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NARUC Gas Distribution

Rate Design Manual (1989)

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GAS DISTRIBUTION RATE DESIGN MANUAL

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theoretical main of zero-inch diameter to the customer function, and allocate
the remaining costs associated with mains to demand. A calculation of a minimum
size main is shown in the illustrative cost allocation study. The contra
argument to the inclusion of certain distribution costs as customer costs is
that mains and services are installed to serve demands of the consumers and
should be allocated to that function. Under this basic system theory, only
those facilities, such as meters, regulators and service taps, are considered to
be customer related, as they vary directly with the number of customers on the
system.

Another controversial item is the inclusion of sales promotion expenses in
the customer cost component. Analysts vary in their opinions as to the extent of
the inclusion. Some would include all, some none, and some a portion of sales
promotion expense in the customer category. With emphasis placed on conser-
vation, many regulatory bodies have prohibited this type of activity, and in
those cases, if cost were incurred, it should be deleted from the study based
upon its being a "below the line" or a stockholder expense.

b. Energy or Commodity Costs

Energy or commodity costs are those which vary with the quantity of gas pro-
duced or purchased. They are largely made up of the commodity portion of
purchased gas cost and the cost of feedstock, catalyst, fuel, and other variable
expenses used in the production of gas from a manufactured or synthetic gas
(SNG) plant. Energy or commodity costs increase or decrease as more or less gas
is consumed.

c. Demand or Capacity Costs

Demand or capacity costs vary with the quantity or size of plant and equip-
ment. They are related to maximum system requirements which the system is

designed to serve during short intervals and do not directly vary with the number of customers or their annual usage. Included in these costs are: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of distribution plant not allocated to customer costs, such as the costs associated with distribution mains in excess of the minimum size.

3. Allocation of Costs to Customer Classes

After the assignment of costs to the customer, energy, and demand categories, each category must be allocated to the various service classifications or to their subdivisions.

a. Customer Costs

Customer costs may be distributed in proportion to the number of customers in a class, or a more detailed study may be made whereby certain components of the customer costs may be distributed on a per-customer basis, directly assigned or distributed on a weighted per-customer basis. The latter method permits recognition of known or ascertainable customer cost differences such as the frequency of meter readings, complexity in obtaining readings or integrating meter reading charts, and the individiual attention which may be given to large customers, such as separate meter reading schedules.

As discussed earlier, while there may be differences on whether certain items of plant should be assigned to customer costs, there are clearly certain expenses which are independent of whether a customer consumes gas or not. Since these costs will not be recouped if little or no gas is consumed, they are generally included in a minimum bill or customer service charge. One of the

useful by-products of a detailed cost of service study is that the customer costs are broken out by service classification or class of customer. When these costs are divided by the number of customers within a particular subdivision, the analyst is provided with an indication of what the minimum or customer service charge should be.

b. Energy or Commodity Costs

Energy or commodity costs may be distributed to customer groups on the basis of the quantity of gas consumed during some historical or projected test period, with or without allowance for losses incurred in transporting the gas from the production plant or city gate station to the customer. If the historical test period were abnormally cold or warm, the sales and related cost should be normalized before allocation. The analyst in reviewing the operation of the system could find that certain classes of customers might appropriately be allocated a greater or lesser than average level of lost and unaccounted for gas. This determination will be affected by such factors as the degree of utilization of distribution facilities, quality of metering equipment and the timing of meter readings relative to purchases.

c. Demand or Capacity Costs

Demand or capacity costs are allocated to customer classes based upon an analysis of system load conditions and on how each customer class affects such costs. These are largely joint or common costs, and their allocation generates the largest controversy surrounding a cost of service study. This subject has been studied and argued for years without resolution, and often represents the largest item which can dramatically alter the result of a study.

d. Other Costs

Other costs, such as those associated with common plant, working capital and administrative and general expenses, cannot be readily categorized as either customer, energy or demand. Thus, they are not normally allocated on the basis of a single classification. These other costs are generally allocated on a composite basis of certain other cost categories. For example: common plant may be allocated on the composite allocation of all production, transmission, storage and distribution plant; and administrative and general expenses may be allocated in accordance with the composite allocation of all other operating and maintenance expense, excluding the cost of gas.

4. Methods of Allocation of Demand or Capacity Costs

a. Theory

There is a wide variety of alternative formulas for allocating and determining demand costs, each of which has received support from some rate experts. No method is universally accepted, although some definitely have more merit than others. The electric industry has produced more alternatives than the gas industry. For instance, in an early 1950 case before the Illinois Commerce Commission, an executive of Commonwealth Edison Company noted the existence of 29 different formulas for the apportionment of demand costs. The application of these formulas produced drastically different cost assignments to the several service classifications.   As a result, the Illinois Commission refused to direct that the utility present such evidence. The NARUC published in 1955, through its Engineering Committee, a detailed discussion of 16 such methods.

The multiplicity of available methods (which in fact reflects the insoluble nature of the problem) has led many recognized experts to express grave doubts about the efficacy of cost of service analyses.

The most commonly used demand allocations for natural gas distribution utilities are the coincident demand method, the non-coincident demand method, the average and peak method, or some modification or combination of the three.

b. Coincident Demand Method

In the coincident demand (peak responsibility) method, allocation is based on the demands of the various classes of customers at the time of system peak. This method favors high load factor customers who take gas at a steady rate all year long by assigning the greater percentage of demand costs to lower load factor heating customers whose consumption is greatest at the time of the system peak. Generally, interruptible customers would receive no allocation of demand costs under this formula since they should be off the system during the peak period. The demand component of the cost of gas is generally allocated on a coincident demand method.

c. Noncoincident Demand Method

This method would result in all classes of customers being allocated a portion of system cost based upon their actual peak, regardless of the time of its occurrence. This method assigns cost to customer classes such as interruptibles, and thereby reduces the costs allocated to the heating customer under the peak demand method. The demand related portion of distribution mains and transmission mains are commonly allocated on a noncoincident demand method.

d. Average and Peak Demand Method

This method reflects a compromise between the coincident and noncoincident demand methods. Total demand costs are multiplied by the system's load factor to arrive at the capacity costs attributed to average use and are apportioned to the various customer classes on an annual volumetric basis. The remaining costs are considered to have been incurred to meet the individual peak demands of the

various classes of service and are allocated on the basis of the coincident peak of each class. This method allocates cost to all classes of customers and tempers the apportionment of costs between the high and low load factor customers.

5. Use of Load Studies For Allocation of Demand Costs

    a. Concepts

As previously mentioned, load data are necessary for a cost of service study. These data are the basis for any demand allocation and, if inaccurate, can give misleading results regardless of the case taken with the remainder of the analysis. The load characteristics of each utility's system and each customer class on a system are unique and must be separately surveyed in each case. The purpose of the survey is to determine for relatively homogenous customer groups such information as load pattern, amount and time of occurrence of maximum load, load factor, and diversity or coincidence factor.

Arriving at load patterns is not an easy task. Most of the necessary information is not readily available from the normal record keeping of a utility. To secure the information requires a systematic activity known as load research. It embraces a whole gamut of engineering, statistical, and mathematical methods and procedures, ranging from the simple application of judgments to available data to refined mathematical probes into the significance of sampling techniques. The gas industry generally has not devoted the same resources to this area in the past as the electric industry on the whole has, so in most cases more reliance will have to be placed on use of existing records than would be preferred. However, since system peaks in the gas industry are highly weather sensitive, a fairly reliable correlation between temperature versus gas consumption can be developed from utility records. By applying a least square fit to