Report No.: SS-742-C-12-106

Date: January 16, 1981

STAFF STUDY

AN OVERVIEW OF ELECTRICITY PRICING POLICIES AND PRACTICES APPLIED TO RAILROAD ELECTRIFICATION

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U.S. DEPARTMENT OF TRANSPORTATION

Technical Report Documentation Page

1. Report No.	2. Government Accession No.	3. Recipient's Catalog No.

4. Title and Subtitle	5. Report Date
An Overview of Electricity Pricing Policies and Practices Applied to Railroad Electrification	November, 1980
	6. Performing Organization Code
7. Author(s)	8. Performing Organization Report No.
9. Performing Organization Name and Address U.S. Department of Transportation Transportation Systems Center Kendall Square Cambridge, MA 02142	10. Work Unit No. (TRAIS) RR-158/R-1343 11. Contract or Grant No.
12. Sponsoring Agency Name and Address Federal Railroad Administration Office of Systems Analysis and Information Research and Analysis Division 400 Seventh St. S.W./ Washington, D.C.	13. Type of Report and Period Covered Staff Study 14. Sponsoring Agency Code

15. Supplementary Notes

16. Abstract

This report contains material for use by the Federal Railroad Administration in its assessment of railroad electrification. An overview is provided of the current policies and practices of the electric utility industry in its pricing of electricity. The application of current practice to electrified railroads is also reviewed. It can be expected that electricity pricing initially set for large scale electrification in the U.S. should follow current practices for serving large industrial loads while accounting for the uniqueness of the railroad load. Special charges may be levied to the railroad for any required utility construction, for standby facilities to cover operational contingencies, and for penalties for disturbances to the electric utility system that must be corrected by the utility. Because U.S. railroads have had so little experience with electrification, a comprehensive analysis should be conducted on the impact of electricity pricing on both the railroads and the electric utilities. This analysis should consider the technical economic and regulatory factors that will affect the price of electric energy to the railroads.

17. Key Words	18. Distribution Statement
Railroads, Electrification, Price of electric energy	This report is intended for individual use to the Department of Transportation. Distribution is to be made by the sponsoring agency.

19. Security Classif. (of this report)	20. Security Classif. (of this page)	21. No. of Pages	22. Price
Unclassified	Unclassified		

Form DOT F 1700.7 (8-72) Reproduction of completed page authorized

EXECUTIVE SUMMARY

BACKGROUND

Government policy decisions and/or economic constraints may require a reassessment of the issue of electrification of the nation's mainline railroads. Electrification results in the substitution of the purchase of diesel oil by electric energy. The pricing of electric energy is complex and involves the consideration of many factors in addition to energy usage. The purpose of this report is to review some of the factors used by the electric utility industry in its pricing of electricity and to discuss the effect of the special nature of the railroad load on the pricing process.

The electric utility industry has the general classification of a "natural monopoly" in that it supplies a service essential to the public interest and welfare, and where direct competition is considered to be wasteful, uneconomical and unsatisfactory in general. Because of this classification, the industry is subject to government regulation which has as its objectives limiting the industries' earnings to a fair rate of return and assuring a quality of service and a continuity of service to all who apply for such service. An electric utility system consists of generating plants, transmission lines, substations, and a distribution system. The system must deliver electric energy to any customer upon demand and at lowest production and transmission cost. The utility meets the demand by placing generating plants on line throughout the day in order of their incremental generation costs. In expanding its system to meet future load, the utility constructs a mix of generating plants for continuous low-cost base-load operation and shorter-time higher-cost peaking operation to match the shape of the daily load curve. Transmission lines are constructed to carry the bulk power generated throughout the utility system. The distribution system is expanded to supply specific industrial, commercial and residential customers.

Summary of the Overview Study

The rate structure for the electric utility is designed so that the total income from the sale of electric energy provides a fair rate of return on the capital investment of the utility. The rate structure is divided into rate schedules for each customer class in some attempt to match electricity price to the utility's cost of serving each customer class. The utility's costs consist of two components: fixed costs to service the capital investment and variable costs primarily for fuel. The rates are designed to recover these costs by a demand charge based on the maximum monthly load of a customer to recover the fixed costs, and an energy charge based on the kilowatt hours (energy) used by the customer to recover the variable costs. Because electric utilities operate as monopolies in their franchise territories, both their fair rates of return and their individual rate schedules are subject to approval by state public utility commissions and, for certain classes of wholesale customers, by the Federal Energy Regulatory Commission.

Customer usage of electricity is measured by the utility at each point of service using appropriately named demand and watthour meters. The translation of the readings into billing to the customer is governed by the rate schedule. The electrified railroad load differs substantially from industrial loads so that special rate schedules must be negotiated between the railroads and the utilities, with public utility commission approval, to insure equitable charges. At any individual substation feeding a section of catenary, the railroad load will fluctuate between zero and peak value many times a day. However, for a large section of electrified railroad, the aggregate electric load for 16 to 20 hours per day is relatively steady with the average load being about half of the peak.

Current practice of utility pricing to electrified railroads in the United States is confined to Amtrak and Conrail, to commuter lines, and to rapid-transit systems.

The present Amtrak 25 Hz system between New Haven and Washington is supplied from the utilities at relatively few points because the catenaries are fed from dedicated transmission lines along the route. Under the new 60-Hz design, the Amtrak system in the Northeast Corridor will be supplied by at least twelve utilities at more than thirty substations in eight states and the District of Columbia; negotiations for rate schedules, methods of metering and billing, are currently under discussion. Extrapolating the Northeast Corridor situation to rest of the country, large scale mainline electrification can be expected to result in separate negotiations with at least 40 electric utilities and their respective regulatory agencies. Practice in most foreign countries differs primarily because the electrified railroads are supplied from nationally owned electric utilities. Negotiations therefore are conducted with only one electric utility for both technical and pricing decisions.

It can be expected that electricity pricing initially set for electrified railroads should follow current policies and practices for serving large industrial loads but accounting for the uniqueness of the railroad load. Special charges may be levied to the railroad for any required utility construction, for standby facilities to cover operational contingencies, and for penalties for disturbances to the electric utility system that must be corrected by the utility.

The whole issue of electricity pricing has been the subject of recent intensive analysis by the industry, their regulatory agencies, and the federal government. An Electric Power Research Institute (EPRI) study group sponsored by the National Association of Regulatory Utility Commissioners has been addressing this issue since 1975. The EPRI study group has been concerned with examining ways of controlling growth in peak demand of electric energy and its impact on electricity prices.

Load management strategies including time of day metering and cost allocation approaches concerned with imbedded cost versus marginal cost are some of the subjects being evaluated by the study group. Appendix A provides a summary of the EPRI work. The Public Utilities Regulatory Policies Act (PURPA) of 1978 was enacted to move utilities to accomplish three major goals; conservation of the energy that electric companies produce, efficient use of facilities and resources by utilities, and equitable electric rates for utility customers.

