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PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850290

DIRECT TESTIMONY

OF PAUL L. CHERNICK

ON BEHALF OF THE

ALBERT EINSTEIN MEDICAL CENTER

UNIVERSITY OF PENNSYLVANIA

NATIONAL RAILROAD PASSENGER CORPORATION

March 24, 1986

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DIRECT TESTIMONY OF

PAUL CHERNICK

1 INTRODUCTION AND QUALIFICATIONS

Q: Mr. Chernick, would you 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.

1.1 Qualifications

Q: Mr. Chernick, would you please briefly summarize your professional education and experience?

A: I received a S.B. degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and a 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 evaluation of power supply options. My work has considered, among other things, the effects of rate design and cost allocations on conservation, efficiency, and equity.

In my current position, I have advised a variety of clients on utility matters. My resume is attached to this testimony as Appendix A.

Q: Mr. Chernick, have you testified previously in utility proceedings?

A: Yes. I have testified approximately forty times on utility issues before this Commission and such other agencies as the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Council, the Texas Public Utilities Commission, the Illinois Commerce 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 Vermont Public Service Board, 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. Subjects I have testified on include cost allocation, rate design, long range energy and demand forecasts, costs of nuclear power, conservation costs and potential effectiveness, generation system reliability, fuel efficiency standards, and ratemaking for utility production investments and conservation programs.

Q: Have you testified previously before this Commission?

A: Yes. I testified in Docket R-842651, a Pennsylvania Power and Light rate case, on behalf of the Office of Consumer Advocate (OCA), and in Docket R-850152, a Philadelphia Electric Company rate case, on behalf of the Utility Users Committee and the University of Pennsylvania.

Q: Have you testified previously on ratemaking for cogenerators and small power producers?

A: Yes. I testified in all of the major rulemaking proceedings on this subject in Massachusetts. In 1981, I presented testimony in the MDPU's first rulemaking on cogeneration and small power production, MDPU 535. I also filed supplementary comments in that case. In March 1985, I presented testimony in the initial phase of a new investigation of these rules, MDPU 84-276. Following promulgation of an interim order in the case, I testified in the second phase of MDPU 84-276, in October 1985. My testimony was cited extensively by the DPU in its order issuing proposed rules, in February 1986.

Q: Have you authored any publications on utility ratemaking issues?

A: Yes. I authored Report 77-1 for the Technology and Policy Program of the Massachusetts Institute of Technology, Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions. I also authored a paper with Michael B. Meyer "An Improved Methodology for Making Capacity/Energy Allocation for Generation and Transmission Plant", which won an Institute Award from the Institute for Public Utilities. My paper "Revenue Stability Target Ratemaking" was published in Public Utilities Fortnightly, and another article "Opening the Utility Market to Conservation: A Competitive Approach" was presented at the 1984 national conference of the International Association of Energy Economists, and was published in the conference proceedings. These publications are listed in my resume.

1.2 The Subject and Structure of this Testimony

Q: What is the subject of your testimony?

A: I have been asked to review the propriety of the rates proposed by the Philadelphia Electric Company (PECO) for auxiliary service to customers having their own generation sources, which are qualifying facilities (QFs) as cogenerators or small power producers under Sections 201 and 210 of the Public Utilities Policy Regulatory Act (PURPA). That auxiliary service includes backup power, to replace QF power when the QF is forced out of service; supplementary power, to provide additional service to the customer when the QF capacity is insufficient; and maintenance power, to replace QF power when the QF is out of service for scheduled maintenance.

Q: How is your testimony structured?

A: The second section discusses the objectives of auxiliary rate design. The third section describes the problems with the rates PECO has proposed. Finally, the fourth section discusses and proposes alternatives to PECO's rates for auxiliary service.

2 OBJECTIVES OF RETAIL RATES FOR QUALIFYING FACILITIES

Q: What are appropriate objectives for the Commission in designing retail rates for qualifying facilities?

A: The Commission's objectives should be:

1. to encourage all QFs which are economically competitive with utility sources of power supply,
2. to fairly price utility services to those QFs,
3. to avoid subsidizing QFs which are not economical, and
4. to encourage QFs to operate in ways which maximize their value to the utility system.

Q: At what costs would a QF be economically competitive with the cost of utility power?

A: Table 1 displays estimates of PECO incremental energy and capacity costs from the current rate case. The energy costs are from PECO production costing runs for PECO's forecast of fuel prices, and for the forecast of fuel prices adopted by OCA. There are three sets of estimated capacity costs: one set supporting PECO's filing,[1] OCA's modification of PECO's original projection, and my independent calculation of PECO capacity costs.

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1. PECO filed a higher revised projection in its rebuttal.

Tables 2 through 4 present these projections in ways which may be more meaningful. Table 2 calculates the levelized value of the energy savings from a cogenerator which starts operation in 1987, 1988, 1989, or 1990 (the years most likely to be affected by current rate decisions), through each year of the forecast period. Avoided energy losses are included for an HT-level customer.[2] The levelized values are calculated at the 9.7% discount rate PECO has adopted (and strenuously defended) in the rate case. Table 3 repeats that process for the capacity benefits shown in Table 1: this calculation would apply to each kW of capacity which was as beneficial to PECO as its own generation. Table 4 recalculates the capacity benefits, increasing the capacity costs by PECO's projected 25% reserve margin, to reflect the value of capacity which reduces peak demand.

I would like to make two observations from this data. First, the value of QFs to the PECO system is quite high, if they allow PECO to avoid costs of the magnitude displayed in Tables 1-4. Second, even under the PECO assumptions, which use very high capacity costs, compared to intervenor projections, the benefit of new generation is dominated by its energy savings. At an 80% capacity factor, a QF would save over five times as much in energy costs as in capacity costs, under PECO's original assumptions, and for the period 1987-2024.

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2. Loss savings would be greater at lower voltage levels.

Q: You described the capacity benefits in Table 4 as reflecting the value of capacity which reduces peak demand. What percentage of QF capacity would you expect to be operating at peak?

A: The answer to that question varies with the technology, since different types of QFs have different seasonal patterns and different availabilities. However, it seems likely that QF capacity in PECO's service territory (particularly that capacity which will require most of the auxiliary services under discussion in this proceeding) will be dominated by cogeneration. In order to be economically attractive, cogeneration will have to serve either a year-round heat load, such as domestic water heating or industrial process steam, or a combination heating and cooling load. Therefore, most cogeneration systems will attempt to operate at the time of PECO's system peak, on hot summer weekdays.

The next question is what fraction of the cogenerators which attempt to operate at system peak (or any other time) will succeed in doing so. The availability of cogenerators may vary between technologies, but it must be fairly high in order to make the cogeneration system viable. One of the common technologies for major cogeneration projects is the combination of a combustion turbine (CT) with a heat recovery boiler. In estimating the reliability of a CT cogeneration system, the Commission should consider the following facts:

1. As displayed in Table 5, PECO's own existing combustion turbines have operated at an average availability of 87.9% in the period 1980-1984. I have excluded some data for units which PECO is planning to retire in the near future: since PECO has ample capacity in the short run, and since it planned to retire those units anyway, it had little incentive to maintain their reliability, or to return them to service promptly following a malfunction. Some of the 13.1% of the time the CTs listed in Table were not available must have been for scheduled maintenance, so the forced outage rate (which is a better measure of the probability the unit will be out of service on system peak) would be less than 13.1%. PECO assumes that new CTs will be out of service 3.2% of the time for planned maintenance: if the same was true of the existing CTs, the unplanned portion of the historical outage rate for those units was only 10.2%.

2. A combustion turbine used in a cogeneration facility would tend to be even more reliable than the PECO units, for two reasons. First, the PECO turbines are used for peaking, and are therefore subjected to the stresses of rapid heating and cooling, while cogenerating combustion turbines would operate in more stable, and hence less strenuous, base-load conditions. Second, the PECO turbines have been surplus capacity for roughly the past decade, so PECO was under no time

pressure to repair units which failed: a cogenerator would have strong economic incentives to bring the turbine back into operation as quickly as possible.

