THE ENERGY JOURNAL

INTERNATIONAL ASSOCIATION FOR ENERGY ECONOMICS

IAEE

Distributed Resources: Toward a New Paradigm of the Electricity Business

Defining Distributed Resource Planning

Charles Feinstein and Jonathan Lesser

Special Issue
International Association for Energy Economics **IAEE**

Defining Distributed Resource Planning

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The concept and objectives of distributed utility planning, sometimes called distributed resource (DR) planning, are unclear. This paper provides a cogent definition of DR planning and explains some of the emerging fallacies over its purpose. The objective of DR planning should be to meet customers' capacity needs at the lowest expected future cost by determining an optimal investment strategy for a given area. Many advocates of DR planning have erroneously defined the objective as deferral of "traditional" transmission and distribution facilities, and have developed methodologies to determine maximum deferral times. Defining the DR planning objective in this manner will always lead to higher than necessary costs, because cost-minimization is not addressed in an appropriate manner. In general, deferral methodologies have misspecified the objective function, used quantitative tools inappropriately, and, perhaps their most critical shortcoming, failed to incorporate the effects of uncertainty on the optimal investment strategy. The solution is to treat deferral as a consequence of developing a least-expected-cost distribution plan, rather than treating deferral as an objective in itself.

INTRODUCTION

Distributed resource (DR) planning is rapidly becoming a new utility planning mantra. Yet the concept is now so broadly interpreted that its practice remains ill-defined and without sufficient guidance to practitioners who will be required to create an empirically workable discipline. Until more precise

The Energy Journal, DR Special Issue.

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definitions accompanied by logical planning guidelines are developed, distributed utility planning efforts will remain vulnerable to uneconomic and fallacious interpretations. The purpose of this paper is to provide a cogent definition of DR planning and explain some of the emerging fallacies. It is essential to expose these fallacies so that distribution utilities and their customers may avoid investments whose costs exceed their benefits.

As the electric utility industry is deregulated, regulators will exercise less control over generation choices. However, it is natural to expect that the transmission and distribution functions, the "poles and wires" business, will retain their natural monopoly characteristics for the foreseeable future and remain regulated. Regulators, many of whom required utilities to use integrated resource planning (IRP) methodologies to minimize the expected future cost of meeting forecast electricity *energy* demand in the pre-deregulated environment, are now looking to DR planning to do the same for *peak* demands experienced by the regulated poles and wires business. This is an admirable goal, as long as the DR planning concepts developed minimize expected future costs.

The objective of DR planning should be equivalent to that of traditional utility planning: identify an investment strategy for a local planning area *that meets customers' capacity needs at the lowest expected future cost*. That is, the concept of optimality that governs DR planning is *cost minimization of required capacity investments*. A local planning area might be a town experiencing rapid residential growth, a district in which a new industry will locate, or a subdivision that will permit a major expansion by an existing industry. The plan that satisfies this objective is known as the "distribution investment resource plan" or (DIRP).

Contrary to the definition offered above, some proponents of DR planning have claimed (in the absence of empirical argument) that its goal should be to *maximize the delay in construction of new transmission and distribution (T&D) facilities*. (They either claim this objective explicitly or the methods they apply to the planning problem are governed by it implicitly.) We will show that, in general, this goal is not equivalent to the least-cost investment strategy except under very limited conditions. Rather, methodologies that maximize the delay in construction of new T&D facilities misspecify the objective function, inappropriately use quantitative tools, and, what is perhaps their most critical shortcoming, fail to incorporate the effects of uncertainty on the optimal investment strategy.

The main issue in DR planning is not deferral of traditional T&D investments; it is whether smaller, more modular, more flexible investments can permit planners to delay larger, more capital intensive investments, until the future needs become more clear. To address that issue, not only must the optimization analysis be done in an appropriate manner, but also the effects of uncertainty on investment performance must be addressed.

Investments considered for distribution planning usually have long useful lives, typically at least 30 years. Therefore, the consequences of making an investment extend far into the future. Investment planning depends on forecasts of the future, which is to say that the costs and benefits of making an investment are based on the future conditions that will occur during the useful life of the investment. Since the future is unknown, the uncertainty in the future conditions must be modeled in order to make appropriate investment decisions.

LITERATURE REVIEW

The literature on DR planning has been reviewed in Pupp (1993); an updated review of the concept is given in Feinstein, Orans, and Chapel (1997). Two early papers approached the problem of DR planning in somewhat different ways. Ma (1979) evaluated various DR scenarios by estimating the "credits" attributable to distribution investments. The main credit was a "deferral credit," based on deferring distribution capacity investments into the future. Lee (1979) compared the costs of expanding a transmission and distribution system with and without distributed elements. His methodology analyzed cash flows of actual decisions and did not base benefits on explicit deferrals. The theme of Lee's (1979) methodology is similar to the argument we make here.

There is nothing controversial about assigning credit to DR investments when they defer otherwise needed capital investments. Indeed, Ma (1979, p. 8.) describes the deferral credit as the difference in "conventional distribution system costs between the policies where [DR] is used and where it is not used. Distribution capacity benefits occur when conventional distribution investments are deferred, cancelled, or required by [DR]." In Ma's formulation, the distribution capacity benefit was measured by the present worth of the difference between two cash flows, which represent the expansion costs with and without DR (Ma 1979, p. 89-90). This appears to be the first instance of the analysis of deferral benefits attributed to distributed resource investments. There is nothing objectionable in this notion. Actual cash flows are delayed, yielding real savings. But DR planning should not be viewed as an exercise in deferring "traditional" T&D investments. Rather, deferral of those investments may be a *consequence* of developing a least-expected-cost distribution plan.

