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# Electric Utility Restructuring, Regulation of Distribution Utilities, and the Fallacy of "Avoided Cost" Rules

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**Abstract**
We show that commonly used "avoided cost" rules, which evaluate investment alternatives by comparing their costs to forecasts of future expected cost, are fundamentally flawed for choosing local area investments in distribution capacity. Use of avoided cost rules: 1) confuses cost-effectiveness tests with benefit-cost tests; 2) makes inappropriate marginal comparisons and violates necessary optimality conditions because of the "lumpy" nature of many distribution system investments; 3) fails to incorporate the effects of uncertainty properly; 4) necessarily leads to excess deferral of traditional distribution capacity investments with distributed generation and DSM investments; and 5) does not lead to lowest expected cost investment plans. We conclude by outlining a more appropriate approach to evaluating distribution investments based on evaluations of actual cash flows associated with investment alternatives under uncertainty.

## 1. Introduction

As the electric utility industry is gradually restructured towards a market providing direct retail choice of electric energy suppliers, state utility regulators will necessarily concentrate on local distribution utilities that provide access to regional power grids. These regulators will no longer focus on utility acquisition of generating assets to meet customers' demand for electricity; instead, they will likely focus on developing rules for distribution system planning and investment, to ensure that local distribution utilities (LDCs) meet what can be characterized as an "obligation to connect." [1]

1 In this paper, we will not consider post-deregulation energy resource issues, such as mandated air

This new regulatory focus on distribution utilities already is leading to development of distribution integrated resource planning (DIRP) rules that will compare alternative distribution system investments.[2] In some cases, regulators have already focused on acquisition of such resources as an alternative to increasing "traditional" local area capacity investments in new "poles and wires" by applying avoided cost rules to determine "correct" amounts of alternative distribution investments that will defer the need for traditional ones.

Methodologies to estimate utility avoided costs were initially developed to determine the payments that utilities were required to make to qualifying independent power generators and small power producers under the 1978 Public Utilities Regulatory Policy Act (PURPA). The original intent was for these avoided costs to represent a utility's incremental cost for alternative energy supplies (Yokell and Marcus 1984). Subsequently, avoided costs became the basis for evaluating other utility acquisitions, especially DSM and renewable energy resources (Tellus 1995; Busch and Eto 1996). Past practice determined avoided costs on the basis of predictions about future fixed and variable costs of an assumed energy generating plant (e.g., a gas-fired combustion turbine), plus marginal costs associated with transmission and distribution investments. In some cases, other social costs, such as environmental externalities, were also incorporated (Tellus 1995).

To the extent that regulators focus more on local distribution capacity investments in the future, using traditional avoided-cost rules to evaluate the value of such investments will suffer from four major problems:

1. Avoided cost rules confuse cost-effectiveness with optimality;
2. Avoided cost rules make inappropriate marginal comparisons;
3. Avoided cost rules either defer traditional distribution capacity investments too long or too little, but never the correct amount; and
4. Avoided cost rules do not incorporate future uncertainties, particularly uncertainty about future local distribution capacity demand.

In the next section, we present a brief description of how standard avoided costs are calculated, focusing on *why* they have been used. In Section 3, we show how avoided cost rules are flawed in the context of determining least-cost distribution expansions. In Section 4, we outline what we believe to be a better approach based on actual investment cash flows and a rigorous treatment of uncertainty. Lastly, Section 5 offers some conclusions and recommendations.

## 2. Why Avoided Cost Rules?

### 2.1. A Brief Review of the History of Avoided Cost Rules

The Public Utilities Regulatory Policies Act of 1978 (PURPA) required utilities to interconnect with non-utility generators in order to promote the utilization of waste and renewable fuels and cogeneration processes for increasing electric power supplies. These non-utility generators were to be paid on the basis of generating costs that the utility was able to avoid by using the energy provided by them.[3] The application of the method has not

pollution limits and renewable resource portfolio requirements, that have arisen in restructured electric markets such as California and Massachusetts, nor existing facilities siting regulations.

2 See Tellus (1995), especially Section VII.4. See also VDPS (1997, Appendix 4).

3 PURPA rules and regulations are reviewed in Devine (1987). This paper also raises important issues

been without controversy, and many rulings were appealed (Betts 1982; Cole 1983; Einhorn 1985; Randazzo 1995).

The Federal Energy Regulatory Commission (FERC) ruled that "[U]nder the full avoided costs standard, the utilities' customers are kept whole, and pay the same rates as they would have paid had the utility not purchased energy and capacity from the qualifying facility (QF)" (FERC 1981, cited in Busch and Eto 1996).[4] The FERC ruling suggests that the avoided cost standard is designed to hold rates constant or, equivalently, keep utility costs constant.

Various technology-specific applications of the avoided cost method have been presented in the literature. Examples of the kinds of analysis that are used to price QFs are found in Burns (1982); House (1983); Yokell and Markus (1984); Flaim (1985); Hoover (1985); Stirba et al. (1985); Galloway and Nielsen (1989); Shalaby (1989); and Usher (1994). This list is not meant to be exhaustive, but merely indicative of some of the work that has occurred in applying avoided costs. The literature is well populated with both practical applications and theoretical arguments. A useful summary of the different methods that can be applied to calculate avoided costs, especially for the integration of demand-side management investments, is Tellus (1995).

A reasonable conclusion to draw from this literature is that although methodologies for determining avoided costs vary from state to state, sometimes from year to year, and, even with respect to technology, the same factors must be taken into account for rate-setting using the avoided cost approach. Those factors include: 1) how much the load is affected by the addition of the non-utility supplied energy; 2) whether it is appropriate to include the effect on the timing and choice of future resource additions (the difference between short- and long-run avoided costs); and 3) how the dispatch of existing generation units is affected by the addition of non-utility supplied energy. An actual stream of avoided costs is determined such that, as noted above, ratepayers are charged the same rates they would have been charged had the purchase not occurred.

