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March 8, 2016

BC HYDRO
2015 RATE DESIGN **EXHIBIT A2-2**

Mr. Tom Loski
Chief Regulatory Officer
Regulatory & Rates Group
British Columbia Hydro and Power Authority
16th Floor – 333 Dunsmuir Street
Vancouver, BC V6B 5R3

Dear Mr. Loski:

Re: British Columbia Hydro and Power Authority
Project No. 3698781/Order G-156-15
2015 Rate Design Application Module 1

Commission staff submit the following document for the record in this proceeding:

Principles of Public Utility Rates, Second Edition
James C. Bonbright
Albert L. Danielsen
David R. Kamerschen
1988

Yours truly,

Laurel Ross

/nd

Enclosure
cc: registered interveners

Principles of Public Utility Rates

Second Edition

by
JAMES C. BONBRIGHT
ALBERT L. DANIELSEN
DAVID R. KAMERSCHEN

with assistance of
JOHN B. LEGLER

Public Utilities Reports, Inc.
Arlington, Virginia

and acceptability. However, the sequence in which the ten attributes are presented is not meant to suggest any order of importance. Moreover, there is, perforce, some inconsistency and redundancy in any such listing. We are simply trying to identify the desirable characteristics of utility performance that regulators should seek to compel through edict.

Revenue-related Attributes:

1. Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety.

2. Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.

3. Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers and with a sense of historical continuity. (Compare "The best tax is an old tax.")

Cost-related Attributes:

4. Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).

5. Reflection of all of the present and future private and social costs and benefits occasioned by a service's provision (i.e., all internalities and externalities).

6. Fairness of the specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity in three

A

dimensions: (1) *horizontal* (i.e., equals treated equally); (2) *vertical* (i.e., unequals treated unequally); and (3) *anonymous* (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).

7. Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).

8. Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

Practical-related Attributes:

9. The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.

10. Freedom from controversies as to proper interpretation.

Lists of this nature are useful in reminding the ratemaker of considerations that might otherwise be neglected, and also useful in suggesting important reasons why problems of practical rate design do not yield readily to scientific principles of optimum pricing. But they are unqualified to serve as a base on which to build these principles because of their ambiguities (how, for example, does one define "undue discrimination"?), their overlapping character, their inconsistencies, and their failure to offer any basis for establishing priorities in the event of a conflict. For such a basis, we must start with a simpler and more fundamental classification of ratemaking functions and objectives.

Some of these attributes in the aforementioned list are based directly on the primary functions of public utility rates first presented in Chapter 4, and the related objectives to be sought in the establishment of a cost-based standard of ratemaking (Chapter 5). These objectives provided the basis for development of the criteria of a fair return (Chapter 10). These same objectives, derived from the four primary functions, can now be used to specify the criteria of a sound rate structure discussed in the following section.

The Primary Criteria Are Based on the Objectives of Regulation

General principles of public utility rates and rate differentials are necessarily based on simplified assumptions both as to the objectives

common instead of joint and in this event, the marginal cost of A *may* include an identifiable part of the common costs. This situation is widespread in the public utilities and in industry in general" (Kahn, 1970, p. 78). If the commodities produced in common have calculable marginal production costs, it must be possible at least in the long run to vary their proportions within the range of economic feasibility (Marshall, 1921, pp. 389-390). Kahn (1970, p. 79) puts it this way:

> If then the proportions are effectively (that is, economically) variable, one can unequivocally identify as the marginal cost of any one product the addition to the total cost of the joint production process occasioned by increasing the output of that one product, while leaving the output of the others unchanged. When instead the products are truly joint, in that they can be economically produced only in fixed proportions, neither of them has a genuine, separate incremental cost function, as far as the joint part of their production process is concerned.

Kahn goes on to show that the economically efficient solution in the case of joint supply which is pervasive throughout the public utility sector involves equating the price of each joint product to its marginal opportunity cost.

CONCLUSION

Having provided this shopping list of limitations, does this change our strong endorsement of marginal cost pricing as a starting point in the establishment of public utility rates? No! We share completely the opinion of one of the theoretical fathers of marginal cost pricing in public utility ratemaking, Vickrey (1955, p. 620), when he states:

> One may, for various good and sufficient reasons, hesitate to embrace marginal cost pricing in all of its ramifications as an absolute standard. But no approach to utility pricing can be considered truly rational which does not give an important and even a major weight to marginal cost considerations. And when adequate weight is given to such consideration, important changes in present pricing practices will be indicated in many areas.

