ELECTRIC POWER TRANSMISSION AND DISTRIBUTION SYSTEMS: COSTS AND THEIR ALLOCATION

by

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Energy Laboratory Report July 1975
No. MIT-EL 75-020

ACKNOWLEDGMENT

The financial support for this work was derived from National Science Foundation Grant No. SIA73-07871 A02. This support is gratefully acknowledged.

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Introduction

The recent increase in costs of generation and the pass through to customers of these costs via "fuel adjustments" has elicited unprecedented reaction from the public and consumer groups to potential inequities in currently existing electricity pricing practices.

Transmission and distribution costs contribute significantly to the total costs of providing electrical service. In 1974, privately-owned electric utilities in the United States spent about 35% (over $7 billion) of their total capital expenditures for transmission and distribution equipment. The expenditures for operation and maintenance of this equipment were about $3.0 billion, an amount equal to about 1/2 the total costs of fuel in 1972.

The costs derived from the transmission and distribution (T&D) system have historically comprised about 2/3 the costs of producing and delivering electricity to residential-commercial customers, and over 1/3 the total costs supplying electricity to large industrial customers. The difference in the T&D equipment and associated operation and maintenance requirements is the major reason that historical costs of electricity to large industrial customers have been significantly less than those for small residential or commercial customers.

The aim of this paper is threefold:

1. To estimate the differences in transmission and distribution equipment required to serve industrial and residential-commercial customers and to allocate to the above two customer classes the average costs of installing this equipment.

2. To estimate the costs of operation and maintenance of the transmission and distribution system, and to allocate these costs to the customer classes.

3. On the basis of the above costs, to calculate the T&D derived average costs for the two customer classes.

This paper does not address the question of what the costs of generation are, nor does it attempt to derive how these costs should be allocated among the customer classes. We do, however, incorporate information on the average costs of generation in our comparisons of costs with price.

Electric power costs, in a rate-making context, have historically been separated into three categories: customer charges, energy charges, and demand charges.[1] Customer charges are those costs which vary with the number and type of customers, such as meters, costs of meter reading, line transformers, etc. Energy charges are those costs which vary most closely with the level of kilowatt generation and delivery, the best example being fuel cost. Demand charges are those costs associated with supply and transmission capability (not utilization). The investment costs of generation, transmission, and distribution facilities provide the best examples in this category. Rate schedules are ostensibly designed to reflect the allocation of these costs to different customer classes at varying levels of energy demand. Due to the decline in average fixed costs with increasing kilowatt hour demand, the rate schedules have generally taken the form of declining block rates.

When allocating costs to determine fair rates for alternative customer classes, the loading of energy and customer charges to kilowatt-hours sold is usually fairly straightforward. However, the determination and allocation of demand charges is much harder to account for because of the difficulty in assigning capacity requirements to kilowatt-hour energy demands, especially when one takes into consideration the probabilistic nature of the load and diversity among loads in different customer classes.

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[1]For a more complete description of pricing practices see refs. (1,2)

In this paper only two broad customer classes are considered, encompassing 1) residential and commercial (or small light and power) customers, and 2) industrial (or large light and power) customers. To determine an allocation of T&D demand charges, we estimate equations that relate T&D equipment to the configuration of sales and customers for various utilities in the country. These equations are then utilized to allocate equipment needs, and thus capital charges, to the appropriate customer categories. This allocation then becomes the vehicle for deriving the differences in costs of service for these two customer categories.

The discussion proceeds as follows: In Section I we investigate how much transmission and distribution equipment is required to service a given kilowatt-hour demand as a function of the configuration of consumers, their consumption, and other characteristics of the service area. In Section II, we present a survey of the capital costs of the various equipment items that comprise the transmission and distribution system. In Section III, the relationship between operation and maintenance expenses and the amount of capital equipment in place, and alternatively, the configuration of electric power sales and customers is examined. Finally, in Section IV, the above costs--capital plus operation and maintenance for the system--are allocated to two customer classes; residential and small light and power customers, and large light and power customers, and compared to actual differences in rates for these customer classes.

For several reasons, the study is confined to privately-owned electric utilities. The data available for privately owned utilities are more complete than for the publicly owned utilities. The data for privately-owned utilities also are more even. Finally, since privately-owned electric utilities, in terms of revenue, customers, electric sales, and total generation account for approximately 80% of the totals for the entire electric industry, little loss of generality is expected.

The equations reported herein were estimated from data for a time-series of cross-sections. Forty-seven "states" were defined. Maryland and the District of Columbia were aggregated into one region, since some data sources did not separate figures for the two areas. Alaska and Hawaii were excluded, and Nebraska was excluded since no privately-owned utilities operate in that state. The data are annual, spanning the period 1965-1971, and comprise the most recent available from the Federal Power Commission.

I. The Need for Transmission and Distribution Equipment

The transmission and distribution system delivers electric power from the point of generation to the point of final consumption. It must have sufficient capacity to meet the peak demand of the area it serves and, simultaniously, to satisfy local energy demand patterns within the service area.

This section addresses itself to the following question: Given the configuration or demand and the characteristics of the service area, what amount of transmission and distribution equipment is needed to satisfy the demand? In particular, functions specifying the needs for the following six equipment items are discussed:

1. Transmission lines (in structure miles)
2. Transmission substations (in kilovolt-amperes capacity)
3. Primary distribution lines (in circuit miles)
4. Distribution substations (in kilovolt-amperes capacity)
5. Line transformers (in kilovolt-amperes capacity)
6. Meters (in number)

In the remainder of this section we report the relationships estimated that relate the six listed equipment items to electricity consumption patterns and the characteristics of the service area. The characteristics we consider relevant (either in the aggregate or separated into two groups representing the two customer classes) are the demand for electric energy, measured in kilowatt-hours of sales; the number of customers in the service area; the area (in square miles) of the service area; and the load density, i.e., the number of kilowatt-hours of energy consumed per unit area (load density). In all cases, several forms of the equations were estimated. The results presented reflect our attempt to be as detailed as data would permit, while at the same time maintaining statistical significance and plausible causal relationships between the variables.