Recommendations for Impact Analysis Study

A comprehensive analysis should be conducted on the impact of railroad electrification on the railroad-electric utility interface, since U.S. railroads have had very little experience with electrification. Electrified railroads will impose an unusual load on the electric utilities which will serve them. The pricing of electricity will have a bearing in the design of the railroad facilities and equipment, and will be a reflection of the features of the railroad load. Comprehensive analysis of the technical, economic, and regulatory factors of utility electric pricing will resolve much of the uncertainty for the future of railroad electrification. The following summary of these factors represent a starting point for a comprehensive impact analysis of the railroad/electric utility interface:

Technical Factors

- Characteristics of railroad load. Negative aspects - low substation load factor; rolling peak load; poor load quality. Positive aspects - long daily load period; acceptable overall load factor.

- Capital trade offs. Trade-off possibilities between railroad capital expenditures to improve load characteristics (and efficiency) against utility capital expenditures to reinforce their system.

- Flexibility of supply system. Catenaries can be supplied by various combinations of utility and railroad-owned transmission lines, substations, and generating stations to achieve cost-effective arrangement for railroad service and utility system growth.

- Electromagnetic compatibility. Specification and cost of locomotives and self-powered cars, as well as other railroad electrical facilities, to balance costs to suppress power harmonics and unbalance in utility lines.

Economic Factors

- Railroad scheduling. Potential for railroad scheduling to reduce electricity demand at the time of utility system load peak. Make use of less costly off-peak power to raise the utility system load factor.

- Metering and billing practice. Methods for treating electrified railroads supplied at multiple points as a single load on the utility system. Metering equipment, power demand measurements, incremental losses for transmitting power to supply points.

- Utility capital costs. Whether the demand charge imposed on the railroads will be based upon the marginal cost for adding generating capacity and transmission facilities for the new load or will be based upon the much lower average or imbedded capital costs.

- Corporate ventures. Opportunity for combined railroad, utility and energy supply (i.e., coal mining) corporate ventures to provide electricity for the railroad and other services for the venture partners.

- Transmission facilities. Sharing of the railroad-owned right of way and transmission lines to be built between the railroad and the utility on some type of joint-use basis.

- Ownership of Fixed Plant. Ownership and operating responsibility of the electrical facilities, including the railroad catenaries by the utilities, to reduce the railroad capital cost, eg the project management concept (REMC) being studied by the TVA.

Regulatory Factors

- Public Utility Commissions and Federal Energy Regulatory Commission (FERC). Responsibilities and past practices on traction power rates; quality of service; maintenance of special service to railroads; standards; safety.

- Public power. Availability of power for electrified railroads from Western Area Power Region (formerly Bureau of Reclamation); Bonneville Power Administration; super transmission cooperative; and others.

- Regeneration. Acceptance by utilities of regenerated power from catenaries; power from railroad-owned cogeneration plants.

- Impact of the Public Utilities Regulatory Policies Act (PURPA). Cost of Service Standard requires that rates for each customer class be designed to reflect the costs of providing service to that class including the cost consequences of both additional kilowatt hour usage and peak kilowatt demand.

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1.0 INTRODUCTION

The electric utility/railroad interface is one of the most important elements to be considered in the analysis of the impacts of railroad electrification. The purpose of this report is to review the mechanisms used by the electric utility industry in its pricing of electricity and the potential application of those mechanisms to wide-scale railroad electrification in the U.S.

The electric utility industry is generally classified as a "natural monopoly" in that it supplies a service essential to the public interest and welfare and because direct competition is considered to be wasteful, uneconomical and unsatisfactory in general. Because of this classification, the industry is subject to government regulation which has as its objective limiting the earnings of electric utilities to a fair rate of return and assuring a quality and a continuity of service to all who apply for such service.

This report briefly describes the economic basis for electric utility pricing, the design of rate structures, and metering and billing practices. A review of current practice in U.S. railroads is provided that illustrate current electricity pricing and policy practices.

2.0 BASIS FOR ELECTRIC UTILITY PRICING

The pricing decision of electric utilities is best appreciated with reference to the major distinguishing characteristics of the industry. Although electric power could be viewed as a homogenous commodity, in fact, it is differentiated by factors, such as rate schedules, which enable the firm to offer a wide variety of services. In addition, it is important to recognize that neither electric utilities nor consumers can practicably store power; thus in the absence of congestion-toll-like rates, the firms must offer reliable generation in order to meet the demands placed on the system.

2.1 Economic - Financial Characteristics

There are three broad characteristics of the electric utility industry which influence the pricing decision. The first of these is the capital/labor ratio of the production process. Electric utilities are inherently a capital rather than a labor intensive production process. Electric power systems require a substantial amount of investment in plant and infrastructure before a dollar of revenue is earned. Generation, transmission, and distribution networks are generally sized to meet maximum peak power loads, with reserve requirements included to reduce the probability of an outage to acceptable levels. Generation of power tends to be in large indivisible blocks of capacity in order to exploit economies of scale.

The capital turnover ratio, the relationship between a firm's investment in operating assets and total gross revenues derived from these assets, is indicative of the underlying technological and engineering requirements exhibited by the electric power industry. It generally is maintained that, on the average, public utilities including the electric power industry require from three to four dollars of investment in operating assets to derive one dollar of revenue. Table 1 illustrates the capital turnover ratios for electric utilities as well as for other industrial activities.

Table 1

Capital Turnover Ratios of Active Nonfinancial Corporations, by Major Industry Classification, 1969

Major industry group	*Capital turnover ratio*
Manufacturing	1.21
Electric, gas, and sanitation	0.32
Retail	2.66
Transportation	0.72
Wholesale	2.88
Communications	0.45
Services	1.19
Construction	2.16
Mining	0.74
Agriculture, forestry, and fisheries	1.39
Other	2.55
All nonfinancial corporations	1.31

SOURCE: Internal Revenue Service, Department of the Treasury, *Preliminary Statistics of Income—1969. Corporation Income Tax Returns*, Publication no. 159 (12–71) (Washington, D.C.: U.S. Government Printing Office, 15 October 1970), Table 3, pp. 27–31.
NOTE: *Capital turnover* is defined as the ratio of gross revenue to net capital investment in assets.

The second characteristic results because of the economies of scale possible in the production and distribution of electric power, thus electric utilities have been considered a prime example of a natural monopoly. Public policy has been predicted on the presumption that the production of electric power involves less resource expenditures under a monopoly or limited franchise market. The physical limits on the size of the market are set by transmission costs, which vary approximately in proportion to distance and inversely with the square of transmission voltages.

If average costs of providing power decline as output rises, a single supplier can produce a given output more cheaply than two suppliers. However, in order for consumers to reap the benefits of cheaper production, it may be necessary to restrain the market power for the single producer. Public utility regulation tries to ensure optimal pricing and output levels which would occur under competitive market conditions. In practice, utility commissions often give much leeway to the industry in designing its rate structure and in capacity expansion planning so long as industry profits are not judged to be "excessive." Such judgements may be based on the return on the firms' "rate bases."

