IDENTIFYING DISTRIBUTED GENERATION AND DEMAND SIDE MANAGEMENT INVESTMENT OPPORTUNITIES [*]

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ABSTRACT

Distributed resources, such as distributed generation and targeted demand side management programs, offer electric utilities alternatives to large transmission and distribution (T&D) system capacity investments. This paper presents a method to estimate how much a utility can afford to pay for these alternatives when the change in system capacity due to the distributed resource is constant from year to year and when there is no uncertainty. The method is concise, has intuitive appeal, has minimal data requirements, and is accurate when benchmarked against two existing case studies. Analysts who want to screen distributed resource investment opportunities with a minimal amount of effort will find the method particularly useful.[1]

INTRODUCTION

Electric utilities have historically satisfied customer demand by generating electricity centrally and distributing it through an extensive transmission and distribution (T&D) network. As demand increases, the utility generates more electricity. Once demand increases beyond a certain level, the capacity of the generation, transmission, and distribution systems can become constrained. The traditional utility response to these constraints is to build new facilities.

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[1] QuickScreen, a windows-based software package based on the results of this paper, is available from Christy Herig at the National Renewable Energy Laboratory (303-384-6546) or John Stevens at Sandia National Laboratories (505-844-7717).

Utilities are considering alternative approaches to dealing with T&D system capacity constraints (Weinberg, Iannucci, and Reading 1991). One approach is to satisfy increased demand in these constrained areas using distributed generation (DG) technologies such as photovoltaics, fuel cells, engine generator sets, or batteries (Philipson 1994, Davidson and Braun 1993). Another approach is to reduce demand using demand side management (DSM) programs that are targeted to these constrained areas (Orans, et. al. 1992). DG and DSM investments can reduce a utility's variable costs and defer capacity investments as illustrated in Figure 1.[2]

DG feeds electricity into the utility grid (the arrow points toward the grid) while DSM "takes the increased demand out of the grid" (the arrow points away from the grid). When properly sited, both DG and DSM can relieve capacity constraints on the generation, transmission, and distribution systems and defer the need to build new facilities as well as reduce the utility's energy generation requirements.[3] Utilities that will benefit most from distributed resources are ones that have high discount rates and high average cost T&D system investments that are made infrequently.

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[2] Reliability considerations, both from a system perspective and a customer's perspective, may become important if system reliability changes when distributed resources are substituted for upgrading T&D facilities. Changes in reliability are not considered in this paper.

[3] DG and DSM are so closely related that Bailey, et. al. (1993) and others have used DG technologies as DSM measures.