A. The Individual Equipment Items

1. Transmission Lines

Transmission lines carry the electric power from the generating stations to the load centers of the demand network. Lines may have different maximum voltage ratings; one line may be rated at 230 kilovolts, while another may have a rating of 765 kilovolts. For this analysis, all lines with voltage ratings of 69 kilovolts and above have been grouped together.

Structure miles of transmission line were the units used to measure the quantity of transmission line in place. Circuit miles or power carrying capacity might have been used, but capital investment in transmission lines is more accurately reflected by structure miles than by circuit miles, since the principal portion of investment is in the towers and easements. (Structure miles of line differ from circuit miles when several lines are on one series of towers; structure miles are counted as if only one line were in place.) Although a measure such as gigawatt miles which accounts for the capacity of the lines might be better than structure miles, data for such a measure were neither available nor readily derivable within acceptable tolerances.

The number of structure miles of transmission line needed to satisfy the demand for electric power was expected to increase with the demand; and, in theory, one should not expect any difference between the amount of equipment needed to transmit a kilowatt-hour of electric energy for residential and small light and power consumption and the amount needed to transmit a kilowatt-hour for large light and power consumption. If demand is held constant, one would expect the area of the state to affect the need for transmission line. To transmit the same amount of energy to a larger area will require more structure miles of transmission line. One also might expect areas with a higher load density to need less line, since the power transmitted could be carried in higher capacity lines.

Also, areas which have higher load densities might be able to take greater advantage of noncoincident demand patterns. Load density may also act as a proxy for population concentration or industrial concentration, both of which should permit utilities in high load density areas to reduce the line needed through economies of scale.

2. Transmission Substations

The quantity of substation equipment in place was measured in volt-amperes of capacity.

The total transmission substation capacity in volt-amperes required to meet a certain demand is expected to be proportional to the level of demand for power. The expectation was that the ratio of capacity to demand by residential and small light and power users would be different from that for large light and power users.

3. Primary Distribution Lines

Primary distribution lines were measured in pole miles (analogous to the structure miles of transmission line). Due to the unavailability of data, observations were for the nine Census regions, rather than by state.[2] Since these lines are used only by customers connected to the distribution system, one would expect that residential and small light and power variables would fully explain the stock of primary distribution line. In particular, the quantity of primary distribution line in place is expected to be a function of the residential and small light and power customers, the residential and small light and power load density, and the region's area.

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[2] Also, the stock of primary distribution lines in place in 1965 (the starting date for the regression) had to be estimated. First, an equation relating the change to the additions to the stock of primary distribution lines was estimated, with a separate constant for each region (numbers in parenthesis are t-statistics):
(footnote continued over)

4. Distribution Substations

Distribution substation equipment was measured in kilovolt-amperes of capacity. The distinction between transmission substation equipment and distribution substation equipment is primarily one of voltage. However, no matter where the demarcation line is drawn, large light and power users are defined by the utilities as those users which take their electric power directly from the transmission system; hence, the amount of distribution substation equipment is expected to be independent of the level of demand by large light and power users.

Expectations are that the level of demand by residential and small light and power users is positively related to the quantity of distribution substation equipment in use. Also, the larger the area served by a particular distribution system, the less localized is the demand (given a constant demand). Assuming that the more the demand is localized, the greater are the economies of scale, one would expect the quantity of equipment to be needed to increase with the size of the service area.

(footnote 2 continued)

$$\Delta \text{ POLE} = (\text{Regional Constant - see below}) + \underset{(4.10)}{.0091}\ \Delta \text{ CUSRSM}$$

where $R^2 = .898$

$F(9,53) = 52$

CUSRSM = number of residential-commercial customers

Constants

Region	Value	t-statistic
New England	446	1.31
Mid.Atlantic	2918	6.77
E.N. Central	5337	8.62
W.N. Central	4439	12.4
S. Atlantic	4959	6.30
E.S. Central	1846	4.95
W.S. Central	5127	11.6
Mountain	2404	5.84
Pacific	2294	3.99

Assuming that the entire system came into existence in 1965, the above equation was used to estimate the total stock in 1965 (619,217) pole miles); the stock was then allocated to the regions in the same proportion as distribution substation capacity.

5. Line Transformers

Line transformers were measured in kilovolt-amperes of capacity. Residential and small light and power demand should determine the level of line transformer needs, assuming that the residential and small light and power users on the average have the same ratio of peak demand to mean demand from area to area. Also, to account for rural areas, one might expect to find, given a constant demand and a larger area, that more substation capacity would be needed, since in a more sparsely populated region each line transformer would be serving fewer customers. Large light and power demand, however, should be irrelevant.

6. Meters

The obvious measure of the quantity of meter equipment in place is number of meters. One would expect the number of meters in use to be determined entirely by the number of customers of various types demanding power.

B. Results of the Regressions

The regression results, and the elasticities for an average state are presented in Tables 1 and 2 below. While the tables are self-explanatory, a few points deserve comment.

1. Separation of kilowatt-hour sales into two classes in the transmission line equation yielded coefficients which were within 5% of one another and not statistically different.
2. In the transmission substation equation, the coefficients were significantly different (t = 2.51); it is possible that this difference is due to different load factors for the the two customer classes.

TABLE I. REGRESSION RESULTS [3]

Equipment item	Explanatory variable	Constant	EST	ESRSM	ESLLP	CUSRSM	CUSLLP	AREA	LD
TRANS		813.2	.1436					.0608[7]	-556.4
R^2 = .840		(3.01)	(19.2)					(15.4)	(3.35)
F(3,325)= 427									
TSUB		674700		712.5	523.2				
R^2 = .910		(2.20)		(19.8)	(12.3)				
F(2,326)= 1643									
POLE [4]		see footnote 5		.9102					-34306[6]
R^2 = .996				(19.8)					(4.03)
F(10,52)= 1336									
DSUB				485.4				9.46	
R^2 = .826				(40.2)				(2.45)	
F(1,327)= 1554									
LT				568.2	102.6			5.15	
R^2 = .937				(32.6)	(5.09)			(2.82)	
F(2,326)= 2412									
METER						1.034	14.40		
R^2 = .989						(138.8)	(9.31)		
F(1,327) = 29500									

EACH COEFFICIENT IN THE ABOVE EQUATIONS IS SIGNIFICANTLY DIFFERENT FROM THE OTHER COEFFICIENTS IN ITS EQUATION

[3] See the Appendix for an explanation of the abbreviations used for the explanatory variables

