Appendix 7

DISTRIBUTION COSTS B ALLOCATION AND PRICING: A BRIEF WHITE PAPER PREPARED FOR THE UTAH COST-OF-SERVICE AND PRICING TASK FORCE

by George R. Compton
Utah Division of Public Utilities

July 13, 2005

I. Topics and organization of White Paper:
   A. The issue as proposed in the 4/13/05 Cost of Service Task Force meeting
   B. Orientation and issues driving the NARUC document, *Charging for Distribution Utility Services: Issues in Rate Design*[1]
   C. Distribution system cost drivers
   D. Cost allocation implications of the cost-causing elements of the distribution system
   E. The wrongheadedness of the zero-intercept basis of distribution cost allocation and pricing
   F. Pricing implications of the distribution cost drivers and the relationship between distribution cost allocation and pricing
   G. The recommended pricing vehicle for recovering shared distribution system costs

II. The issue as proposed in the 4/13/05 Cost of Service Task Force meeting:
What is the basis for allocating distribution costs among customer classes? (Class demand? Class demographics?) What portion of distribution costs are not caused specifically by demand, per se? How should the non-demand-related distribution costs be allocated? How should the non-demand-related distribution costs be priced?

III. Orientation and issues driving the NARUC document, *Charging for Distribution Utility Services: Issues in Rate Design.* This document will be quoted liberally in this white paper. The following brief discussion will enable the readers to understand the

---

[1] The National Association of Regulatory Utility Commissioners= document authored by Frederick Weston and the Regulatory Assistance Project, funded by The Energy Foundation, December 2000.

issues forming the background for the NARUC document:

A. With the breaking up of vertically integrated utilities and the unbundling of distribution services there came a concern in some quarters that *distribution-only utilities* would attempt to recover their costs (which are almost entirely fixed) through customer charges that were pretty much uniform by customer class. To avoid that eventuality, the author sought to demonstrate how a customer=s amount of consumption contributed to the magnitude of the cost of a distribution system. Of the two primary measures of consumption, demand and energy, it is the former that correlates the most closely with distribution plant costs. The author also recognized geographic and demographic factors B not just demand -- as often contributing even more heavily to distribution costs. As the quotations will show, the NARUC document=s author, if anything, seems to favor energy charges over demand charges for the recovery of distribution costs.

IV. Distribution system cost drivers:

A. NARUC document quotes:

1. ADistribution investment can make up anywhere between ten and forty percent of a vertically-integrated utility=s costs, depending on the demographic, geographic, and other cost (in particular generation) characteristics of the company.@ [p.10]

2. AAnother dimension of cost, and perhaps most revealing, is the geographic. There are several aspects to it. First are the topographical and meteorological characteristics of the area over which the distribution system is laid. Elevations, plant life, weather, soil conditions, and so on all have effects on costs. So too demography, which is captured partly by demand and numbers of customers, *but also affecting costs is the density of customers in an area (sometimes expressed as customers per mile)* [emphasis added].@ [p.36]

3. AThe question is whether there is some amount of capacity in excess of the minimum needed to meet peak demand that can cost-effectively be installed. The additional capacity B larger substations, conductors, transformers B will reduce energy losses; if the cost of energy saved is

greater than that of the additional capacity, then the investment will be cost-effective and should be made. For the purposes of cost analysis and rate design, these kinds of distribution investments are rightly treated as energy-related.@ [p.32]

B. The cost-causing elements of non-customer-specific distribution costs (i.e., all distribution plant-related costs except for meters and service Adrops@) can be categorized as follows:

1. Customer demographics, e.g., density and average distance from the sub-stations. The more spread out are the customers, the greater will be the number of circuit miles to serve them and the greater will be the distribution system costs.

2. Infrastructure, i.e., rights-of-ways, power poles/conduit/trenches (with ancillary equipment) and their installation and maintenance costs. The as-installed cost per lineal foot or circuit-mile of right-of-way, and of pole lines, of conduit, and of trenches, and the relative contribution of those three primary structural elements to the total mix, establishes the average infrastructure unit-cost of the distribution system.

   a. Rights-of-way costs and infrastructure installation costs are a function of real estate costs and the physical topography (e.g., mountains or flat lands, swampy or dry, etc.).

   b. A distinguishing feature of the infrastructure is that in that it is overwhelmingly shared. As with streets, sewer systems, and other elements of a town or city=s civil infrastructure, most of the electric infrastructure can=t be identified with individual consumers but are utilized in some communal fashion.