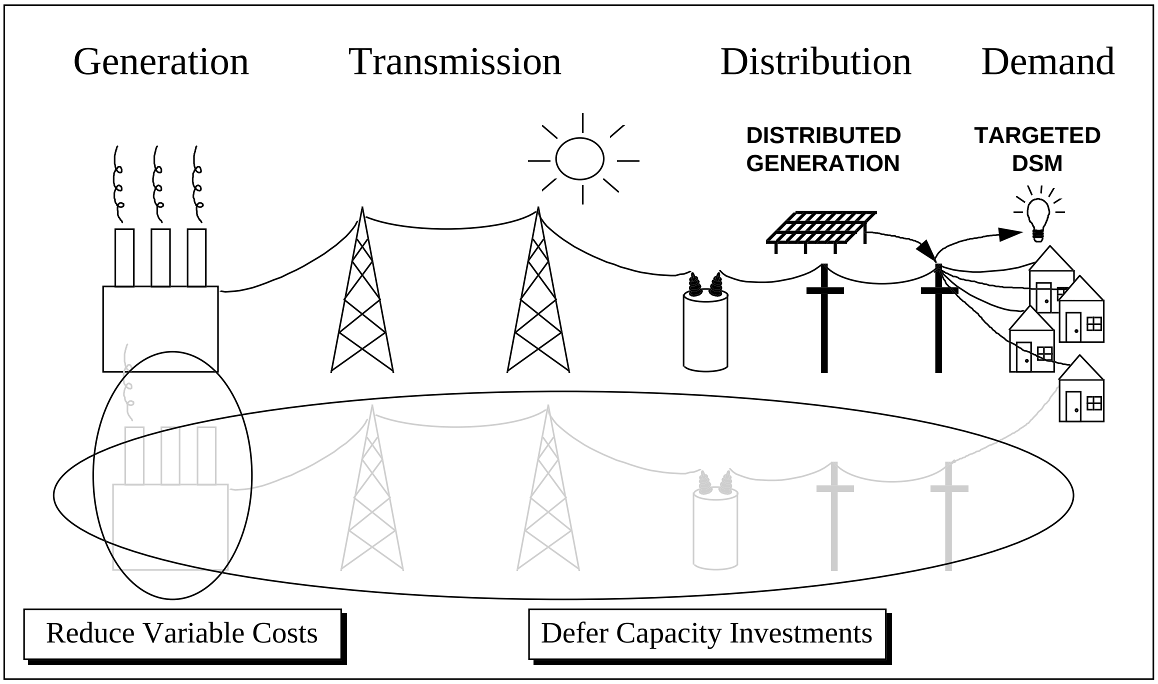

Figure 1. The benefits of distributed generation and targeted DSM to the utility system.

OBJECTIVE

Evaluating the cost-effectiveness of distributed resources is a crucial resource planning issue. Two of the earliest and most comprehensive evaluations were performed for Pacific Gas and Electric Company (PG&E). One study, performed by Shugar (1990), assessed the benefits associated with a 500 kW distributed photovoltaic (PV) generation plant. The other study, performed by Orans, et. al. (1992), designed a least-cost T&D resource plan using targeted DSM programs. Much of the work in assessing the benefits of DG and targeted DSM can be traced to these two efforts.

These two studies differed in what they were evaluating, method of evaluation, and methodological contributions. The DG study assessed the benefits associated with a single plant by dividing the utility system into many parts; it focused on developing technical evaluation methods. The targeted DSM study assessed the benefits associated with a wide range of DSM programs covering a period of years by evaluating the benefits in aggregate; it focused on developing economic evaluation methods.

The method presented in this paper takes the primary economic results from the DSM study and the key technical findings from the DG study and offers a more direct, less data intensive, approach to making decisions about when to invest in distributed resources. The method is based on the simplification that the economic analysis can be uncoupled from the technical analysis. One first estimates the cost savings associated with a perfect distributed resource and then modifies the result by the operational characteristics of the particular investment. This simplification becomes less valid if the change in system capacity associated with the distributed resource is not constant from year to year. This situation can occur when peak load timing is uncertain, when the peak load shifts from summer to winter early in the planning period, or when there is a large penetration of distributed resources on the constrained portion of the system.

The first section reviews the economic evaluation method from the targeted DSM study and highlights the technical evaluation results from the DG studies. The second section develops a general distributed resource economic evaluation approach. The third section summarizes the results from the second section in an equation to calculate the break-even price of a distributed resource and then benchmarks the equation's accuracy by comparing results with two existing DSM and DG studies. The final section presents conclusions and further research needs. Appendix A includes the nomenclature used in the paper and Appendix B contains data from the DSM case study. Readers that are interested only in final results should focus on the break-even price section.

EXISTING DISTRIBUTED RESOURCE EVALUATIONS

DSM ECONOMIC EVALUATION

Orans, Woo, and Horii (1994) developed a dynamic planning model for DSM evaluation in PG&E's planning area called the Delta Area. The model is referred to as the Delta Model. The Delta Model consists of marginal costing, evaluation, and implementation modules.

The marginal costing module accepts inputs on the utility's marginal generation and bulk transmission costs, annual marginal energy costs, and annual growth related investments (k_t in constant $) for a particular T&D planning area over some planning period (T years). The marginal T&D capacity cost (C in $/kW), which is based on the present worth costing methodology (Woo, et. al. 1994), is calculated to be the difference between the present value cost of the existing plan and the present value cost of the plan that is deferred by reducing demand by 1 kW (i.e., years of deferral is equal to 1 kW divided by annual load growth during the deferral period, L). r is the discount rate and i_t is the T&D investment escalation rate in year t.

