ELECTRIC UTILITY COST ALLOCATION MANUAL

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NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS

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CHAPTER 5

FUNCTIONALIZATION AND ALLOCATION OF TRANSMISSION PLANT

The transmission system may be defined for ratemaking purposes as a group of highly integrated bulk power supply facilities, con-sisting of high voltage power lines and substations. They are designed and operated by a utility to transport electric power reliably and economically from points of origin on its system to distribution loads or load centers located within its franchise area, or to other points of delivery on its system[1]. The points of origin of power so transported may be from the utility's own production resources, or may be that of another utility which is then delivered by that utility to the other's system through various transmission interconnections. The transmission function is generally concluded at the high-voltage side of a distribution substation owned by the utility, or at points where the ownership of bulk power supply facilities change.

The two principal characteristics that distinguish one transmission system from another are the voltages at which the bulk power supply facilities are designed and operated, and the way in which those facilities are configured.

The voltages of transmission facilities can and do vary widely from one electric system to another. For example, where one system's predominant backbone transmission facilities may consist of 345KV or higher voltage facilities, another's may consist of 115KV facilities, while still another's may have a combination of facilities which operate at various transmission voltages.

[1]The Federal Energy Regulatory Commission defines a transmission system to include: (1) all land, conversion structures, and equipment employed at a primary source of supply (i.e., generating station, or point of receipt in the case of purchase power) to change the voltage or frequency of electricity for the purpose of its more efficient or convenient transmission; (2) all land, structures, high tension apparatus, and their control and protective equipment between a generating or receiving point and the entrance to a distribution center or wholesale point; and (3) all lines and equipment whose primary pupose is to augment, integrate or tie together the sources of power supply. (1 FERC Para, 15,064).

The way in which transmission facilities are configured also varies widely from system to system. For example, some systems may be highly integrated, where facilities of the same or different voltages are configured to form networks that provide a number of alternative paths through which power may flow from one point to another. Other systems may be essentially radial, where few or no alternative paths exist to transport power from one point to another.

In general, the transmission system may be considered to be comprised of a number of subsystems, or component parts, which operate together to deliver bulk power supply to various points or load centers. The most commonly used terms to differentiate the various subsystems from each other are: (1) the backbone and inter-tie facilities; (2) generation step-up facilities; (3) subtransmission plant; and (4) radial facilities.

In addition, there are other plant components that may perform a function not perceived as being predominately related to transmission, but nonetheless contributing to the economic and reliable operation of the transmission system. In a cost of service format, these particular plant facilities, which are represented as investment costs recorded in a utility's production or distribution plant accounts, are often referred to as "plant reclassifications."

The use of transmission subsystems is both a useful means of generally explaining the different aspects of transmission system design and operation, and is particularly applicable to the ratemaking process. For example, where certain classes of electric utility customers require service from the transmission system as a whole, other classes may not require the use of all components of the system. Thus, the use of subsystems or plant groupings provides the basis upon which cost responsibilities among customer groups may be differentiated.

This chapter first discusses two methods of transmission system functionalization; with more detailed attention paid to subfunctionalization methods. Next, several methods used to allocate transmission plant costs are presented. The careful reader will see similarities with Chapter 4. Finally, the treatment of wheeling costs is discussed.

I. FUNCTIONALIZATION OF THE TRANSMISSION SYSTEM

Functionalization may be defined as the process of grouping costs associated with a facility that performs a certain function with the costs of other facilities that perform similar functions. The extent to which transmission plant is functionalized in a cost of service analysis will usually depend upon the design and operating characteristics of classes of facilities, their different cost characteristics, and the type and nature of electric services being provided by the utility.

The process of transmission plant functionalization usually begins with the identification and grouping of those higher-order customers, and concludes with those groups of facilities of a lesser order that are required to serve only particular customers or groups of customers.

The number of transmission plant cost groups can range from one to several. Where only one transmission cost group is recognized, the functionalization method is referred to as the "rolled-in method." Where more than one group of transmission facilities is recognized, the functionalization method is usually called the "subfunctionalization method."