[4] Data for this equation are by region and are for <u>all</u> utilities

(continued over)

TABLE I. REGRESSION RESULTS (continued)

[5]Separate constants for each region were estimated (t-statistics)

New England	28276
	(9.24)
Middle Atlantic	71858
	(14.7)
East North Central	56504
	(19.0)
West North Central	30614
	(16.3)
South Atlantic	29631
	(10.3)
East South Central	12486
	(7.89)
West South Central	23143
	(9.87)
Mountain	8442
	(5.55)
Pacific	11490
	(3.95)

[6]Residential and small light and power sales only

[7]For the Mountain region, the fraction of the area estimated to be serviced by electric utilities was .1927 (t = 3.56). This fraction was estimated by multiplying the AREA term (and its coefficient) by the coefficient representing the fraction for only the Mountain states and then regressing the equation. The AREA term then appeared as follows:

$$B_2 \times F^{MTN} \times AREA$$

where B_2 is the coefficient of the AREA term, F is the fraction of land area in the Mountain states which is serviced by electric utilities, and MTN is a variable which equals 1 for a Mountain state and 0 otherwise.

TABLE 2. ELASTICITIES [8]

Equipment item	Explanatory variable	EST	ESRSM	ESLLP	CUSRSM	CUSLLP	AREA	LD
TRANS		0.46					0.46	-0.06
TSUB			0.59	0.35				
POLE			0.61					-0.11
DSUB			0.89				0.10	
LT			0.83	0.12			0.04	
METER					0.93	0.06		

[8] See the Appendix for an explanation of the abbreviations used for the variables

3. Large light and power sales were found to be a significant item in the line transformer equation. Why this should come about is unclear. One possibility, though not entirely convincing, is that large light and power users need a certain amount of low-voltage power for office and administrative purposes.

4. Large light and power customers use several meters; perhaps this phenomenon results from the existence of separate facilities which are billed centrally.

II. The Costs of Transmission and Distribution Equipment

This section surveys the costs of distribution transformers (for both overhead and underground systems), distribution substations, transmission and distribution lines, transmission substations and the cost of metering systems for both residential and large commercial and industrial consumers.

The costs of various T&D equipment items are complex functions of equipment ratings, type of installation, and geographic region of the country. The complexity is further compounded by the diversity of equipment constructions, mounting possibilities, voltage levels, whether the equipment is for single-phase or three-phase operation. For this reason, it is difficult to obtain good average costs from point estimates for each of the equipment categories discussed in the previous section. To circumvent this difficulty as much as possible, we have utilized data on aggregate expenditures and equipment additions by the entire industry in various regions of the country when it was available. This was possible for transmission lines, distribution lines, and transmission substations, where the unit costs were derived from data published in Electrical World's Annual Statistical Reports. For distribution substations, line transformers, and metering systems, no such comprehensive costs statistics are available.

Fortunately, as we shall see in Section IV, the major components of the total cost of delivering electricity are: 1) the costs of high voltage transmission lines, 2) the costs of distribution lines, and 3) the operation and maintenance costs of the transmission/distribution system (to be discussed in Section III), so that the unavailability of good data for the remaining equipment categories is not such an important limitation. The above three items comprise about 80% of the total costs of transmission and distribution, while the other components, including transmission substations, distribution substations, line transformers and meters each contribute a mill or less per kilowatt-hour to the final cost of delivered electricity. For this reason, in this section we shall investigate the costs of structure miles of transmission and pole miles of distribution much more thoroughly than the other components of the T&D system. To provide only rough estimates of the contribution of the other equipment categories, we have utilized point estimates of their costs which were obtained from New England company sources.

A. Costs of Transmission Lines

Table 3 gives regional average costs for various categories of transmission line computed from three year averages of data published in Electrical World. The numbers were calculated as the ratio of the sum of undeflated capital expenditures to the sum of new structure miles energized (or cable miles for underground categories) for each of the three year periods. The numbers exhibit some interesting trends both geographically and through time.

From a purely analytical point of view one can see, especially for the high voltage overhead and underground categories, that there is significant instability in the time behavior of the costs, even after grouping years together in three year blocks. The numbers in parentheses accompanying the total U.S. averages are the total structure miles (or cable miles) in each sample. The observed variability in costs is in part related to size of the samples. For low voltage overhead lines, the bulk of new additions in this sample, the costs exhibit much more stable trends. In both overhead categories, the national averages indicate that between 1966 (midyear of 1965-1967 grouping) and 1972, the cost for both low and high voltage lines almost doubled per structure mile. This corresponds to a rate of escalation of almost 11% per year in a period when the overall rate of inflation was fairly low and stable. For the underground categories, the costs per cable

TRENDS IN TRANSMISSION LINE COSTS (Regional Breakdown)

Three Year Aggregate Averages

REGION	YEAR	$(000)/Structure Mile Overhead High Voltage 345 KV and above	$(000)/Structure Mile Overhead Low Voltage Above 69 KV thru 230 KV	$(000)/Cable Mile Underground High Voltage 230 to 345 KV	$(000)/Cable Mile Underground Low Voltage Above 69 KV thru 161 KV
NEW ENGLAND	73-71	150	107	-	447
	70-68	122	82	-	400
	67-65	205	69	-	280
MIDDLE ATLANTIC	73-71	379	143	1243 i	259
	70-68	254	83	220 i	180
	67-65	111	68	171 i	145
EAST NORTH CENTRAL	73-71	118	76	702 i	578
	70-68	111	48	569 i	762
	67-65	100	38	-	141
WEST NORTH CENTRAL	73-71	88	34	-	163 i
	70-68	47	25	-	224
	67-65	45	21	-	24 i
SOUTH ATLANTIC	73-71	177	76	260 i	1086
	70-68	292 i	60	571 i	570
	67-65	59	38	-	367
EAST SOUTH CENTRAL	73-71	97	51	-	-
	70-68	63	33	-	-
	67-65	130	32	-	-
WEST SOUTH CENTRAL	73-71	57	39	-	239 i
	70-68	83	35	-	397
	67-65	64	29	-	47
MOUNTAIN	73-71	296 i	56	-	597
	70-68	96	29	-	767
	67-65	34	24	-	131
PACIFIC	73-71	161	70	-	579
	70-68	60	60	-	595
	67-65	128	34	905 i	281
TOTAL U. S.	73-71	145(9316)	63(24089)	1049(121)	488(256)
	70-68	90	45	700	451
	67-65	76	33	185	145

Source: Electrical World, various issues

i = insignificant (based on a very small sample)

TABLE 3

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	67-65	130	32	-	-
WEST SOUTH CENTRAL	73-71	57	39	-	239[i]
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TABLE 3

mile have averaged about 7-8 times the overhead costs in the later years.