3. Voltage/capacity. The higher the gauge of the wires used to serve the loads, the higher the cost of those wires. As with transmission lines, distribution line costs are directly proportional to the distance traversed. But while there is also a strong correlation between transmission unit costs and voltage levels (with the larger voltages requiring taller and more expensive towers), a single distribution pole line, for example, can serve anywhere from one to hundreds of residential customers. In other words,

there is a smaller correlation between costs and voltages or customers served with distribution systems than there is with transmission systems.

4. Conclusion: The three primary drivers of distribution costs are the customer demographics, unit infrastructure costs, and average voltage capability. The last item of the three is probably the least determining.

   a. Referring to the quoted observation that distribution costs can range from ten to forty percent of total costs, one might infer that the fourfold increase in the percentage share can=t be attributable to much greater customer-average kW demands, but rather to differences in geography and demographics. Example: My residential subdivision in Alpine consists of lots that average 3/4 acres. The infrastructure is trenches. The distribution cost savings had the Power Company built for half the average household kW loads, or the added costs had the Power Company built for twice the average household kW loads, would have been minimal. The greater drivers of the average-per-customer distribution costs in my neighborhood were the size of the lots and the decision to use trenches rather than power poles.

V. Cost allocation implications of the cost-causing elements of the distribution system

A. As just described, the primary distribution cost drivers are demographics, voltage demand or capacity requirements, and the supporting infrastructure (e.g., rights-of-way, and the purchase and installation of power poles, conduit and trenches). The first item has almost nothing to do with capacity, and the third item has little to do with capacity. With demand, or capacity, being only one B and perhaps the least consequential B of the three major cost-causing elements that drive distribution costs, one would not expect distribution costs to be allocated solely on the basis of demand.

B. On the basis of their lower neighborhood densities and greater average distances from the substations, one would expect that the residential class would receive a larger allocation of distribution costs relative to their loads/demands than would the commercial classes. Offsetting the density/distance factor with regard to residential costs versus commercial costs might be the fact that unit infrastructure costs are higher in urban centers (where the commercial customers are more heavily concentrated) than in the suburbs.

1. PacifiCorp-Oregon has recognized the differential in average distances from substations in establishing the classes= distribution cost allocations.
2. In the late 1970s in Utah, Mountain Bell=s rural customers paid Aurban zone@ monthly surcharges in recognition of the greater costs to extend their access Aloops@ outside the urban areas.[2]

C. The most plausible justification for the practice of allocating distribution costs among customer classes primarily on the basis of relative demand is its ease of administration. Oregon=s experience notwithstanding, easily quantifiable and unambiguous demographic measures by which distribution costs might be allocated are not always readily apparent.

VI. The wrongheadedness of the zero-intercept basis of distribution cost allocation and pricing

A. NARUC document quote: AThe zero-intercept method [also known as the minimum-system method] attempts to model a system that has no demand-serving capability whatsoever, but what remains is not necessarily a system whose costs are driven any more by the number of customers than it is by geographical considerations, whose causative properties are neither squarely demand- nor customer-related.@ [p.31]

B. Some time ago the industry=s costing/pricing analysts observed that even if the existing distribution system=s Awires@ actually contained no metal/conductivity (which would constitute the zero-intercept, where distribution costs are graphed as a function of voltage/capacity, starting with zero voltage and working up), there would still be a lot of costs involved B e.g., for rights-of-ways, power poles, cross-arms, insulators, etc. While the positive-cost, zero-intercept observation is entirely correct, many zero-intercept devotees got into trouble because they didn=t

[2] The then-affiliate to AT&T, Mountain Bell, was one of Qwest=s predecessor companies.

think beyond the conventional energy-demand-customer tri-part utility costing classifications. With no conductivity built into the system, it clearly would incorporate no demand or energy costs. The conclusion then reached was that this substantial residual share of distribution costs must B by elimination of the other two cost classifications B constitute customer costs.