B

Any regulatory economist who makes an investment in human capital on the economics of marginal cost pricing — whether it be short-run or long-run — will be able to amortize it quite rapidly.

community, that must interfere with an unbiased appraisal of the relative merits of the two forms of organization from the standpoint of the nation. Our opinion is that the weight of the argument favors attempts to put publicly and privately owned electric power systems more nearly on a par, taxwise, by a combination of a heavier public tax load and a lighter private tax load. But this is not a book on public utility taxation or on public ownership, and the questions raised here demand thoroughgoing separate studies.

SUMMARY

Regulatory commissions and economists in general agree that the goals for a socially optimal rate design are economic efficiency, fairness, and adequacy. (Portions of this summary are drawn from Kamerschen, 1986). A principal conclusion that can be derived from socially optimal ratemaking principles is that top priority for efficient pricing mandates that prices in general should be based on costs and in particular that a marginal cost standard is most appropriate. Put differently, first-best socially optimal ratemaking dictates that differences in rates generally should be based on differences in costs (i.e., cost of service) rather than on differences in demand (i.e., value of service). But this theoretic standard may need to be tempered by such practical considerations as measurement difficulties. In fact the problem of translating abstract theory to practical application is probably the major reason that the U.S. has lagged behind France and England in employing marginal cost pricing. Marginal cost measurement is still partly an art with judgment calls. If these measurement problems become severe, a case can be made for an embedded cost approach (see Chapter 19). Any cost based approach to pricing is better than pricing without regard to costs. A value of service standard is called for only in a second-best world where the cost approach produces an abundance or a paucity of revenues to satisfy the revenue requirement (see Chapter 20). A second level of priority needs to be given to such criteria as stability and predictability of rates and revenues. An embedded cost approach if followed consistently would probably yield the most stable rates, but it would not provide accurate pricing signals.

We believe that it is virtually impossible to exaggerate the importance of marginal costs — i.e., the *change* in total costs resulting from a *change* in output as from changing the volume of kilowatt-hours (kwh) of electricity or therms of gas or message-minutes of telecommunications, or of changing the kilowatt of capacity, etc., — in socially optimal ratemaking. Long-run marginal costs are the

additional costs of providing a service — both the additional operating expenses, customer costs, and the cost of any additional construction, including a return on the rate base. Since the most efficient generating units (usually consisting of a fuel supply system, a burner, a boiler and generator) in a typical multiunit plant are only available in large lumps (e.g., 900,000-KW), the practical measure is incremental costs when plant is changed by the unit sizes actually employed. In electric ratemaking, the marginal costs need to be calibrated for all of the service including the provision of *energy* over a period of the time, *customer* access to the system, and the accomodation of peak energy *demand* at a given point in time. It is also important to emphasize that marginal costs are both causal and avoidable. If demand increases, the increase in costs is *caused* by the increase in output. If demand decreases, the concomitant decrease in output causes a reduction or *avoidance* of certain costs. The correct prices must be based on the correct marginal costs if maximum economic efficiency is to be attained.

While whether rates should be based upon short-run or long-run marginal costs is a dilemma, we support flexibility in selection depending on the constraints and assumptions. In general, but with notable exceptions, we prefer the long-run version as the appropriate standard, despite the greater task of measurement and the sometimes unrealistic assumption as to rapidly and continuously adjusting capacity. The argument in favor of the short-run period centers on the belief that rates should be determined by the current cost of providing the service and that plants are indivisible, irreversible, and durable. The goal is to discourage consumption when present capacity is inadequate to satisfy a utility's demands. The argument for long-run version is based on the conviction that a rate level and rate structure should be as stable (and predictable) as possible. Under short-run marginal costs, rates would change rapidly as the volume of output changes, which in turn would burden the regulatory commissions. Moreover, consumers often consider long-run anticipated rates when choosing between substitute services (e.g., gas vs. electric ranges). But in certain circumstances — e.g., unintentional overequipment, a lumpy investment, unimportance of rate stability, etc. — short-run marginal costs are preferred. In short, asking us to pick between long-run and short-run marginal costs is like asking whether we find Kathleen Turner or Cybill Shepherd more attractive.