Although developing avoided costs may be an appropriate way to price the energy provided by QFs, it does not provide an appropriate guide for distribution system investment planning. The distribution investment-planning problem is fundamentally different than the QF pricing problem. Applying the same method to both problems is almost certainly inappropriate for at least one of them. The purpose of this paper is to explore why applying the avoided cost method to the distribution investment problem is inappropriate.

### 2.2. Avoided Costs for Distribution System Investment Planning: Literature Review and Theory

One of the problems that distribution planners confront is how best to integrate alternative resources, such as distributed generation and storage, renewable technologies, and demand-side management programs, into expansion plans that rely on more traditional investments such as substations and feeders. Early investigations of the impacts of such integration were made by Lee, Peschon, and Germond (1979) and Ma, Isaksen, and Patton (1979). Those studies can be viewed as two different approaches to evaluating the value of alternative investments.

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arising out of the adversarial nature of the process for negotiating or settling the avoided cost rates.

4 A slightly different definition can be found in PURPA Sec. 210, *Definitions*, cited in Tellus (1995).

Lee, Peschon, and Germond (1979) compared the costs of expanding a transmission and distribution system with and without distributed elements. Their methodology analyzed cash flows associated with actual decisions. Alternatively, Ma, Isaksen, and Patton (1979) defined a "deferral credit," which was based on deferring distribution capacity investments into the future. This deferral benefit equaled the difference between two cash flows, where the alternate investments defer or eliminate the need for planned conventional distribution investments. The present value cost difference between the original policy and the deferred policy is the deferral benefit, which thus defined is identical to the avoided cost.

The difference between these two early approaches is somewhat subtle. The deferral benefit/avoided cost results from a particular mode of integration of traditional and alternative resources: the alternative resources are used to defer or cancel (most often, defer) the elements in a traditional expansion plan.

More recent work in distribution system planning has generally followed the deferral approach, measuring benefits by assigning credits to such items as deferred generation capacity, deferred transmission capacity, deferred distribution capacity, reliability credits, and other items. Zaininger, Clark, and Brownell (1990), Shugar et al. (1991), and El-Gasseir (1991) each attempted to measure the benefits of alternative investments using such credits.

Orans et al. (1991) reformulated the distribution system analysis methodology while retaining the idea of the deferral benefit. Their contribution was to develop a methodology that defines and applies an area-specific marginal cost of distribution capacity and explicitly seeks a least-cost expansion plan by attempting to identify an optimal deferral strategy. That methodology was applied by Orans, Woo, and Horii (1994), Woo and Horii (1995), and Hoff (1996) to identify so-called cost-effective alternative investments. The notion of a cost-effective investment is based on the avoided cost provided by that investment. Indeed, the purpose of these latter approaches is to determine how valuable alternative investments are to defer traditional distribution expansion plans.

Tellus (1995, I-6), for example, states that, in order to provide an accurate assessment of the deferral benefit, an "optimal" plan must be deferred: "[A]voided costs are the net savings *over the long run* in moving from a *least-cost ('optimal') plan* in the absence of the alternative resource under consideration to a least-cost plan inclusive of the alternative resource under consideration." (emphasis in original) Although this statement seems intuitively accurate, the main idea is internally inconsistent: if an optimal base expansion plan were available, then there would be no need for an avoided cost or deferral credit evaluation, since one would already have a technique to discover optimal plans. That ought to entail the capability to identify optimal plans that included "alternative" investments. We suggest that, in the spirit of the methodology advanced by Lee, Peschon, and Germond (1979), the appropriate integration of traditional and alternative resources occurs when an entirely new expansion plan is found by using methods that identify least cost policies. It makes little sense to measure the value of alternative investments by computing how much they could delay an existing distribution capacity expansion plan if inclusion of that alternative resource would result in a completely different optimal solution to the planning problem. Yet that is the basis of the avoided cost measurement of the value of the alternative investment.

Thus, avoided costs do not necessarily measure the value of alternative investments, since the "optimal" expansion plan with the alternative investment included need not be a deferred version of the initial plan. Although this observation was made by Lee, Peschon, and Germond (1979), it apparently was not pursued sufficiently in subsequent studies. Therefore, avoided costs are inaccurate on two counts: they are neither based on deferring an optimal plan nor are they a measure of the effect the alternative investment has on optimal investment strategy. It is also incorrect to claim that avoided costs provide either a lower or an upper bound on the true value of the alternative investment. The avoided cost stream determined by deferring a non-optimal plan may be in any relationship whatever to the true value of the alternative investment. This is especially true in the presence of load uncertainty. An optimal plan must be optimal with respect to the *uncertain* load, not the expected load. Because load uncertainty will tend to be exacerbated at the local level, this point becomes more important when determining optimal local area investment strategies.

In order to illustrate other objections to the avoided cost approach, it is necessary to discuss an approach to measuring avoided costs in detail. This discussion is found in Feinstein and Lesser (1997) and is presented here in abbreviated form for completeness.