3. The PECO data on CT availability is no fluke. Table 6 presents similar availability data for Northeast Utilities CTs, which operate under the same type of peaking conditions as do PECO's CTs, and which have also been excess capacity since 1975. These units have maintained over 90% availability: assuming the standard New England Power Pool maintenance allowance, this would be equivalent to a 6% forced outage rate.

4. PECO projects that new large (100 MW) CTs, operated in peaking mode, would have forced outage rates of only 8%.

5. The California Energy Commission Technical Assessment Manual estimates that the availability factor for new CTs will be 90%, based on historical availability factor data.

6. The New England Power Pool projects that new CTs, operated in peaking mode, would have forced outage rates of only 10%, and would require less than 2 weeks of maintenance per year (specifically, 1 week/year, with 3 extra weeks every fourth year).

Q: How can a utility best achieve the objectives of QF rate design?

A: The objectives can best be met by offering a fair price for the power generated by the QF, and gaining the QF's agreement to sell all of the power it generates to the utility, and to purchase all of its requirements from the utility. This strategy greatly simplifies the process of fairly billing for power used by the QF and associated facilities.

Q: Has PECO offered such a fair price?

A: No. PECO appears to offer QFs only an approximation of the short-run energy savings they create, without recognizing either the long-run energy benefits of the QFs, or their capacity value. Capacity payments are negotiable under certain limited (and ill-defined) circumstances, but there is no indication that PECO would offer capacity payments anywhere near the level of its projected capacity costs. Even the short-run savings calculation appears to ignore the line losses avoided by QF operation. As a result, there is only very limited current QF sales to PECO, and little interest in future sales to PECO.

Q: If PECO does not offer adequate purchase prices for QF power, is there any way to achieve the objectives you outlined above, and to allow the construction of economical cogeneration?

A: If PECO does not buy the QF power, it can still encourage construction of some economical plants by setting its retail rates to cogenerators so that those rates:

1. are not discriminatory, compared to other retail rates,

2. reflect the savings to the system produced by the QF's operation, and

3. charge QFs only for the utility equipment and services they utilize.

Regardless of PECO's preferences, QFs are entitled under the FERC regulations implementing PURPA to dedicate their generation to their own use, or that of associated facilities, and to purchase from the utility only that power which they need, at a fair price.

3 PROBLEMS WITH PECO'S FILING

Q: What major problems have you identified in the PECO auxiliary rate proposals?

A: The PECO auxiliary rate proposals would violate all three of the principles I listed in the preceding section. Those proposals treat QFs less favorably than other customers, fail to reflect the system savings from QF operation, and charge QFs for equipment and services they do not utilize. These errors can be dealt with under three major headings.

The first major problem is that PECO has indicated a desire to discriminate against QFs, by refusing them services which are, or would be, provided to other customers. The second major problem is that PECO charges QF backup power on the same rate as other customers, implicitly assuming that QF outages are as coincident with system peak as are the peak demands of other customers served at the same voltage. The third major problem is that all of PECO's auxiliary charges treat QFs as if they required the same capacity mix as do other customers: in fact, QFs supply their own expensive base-load capacity and require primarily peaking and intermediate capacity.

3.1 PECO's Discrimination Against Cogenerators

Q: Other than those two major pricing problems, what are the other shortcomings in PECO's treatment of QFs?

A: PECO has indicated an intention to discriminate against QFs in a number of ways. For example, PECO has stated that it will not voluntarily provide auxiliary service to a customer to replace power usually supplied by a third-party QF. I also understand that PECO has threatened to refuse supplementary service, unless the part of the customer's load which is served by the QF is physically separated from the PECO-served load. Finally, I understand that PECO has insisted that parallel operation of QF facilities would only be allowed through a single interconnection point, even for customers currently served through several delivery points.

Each of these limitations would discourage some economical QFs, require others to make uneconomical investments in internal transmission and in backup generation, and decrease the operating efficiency and quality of service for many of the affected QFs. Both the Commission's order in this case, and PECO's tariffs (including the terms and conditions) should reflect the general principle that all services, arrangements, and forms of interconnection available to full-requirements customers will be available to QFs, except where legitimate technical factors differ between full-requirements and auxiliary service. Such legitimate factors would include the effects on worker safety and system reliability and stability, due to QF operation, a QF customer's internal transmission, and similar factors. A general concern that <u>some</u> QF installation might cause a technical difficulty in the future does not justify limitations on service to QFs which do not create that problem. Where PECO identifies a legitimate and specific problem, whether for a full-requirements customer or for an auxiliary customer, the customer should have the right to receive all normal services, if it corrects the problem internally, or reimburses PECO for any special costs incurred to resolve the problem, above the costs which are useful for general system operation.

3.2 PECO's Backup Rate Proposal Erroneously Treats QF Outages as If They Were as Coincident as Those of Other Customers

Q: What is the most significant difference between the peak demand of a backup service customer and that of a full requirements customer?

A: The most important difference lies in the timing of the peak demands. The backup customer will place its peak load on the system when the QF is out of service, an event which is totally independent of system loads. For example, if backup service is taken for 10% of the hours in a year (or 876 hours), the probability that one of those hours will be the system peak hour is only 10%. The amount of backup power taken at the annual peak, or monthly peaks, or other high-load hours, has virtually no relationship to the maximum backup power taken during the month or the year.[3]

In contrast, the full-requirements customer will usually be using a large percentage of its maximum demand, at the time of system peak, or at other high-load hours. An industrial customer with essentially constant operations, at least in

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3. Of course, the contribution of the backup load to any hour's system demand must be less than or equal to the maximum backup load.

the day-time shifts, will experience virtually the same peak demand every day. A customer with large air-conditioning loads (which would include most commercial and institutional customers) would generally have its highest loads on the hot summer weekdays which tend to be system peak days.[4] While the peak system hour may not be the peak hour for either of these customers (and the peaks may even fall on different days), the customer's contribution to the system peak will be a large fraction of the customer's own peak demand: for HT customers, this fraction exceeds 80%.[5] For the full-requirements customer, the customer's demand is a meaningful proxy for its contribution to system peak.

Q: What is the significance of these differences for the design of backup rates?

A: It is reasonable to charge full-requirement customers a demand charge which assumes that the customer non-coincident peak is about 80% of the customer's contribution to system peak. It is totally unreasonable to apply the same charge to the non-coincident peak of backup customers, who contribute only about 10% of their peak load to the system peak. If the backup charge is based solely on the applicable demand charge for full-requirements customers, the demand charge for backup service should be reduced by the ratio of the system peak

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4. After all, those are the system peak days because <u>everybody</u> is using air conditioning, as well as their usual activities.

5. See Exhibit WFS-1, page 63, Docket R-851052.

coincidence of backup demand to that of full-requirements demand. For a full-requirements coincidence of 82.5%, and a forced outage rate of 10%,[6] the backup demand charge should be only 12.1% of the full-requirements charge. It may be preferable to fundamentally redesign the backup demand charge, as by the addition of a standby charge, and by elimination of the ratchet, in which case the upper limit on the effective backup demand charge should be 12.1% of the full-requirements charge.

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6. As further experience with actual QFs is accumulated, this figure can be refined.

3.3 PECO's Supplementary and Backup Proposals Fail to Recognize that PECO's Least Expensive Capacity Serves These Loads

Q: How do PECO's auxiliary rate proposals fail to address differences in the mix of capacity required by different types of customer demands?

A: PECO proposes to use the same demand charge for auxiliary service that is charged for full-requirements service. This demand charge reflects the cost of a mix of capacity, including peaking capacity (hydro and oil), baseload capacity (coal and nuclear), and intermediate capacity (oil-fired steam units). This mix was installed to economically meet the total customer load curve: the more expensive base-load units were built because their ability to economically operate for many hours every year (and the energy savings resulting from that operation) justified their construction.[7]

If every PECO customer had the same load shape, every customer would be responsible for the same mix of capacity. For example, PECO asserts that the optimal amount of baseload capacity for the PECO system is equal to minimum continuous load, divided by the average baseload capacity factor, which

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7. See PECO Statement 14, Docket R-851052.