A. The Rolled-in Transmission Plant Method

Under the rolled-in transmission method of functionalization, the transmission system is comprised of highly integrated facilities which are designed and operated collectively to deliver bulk power supply from point to point on the system. Thus, where facilities of various operating voltages form integrated transmission networks, each element within those networks is considered to be contributing to the economic and reliable operation of the overall system.

While the concept of a fully integrated transmission system is the principal reason for treating it as a single system for ratemaking purposes, there are certain transmission facilities that are not integrated. These facilities, principally radial transmission lines, are used exclusively to serve specific customer loads at transmission voltages. The philosophy for rolling-in these radial lines is that they represent a short-term strategy in which a utility is able to maximize long-term system efficiency, without sacrificing reliability, by phasing-in transmission system expansions. In effect, radial transmission lines are perceived as the initial phase of transmission expansion from which network or looped facilities will ultimately emerge as system loads begin to grow. Therefore, since all customers are generally expected to benefit from the strategy of overall transmission cost minimization, all should be expected to share the costs of the system.

B. The Subfunctionalized Transmission Plant Method

The main alternative method to the rolled-in approach is the subfunctionalization of the transmission system. Under this approach, transmission subsystems may be distinguished from one another by the utility's use of them, or, on the basis of line configuration, geographic circumstances and voltage level, among other considerations.

The data requirements imposed by subfunctionalization are substantially more demanding than those imposed by the rolled-in method. Not only are detailed plant account records and schematic diagrams required to evaluate the function or role performed by each transmission element, but a high degree of subjective judgment is required to categorize these elements when their function is less than clear, or where an element performs multiple functions. For example, substation structures may house integrated transmission plant components that require the use of micro-allocation methods to apportion investment costs among all the subfunctionalized plant categories. In order to perform such micro-allocations, detailed plant cost accounting data as well as facility demand data must be available.

In addition, subfunctionalization gives rise to questions concerning the manner in which facilities of different vintages should be accounted for in the cost of service analysis. For example, subtransmission investment of early vintage is more depreciated than other subsystems within the transmission system. In order to recognize any vintage difference in the functionalization of depreciation reserve, a detailed review of a utility's historic plant accounting records will need to be undertaken.

Because of these substantial requirements, the extent to which transmission plant is to be functionalized should be limited to the number of plant categories that adequately recognize the different cost consequences that may exist among customers or groups of customers.

Under subfunctionalization, the main distinction is usually between those facilities that interconnect all the major power sources with each other -- the backbone transmission facilities -- and everything else. Utilities have identified subsystems such as generation step-up facilities, system interconnection and subtransmission, among others. These transmission system components and other non-backbone facilities may often be considered as a separate network of facilities that are either not used to support the backbone system, or represent facilities that require special recognition in the ratemaking process.

1. Backbone and Inter-tie Transmission Facilities

Backbone and inter-tie transmission facilities are generally considered to be the network of high-voltage facilities through which a utility's major production sources, both on and off its system, are integrated. As power systems have expanded to meet increased demands for electric energy, lower voltage networks have been overlaid with higher voltage transmission facilities to improve transmission system reliability and to capture economy benefits. Today, 115KV to 765KV (and even higher) voltage facilities constitute the backbone of most large transmission systems or power pools. Where a utility is a member of a formal power pool, through which reliability and economy gains may be realized from coordinated utility operations, it is not unusual that segments of an area-wide EHV backbone transmission network will be owned by several different utilities consistent with their pool obligations. The points at which ownership changes between utilities are often referred to as the pool inter-ties or interconnection points. Power flows in either direction over these inter-ties as a result of the coordinated operations of the interconnected utility members. This classification of transmission plant investment becomes significant in utility cost allocation studies where loads are served exclusively from the high voltage transmission network without appreciable support from the lower voltage networks. These facilities are generally allocated to all classes of firm power customers.

2. Generation Step-Up Facilities

Generation step-up facilities generally refer to the substations through which power is transformed from a utility's generation output voltages to its various transmission voltages. This classification is based on the concept that such facilities are an extension of production plant and should be treated accordingly, particularly where wheeling services are directly or indirectly involved in the cost allocations. Under this theory, all classes of firm load are generally allocated generation step-up costs except wheeling customers.