Orans et al. (1991) defined the marginal capacity cost with respect to an existing capacity expansion plan, $k_t$: $t = 1,2, \ldots ,T$, where $k_t$ is the capital expenditure in year $t$ of the plan, which has a finite horizon $T$. The argument that determines the estimate of the marginal capacity cost is the following: if a distributed investment with a lifetime of $T$ years is installed in year 1 and provides the peak-load relieving capacity $\Delta K$, then the capacity expansion plan will be delayed by $\tau = \Delta K/L$, where $L$ is the (deterministic) annual peak load growth rate. The difference in present values of the two expansion plans is denoted

$$\Delta PV = \sum_{t=0}^{T} \frac{k_t}{(1+r)^t} - \sum_{t=0}^{T} \frac{k_t(1+i_t)^{\tau}}{(1+r)^{t+\tau}}, \tag{1}$$

where $r$ is the discount rate and $i$ is the cost escalation rate at time $t$ of the existing capacity expansion plan. This is identical to Ma, Isaksen, and Patton (1979). The marginal distribution capacity cost (*MDCC*) is defined by

$$MDCC = \frac{\Delta PV}{\Delta K}. \tag{2}$$

This is precisely the avoided cost of the expansion plan, expressed in \$/kW. Woo et al. (1995, 116) write "$\Delta PV$ measures the benefit of $\Delta K$ MW of $D[R]$ capacity installed in year 1 that lasts for $T$ years,"[5] which is correct for actual, non-marginal cash flows. Thus, equation (1) identifies a non-marginal value of deferral. It is this value that is compared to the non-marginal cost of new capacity investments that contribute to such a deferral. This estimate of marginal/avoided cost will, under the conditions usually encountered in practice, over-estimate the amount of alternative investments that should optimally be installed in a local planning area compared with the least-cost solution. Using this value of avoided cost in the way it is used in practice will not yield the least-cost investment plan for a local area. On the contrary, not only will the resultant investment plan not be least-cost, but the practical application of (2) will tend to yield exactly the same cost as the original T&D expansion plan. That is, applying (2) in practice will tend to delay traditional T&D investments for as long as possible, without adding any additional costs. This is a direct consequence of the basis of avoided cost as cited by FERC (1981) and quoted above—there is no effect on

5 "$D[R]$" refers to distributed resource investment capacity.

ratepayers when avoided costs are used to price QFs When avoided costs are used to value distribution investments, the effect is the same: costs do not change. But this is not optimal. Indeed, decisions are not based on optimal choices, but rather on so-called cost-effective ones.

Hoff (1996, 98) writes that "[A]n alternative investment is cost-effective if there is a positive net present value associated with the investment." He defines a "break-even price" $P$ of an alternative investment with respect to the peak load reduction ($MD$) that it could provide in the T&D system, by the equation

$$P = (MDCC)MD. \tag{3}$$

Equation (3) provides a recipe for choosing to install an alternative investment: select an investment if the cost of the new incremental capacity investment, $W$, is less than $P/MD$ (Woo et al. 1995).

It is well known that the optimal level of investment for a continuous variable amount of investment activity occurs at the point at which the marginal benefit of an investment equals its marginal cost. The benefit in this problem is the present value of the delay of the traditional T&D expansion plan. The actual marginal cost is the present value cost of the alternative investments that induce the delay. But since both the cash flows and the deferral effects are "lumpy," derivatives are not well defined in most cases. Therefore, neither the marginal benefits as defined in (2) nor the marginal costs of the alternative investments expressed in \$/kW are marginal, even though the units—\$/kW—are correct.

If an alternate distribution investment passes the test $W < MDCC$, then the conclusion will be to add the investment to the plan and defer the traditional investments by the corresponding time, $\tau$. But these are not marginal considerations; a marginal amount of load reduction capability is not being added. Instead, an investment of arbitrary capacity is being added if it is cost-effective in the non-marginal sense, as defined by the authors cited, with respect to actual (non-marginal) changes in cash flows. It is certainly true that non-marginal, cost-effective investments that reduce the total cost can be found by applying these considerations. However, either of equations (2) or (3) permit such non-marginal additions until the change in present value of the traditional T&D plans is equal to the cost of the alternative investments. Hoff (1996) correctly calls this the break-even price, since that is exactly what happens: alternative investments are added until the non-marginal decrease in cost of the T&D plan, due to deferral, is exactly equal to the non-marginal increase in cost of the alternative investments. Clearly, if this method is implemented, the total costs do not change, and the deferred T&D investment plan with integrated alternative investments costs no less than the original T&D investment plan; deferrals merely pay for the alternative investments.

A consequence of using the deferral method, then, is that alternative investments can be used to defer traditional T&D investments for as long as possible without adding additional costs. That is what this concept of cost-effectiveness implies. But what is cost-effective is not necessarily optimal, unless the objective is to maximize the amount of deferral provided by the alternative investments, or what is the same thing, to maximize the penetration of alternate investments, beyond the point at which they are part of the optimal solution.

The fundamental reason that the solution provided by the avoided cost method is not least cost is that the avoided cost method confuses average cost with true marginal cost. This is evident from examination of equation (2). In equation (2), $\Delta PV$ is the change in present value of the cash flow stream, and $\Delta K$ is the change in capacity provided by the DSM or other investment. We show elsewhere (Feinstein and Lesser 1997) that, under commonly assumed conditions, the avoided cost deferral solution determined by application of (2) will always overestimate deferral times. Furthermore, varying some of these assumptions can lead to more perverse results, as we demonstrate in the next section.

## 3. Effects of Using an Avoided Cost Approach for Distribution Planning

Analogous with typical least-cost integrated resource planning criteria, assume regulators wish to develop a process for least-cost distribution utility (DU) planning. Thus, regulators require the distribution utility to develop a least-cost portfolio of investments that satisfy customers' instantaneous demands for electricity. The portfolio will conceivably contain investments in "traditional" engineering investments, such as new distribution circuits, substations, transformers; it may also contain "distributed" investments including local generation and capacity-reducing DSM resources.