PECO assumes to be 65%.[8] For the system, the minimum load is 50% of peak demand, including 15% due to pumped hydro loads, so the PECO formula recommends installation of base capacity equal to 77% of peak.

Consider what the PECO formula would imply for system additions to serve backup loads. The minimum continuous backup load is zero, since there will be many hours when no backup service is required.[9] For example, Table 7 calculates the probabilities of various numbers of QFs being out of service, if there are 40 backup customers, all have 10% forced outage rates, and none take maintenance service.[10] There would be an average of 129 hours/year with no backup load, 575 hours with only one QF (2.5% of the load) on backup, 1247 hours with only two QFs on backup, and so on. In this example, over 22% of the hours have less than half of the <u>average</u> backup load of 4 customers, and less than a sixth the maximum load of about 13 customers. The pumping load would be spread very thinly, since there would be many low-load hours between the high-load periods. Hence, the optimal amount of baseload capacity needed to serve the backup customers is a very small part of the total capacity required, perhaps 5% or so.

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8. Ibid., page 21.

9. As the number of QFs using backup service grows, the number of zero-backup hours will shrink, but the minimum load will still be very small.

10. Maintenance reduces the exposure of the QF to a forced outage.

In fact, the individual backup customer requires a service from the PECO system which is more like that provided by peaking capacity than it is like that provided by PECO's mix of installed plants. The QF provides its own power most of the time, and relies on the system for backup in limited periods, just as the system relies on its peakers for limited periods.

Supplementary power is more like full-requirement loads than is backup, in that some supplementary power is likely to be required a large percentage of the time. However, the QF customer is supplying its own base-load power,[11] and therefore requires less of the utility's base-load power. For example, a customer which had total loads shaped just like the system loads (although much smaller), and satisfied 30% of its peak demand with a QF, would require supplementary power primarily from peaking and intermediate facilities. Applying the PECO criterion, the customer would need supplementary baseload of 20% of its peak (5% for minimum load, and 15% for pumped storage), or 29% of its peak supplementary demand. Unless base-load capacity is very inexpensive, it would not pay to invest in nearly as much of it to serve supplementary customers as it would to serve full-requirements customers.

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11. In most situations, economic considerations will strongly encourage design of QFs, particularly cogenerators, for long hours of operation.

Q: What is the effect of PECO charging backup and supplementary customers as if they were using the same mix of plant as do full-requirements customers?

A: The effect is to vastly overcharge auxiliary customers on PECO's proposed rates. If a full-requirements customer pays for baseload capacity equivalent to 77% of its peak load, through the demand charge, and then uses a minimum of 35% (and an average of 60%) of its peak load throughout the year, it recovers in energy savings a substantial part of extra demand charge due to the baseload investment.[12] If the supplementary customer, using only 7% of its peak load at minimum and only 43% of peak on average, is charged the same demand charge as the full-requirements customer, it would receive only about 70% of the fuel savings the full-requirements customer received, and would not get the benefits of the base-load for which it has paid.

The result of PECO's proposal is that auxiliary customers would be charged for more base-load capacity than they need, and for more base-load capacity than is cost-effective for them.

Q: Is the need for a separate supplementary rate influenced by the nature of the full-requirements rate?

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12. Whether the savings equal or exceed the baseload investment costs is dependent on whether the baseload plant's fuel savings cover its fixed costs.

A: Yes. The problems of pricing supplementary power[13] on the same basis as full-requirements power would largely be resolved if the Commission were to adopt a general rate design with small demand charges and limited, if any, ratchets. This is already the case in the residential class: for the residential QF owner, the full-requirements rate is a suitable supplementary rate. For classes in which a large fraction of costs are recovered through demand charges, especially ratcheted demand charges, the Commission should reduce the demand charges for auxiliary (and particularly for supplementary) service. There are four reasons to distinguish auxiliary rates from full-requirement rates, in this regard:

- designing auxiliary rates with large demand charges will discourage QF development, resulting in increased costs to the Philadelphia area, to PECO customers as a whole, and (given the high costs of power the QFs will allow PECO to avoid) to full-requirements customers;

- designing auxiliary rates with large demand charges will give auxiliary service customers improper price signals, and will result in sub-optimally designed QF's;

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13. This would also resolve some of the pricing problems for backup, but would not address the off-peak nature of the service.

- QF loads inherently require less of PECO's most expensive capacity; and

- QFs actively supply their own baseload capacity, so the full-requirements demand rates would charge them for capacity they have already provided.

Q: What are the effects of the improper prices signals you mentioned?

A: The high demand charges and ratchets would encourage QFs to provide their own peaking capacity for backup and supplementary power, and to install generation in smaller units, to decrease the size of any individual outage. These may be very expensive solutions to a problem -- supplying peaking capacity -- which PECO can perform very inexpensively.[14] PECO peaking capacity can be centrally located, optimally sized, and dispatched to meet any of a variety of system needs, including peak demand from full-requirements or auxiliary customers, backup of auxiliary customers, backup of other PECO units, and providing support to other utilities. For 40 auxiliary customers, of 10 MW each, to provide their own backup peaking capacity would require 400 MW of small capacity additions: for PECO to provide the necessary capacity would require only about 50 MW (assuming a 10% forced outage rate and a 25% reserve

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14. PECO is currently retiring peaking capacity which costs only $10-$15/kW-year to maintain on the system.

requirement), which could be satisfied by a portion of a larger unit, or even by retaining existing units. The same considerations apply for QFs adding peaking capacity to reduce their supplemental demands.[15]

While the high demand charges would tend to encourage excessive QF efforts to replace peaking capacity, the lower energy charges PECO proposes give limited credit for displacing expensive PECO baseload capacity. The funds which go into QF backup investments will tend to be taken away from investment in greater QF capacity, and in investments which will allow for greater QF output outside the customer's peak period.

To summarize, PECO's proposed auxiliary rates will encourage QFs to invest in peaking capacity, which PECO can supply less expensively, and discourage investment in baseload QF capacity, which could replace much more expensive utility investments. Instead, PECO should be rewarding customers substantially for reducing PECO's expensive baseload

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15. Note that many of the same economies and efficiencies could be achieved by allowing the auxiliary customers to own a block of capacity in common (whether on their own sites or elsewhere on the PECO system), and drawing on this capacity as needed through the PECO transmission system. Much of the inefficiency arises from the requirement that peaking capacity be provided on site, rather than from ownership constraints. However, if there is to be a common peaking resource for auxiliary service, dispatched through PECO, it might as well be owned by PECO, which can also draw on the capacity to back up its own plants and to provide power to other utilities.

obligations, and rewarding them much less for reducing PECO's inexpensive peaking obligations.

Q: Have you quantified the extent to which PECO's proposed auxiliary rate design would penalize infrequent auxiliary service, and encourage wasteful customer investments in peaking capacity?

A: Yes. Table 8 illustrates just how strongly PECO's proposed auxiliary rate design penalizes short duration summer demands, compared to high load-factor year-round usage, and compared to the highest possible cost of serving infrequent supplementary loads.[16] The hypothetical auxiliary HT customer uses 4 MW and 2880 MWH of supplementary power in each of the winter months, and 3600 MWH in each of the summer months. The summer peak demand is varied from 5 to 24 MW.[17] Due to the high demand charges, the hours-use energy blocks,

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16. I have set up this example in terms of supplementary power. Under PECO's proposal, backup power, which has an even lower annual load factor than supplemental, and is inherently non-coincident load, would be charged under the same rate as supplemental power. Therefore, all the problems illustrated in this example for PECO's supplementary rate are even worse for its backup rate.

