying an average loss ratio and the GRT.

Q. PLEASE EXPLAIN WHY PEPCO SHOULD USE MARGINAL, RATHER THAN

AVERAGE, LOSSES, AND EXPLAIN HOW SUCH LOSSES CAN BE CALCULATED.

A. Line losses increase much faster than load, and generally as the square of load (Fink, p. 18-102). As derived in Exhibit (H)-25, the marginal loss ratio, (sales + losses)/(sales) is

$$(1 + L) / (1 - L)$$

where L = (average losses) / generation. The value of L at class peak can be calculated for GT low voltage and for street lighting as 0.071622 and 0.0910706 respectively, from DR OPC-9-2. Thus, marginal losses at peak are about 15.43% and 20.04%, respectively. Exhibit (H)=18 derives marginal loss multipliers for each rating period for GT. Exhibit (H)-19 does the same for SL. Note that percent marginal and average losses increase with load.

Q. PLEASE EXPLAIN WHY YOU USED LOW-VOLTAGE GT LOSS RATIOS, RATHER THAN LOSS RATIOS FOR THE ENTIRE GT CLASS.

A. The rates being derived here (and in PEPCO's marginal cost study in DR OPC-12-3) are for the low-voltage GT customers. The high-voltage customers receive discounts of 5-10% of their entire bill (excluding Fuel Adjustment), to reflect their lower losses and their lack of load on the secondary system. PEPCO's method would charge all GT customers less than their marginal energy cost.

Q. PLEASE DESCRIBE PEPCO's ERRORS IN ESTIMATING "OTHER ENERGY COSTS".

A. PEPCO divides total "other energy costs" (OEC) by a figure labeled "Net System Output (kwh) (Excl. Interchange)", when in fact that kwh figure <u>includes</u> interchange (see FERC 1, 1981, p. 401). Since the purpose is to determine the (presumably marginal) cost per kwh generated, the label identifies the desired quantity, which is 15594865 mwh, not the 17768435 mwh PEPCO uses.

Also, this is a generation-level cost per kwh, and line losses should be added to it as well.

Q. DID YOUR ESTIMATION PROCESS FOR THE SL RATE VARY FROM THAT OF THE GT RATE?

A. Yes, in two ways. First, I recognized that the summer peak-period energy used by SL is used near the end of the peak period, when running costs and losses are apt to resemble the costs and losses in the intermediate period. Therefore, I used the average of peak period and intermediate period values for both running costs and average losses in the summer peak period.

Second, I recognized that the pattern of SL loads does not approximate the patterns of loads on the common plant that SL utilizes. As a proxy for system load factor by period, I used the GT load factors.

Q. WERE PEPCO'S ERRORS IN THE SL MARGINAL COST ANALYSIS THE SAME AS ITS ERRORS IN THE GT MARGINAL COST ANALYSIS?

A. Not exactly. PEPCO appears to properly include "other energy costs" in generation-level costs <u>before</u> applying a loss adjustment. On the other hand, PEPCO uses higher marginal running costs by period for SL than for GT, without any explanation of this inconsistency. Since the SL marginal costs are completely undocumented, I used the GT marginal fuel cost estimates.

Q. HAVE YOU QUANTIFIED THE MAGNITUDE OF THE MARGINAL ENERGY COST, APPROPRIATELY CALCULATED?

A. Yes. Exhibit (H)-20 corrects PEPCO's marginal losses and OEC for GT and calculates the energy contribution to total revenues. Exhibit (H)-21 does the same for SL.

Q. ARE YOU AWARE OF OTHER ESTIMATES OF MARGINAL ENERGY COSTS IN THIS CASE?

A. Yes, I am aware that Mr. Gold has estimated marginal energy costs for PEPCO at the generation level. I note that Mr. Gold's estimates agree with my GT estimates to within a few mills, while both Mr. Gold's and my estimates differ substantially from PEPCO's estimates.

Q. WHAT ARE YOUR CONCLUSIONS CONCERNING PEPCO'S MARGINAL COST ESTIMATES?

A. PEPCO appears to have significantly understated the marginal energy cost for the GT rate and to have overstated the marginal energy cost for the SL rate.

Q. WHAT ARE YOUR RECOMMENDATIONS FOR PEPCO'S FUTURE MARGINAL COST STUDIES AND FOR THE USE OF MARGINAL COSTS IN THIS CASE?