3. Subtransmission Plant

Subtransmission plant refers to those lower voltage facilities on some utilities' systems whose function, over time, has changed to a quasi-transmission role in the delivery of electric power supply. As generation station sites become further removed from the utility's loads, the character of the transmission system has significantly changed. Today, facilities operating at voltages of 115 KV or higher are considered to be transmission, while facilities operating at voltages below 25 KV are generally considered to be distribution. Those facilities operating at voltages between 25 KV and 115 volts are now commonly referred to as subtransmission facilities. Accordingly, subtransmission may be defined to represent that portion of utility plant used for the purpose of transferring electric energy from convenient points on a utility's backbone transmission system to its distribution system, or to other utility systems, such as points of interconnection with wholesale customers' facilities. Cost responsibility for subtransmission plant is usually assigned to only those loads served directly at the subtransmission voltages and those distribution loads fed through subtransmission facilities. Customers served at voltages higher than subtransmission are not allocated these costs on the theory that the subtransmission facilities are not required or used to provide the higher voltage services.

4. Radial Facilities

Radial transmission facilities represent those facilities that are not networked with other transmission facilities, but are used to serve specific loads directly. For cost of service purposes, these facilities may be directly assigned to specific customers on the theory that these facilities are not used or useful in providing service to customers not directly connected to them.

5. Plant Reclassifications

In some instances, distribution line and substation investments recorded in the distribution plant accounts may be reassigned to transmission because of their functional characteristics. An example of this is when a power generator is not directly interconnected with the transmission system but feeds directly into the distribution system. This could occur when a combustion turbine generator is located within a distribution load center. In this case, distribution facilities which provide the shortest path from the generator to the transmission system may be considered for reassignment to the transmission function on the theory that these facilities represent an integral part of the power supply network. The advent of cogeneration has added significantly to the importance of this reclassification because, in many cases, a cogenerator is connected to a utility's electrical system at a distribution voltage.

In other instances, large capacitor banks and synchronous condensers located within the distribution system may also be considered part of the transmission system. Synchronous condensers and capacitor banks generate volt-amperes reactives (VAR's) which feed into the transmission system and help stabilize transmission voltages and improve system power factor. The installation of large capacitor banks on the transmission system can cost as much as three times more per VAR than if they were installed at the distribution level. Thus, even though large capacitor banks and synchronous condensers have a significant influence in the operation of the transmission system, they are often installed at the distribution level to save in installation costs. In some cases where synchronous condensers are installed at the distribution level and are assigned to the transmission function, the shortest distribution path from these facilities to the transmission system as well as the condensers themselves may also be assigned to the transmission function.

II. METHODS OF ALLOCATING TRANSMISSION PLANT

A utility keeps track of its transmission plant costs in a manner suitable for ratemaking purposes in order to charge customers a cost-based rate for providing them with transmission services. These costs may be rolled-in or subfunctionalized to effect the appropriate assignment of costs based on the contribution of each customer group to the applicable plant cost category.

Costs are assigned using one of two general principles: (1) allocation; or (2) direct assignment. Allocation is an indirect method of cost assignment under which customer cost responsibilities are usually measured in terms of usages, e.g., KW, KWH or KVA. The premise of cost allocation is that the cost of providing transmission service to a customer is proportional to the demand that customer imposes on the system or its components. There are several methods discussed below to calculate these relationships. Direct assignment, as its name implies, rests on the premise that, insofar as facilities are used exclusively by a customer, the costs of those facilities can be imposed directly on that customer.

After transmission costs are separated into appropriate demand or energy allocation categories, it is necessary to then select a method of assigning cost allocation responsibility to various customers. In general, customers are allocated a portion of the fully distributed (embedded) cost of the transmission system on a basis similar to the way production costs are allocated. The reason for this is that the transmission system is essentially considered to be an extension of the production system, where the planning and operation of one is inexorably linked to the other. Thus, the major factors that drive production costs, it is argued, tend to drive transmission costs as well.

On the other hand, the transmission system is designed to reliably and economically deliver bulk power supply throughout the system, even under adverse operating conditions. In transmission contingency planning, the keystone to reliability is redundancy which translates, in effect, to capacity being built in excess of that which is minimally required to deliver load. The redundant character of the transmission system then gives rise to the theory that its capacity is separable into two functional components: (1) an energy-delivery system component, allocable on an energy basis; and (2) a reliability component, allocable on the basis of some demand or capacity measurement. This particular approach, however, is not in common usage.