What items should be included in the marginal cost calculus? Marginal cost pricing mandates time of use or peak load rates since marginal costs vary at different times of the day and perhaps of the year. However, it is important to recognize that time of use considerations are also relevant when embedded costs are employed. That

is, marginal cost pricing requires time of use pricing, but time of use pricing can be justified under average costs, embedded costs, or fully allocated costs as well as marginal costs.

Clearly, peaking is relevant to the proper calculation of marginal cost. Peaking exists whenever there is a systematic or recurring (or stochastic) cycle on a daily, weekly, or seasonal basis in the demand for electricity. While significant peaking problems exist in all public utilities, the most important peaking problem for most electric companies is the recurring cycle of summer peak demand. The generation, transmission, and distribution systems have been built to serve peak demand. During off-peak periods much of this capacity is idle. When peak demand determines the needed capacity, the marginal cost of serving peak demand is higher than the marginal cost of serving off-peak demand. In the long run, peak demand usage presses against the capacity of the system and both operating *and* capacity costs are higher. Off-peak demand usage usually does *not* press against the system capacity, so only operating costs need be considered. Thus, capacity costs are primarily caused by the peak user. Moreover, the energy cost produced during peak periods is generally higher than the cost during off-peak periods in the case of electricity. In short, prices based on marginal costs should be greater during peak periods. Because an electric company must size its system to meet the peaks, any peak period user is contributing to the peak, regardless of its off peak usage. Thus, all peak users contribute to the peak and all nonpeak usage is irrelevant. Whether it is difficult for the large customers to react to peak rates by changing load patterns is also not relevant. The benefit/cost ratio is the criteria for utilization of peak tariffs for any class of customers.

Peak tariffs for some large power and special contract customers are not necessarily discriminatory. Only tariffs based on pricing programs which do not follow costs are discriminatory. Costing periods by time of day and season are an important feature of a commission's attempt to send proper price signals for the efficient use of electricity. Except for practical constraints, the finer the time period definition the more precise the price signal can be.

To the extent that prices differ from the marginal cost of producing, selling, storing, and delivering service (with due allowance for risk and uncertainty), they are discriminatory. Therefore, a good working rule is that rates should deviate as little as possible from marginal costs, if the utility's revenue requirement is met.

Time of use tariffs are efficient because they are put on cost causers. While it is true that large power users can and will alter their loads in response to time of use tariffs, this is irrelevant to the cost-

tracking purpose of the tariffs. Economic efficiency simply dictates that consumers should be faced with prices reflecting the true costs they impose on society regardless of how they choose to react to these tariffs.

There is no question that the utilization of time of use tariffs is a cost/benefit question since hourly, but not necessarily seasonal, time of use rates require a significant investment in metering equipment. The benefits are derived from the efficiencies generated by tariffs which reflect true costs; the costs are the additional metering expenses needed to record time of use usage as well as the other administrative costs associated with a more complex rate structure. Microelectronic metering technology is changing so rapidly that many rate structures previously considered prohibitively costly if not impossible to implement are now, or soon will be, economically feasible.

While some departure from marginal cost pricing is necessary in the possible, but not inevitable, event of a underecovery of revenue, economic efficiency mandates that we depart from strict marginal cost pricing so as to generate the least distortion or the least damage in terms of welfare losses. The least distortive or damaging way of departing from marginal cost pricing is to first raise the relatively price inelastic customer charge above marginal costs. If this still results in deficient revenue, the charge for the early blocks of usage should be raised above marginal costs until the revenue constraint is satisfied. The result will be a declining block monthly rate structure with a relatively high customer charge. If the data and spirit are willing, a rigorous Ramsey pricing procedure is possible.

Up until about 1965, when the inflation rate was low and economies of scale were unexhausted in the electric power industry, strict marginal cost pricing would have underrecovered revenue requirements. Economic efficiency at that time called for the increasing of prices above marginal costs, first in the customer charge, and then in the early blocks of monthly usage, producing a declining block rate structure. In the 1970s and early 1980s, with inflation raising marginal costs relative to embedded costs and the exhaustion of economies of scale for the larger companies in the electric power industry, marginal cost pricing would have led to an overrecovery of revenue requirements.

Under these conditions, declining block rates were no longer economically efficient. In fact, just the opposite was required, or an inversion of the rate structure, to ensure economic efficiency. Today we are back into the situation where a declining block rate structure may be justified on grounds of economic efficiency. The theory has not changed, but economic conditions have.