Although an individual market is served by a single firm, the industry is composed of numerous interdependent firms. The interdependency results from several conditions. Since peak load periods may differ from market to market, systemwide economies can be attained by the interchange of power. New generation capacity is added in large "lumps" which give to the firms excess capacity for some periods of time. Again systemwide economies accrue if such excess capacity is used to supply those firms having insufficient capacity. The need for reliable service has also led to an increasingly linked national network among utilities. Such links provide a backup reserve of power which can be drawn upon to cover emergency downtime of equipment. Finally, as the overall power-load has increased, extra high voltage transmission (230 to 765 KVA) have become more profitable leading to greater long distance transmission.

The third set of characteristics concerns the financial environment for electric utilities. As a general rule, firms which are highly capital intensive have greater percentage variability in net operating income than average firms because of the large component of fixed operating expenses. As a consequence, such firms are likely to have a lower debt to equity ratio. Public utilities are a noticeable exception to this rule.

2.2 Regulatory Control

State and federal regulatory authorities operate under statutes that authorize them to exercise control over total revenues obtained from public utility services. The revenue requirement is the total amount required to cover the operating expenses (including depreciation and taxes) and to provide a normal profit to a regulated utility. An added objective is to provide the regulated utility with sufficient earnings over the near term and to attract capital for expansion. This, coupled with the fact that the demand for electric power is relatively inelastic with respect to income and price fluctuations, results in gross revenues, operating expenses, and net operating income being relatively stable. Revenue stability is also assured because of restricted entry and competition. As a consequence, the capital structure of electric utilities can support a debt-to-equity ratio substantially higher than for other industrial enterprises. The relatively large amount of debt capital, however, does represent a fixed financial obligation against the electric utility. Thus, the firms are faced with high but stable operating and financial expenses which must be covered by the rate making process.

3.0 DESIGN OF RATE STRUCTURES

The nature of the electric utility's product permits an extensive amount of market segmentation. Thus, firms are able to price units of power differently to different buyers. Such pricing practices are referred to as price discrimination. For utilities, two types of price discrimination are possible. The first is the use of progressively lower rate to marginal cost ratios as the volume consumed by a given buyer increases. Rates of this sort are termed block rates. The second form of discrimination charges different prices relative to cost to different customer classes. In this case, two buyers consuming the same quantity of power would be paying different prices. Pricing of this sort is based upon the relative price elasticities of demand of the various customer classes.

3.1 Rate Classification

Customer classes are designed to group users who place similar demands upon the system. Such definitions can be used to encourage or discourage particular types of power use. Since the peak load problem is pervasive, classes have been designed to reduce the severity of the peaking demand. Large industrial users often acquire power under terms which allow the utility to interrupt service during peak periods. This service forces the buying firm to incur either the costs of supplying stand-by generating capacity itself or of shutting down operations during the peak period. Buyers concede to this arrangement because the rate structure associated with interruptable service offsets the costs of interruption.

Public utility commissions serve to constrain the monopoly and price discriminating power of the utilities by linking the rates permitted to the cost of service to a particular class. The cost of service is composed of several types of costs. These can be classified as capacity costs (further divided into generation, transmission, and primary and standby distribution capacity), energy costs (i.e., operating and maintenance costs), and customer costs (billing, metering, service drops--wire from a distribution line to the point of consumption--etc.)

3.2 Fixed and Variable Costs

At any given time period, capacity costs are fixed, thus independent of system output, and energy costs are variable. Customer costs vary with the number and type of customer rather than peak power demands (KW) or energy consumptions (KWH).

The fixed costs incurred in building adequate capacity to meet peak load demands can be covered by a rate structure which charges customers some flat amount based on peak demand rather than actual use. In practice, these costs may be met by a combination of a flat charge and a declining block rate within a customer class.

Fixed customer costs can be covered in a similar fashion. The allocation among customer classes would be based upon the services actually provided. However, in both cases, portions of the fixed costs are jointly incurred and cannot be uniquely associated with particular user. Allocations of these costs must be somewhat arbitrary.

Since energy costs vary with consumption, allocation of these costs are based upon actual use rates.

3.3 Pricing Policies

Public utility commissions have traditionally adopted pricing policies allowing for a "fair return" on investment and yielding sufficient revenue to cover total costs. Average cost pricing is consistent with both these objectives. Regulatory authorities have not required, and in certain cases, have legally blocked attempts to incorporate marginal cost pricing rules into electric utility rate structures.

The use of average costs as the basis for establishing the rates to which consumers respond does not force each consumer to bear the costs of a decision. If all costs are averaged over all users in a class and if costs were to rise in order to meet added peak period demand from some of the users in the class, portions of the incremental costs would be borne by those users who had not imposed any added burden.

Marginal cost pricing would have the advantage of charging the full incremental costs to the consumers imposing the burden, thereby assuring that the benefits to be derived from the additional power demanded will exceed the added costs of providing it. Current pricing policies under review include the use of marginal costs for at least some of the cost components. Time of day pricing has been suggested as a method by which customers would be presented with higher rates in the peak period. Such rates would reflect not only the short run variable costs of providing service but would allocate the fixed costs of providing peak load capability to peak load users. This approach differs from the current practice of setting rates based partially upon a firm's peak demand in recognizing that it is the timing of that demand which is important to the system. In this respect, such pricing practices would be similar to congestion tolls.

4.0 METERING AND BILLING PRACTICES

Metering and billing practices are defined in documents called Rate Schedules which are published by the electric utility companies. These Rate Schedules must be approved by the regulatory commission in each state; they then govern the sale of electricity by each utility to its customers. The Rate Schedule is divided into classes of service for which each has a designated Schedule; each Schedule is further subdivided into categories of charges. A utility cannot sell electricity to any customer unless a class of service and charges have been established in the Rate Schedule and approved by the regulatory commission of the state. The Rate Schedules differ among utilities but still contain the same elements which we shall describe in this section.

4.1 Rate Schedules - Services

A typical set of service categories is given by Potomac Electric Power Company (PEPCO) for the District of Columbia as follows:*

Residential Service	Schedules "R" and "AE"
General Service	Schedules "GS and "GT"
Heating Service	Schedule "HS"
Temporary or Supplementary Service	Schedule "T"
Outdoor Lighting Service	Schedule "OL"
Street Lighting Service	Schedules "SL", "SSL-OH", and "SSL-UG"
Traffic Signal Service	Schedules "TS" and "DC-TR"
Rapid Transit Service	Schedule "RT"

Electric railroad customers would be supplied under the Rapid Transit Service Schedule "RT" (now used for WMATA) or under a high-voltage category of the General Service Schedule "GS".