Later work followed the deferral logic, measuring benefits by assigning credits to such items as deferred generation capacity, deferred transmission capacity, deferred distribution capacity, reliability credits, and other items. Zaininger (1990), Shugar (1991), and El-Gasseir (1991) each attempted to measure the benefits of distributed investments using such credits. Orans (1991) reformulated the methodology while retaining the idea of the deferral benefit. The methodology defines and applies an area-specific marginal cost of distribution capacity. It will be necessary to review this methodology in some detail, since Orans (1994), Woo (1995), and Hoff (1996) apply identical equations, some of the same methods, and essentially the same ideas, although some salient points seem to have been lost in the most recent efforts.

Orans (1991) defined the marginal capacity cost with respect to an existing capacity expansion plan, $\{k_t : t=1,2,...,T\}$, 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 ΔK, then the capacity expansion plan will be delayed by $\Delta t = \Delta K/L$, where L is the (deterministic) annual peak load growth rate. The difference in present values of the two expansion plans is denoted

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

where r is the discount rate and i_t is the cost escalation rate at time t of the existing capacity expansion plan. This is identical to Ma (1979). The marginal distribution capacity cost (MDCC) then is defined by

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

What is interesting to note is that this definition of marginal cost is based on *non-marginal* quantities. Although Orans (1991; 1994), and Woo (1995) suggest that MDCC should be considered a marginal cost, they use equation (2) as it is written, for some arbitrary amount of added capacity ΔK. Indeed, Woo (1995, p.116) writes, "ΔPV measures the benefit of ΔK MW of D[R] capacity installed in year 1 that lasts for T years." This is correct for the actual, non-marginal cash flows. But it is important to note that (2) provides an estimate of the true marginal cost in exactly the same way and with only the same accuracy as a secant line provides an estimate to the slope of a nonlinear function.[1] Thus, these authors identify a non-marginal value of deferral. It is this value that is compared to the non-marginal cost of investments that contribute to such a deferral.

If this approximation did not bias the choice of DR investments, it would not be objectionable. However, as we shall show, this estimate of marginal cost will, under the conditions usually encountered in practice, *overestimate* the amount of distributed resources that should optimally be installed in a local planning area compared with the least-cost solution. That is, using this value of marginal 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. What is actually accomplished in applying (2) in practice is to delay traditional T&D investments for as long as possible, without adding any additional costs.

The analysis of the DR investment problem continues with the definition of a *cost-effective distributed resource.* Orans (1991, p.91) defined a cost effective distributed resource investment as one that "will have a net cost per kW which is lower than the combined local T&D capacity cost," i.e., that cost-effectiveness means that the cost per kW of a distributed resource that provides ΔK kW is less than MDCC. This is exactly what Woo (1995, p.116) states: "[W]hether a D[R] unit will be installed in a distributed planning area at the beginning of the first-year [sic] is determined by the following inequality:

$$W < MDCC \tag{3}$$

where W = net capacity price= \$/kW life-cycle capacity cost of a D[R] device over T years, net of any generation and bulk transmission cost savings." Woo does not state whether the capacity of the DR unit is the same ΔK that is used to define MDCC in (2). If it is the same, the inequality is comparing non-marginal cash flows (which follows by multiplying both sides of the inequality by the capacity ΔK). If not, applicability of the inequality must be based on some implicit claim that the estimate of MDCC given by (2) is applicable to any DR unit regardless of capacity. It is also worth noting that Hoff (1996, p.98) writes that "[a] distributed resource is cost-effective if there is a positive net present value associated with the investment." Hoff thus defines cost-

1. The slope of a secant line of a function $f(x)$ at a point x is given by the ratio $[f(x+\Delta x)-f(x)]/\Delta x$, for some increment of the independent variable Δx, and the derivative of the function $f(x)$ at the point x is the limit of this slope as Δx approaches zero. Hence, the slope of a secant line need not be an accurate estimate of the actual slope of a function.

effectiveness in the same way as Orans (1991) and Woo (1995). Indeed, Hoff (1996, p. 95) goes somewhat further and defines a "break-even price" P of a distributed technology with respect to the peak load reduction (M^D) that it could provide in the T&D system, by the equation[2]

$$P = (MDCC) M^D \tag{4}$$

This equation provides a recipe for choosing to install a distributed resource. The recipe is equivalent to Woo's inequality cited above, with $W \leq P/M^D$.

Before proceeding to a further analysis of these considerations, it is worthwhile to recall the problem that was addressed in Orans (1991). That report described a method that integrated targeted DSM into an existing T&D expansion plan. The issue was whether DSM could be used in a *cost-effective* way to delay the investments in the expansion plan. The method was based on equation (2), with the estimate of MDCC updated as the expansion plan changed upon introduction of DSM programs (Orans 1991, pp. 85ff.). At each iteration of the algorithm, the updated marginal cost, based on all current investments, is used to select the next most cost-effective investment, using the definition cited above. Each competing DSM program is ranked by cost-effectiveness, so that the program that is selected for inclusion in the investment plan has the least per kW cost among all those programs that have per kW cost less than the marginal cost. The algorithm stops when there are no more cost-effective investments. The result is claimed to be the least-cost expansion plan in the class of plans that integrate DSM with the existing, delayed, T&D plan.