As discussed in Section 2, the basis of the avoided cost approach to distribution capacity planning is the idea that a relatively small capacity alternative investment can be used to defer an existing expansion plan involving larger scale, traditional distribution infrastructure investments. The deferring investment is presumed to be of sufficient size to absorb the need for distribution capacity induced by peak load growth. If that need is absorbed, then other investments, presumably timed so that all incremental peak load growth is met, can be delayed. That delay is translated into a measurable benefit using the time value of money.

To examine additional weaknesses of the avoided cost approach, it is useful to develop a simple mathematical formulation. Suppose that the present value of the traditional or deferrable investment stream is $K_1$. The total cost of any combination of the (possibly deferred) traditional and alternative resources equals

$$TC(t) = \frac{K_1}{(1+\rho)^t} + K_2(t), \tag{4}$$

where $t$ is the time, typically measured in years, that the traditional investments are deferred, $K_2(t)$ is the present value of the capital cost of the alternative investments used to accomplish the deferral, and $\rho$ is the discount rate. Under the assumptions usually found in practice, $K_2(t)$ is expressed as the total cost of investments that meet the annual peak load growth increases for $t = 1,2,3,\ldots$ Thus,

$$\begin{aligned} K_2(t) &= k_2, && t=1 \\ &= k_2\left(1+\frac{1}{1+\rho}\right), && t=2 \\ &= k_2\left(1+\frac{1}{1+\rho}+\frac{1}{(1+\rho)^2}\right), && t=3 \\ &= k_2\left(1+\frac{1}{1+\rho}+\frac{1}{(1+\rho)^2}+\ldots+\frac{1}{(1+\rho)^N}\right), && t=N \\ &\ldots \end{aligned} \tag{5}$$

The fundamental idea in the avoided cost approach is to find $N$ such that the saving achieved by deferral—the avoided cost—is greater than the cost of the investments that create the deferral. The saving achieved by $N$-years' deferral is $K_1(1 - 1/(1+\rho)^N)$. The cost of this deferral is $K_2(N)$. What is usually done is to investigate the cost of one year's deferral. If the cost of one years' deferral is less than $K_1(1 - 1/(1+\rho))$, then deferral is deemed cost-effective, and a recommendation will be made to invest in whatever resources create the deferral. There are several implications of this approach that are misleading and, if used, will lead to suboptimal investment decisions. In the next sections, we examine these implications.

### 3.1. Avoided Cost Analysis and Infinite Deferral

One implication of the formulation in equation (5) is that, if it makes sense to defer an investment for one year, then it will make sense to defer it forever. This follows simply by iterating the condition that determines the cost-effectiveness of a single year's deferral. The necessary and sufficient condition for a single year's deferral is

$$K_1\left(1 - \frac{1}{1+\rho}\right) > k_2 . \tag{6}$$

This is equivalent to

$$K_1 > \frac{K_1}{1+\rho} + k_2 . \tag{7}$$

Iterating the inequality in (7) yields

$$\begin{aligned} K_1 &> \frac{K_1}{1+\rho} + k_2 > \frac{K_1/(1+\rho) + k_2}{1+\rho} + k_2 \\ &= \frac{K_1}{(1+\rho)^2} + k_2\left(1 + \frac{1}{1+\rho}\right). \end{aligned} \tag{8}$$

Continued iteration of (8) shows that the right hand side of the inequality is continually decreasing. Therefore, in the limit, the minimum cost to serve the increased load is the cost of a never-ending sequence of annual deferrals. There is nothing mathematically wrong with this conclusion. However, as we show in the next section, this result is extremely unstable and dependent on unrealistic assumptions.

### 3.2. Instability of the Avoided Cost Solution

The instability of the avoided cost solution is a consequence of the effects of condition (7) on the behavior of equations (5) and (6). To see this, note that the total cost given by equation (5) is the sum of two functions. The first term in equation (4) is the present value of the deferred traditional investment. This is a convex, decreasing function of the deferral time, $t$. As defined, the second term, given by equation (5), is a discontinuous function. It is natural to extend equation (5) to all $t > 0$ by considering the effect of investing in alternate distribution investments to some amount less than that which would provide a full year's deferral. In that case, we may rewrite equation (5) as

$$K_2(t) = k_2 t, \qquad 0 < t < 1$$

$$= k_2\left(1 + \frac{t-1}{1+\rho}\right) \qquad 1 \le t < 2$$

$$= k_2\left(1 + \frac{1}{1+\rho} + \frac{t-2}{(1+\rho)^2}\right) \qquad 2 \le t < 3$$

...

$$= k_2\left(1 + \frac{1}{1+\rho} + \frac{1}{(1+\rho)^2} + \ldots + \frac{t-N+1}{(1+\rho)^N}\right) \qquad N-1 \le t < N \tag{9}$$

$K_2(t)$ is continuous, but not continuously differentiable, concave, and increasing. Therefore, despite the monotonicity of its constituents, $TC(\cdot)$ can exhibit many different kinds of behavior. An example, based on a recent regulatory docket in the State of Vermont, illustrates the behavior of the solution.[6] Suppose that the traditional investment has capital cost \$2,500,000 with 40 year engineering life. Let $\rho = 8.74$ percent. (The corresponds to a combined annual interest rate of 12%, with 3% inflation, compounded annually.) Normally, in an avoided cost analysis, it is assumed that the investment will be repeated indefinitely; the capital cost that can be deferred is the present value of such a repeated stream. Thus, $k_1 = \$2{,}500{,}000\ (1 - (1.0874)^{-40})^{-1} = \$2{,}590{,}751$. The value of deferring this stream by exactly one year is $k_1(1 - 1/(1+\rho)) = \$208{,}232$. This amount is known as the real economic carrying charge (*RECC*).