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*PEPCO also publishes Rate Schedules for their customers in the states of Virginia and Maryland.

4.2 Rate Schedule - Charges

The schedule for a particular service lists a set of charge components which make up the total charge to the customer. The charge components are used by all utilities with somewhat different terminology. The charge components which are used in a typical (PEPCO) General Service category include the following:

- Energy Charge - The charge is expressed in terms of cents per kilowatthour (¢/kWh) and is directly proportional to the energy consumed by the customer for the month. The energy charge is usually stepped down as a function of use (rate blocks) and may be higher during the on-peak months (June-October) than during the off-peak months. For example, the highest usage energy charge for PEPCO is 2.067 ¢/kWh during the on-peak months and 1.496 ¢/kWh during the off-peak months.

- Demand Charge - The charge is expressed in terms of dollars per kilowatt ($/kW) and is directly proportional to the maximum demand by the customer on the electric utility during the month. For some utilities, the highest demand during the past 12 months is used as the basis for demand charges. The demand is usually measured over a 15-min. period. Some utilities use 30 min.; some use 5 min. for violently fluctuating loads; some average the demand over the four highest days each month. The demand charge is usually stepped down as a function of the month used and is higher during the on-peak months than the off-peak months. For example, the highest usage demand charge for PEPCO is $6.00/kW per month during the on-peak months and $4.80 per month during the off-peak months.

- Demand Charge (con't)

  Contract limits with large users such as railroads generally provide for minimum and maximum values for the demand kW. A minimum value is charged regardless of usage, and penalties are imposed if the maximum value is exceeded.

- Fuel Rate (Charge) - The charge, also called the energy adjustment charge, is expressed in terms of cents per kilowatthour (¢/kWh), and is added to the energy charge. The fuel rate charge reflects the cost of fuel to the utility that is passed on directly to the customer. The structure of the charge depends upon the particular utility and particular state regulatory commission. Basically, the utility calculates the total cost of fossil and nuclear fuel in their own plants, and in the plants from which they have purchased energy, for a one-year period. The utility divides that annual total fuel cost by the kilowatt-hours generated and purchased in the same period to arrive at a fuel rate (charge). The existing fuel rate is updated either on an annual basis (e.g. July 1st each year), every month, or at other appropriate time intervals. The utility may require the state regulatory commission's approval for each change of the fuel rate. Typical fuel rates for PEPCO are 1.47483 ¢/kWh for the General Service Schedule in the state of Maryland.

- Power Factor (Charge) - The charge is made as a penalty on the customer based on the cost to the utility to correct the power factor to the required range. The power factor is the ratio of kW to kVA, and is a measure of the portion of the electric current that the utility delivers to the customer that is producing energy. Unity power factor (PF = 1.0) means o Power Factor (Charge) - (con't)

that all of the current is producing energy. Power factor less than unity (lagging for inductive loading and leading for capacitive loading) means that a given amount of current produces less energy compared to unity power factor loading. The charges take several forms. One form is a multiplier on the demand charge if the power factor is less than 0.85. For Example, PEPCO specifies a multiplier of 1.111 for a power factor less than 0.85. Another form is a monthly cost for correction in terms of $/kVar of capacitors to raise the customer's power factor to 0.85. PEPCO specifies a reactive charge of $0.15/kVar in its District of Columbia Rapid Transit Service rate.

o Special Facilities (Charge) - The fixed monthly charge made to cover use of the frequency converters at the substation which convert 60 Hz 3-phase power to 25 Hz 1-phase power for railroad use. While this charge pays for depreciation, daily operation, and normal maintenance of the rotary converters, it does not cover charges for major repairs and major parts replacement, which are billed separately after these jobs are approved by the railroad. As an example, a fixed monthly charge of $50,000/mo. is charged for the nine units (including standby reserve) located at four Philadelphia Electric Substations which serve the Northeast Corridor and commuter service. Their combined capacity is 152,500 kW for a fixed monthly charge of $0.328/kW.

Depending upon the companies and the schedules, there are numerous other charges for special conditions.

4.3 Instrumentation

A special class of instruments termed "meters" in the industry act as the cash registers for measuring the electrical quantities that are used for billing the customer. The type and accuracy of these meters are subject to the approval of state regulatory commissions. The meters will be described by the electrical quantities that they measure as follows:

- Energy - A watthour meter (Fig. 1) measures and records the electric energy used by a customer. The meter is basically a motor which runs at a velocity proportional to the rate of energy use, or the power used by the customer. The motor drives a register or counter that accumulates the number of revolutions of the motor, which is proportional to the energy passed through the watthour meter to the customer. The design and manufacture of the watthour meter is highly developed so that available units are both accurate and cheap. The typical price is less than $30.00 per meter and accuracy is typically within 0.2 percent. Watthour meters used to measure energy supplied to the railroads are very similar to the units used to measure energy supplied to homes and offices.

- Demand - A modified watthour meter is used to measure demand in kW, i.e., the rate at which the customer uses electrical energy. The meter runs for some predetermined interval such as 15 min. At the end of the period, the reading is transferred to a pointer or a register and the meter starts on the next interval. In some meters, the active pointer pushes a second pointer which is left at the highest reading for the month (Fig. 2). The meter reader resets the pointer.

- Power Factor - The power factor is usually measured indirectly by measuring the reactive power demand. The meter is a modified form of the same type of watthour meter that is used to measure the real power demand. The power factor for any interval can then be calculated at the billing office from the two demand readings (real power in kW and reactive power in rkVA) for the purpose of adding charges to the bill if the measured power factor is too low.

- Recorders - Printing type meters, now replaced by magnetic tape recorders, are used for large industrial customers to record kilowatthours and kW demand plus rkVA demand at 15 min. or 30 min. intervals throughout the month. The meter reader replaces the tape each month and takes the record back to the billing office for calculating the monthly bill.

4.4 Point of Service

Metering and billing practice is impacted by point of service in two ways. First, is the voltage level at which the customer receives service and where the metering equipment is located. Second, is the provision of service to the same customer at multiple delivery points? The impact of each dimension will be described as follows:

- Voltage Level - Three levels are used: (1) secondary service at typical 3-wire 1-phase voltages of 120/240 V, or 4-wire 3-phase voltages up to 265/460 V. No discounts apply. Primary service 4 kV or above, where the customer provides the transformer and other equipment. A typical discount of five percent is allowed on the total bill, exclusive of fuel charge. (3) High voltage service at 69 kV or above, where the customer provides the transformer and other equipment. A typical discount of ten percent is allowed on the total bill, exclusive of fuel charge.