Customer transmission cost responsibility in the cost of service is expressed in terms of allocation ratios. These ratios are usually developed on the basis of customer demands to the sum of all demands deemed to be imposed on the total system or subsystem. Thus, the demand of the customer is included in both the numerator and denominator of the allocation factor and the customer is accordingly allocated a portion of the total costs. Since firm power loads are the highest order of electric service, all fixed costs are deemed incurred to provide such service. Conversely, non-firm service may either be opportunity-type sales without availability assurances, or sales from surplus capacity with limited assurances of availability. Thus, revenues derived from these sales, usually based on negotiated rates, may recover costs anywhere in the range of zero to the amount of the fully distributed costs. With value of service negotiated prices, revenues may even exceed fully distributed costs. In recognition of this cost or price flexibility, the demands for non-firm customers are usually excluded from the allocation factor determinations and, concomitantly, the revenues collected from non-firm customers are treated as credits in the cost of service.

Numerical examples for several allocation methods are provided with data contained in Table 5-1.

TABLE 5-1

1988 SYSTEM AND CUSTOMER DATA - TRANSMISSION LEVEL

	SYSTEM			CUSTOMER GROUP		
Month	KWH (millions)[1]	CP Demand (MW)[1]	NCP Demand (MW)[2]	CP Demand (MW)[1]	NCP Demand (MW)[1]	KWH (millions)[3]
Jan	5610	10520	11074	337	319	166
Feb	5130	10570	11126	344	315	153
Mar	5590	10180	10716	354	344	179
Apr	5400	10620	11178	361	358	180
May	5670	11190	11779	410	403	210
Jun	5860	12090	12726	431	427	215
Jul	6580	13730	14453	524	515	268
Aug	6910	14610	15379	524	520	271
Sep	6410	15050	15842	491	489	246
Oct	6110	12380	13032	405	405	211
Nov	5500	10770	11337	364	336	169
Dec	5700	11120	11705	355	347	181
Total	70470	142830	150347	4900	4778	2449

[1] Basic data supplied by Southern California Edison Company.

[2] Assuming .95 coincidence factor.

[3] Assuming 70% monthly load factor.

A. Allocation Methods

1. The Single System Coincident Peak (1CP) Demand Allocation Method

The single highest peak demand is the overriding consideration that drives power supply cost decisions. Customer contribution to this single annual system peak is used to measure customer responsibility. The result is that those customers which most heavily contribute to the single monthly peak will pay a proportionally larger amount of the cost of maintaining the transmission system.

The calculation of the 1CP demand allocation requires a knowledge of the company's single transmission system peak demand (exclusive of non-firm demands) and the demand of the customer group at the same hour and day of that month. The 1CP demand allocation ratio is computed by dividing the customer group's 1CP demand by the utility's transmission demand at the time of the system peak, as follows:

$$\text{1CP Customer Group Demand Ratio} = \frac{\text{Customer Group 1CP Metered Demand + Demand Losses}}{\text{Firm Transmission Peak Demand}}$$

In order to determine the transmission system peak demands, the company must be able to monitor the utility's demands on its production facilities and the power flows entering its system. To determine the customer group's actual demand at the time of the transmission system's peak demand, the utility must have either time-demand meters, or employ statistical techniques to determine the relationship between the individual customer's billing demand and its actual incurrence. See Table 5-2 for illustrative example of 1CP allocation methodology.

TABLE 5-2

EXAMPLE OF SINGLE SYSTEM PEAK DEMAND ALLOCATION

Customer group CP demand at system CP (Sep)	491
System CP(MW)	15050
1 CP customer group demand ratio	.03262

2. The Average Seasonal System Coincident Peak Method

Because of heating and air conditioning loads, a utility may experience peak demands of comparable magnitude during different seasons of the year. The peak demands during those seasons may be considerably higher than those for the remaining months of the year, and the actual peak month may rotate from year to year between the seasons. In addition, the high level of usages may be sustained longer in one season than the other.

The calculation of the average seasonal CP demand allocation requires data for the company's transmission peak demands for the allocation periods selected and the demands of the customer groups at the same hours and days for each of those periods. The problem of implementation is the same as for the 1CP demand allocation method, except that data for more than one period is needed.