A. In this case, I recommend that estimates equal to or similar to my estimates be used for rate design purposes. This will result in lower SL rates, higher GT energy rates, and lower GT demand rates than those recommended by PEPCO.

In the future, PEPCO should:

(1) use marginal losses by period rather than average annual energy losses;

(2) add marginal losses to other energy costs;

(3) calculate the correlation between load and marginal energy cost within each period and, if significant, increase marginal delivered energy costs to reflect higher costs of losses;

(4) use low voltage GT losses to calculate low voltage GT rates, and high voltage GT losses to calculate the high voltage discounts;

(5) average costs across hours in proportion to class consumption per hour rather than by a simple average;

(6) use consistent marginal costs for GT and SL; and,

(7) use estimated fuel prices for the period during which the rates will be in effect rather than historical prices.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Exhibits of
Paul L. Chernick

OPC Exhibit H
through (H)- 25

INFORMATION AND DATA EXAMINED

BY MR. PAUL L. CHERNICK

1. PEPCO's responses to OPC's 9th and 12th sets of information requests.

2. Mr. Schmidt's testimony and exhibits and Mr. Schmidt's supplemental testimony and exhibits.

3. The standard engineering references listed in the bibliography attached to this testimony.

Study	Plant Type	Size	Capacity Factor
Easterling/NRC(2)	Supercritical Coal	400+	56.6%
Perl/NERA (2)	Supercritical Coal	600	68.8
EPRI (3)	Coal	>600 600-700	62.2 (1) 63.7 (1)
	Oil	600-700 >600	60.0 (1) 64.5 (1)
	Chalk Point 3		48.9 (1)
	Connemaugh 1		58.8 (1)
	Connemaugh 2		59.1 (1)

Table 1 : Capacity Factor Estimates

Notes: (1) Equivalent Availability Factor - corrected for load following

(2) Econometric projections, based on data through 1979

(3) Estimated actuals, through 1977

Study[1]	EFOR[2]	Plant Size as % of Previous System Capacity	ELCR[3]
	%		
Kahn	15	4.89	.538
	19.7	"	.475
	15	2.53	.606
NEPOOL	18-26.4	5.40	.537
		4.39 - 5.14	.526 - . 561

Table 2 : Sources of ELCR estimates

Notes: (1) See bibliography

(2) Equivalent Forced Outage Rate

(3) Effective Load Carrying Ratio = MW load carried ÷ MW capacity

Name		MW (Max. Generator Nameplate)	On-Line Date	Gross Plant in Service Year End 1981 ($1000)	Accumulated Depreciation Year End 1981 ($1000)
Chalk Point	Unit 1	363.8	11/64	459,207	125,947
	Unit 2	363.8	6/65		
	Unit 3	659.0	5/75		
	Unit 4	659.0	12/81		
Connemaugh	Unit 1	91/936*	7/70	24,765	10,818
	Unit 2	91/936*	7/71		
Morgantown	Unit 1	625.5	7/70	221,410	94,224
	Unit 2	625.5	2/71		

Table 3 : PEPCo. Steam Units Contributing To Energy Related Plant

Source : 1981 FERC Form 1, except for accumulated depreciation which was estimated by depreciating annual gross plant at 4.08%

Notes: * PEPCo. owns a 9.72% share of Connemaugh 1 & 2. 91 mw's PEPCo.'s share; 936 is rating for entire unit.

Name		MW of steam Unit (max. generator nameplate (1)	ELCF (2)	Equivalent MW of Combustion Turbine (3)	Cost/KW of Combustion Turbine $ (4)	Cost of Equivalent Combustion ($1000) (5)
Chalk Point	Unit 1	363.8	.868	315.8	67.69	21,343
	Unit 2	363.8	.868	315.8	67.59	21,343
	Unit 3	659.0	.744	490.3	122.46	60,042
	Unit 4	659.0	.744	490.3	205.74	100,873
Connemaugh	Unit 1	91.0	.627*	57.0	88.33	5,039
	Unit 2	91.0	.627*	57.0	91.01	5,192
Morgantown	Unit 1	625.5	.758	474.1	88.33	41,880
	Unit 2	625.5	.758	474.1	89.67	42,515

Table 4 : Calculation of Cost of Equivalent Combustion Turbine Capacity

Source: Column (1) - 1981 FERC Form 1
Column (2) - ELCF = $1 - \left[(\text{MW of Steam Unit} - 50)\ \frac{.4}{950}\right]$
Column (3) - Columns (1) x (2)
Column (4) - 1980 Cost/KW deflated to commercial operation date of steam unit
Column (5) - Columns (3) x (4)

Note: *ELCF for Connemaugh Units 1 & 2 calculated based on total size (936 mw) of each unit.