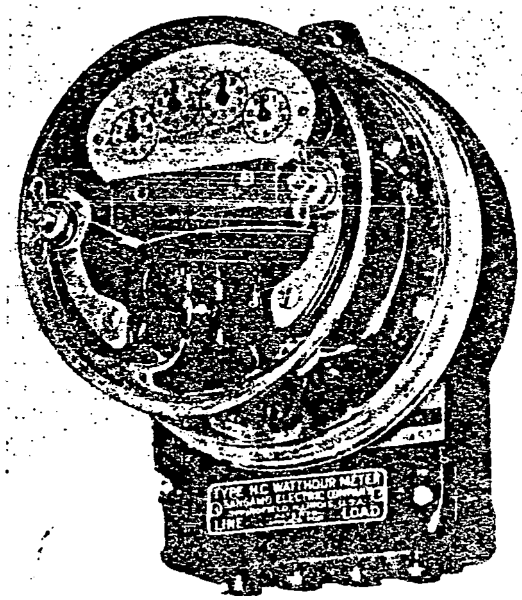

Fig. 1. Typical Watthour Meter

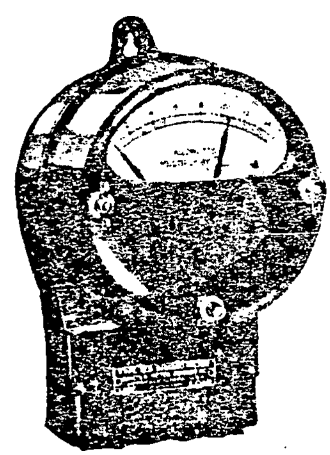

Fig. 2. Two-pointer Type Demand Meter (Wattmeter)

- <u>Multiple Delivery Points</u> - Billing can be individual or consolidated. Obviously, consolidated billing is least costly for any rate system with descending rates for increased energy or demand. Under consolidated billing, the energy and fuel charges are based upon the sum of the registrations of all watthour meters at the delivery points. The demand charge, on the other hand, can either be based on the 15- or 30-min. coincident demand of all of the delivery points, or the sum of all of the non-coincident (individual) peak demands of each of the delivery points. Unless an allowance is made for the diversity of non-coincidental demand, a coincident demand basis for billing is less costly. The utility may make additional fixed charges for use of delivery points; for example, in the District of Columbia, PEPCO charges $200/month per delivery point for their Rapid Transit Service Rate "RT".

An example of a typical monthly charge is contained in Appendix B.

Electric rates for large industrial customers (including railway propulsion) are usually negotiated with respect to all of the major and minor charge categories. The rates are also modified as a result of hearings before the state regulatory commissions. The components of an equitable electric rate schedule should be traceable to the costs to the utility to provide the service required by the large industrial customer.

5.0 CURRENT PRACTICE IN U.S. RAILROADS

Current electrification of U.S. railroads is special frequency 25 Hz power with the exception of the private coal hauling railroads - the Mushingham, Black Mesa and Luke Powell, and Texas Utilities. These private coal hauling railroads are captive to their respective utilities and do not represent typical commercial frequency systems.

The Northeast Corridor, north of New York, will be electrified at 60 Hz commercial frequency power. Although firm electricity pricing has yet to be established for this sector of the corridor, a summary of the status of the establishing pricing policies can be given.

5.1 25 Hz Power in the Northeast Corridor

The Northeast Corridor is currently electrified from Washington, D.C. to New Haven, Conn. using single-phase ac traction power supplied to the catenary at 11 kV, 25 Hz. This power is generated by the local utilities and delivered to the railroad at various supply points along the right-of-way. Rotary frequency converters are used at these supply points to alter the utility power from three-phase, 60 Hz to single-phase, 25 Hz for railroad use.

For the route from Washington D.C. to New York City, the Corridor is supplied by five electric utilities:

- Consolidated Edison of New York (Con Ed)
- Public Service Electric and Gas of New Jersey (PSE and G)
- Philadelphia Electric Co. (P.E.)
- Baltimore Gas and Electric Co. (B.G. and E.)
- Potomac Electric Power Co. (PEPCO)

Each of these utilities has a set of rate schedules that apply to the various classes of service or types of users. If a utility operates in more than one state, then a separate rate schedule, approved by a state regulatory agency, is used for each state where that utility operates and sells electric power. Some of the utilities, such as Con Ed, have special rate schedules for traction power, while others apply the same rates used for other users of electric power to determine the charges for power.

The charges for traction power supplied to the Corridor for 25 Hz power by an electric utility are generally composed of the following components:

- Energy charge
- Demand charge
- Fuel Rate charge
- Power factor charge
- Special facilities charge
- State or local tax

Each of these charges is discussed below, and an example showing how they are applied by one electric utility is also given.

- <u>Energy Charge</u>

  The monthly energy charge to the railroad by an electric utility is based on the sum of all of the energy delivered by the utility at the various supply points. This energy is expressed in Kilowatt hours (kWh)* and is metered at each supply point. The sum of these meter readings is used to fix the energy charge.

  A rate schedule is used to determine the monthly energy

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* One kWh equals 2.65 million foot-pounds or 3415 Btu.

o Energy Charge (con't)

charge from the total kWh supplied to the railroad. Generally, these rate schedules apply different rates (¢/kWh) for each increment or block of energy used, with decreasing rates applied to successive blocks. Decreasing unit charges for additional blocks of energy are used in the following rate schedules that apply to railroads:

Power Company	Rate Schedule
Con Ed	S. C. No. 5 - Traction Power
P.S.E. and G.	LPL - Large power and Lighting
Phila. Elec.	PD - Primary - Distribution Power HT - High-Tension Power
B.G. and E.	T - 13,200 V and over

The rate blocks are based on the kWh of energy used for both Con Ed (S. C. No. 5) and PSE and G (schedule LPL). The rate blocks are based on the hours of billing demand for both of the Phila. Elec. schedules (PD and HT). The B.G. and E. energy rate blocks (schedule T) are set by two different criteria. The changeover from the first block rate to the second block rate is based on kWh of energy used, while the changeover from the second block rate to the third (last) block rate is based on the ratio of kWh to kW of billing demand.

There are two exceptions to this decreasing block rate approach:

- Energy Charge (con't)

  - PEPCO, schedule RT (Rapid Transit Service), which uses a flat (constant) energy rate of 0.623 ¢/kWh.

  - PSE and G, schedule HTS (High Tension Service), which also uses a flat or constant rate, which varies with time-of-day:

    On-peak rate* = 3.4¢/kWh

    Intermediate rate = 3.2¢/kWh

    Off-peak rate = 2.7¢/kWh

  No seasonal adjustments are made to any of the above energy charges.

- Demand Charge

  The monthly demand charge is generally adjusted for three factors:

  - peak demand (decreasing rate blocks)
  - season of the year
  - supply voltage

  Con Edison (S.C. No. 5) adjusts the demand charge for all three factors. The lowest monthly demand charge ($4.36.kW) applies to high tension service, winter billing (October 16 through May 14), and a peak demand in excess of 200 kW. Their highest demand charge ($11.83/kW)

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*Traction Power is charged the off-peak rate for the 8 a.m. to 10 a.m. and 4 p.m. to 6 p.m. intervals. For other PSE and G schedule HTS customers:
On-peak = 8 a.m. through 10 p.m., Mondays through Fridays.
Intermediate peak = 8 a.m. through 10 p.m., Saturdays.
Off-peak = all other hours.