The average seasonal CP demand allocation ratio is computed by dividing the sum of the customer group's demands at the peak periods by the sum of the utility's transmission demands during those same periods. The demand ratios are computed as follows:

$$\text{Seasonal CP Demand Ratio} = \frac{\text{Sum of Customer Seasonal CP Demands \& Demand Losses}}{\text{Sum of Seasonal Transmission System Peaks}}$$

Implementation of the average seasonal CP demand allocation method will involve the same type of data and the same difficulties, except that data for more than one allocation period are required. See Table 5-3 for sample application of seasonal CP allocation methodology.

TABLE 5-3

EXAMPLE OF AVERAGE SEASONAL SYSTEM COINCIDENT PEAK ALLOCATION

Customer group CP total for months of July, August and September*	1539
System CP total for the same month(MW)	43390
Customer group average seasonal demand ratio	.03547

* Selection of July-September period is based on criterion of using months with system CP demand of at least 90% of system annual CP demand. Actual selection may consider historical occurrence of CP demand in additional months.

3. The Average of the 12 Monthly System Coincident (12 CP) Peak Method

The 12 CP demand allocation method is based on the principle that a utility installs facilities to maintain a reasonably constant level of reliability throughout the year or that significant variations in monthly peak demands are not present. Under this method, no single peak demand or seasonal peak demands are of any significantly greater magnitude than any of the other monthly coincident peak demands. Thus, the relative importance of each month is considered.

To implement this method, data for the monthly coincident peak demands of each customer at each delivery point for the year must be available. For example, if the company's monthly system peak demand for August occurs on August 10th at 4 P.M., then data for each customers' demand at that specific point in time must be available. Additionally, similar data would be required for each day the company's system peak occurred in the other eleven months in the selected test year.

Customer responsibility under this allocation method is computed as follows:

$$\text{12CP Customer Group Demand Ratio} = \frac{\text{Cust Group 12CP Metered Demand + Demand Losses}}{\text{Transmission System 12CP Demand}}$$

Coincident peak demand data for individual customers such as municipal or cooperative systems is usually readily available by delivery point. The coincident peak demands of individual or groups of retail customers are not available since many retail loads are not demand metered. See Table 5-4 for sample application of this methodology.

TABLE 5-4

EXAMPLE OF 12 MONTHLY SYSTEM COINCIDENT PEAK ALLOCATION

Customer group CP demand total(MW)	4900
System CP demand total(MW)	142830
12 CP customer group demand ratio	.03431

4. The Single Non-Coincident Peak (NCP) Demand Allocation Method

The NCP method attempts to give recognition to the maximum demand placed upon a system during the year by all customers. This method is based on the theory that facilities are sized to meet these maximum demands. Therefore, the costs of the facilities are allocated in accordance with each customer's contribution to the sum of the maximum demands of all customers' imposed on the facilities.

Customer responsibility under this method is computed as follows:

$$\text{Customer Group NCP Demand Ratio} = \frac{\text{Cust Group NCP Metered Demand + Demand Losses}}{\text{Transmission System NCP Demand}}$$

Data for individual customers such as municipal or cooperative systems is usually readily available by delivery point. The maximum peak demands of individual or groups of retail customers are not available since many retail loads are not demand metered. Thus, large groups of retail customers will benefit from the diversity among their loads in the allocation process. See Table 5-5 for a sample application of the single NCP allocation methodology.

TABLE 5-5

EXAMPLE OF SINGLE NON-COINCIDENT PEAK DEMAND ALLOCATION

Customer group NCP demand (MW)	520
System NCP demand*	15842
Customer group NCP demand ratio	.03282

* Assuming a coincidence factor of .95 for the system, NCP for CP demand of 15050 MW would equal 15842 MW.

5. The Monthly Average NCP Demand Allocation Method

The monthly average NCP demand allocation method attempts to give recognition to the variation or diversity among monthly NCP demands placed on a system during the year by all customers. This in effect recognizes the fact that facilities are installed to provide reliable service throughout the year including periods of scheduled maintenance. Costs of the facilities are allocated in accordance with each customer's average monthly contribution to the sum of the average monthly maximum demands of all customers.