One implication of marginal cost pricing is that industrial customers are entitled to lower rates than residential ratepayers to the extent that (marginal) costs of service are lower. Thus, the customer is entitled to metered service to the extent possible using modern metering technologies, with due consideration given to customer classes and metering costs. For instance, the lower cost-to-service customer is entitled to measured service. The customer is also entitled to seasonal price differentials and time-of-day pricing for electric service.

All state commissions and larger publicly owned utilities are required under the 1978 Public Utility Regulatory Policies Act (PURPA) to consider the feasibility of a variety of what were previously unconventional rate structures, including time of use rates. The irony is that declining block rates may be economically efficient and should be implemented now, while those drafting PURPA envisioned marginal costs greater than average costs and increasing block rates.

PURPA made ratemaking for electric companies a national standard. (This section draws on the thoughtful analyses of Partridge, 1979; Renshaw and Renshaw, 1979; Olsen and Leininger, 1980; Berg, 1981; Journey, 1981; Austin and Stutz, 1983; and Steiert, 1985.) The purpose was to: (1) make efficient use of facilities and reserves by having rates reflect to the extent practical the costs to supply each user with time of use (daily and seasonal) differentials; (2) conserve energy by mandating that rates should not decrease as consumption increases unless cost justified and requiring that load management and commercial and industrial interruptible rates techniques be made available to users; and (3) make rates equitable.

INTRODUCTION

Writers on the economic principles of public utility rates have suggested that, when the rates of any given utility enterprise must be made to cover total costs of production even though the enterprise is operating under conditions of declining unit costs, each individual rate should be made up of two components: a minimum rate set at the marginal cost of the service, and a surcharge or quasi tax designed to contribute some appropriate share of those additional revenue requirements which would fail to be covered if all rates were held down to their minima. While even the surcharge would not be independent of marginal cost, its relationship thereto would not necessarily be a simple one and might well be deliberately biased by value-of-service considerations. The same idea is implicit in the more popular but cruder assertion that public utility rates should be set somewhere between cost of service (that is, marginal costs) as a lower limit and value of service (that is, what the traffic or market will bear) as an upper limit.

General Use of Fully Distributed Costs

In actual practice, however, rate structures are seldom built up in this two-step manner. Instead, they are derived from apportioned total costs of service. Thus, with an electric utility company, the analyst may first distribute total annual costs among many classes of service, more or less: residential, commercial, industrial power, street lighting, etc. The analyst may then redistribute the costs of each class among the units of service within this class, distinguishing among customer units, energy units (kilowatt-hours), and maximum-demand units (kilowatts). The first apportionment is supposed to indicate the aggregate revenues that would be due from each class of service if rates were to be based solely on costs of production. The second apportionment is supposed to serve as a guide to the determination of the pattern of each class rate — a pattern that may be composed of a minimum monthly charge per customer, a set of declining block-energy charges, and (for larger consumers) a set of declining block-demand charges.

Even those experts who make and defend these apportioned total costs in rate cases before public service commissions or courts seldom, if ever, offer them as final measures of reasonable rates and rate relationships. Instead, they concede that rates which deviate substantially from the cost apportionments may be justified by a variety of noncost considerations. This concession goes to the point of recognizing

the validity and compensatory character of competitive or promotional rates, such as one for large industrial power, which fail to cover the very costs which the analysts have imputed to the class of service in question.

Some Problems with Their Use

But there remains the question what, if any, significance should be attached to these fully distributed costs even as guides, or even as points of departure for rate determination, in view of the admitted fact that they fail to mark the dividing line between compensatory and noncompensatory charges for particular classes or quantities of service. And to this question the customary answers are woefully inadequate. The reply most frequently offered is that cost of service is only one of several factors to be considered in rate-structure determination. But this assertion, while quite valid, is also quite beside the point. For the question at issue concerns the doubtful meaning and significance of apportioned total costs and not the weight to be given to a clearly defined specific cost as a basis of ratemaking.

Mindful of the widespread failure of the cost analysts themselves to supply a really satisfactory answer to this critical question, and mindful also of the notorious disagreements among the experts as to the choice of the most rational method of overhead-cost apportionment — a disagreement which seems to defy resolution because of the absence of any objective standard of rationality — public utility managements and public service commissions often have denied or doubted the value of comprehensive total-cost apportionments even as useful guides to rate-structure design. Their doubt is fortified by recognition of the heavy expense and time-consuming character of any thoroughgoing cost analysis as well as by an awareness of the danger that unsophisticated participants in a rate case may be under the illusion that the apportioned costs mean what they seem to mean. Many economists would like to see the fully distributed cost concept dispatched to the museum of antiquated and irrelevant ideas.