Geographically, it can be seen that highest costs for overhead line construction occur in the Middle Atlantic and New England States, followed by the Pacific, East North Central, and South Atlantic States. These trends are most likely attributable to geographic trends in costs of land and labor. In the low voltage overhead category, where the bulk of new construction takes place, there is difference by a factor of 3.5 ($^{143}/_{39}$) between the costs of a structure mile of transmission in the highest and lowest cost regions.

B. Costs of Primary Distribution Lines

In Table 4 we report aggregate average costs for primary distribution lines, again computed from data available from Electrical World. In this table, the sizes of the samples are much larger than for the transmission lines categories, and consequently much less variability exists in the estimates. The same geographic trends that existed for transmission line costs are apparent for distribution lines, again probably attributable to the differences in costs of land and labor in various regions of the country. The ratio of costs in the highest to lowest cost region is about 3.1, compared to 3.5 for transmission costs.

The ratio of costs of underground to overhead distribution, however, is not nearly as large as existed for transmission. On a national average, underground distribution is only 2-3 times as expensive as equivalent overhead capability, while for high voltage transmission the factor was 7-8.

On a national average, the costs of primary distribution have been escalating at a rate of about 3.0 - 3.5% per year, much less than for the equivalent transmission categories.

TRENDS IN PRIMARY DISTRIBUTION LINE COSTS

Three Year Aggregate Averages

REGION	YEAR	$(000)/Structure Mile Overhead 69KV and Below	$(000)/Cable Mile Underground 69KV and Below
NEW ENGLAND	71-73	36	98
	68-70	37	80
	65-67	29	78
MIDDLE ATLANTIC	71-73	41	98
	68-70	33	93
	65-67	30	82
EAST N. CENTRAL	71-73	24	43
	68-70	22	40
	65-67	19	33
WEST N. CENTRAL	71-73	13	18
	68-70	16	20
	65-67	13	35
SOUTH ATLANTIC	71-73	23	48
	68-70	29	38
	65-67	20	28
EAST S. CENTRAL	71-73	16	39
	68-70	18	53
	65-67	16	16
WEST S. CENTRAL	71-73	14	28
	68-70	17	38
	65-67	11	37
MOUNTAIN	71-73	20	35
	68-70	15	34
	65-67	11	24
PACIFIC	71-73	51	62
	68-70	46	52
	65-67	26	38
TOTAL U.S.	71-73	22(109,050)	45(21,420)
	68-70	25	46
	65-67	18	41

Source: Electrical World, various issues

TABLE 4

TRENDS IN SUBSTATION COSTS

Aggregate Averages

	1953 1954 1955	1956 1957 1958	1959 1960 1961	1962 1963 1964	1965 1966 1967	1968 1969 1970	1971 1972 1973
New England	11.3	10.3	8.8	7.2	11.3	11.6	10.8
Middle Atlantic	14.7	14.1	12.7	10.2	10.4	13.0	10.1
East North Central	13.7	15.7	11.8	8.6	7.4	10.4	9.2
West North Central	14.6	12.8	10.3	8.2	8.6	7.9	7.3
South Atlantic	11.9	8.6	6.9	5.4	6.4	7.8	7.7
East South Central	10.4	11.3	10.4	6.7	7.8	11.0	5.2
West South Central	9.7	8.5	6.4	7.4	6.2	6.7	7.9
Mountain	17.4	10.2	11.8	6.7	8.6	12.4	12.7
Pacific	14.5	12.0	13.5	10.8	12.1	14.4	12.0
TOTAL U.S.	12.7	11.8	10.2	8.0	8.2	10.1	8.7

*In dollars per KVA of installed capacity

Source: Electrical World, various issues

TABLE 5

C. Transmission Substation Costs

In Table 5 we give the trends in costs of substations. For this equipment category the regional and time variability of costs are much less predominant than for transmission or distribution lines. The historical trend in costs exhibited a decline from around $12.70 per KVA in 1954 to a low of $8.20 per KVA in the early sixties. Since that time, the unit costs have increased only slightly because economies of scale have tended to offset other escalating factors. Regionally, there exists a factor of 2 variation in costs with the central portions of the country enjoying the lower costs.

D. Costs of Other Equipment Categories

The costs of distribution substations, line transformers, and meters are not nearly as large a component of the total costs of delivered electricity as are the costs of transmission and distribution lines. Transformers exhibit tremendous economies of scale with costs per KVA differing by as much as factors of 10 or more between low capacity and high capacity units. Point estimates obtained from New England company sources suggest that distribution substation equipment, because of the lower equipment ratings used in the distribution system, may average 1.5 - 3.0 times the cost per KVA of transmission substations. Line transformers, which step-down the voltage to that used at the point consumption may average 2-4 times the costs per KVA of transmission substations. We shall see in Section IV that neither of these quantities is too significant in the final cost of electricity.

The costs of various kinds of meters are presented in Table 6. The installed cost of a standard single phase residential meter is about $25, while that for a one-hour demand meter is about $70. A full complement of meters and recorders for a large industrial customer may cost

METERS COSTS

Point Estimates - $1973

	$
° Residential and Small Commercial Consumer (1)	
- Single-Phase meter (2)	25.00
- One hour demand meter (2)	69.36
° Large Commercial and Industrial Consumer	
- Recording Demand meter	600.00
- Watt hour meter	200.00
- Potential Transformer	
Connected to 14 KV Line	244.00
Connected to 4 KV Line	150.00
- Current Transformer	
Connected to 14 KV Line	
Demand < 1000 KVA	210.00
~ 2500 KVA	226.00
Connected to 4 KV Line	
Demand ~ 200 KVA	150.00
- Installation	$50 - 100.00
° TOTAL	$1200 - $1400

(1) Demand less than 48 KW

(2) Includes $6.50 for installation cost

Source: Boston Edison Company

TABLE 6

as much as $1200-1400, but very few industrial customers utilize a complete system. Most industrial customers utilize equipment similar to the one-hour demand meter.