Whether the algorithm presented in Orans (1991) is a globally convergent optimization procedure that will identify the least-cost solution to the investment problem is both questionable and beyond the scope of this paper.[3] Indeed, the algorithm will typically identify a superior investment plan, and that may be sufficient for the purpose it was intended. For our present purposes, there are two important points to consider: (i) a DSM program is brought into the investment plan if it is cost-effective with respect to marginal cost; and (ii) the marginal cost itself is updated by the algorithm after a program is brought into the plan. This latter point is important because marginal cost as defined in equation (2) *changes* as DSM programs are added to the expansion plan. As

2. See Hoff (1996, p. 99, eq. 14; applied on p.100, eq. 15).

3. Analysis of such issues as the descent property of the algorithm, the closedness of the algorithm, and the nature of the solution set are essential to resolving the question of global convergence. The theory of global convergence of descent algorithms is developed in Luenberger (1973).

DSM programs are added into the expansion plan, the traditional T&D investments are delayed and the marginal cost—more properly, the incremental value of further delay—given by (2) *decreases*, as a consequence of the specification in (1). Therefore, if this value is not changed as DSM programs are added to an expansion plan, remaining programs not yet added to the plan may appear to be cost-effective when in fact they would not be if the estimate of marginal cost were updated. Neither Woo (1995) nor Hoff (1996) addresses the dynamic behavior of the marginal costs they define in their papers.

The apparent basis of the definition of marginal cost and the notion of cost-effectiveness is a well-known result: the optimal level of investment for a continuously 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 investment. The actual marginal cost is the present value cost of the DR investments that induce the delay. In order to fit this problem into the context of the well-known result cited above, marginal quantities have to be defined. 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 DR investments expressed in $/kW are marginal, even though the units—$/kW—are correct

Although calling these quantities "marginal" is not objectionable *per se*, it is objectionable to treat these non-marginal quantities as if they were the correct marginal costs for the purposes of claiming optimality while simultaneously treating them as non-marginal quantities for the purposes of deciding whether to include DR investments in an expansion plan. Because of this confusion, practical application of equations (1) - (4) will overestimate the amount of DR investments that should be added to the expansion plan.

Suppose (3) were used to decide whether to add a DR investment to the expansion plan. Now, either that particular DR investment was used to define ΔPV in (1) or not. If so, then the MDCC defined in (2) is based on the non-marginal quantities that correspond to the particular investment and the inequality in (3) simply tests whether the total reduction in PV is greater or less than the actual cost of the DR investment. If not, then the MDCC is based on non-marginal quantities that need have no relationship to the costs and effects of the DR investment under consideration.

In either case, if the investment passes the test, $W < MDCC$, then the conclusion is to add the investment to the plan, and defer the traditional investments by the corresponding value of Δt. But these are not marginal considerations; a marginal amount of DR 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. Either (3) or (4) permits such non-marginal additions until the change in present value of the traditional T&D plans is equal to the cost of the DR investments. Hoff (1996) correctly calls this the break-even price, since that is exactly what happens: DR 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 DR investments. Clearly, if this method is implemented, the total costs do not change and the deferred T&D investment plan with integrated DR investments costs no less than the original T&D investment plan. The deferral merely paid for the DR investments.

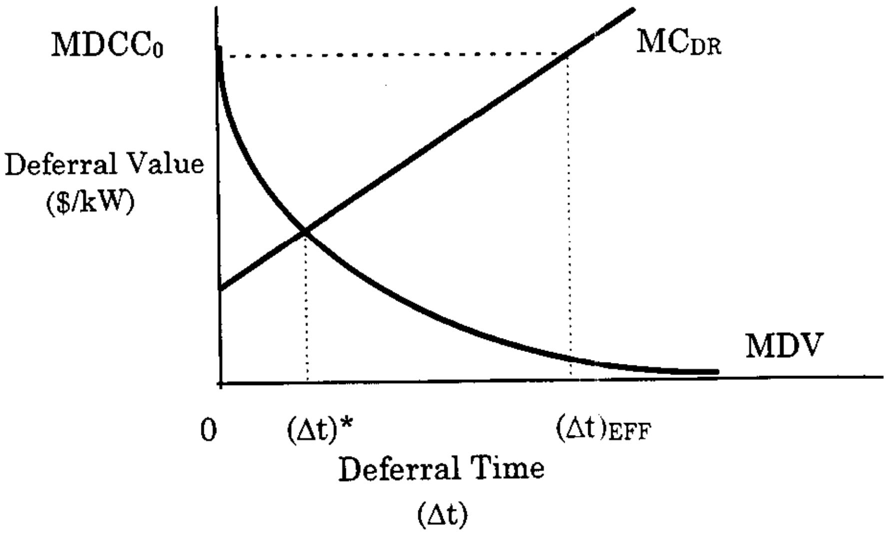
A consequence of this method, then, is that DR investments are used to defer traditional T&D investments for as long as possible without adding additional costs. That is what this concept of *cost-effectiveness* implies. This is a fundamental flaw in the approaches noted above. What is cost-effective is not necessarily optimal, unless the objective is to maximize the amount of deferral provided by the distributed resources.