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

The marginal cost (C) is annualized to each year in the planning period (C_t, for $t=0,\ldots,T$) and the annual marginal costs allocated to each hour in each year (C_{th}, for $t=0,\ldots,T;\ h=1,\ldots,8760$) using a weighting factor (W_{th}) based on hourly loads. This results in a marginal T&D cost for each hour of each year of the planning period.

$$C_{th}=C_tW_{th}\ . \tag{2}$$

The evaluation module determines a DSM program's cost-effectiveness by combining the hourly marginal costs with the technical effects of a particular DSM program. These technical effects include the reductions in peak demand and energy consumption and are estimated using engineering simulation models.

The avoided local T&D costs equal the present value of the marginal T&D cost (C_{th}) times the corresponding change in the area's load due to all DSM programs for each hour of each year (ΔD_{th}). ΔD_{th} is the sum of individual demand reductions due to various DSM programs applied to different end uses.

$$Avoided\ T\&D\ Costs = \sum_t \sum_h \frac{C_{th}^D \Delta D_{th}}{(1+r)^t} \ . \qquad (3)$$

The implementation module introduces a particular DSM program into the local T&D plan according to its cost-effectiveness.

DG TECHNICAL EVALUATION

A 500 kW PV plant was constructed in PG&E's service territory in Kerman, California, to empirically validate the results by Shugar (1990). The primary objectives of the validation effort were to determine the magnitude of benefits provided by the Kerman PV power plant to PG&E and to improve and document methods to determine the value of DG in general (Wenger and Hoff 1995).

The validation effort focused on assessing DG's technical effectiveness. Measured data were combined with existing utility engineering models to determine the operational effect of the PV plant on the utility system. Once the detailed analyses were performed, the evaluation was simplified in terms of methods as well as the amount of data required. While a great deal of effort can be devoted to assessing the technical effect of DG, the validation effort showed that accurate results can be obtained with a minimal amount of data.

GENERALIZED DISTRIBUTED RESOURCE EVALUATION

Deploying distributed resources can result in both capacity and variable cost savings as well as capacity and variable costs. This section develops the economic methods necessary to obtain these values. It describes the conditions required to uncouple the economic evaluation from the technical evaluation. This greatly reduces the effort and data required to perform the analysis.

CAPACITY COST SAVINGS

Method Simplification

The first category of cost savings is capacity cost savings. T&D capacity costs that are avoided due to a set of DSM programs are calculated by Orans, Woo, and Horii (1994) using Equation (3). This equation, which is equally applicable to DG investments, can be used throughout the utility, such as the bulk transmission and generation systems.

Equation (3) is simplified by substituting Equation (2) into the equation and observing that the capacity cost savings for any particular distributed resource is independent of other investments since the total demand reduction (ΔD_{th}) equals the sum of individual demand reductions (represented by Δd_{th}).[4] Thus, the capacity cost savings for any particular distributed resource equals

$$Capacity\ Cost\ Savings = \sum_t \frac{C_t}{(1+r)^t} \sum_h W_{th} \Delta d_{th} \quad . \tag{4}$$

[4] To be completely accurate, one would need to evaluate the technical effect of each distributed resource investment individually, select the most cost-effective alternative, and then repeat the technical evaluation.

Equation (4) can be further simplified if the annual change in system capacity is constant from year to year. For example, this means that if a particular investment reduces demand by 3 kW this year it will reduce demand by 3 kW in subsequent years. This is a realistic assumption because, while the magnitude of the load may change, the shape of the load is likely to remain constant.[5] Once this assumption is made,[6] the subscripts of year (t) in W and Δd are dropped and the two summation terms are separated.

$$Capacity\ Cost\ Savings = \left[\sum_t \frac{C_t}{(1+r)^t}\right]\left[\sum_h W_h \Delta d_h\right] . \tag{5}$$

Since the first bracketed term in Equation (5) is the present value of the annualized marginal cost,

$$Capacity\ Cost\ Savings = (C)(M) \tag{6}$$

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[5] This does not mean that the load shape will not change in the future if more investments are made in the future. It means that, if no more investments are made, the change in shape in the first year is representative of the change in shape in future years.