Metering has recently received much attention in the context of peak-load pricing initiatives, but it will be seen in Section IV that the cost of the meter itself contributes a very small amount to the average cost of electricity. The costs of meter reading and billing are much more significant, and this is addressed further in the next section.

III. The Costs of Operating and Maintaining the Transmission and Distribution Systems

The final component of costs associated with T&D are the operation and maintenance expenses. These are the labor, equipment, and material-related expenses needed to maintain reliable operation of the T&D systems. In this section we focus upon the following question: How are the transmission and distribution operation and maintenance expenses of an electric utility related to the equipment installed and/or the configuration of demand placed upon the system?

For both the transmission and distribution categories, where data on installed equipment inventory are available, we used measures of installed equipment as explanatory variables. In addition, since the transmission and distribution equipment requirements are closely associated with the configuration of demand, we also estimated an alternative specification with customer and sales terms as explanatory variables. Both forms are useful, but for different purposes. The first relates the operation and maintenance costs to the equipment configuration of a utility, and is most useful in an engineering planning context. The second relates operation and maintenance costs to the configuration of customers and energy sales, and is useful for allocating costs to the different customer classes for the purposes of ratemaking.[10] When appropriate, results for both specifications are reported.

A. The Expenses for Operation and Maintenance of the Transmission and Distribution Systems

1. Operation and Maintenance Expenses for Transmission

The operation and maintenance expenses[11] for transmission

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[10]The first form can be used in a ratemaking context also, but a two step process must be used. First, costs must be allocated to equipment, then in turn, allocated to customers. In the second form, the customer allocation is done directly.

[11]An itemized list of all expenses, whether for transmission, distribution, or general, may be found in Reference (7).

may be divided into three basic categories. First are the expenses attributable solely to the transmission network, namely overhead and underground line expenses, expenses on structures, and expenses for transmission of electricity by others. The second category is comprised of expenses attributable solely to transmission substations and includes station equipment expenses and load dispatching expenses. The third category encompasses expenses attributable both to the transmission network and to the transmission substations. It includes expenses for supervising and engineering, expenses for rents, and miscellaneous expenses.

2. Operation and Maintenance Expenses for Distribution

Operation and maintenance expenses for distribution may be divided into several categories according to the particular equipment which gives rise to the expense. The first category includes expenses for distribution substations, namely load dispatching and general station expenses. Expenses for line transformers and for meters comprise the second and third categories, while expenses for overhead and underground distribution lines comprise the fourth category. Expenses in the fifth category are not attributable to any one type of equipment. These are expenses for supervising and engineering, rents, street lighting, and signal systems, customer installation, and miscellaneous distribution.

Under the equipment specification, operation and maintenance expenses for distribution are a function of the quantities of the various types of distribution equipment (substations, line transformers, meters, distribution poles and lines) in place.

Under the customer/sales specification, operation and maintenance expenses for distribution are a function of the number of customers and the level of electric power sales. Though large light and power customers are defined as those which take their power directly from the transmission system, we tested the hypothesis that operation and maintenance expenses for distribution might be somewhat affected by the number of large light and power customers and the level of large light and power sales[12].

3. General and Administrative Expenses

This class of expenses is by far the most heterogeneous and is least susceptible of categorization. However, its members can be divided into three rough categories: those attributable to the number of customers, those attributable to the level of sales, and those not readily attributable to either customers or sales, but to the administrative overhead.

General expenses attributable to the level of customers include expenses for supervision of customer accounts, meter reading, customer records and collection expenses, uncollectible amounts, and miscellaneous customer accounts expenses. Expenses attributable to the level of sales include expenses for supervision of sales, demonstrating, selling, advertising, and miscellaneous expenses, and net expenses for jobbing, merchandising, and contract work.

The administrative expense category includes items which, though likely to be greater when sales are greater, are not a direct result of sales. The best examples of such expenses are expenses for property insurance, injuries and damages, franchise requirements, and regulatory expenses and credits of duplicate charges. Other expenses with which the level of sales has a closer nexus are expenses for administrative and general salaries and pensions, office supplies, general plant maintenance, rents, and outside rents (net of transferred administrative expenses).

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[12] In Section I we found that the level of large light and power sales was a component of the demand for line transformers.

General expenses are not expected to be determined by equipment levels, but rather solely by the number of customers and the level of electric power sales, according to the customer/sales specification. Since we suspected that the general expenses attributable to the customers and the power they consumed might differ for different customer categories, both sales and customers were separated into two categories.

B. Results of the Regressions

The regression results, and the elasticities for an average state, are presented in Tables 7 and 8 below. A few comments are in order.

1. In the transmission expenses equation (equipment specification), the overhead transmission line coefficient was insignificant and very small in relation to the underground line coefficient.

2. In the distribution expenses equation (equipment specification), the coefficient for line transformer capacity was negative, contrary to hypothesis; hence, the variable was dropped from the equation. When the line transformer term was dropped from the equation, the coefficient for distribution substation capacity became marginally significant. Adding the distribution substation capacity to the line transformer capacity produced a term with a quite <u>in</u>significant coefficient, suggesting that the number of meters alone adequately explained the level of operation and maintenance expenses for distribution. This result is not altogether surprising, since meters, line transformer capacity, and distribution substation capacity are highly correlated (all three pairwise correlation coefficients exceed 0.9).

3. In the transmission expenses equation (customer/sales specification), the total number of customers was originally tried and was significant. When customers were separated into two classes, the large

light and power customer coefficient was negative so the term was then dropped.[13]

4. In the distribution expenses equation (customer/sales specification) the coefficients of the sales terms, whether for both customer classes together, separately, or one at a time were negative and were dropped.

5. In the general expenses equation, total sales were insignificant; when the sales were separated, the coefficient for residential and small light and power sales was positive while the coefficient for large light and power sales was negative. Removing the large light and power term caused the coefficient for residential and small light and power sales to become insignificant. Consequently, all sales terms were dropped from the equation.