This can be seen in Figure 1, which illustrates the comparisons used by Woo (1995) and Hoff (1996). The marginal benefit of some arbitrary incremental deferral Δt at time $t=0$ is found by (1) and (2), assuming an existing T&D expansion plan. This is the value $MDCC_0$. Differentiating equation (1) with respect to the amount of installed DR resources ΔK ($= L\Delta t$) provides the marginal value of deferral as a function of Δt, shown in Figure 1 as MDV. The existing expansion plan can be deferred using some combination of distributed resources. The marginal cost of DR investments (MC_{DR}) is assumed to increase as those investments defer the existing expansion plan for larger periods Δt, since $\Delta t = \Delta K/L$.

If $MDCC_0$ is used as the basis for determining cost-effective deferral of the traditional plan with DR investments, the amount of deferral will equal (Δt_{EFF}). This corresponds to the point where marginal cost of DR equals $MDCC_0$. The optimal deferral solution, however, is (Δt^*), such that $MDV(\Delta t^*) = MC_{DR}(\Delta t^*)$, with ($\Delta t^*$) $\leq$ (Δt_{EFF}) since MDV is a decreasing function. Woo (1995) and Hoff (1996) have used an arbitrary average incremental cost, calculated from equation (2), as a substitute for marginal cost. As a result, their methodologies lead to greater than optimal investment in DR resources.

In the next section, we present and analyze a simple mathematical model that formalizes some of these notions.

Figure 1. Calculation of "Cost-Effective Deferral"



A SIMPLE MODEL OF THE DR INVESTMENT PROBLEM

The model we present in this section is designed to capture an essential aspect of DR planning: the cost-minimizing solution will not necessarily occur at a level of investment in distributed resources that maximizes the delay of more traditional T&D investments. In particular, we show that investing in distributed resources until they are no longer *cost-effective* (as defined in Orans (1991; 1994), Woo (1995), and Hoff (1996), as discussed above) is inconsistent with a least-cost investment policy. In fact, the cost-effective criterion, as implemented, erroneously defines the "least-cost" solution as one that requires purchase of DR investments to defer T&D upgrades as long as possible. This consequence of applying the cost-effectiveness criterion has not been previously recognized.

There is a fundamental difference in the approaches taken in Orans (1991) compared with Woo (1995) and Hoff (1996). The latter apparently base their analysis of DR programs upon an unchanging value of the estimate of the marginal cost of capacity. As we have noted, Orans (1991) recognized that this estimate would decrease as more programs are introduced into the expansion plan. Since the latter approaches seem to have ignored this effect, they will over-estimate the amount of DR investments that are identified as "cost-effective." This is another way of stating the difference between decisions based on marginal costs and those based on average costs.

Although Figure 1 provides a simple graphical explanation, to understand better why cost-minimizing solutions will usually not correspond to delay-maximizing ones, consider a simple deterministic model. We will address uncertainty later in the paper. For ease of exposition, we assume that load growth is constant and equal to L megawatts (MW) per year. We assume there are only two types of resource investments available. Resource investment 1, I_1, is assumed to be "lumpy," and able to increase area capacity by K MW, where the value of K is much larger than L. Resource investment 2, I_2 , is assumed to be incremental and available in $L\Delta t$ blocks, where Δt represents an arbitrary time period. Thus, I_2 can be installed to match local area load growth arbitrarily closely. We further assume that the total amount of I_2 available is N MW. Therefore, the maximum time delay possible is N/L. For example, there may be only so many electrically heated houses in an area than can be fuel-switched. Note that this is not necessarily the maximum deferral solution noted in the literature cited, since it may not be "cost-effective" to install N MW of I_2. The *maximum deferral* solution will occur at that level of I_2 where the present value of the cost of incremental investments equals the present value of the avoided cost of the deferred large, lumpy investment.

Since the fundamental DR planning tradeoff in a deterministic setting is one of excess capacity versus economies of scale, we assume that the initial cost per MW of investment 2, C_2 , is greater than that of investment 1, C_1. If this were not so, the minimum cost solution would clearly be to delay investment 1 as long as feasible. Thus, assume that $C_2 = \alpha C_1$, where $\alpha > 1$.

The investment problem can be formulated as follows: minimize the total cost of meeting future local area load growth by matching that load growth until time T^* through additions of I_2, at which time install the large, lumpy I_1. Because the capacity addition provided by I_1 is large relative to load growth, its installation effectively ends the need for further investments in capacity.

Let u represent the cumulative amount of I_2 installed until T^*. Let $V(u)$ represent the present value of the total cost of installing those u units of I_2. We assume that $V(u)$ is increasing and convex. Thus, $dV(u)/du = MC(u) = v(u) > 0$, where $MC(u)$ indicates the marginal cost of installing I_2, and that $d^2V(u)/d^2u = dv(u)/du > 0$. From this, it follows that the present value of installing du units of I_2 at time t equals $v(u)\ e^{-rt}du$, where r is the discount rate.