[6] Even the formulation of the problem by Orans, et. al. (1992) does not fully account for a changing effect over time because it collapses the details of the capacity expansion plan into a single marginal cost using Equation (1), annualizes the result, and then incorporates the technical effects. Changes that varied over time would shift different portions of the plan in different ways, thus requiring that the technical effects of any particular distributed resource be considered before the marginal cost is calculated.

where C is the marginal capacity cost and M, the capacity increase/demand reduction, equals $\sum_h W_h \Delta d_h$.

There are several things to notice about Equation (6). First, the economic analysis is independent of the technical analysis: the marginal capacity cost does not depend on the output characteristics of the particular resource. That is, no technical details about distributed resource performance are required to calculate the marginal capacity cost (C, which is a single number). Second, the technical analysis results in a single number (M) that describes the change in capacity. While Orans, et. al., calculate M using detailed load information, varying levels of effort can be used to obtain this number.

Marginal Capacity Cost

The marginal capacity cost (C) is calculated by determining the point at which the utility is indifferent between investing in a capacity expansion plan immediately or deferring the plan. In order to accomplish this, the present value cost of the existing plan must equal the cost of a distributed resource plus the present value cost of the deferred plan minus any salvage value of the plan (S) that remains at the end of the planning period. The salvage value is considered because the life of the deferred plan is longer than the life of the original plan. The distributed resource has a price of C (\$/kW), capacity of I (kW), and its life is the same as the expansion planning period. Assuming, as Pacific Gas and Electric Company (1991) has done, a constant escalation rate of i, a discount rate of r, and growth related investments in year t of k_t,

$$\sum_{t=0}^{T} \frac{k_t}{(1+r)^t} = C * I + \left(\sum_{t=0}^{T} \frac{k_t}{(1+r)^t} \right) \left(\frac{1+i}{1+r} \right)^{\frac{I}{L}} - S \left(\frac{1}{1+r} \right)^T \ . \tag{7}$$

Equation (7) can be rearranged in terms of *C*.

$$C = \left(\frac{\sum_{t=0}^{T} \frac{k_t}{(1+r)^t}}{I} \right) \left[1 - \left(\frac{1+i}{1+r} \right)^{\frac{I}{L}} \right] + \left(\frac{S}{I} \right) \left(\frac{1}{1+r} \right)^T \ . \tag{8}$$

When *I* equals 1 kW and the salvage value is negligible, Equation (8) equals Equation (1), which is the result derived by Orans, Woo, and Horii (1994) for a constant escalation rate (*i*). Rather than letting *I* equal 1, however, assume that the utility is on a yearly planning cycle and that *I* equals the annual load growth (*I* equals *L*). That is, sufficient distributed resources are installed to defer the capacity expansion plan for one year. Neglecting any salvage value, Equation (8) in this case reduces to

$$C = \left(\frac{X}{L} \right) \left[\frac{r-i}{1+r} \right] \tag{9}$$

where *X* is the present value cost of the capacity expansion plan (i.e., $X = \sum_{t=0}^{T} \frac{k_t}{(1+r)^t}$).

The only inputs that are explicitly required to determine the marginal capacity cost are the present value expansion plan cost (*X*), the annual load growth (*L*), the escalation rate of the plan (*i*), and the discount rate (*r*). It is implicitly assumed that the expansion planning period and the distributed resource investment life are the same. Notice that the details about the capacity expansion plan are unnecessary; only the present value cost of the expansion plan is required. Notice also that Equation (9) indicates that utilities that have high discount rates and are facing costly (on a $/kW basis), but infrequent, T&D investments will find distributed resources to have particularly high value. Equation (9) is used in this paper to calculate the capacity cost savings.

Applicability Throughout Utility System

Equation (9) is applicable to any portion of the utility system. This is illustrated using the generation system. Suppose that generation system capacity investments are made annually with the capacity of the investment equal to system load growth (*L*), investment life is the same as the generation system capacity expansion planning period and both are very long, the present value cost of an immediate investment in generation is k_0, and that the cost of an investment in generation is escalating at a rate *i* [i.e., $k_t = k_0(1+i)^t$]. The present value cost of this plan (*X*) equals $\sum_{t=0}^{\infty} k_0 \left(\frac{1+i}{1+r}\right)^t$ which reduces to $k_0\left[\frac{1+r}{r-i}\right]$.