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[13] Use of the specification reported instead of one using all customers affects the costs derived in Section IV below by at most 0.1 mil.

TABLE 7 - REGRESSION RESULTS[14]

Expense item \ Explanatory variables	Equipment Specification			Customer/Sales Specification			
	UNDER	TSUB	METER	CUSRSM		ESRSM	ESLLP
OMT	2917.6 (5.10)	.3659 (46.4)		1.75 (6.53)		199.1 (6.33)	92.11 (4.78)
	R^2 = .810 F (1,327) = 1393			R^2 = .895 F (2,326) = 1382			
OMD			17.766 (143.2)	18.80 (89.2)	159.8 (3.65)		
			R^2 = .973 F(0,328)=11900	R^2 = .974 F(1,327) = 12400			
OMG				26.05 (66.9)	908.3 (11.2)		
				R^2 = .960 F (2,326) = 7878			

EACH COEFFICIENT IN THE ABOVE EQUATIONS IS SIGNIFICANTLY DIFFERENT FROM THE OTHER COEFFICIENTS IN ITS EQUATION.

TABLE 8 - ELASTICITIES[14]

Expense item \ Explanatory variables	Equipment Specification			Customer/Sales Specification			
	UNDER	TSUB	METER	CUSRSM	CUSLLP	ESRSM	ESLLP
OMT	.04	.95		.41		.43	.16
OMD			1.03	.98	.04		
OMG				.91	.15		

[14] See the Appendix for an explanation of the abbreviations used for the variables.

IV. The Allocated Costs of Transmission and Distribution

Using the equation results presented in Sections I and III and the cost data in Section II, we now compute the cost per kilowatt-hour[15] of electric energy attributable to transmission and distribution for residential and small light and power customers and for large light and power customers for the total United States and each of the nine census regions. This is done by allocating to the two customer classes the costs for installing and operating the various equipment items in proportion to the factors that create the need for the equipment. This is done by utilizing the estimated relationships of Section I to allocate demand charges to the two customer classes, and the estimated relationships of Section III to derive the customer and energy related operation and maintenance expenses.

The demand charges are calculated on a per kilowatt-hour basis. Capital expenditures are converted to an annual charge by using an annual capital charge rate. This corresponds to the percentage of the capital expenditures for an equipment item that must be recovered each year to cover the costs of capital, associated taxes, depreciation, etc., over the life of the equipment. For the calculations here, we have used a value for the annual capital charge rate of 13.5%, the same as that used in the National Power Survey of 1970[16] for similar calculations.

Utilizing this annual capital charge rate and the cost for each equipment item, the average costs per kilowatt-hour proportional to the customer and energy related explanatory variables are then obtained as illustrated by the following example. The quantity of structure

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[15] The cost derived is the "fair value" cost, since the equipment costs used are 1972 (replacement) values.

[16] See ref.(3), p. IV-3-69.

miles of transmission line are estimated by the following equation:

$$SM = 813.2 + .1436\ EST + (.0608)\ (.1927^{DMTN})\ AREA\ - 556.4\ LD$$

where SM = Structure miles of transmission line

EST = Annual energy sales to all ultimate customers in millions of Kwh

AREA = Area of states in square miles

DMTN = A dummy variable representing the mountain states (= 1 for mountain states, = 0 otherwise)

LD = Lead density in millions of Kwh per square mile

Each million kilowatt-hours consumed (in a given state) would require .1436 structure miles of transmission line. Multiplying .1436 structure miles by the product of the cost per structure mile and the annual capital charge rate produces the annual capital charge for transmission incurred by 10^6 Kwh, a figure which can be adjusted to ¢/Kwh. These costs are then allocated to each customer class (in this case equally).

For the other terms in the equation, we averaged the total costs over the total kilowatt-hours consumed in order to arrive at a cost per kilowatt-hour. For example, multiplying the constant by the annual capital charge and dividing by the total number of kilowatt-hours consumed would yield the fully distributed annual cost of transmission per kilowatt-hour due to the constant. For the area term, one would multiply the coefficient of the area term (which is structure miles per unit area) by the annual capital charge rate and by the number of square miles in the state, and then divide by the total number of kilowatt-hours consumed.

Allocating the operation and maintenance costs to the two customer classes proceeds similarly, but is simpler because the dependent variables are already measured in dollar terms. Allocation requires only that the coefficient of a term, say, large light and power customers, be multiplied by the number of large light and power customers and then divided by the number of kilowatt-hours sold to this customer class.

After the costs have been allocated to the various terms of the equations in this way, they can then be further allocated to one of the two customer classes, or to both. Costs attributable to constants and other terms but which did not represent one class of customers only were allocated to both classes equally on a per kilowatt-hour basis, while costs attributable to terms which represent one customer class only were allocated to only that class. The results of allocating transmission and distribution costs to the two customer classes for the total U.S. and each of the nine census regions are given in Table 9.

The allocated costs for transmission equipment, distribution equipment, and T&D operation and maintenance are given in columns (1), (2), and (3), respectively, of Table 9. For residential and small light and power customers the average allocated costs of T&D vary from 1.04 to 2.35¢/kwhr., while for industrial, or large and power customers, the costs vary from 0.36 to 0.82¢/kwhr. Also given in column (5) of the table are the estimated costs of generation for each region. These values were obtained from complementary research of the authors described in ref.(6). When added to the total T&D costs of column (4), we obtain an estimate of the total costs of power in each region. In column (7) we report the actual average price paid by the two customer classes for privately-owned utilities in 1972. (ref. (4)).