Since investments in I_2 precisely match load, $u(t) = Lt$. Since $du = Ldt$, it follows that the present value of the cost of installing u units of I_2 is

$$PV_2 = \int_0^{u/L} v(LT)e^{-rt}Ldt \tag{5}$$

The optimal amount u^* of investment is the value that minimizes the present value cost of installing u^* units plus the deferred cost of installing I_1. The objective function to be minimized is then

$$J(u) = PV_2 + PV_1 = \int_0^{u/L} v(Lt)e^{-rt}Ldt + KC_1e^{(i-r)u/L} \tag{6}$$

where $J(u)$ is the total present value cost of installing I_1 and I_2. The escalation rate of the cost of the I_1 is denoted by i. The optimal value u^* must satisfy $dJ(u)/du = 0$, or

$$v(u^*)e^{-ru*/L}L + \frac{(i-r)}{L}KC_1e^{(i-r)u*/L} = 0 \tag{7}$$

This value will yield an interior minimum if $d^2J/d^2u\ (u^*) > 0$, or

$$\frac{d}{du}[(v(u)e^{-ru/L})]_{u*}L + \frac{(i-r)^2}{L^2}KC_1e^{(i-r)u*/L} > 0 \tag{8}$$

A sufficient, but not necessary, condition for (8) to hold is that $v(u)\ e^{-ru/L}$ is an increasing function, which requires that the marginal cost of installing u units of DR is increasing at an increasing rate.

We next must determine whether conditions (7) and (8), which characterize the cost-minimizing solution u^*, are consistent with the conditions for maximum deferral. Let $\bar{u}$ be the amount of I_2 that maximizes deferral of I_1.

The maximum deferral solution can be found by selecting $\bar{u}$ so that the time $T = \bar{u}/L$ is a maximum, while maintaining cost-effectiveness of the investments. Based on the literature cited above, a distributed investment is cost-effective if the present value of the cost of I_2 is less than or equal to the present value of the avoided cost of I_1. Thus, we can state the problem as

$$maximize \qquad u/L \tag{9a}$$

$$subject\ to \quad (1 - e^{(i-r)u/L})KC \geq \int_0^{u/L} v(Lt)e^{-rt}Ldt \tag{9b}$$

The Lagrangian for this problem is

$$\Lambda = u/L + \lambda[(1 - e^{(i-r)u/L})KC_1 - \int_0^{u/L} v(Lt)e^{-rt}Ldt] \tag{10}$$

The Kuhn-Tucker conditions are

$$\frac{\partial \Lambda}{\partial u} = \frac{1}{L} + \lambda[-\frac{(i-r)}{L}KC_1 e^{(i-r)u/L} - v(u)e^{-ru/L}L] = 0 \tag{11a}$$

$$\lambda[(1 - e^{(i-r)u/L})KC_1 - \int_0^{u/L} v(Lt)e^{-rt}Ldt] = 0 \tag{11b}$$

$$\lambda \geq 0 \tag{11c}$$

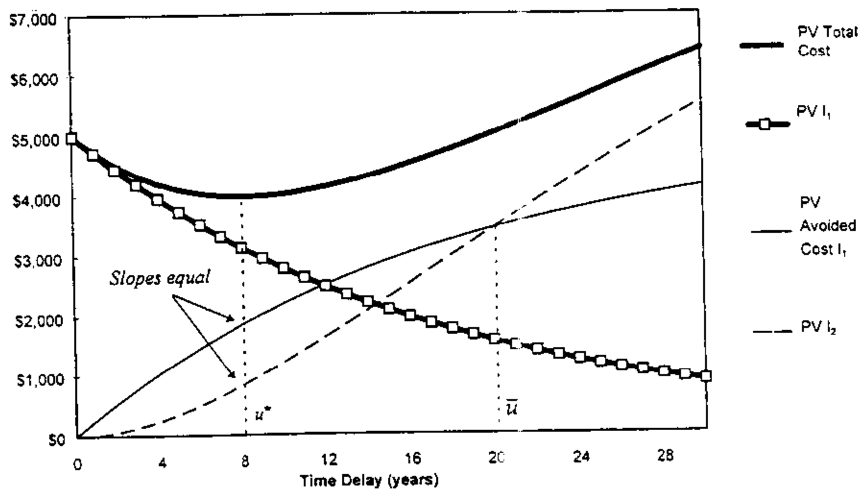
Since $1/L > 0$ and $\lambda \geq 0$, it follows from (11a) that

$$-\frac{(i-r)}{L}KC_1 e^{(i-r)\bar{u}/L} < v(\bar{u})e^{-r\bar{u}/L}L \tag{12}$$

To examine the relationship between u^* and $\bar{u}$, we must compare equations (12) and (7). When $\bar{u} = u^*$, equality holds in (12). By assumption, $v(u)e^{-ru/L}$ is monotone increasing, so that it crosses the decreasing function

$-\frac{(i-r)}{L}KC_1e^{(i-r)u/L}$ from below at u^*. Thus, (12) implies that $u^* < \bar{u}$. Therefore, the maximum deferral solution will *always* result in a higher present value total cost. This is illustrated in Figure 2, below. (This figure is derived from a simple spreadsheet model developed by the authors and discussed in the Appendix. The spreadsheet is available on request.)

Figure 2. Comparison of Cost-Minimizing and Maximum Deferral Solutions



In Figure 2, u^* induces approximately eight years' deferral in I_1. At that level of investment in I_2, the rate of change in the savings from delay of I_1 is equal to the rate of change in the total present value of the cost of the I_2, the condition stated in equation (7). In contrast, the maximum delay solution $\bar{u}$ occurs at just over 20 years deferral, such that the total present value of the savings from delaying I_1, which is given by $(1 - e^{-ru/L})KC_1$, is equal to the total present value of the cost of investing in $\bar{u}$ units of I_2.