17. At 5 MW, the monthly load factor in each month is 100%, and the annual load factor is 85%. This is not a very likely example of a full-requirements customer, let alone a supplementary customer. Typical full-requirements loads might look more like the pattern shown under the 8 or 10 MW columns, and supplementary load factors would tend to be lower (corresponding to higher summer peak loads in Table 8), for efficient designs. I include the extreme high-load-factor customer in this comparison only for illustrative purposes: the important points can all be made by comparing the realistic cases, in which the peak summer load varies between 8 MW and 24 MW.

and the ratchets, the incentives to control maximum summer demand are enormous: an increase in the customer's summer demand costs about $200/kW-year. At the HT rate's 82.5% coincidence factor, the charge for each kW of increased coincident demand is about 21% higher than the charge per kW of customer demand, so one hour of increased coincident demand can cost as much as $235/kW-year, and four hours can cost as much as $285/kW-year. These annual charges are close to the total cost of the customer's construction of its own peaking capacity.[18]

Table 8 also shows the effect on the average cents/kWh rate of the changes in customer summer demand. The high load-factor supplementary customer pays 6.9 cents/kWh, while a customer with twice the peak supplementary demand pays 9.5 - 10 cents, and a customer who only uses supplementary power as a peaking source (at a 17.8% load factor) pays 14.1 to 15.9 cents/kWh.[19] Of course, the average cost in cents/kWh should increase as load factor goes down, but as the bottom portion of Table 8 demonstrates, PECO's supplementary rate would increase the charges well beyond the cost of serving infrequent supplementary loads, even if that service were provided entirely with brand new peaking capacity. At high load factors, the average cost of power under PECO's rates

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18. Building a utility CT might cost $300/kW today: smaller customer peaking facilities would be somewhat more.

19. Time-of-use energy adjustments would further increase the cost burden on the infrequent supplemental customer.

lies below that of service from new CTs, as it should. At lower load factors, the supplementary charge should come to resemble the cost of service from peaking capacity. Instead, PECO charges low load-factor supplementary customers for average system capacity, the cost of which is heavily influenced by the cost of base-load plants, for a peaking service, producing preposterously high cent/kWh rates. The base-load capacity costs are charged through the demand charge (amplified by the ratchet) and through the hours-use blocks in the energy charges, and therefore fall very heavily on customers with very little need for, or benefit from, the baseload plants.

4 SOLUTIONS TO THE PROBLEMS IN PECO'S FILING

4.1 The Occidental Chemical Proposal

Q: Would adoption of the ratemaking proposals of Mr. Ross resolve some of the issues you raised above?

A: Yes, as regards backup power. Mr. Ross suggests that backup power charges be prorated on the period of use: this would greatly reduce the demand charges for most QFs, especially the most reliable ones, which are least likely to contribute to system peak. QFs which experience long outages would pay larger backup charges than those which are out for only a few hours in a month, as is appropriate.

I do have some concerns about Mr. Ross's backup power proposal. Specifically, he proposes a very high standby charge, which would be a significant -- and as far as I can determine, unwarranted -- burden on reliable QFs. Among other things, his calculation of this charge assumes that QFs require the same amount of backup as do PECO's larger and less reliable units, and that backup power will be supplied by the average mix of PECO capacity. Neither of these assumptions is appropriate. The fixed minimum monthly charge also reduces the incentives for QFs to avoid short outages, the charges for which would be covered by the minimum charge.

Mr. Ross does not deal with one issue which arises for any situation in which different rates are charged for different simultaneous services, whether those are maintenance and supplementary, as under the PECO proposal, or backup and supplementary, as under Mr. Ross's proposal.[20] For example, take the case of a customer with a 15 MW maximum load and a 5 MW cogenerator, leaving 10 MW to be served by PECO at peak. If the customer is operating at a load of 9 MW (of which 4 MW is being served by PECo on supplementary service) when the cogenerator goes down, raising the load on PECO to 9 MW, will PECO treat that as part of the supplementary service? More importantly, given the hours-use block structure in the HT rate, will PECO allocate energy first to the supplementary load, or to the backup load? Since the backup demand would be prorated under Mr. Ross's proposal, more kWh would wind up in the inexpensive tail block under the backup rate than the supplementary rate.[21] Trying to determine what loads would have been served by a QF which is out service may lead to

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20. Given the differences in the nature, and cost of serving, supplementary and backup power, it would be difficult to design a rate which could be fairly applied to both. Specifically, to recognize the non-coincident nature of backup demands, even during the peak months, demand charges (or time-of-use surcharges) would have to be assessed as a function of actual system loads (or operating costs) by hour. Backup service, being randomly distributed, would rarely fall the into ~~to~~ high-cost hours, while supplementary service would use much more power at these times. This approach is technically feasible, although it would involve significant administrative complexities.

21. A similar problem would arise for maintenance service under PECO's proposal.

endless disputes, especially for QFs with naturally variable output (e.g., hydro facilities, cogenerators with variable heat demands).

I would suggest that the Commission resolve this problem by allowing the auxiliary customer, when entitled to service under two forms of auxiliary service, to specify to which service its demand will be charged first.[22] Energy should then be charged to that demand at a 100% load factor, with the remaining energy charged to the other service. For example, if our sample customer elects to use backup first, it would be charged for 5 MW of backup demand (however that charge is structured), and for 5 MWH of backup energy for each hour of the outage, with the remaining demand and energy charged under supplementary rates.

Q: Is Mr. Ross's treatment of supplementary rates appropriate?

A: No. Mr. Ross does not address the problems in PECO's supplementary rates at all.

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22. Of course, a customer is entitled to a service only if it meets the normal definition of that service. A customer which claims backup or maintenance service should be able to demonstrate that its QF generator is not operating: specifically, PECO should have the right to verify the existence of an outage by a site visit.

4.2 Alternative Approaches

Q: How would you suggest that the Commission approach the pricing of services to QFs?

A: The key solution to the problems raised involves the pricing of PECO services to QFs in a manner which more closely reflects the costs and benefits of the QFs to the system. There are three ways in which this pricing can be improved:

- price backup power to reflect the non-coincident nature of the customer demands,
- recover more of PECO's costs through energy charges, rather than demand charges, and
- recover the backup demand charges in ways which better track cost causation, such as prorating the charge on the length of the outage, or charging per kW-day, rather than per kW-month, of backup demand.

I understand that Mr. Rudden will be proposing specific backup and maintenance rates. I will propose only a supplementary rate.

Q: How would you suggest that the Commission design the supplementary rate?

A: To avoid the problem of charging large base-load capacity charges to customers who are using primarily peaking and intermediate services, I recommend that the Commission establish a supplementary demand charge which recovers only the cost of peaking capacity, and peak-demand-related transmission and distribution. I also recommend that the Commission eliminate the hours-use blocks in the supplementary rate schedules, and replace those blocks with a flat energy charge.

Q: Have you calculated what these rates should be?

A: I do not have sufficient data at this time to compute all of the elements of the rates. However, for the HT rate, the demand charge should recover approximately $40/kW-year of coincident demand. This figure is composed of $10/kW-year for embedded peaking generation capacity, and $30/kW-year for transmission and distribution costs. The peaking capacity costs are estimated from the cost of the peaking capacity which PECO is retiring prematurely: that capacity costs less than $10/kW year, and I have assumed that the peaking capacity PECO is keeping is not much more expensive than the capacity it is discarding. The derivation of a transmission charge is more complicated.

From page 25 of Exhibit WFS-1 in Docket R-851052, transmission operating expenses are 6.1% of the total demand-allocated production and transmission expenses, and from page 27, transmission original plant cost is 8.8% of the corresponding total for production and transmission. Plant contributes more to the rate effect of these components than do expenses, so about 8% of the demand-allocated production and transmission costs are due to transmission. From page 39 of WFS-1, the cost of production and transmission allocated to the HT class is $366.73 per kilowatt of contribution to the 4-CP peak. Since about 8% of this amount is due to transmission, the transmission cost is $30/kW of peak demand.

Q: Can you convert this $40/kW cost per peak kW to a charge per billing kW?

A: Again, I can approximate the result, although I do not have precisely the data needed for an exact figure. From page 63 of WFS-1, the HT class has 2,925,859 kW of customer demands, and 2,255,576 kW of 4-CP peak demand. Due to this diversity, the annual charge per kW of customer annual peak should be 77.1% of the charge per kW of peak demand, or about $30.84. If the average monthly metered demand is 80% of the peak month,[23] the monthly charge would be $3.21/kW. I would suggest that the Commission use this value, unless a more precise calculation is produced in the course of this proceeding.[24]

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23. This figure will only be know for the supplementary rider once some experience has been gained in the actual operation of PECO's QF customers. I have assumed that it will be somewhat lower than the corresponding ratio for full-requirements customers.