- Power Factor Change (con't)

  if the Philadelphia Electric Co.'s prescribed or standard power factor for large users (demand over 2500 kW) is 95 percent and their demand charge is \$3.00/kW, then their adjusted demand charge for an actual power factor of only 82 percent would be:

  $$\frac{95}{82} \times \$3.00 - \$3.48$$

  Power factor is either determined by actual tests when the customer's load is at least 2/3 of the demand load, or reactive metering is installed to measure reactive power in rkVA.

  An alternate means of charging for a customer's low power factor (excessive reactive kVA) instead of increasing the demand charge, is to bill customer for the excessive reactive power over the amount of reactive power that would be present with a power factor of 85 percent. As an example, PEPCO has a traction power reactive charge of \$0.15/rkVA for the rkVA used in excess of the rkVA that would result in an 85 percent power factor.

- Special Facilities Charges

  Special facilities charges are used to cover costs of special equipment and facilities supplied to customers, such as rotary frequency converters at substations. The rotary converter charges are typically \$15,000/mo. per substation for operation and routine maintenance. Also amortization of rotary converter capital costs ranges from \$14,000/mo. to \$17,000/mo. per substation, depending on the combined rating. Additional major repair costs would be separately billed additional charges.

All of the utilities in the New England region belong to the New England Electric Power Pool.

Each of the electric utilities listed above will set rate schedules for selling electric energy to the railroad. The rates are expected to be based on the High Tension Service Class described in the previous section except as modified for the uniqueness of the railroad load. With the exception of New England Electric Power Co., all of the other electric utilities operate within single state boundaries as far as railroad service is concerned. New England Electric Power Service Co. will supply the railroad in the states of Rhode Island and portions of Massachusetts. The individual state public utility commissions will have approval authority of the rate schedules applied to the railroad.

Discussions to date on electricity pricing have been of a general nature. However, a few specific conclusions have been reached and these are summarized below.

Because of bad utility experience with the re-electrification between New York and New Haven in not getting prompt payments from the Federal government, the utilities are insisting that the FRA pay up front all engineering expenses the utilities are incurring in getting ready to electrify. After electrification has occurred, the utilities will refund the government and roll those engineering expenses into the rate. The electric utilities also are requiring capital contributions from the FRA for any major equipment that must be procured and installed to serve the railroad load.

Within each utility boundary conjunctive billing, as well as consolidation of billing, is being discussed but no decision has yet been reached. In conjunctive billing, all substation meters are simultaneously read and added to get the 15 minute (or 30 minute) power demand for billing purposes; this approach should result in the lowest demand charge. Discussions have been made to consolidate the billings beyond each utility boundary up to the power pool level. This approach would take maximum advantage of the declining block rate structure; the utilities have stated that they are not interested in this billing arrangement. The center fed power distribution system being implemented in this section of the Corridor utilizes the closings of phase breaks for power system/railroad substation failure contingencies.

The electric utilities have taken the position that for railroad substations at the end points of the utility boundary, additional power from its system may be required as a result of substation not served by that utility being out of service. The utilities are planning to charge, as part of their normal billing, a generating capacity reserve charge because of this situation. There is apparently precedent for this charge, since it currently exists in some of the billing schedules used by electric utilities in this country.

6.0 CURRENT PRACTICE IN OTHER COUNTRIES

6.1 Japan

The railroads in Japan are supplied with commercial frequency power by nine electric power companies, each supplying electric power needs for a geographic region. While each electric power company has its own rate structure, the forms of the various rate structures, i.e., the types of charges, are similar from one electric power company to another. Rate schedule practices for the various classes of service in Japan are similar to those of the U.S.

The traction power rates, including demand charges, are slightly higher than the indistrial class power rates. The reason that the traction power rates are greater than the other power rates is probably the result of the expenses of utility reinforcement for the single-phase traction power load; these expenses usually are not incurred with conventional power three-phase loads.

There are two basic components of the electricity charge for traction power in Japan:

- o A monthly demand charge.
- o A monthly energy charge.

The monthly demand charge is set by contractual arrangement between the power company (seller) and the railroad (buyer), and is based on the peak demand (kW) expected in a one month billing period. Actual demand is monitored by meters at the delivery points; if the contracted peak demand is exceeded, there is a penalty charge. However, there is no saving (or reduced charge) if the peak demand is below the contracted value since the electric power company had to construct greater capacity to meet the peak demand whether it is used or not.

The monthly energy charge is based on watthour meter readings at the various delivery points of supply.

There is no fuel adjustment charge--the high costs of fuel are reflected in the above energy charges.

Both the demand charges and the energy charges are computed with a two-step system where the first 80 percent of both the demand charge and energy charge is computed at one set of rates (yen/kW and yen/kWh, respectively) while the last 20 percent of the demand and energy charges are computed at 25 percent higher rates. For example, current charges to the railroads by the Kansai Electric Co. use the following two-step rates for both demand and energy:

	Demand Charge		Energy Charge	
	yen/kW	$/kW*	yen/kWh	¢/kWh*
First Step (first 80%)	1740	7.73	11.84	5.26
Second Step (last 20%)	2175	9.67	14.80	6.58

The justification for this two-step system is that the last 20 percent of generating capacity (new capacity with a growing load) costs more to install than the older capacity.

There are two other factors that affect the electric rate for traction power in Japan:

- o Seasonal rate adjustments
- o Diversity factor

Seasonal Rate Adjustments - During the months of July, August, and September, all the energy rates, including those for traction power, are boosted by 10 percent, while the demand rates remain unchanged. This seasonal increase in all energy rates was only recently introduced (1979) with the objective of controlling the summer peak loads by making consumers more aware of the need to conserve energy.

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*Based on an exchange rate of 225 yen/$.

Diversity Factor - When traction power is supplied by one power company to a set of railroad substations that are all supplying one railroad line, it is realized that the peak demands for the various substations on this line will most likely occur at different times, creating a "walking peak load." The coincident or conjunctive or actual peak load supplied to the railroad at any time will therefore be lower than the sum of the individual peak loads for the power supplied to each substation. A diversity factor is used to allow for this in determining the contractual peak demand. This factor is greater than unity and is used to reduce the demand charges from the sum of the non-coincident demand charges of the various substations along the route.

6.2 France

The French National Railways (SNCF) is supplied with commercial frequency power by Electricite de France (EDF) under the general rates of a rate structure called the "Green Tariff."*

This rate structure contains a fixed rate based on peak usage (demand charge) and an energy rate for the actual electric energy supplied. While the fixed rate is uniform throughout France and not affected by the supply voltage, the energy rate is affected by a number of factors such as supply voltage, season of the year, time-of-day, and the overall power factor of the load. The fixed rate is reduced if the actual peak power is less than the authorized amount, in an effort to reduce peak loads.