An Example and Further Discussion

It may be useful to consider an example taken from the literature. Hoff (1996), following Orans (1994), defines the marginal capacity cost of an investment plan by equating the present value of the cost of the plan with the cost of a distributed resource that could be used to defer the plan plus the present value of the cost of the deferred plan, or (Hoff 1996, eq. 8)

$$X = Cu + X\left[\frac{(1+i)}{(1+r)}\right]^{u/L} \tag{13}$$

where X is the present value of the T&D investment plan, C is referred to as the marginal capacity cost of the T&D investment plan, which is set equal to the so-called break-even cost of the distributed resource ($/kW), u is the capacity of the distributed resource to be installed (kW), L is the peak load growth rate (kW/yr), i is the inflation rate, and r is the discount rate. Salvage value is assumed negligible.

The right hand side of equation (13) is the objective function specified by equation (6), $J(u)$, expressed in discrete time. In particular, $X = KC_1$, the present worth of the deferrable investments, and $Cu = \int_0^{u/L} v(Lt)e^{-rt}Ldt$ is the cost of the distributed resource investment. The discounting term is the discrete time analog of the continuous discounting used in specifying $J(u)$. Instead of selecting the capacity u optimally for a given value of C, equation (13) suggests that a value of C can be found for a given u. Indeed, Hoff (1996) proceeds by setting $u = L$, and finding the cost C that induces a year's worth of deferral of X, which is

$$C = \left(\frac{X}{L}\right)\left[\frac{(r-i)}{(1+r)}\right] \tag{14}$$

This approach is flawed. Equations (13) and (14) state that the distributed resource investment is such that one is indifferent between making it and investing $X = KC_1$ now. This makes little economic sense as a guide to investment in either a regulated or a competitive environment. Economic welfare will be increased by selecting optimal investment quantities, rather than investing in a particular alternative to the point when one is indifferent between it and other available alternatives.

An analogy may be useful to explain this point further. Imagine that you are ready to replace your automobile with a new, $30,000 car. A mechanic arrives and says that he can extend the life of the current auto for a relatively small amount of money. Suppose that he offers the following two choices: 1) for about $500, you can get another six months of life from the old car; and 2) for about \$1,700 he will get you an additional year. Ignoring inflation, and if the prevailing interest rate is around 6%, equation (14) says to take the year's extension. That is, the current \$30,000 investment can be deferred for a year, reducing its present value to approximately \$28,300 (which means that a deposit of \$28,300 now will yield \$30,000 in a year, just in time to buy the car which did not inflate in price), at a present cost of \$1,700, so that the total investment is still \$30,000. Now consider the other offer. At a cost of about \$500, the purchase can be deferred six months. In order to yield the required \$30,000 in six months, a deposit of approximately \$29,100 is required. Thus, the total investment is about \$29,600. The difference is about \$400, which can be used to buy gasoline. This is the solution that more closely corresponds to u^* as defined by equation (7).

The difference between the maximal deferral solution and the optimal solution can be illustrated using the numbers in the example presented in Hoff (1996). The values are taken from Orans (1991). Set X = \$112,300,000, L = 9,000 kW/yr, r = 0.11/yr, and i = 0.06/yr. The marginal cost/distributed resource break-even price is C = \$562/kW, as found by Hoff. This is interpreted as the cost of distributed resource investment in equation (14). It is worth noting that this so-called break-even cost, which has the appearance of a marginal capital cost, is treated as the *average* cost of installing L units of distributed resource in equation (14). Now suppose that the average cost of distributed resources were indeed \$562/kW. The optimal amount to invest, u^*, is given by the solution to equation (7), which in this case is

$$C + X\left[\frac{(1+i)}{(1+r)}\right]^{u^*/L} \ln\left[\frac{(1+i)}{(1+r)}\right]\left(\frac{1}{L}\right) = 0 \qquad (15)$$

The optimal value is u^* = 4,504 kW. That is, the optimal value is half the maximal deferral value (where maximal deferral in this example is one year). In this case, the difference in the objective function values is very small, despite the relatively large difference in policy.

Summary

The purpose of this section was to discuss the role of cost minimization in DR planning. The essential point of the arguments presented here is that the planning approaches that are based on maximizing deferral credits attributable to distributed resources have misspecified the objective function they seek to optimize. This misspecification is either implicit or explicit. Implicit misspecification results from seeking the least-cost solution by applying the cost-effective criterion, which has been shown to yield the solution to the maximum deferral problem. Explicit misspecification is adopted by those who believe that the objective of DR planning is to defer traditional T&D investments for as long as possible, and who use the cost-effective criterion to support their arguments. The result of that misspecification is that the current practice finds solutions that are not least cost but instead defer traditional T&D investments. Despite claims to the contrary, the two solutions are not the same: "cost-effective" solutions are not optimal, and maximal deferral solutions induce a natural bias toward investment in distributed resources.

Other misconceptions arise from misspecification of the objective function. The methodologies that determine maximal deferral credit do not account correctly for the "lumpiness" of investments. Indeed, as we have shown, the deferral methodologies attempt to estimate a marginal cost of capacity provided by traditional T&D investments. This estimate is arbitrary since it is based on a finite amount of deferred capacity rather than a true differential. Using such an arbitrary estimate, the methodologies recommend the use of *$/kW* values to evaluate the cost-effectiveness of investments that contributes to deferring new T&D capacity investments. This is the essential idea in equation (14) above. Such a metric for evaluation of lumpy capacity alternatives can be misleading.