24. Depending on the outcome of the rate case, this value may be somewhat too high: specifically, a lower allowed return would reduce the capacity charge. This is a small effect,

Q: Have you computed the value of the energy charge which would be associated with this demand charge?

A: Yes. From page 6a of WFS-1, PECO is requesting $972,180,000 from rate HT. If all of rate HT were on the auxiliary rider, the $30.84 annual demand charge (times 2,925,859 kW of customer maximum demands) would recover $90,233,000. The requested customer charge of $264.15/customer month, times 2316 customers and 12 months, yields $7,341,257. Subtracting these revenues from the total request leaves $874,605,000 to be recovered through the energy charge. Page 39 of WFS-1 reports the energy corresponding to these costs: 12,947,425 MWH. Thus, the required energy charge is 6.76 cents/kWH, or approximately the middle block of PECO's hours-use rate.

Q: What additional charges and discounts would be applied to determine the final bills?

A: The high voltage discount and the time-of-use adjustment would still apply. Neither of the existing demand ratchets would be applicable under the supplementary rider.

Q: Does this conclude your testimony?

A: Yes.

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however, and the $3.21/kW-month charge could be adopted independent of the rate case.

TABLE 1: PECo PROJECTED INCREMENTAL COSTS FOR PECo

	ENERGY		CAPACITY COSTS ($/kW-yr)		
	($/MWH)	($/MWH)	$/KW	$/KW	$/KW
Projected by:	PECo	OCA	PECo	OCA	R&I
	[1]	[2]	[3]	[4]	[5]
1987	$40	$31	$113	$57	$39
1988	$42	$33	$120	$60	$41
1989	$48	$47	$128	$64	$35
1990	$57	$47	$137	$68	$36
1991	$64	$54	$145	$72	$41
1992	$72	$70	$153	$77	$64
1993	$87	$71	$163	$81	$66
1994	$109	$97	$172	$86	$67
1995	$123	$129	$183	$91	$73
1996	$144	$120	$194	$97	$76
1997	$156	$131	$205	$103	$148
1998	$158	$159	$218	$109	$127
1999	$168	$140	$231	$115	$117
2000	$180	$143	$245	$122	$110
2001	$185	$175	$251	$126	$103
2002	$228	$187	$275	$137	$97
2003	$221	$181	$291	$146	$90
2004	$248	$244	$309	$154	$84
2005	$267	$213	$327	$164	$79
2006	$284	$230	$347	$173	$73
2007	$308	$296	$368	$184	$68
2008	$351	$270	$390	$195	$65
2009	$345	$277	$413	$207	$63
2010	$394	$371	$438	$219	$60
2011	$429	$342	$464	$232	$57
2012	$448	$359	$492	$246	$54
2013	$497	$482	$522	$261	$52
2014	$565	$451	$553	$276	$49
2015	$566	$459	$586	$293	$46
2016	$655	$623	$621	$311	$44
2017	$712	$575	$658	$329	$39
2018	$712	$587	$698	$349	$36
2019	$800	$770	$740	$370	$32
2020	$886	$727	$784	$392	$28
2021	$924	$760	$831	$416	$25
2022	$1,061	$1,040	$881	$441	$21
2023	$1,192	$947	$934	$467	$7
2024	$1,256	$1,029	$990	$495	$5

Notes: All data from Docket # R-850152

1. Paul L. Chernick, R-850152, Table 3.1, Col. 6, Avoided Energy Cost
2. Avoided Energy Cost assuming OCA Fuel Savings (R-850152 Table 3.6) Capacity Factor 60%
3. and 4. PECo Projections PJM Capacity Charge (IR-OCA-2-25b)
5. Total Capacity value of Limerick 1 (Section 2, R-850152) divided by additional required capacity.

TABLE 2: LEVELIZED INCREMENTAL ENERGY COSTS ($/MWH)

To Year:	PECo From: 1987	1988	1989	1990	OCA From: 1987	1988	1989	1990
1987	$41				$32			
1988	$42	$43			$33	$35		
1989	$44	$46	$48		$38	$41	$49	
1990	$48	$50	$54	$59	$40	$43	$49	$48
1991	$51	$54	$58	$63	$43	$46	$51	$52
1992	$54	$57	$62	$66	$47	$51	$56	$58
1993	$58	$61	$66	$71	$49	$53	$58	$61
1994	$63	$67	$72	$78	$54	$59	$64	$68
1995	$67	$72	$78	$85	$60	$65	$71	$76
1996	$73	$78	$85	$92	$64	$69	$76	$82
1997	$77	$83	$90	$98	$68	$74	$80	$86
1998	$82	$88	$95	$103	$73	$79	$86	$92
1999	$85	$92	$99	$107	$76	$82	$89	$96
2000	$89	$96	$103	$112	$78	$85	$92	$98
2001	$92	$99	$107	$115	$82	$88	$96	$102
2002	$97	$104	$112	$120	$85	$92	$99	$106
2003	$100	$107	$116	$124	$87	$94	$102	$109
2004	$103	$111	$120	$129	$91	$98	$106	$114
2005	$107	$115	$124	$133	$94	$101	$109	$117
2006	$110	$118	$127	$137	$96	$104	$112	$120
2007	$114	$122	$131	$141	$100	$107	$116	$124
2008	$117	$126	$136	$146	$102	$110	$119	$127
2009	$120	$129	$139	$149	$105	$113	$122	$130
2010	$124	$133	$143	$154	$108	$116	$126	$134
2011	$127	$137	$147	$158	$111	$119	$129	$137
2012	$131	$140	$151	$162	$113	$122	$131	$141
2013	$134	$144	$155	$166	$116	$126	$135	$145
2014	$137	$148	$159	$170	$119	$128	$138	$148
2015	$141	$151	$162	$174	$122	$131	$141	$151
2016	$144	$155	$166	$179	$125	$135	$145	$156
2017	$147	$159	$171	$183	$128	$138	$149	$159
2018	$151	$162	$174	$187	$130	$141	$152	$162
2019	$154	$165	$178	$191	$134	$144	$155	$166
2020	$157	$169	$182	$195	$136	$147	$158	$170
2021	$160	$172	$186	$200	$139	$150	$161	$173
2022	$164	$176	$190	$204	$142	$153	$165	$177
2023	$167	$180	$194	$208	$145	$156	$169	$181
2024	$171	$184	$198	$213	$148	$159	$172	$184

Notes: Includes loss factor of 1.03587 times customer use generation.
All costs levelized at 9.7%.

TABLE 3: LEVELIZED INCREMENTAL CAPACITY COSTS, PER KILOWATT OF PECO GENERATION.