C. The implication for cost allocations was that the distribution costs should be allocated in proportion to the customer count (i.e., if residential customers constitute 95% of the number of customers of a utility, that class should pay 95% of the non-customer-specific distribution costs). The implication for pricing was that the distribution costs B again as customer *costs* -- should be collected via flat-rate (i.e., without regard for individual consumption levels) customer *charges*. The latter would typically yield something in excess of $20 per month.

D. The erroneous assumption behind the zero-intercept pricing and costing policy conclusion is that there can only be the standard three cost classification categories B demand, energy, and customer. It is not unreasonable to regard Acustomer costs@ as applying narrowly to costs that can be identified with specific customers. (The Utah Commission did that in designating what costs are allowed to be recovered in the customer charge.[3]) Having ruled out demand and energy as cost bases of the minimum distribution system, and having limited the customer costs portion, the previous discussion should suggest powerfully a fourth cost basis for the zero-intercept, or minimum distribution system. It is Ademography/ infrastructure.@ I would suggest a particularly strong justification for placing the shared portion of the minimum system (which is almost all of it) in this fourth cost classification category.

    1. The existence of a fourth *costing* category does not necessitate the creation of a fourth *pricing* category. Insofar as inter-class demographic/ infrastructure cost differences are recognized, such can be reflected in the pricing structure by augmenting any one, or a combination of two or three, of the standard basic rate elements B i.e., beyond the levels that would reflect unambiguous demand, energy, or customer costs.

[3] Report and Order in Docket 84-035-01, dated July 1, 1985.

VII. Pricing implications of the distribution cost drivers and the relationship between distribution cost allocation and pricing

A. NARUC document quote: ATоo great a dependence on cost studies is to be captured by their underlying assumptions and methodological flaws. Utilities and commissions should be cautious before adopting a particular method on the basis of what may be a superficial appeal. More important, however, is the concern that a costing method, once adopted, becomes the predominant B and unchallenged B determinant of rate design.@ [Pp 6-7]

B. We have observed that the bulk of the costs for the minimum distribution system are for the shared infrastructure. The two primary mechanisms for recovering the costs of the shared infrastructure in the civic sector (e.g., highways, local streets and sewage systems) are direct or indirect user fees (e.g., gasoline taxes) and taxes, per se (e.g. property taxes). The latter reflects more the notion of ability-to-pay than benefits-received.

C. Paying for shared electrical distribution infrastructure via the customer charge has been largely, and appropriately, rejected by utility regulators. It would be the equivalent of a governmental head, or poll, tax B reflecting neither ability-to-pay nor benefits-received.

D. While tax subsidies based upon an ability to pay may underwrite a portion of the costs of municipal utility systems, recovering the costs of privately owned utilities on the basis of an ability to pay is not practically feasible, even if it were desirable. That leaves benefits-received B by way of usage fees B as the appropriate vehicle for recovering the utility=s shared infrastructure costs.

E. The single best measure of benefits received from an electric utility is energy consumption. At the least, it should be clear that if the shared infrastructure costs were recovered entirely on the basis of demand costs rather than on the basis of energy costs or a combination of energy and demand costs, that there would be a failure to fully connect revenues with benefits received.

1. Example: Consider two retail entities that are identical in every respect except that one operates 24-7 while the other operates for ten hours per day, six days a week. Assume that the basic customer, energy, and

demand charges cover the full plant and operating costs of generation and transmission as well as the explicit customer-, demand-, and energy-driven costs of the distribution system. Would it make sense for the two customers to pay the same amount towards the cost of the distribution Aminimum system@ when the 24-7 customer uses more than twice the amount of energy as the other customer? Such would be the case if the minimum system costs were collected entirely from the demand charge. The 24-7 customer is obviously receiving more benefits from the shared system. ***In a word, it is clear that if the benefits-received objective is to be achieved in this context, then a portion of the minimum system costs must be borne by the energy charge as well as by the demand charge.***

VIII. The recommended pricing vehicle for recovering shared distribution system costs.

A. NARUC document quotes:

1. AVolumetric, energy-based unit prices *for distribution services* [emphasis added]...are the preferred approach. This is particularly true for lower-volume consumers. Such rates promote long-run economic efficiency and are fair.... For larger[-]volume customers, a multi-part price structure that differentiates between demand-related and energy-related costs will work, to the extent that, as with energy-only pricing, customers pay only for what they use *and that, as their consumption changes, so do their bills* [emphasis added]. [p. 7]