	Steam Units		Equivalent Combustion Turbines		Energy Serving Portion of Steam Units	
	Gross Plant in Service (1)	Accumulated Depreciation (2)	Gross Plant in Service (3)	Accumulated Depreciation (4)	Gross Plant in Service (5)	Accumulated Depreciation (6)
Chalk Point	459,207	125,947	203,601	50,873	255,606	10,429
Connemaugh	24,765	10,818	10,231	4,793	14,534	6,025
Morgantown	221,410	94,224	84,395	39,582	137,015	54,642
TOTAL					407,155	135,741

All Figures $1000, year end 1981

Table 5 : Energy Serving Portion of Steam Units

Source : Column (1) - See Table 3
Column (2) - See Table 3
Column (3) - Sum of Column (5), Table 4 for units at each plant
Column (4) - Estimated by depreciating annual gross plant at 4.08%
Column (5) - Column (1) - (3)
Column (6) - Column (2) - (4)

Account	PEPCo. Total (1)	Energy Serving Portion (2)	% Energy Serving (3)
Production Plant in Service	1,137,146	407,155	35.79
Accumulated Depreciation	284,468	135,471	47.72
Net Plant	853,073	272,414	31.93

Table 6 : Energy Serving Portion of Production Plant

Source : Column (1) - Ex. G(1)
Column (2) - Table 5
Column (3) - $\frac{\text{Column (2)}}{\text{Column (1)}} \times 100\%$

	Steam Units			Equivalent Combustion Turbines			Energy Serving Portion of Steam Units
	Non-Fuel O & M ($1000) (1)	MW (2)	Non-Fuel O & M/kw $ (3)	Non-Fuel O & M ($1000) (4)	MW (5)	Non-Fuel O & M/kw (6)	Non-Fuel O & M ($1000) (7)
Chalk Point	19,215	2046	9.391	2144	1612.1	1.382	17,071
Connemaugh	3,199	182	17.577	152	114	1.382	3,047
Morgantown	14,259	1252	11.389	1261	948.3	1.382	12,998
TOTAL	36,673	3480	10.538	3557	2674.4	1.382	22,116

Table 7 : Energy Serving Portion of Non-Fuel O & M for Chalk Point, Connemaugh and Morgantown Plants

Source : Column (1), (2) -1981 FERC Form 1
Column (3) -Column (1) ÷ Column (2)

Column (4) -Column (5) x (6)
Column (5) -Sum of Column (3), Table 4 for Units at each plant
Column (6) -Average for all PEPCo. combustion turbines, 1981 FERC Form 1
Column (7) -Column (1) - (4)

	Demand		Energy		
	($1000)	% of Total	($1000)	% of Total	Total ($1000)
Combustion Turbines[1]	867	100	0	0	867
Connemaugh Diesel[1]	13	100	0	0	13
Chalk Point, Connemaugh, Morgantown Steam Units[2]	3,557	9.70	33,116	90.30	36,673
Benning, Dickerson, Potomac River Steam Units[1]	10,991	40.98	15,830	59.02	26,821
TOTAL	15,428	23.966	48,946	76.034	65,374

Table 8 : Allocation of 1981 Non-Fuel Production Plant O & M To Demand and Energy

Source: 1981 FERC Form 1 except as noted

Notes: 1. PEPCo. allocation method. Peaking units - 100% demand. Steam Units - Accounts 500, 502-507 Demand; Accounts 510-514 Energy

2. From Table 7

	Loss Factor:	1.0	0.7	0.5	0.0
	Load Factor[a]	1.0	0.81	0.66	0.0
# of pipes					
1	ampacity	650	701	760	1020[b]
2	ampacity	543	600	661	929[b]

Table 9 : Calculation of Demand Portion of 138kv Cables

Notes:

a. for Loss Factor = .3 (Load Factor) +.7 $(\text{Load Factor})^{(2)}$

b. extrapolated linearly from ratings at 81% and 66% load factor.