	PECo				OCA				A&I			
From:	1987	1988	1989	1990	1987	1988	1989	1990	1987	1988	1989	1990
To Year:												
1987	$118				$59				$40			
1988	$122	$126			$61	$63			$41	$43		
1989	$125	$90	$133		$63	$65	$67		$40	$40	$37	
1990	$129	$105	$138	$143	$65	$67	$69	$71	$40	$39	$37	$38
1991	$133	$115	$142	$147	$66	$69	$71	$73	$40	$40	$39	$40
1992	$136	$123	$146	$151	$68	$70	$73	$75	$44	$44	$45	$48
1993	$140	$129	$150	$155	$70	$72	$75	$77	$46	$48	$49	$53
1994	$143	$135	$154	$159	$72	$74	$77	$79	$48	$50	$52	$56
1995	$147	$141	$158	$163	$73	$76	$79	$82	$50	$52	$54	$58
1996	$150	$146	$162	$167	$75	$78	$81	$84	$52	$54	$57	$61
1997	$154	$151	$165	$171	$77	$80	$83	$86	$58	$61	$64	$69
1998	$157	$156	$169	$176	$79	$82	$85	$88	$61	$65	$68	$74
1999	$161	$160	$173	$180	$80	$84	$87	$90	$64	$67	$71	$77
2000	$164	$164	$177	$184	$82	$85	$89	$92	$66	$69	$73	$79
2001	$167	$168	$181	$188	$84	$87	$90	$94	$67	$71	$75	$80
2002	$171	$173	$185	$192	$85	$89	$92	$96	$68	$72	$76	$81
2003	$174	$177	$188	$196	$87	$91	$94	$98	$69	$72	$76	$81
2004	$178	$181	$192	$200	$89	$92	$96	$100	$69	$73	$77	$82
2005	$181	$185	$196	$204	$90	$94	$98	$102	$70	$73	$77	$82
2006	$184	$188	$200	$208	$92	$96	$100	$104	$70	$73	$77	$82
2007	$187	$192	$204	$212	$94	$98	$102	$106	$70	$73	$77	$81
2008	$191	$196	$207	$216	$95	$99	$104	$108	$70	$73	$76	$81
2009	$194	$200	$211	$220	$97	$101	$105	$110	$70	$73	$76	$81
2010	$197	$203	$214	$224	$98	$103	$107	$112	$70	$73	$76	$81
2011	$200	$207	$218	$227	$100	$104	$109	$114	$69	$73	$76	$80
2012	$203	$210	$221	$231	$101	$106	$111	$116	$69	$72	$76	$80
2013	$206	$213	$225	$235	$103	$108	$112	$117	$69	$72	$75	$80
2014	$209	$217	$228	$239	$104	$109	$114	$119	$69	$72	$75	$79
2015	$212	$220	$232	$242	$106	$111	$116	$121	$69	$72	$75	$79
2016	$214	$223	$235	$246	$107	$112	$117	$123	$69	$72	$75	$79
2017	$217	$226	$238	$249	$109	$114	$119	$125	$69	$71	$74	$78
2018	$220	$229	$241	$252	$110	$115	$121	$126	$68	$71	$74	$78
2019	$223	$232	$244	$256	$111	$117	$122	$128	$68	$71	$74	$78
2020	$225	$235	$247	$259	$113	$118	$124	$130	$68	$71	$74	$78
2021	$228	$238	$250	$262	$114	$119	$125	$131	$68	$71	$74	$77
2022	$230	$241	$253	$265	$115	$121	$127	$133	$68	$70	$73	$77
2023	$233	$243	$256	$269	$116	$122	$128	$134	$68	$70	$73	$77
2024	$235	$246	$259	$272	$118	$123	$129	$136	$67	$70	$73	$76

Includes peak loss factor of: 1.0440

All Costs levelized at 9.7%

TABLE 4: LEVELIZED INCREMENTAL CAPACITY COSTS,
PER KILOWATT OF PECO LOAD

	PECo				OCA				A&I			
From:	1987	1988	1989	1990	1987	1988	1989	1990	1987	1988	1989	1990
To Year												
1987	$138				$69				$47			
1988	$142	$147			$71	$73			$48	$50		
1989	$149	$107	$158		$74	$77	$79		$48	$47	$44	
1990	$153	$124	$164	$170	$77	$79	$82	$85	$47	$47	$44	$45
1991	$160	$138	$171	$177	$80	$83	$85	$88	$48	$48	$47	$48
1992	$162	$145	$173	$179	$81	$84	$86	$89	$52	$53	$53	$57
1993	$167	$154	$179	$185	$83	$86	$89	$92	$55	$57	$58	$63
1994	$172	$162	$184	$190	$86	$89	$92	$95	$58	$60	$62	$67
1995	$176	$169	$189	$195	$88	$91	$94	$98	$60	$63	$65	$70
1996	$180	$175	$193	$200	$90	$93	$97	$100	$63	$65	$68	$72
1997	$184	$181	$198	$205	$92	$96	$99	$103	$69	$73	$76	$82
1998	$188	$186	$203	$210	$94	$98	$101	$105	$74	$77	$82	$88
1999	$193	$192	$208	$215	$96	$100	$104	$108	$77	$81	$85	$92
2000	$197	$197	$212	$220	$98	$102	$106	$110	$79	$83	$88	$94
2001	$201	$202	$216	$225	$100	$104	$108	$112	$80	$85	$89	$96
2002	$205	$207	$221	$230	$102	$106	$111	$115	$82	$86	$91	$97
2003	$209	$212	$226	$234	$104	$109	$113	$117	$82	$87	$91	$98
2004	$213	$216	$230	$239	$106	$111	$115	$120	$83	$87	$92	$98
2005	$217	$221	$235	$244	$108	$113	$117	$122	$83	$87	$92	$98
2006	$221	$226	$239	$249	$110	$115	$120	$125	$83	$87	$92	$98
2007	$224	$230	$244	$254	$112	$117	$122	$127	$83	$87	$92	$97
2008	$228	$235	$248	$258	$114	$119	$124	$129	$83	$87	$92	$97
2009	$232	$239	$252	$263	$116	$121	$126	$132	$83	$87	$91	$97
2010	$236	$243	$257	$268	$118	$123	$128	$134	$83	$87	$91	$96
2011	$239	$247	$261	$272	$120	$125	$130	$136	$83	$87	$91	$96
2012	$243	$251	$265	$277	$121	$127	$133	$138	$83	$87	$91	$96
2013	$247	$256	$269	$281	$123	$129	$135	$141	$83	$86	$90	$95
2014	$250	$259	$273	$286	$125	$131	$137	$143	$83	$86	$90	$95
2015	$253	$263	$277	$290	$127	$133	$139	$145	$82	$86	$90	$95
2016	$257	$267	$281	$294	$128	$134	$141	$147	$82	$86	$89	$94
2017	$260	$271	$285	$298	$130	$136	$143	$149	$82	$86	$89	$94
2018	$263	$274	$289	$302	$132	$138	$144	$151	$82	$85	$89	$94
2019	$267	$278	$293	$306	$133	$140	$146	$153	$82	$85	$89	$93
2020	$270	$281	$296	$310	$135	$141	$148	$155	$81	$85	$88	$93
2021	$273	$285	$300	$314	$136	$143	$150	$157	$81	$85	$88	$93
2022	$276	$288	$303	$318	$138	$145	$152	$159	$81	$84	$88	$92
2023	$279	$291	$307	$322	$139	$146	$153	$161	$81	$84	$87	$92
2024	$281	$295	$310	$325	$141	$148	$155	$163	$81	$84	$87	$92

TABLE 5: AVAILABILITY FACTOR (AF), YEARLY VALUES AND AVERAGE OF 1980-84 VALUES, PECO COMBUSTION TURBINES

UNIT	1980	1981	1982	1983	1984	Average AF 1980-84
Chester 7	88.8%	97.2%	97.7%	94.1%	90.2%	93.6%
Chester 8	93.8%	97.1%	97.1%	69.1%	70.2%	85.5%
Chester 9	92.9%	93.8%	93.3%	92.8%	76.0%	89.8%
Croydon 11	52.5%	95.4%	65.7%	87.9%	90.7%	78.4%
Croydon 12	62.7%	65.1%	85.5%	95.8%	87.4%	79.3%
Croydon 21	78.4%	48.8%	74.8%	85.0%	91.3%	75.6%
Croydon 22	61.9%	71.0%	84.9%	65.5%	72.5%	71.2%
Croydon 31	63.4%	73.3%	82.9%	86.0%	85.6%	78.2%
Croydon 32	78.9%	97.1%	67.9%	76.2%	83.6%	80.7%
Croydon 41	70.2%	86.4%	49.7%	77.7%	78.6%	72.5%
Croydon 42	84.3%	96.5%	78.9%	75.2%	90.9%	85.1%
Deleware 9	93.3%	75.3%	94.6%	99.3%	79.4%	88.4%
Deleware 10	95.6%	92.6%	92.7%	94.8%	93.5%	93.8%
Deleware 11	97.6%	93.9%	77.3%	98.3%	91.9%	91.8%
Deleware 12	53.3%	58.2%	94.8%	94.4%	70.4%	74.2%
Eddystone 10	96.9%	94.2%	94.8%	96.1%	80.0%	92.4%
Eddystone 20	89.8%	89.6%	87.1%	77.7%	92.4%	87.3%
Eddystone 30	94.5%	92.3%	93.3%	91.8%	98.1%	94.0%
Eddystone 40	98.7%	97.4%	95.7%	94.7%	56.1%	88.5%
Falls 1	94.0%	98.4%	95.5%	96.6%	95.5%	96.0%
Falls 2	81.9%	98.6%	92.3%	70.6%	89.4%	86.6%
Falls 3	99.9%	97.6%	98.8%	94.2%	92.5%	96.6%
Moser 1	96.7%	95.7%	97.0%	93.6%	86.4%	93.9%
Moser 2	84.9%	94.6%	94.1%	94.2%	89.9%	91.6%
Moser 3	92.3%	96.8%	97.8%	97.3%	95.9%	96.0%