Monthly billing is done separately for each of the 419 power stations that serve as tie-points to supply the SNCF. The two components of each bill are:

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*This is generally applied to all of France except the Southwest System, the Montpellier Region, and the Paris-Le Mans-Rennes line, which are supplied by EDF under a more favorable "Contract No. 1", which recognizes SNCF - owned generation facilities in this zone.

- o demand charges (Franc/KW)
- o energy charges 9centimes/kWh)

The <u>demand charge</u> is based on a fixed rate of 125.52 F/KW, independent of the supply voltage. If the peak demand (measured over a 10 min. period) is less than the authorized value, then a credit is earned for the next billing period, based on a progressive scale to encourage reduced demand during peak hours.

The <u>energy charge</u> is based on a rate which depends on a number of factors:

- o the geographic zone
- o the supply voltage
- o the time of use
- o the power factor

France is divided into 20 zones by the EDF, with somewhat different energy rates for each zone.

Supply voltages to the SNCF vary from less than 30 KV to 220 KV, with approximately 2/3 of the substations at 63 KV. In general, the higher the supply voltage, the lower the energy rates.

The time-of-use also affects the energy rates. There are five rate classes for this as follows:

Peak		rate	class	1
HP (busy) Winter	,	"	"	2
HP (busy) Summer	,	"	"	3
HC (slack) Winter	,	"	"	4
HC (slack) Summer	,	"	"	5

The peak rate only applied from 9 to 11 AM and 6 to 8 PM during the four winter months of Nov., Dec., Jan., and not on Sundays.

Busy rates (HP) apply 6 AM to 10 PM, except Sunday and peak hours.

Slack rates (HC) apply from 10 PM to 6 AM and all day Sunday.

Winter busy and slack rates apply during the months of October through March, while summer busy and slack rates apply the rest of the year.

The power factor or ratio of reactive power to real power also affects the energy rates. If the power factor is lower than 85 percent (more than 60 percent reactive power), a penalty is imposed. On the other hand, if the power factor is greater than 85 percent (less than 60 percent reactive power) then a credit is earned on the energy charges.

6.3 United Kingdom

The nationalized British Rail (BR) is supplied with commercial frequency electric power throughout England and Wales by the Central Electricity Generating Board (C.E.G.B.) In Scotland, BR is supplied by the South of Scotland Electricity Board. Both utilities are privately owned and government regulated. Commuter rail service into London is provided by London Transport, which generates its own traction power using dedicated power plants.

The rate structure that C.E.G.B. applies to traction power sold to BR is similar to the commercial high voltage rate structure, except for a small price penalty for the single-phase unbalance of the BR load. However, there is no rate penalty for a low power factor. The actual rates are privately negotiated between the C.E.G.B. and BR; these rates are not publically available. In general, the rates are based upon demand charges, energy charges, and fuel adjustment charges which is similar to current practice throughout most of the U.S. The rates to BR may also include seasonal and time-of-day adjustments. The rates also allow for some re-generation which is now done on the Glasgow line and is anticipated to be done more widely in the future.

Billing to British Rail by the C.E.G.B. is done on a regional basis for each of the five C.E.G.B. regions. The demand charges are based on 30 minute peak usage. For billing purposes, the C.E.G.B. consolidates the entire BR demand for all five regions into a single demand charge.

APPENDIX A

SUMMARY OF THE ELECTRIC UTILITY RATE DESIGN STUDY

A study group was organized by EPRI in 1975 to respond to the request by the National Association of Regulatory Utility Commissioners to examine ways of controlling the growth in peak demand and its impact on electricity prices. The study group put together by EPRI is called the Electric Utility Rate Design Study. More than eighty reports have been prepared by the Rate Design Study. Over 100,000 copies of these documents have been distributed throughout the industry, to regulators, utility analysts and other researchers.

During the first phase of the Study (roughly 1975-1977), the research was divided into ten topics as listed below:

1. Analysis of Various Pricing Approaches
2. Considerations of Demand Elasticity for Electricity
3. Rate Experiments Involving Small Customers
4. Costing for Peak-Load Pricing
5. Ratemaking
6. Measuring the Potential Cost Advantages of Peak-Load Pricing
7. Metering
8. Technology for Utilizing Off-Peak Energy
9. Mechanical Controls
10. Customer Acceptance

For each topic, an advisory group "task force" prepared a report about a single topic. In addition, one or more consultants worked on each topic. In some cases, a consultant prepared a report about a single topic; in other cases, a consultant may have worked on three or four topics, and submitted as many reports.

During the second phase of the Study (roughly 1978-1979), the research was divided into four topics as listed below:

I. Costing, Rate Design and Elasticity

II. Load Controls and Equipment for Using Off-Peak Energy

III. Customer Response

IV. Cost-Benefit Analysis

For each of these four topics, there was again an industry advisory group. However, only consultants prepared reports with advice and criticism from the advisory groups.

To help readers identify reports and locate information that was produced, during either phase, the first phase topics (1-10) and their second phase counterparts (I-IV) are combined below:

I. Costing, Rate Design and Elasticity

1. Analysis of Various Pricing Approaches
2. Considerations of Demand Elasticity for Electricity
3. Rate Experiments Involving Small Customers
4. Costing for Peak-Load Pricing
5. Ratemaking

II. Load Controls and Equipment for Using Off-Peak Energy

7. Metering
8. Technology for Utilizing Off-Peak Energy
9. Mechanical Controls

III. Customer Response

10. Customer Acceptance

IV. Cost-Benefit Analysis

6. Measuring the Potential Cost Advantages of Peak-Load Pricing

A guide to the Rate Design Study has been put together by EPRI. The guide lists the reports from both phases of the study; and, presently available and forthcoming reports are listed under the appropriate second phase topic heading.

More information on the Guide to the Electric Utility Rate Design Study Reports can be obtained by contacting EPRI:

EPRI
P.O. Box 10412
Palo Alto, CA 94303

Attention: Rate Design Study

APPENDIX B

AN ILLUSTRATION OF MONTHLY BILLING

This appendix illustrates how the monthly billing to a section of the Northeast Corridor by each of two electric utility suppliers would be determined for identical electrical consumption from each of the two utilities. The two utility suppliers used in this example are:

- o Philadelphia Electric Co. (PECo)
- o Public Service Electric and Gas Co. (PSE&G)

Consumption

The monthly electrical consumption (from each of these suppliers) that is used in this example is based on the actual electrical consumption supplied by PECo in January 1977, as follows:

- o Peak demand: 123,690 kW
- o Energy Usage: 51,291,900 kWh
- o Power Factor: 85 percent

Rates

The rate information for PECo is summarized in Table B-1. It is based on Rate HT (High-Tension Power) for a supply voltage of 33 kV. Additional information on the power factor adjustment to the demand charge and the rate used for the additional fuel adjustment charge are also provided in Table B-1.