COSTS OF ELECTRIC POWER FOR PRIVATELY-OWNED UTILITIES 1972

Residential & Commercial

	(1) Transmission Equipment	(2) Distribution Equipment	(3) Operation & Maintenance	(4) Total T&D	(5) Est. Cost of Gen.	(6) Est. Total Cost	(7) Average Revenue [18]
U.S. Average	0.45	0.58	0.50	1.54	0.69	2.23	2.37
New England	0.49	0.86	0.60	1.94	0.81	2.71	2.82
Middle Atlantic	0.68	1.05	0.61	2.35	0.79	3.14	2.93
East North Central	0.34	0.63	0.56	1.53	0.73	2.26	2.47
West North Central	0.49	0.42	0.57	1.47	0.78	2.25	2.59
South Atlantic	0.46	0.53	0.44	1.41	0.75	2.16	2.12
East South Central	0.27	0.34	0.43	1.04	0.62	1.66	1.99
West South Central	0.31	0.40	0.42	1.13	0.69	1.82	1.97
Mountain	0.51	0.65	0.45	1.61	0.58	2.19	2.05
Pacific	0.61	0.90	0.44	1.95	0.52	2.47	1.78 [17]

Industrial

	(1) Transmission Equipment	(2) Distribution Equipment	(3) Operation & Maintenance	(4) Total T&D	(5) Est. Cost of Gen.	(6) Est. Total Cost	(7) Average Revenue [18]
U.S. Average	0.43	0.06	0.08	0.57	0.69	1.26	1.17
New England	0.46	0.09	0.13	0.68	0.81	1.49	1.71
Middle Atlantic	0.66	0.07	0.10	0.82	0.79	1.61	1.48
East North Central	0.32	0.05	0.07	0.44	0.73	1.17	1.20
West North Central	0.47	0.07	0.11	0.65	0.78	1.43	1.37
South Atlantic	0.43	0.05	0.08	0.56	0.75	1.31	1.11
East South Central	0.26	0.04	0.06	0.36	0.62	0.99	1.01
West South Central	0.29	0.08	0.13	0.50	0.69	1.19	0.85
Mountain	0.49	0.12	0.14	0.74	0.58	1.32	0.97 [17]
Pacific	0.58	0.05	0.06	0.69	0.52	1.21	0.96 [17]

[17] Pacific Residential & Commercial 2:19 ¢/kwhr. when excluding Wash. & Oregon
Mountain Industrial 1.18 ¢/kwhr. when excluding Mont. & Id.
Pacific Industrial 1.05 ¢/kwhr. when excluding Wash. & Oregon

[18] Column (7) computed from actual sales and revenues of investor owned utilities reported in ref. (4).

TABLE 9

With the exception of the Pacific region, our estimated costs of residential and small light and power sales are quite close to the actual revenues received, generally within 20%[19]. In the Pacific region, if the states of Washington and Oregon are excluded, the average revenue was 2.19¢ per kwhr, much closer to the estimated cost. For industrial sales our estimated costs are generally higher than the average revenue received. A reason for this may be that we have used 1972 transmission line costs rather than average cost of the entire transmission system. Since transmission costs have been escalating so rapidly, our 1972 values would be higher than the average installed cost of lines of all vintages. Another reason may be that because of differences in load factors, large light and power customers are apportioned a smaller share of generation costs than residential and small light and power customers, and we have assumed they are equally apportioned. Another reason may be that some discrimination in pricing is taking place, but these results are much too inconclusive to tell.

This allocation of costs reveals that for the U.S. as a whole, the cost of distribution equipment, operation and maintenance of that equipment, and general administrative overhead contribute about 1¢/kwh to the costs of power for residential and small light and power customers over and above the contribution to costs of power for large light and power customers. This excess is the main reason for the large difference in electric power costs to residential-commercial and the industrial sectors.

Table 10 further details the allocation of the T&D costs. In this table we have detailed for the two customer classes the costs of electric power by equipment category of origin. This table shows that almost 70% of the costs of power to residential and small light and power customers are related to transmission and distribution. Of this 70%, almost half can be attributed to costs of installing transmission and distribution

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[19] It must be pointed out here that our computed costs are what are termed "fair value" costs, i.e. using 1972 data we compute what would actually be the costs of replacement of the existing system in 1972. In reality rates are set by state and federal regulatory authorities using fairly well establishes administrative procedures. Regulatory commissions attempt to set prices that will yield a predetermined "fair rate return" on an <u>original cost rate base</u> after deductions for operation and maintenance costs, depreciation and taxes have been made. For this reason, one would not expect our calculated costs to be that close to actual per unit revenues. That the costs and revenues of Table 9 are so close is an indication that the procedure we have used has merit, but the error bounds on our estimates of costs are great enough that conclusions based on comparisons of costs and actual revenues are not possible.

U.S. AVERAGE COSTS OF T&D, 1972

Equipment Item	Residential and Small Light & Power ¢/kwhr.	Residential and Small Light & Power %Total Cost	Large Light & Power ¢/kwhr.	Large Light & Power %Total Cost
Transmission				
Structure miles	0.367	16.5	0.367	28.9
Substations	0.087	3.9	0.064	5.0
Total Transmission	0.454	20.4	0.432	33.9
Distribution				
Substations	0.060	2.7	0.002	0.2
Line Transformers	0.103	4.6	0.018	1.4
Pole Miles	0.392	17.6	—	—
Meters	0.029	1.3	0.039	3.1
Total Distribution	0.585	26.2	0.060	4.7
Operation and Maintenance				
Transmission	0.041	1.8	0.011	0.9
Distribution	0.192	8.6	0.011	0.9
General	0.266	11.9	0.062	4.9
Total Operation and Maintenance	0.498	22.3	0.084	6.7
Total T&D	1.538	68.9	0.576	45.4
Estimated Cost of Generation[20]	0.693	31.1	0.693	54.6
Total Cost of Power	2.231	100.0	1.269	100.0

[20]Derived from ref. (6).

TABLE 10

lines, the two items of T&D equipment that exhibited the most significant regional cost variations. For large light and power customers on the other hand, transmission equipment related costs are only 34% of the total cost of power, while generation comprises about 55%. Distribution equipment and operation and maintenance, including billing, comprise the other 11%.

This detailed cost analysis allows one to analyze the sensitivity of total power costs to changes in the component cost structure. To illustrate this, we compute what the effects would be on the costs of power if utilities were to utilize exclusively underground distribution lines, which are much more costly than overhead lines. Distribution lines, at $26,000 per pole mile, contributed on the average about 0.4¢ per kilowatt-hour to the cost of residential-commercial power in 1972. Table 2 showed that underground distribution lines are 2-4 times as expensive as overhead lines. If all primary distribution lines were to be installed underground, the effect would be to raise the costs of power to residential and small light and power customers by an average of about 1.0¢ per kilowatt-hour (in 1972 dollars). This can be compared with the average increase in revenue per kilowatt-hour in 1974 of 0.51¢, due largely to increases in cost of fuel in that year. The impact of undergrounding distribution on costs would therefore have at least as large an effect on total power costs as the increases in cost of fuel following the Arab Oil Embargo.