Suppose that the capital cost of exactly one year's worth an alternate investment is $k_2 =$ \$205,000, and that this investment has an infinite economic life. Since this amount is less than the RECC, which is just the avoided cost of the infinitely long capital stream, the conclusion is to defer for one year. Of course, if the future costs are constant in real terms, then as shown in equation (4), the avoided cost solution will be to defer indefinitely. Indeed, the present value of an infinite stream of annual deferrals, each costing $k_2$, is $\$205{,}000((1 - 1/(1+\rho))^{-1} = \$2{,}550{,}538 < \$2{,}590{,}751 = k_1$.

Now suppose that the cost of the alternate investment is $k_2 = \$210{,}000$. In this case, it is straightforward to show that the avoided cost analysis recommends no deferral whatsoever. Thus, a 2% change in initial cost switches the solution from infinite deferral, recommending never to build the traditional investment, to no deferral, recommending that the traditional investment be built immediately. From a planning perspective, this instability is disturbing. And, that instability is compounded by the effects of differential real cost escalations of the investments and differential economic lifetimes. These effects are discussed in the next two sections.

### 3.3. Instability and Differential Real Escalation Rates of Investment Costs

Implicit in the avoided cost approach is the assumption that the costs and the effects on load growth of a particular deferring investment are constant for the foreseeable future. This assumption is clearly implicit, because if one believed that the incremental effects of

6 Docket No. 5980, Investigation into the Department of Public Service's proposed Energy Efficiency Plan, October 1, 1997.

alternative investments would change as other like investments were added, those changes would have to be *explicitly* treated in the analysis. Either the cost of a single year's deferral would have to change or the amount of deferral possible for a given program would have to change. One year would not look like any other year, but for real discounting, and intertemporal tradeoffs would be required. None of this is present in the avoided cost analysis.

Normally, as alternative capacity-providing investments are made, the cost of subsequent investments can be expected to increase. This is simply the realization of an upward sloping supply curve. Suppose, therefore, that the real annual escalation rate of an alternate investment costs equals $\delta_2$ percent, where $\delta_2$ is constant over time. For ease of exposition, assume that the real cost escalation rate of the traditional investment, $\delta_1$, equals 0 percent. Then, we can rewrite equations (4) and (5) as

$$TC(t) = \frac{k_1}{(1+\rho)^t} + K'_2(t) \tag{4'}$$

$$K'_2(t) = \sum_{i=0}^{t} k_2\pi_2 , \tag{5'}$$

where $\pi_2 = (1 + \delta_2)/(1 + \rho)$ and we assume that $\delta_2 < \rho$. In this case, the present value of an infinite stream of annual deferrals, each costing $k_2$ is $k_2(1 - \pi_2)^{-1}$. Using the same data from the previous example, the cost of the infinite stream of traditional investments is $2,590,751 = $k_1$. Assume that the real escalation rate of the alternate investments is 0.5 percent. Then, $\pi_2 = (1 + \delta_2)/(1 + \rho) = 0.9242$, and the present value of an infinite stream of deferrals is $205,000$(1 - \pi_2)^{-1}$ = $2,705,303 > $2,590,751 = $k_1$. Thus, with a real escalation rate of only 0.5 percent, infinite deferral no longer makes economic sense. Instead, the avoided cost deferral solution will occur for the value of $T$ such that $205,000(1 + 0.9242 + 0.9242$^2$ + ... + 0.9242$^{T-1}$) = $2,590,751(1 – (1.0874)$^{-T}$). It can be shown that a value of $T = 8.15$ years provides a solution. However, the minimum cost solution occurs when $T = 3.62$ years, demonstrating how the avoided cost approach can overestimate deferral.

A further demonstration that avoided costs do not lead to cost minimization can be seen using the description of the alternative investment's capital cost given by (6′). The minimum cost is found by differentiating $TC(t)$. There are relatively few cases, and they can best be illustrated by example.

Consider the data above, $k_1$ = $2,590,751, $k_2$ = $205,000, and $\rho = 0.0874$. The total cost function possesses a collection of local minimums, which occur at $t^* = 0.68, 1.68, 2.68$, etc. Each local minimum has smaller total cost than the subsequent total cost for an integer value of deferral; i.e., $TC(0.68) < TC(1)$, $TC(1.68) < TC(2)$, $TC(2.68) < TC(3)$, etc. Yet the sequence of total costs is decreasing as deferral time increases; i.e., $TC(n) > TC(n + 1)$, $n = 0,1,2, \ldots$ Therefore, the solution is to defer indefinitely. This is indeed the least cost solution.

Now set $k_2$ = $210,000. The avoided cost solution is not to defer the traditional investment at all. However, the optimal amount of deferral is $t^* = 0.40$. The total cost of this policy is

$TC(0.40) = 2{,}590{,}751\ (1.0874)^{-0.40} + 210{,}000\ (0.40) = \$2{,}589{,}359 < k_1.$

### 3.4. Instability and Differential Lifetimes

Typically, the avoided cost approach assumes that the economic lifetime of deferring investments is infinite. Since this will likely not be the case, we need to investigate the effects on the deferral decision from relaxing this assumption. For example, the life of a typical DSM program may be far shorter than the engineering life of the feeder or substation that is being deferred. Yet such considerations often do not enter avoided cost analyses. To incorporate different economic lifetimes, it is necessary to adjust the values of $K_1$ and $K_2$ and apply equations (4) and (5′).

For example, suppose as initially defined in Section 3.2, that $T_1 = 40$, $\delta_1 = 0.0$, $k_2 =$ \$205,000, $\delta_2 = 0.0$, and $\rho = 8.74$ percent. In that case, we found that infinite deferral made sense if $K_1 \leq \$208{,}232$. If we adjust $K_2$ to account for an infinite series of replacements, we find that a lifetime of $T_2 \geq 49.5$ years is consistent with infinite deferral, while $T_2 \leq 49.5$ years implies no deferral whatsoever under the avoided cost approach.