The rate information for PSE&G is summarized in Table B-2. It is based on Rate Schedule HTS (High Tension Service). Additional information on the Energy Adjustment Charge to cover fuel adjustments, distribution losses and taxes is also provided in Table B-2.

Assumptions

Two assumptions were required about electrical consumption in order to develop this illustrative example:

1. The total energy consumption per day is the same for each day of the 31-day month, so that the kWh consumed is proportional to the elapsed time in the billing period.

2. The total energy consumption over the month is divided as follows:

On-Peak Energy:	50 percent
Intermediate-Peak Energy:	20 percent
Off-Peak Energy:	30 percent

The first assumption is required because the PECo uses decreasing rate blocks for both demand and energy charges and the energy charges are based on hours of use, not the kWh used. The second assumption is required because PSE&G uses time-of-day metering for energy charges, with significant rate variations based on time-of-day. The definitions of on-peak, intermediate-peak and off-peak are contained in Table B-2.

PECo Monthly Charge

The PECo demand charge is based on the 30-minute peak monthly rate-of-use. Two rate blocks are used, and a penalty is imposed on the demand charge for a power factor lower than 95 percent. The demand charge is calculated below:

$$\text{Demand Charge} = \frac{95}{85} \quad (50 \text{ kW} \times \$4.46/\text{kW}) + (123{,}640 \text{ kW} \times \$2.98/\text{kW})$$

$$= \$412{,}043$$

The PECo energy charge is based on the total energy consumed. Three rate blocks are based on hours of use, rather than kWh used. (This example assumes that kWh consumed is proportional to hours of use).

The energy charge is calculated below:

$$\text{Energy Charge} = \frac{150}{744} \times 51{,}291{,}900 \text{ kWh} \times \$0.0507/\text{kWh})$$

$$+ \frac{150}{744} \times 51{,}291{,}900 \text{ kWh} \times \$0.422/\text{kWh})$$

$$+ \frac{744 - 300}{744} \times 51{,}291{,}900 \text{ kWh} \times \$0.0339/\text{kWh})$$

$$= \$1{,}998{,}357$$

The PECo Customer Charge is $71.50.

The discount for high voltage service (33 kV) is 5¢/kW for the first 2,000 kW of demand, or a $100 credit.

The State Tax of 3.98 percent applies to all of the above charges.

The fuel adjustment charge (not taxable of 0.3163 ¢/kWh applies to all energy used. It is calculated below:

$$\text{Fuel Adjustment Charge} = \$0.003163/\text{kWh} \times 51{,}291{,}900 \text{ kWh}$$

$$= \$162{,}236$$

A summary of all the PECo charges is shown below:

Demand Charge	$ 412,043
Energy Charge	1,998,357
Customer Charge	72
Subtotal	2,410,472
Less discount for 33 kV	100
Subtotal	2,410,372
State Tax (3.98%)	95,933
Subtotal	2,506,305
Fuel Adjustment Charge	162,236
Total Monthly Charge	$2,668,541

PSE&G Monthly Charge

The PSE&G demand charge is based on the 15-minute peak monthly rate-of-use. Seasonally higher in the summer months, this charge is based on a flat rate rather than rate block steps. There is no penalty imposed on demand charge for the 85 percent power factor; lower power factors would incur a penalty. The demand charge for the January consumption is calculated below:

Demand Charge = $5.15/kW x 123,690 = $637,004

The PSE&G energy charge is based on total energy consumed and the time-of-day of consumption. There is no seasonal adjustment. The assumed energy charge is calculated below, based on the assumed distribution of On-Peak, Intermediate Peak, and Off-Peak usage shown earlier:

Energy Charge = 0.5 x $0.034/kWh x 51,291,900
+0.2 x $0.032/kWh x 51,291,900
+0.3 x $0.027/kWh x 51,291,900
= $1,615,695

The PSE&G Customer Charge is $1,640 per month.

The discount for high voltage service is 5 percent, and applies to the entire bill, exclusive of the Customer Charge (Facilities Charge).

There is no direct state tax (New Jersey) on these charges. Rather, it is combined with the fuel adjustment charge and a charge for distribution losses into an Energy Adjustment Charge, which applies to all energy consumed. This energy adjustment charge is calculated below:

Energy Adjustment Charge = $0.011078/kWh x 51,291,900 kWh
(Fuel Adjustment, taxes
and distribution losses)= $568,212

A summary of all the PSE&G charges is shown below:

Demand Charge	$ 637,004
Energy Charge	1,615,695
Energy Adjustment Charge	568,212
Subtotal	$2,820,911
Less 5% Discount	141,046
	$2,679,865
Customer Charge	1,640
Total Monthly Charge	$2,678,225

A comparison of the two monthly charges shows that while they are based on completely different forms of rate schedule, the total charges differ by less than one percent.

Table B-1

Monthly Rate Information for Philadelphia Electric Co.

(Based on Rate HT)

Demand Charge (Capacity Charge):

- $4.46 per kW for the first 50 kW of demand
- $2.98 per kW for the excess over 50 kW of demand

A power factor penalty adjusts demand charge by the ratio of 95 to (actual power factor) for power factors lower than 95 percent

Energy Charge:

- 5.07¢/kWh for the first 150 hours of use
- 4.22¢/kWh for the next 150 hours of use
- 3.39¢/kWh for additional use

Customer Charge: $71.50

Discount for High Voltage Service:

- 5¢/kW for the first 2,000 kW of demand - 33 kV Service
- 10¢/kW for the first 10,000 kV of demand - 66 kV Service

State Tax: 3.98 percent of above items

Fuel Adjustment Charge (Energy Cost Rate):

0.3163¢/kWh for all energy used. Not taxable.

Table B-2

Monthly Rate Information for Public Service Electric & Gas Co.

Demand Charge (Kilowatt Charge):

$6.05 per kW (flat rate) - June through October

$5.15 per kW (flat rate) - November through May

A power factor penalty adjusts demand charge by the ratio of 85 to (actual power factor) for power factors lower than 85 percent.

Energy Charge (Kilowatthour Charge):

- o 3.40¢/kWh, On-Peak
- o 3.20¢/kWh, Intermediate
- o 2.70¢/kWh, Off-Peak

For rail traction power,

On-Peak is 10 AM to 4 PM and 6 PM to 10 PM Mondays through Fridays

Intermediate is 8 AM to 10 PM on Saturdays

Off-Peak is 8 AM to 10 AM and 4 PM to 6 PM, Mondays through Fridays

10 PM to 8 AM daily including Sunday

8 AM to 10 PM Sundays

Customer Charge: $1,640.00

Discount for High Voltage Service: 5 percent for all but facilities charge

Energy Adjustment Charge (For Fuel Adjustment, State Tax and Distribution Losses):

$1.1078¢/kWh for all energy used.