It also may be noted that the technology now is available for a utility to make sophisticated cost-of-service studies on a microcomputer, thereby lowering the costs by reducing reliance on the mainframe modelling often done in data processing departments. This means that a utility can save time, lower filing costs, and/or increase the quality and comprehensiveness of its studies (Clark, 1985). Of course, the expenditures for personnel, and other filing costs whether internal or external, are includable. Also, the legal fees are generally recognized, if they are within reason and necessary for the performance of services

(see *PUF*, Oct. 26, 1978, pp.58-60). Legal expenditures which are nonrecurring and are for the benefit of shareholders have been excluded or have been amortized over some time frame. These cost considerations are important to the company making the decision about whether or not to incur them, but have relatively little effect on the real social cost of regulation.

The adverse or skeptical attitude of many public utility companies, public service commissions, and regulatory scholars toward fully distributed cost apportionments may well be justified. The extent to which electric companies make such apportionments for their private use, or in order to have them available if they should be demanded by a commission, is not a matter of record. But comprehensive apportionments have not been presented officially in all of the rate cases. Some state commissions such as California, New York, and Wisconsin are recognized leaders in their review of rate structures. However, despite these apprehensions, one should not condemn the procedure too hastily, for it is not devoid of at least a *plausible* rationale. What, then, is this rationale? This is the primary question for discussion in the present chapter.

Before going into any extended embedded cost considerations, we need to be mindful of three different technical concepts relating to the cost of serving different customers. (We draw on Phillips, 1984, p. 404.) The utility's *load factor* is defined as the average load divided by the peak load. This is obviously an important factor for a nonstorable and nontransferable service such as electricity. Utilities like a high load factor to spread out their considerable fixed costs. Users also have load factors defined as their average consumption divided by their maximum consumption. Utilities prefer high load customers. The *utiltization factor* is defined as the peak load divided by the system capacity. Since utilities must have some reserve capacity to meet emergencies, a high utilization factor is a double-edged sword. The *diversity factor* is defined as the sum of the noncoincidental maximum demands of a system's users divided by the maximum demand on the whole system. Because of differences in the time of use, the diversity factor is greater than one. Utilities strive for a high diversity factor. All three of these factors are interrelated (Clemens, 1950, p. 284).

FULLY DISTRIBUTED COSTS AS FIRST APPROXIMATIONS OF MEASURES OF REASONABLE RATES

Proper Approach of the Cost Analyst

Fully distributed cost analysis is of many different types, and

CONCLUSION

The previous chapters have discussed marginal and embedded costs as if they were mutually exclusive. However, as a practical matter it is feasible to use both in designing rates. For instance, according to Malko and Nicolai (1985) the Wisconsin Public Service considers and uses both embedded and marginal cost studies in the electricity ratemaking process. Embedded costs are used in the determination of customer class revenue allocations, whereas marginal costs are used to design specific rates and to determine rate relationships (e.g., peak and off-peak rates).

This chapter began by raising the question what, if any, significance should be attached to fully distributed cost apportionment as points of departure for public utility ratemaking. As a provisional answer, it suggested that the significance must lie in whatever claim can be made for the apportioned costs as indices, not of absolute costs but of relative differential or incremental or marginal costs. It then distinguished two types of full-cost apportionment, the double-step (or "railroad") type and the single-step (or "public utility") type, and proceeded to give major attention to the latter. A tentative opinion on the merits of this second type is now in order.

In our opinion, these merits are so dubious that they fully justify the skepticism with which utility cost analysis has been received by public utility companies and public service commissions. The basic deficiency of this analysis lies in its failure to distinguish between actual cost finding and mere cost apportionment — between those costs that can be imputed to specific classes or units of service by differential cost analysis and those other costs that should be deemed unallocable from the standpoint of cost determination even if they are somehow apportioned as a provisional step in rate determination. This failure seems critical.