Cable Size	Cables per Duct Bank	Ampacity Per Cable At Load Factor Of 75% (a)	50% (b)	0% (c)
#40	1	281	295	323
				(1.149) (d)
#4/0	12	83	96	122
				(1.470)
750 kcm	1	562	606	694
				(1.235)
750kcm	2	348	432	600
				(1.724)
average ratio				1.395

Table 10 : Effect of Load Factor on Primary Cable Ampacity

Notes:

a. From Table XXXVIII, EEI (1957)

b. Extrapolated linearly from ampacities differences at 75% and 50% load factors.

c. Ratio of ampacities at 0% and 75% load factors.

Class	Demand at Line Transformer Input (a)	% Total From (a) (b)	% Total From PEPCo. (c)
Residential	398555	28.876	40.008
GS	658219	47.689	30.225
GT	298994	21.662	18.272
SL	24470	1.773	1.495
Total	1380238	100.00	100.000

Table 11 : Derivation of Improved Line Transformer Allocator

Notes :

a. Residential class from text, other from p. 424, Class of Business Cost Allocation Study

b. Factor D18, Class of Business Cost Allocation Study

Conductor Size	Sets	100%	75%	50%	0%[c]	Ratio[d]
		Load Factor (ampacities[e])				
1/0 [a]	1	282	298	319	356	1.195
500 [a]	1	707	770	832	957	1.243
250 [b]	3	395	445	500	605	1.210
500 [b]	3	578	660	752	926	1.231
Average						1.212

Table 12 : Affect of Load Factor on Secondary Conductor Ampacity

Notes:

a. For URD: 1 set of three conductors, 75% design load factor.

b. For network: 3 sets, 50% design load factor. PEPCo. apparently uses many more than 3 sets per duct bank, but the source lists only 1-3 sets.

c. Extrapolated from 100% and 50%.

d. (ampacity at 0% LF)/(ampacity at 75% LF) for URD, (ampacity at 0% LF)/(ampacity at 50% LF) for network.

e. From EEI, p. 10-50, Table XLVII.

Class	Demand at Output of Line Transformer	% Total	
	(a)	from (a) (b)	from PEPCo. (c)
Residential	427630	28.747	46.927
GS	714962	48.063	35.800
GT	320845	21.575	16.070
SL	24026	1.615	1.203
Total	1487563	100.000	100.000

Table 13: Improved Allocation of Secondary Line, Demand Portion

Notes:

a. From p. 425, Class of Business Cost Allocation Study, except residential (from text), and total

c. Allocator D13 or D17.

Class	Customer Number (N) (a)	Demand Per Customer (D) (b)	N ÷ D	%	Customers Without Services (c)	Services (d)	%
Residential	172675	5.4274	31815	97.525	77112	95563	81.120
GS - LV	24028	29.755	807.5	2.475	1975	22071	18.735
GT	171	1876.8	.0911	0.000	0	171	0.146
Total			32623	100.000	79069	117805	100.000

Table 14 : Derivation of Customer Allocator for Services

Notes :

a. Allocator C-13, CoBCAS customers at secondary excluding street lighting.

b. (Allocator D-21)/(Allocator C-13; demand per customer, as above.)

c. % x 79069; assumes probability of no service is inversely proportional to average demand.

d. (Customer Number) - (Customers Without Services).

Type of Service	Number of D.C. Services[a]	Service Ampacity	Total Ampacity (KA)
Overhead	57206	100[b]	5721
URD	1066	150[c]	160
Other Underground	59533	70[d]	4167
Total	117805		10048
			x 120V
			1205760KVA
			x .8 power factor
			964608KW

Table 15 : Derivation of Total Service Ampacity

Notes:
a. DR PC-9-31, pp. 18, 23; see pp. 16-17 for service types.

b. #4 copper; see Fink (1978), p. 19-16, note 3.

c. #2/0 aluminum; see DR PC-9-54, item 1.

d. #4 copper; see Fink (1978), Table 19-2, 60° rating.