DSM acquisition decisions for solving capacity expansion problems, for example, are often based on evaluation of per-kW "avoided cost" values. This type of evaluation may be appropriate when assessing the benefits and costs of additional DSM acquisition when the problem to be solved is minimizing the cost of additional *energy* consumption. System energy tradeoffs can be made on a per-kWh basis because decisions can be made at the 1 kWh level. A similar argument cannot be made for the *capacity* effects of DR investments. One cannot, for example, purchase a 1 kW distribution line upgrade or transformer. Making DSM investment decisions by comparing the per kW average costs of DSM to the per kW average cost of transmission upgrades is wrong; such a marginal decision is infeasible. This does not mean DSM is inappropriate *per se*, but rather that evaluation of any DR alternatives should be based on the actual cash flows induced by the actual decisions. Converting actual lumpy cash flows into marginal costs by equation (14) or its equivalent introduces an arbitrary metric into the analysis.

THE TREATMENT OF UNCERTAINTY

As noted in the introduction to this paper, we claim that a fundamentally important part of distribution investment resource planning is the treatment of uncertainty. In fact, it is possible to distinguish among alternate methodologies according to the way they treat uncertainty. The methodologies described in the literature, e.g., Hoff (1996), Woo (1995), Orans (1991: 1994), Shugar (1991), Zaininger (1990), Lee (1979), Ma(1979), do not address the problem of planning under uncertainty. Ignoring the consequences of uncertainty for local area investment planning is inappropriate for several reasons.

The investments considered in distribution planning have long useful lives, typically at least 30 years. Therefore, the consequences of making an investment extend far into the future. Investment planning depends on forecasts of the future, which is to say that the costs and benefits of making an investment are based on the future conditions that will occur during the useful life of the investment. Hence, the uncertainty in future conditions must be made part of the analytic procedure that specifies investment strategy. Regardless of the methodology chosen, it is essential to discover whether different uncertainties materially affect the investment decisions.

Moreover, the effects of uncertainty can differ depending on the size (capacity or first cost) of the investment. Indeed, although distribution investments typically have long lives regardless of size, larger, lumpy investments are riskier than smaller, more modular ones. It is interesting to contrast this claim with the well-known result of Manne (1961). Manne concluded that uncertainty motivated larger capacity investments, in a manner analogous to the optimal treatment of stockout risk in inventory analysis. Manne did not consider the hedging characteristics of smaller capacity increments. Further, one must be precise about what one means by "risk." There is less risk in adding a 2 MW investment when peak load is 20 MW compared with adding a 20 MW investment under the same peak load condition, because the need for larger capacity alternatives may never materialize, while the smaller alternatives are far more likely to be needed. Generally, uncertainty in future load makes the capital investment in the larger investments more difficult to justify *a priori*.

Methods that do not address uncertainty cannot answer any of the following questions:

- What effect does uncertainty have on investment decisions?
- What is the benefit of investing in smaller but more modular investments?
- What is the value of making more flexible investments, with smaller leadtimes and less initial capital cost?
- What is the benefit of the option to delay investments, thereby waiting to observe what the future conditions become?

- What is the benefit of learning more about current conditions, so that future forecasts can be modified?

- How does the optimal investment policy change as a function of future conditions?

Answers to these questions are important because of the nature of the DR planning problem. As we have argued, the purpose of DR planning is not deferral of traditional T&D investments. Rather it is to determine whether smaller, more modular, and more flexible investments can permit planners to delay larger, more capital intensive investments, until future needs become more clear. The answers to the questions above comprise a complete answer to the main issue of DR planning.

A fundamentally important uncertainty is local area peak load growth. If load growth were certain and predictable, the hedging qualities of DR investments would not be worth very much. But if the load growth is uncertain, and forecasts can be improved after learning or observation of changing conditions, then DR investments can become very valuable. Methodologies that do not address the interplay between uncertainty and optimal investments cannot address the consequences of load growth uncertainty.

It is also important to note that this is a methodological issue as well as a conceptual one. Once a planner has recognized that uncertainty is a critical element in DR planning, the question of how best to model the effects of uncertainty must be answered. We briefly discuss some aspects of modeling uncertainty and close this section with an example that reveals some of the subtleties of analysis under uncertainty. Further discussion of the analysis of the investment problem under uncertainty is beyond the scope of this paper. A complete approach to solving the DR planning problem under uncertainty is presented in Feinstein, Morris, and Chapel (1997), and Feinstein and Morris (1997).

An important aspect is that uncertainty must be modeled comprehensively. All uncertain variables that can influence the value of investments should be modeled. If that is not done, it will not be possible to evaluate the consequences of a change in future conditions. We have found that uncertainties in load growth, weather, fuel cost, siting, and regulatory environment are important aspects of investment analysis. Further, the joint behavior of uncertain variables must be characterized. It is important to recognize how knowledge of one variable affects the uncertainty in another. A convenient way to approach this question is to define scenarios that comprise the joint occurrence of several events.

A successful model will represent the interplay between the value of investment alternatives and the resolution of uncertain events. Representing such relationships permits the formulation of an optimization problem that has as its solution the optimal investment policy under uncertainty. The optimal investment strategy will necessarily be contingent on the actual observations made in the future. In general, such a strategy cannot be found by purely deterministic methods. In particular, it is worth noting that the optimal strategy under uncertainty need not be optimal under any single forecast or single scenario. This is an important point, since a common misconception is that the optimal strategy under uncertainty can be found by specifying scenarios, finding the optimal (deterministic) strategy for each scenario, and selecting the optimal strategy under uncertainty from among them. This is false, as the following example (Morris 1996) illustrates.