Several other factors will affect the avoided cost deferral solution. First, since optimal deferral times vary with the economic lifetimes of alternative distributed resources and since, in practice, those lifetimes will often be uncertain, avoided cost deferral decisions will be unstable. Second, technological change will affect avoided cost solutions. The most obvious indication of this fact is that both the traditional and the alternative investments are characterized as an infinite sequence of identical replacements. This creates a choice between alternatives that may not be representative of future conditions. Yet the correct approach is to recognize that at the end of an incremental resource's lifetime, the decision will not necessarily be to replace that resource with an identical one. Instead, the decision needs to account for real changes in costs and technologies. The avoided cost methodologies do not do this.

### 3.5. Avoided Cost Solutions are not Dynamically Optimal

The avoided cost approach explicitly considers only annual decisions, although implicitly, as we have argued above, it characterizes—incorrectly—the foreseeable future. In any event, the so-called cost-effective annual decision will place the planner in an investment situation a year later that is not necessarily part of an optimal policy.

It is well-known that a dynamically optimal policy is not a sequence of short-run optimal decisions, much less a sequence of cost-effective (non-optimal) decisions. Dynamic optimality requires making intertemporal tradeoffs; such tradeoffs may result in short-term sacrifices in order to yield long-term benefits. Yet the avoided cost methodology suggests that it is best to invest in assets that are cost-effective in each year. This "greedy" (second-best) approach to decision making is almost never optimal. Nor is it necessarily anywhere near optimal. There is simply no logical relationship between the short-term greedy deferral solution and the long-term optimal policy. Since the avoided cost methodology does not identify a dynamically optimal solution, it should not be used to evaluate the optimality of long-term investments.

## 4. The Effects of Uncertainty

The main driver of distribution system investments is load growth. Load growth is uncertain. It is possible to learn about future load growth by observing load behavior over time. Such learning may cause decision makers to revise their estimates of future load behavior. As those estimates are altered, the decisions that respond to those estimates will change. These are facts that describe the distribution planning problem. A methodology that is appropriate to analyze that problem should respond to all of those facts. The avoided cost approach responds to none of them.

None of the avoided cost literature treats uncertainty in anything approaching a comprehensive manner. Tellus (1995), for example, despite being billed as a general handbook for electric utilities, touches only briefly on the issue. Yokell and Marcus (1984) do address uncertainty, but only to the extent that it may affect payments to independent power producers and therefore their ability to secure financing. Many others ignore uncertainty altogether.

The effects of uncertainty cannot be addressed simply through sensitivity or scenario analysis. To do so is to invite sub-optimal resource investment decisions (Feinstein and Lesser 1997). It was because the conditional investment solutions embedded in equation (4) historically were computationally intractable that the use of avoided costs became necessary. The effects of uncertainty will also likely be exacerbated at the local planning level. That is, to the extent that events in the various sub-areas of a local distribution utility's service territory differ (e.g., economic growth and industry expansion, population growth, weather patterns, etc.), these events will no longer tend to average out across an entire service territory. In other words, while we may usefully aggregate system energy requirements for an entire regulated utility, the differences among local areas do *not* lend themselves to a similar aggregation. It makes little sense, for example, to average peak load growth rates in an urban area experiencing rapid industrial expansion and economic development with a rural area experiencing net depopulation when determining optimal local capacity investments.

It may be that the avoided cost approach has been used for lack of a better method to address distribution planning. That may have been the case previously, but newer methods have become available (Feinstein, Chapel, and Morris 1997). We believe these new methods are more appropriate for addressing the distribution investment problem faced by utilities.

### 4.1. Problem Formulation

Although the details of these newer methods proposed for distribution capacity planning are beyond the scope of this paper, some aspects of the methodology are presented here for completeness. The essential distinction between the avoided cost approach and the proposed methodology is in the problem formulation. The objective of the distribution utility capacity planning problem is to meet customers' capacity and energy needs over the indefinite future at the lowest expected present value of all future costs. There are several aspects of this problem statement that require further discussion.

The minimum cost objective may seem innocuous, but in fact represents an essential difference between the proposed methodology and the avoided cost approach. As we have stated, the avoided cost approach finds a solution that delays the construction of new T&D facilities by investing in other resources until, in the limit, the total cost of the alternative investments exceeds the total benefit of T&D delay. This is not necessarily the minimum cost solution.

The simplest problem formulation is deterministic. The solution to the deterministic planning problem is a sequence of capital investments in technology that provides the capacity necessary to meet the area load over time. Let $\mathbf{k}(t)$ be a vector whose $i$th component, $k_i(t)$, is the amount of capacity of type $i$ in the system at time $t$. The solution to the deterministic planning problem is to specify the function $\mathbf{k}(t)$ from some initial time $t_o$ to $\infty$, which represents the indefinite future. Let $L(t)$ represent the aggregate peak load (i.e., electricity demand) that must be satisfied by the system at time $t$. Let $C(\mathbf{k}(t),t)$ be the amount of effective capacity provided by the $k(t)$ of technologies at time $t$. A solution $\tilde{\mathbf{k}}(t)$ is said to be feasible if and only if $C(t,\tilde{\mathbf{k}}(t)) \geq L(t)$ for all $t \in [0,\infty)$. When this constraint is satisfied, no demand is unserved.