Among the more specific deficiencies of the typical fully distributed cost analysis of the public utility type, three seem especially serious. In the first place, the capacity costs or demand-related costs are usually derived from book values of plant and equipment that reflect sunk costs in dollars of original investment, not costs that can be said to vary, except in a very indirect way, with present and future increases in plant capacity. In theory, this particular objection might be met by the use of appraised current values of the utility plant and equipment rather than by the use of book values. But if the appraised values were of no better quality than the fair values that are accepted as

measures of the rate base in states applying a fair-value rule of ratemaking, their advantage over book values would be dubious.

In the second place, cost analysts, faced with the necessity of apportioning all of their costs among three (or four) arbitrarily selected functional-cost categories, face dilemmas such as that noted in the section of this chapter on customer costs. They are therefore bound to be impaled on one horn of a trilemma; and one may suspect that they would choose whatever impalement they believe to be less harmful in its consequences for sound ratemaking in view of noncost considerations.

And in the third place, most analysts, unwilling to follow the implications of joint-cost and byproduct cost analysis in their treatment of demand-related costs, accept some compromise formula of apportionment, such as one which imputes capacity costs in proportion to noncoincidental maximum class demand. Here, too, one may suspect that the choice of the formula depends, not on principles of cost imputation but rather on types of apportionment which tend to justify whatever rate structure is advocated for noncost reasons.

What has just been stated, however, is by no means meant to imply that cost analysis is useless for ratemaking purposes. On the contrary, it is utterly essential that demanders and suppliers bear the cost consequences of their decisions. But the really important analyses are not those which attempt to apportion total capital and operating costs among the different classes or units of service. Instead, they are the analyses designed to disclose differential, or incremental, or marginal, or escapable costs — costs which are not ordinarily derivable from total costs and which cannot be added together so as to equal this total under conditions of decreasing costs.

It is these costs which should be the primary object of study of the utility cost analyst. Whether or not, in addition, some kind of apportionment of unallocable cost residues is also worth making is a secondary question, on which we venture no present opinion.

In short, then, a thorough reexamination of the whole philosophy of modern public utility cost analysis has long been overdue. If this country were Great Britain, the appointment of a governmental commission to make such a reexamination would be called for. We recognize that, even within an embedded cost of service approach to ratemaking, more innovative ratemaking is possible to encourage efficient use. For instance, Vierima and Malko (1981) discussed how such innovative gas pricing as inverted, benchmark, auction, and flat seasonal rates were considered for the Wisconsin Public Service Commission in the late 1970s and early 1980s. There also have been a

number of studies done of the different cost methodologies (e.g., see Malko and Uhler, 1979).

The commission would, no doubt, note that, for example, high voltage transmission lines may be used for residential, commercial, or industrial users. Since there is no conceptually correct method to assign these costs optimally to any single type of service, the ensuing arbitrary allocations may involve subsidization. According to fully distributed costs, all clearly causally related costs are assigned to a particular good or service. All other costs are arbitrarily allocated to categories on the basis of some relative measure of physical output or on the basis of maximum demand in the hopes that this will be acceptable or useful. There is no way to validate that an arbitrary noncausal cost allocation is correct (or incorrect). "Quite simply, the basic defect of fully distributed costs as a basis for ratemaking is that they do not necessarily measure marginal cost responsibility in a causal sense" (Kahn, 1970, p. 151). To make sure that no subsidies are involved, one must look to stand-alone or incremental costs under break-even conditions and not fully distributed costs.

On the other hand, Brown and Sibley (1986, Chapter 3), using the concept of the Aumann-Shapley price, show that the fully distributed costs is neither arbitrary (axiomatic) nor subsidizing under certain cost conditions (*viz.*, when the firm's joint cost function is additively separate with a fixed cost). Proponents of fully distributed costs rates claim greater practicality in data requirements over Ramsey pricing as fully distributed costs rates purportedly can ignore completely demand elasticity. However this advantage is not so clear when fully distributed costs rates are adjusted for repression (i.e. demand elasticity) as is increasingly true to avoid surpluses or deficits. In a similar vein, a NARUC Task Force (1977) suggested that the fully distributed costs approach had some advantages including: (1) elimination of revenue shortages or surpluses arising under other pricing schemes; and (2) continuity and stability of prices (see Weigel, 1983). The NARUC Task Force also opined that economists have not developed a workable consensus for defining the marginal costs of electric generation and distribution. They did indicate that the primary disadvantage of fully distributed costs was some sacrifice in economic efficiency. Once again, we see why Judge Holmes (1912) once commented that sagacious rate regulation mandates an intermediate course determined by judgement and fairness, "between Scylla and Charybdis".