As with the NCP method, data for individual customers such as municipal or co-operative systems is usually readily available by delivery point. The maximum peak demands of individual or groups of retail customers are not available since many retail loads are not demand metered. See Table 5-6 for sample application of monthly average NCP allocation methodology.

TABLE 5-6

EXAMPLE OF MONTHLY AVERAGE NCP DEMAND ALLOCATION

Customer group NCP demand total(MW)	4778
System NCP demand total*	150347
Customer group monthly average NCP demand ratio	.03178

* Assuming a coincidence factor of .95 for the system, NCP for system CP monthly demands as shown in Table 5-1 would total 150347 MW.

6. Average and Excess Allocation Method

In contrast to the various peak demand allocation methods which assign costs based entirely on peak demand responsibility, under the average and excess demand allocation method (A&E) transmission costs are divided into two parts for allocation purposes on both demand and energy based on the system load factor (the ratio of the average load over a designated period to the peak demand occurring in that period). As such, the A&E method emphasizes or recognizes the extent of the use of capacity resulting in allocation of an increasing proportion of capacity costs to a customer group as its load factor increases. This theory implies that a utility's capacity serves a dual function -- while system peak demands establish the level of capacity, providing continuous service creates additional incentive for such capacity costs. Use of the A&E method for allocating transmission costs is typically employed for consistency when production costs are allocated on the same basis.

Because the A&E method does not recognize the coincident peak contribution of a customer group's load, the data necessary to perform the calculation is limited to the energy consumption and maximum (non-coincident) demand for a given period.

The first half of the formula, the "average" component representing the customer group's average energy consumption, allocates transmission costs on an energy use or average demand basis. The second half of the formula, the "excess" component is derived from the difference between the customer group's maximum non-coincident peak demand and the "average" demand component. The A&E method is expressed algebraically as follows:

$$D = L \times \frac{A}{B} + (1-L) \times \frac{C}{E}$$

Where: D = customer group's demand responsibility ratio
L = system's annual load factor
A = customer group's energy requirements
B = total system energy requirements
C = customer group's "excess" demand responsibility
E = sum of all customer groups' "excess" demand responsibility

Implementation problems associated with the A&E method are inherent in the complexity of the computation. Additional complications may arise in an attempt to recognize that demand meter readings are not taken on a consistent basis, e.g., a large bulk power customer may reflect a greater degree of diversity as compared to a smaller low voltage distribution customer with little or no diversity. See Table 5-7 for sample application of average and excess allocation methodology.

TABLE 5-7

EXAMPLE OF AVERAGE AND EXCESS DEMAND ALLOCATION

$$D = L \times \frac{A}{B} + (1-L) \times \frac{C}{E}$$

Where: D = customer group's demand responsibility ratio

L = system's annual load factor = $\frac{\text{average load for year}}{\text{peak load for year}}$

$$= \frac{\dfrac{\text{70470 million KWH (Table 5-1)}}{\text{8784 hrs/yr}}}{\text{15,050,000 KW (Table 5-1)}} = 53.3\%$$

A = customer group's energy requirements = 2449 million KWH assuming monthly load factor of 70%

B = total system energy requirements = 70,470 million KWH

(1-L) = 46.5%

C = customer group's "excess" demand responsibility

$$= \text{520 MW (Table 5-1)} - \frac{\text{2449 million KWH}}{\text{8784 hrs in 1988}} = \text{241 MW}$$

$$E = \text{15842 MW (Table 5-1 CP demand for system at .95 coincidence factor)} - \frac{\text{70470 million KWH}}{\text{8784 hrs in 1988}}$$

$$= \text{7819 MW}$$

Therefore: $D = (53.3\%)\ \dfrac{2449 \times 10^6}{70{,}470 \times 10^6} + (46.7\%)\ \dfrac{\text{241 MW}}{\text{7819 MW}} = .032917$

7. Combination of Other Methods

The preceding discussions have addressed situations involving allocation of various firm transmission investments to firm power loads. Depending on the factual situation present on a utility's system, it may be appropriate to employ a combination of methods to properly allocate cost responsibility to customers. Thus, an NCP allocation is sometimes used to allocate subtransmission costs, while a peak responsibility method based on coincident demands is used for the higher order transmission facilities. In addition, where certain customers may exhibit load patterns that are not adequately represented in their coincident load data, other factors not normally employed in a peak responsibility method may need to be introduced to assure proper cost allocation.