If we idealize the notion of investment in capacity, we can assume that $\mathbf{k}(t)$ is continuous and twice differentiable. Let $V[t,L(t),\mathbf{k}(t),\mathbf{k}'(t)]$ specify the instantaneous cost rate at time $t$ that results from serving the actual load $L(t)$ with capacity $\mathbf{k}(t)$ while making investments at the rate $\mathbf{k}'(t)$. The objective of the investment policy is to minimize the present value of these costs over the planning period. Let $\rho$ represent the instantaneous interest rate, assumed to be constant, and let the initial conditions on load and system capacity be denoted by $L(0)$ and $\mathbf{k}(0)$ respectively. Then the optimal *deterministic* investment policy will be the vector function $\mathbf{k}^*(t)$ that solves the following problem.

$$\text{minimize} \int_{t_o}^{\infty} e^{-\rho t} V[t,L(t),\mathbf{k}(t),\mathbf{k}'(t)] \tag{10a}$$

subject to:

$$C(t,\mathbf{k}(t)) \geq L(t) \tag{10b}$$

$$L(t_o) = L(0) \tag{10c}$$

$$\mathbf{k}(t_o) = \mathbf{k}(0)\,. \tag{10d}$$

The solution to (10) satisfies a set of necessary conditions that includes the Euler-Lagrange differential equation (Bliss 1925). Finding a solution to that equation is an exercise in the calculus of variations, which can be a formidable challenge, as would be the complete specification of the functions $V$ and $C$ in a form amenable to analysis.

More importantly, the investment in capacity assets is *not* a smooth process. It is more appropriate to consider that the investments in capacity occur at discrete times and in discrete amounts. Thus, it is natural to consider that the time interval $t \in [t_o,\infty)$ is composed of periods of possibly variable duration, indexed by the variable $t$. Let $\mathbf{x}(t)$ be the decision vector of additional capacity investments made during period $t$. This may also include investments that are retired from service during the period, so any component of $\mathbf{x}(t)$ could be negative. Let $I[t,\mathbf{x}(t)]$ represent the investment cost of acquiring technologies $\mathbf{x}(t)$ at the beginning of period $t$. Let $\mathbf{k}(t)$ be the vector of capacity installed in the system prior to period $t$. Then $\mathbf{k}(t+1) = \mathbf{k}(t) + \mathbf{x}(t)$ is the vector of capacity installed at the beginning of period $t+1$. As before, let $L(t)$ be the load on the system at the beginning of period $t$. Let $V[t,L(t),\mathbf{k}(t),\mathbf{x}(t)]$ represent the operating cost of serving the load during period $t$ given that

$L(t)$ is the load at the beginning of the period, $k(t)$ is the initial capital stock and new investments $x(t)$ are made during the period. The solution to the discrete deterministic distribution planning problem is the investment sequence $\{x(t): t_o \leq t < \infty\}$ that solves

$$\text{minimize} \sum_{t=t_o}^{\infty} e^{-\rho t}\{I[t,x(t)] + V[t,L(t),k(t),x(t)]\} \tag{11a}$$

$$\text{subject to} \quad C(t,k(t) + x(t)) \geq L(t) \tag{11b}$$

$$L(t_o) = L(0) \tag{11c}$$

$$k(t_o) = k(0) \tag{11d}$$

The key idea embedded in this formulation is that time is not indexed by a fixed interval, say year by year, which could define a problem of enormous dimension (e.g., 10 possible technology choices over a 10 year planning period implies $10^{10}$, or 10 billion separate strategies that would have to be evaluated). Rather, this formulation recognizes that capacity decisions need only be made when capacity is needed (e.g., if the technologies each supplied two years of load growth, there would be only $10^5$, or 100,000 separate strategies that would have to be evaluated). The resulting deterministic planning problem is in the form of a discrete optimal control problem, with $x(t)$ as the control variable. The optimal solution to this problem is again a function $x^*(t)$ that satisfies a set of necessary conditions that are variants of the Euler-Lagrange equations, first developed by Pontryagin and extended to discrete time models in a straightforward manner (Pontryagin et al. 1962; Kharatishvili 1967). The discretization of the problem makes it somewhat easier to solve, although the functions $V$ and $C$ still need to be expressed analytically, if one is to make efficient use of the necessary conditions to characterize the solution.

There remain two other aspects of the problem that (11) does not address directly: the length of each period and the behavior of the load during each period (and from period to period) is unspecified. We address these issues by incorporating a stochastic-process model of load uncertainty into the formulation, and explicitly modeling the ability of the utility to adopt strategies that respond flexibly as the uncertainty resolves over time. Thus, assume $L(t)$ is a random variable (a specific stochastic process is proposed below). It follows that the cost of meeting the load, the function $V[t,L(t),k(t),x(t)]$, is also a random variable. Therefore, the proper form for the objective (11a) is the expected present value of the cash flow stream. Denoting the expectation operator by $E$, we formulate the stochastic optimal control problem:

$$\text{minimize } E\left\{ \sum_{t=t_o}^{\infty} e^{-\rho t}(I[t,x(t)] + V[t,L(t),k(t),x(t)]) + e^{-\rho T}V_\infty[T,L(T),k(T)] \right\} \tag{12a}$$

$$\text{subject to} \quad C(t,k(t) + x(t)) \geq L(t) \tag{12b}$$

$$L(t_o) = L(0) \tag{12c}$$

$$k(t_o) = k(0) \tag{12d}$$

where $V_\infty[T,L(T),k(T)]$ is the expected present value of the cost from time $T$ to infinity, based on estimates of the future capital and operations costs of serving load.

Conceptually, there is a great gulf between problems (11) and (12), despite the apparent similarity in notation. In particular, the specification in (12) raises four interrelated modeling issues:

(a) How can the probabilistic dynamics of load be specified?
(b) How can the probability distribution on time to the next decision be specified?
(c) Is there a practical solution technique for finding the optimal decision strategy and associated costs in real distribution utility problems?
(d) How can a meaningful terminal value model be specified?