Salem 3	94.8%	92.5%	97.4%	92.0%	93.2%	94.0%
Schuylkill 10	93.0%	67.7%	79.3%	94.1%	91.7%	85.2%
Schuylkill 11	96.2%	90.2%	65.3%	75.2%	80.5%	81.5%
Southwark 3	81.8%	93.0%	91.1%	69.2%	63.2%	79.7%
Southwark 4	92.1%	97.2%	92.4%	99.0%	87.7%	93.7%
Southwark 5	97.0%	98.3%	89.5%	96.6%	97.0%	95.7%
Southwark 6	92.3%	87.5%	89.6%	94.1%	91.9%	91.1%
Average CT:	85.8%	88.2%	87.1%	88.1%	85.4%	86.9%

Source: Docket No. R-850152, IR-OCA-6-22.

TABLE 6: Availability Factors, NorthEast Utilities Combustion Turbines, 1971-84

Plant	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	AVERAGE
Branford 10 [1]	78.6%	97.0%	72.2%	98.4%	95.8%	97.7%	95.8%	94.7%	91.1%	86.5%	81.8%	72.7%			88.5%
Cos Cob 10	94.1%	96.8%	59.7%	92.3%	94.3%	95.5%	93.3%	95.5%	94.8%	97.3%	95.5%	92.6%	86.8%	98.2%	91.9%
Cos Cob 11	98.1%	92.3%	80.6%	90.0%	96.0%	91.2%	90.5%	83.1%	97.4%	97.2%	96.5%	95.0%	97.2%	99.1%	93.2%
Cos Cob 12	70.7%	96.4%	80.3%	82.1%	94.0%	95.9%	98.9%	91.9%	94.0%	98.5%	88.8%	91.6%	8.6%	7.8%	78.5%
Devon 10 [3]	97.9%	97.0%	94.8%	96.6%	95.7%	96.0%	98.4%	92.9%	98.9%	86.5%	94.6%	98.2%	98.2%	57.6%	93.1%
Doreen 10	98.8%	98.0%	95.9%	96.1%	82.1%	99.5%	97.4%	98.7%	95.7%	97.2%	97.9%	98.8%	99.5%	98.7%	96.7%
Enfield 10	97.5%	93.9%	97.5%	90.7%	80.3%	98.3%	99.0%	98.8%	97.7%	96.3%	98.7%	98.5%	99.0%	94.7%	95.8%
E. Springfield 10	92.6%	99.2%	95.6%	97.5%	97.3%	98.8%	98.5%	98.5%	98.7%						97.4%
Franklin Drive 19	93.1%	99.4%	99.0%	96.0%	96.1%	99.0%	97.3%	98.0%	97.7%	98.0%	97.8%	96.0%	97.1%	97.6%	97.3%
Middletown 10	90.7%	73.3%	97.7%	92.4%	93.8%	74.9%	99.9%	98.6%	97.8%	8.6%	0.0%	0.0%	25.0%	98.1%	67.9%
Norwalk Harbor 10	36.7%	93.0%	87.0%	94.4%	60.0%	11.8%	94.0%	99.5%	98.9%	98.5%	98.7%	98.8%	5.3%	81.1%	75.6%
Silver Lake 10	94.0%	98.7%	97.3%	98.6%	90.9%	60.9%	100.0%	99.6%	99.3%	100.0%	99.3%	89.6%			94.0%
Silver Lake 11 [2]	94.9%	99.5%	96.7%	94.5%	96.7%	98.8%									96.9%
Silver Lake 12 [3]	90.3%	92.8%	94.6%	49.5%	90.4%	99.7%	83.7%	99.9%	99.5%	100.0%	99.3%	96.7%	90.0%	81.8%	90.6%
Silver Lake 13	98.3%	99.1%	95.4%	94.2%	72.7%	99.9%	99.8%	97.9%	99.9%	99.8%	99.1%	96.9%			96.1%
South Meadow 11	85.5%	68.9%	90.2%	96.2%	99.3%	96.4%	90.4%	98.6%	91.4%	82.6%	94.8%	55.3%	0.0%	54.5%	78.9%
South Meadow 12	81.5%	96.7%	94.1%	97.3%	95.6%	98.4%	96.6%	99.8%	98.7%	99.3%	98.9%	88.8%	97.0%	96.6%	95.7%
South Meadow 13	96.3%	80.3%	95.7%	98.3%	98.5%	98.9%	95.8%	99.6%	99.1%	99.9%	95.8%	94.0%	96.8%	98.6%	96.3%
South Meadow 14	93.0%	94.4%	78.4%	97.8%	99.8%	99.0%	95.8%	98.7%	98.7%	99.1%	99.8%	97.2%	97.3%	96.5%	96.1%
Torrington 10 [3]	97.6%	98.3%	76.5%	97.0%	95.2%	96.0%	98.3%	98.2%	95.5%	98.3%	89.3%	78.8%	0.0%	73.7%	85.2%
Tracey 10	98.3%	97.4%	96.5%	90.2%	93.9%	98.1%	100.0%	90.1%	98.5%						95.9%
Tunnel 10 [3]	97.6%	97.0%	97.7%	93.9%	97.7%	95.3%	98.6%	98.8%	98.4%	97.6%	93.2%	98.7%	99.6%	76.8%	95.8%
Woodland Road 10 [3]	76.7%	82.4%	98.4%	93.1%	92.6%	98.4%	98.7%	98.8%	98.5%	98.0%	99.1%	98.6%	56.5%	52.8%	88.8%
W. Springfield 10	67.0%	99.0%	75.5%	99.7%	95.7%	98.8%	98.8%	96.8%	98.4%	93.7%	98.6%	97.0%	98.4%	98.1%	94.0%
AVERAGES:	88.3%	93.4%	89.5%	92.8%	91.9%	91.6%	96.5%	96.8%	97.3%	92.0%	91.3%	87.3%	69.6%	81.2%	90.8%

Notes: 1. Retired July, 1984. 0% for 1983 deleted.
2. Silver Lake 11 did not generate in 1978 and 1979. 34.5% for 1977 deleted.
3. To be retired 1986/87.

Sources: NU, Vol.2 Power Facilities Forecast. April, 1981 and 1985.
WMEC, Performance Program Proposal. February, 1982 and March, 1984.