2. AIt is not enough to assert a principle of economics to justify a particular rate design. Economic efficiency is an important consideration when structuring rates, but it is by no means the only one, or even the foremost. Fairness, rate stability, revenue stability, administrability, non-discrimination, and environmental protection are equally significant, and regulators often have to find ways to reconcile these sometimes competing goals.@ [p. 6]

B. The recently concluded PacifiCorp general rate case culminated in price increases that averaged approximately 4.4%. With two major exceptions, roughly that percentage was applied to all of the tariffed rate elements.[4] One of those exceptions was the residential customer charge, which remained at $0.98 per month. The other exception was the Schedule 6 (large commercial) energy charge, *which actually declined* -- but with a Acompensatory@[5] larger-than-average increase in that schedule=s demand charge. This exception allowed very high load-factor customers to experience a billing increase of between one and two percent while low load-factor customers experienced an increase that was above 5% (and as high as 6.5% in the summer).

1. The primary justification given for shifting partial distribution cost recovery away from the commercial class energy charge and placing it almost entirely on the demand charge was that distribution costs are allocated among customer classes on the basis of demand. A related justification was that PacifiCorp is more capacity constrained than energy constrained, and that the demand charge sends more of a capacity pricing signal than does the energy charge.

    a. Net revenue stability is a regulatory objective whose support for demand rather than energy charges was not brought up in the rate case=s pricing discussions. It=s my impression that monthly peak demands are more constant on a year-to-year basis than are customers= energy usages. (The latter is affected by the weather and, in the industrial sector, by how long major electricity-consuming equipment is operated, not whether or not it is operated at all.) Accordingly, this objective will tend to encourage greater infrastructure cost recovery via the demand charges rather than the energy charges.

[4] The exceptions were requisites for the endorsements by two of the parties of the stipulation which settled the case.

[5] It was compensatory in the sense that the desired level of revenues from the rate schedule could be achieved despite the reduced energy charge. But the effect on individual customers within the schedule was rarely neutral. There were major winners and major losers, depending upon the customer=s load factor.

2. There are a number of arguments against the demand-to-energy, distribution cost recovery pricing shift.

   a. There is no immutable law of regulatory economics that says that there must be a one-to-one correspondence between costing and pricing structures. With the Utah residential price structure, for example, demand costs as well as most customer costs B along with the energy costs B are recovered via the cents-per-kWh energy charge(s).

   b. Because the Schedule 6 demand charge is not time-of-day based, and even if it were, because there is no demand charge incentive to reduce prospective peak period demands once the month=s peak had been reached, demand charges are regarded as relatively ineffectual in discouraging peak period consumption. The price signal effects of high energy charges are always in place.

   c. In the context of a general rate increase, to give some customers within a rates class a much larger increase than is placed upon others is considered a major breach of utility regulatory protocol. Referring back to the listed regulatory objectives regarding pricing, the described Arearranging@ of the demand and energy charges is a flagrant violation of the rate stability and gradualism goal. Allowing high load factor customers to pay little or nothing more for the distribution system than would customers with the same level of demand but with much lower consumption levels also violates the fairness objective. Finally, shifting the pricing away from the energy charge also subtracts from the environmental/ conservation objective.[6]

C. It is the Division=s recommendation that pursuant to the next general rate case that a zero-intercept, or minimum-system, study be conducted for the purpose of ascertaining what share of the distribution system costs are *not* demand related.

[6] That objective has been employed as justification for using the energy charge to collect most of the narrowly defined residential customer costs.

That knowledge should illuminate our policy deliberations regarding what portion of the distribution system costs should be recovered through the demand charge and what portion should be recovered through the energy charge.

1. Partly to move us back closer to the status quo ante, it would be my personal recommendation to collect at least half of the costs that are not directly attributable to demand through the energy charge.
2. The Division sees no compelling need at this time to alter the mechanism (i.e., class non-coincident peak demand) by which distribution system costs are allocated among customer classes.