### 4.2. Modeling Load Dynamics and Uncertainty

For distribution planning, a key issue is at what point in the future will load growth result in new capacity requirements? Thus, a complete description of potential load trajectories over time is required in order to specify the probability distribution on time to the next decision. It is desirable to describe load growth in terms of multiple trends that persist for uncertain durations, because area loads typically grow at some steady rate for several years and then transition to a rapid growth spurt for a period of time. This suggests that a good way to model future load conditions is to characterize likelihoods of the possible trends and their durations. A simple yet robust mathematical representation is a Markov chain described by a transition matrix of conditional probabilities. If there are $n$ discrete load growth states, then $n(n-1)$ conditional probabilities must be specified. A method for estimating these parameters has been developed (Feinstein and Morris 1998a).

It is worth noting how this model of load behavior differs from the more traditional approaches. A standard technique is to estimate an average growth rate by fitting a regression line through historical data and to estimate variance using the regression residuals. This ignores trends or correlations in the data and, in so doing, systematically underestimates the future load uncertainty. Moreover, the regression model presupposes that additional observations provide no information. In the Markov setting, the likelihood of future load behavior depends on the current conditions, so observations modify forecasts.

The Markov model also responds to the fact that the distant past is rarely representative of the future, especially for local area planning. Growth trends are driven by real events such as changes in zoning laws and shifts in the local economic conditions. If the future is believed to be different than the past, the model allows the user to specify appropriate parameters that capture those beliefs.

### 4.3. Modeling Uncertainty in Time to the Next Decision

Constraint (12b) implies that no unserved energy is permitted during any period, an assumption required by some utility planners. This suggests that the time to the next capacity decision depends on the amount of capacity installed and on the load growth.

The Markov load model may be used to determine the dynamic state probabilities that characterize the chance that the cumulative load growth will grow from any level $L$ at time $t_i$ to any higher level $L'$ over a period of duration $\tau$. From these state probabilities, we then determine the first-passage-time probability distribution, which is the probability that starting at level $L$, cumulative load will reach level $L'$ for the first time at the exact time $t_i + \tau$ (Howard 1971). If we define, for a given capacity installation of size $C$, $L' = L + C$, the distribution on time to the next decision is identical to the first passage time distribution.

In practice, we employ a discrete three-branch approximation that matches the first five moments of the actual distribution. This approximation is based on Gaussian quadrature (Miller et al. 1983). Further details on the dynamic probabilistic model of load growth are contained in Feinstein and Morris (1998a,b) and Feinstein, Morris, and Chapel (1997).

### 4.4. Dynamic Programming Solution Technique

A powerful approach to solving a stochastic control problem is to apply Bellman's principle of optimality (Bellman 1957). This principle suggests that a complex problem, such as (12), can be viewed as a sequence of simpler problems. The solution procedure that incorporates this principle is known as dynamic programming. The decision variables in the problem are the various investment alternatives. As described above, the timing of the decisions is related to the load uncertainty and the incremental capacity provided by each investment.

Dynamic programming is not an algorithm. Rather, successful application of the procedure is based on the art of mathematical modeling rather than on numerical aspects of problem solution. A critical aspect of that modeling is to apply the notion of *state* to the problem. The state variable for problem (12) is a triple. The first component of the state is the collection of all investment decisions made through stage $m$, independent of the order in which they were made. This makes sense as a state descriptor because electric utilities economically dispatch their technologies on hand so as to minimize operating cost, independently of their capital cost or when they were installed. The second component of the state is the peak load on the system. The third component of the state is the most recent load growth rate. The Markov model requires this information to forecast the next load growth rate. Further discussion can be found in standard references on dynamic programming such as Bellman (1957) and Hillier et al. (1986).

### 4.5. Terminal Value Model

A final formulation issue concerns the infinite time horizon in the objective function (12a). Although we require a solution over the indefinite future, we also require a *practical and usable* approach to the distribution planning problem.

Although the future conditions influence the near-term decisions, it becomes less and less appropriate to model the system in detail as we move into the distant future. The formulation of the terminal value model $V_\infty[T,L(T),k(T)]$ is that it should represent the best estimate of the "cost-to-go" from any terminal point. By assuming that near-term investments will be operated until their lifetimes expire, and assessing values of capital and operating costs of future assets, the cost-to-go can be relatively simply expressed (Feinstein et al. 1997). The decision maker can vary the assessments of the future and observe how the optimal policy responds.

## 5. Conclusions

Avoided costs may have served a useful purpose for determining payments to qualifying facilities under PURPA and may still do so. But they are not useful for distribution planning efforts. As we have shown, using avoided costs to determine a mix of traditional and non-traditional distribution investments will almost never result in selecting a least-cost mix, even in the absence of uncertainty. We have shown that using traditional avoided cost rules to evaluate distribution capacity investments will:

- Confuse cost-effectiveness with optimality;
- Make inappropriate marginal comparisons; and
- Defer traditional capacity investments either too long or not enough, but not the correct amount; the typical mistake will be to overestimate deferral times.

Avoided cost methods are primarily short-term, static, and deterministic in nature, but the distribution investment problem is long-term, dynamic, and uncertain. Avoided cost methods are also unstable and unreliable. If these methods are used to determine distribution capacity investments, utility customers will almost certainly pay more for distribution "ready-to-serve" charges than they would if a least-cost investment strategy were developed correctly.

Although determining dynamically optimal solutions to an uncertainty distribution capacity investment problem may have been intractable in the past, new planning methodologies are now available that can provide dynamic, least-cost solutions. These methodologies should be used and developed further, rather than continuing to use avoided cost methods that are inappropriate by design and misleading in their recommendations.

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