TABLE 7: BINOMIAL DISTRIBUTION OF QF OUTAGES

Forced Outage Rate p	Total QF's n	QF's in Forced Outage x	Probability of x	Hours /Year
10%	40	0	1.478%	129.5
		1	6.569%	575.5
		2	14.233%	1246.8
		3	20.032%	1754.8
		4	20.589%	1803.6
		5	16.471%	1442.9
		6	10.676%	935.2
		7	5.761%	504.7
		8	2.641%	231.3
		9	1.043%	91.4
		10	0.359%	31.5
		11	0.109%	9.5
		12	0.029%	2.6
		13	0.007%	0.6
		14	0.001%	0.1
		15	0.000%	0.0
		16	0.000%	0.0
		17	0.000%	0.0
		18	0.000%	0.0
		19	0.000%	0.0
		20	0.000%	0.0
		21	0.000%	0.0
		22	0.000%	0.0
		23	0.000%	0.0
		24	0.000%	0.0
		25	0.000%	0.0
		26	0.000%	0.0
		27	0.000%	0.0
		28	0.000%	0.0
		29	0.000%	0.0
		30	0.000%	0.0
		31	0.000%	0.0
		32	0.000%	0.0
		33	0.000%	0.0
		34	0.000%	0.0
		35	0.000%	0.0
		36	0.000%	0.0
		37	0.000%	0.0
		38	0.000%	0.0
		39	0.000%	0.0
		40	0.000%	0.0

$$\text{Probability} = \binom{N}{X} * P^{x} * (1 - P)^{(n - x)}$$

TABLE 8 (Revised): EFFECTS OF HIGH DEMAND CHARGES AND RATCHETS FOR SUPPLEMENTARY LOADS

Maximum Summer Demand (MW)		5	6	7	8	9	10	11
Summer Monthly MWH		3600	3600	3600	3600	3600	3600	3600
150 hrs @	$0.0964	750	900	1050	1200	1350	1500	1650
Next 150 @	$0.0668	750	900	1050	1200	1350	1500	1650
Remainder @	$0.0375	2100	1800	1500	1200	900	600	300
Monthly Energy Bill ($1000)		$201	$214	$228	$241	$254	$267	$281
Winter Billing Demand (MW)		4	4.8	5.6	6.4	7.2	8	8.8
Winter Monthly MWH		2880	2880	2880	2880	2880	2880	2880
150 hrs @	$0.0964	600	720	840	960	1080	1200	1320
Next 150 @	$0.0668	600	720	840	960	1080	1200	1320
Remainder @	$0.0375	1680	1440	1200	960	720	480	240
Monthly Energy Bill ($1000)		$161	$172	$182	$193	$203	$214	$224
Annual Load Factor		85.5%	71.2%	61.1%	53.4%	47.5%	42.7%	38.9%
Total Bills:								
With One Summer Month At Maximum Demand: Annual Bill ($1000)		$2,583	$2,751	$2,918	$3,086	$3,254	$3,422	$3,589
Cost of Last kW			$168	$168	$168	$168	$168	$168
Average Cost/kWh		$0.069	$0.073	$0.078	$0.082	$0.087	$0.091	$0.096
With Four Summer Months At Maximum Demand: Annual Bill ($1000)		$2,583	$2,819	$3,054	$3,290	$3,526	$3,762	$3,997
Cost of Last kW			$236	$236	$236	$236	$236	$236
Average Cost/kWh		$0.069	$0.075	$0.082	$0.088	$0.094	$0.100	$0.107
Cost of Service with CTs [1]		$3,021	$3,101	$3,181	$3,261	$3,341	$3,421	$3,501
Cost/kWh		$0.081	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094
Demand at:	$9.44 /kw-month							

Note: [1] Assumes $50/kwyr Generation; $30/kwyr T&D; 7 cts/kwh Energy.

TABLE 8 (Revised): EFFECTS OF HIGH DEMAND CHARGES AND RATCHETS FOR SUPPLEMENTARY LOADS

Maximum Summer Demand (MW)		12	13	14	15	16	17
Summer Monthly MWH		3600	3600	3600	3600	3600	3600
150 hrs @	$0.0964	1800	1950	2100	2250	2400	2550
Next 150 @	$0.0668	1800	1650	1500	1350	1200	1050
Remainder @	$0.0375	0	0	0	0	0	0
Monthly Energy Bill ($1000)		$294	$298	$303	$307	$312	$316
Winter Billing Demand (MW)		9.6	10.4	11.2	12	12.8	13.6
Winter Monthly MWH		2880	2880	2880	2880	2880	2880
150 hrs @	$0.0964	1440	1560	1680	1800	1920	2040
Next 150 @	$0.0668	1440	1320	1200	1080	960	840
Remainder @	$0.0375	0	0	0	0	0	0
Monthly Energy Bill ($1000)		$235	$239	$242	$246	$249	$253
Annual Load Factor		35.6%	32.9%	30.5%	28.5%	26.7%	25.1%
Total Bills:							
With One Summer Month At Maximum Demand: Annual Bill ($1000)		$3,757	$3,860	$3,963	$4,065	$4,168	$4,271
Cost of Last kW		$168	$103	$103	$103	$103	$103
Average Cost/kWh		$0.100	$0.103	$0.106	$0.109	$0.111	$0.114
With Four Summer Months At Maximum Demand: Annual Bill ($1000)		$4,233	$4,378	$4,522	$4,666	$4,811	$4,955
Cost of Last kW		$236	$144	$144	$144	$144	$144
Average Cost/kWh		$0.113	$0.117	$0.121	$0.125	$0.128	$0.132
Cost of Service with CTs [1]		$3,581	$3,661	$3,741	$3,821	$3,901	$3,981
Cost/kWh		$0.096	$0.098	$0.100	$0.102	$0.104	$0.106
Demand at: /kw-month	$9.44						

Note: [1] Assumes $50/kwyr Generation; $30/kwyr T&D; 7 cts/kwh Energy. REVIST8/03-Apr-86

TABLE 8 (Revised): EFFECTS OF HIGH DEMAND CHARGES AND RATCHETS FOR SUPPLEMENTARY LOADS

Maximum Summer Demand (MW)		18	19	20	21	22	23
Summer Monthly MWH		3600	3600	3600	3600	3600	3600
150 hrs @	$0.0964	2700	2850	3000	3150	3300	3450
Next 150 @	$0.0668	900	750	600	450	300	150
Remainder @	$0.0375	0	0	0	0	0	0
Monthly Energy Bill ($1000)		$320	$325	$329	$334	$338	$343
Winter Billing Demand (MW)		14.4	15.2	16	16.8	17.6	18.4
Winter Monthly MWH		2880	2880	2880	2880	2880	2880
150 hrs @	$0.0964	2160	2280	2400	2520	2640	2760
Next 150 @	$0.0668	720	600	480	360	240	120
Remainder @	$0.0375	0	0	0	0	0	0
Monthly Energy Bill ($1000)		$256	$260	$263	$267	$271	$274
Annual Load Factor		23.7%	22.5%	21.4%	20.4%	19.4%	18.6%
Total Bills:							
With One Summer Month At Maximum Demand: Annual Bill ($1000)		$4,373	$4,476	$4,579	$4,682	$4,784	$4,887
Cost of Last kW		$103	$103	$103	$103	$103	$103
Average Cost/kWh		$0.117	$0.120	$0.122	$0.125	$0.128	$0.131
With Four Summer Months At Maximum Demand: Annual Bill ($1000)		$5,099	$5,244	$5,388	$5,532	$5,677	$5,821
Cost of Last kW		$144	$144	$144	$144	$144	$144
Average Cost/kWh		$0.136	$0.140	$0.144	$0.148	$0.152	$0.155
Cost of Service with CTs [1]		$4,061	$4,141	$4,221	$4,301	$4,381	$4,461
Cost/kWh		$0.108	$0.111	$0.113	$0.115	$0.117	$0.119
Demand at: /kw-month	$9.44						

Note: [1] Assumes $50/kwyr Generation; $30/kwyr T&D; 7 cts/kwh Energy.

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TABLE 8 (Revised): EFFECTS OF HIGH DEMAND CHARGES AND RATCHETS FOR SUPPLEMENTARY LOADS

Maximum Summer Demand (MW)		24
Summer Monthly MWH		3600
150 hrs @	$0.0964	3600
Next 150 @	$0.0668	0
Remainder @	$0.0375	0
Monthly Energy Bill ($1000)		$347
Winter Billing Demand (MW)		19.2
Winter Monthly MWH		2880
150 hrs @	$0.0964	2880
Next 150 @	$0.0668	0
Remainder @	$0.0375	0
Monthly Energy Bill ($1000)		$278
Annual Load Factor		17.8%
Total Bills:		
With One Summer Month At Maximum Demand: Annual Bill ($1000)		$4,990
Cost of Last kW		$103
Average Cost/kWh		$0.133
With Four Summer Months At Maximum Demand: Annual Bill ($1000)		$5,965
Cost of Last kW		$144
Average Cost/kWh		$0.159
Cost of Service with CTs [1]		$4,541
Cost/kWh		$0.121
Demand at: /kw-month	$9.44	