Transmission line costs are also an important item in the future costs of power. Table 10 showed that in 1972 transmission lines comprised 16% of the costs of power for residential and small light and power users, and 29% for large light and power users. These costs, over the period of 1966 to 1972, almost doubled per structure mile for overhead lines. If this rate of escalation were to continue to 1985, the component cost of transmission lines would be well over 1¢ per kilowatt-hour (in 1972 dollars) on a U.S. average, and could be as high as 2.5 - 3.0¢ per kilowatt-hour in the higher cost Northeast region. This would represent almost a doubling in real power costs for the Northeast and substantial increases for the rest of the country. The costs of undergrounding transmission on top of this, at 7-8 times the per unit costs of overhead lines, would be devastating even when excluding the higher operation and maintenance costs one would expect to accompany the undergrounding.

A final item of importance is the cost of meters and meter reading. The average cost per kilowatt-hour of the meter itself is shown in Table 10 to be only about 0.3 mill, or about 2% of total power costs. In response to the financial difficulties of the utilities and what some perceive as the need to distribute more equitably the costs of generation, many sophisticated metering techniques are being discussed, especially in the context of various peak-load pricing initiatives. One of the uncertainties is whether the benefits to be accrued more than offset the additional costs of the more advanced demand or time-of-day metering devices required. What this analysis shows is that higher cost of metering itself would have only marginal effects on the costs of power. What may be more significant are the costs of meter reading and billing under more sophisticated pricing schemes. Billing and meter reading are included, among other things, in the General Operation and Maintenance category of expenditures in Table 10. For residential and small light and power customers these expenses comprise about 12% of total power costs.

Conclusions

The results of this paper show that when assessing the future outlook for electricity prices and costs of supply, the transmission and distribution costs must be weighed heavily since they are such a large component of the final costs of electricity.

The costs of installing and operating the T&D system of an electric utility comprised, on a national average, about 70% (1.5¢ per kwh) of the cost of power delivered to residential and small light and power customers in 1972. Transmission and distribution lines, the two most costly equipment items, comprised about half of these costs. For large light and power customers, T&D costs comprised about 45% (0.6¢/kwh) of the total power costs in 1972, with 60% of this accounted for by transmission line installation costs.

There are significant regional variations in the costs of T&D. Our analysis indicates that the T&D component of costs ranged from 1.0 to 2.3¢ per kwhr. in 1972, depending on the region of the country, for residential and small light and power sales. For industrial sales, the T&D component of costs varied from 0.36 to 0.82¢ per kwhr.

The main difference in costs of serving residential-commercial and large industrial customers is the cost of building and operating the distribution system. Distribution equipment installation charges and associated operation and maintenance expenses for residential and small light and power users exceed those for large light and power users by about 0.9¢ per kwh on a national average in 1972. This difference is the primary explanation for the higher rates paid by small users of electricity.

APPENDIX: ABBREVIATIONS FOR, SOURCES OF, AND SOME STATICTICS OF THE DATA USED

ABBREVIATION	SOURCE	DESCRIPTION*	MEAN	MINIMUM	MAXIMUM
AREA	3	Area of "states" in square miles	61436.5	1049	262134
CUSLLP	1	Number of large light and power customers	5487.3	22	33192
CUSRSM	1	Number of residential & small light & power customers	1153330	26238	5994697
	1***	" " "	7716177	2584463	1438439
CUSTOT	1	Number of customers - all types	1160045	26478	6038928
DSUB	2	Distribution substation capacity in KVA	5740618	66000	29753890
ESLLP	1	Annual energy sales to large light & power customers in millions of Kwh	8533.4	208	46458
ESRSM	1	Annual energy sales to residential & small light & power customers in millions of Kwh	10504	332	62492
	1***	" " " "	71008	21004	142526
EST	1	Annual energy sales to all ultimate customers in millions of Kwh	19807.4	565	95369
LD	EST/AREA	Load density in millions of Kwh. annually per square mile	.6786	.0137	5.2440
LDRSM	EST/AREA***	Residential & small light & power load density in millions of Kwh per sq. mile	.3478	.0272	1.1386
LT	2	Line transformer capacity in KVA	7226619	87152	36961310
METER	2	Number of meters	1280082	20791	6517876
OMD**	2	Operation & maintenance expenditures for distribution in 1967 dollars	22018990	338962	127622300
OMG**	2	General & administrative expenses in 1967 dollars	33005070	411489	209474400
OMT**	2	Operation & maintenance expenditures for transmission in 1967 dollars	4886232	161749	36631490
POLE	4***	Pole miles of primary distribution line	106561	28802	199062
TRANS	2	Structure miles of transmission line	6122.0	0	27328
TSUB	2	Transmission substation capacity in Kva	12623100	0	64472000
UNDER	2	Circuit miles of underground transmission line	60.57	0	2879

*Note: All data are by state and for investor-owned utilities only unless otherwise noted

**Deflated by the wholesale price index for non-farm industrial commodities to 1967 dollars.

***Regional: all utilities

Sources:
1. Statistical Yearbook of the Electric Utility Industry, Edison Electric Institute, for the years 1965 through 1971.
2. Statistics of Privately Owned Electric Utilities in the United States, Federal Power Commission, for the years 1965 through 1971.
3. Statistical Abstract of the United States, Bureau of the Census, 1972
4. Electrical World, for the years 1965 to 1971.

Average Cost Figures Used
For Calculations in tables 9 and 10.
(1972 Dollars)

	Overhead Transmission Line costs in $1000 per Structure Mile	Transmission Substation Costs in $/KVA	Primary Distribution Line Costs in $1000 per Pole Mile
New England	123	10.80	44.7
Mid. Atlantic	261	10.10	53.2
E.N. Central	97	9.20	27.7
W.N. Central	61	7.30	13.7
South Atlantic	126	7.70	27.5
E.S. Central	74	5.20	18.0
W.S. Central	58	7.90	15.7
Mountain	77	12.70	24.7
Pacific	155	12.00	54.4
Average U.S.	110	8.80	26.0

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