Class	Sum of Customer Peaks[a] (1)	Coincidence Factor (2)	Sum of Peaks on Services[b] (3)	Credit for Minimum Services[c] (4)	Excess Demand on Services[d] (5)	% (6)
Residential	937173	0.7	656021	391334	264689	23.665
GS - LV	714962	1.0	714962	180716	534246	47.765
GT	320945	1.0	320945	1399	319546	28.570
					1,118,481	100.000

Table 16 : Derivation of Demand Allocator for Services

Notes: a. Allocator D-21, CoBCAS

b. (1) x (2)

c. % of services (from Table 12) times 964608 kw (from Table 13). For residential, only half of credit is taken - see text.

d. (3) - (4)

Period	GHW (a)	% of Hours (b)	Load Factor (c)	% Losses (d)	Marginal Loss Ratio (e)
Summer					
peak	373.8	7.868	.7819	5.600	1.1186
intermediate	318.7	7.868	.6666	4.774	1.1003
off-peak	525.9	18.148	.4769	3.416	1.0707
Winter					
peak	581.5	15.174	.6307	4.517	1.0946
intermediate	505.1	15.174	.5478	3.924	1.0817
off-peak	842.0	35.769	.3874	2.775	1.0571

Table 17: Calculation of Marginal Losses for GT

Notes:
a. from DR PC-12-3
b. ibid, "street light kwh by rating period. 24 hr"
c. GWH ÷ (% hours) ÷ 8760 ÷ (GTpeak load); peak of 593624 from DR PC-9-2.
d. (load factor) x (peak losses); peak losses 7.1622% from DR PC-9-2. Peak losses in DR PC-9-2 appear to be too low compared to energy losses; PEPCo. was unable to provide derivations of these figures. Thus, marginal losses are probably higher than calculated here.
e. (1 + L)/(1-L), where L = (% losses)/100.

Period	Load Factor (a)	% Losses (b)	Marginal Loss Ratio (c)
Summer			
peak	.7243[d]	6.597	1.1413
intermediate	.6666	6.071	1.1293
off-peak	.4769	4.343	1.0908
Winter			
peak	.6307	5.744	1.1219
intermediate	.5478	4.989	1.1050
off-peak	.3874	3.528	1.0731

Table 18 : Calculation of Marginal Losses for SL

Notes :

a. From Table 17

b. See Note (d), Table 17 SL peak loss is 9.1076%, from DROPC-9-2.

c. See Note (e), Table 17

d. Average of Summer peak and intermediate periods

Period	Generation Level Fuel ¢/kwh (a)	Generation Level OEC ¢/kwh (b)	Marginal Loss Ratio (c)	Sales Level Cost ¢/kwh (d)	KWH (a)	Revenue $ (e)
Summer						
peak	5.262	.267	1.1186	6.699	373797971	25040726
intermediate	4.000	.267	1.1003	4.995	318671616	15917647
off-peak	2.593	.267	1.0707	3.258	525911444	17134195
Winter						
peak	4.511	.267	1.0946	5.564	581489942	32354100
intermediate	3.998	.267	1.0817	4.908	505087383	24789689
off-peak	2.593	.267	1.0571	3.216	841993773	27078520
					TOTAL	142313877
						[illegible]

Table 19: Calculation of Marginal Costs of GT

Notes:
- a. from DR PC-12-3
- b. from text; other energy costs
- c. from Table 17
- d. (fuel + OEC) x marginal losses ÷ .94
- e. sales level cost x kwh

Period	Generation Level Cost ¢/kwh (a)	Marginal Loss Ratio (b)	Marginal Sales Level Cost ¢/kwh (c)	% of Energy (d)	Contribution to Energy Cos ¢/kwh (e)
Summer					
peak	4.948[f]	1.1413	5.647	1.378	.078
intermediate	3.267	1.1293	4.819	8.410	.405
off-peak	2.860	1.0908	3.120	18.499	.577
Winter					
peak	3.778	1.1219	5.360	8.061	.432
intermediate	4.265	1.1050	4.713	16.609	.783
off-peak	2.860	1.0731	3.069	47.044	1.444
					3.719
					(3.956)[g]

Table 20 : Derivation of Marginal Energy Cost for SL

Notes: a. sum of fuel and OEC from Table 21. PEPCo. inexplicably assumes higher generation level costs for SL than for GT. PEPCo. properly applies losses to OEC for SL, although not for GT. See DR PC-12-3.