With regard to non-firm transmission services, while it may or may not be true that such services should not be held responsible for any demand costs, it should also be recognized that non-firm services require very close analysis of service contract provisions to determine utility obligations in order to establish the correct basis for allocation.

B. Direct Assignment

The costs of specific transmission facilities, such as long radial transmission lines and substations, may be directly assigned to particular customers. Direct assignments of such costs implies that the facilities can be considered entirely apart from the integrated system. In fact, the case for the independence of the facilities must be unequivocal since the customer must be willing to bear all the costs of service that, due to the unintegrated character of the facilities, may be just as high for service that is less reliable than service on the integrated system.

Costs assigned directly to customers are often collected via a special facilities charge. The charge can reflect: (1) the installed costs of the facilities; or (2) the average system cost of such facilities.

The plant costs that are directly assigned to a customer group must be excluded from the utility's total transmission plant costs for allocation. Alternatively, the revenue can be treated for costing as a revenue credit.

III. WHEELING

Wheeling is a transfer of power over transmission facilities owned by a utility that does not produce or sell the transferred power. The transfer may either be on a simultaneous or non-simultaneous basis. On either basis, the actual source of the power delivered to the purchasing system is not necessarily from the contracted for power source. Instead, power from other sources may flow over the integrated transmission system to satisfy the loads of the owner who has contracted for the specific source of power that is to be wheeled. Power from the specific source will in turn be used to meet other loads on the integrated system. This process is often referred to as service by displacement. When the power to be wheeled is from a hydroelectric facility, the wheeling system will often assume scheduling responsibilities by entering into "energy banking" arrangements to maximize fuel cost economies on its own system. The energy banking arrangements are often used in the wheeling of preference power from a power marketing agency to small distribution systems dispersed within a larger system which performs the necessary wheeling services.

The simultaneous or non-simultaneous wheeling of power may be conducted on either a firm or non-firm basis. In either case, a continuous contract path is generally required between the power source and load of the system which is receiving wheeling service. Firm transmission services are intended to be available at all times during the contract and are essentially the unbundled transmission portion of requirements rates. The functionalization and allocation methods applied to requirements service are applicable to firm transmission service as well.

Non-firm wheeling service is usually available under arrangements which do not provide assurances of continuous availability to the customer. Intuitively, it would appear that the costs to be recovered for non-firm wheeling should be less than costs recovered for firm wheeling, provided that the costing basis for both is identical. However, since non-firm wheeling service is often associated with opportunity or interchange transactions among power systems -- where such transactions usually reflect incremental cost pricing or other non-embedded cost measurements -- the benefits of the interchange transactions may also be considered in the development of non-firm wheeling rates. Such consideration may be expressed in terms of the costs of foregone opportunities to the utility providing non-firm wheeling service. Thus, the methods of allocation used in costing firm transmission service may or may not represent a cost ceiling for non-firm transmission service rates.

The advance in computer technology is providing additional capability for allocating costs to more accurately determine revenue from providing transmission service. One of the new methods for allocating and pricing transmission service is based on the positive difference, MW-mile methodology. The development and application of the positive difference, MW-mile method for each party is a multi-step process. The first step is to compute the MW-mile rating of the wheeling utility's transmission system by multiplying the length of each transmission line by a percentage of the thermal rating of the line. The products are summed to provide the aggregate MW-mile and are determined at least annually. The aggregate MW-miles are summed and divided into the functionalized transmission cost of service of the wheeling utility to yield a dollar per MW-mile billing charge. The next step is to determine the wheeling utility's MW-mile billing units. Billing units are determined by the use of computer models. The utility arranges for two simulations of power flows on its system, one simulation with wheeling for the wheeling recipient and one without. The simulations are compared to determine the effects on the system of the wheeling utility's wheeling. Negative changes (i.e., line unloadings) are sometimes ignored. Each positive MW change on a line is multiplied by the line length and the products are summed to yield the wheeling utility's positive MW-mile billing units. The billing units are multiplied by the utility's MW-mile charge to develop the bill.