Consider the problem of deciding when to install a substation. The alternatives are either one, two, or three years from now. Assuming a nominal load growth rate, a traditional deterministic business plan would evaluate each of the investment policies separately and might find the costs of each alternative as $16, $12, and $10 million, respectively. The optimal decision is to install the substation three years from now.

But now suppose that there is some uncertainty in the load forecast. In particular, suppose that three deterministic forecasts are made, a low growth case, a nominal case, and a high growth case. Now each policy's cost is a function of the load growth case and can be expressed as a matrix:

Present Value Cost of Installing Substation (Millions of dollars)

	Load Growth		
Installation Timing	Low	Nominal	High
1 Year from Now	$12	$16	$28
2 Years from Now	$10	$12	$30
3 Years from Now	$8	$10	$40

In this case, the optimal solution is to install the substation next year if load growth is high, with present value cost of $28 million. If load growth is low or nominal, however, the lowest present value cost solution is to wait until year 3 for installation. Note that the middle column contains the costs noted above for the nominal case.

These evaluations are based on deterministic assessments of future conditions. This is the kind of analysis that a deterministic solution might lead to: find a good deterministic solution and see how robust it is under different scenarios. Perhaps not a bad approach, but if we are willing to learn more about the probability of occurrence of each of the load growth states, we can do better.

In particular, suppose that the probability distribution on load growth states was 0.25 for low, 0.50 for nominal, and 0.25 for high. The optimal policy provides the least *expected* cost. The expected cost of installing one year from now is 0.25($12) + 0.50($16) +0.25($28) = $18 million. Similarly the expected cost of installing two years from now is $16 million, and the expected cost of installing three years from now is $17 million. The optimal policy under uncertainty, in this case installing the substation two years from now, is not optimal under any deterministic scenario. Thus, analyzing problems under uncertainty using deterministic methods and logic can be misleading.

It is also instructive to take this example one step further by adding an option to delay. The option to delay is something that is provided by a distributed resource or any modular investment. Let us make the simplifying assumption that the future is learned perfectly after one year's delay and subsequent observation of load conditions. Thus, the value of building in the first year is $18 million, as found above. But if the option to delay were taken, the future is revealed. If load growth is low, which occurs with probability 1/4, then the optimal decision is to build in the third year, which costs $8 million (see matrix above). If load growth is nominal, build in the third year, which costs $10 million, and if load growth is high, build in the second year, which costs $30 million. The optimal policy is contingent on load growth and has an expected cost of 0.25($8) + 0.50($10) + 0.25($30) = $14.5 million. Hence, the expected value of the delayed policy is superior to building now and the value of such flexibility is given by $16 - $14.5 = $1.5 million, the difference between the best inflexible policy, which is to build in the second year, and the flexible policy, which we have just developed. This is the appropriate way to find the break-even cost of distributed resource investments under uncertainty.

CONCLUSION

The purpose of this paper was to define an approach to the DR planning problem. We began with a critique of the deferral method of analysis and showed that it does not lead to optimal solutions under certainty. We argued that this was because the objective of the analysis was misspecified, either implicitly or explicitly. DR planning requires identification of optimal investment policies, not so-called "cost-effective" ones. We further argued that methodologies that do not directly address the lumpiness of the more traditional T&D investments make decisions based on infeasible apparent marginal costs, and suggest ranking in terms of a $/kW criterion that can be misleading. A further reason for doubting the deferral approach is that it requires specification of a traditional

T&D plan, which it defers. There is no reason to believe that such a deferred plan will be optimal. Finally, we addressed the issue of uncertainty. We claimed that the critical issue in DR planning is optimal investment under uncertainty. Therefore, a successful methodology for DR planning will identify optimal investment strategies, where optimal means least cost with respect to actual cash flows, under uncertainty. If any of these elements are not present in an analysis approach, then the approach will be flawed and not ideally applicable to the DR investment problem.

APPENDIX: A Deterministic Model of DR Investment

The above results in the third section of this paper can be illustrated using a simple spread sheet model that computes maximum deferral and optimal deferral solutions. The model uses a discrete-time approximation for discounting costs. For ease of analysis, the model assumes an exponential cost function for the distributed resource, I_2, of the form:

$$TC_{SM} = F + \alpha C_1 (u/\delta)^{\beta} \qquad \text{(A1-1)}$$

where F = fixed cost and δ, β are parameters such that $\delta > 0$ and $\beta \geq 1$.

User inputs include the discount rate r, the size and the cost per kW for the lumpy resource, I_1, (K, C_1), the cost escalation rate of the lumpy resource (i), the distributed resource cost multiplier (α), the annual load growth in MW (L), the fixed costs associated with I_2 (F), and the degree to which there are decreasing scale economies associated with additional investments in the small resource (δ, β).

For example, Figure 2 in the text above is based on the following set of parameters.

Parameter	Value
r	6.0%
i	0.0%
L	0.25 MW/yr
K	50 MW
C_1	$100/kW
Fixed Cost	$0
α	2.8
δ	1.0
β	2.0

The spreadsheet is available upon request from the authors. Interested readers are encouraged to modify these parameters to determine the impacts on optimal and maximum deferral solutions.

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