b. From Table 18.

c. (generation cost) x (loss ratio); excludes GRT.

d. PEPCo. Ex. (G)-5, p. 1

e. (sales level cost) x (% energy)

f. average of GT peak and intermediate

g. 3.719 ÷ .94 for GRT

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APPENDIX C:

RELATIONSHIP OF LOSSES, INPUT, AND OUTPUT

Appendix C

As shown in Figure C for a simplified circuit:

$$\text{Losses} = I^2 R_L = \left(V_o^2 / R_o^2\right) R_L$$

$$\text{Output to customers} = I^2 R_o = V_o^2 / R_o$$

V_o is constant, as is R_L

$$\text{input} = \text{output} + \text{losses} = I^2\left(R_o + R_L\right)$$

$$= V_o^2 \left(R_o + R_L\right) / R_o^2$$

$$\frac{d\ (\text{input})}{d\ (R_o)} = - V_o^2 / R_o^2 - 2V_o^2 R_L / R_o^3$$

$$\text{Output} = V_o^2 / R_o \Rightarrow R_o = V_o^2/\text{output}$$

$$\frac{d\ R_o}{d\ \text{Output}} = - V_o^2 / (\text{output})^2 = -V_o^2 / \left(V_o^2 / R_o\right)^2$$

$$= - R_o^2 / V_o^2$$

$$\frac{d\ \text{Input}}{d\ \text{Output}} = \frac{d\ \text{input}}{d\ R_o} \times \frac{d\ R_o}{d\ \text{output}}$$

$$= \left(- V_o^2/R_o^2 - 2\ V_o^2 R_L / R_o^3\right) \times \left(- R_o^2/V_o^2\right)$$

$$= 1 + 2 \left[\left(V_o^2/R_o^2\right) R_L\right] \left[R_o/V_o^2\right]$$

$$= 1 + 2 \times \text{losses}/\text{output}$$

$$= 1 + 2 \times \text{losses} / (\text{input} - \text{losses})$$

$$= (\text{input} + \text{losses}) / (\text{input} - \text{losses})$$

$$= (1 + L) / (1 - L)$$

where $L = \text{losses} \div \text{input}$

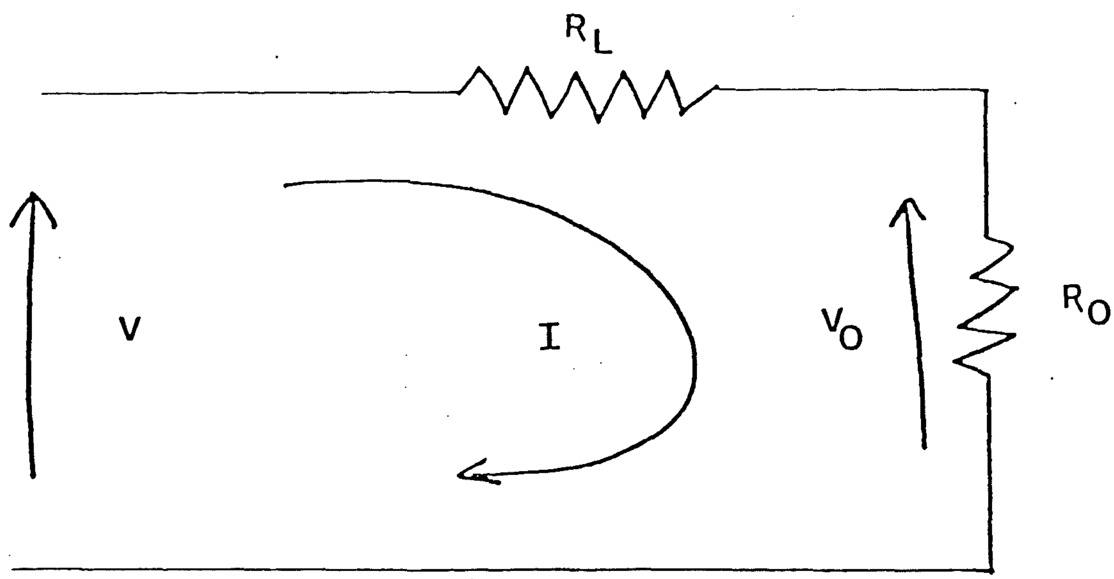

FIGURE C