Substituting this into Equation (9) and recognizing that *L* is the capacity of the generation investment, the marginal generation capacity cost equals the average generation cost (i.e., $C = \frac{k_0}{L}$).

VARIABLE COST SAVINGS

The second category of cost savings is variable cost savings. Variable cost savings are based on energy production and distributed resource location. The variable cost savings associated with a distributed resource equals the present value of the avoided variable costs. The investment has an annual energy output/energy savings of *E* (*E* is adjusted to reflect the change in system losses due to the location of the distributed resource using a model such as the one presented by Hoff and Shugar 1995), a life of *T* years, *r* is the discount rate, *e* is the variable cost escalation rate, and V_0 ($/kWh) is the current variable cost.

$$Variable\ Cost\ Savings = \sum_{k=0}^{T-1} \left(V_0\right)\left(\frac{1+e}{1+r}\right)^k E \quad . \tag{10}$$

This can be reduced to

$$Variable\ Cost\ Savings = \left(V\right)\left(E\right) \tag{11}$$

where the present value marginal variable cost for a technology with an annual energy output/energy savings of 1 kWh for *T* years is

$$V = \left(V_0\right)\left[\frac{1+r}{r-e}\right]\left[1-\left(\frac{1+e}{1+r}\right)^T\right] . \tag{12}$$

Notice that, like the capacity cost savings calculation, the marginal variable cost calculation does not depend on the characteristics of the particular distributed resource.

This variable cost savings calculation can account for situations when the marginal energy cost varies by time of day and season. Rather than having an annual estimate of E and V_0, there would be an estimate of E and V_0 for each period during the year.

DISTRIBUTED RESOURCE COSTS

There are costs in addition to cost savings. The two kinds of costs are capacity costs and variable costs. The capacity cost of a distributed resource is the present value of the investment's capital cost. If P is the price ($/kW for DG, $/program for DSM) and F is a factor that converts this to a present value cost (i.e., it is this factor that accounts for taxes, insurance, rate-of-return, etc.), then the capacity cost associated with having to make the investment is $(P)(F)$.

Although the variable costs could also be modeled as a separate cost category, another approach is to model them as a negative variable cost savings. When this is done, they are computed using Equations (11) and (12) where V_0 is a negative rather than a positive number.

BREAK-EVEN PRICE

EQUATION SPECIFICATION

A distributed resource is cost-effective[7] if there is a positive net present value associated with the investment. The first summation term in the following equation includes only capacity cost savings. The second term includes both variable cost savings and variable costs (i.e., some of the terms can be negative). The third term is the present value capital cost of the distributed resource investment.

$$\text{Net Present Value} = \sum_j C^j M^j + \sum_k V^k E^k - (P)(F) \tag{13}$$

where C^j is the *jth* marginal capacity cost (*j* corresponds to some portion of the utility, such as the generation, bulk transmission, or T&D system), V^k is the *kth* present value marginal variable cost (*k* corresponds to the different marginal variable costs, such as energy and environmental costs), and *F* is the factor that converts the distributed resource capital cost to a present value capital cost. M^j is the change in capacity associated with system *j*, and E^k is the energy production/energy savings associated with variable cost savings *k*. *C* is calculated using Equation (9), *V* is calculated using Equation (12), and *F*

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7 Inclusion or exclusion of certain costs or costs savings, such as lost revenues and environmental externalities, will determine what definition of cost-effectiveness is being used (e.g., ratepayer impact, total resource cost, etc.).

is specific to the utility and type of investment. Results from Wenger and Hoff (1995) indicate that *M* and *E* can be accurately determined with a minimal amount of data.

Equation (13) is set equal to zero and solved in terms of *P* to obtain the break-even distributed resource investment price. This is the most that the utility can spend on a distributed resource and the investment still be cost-effective.

$$P = \left[\sum_j C^j M^j + \sum_k V^k E^k\right]\left[\frac{1}{F}\right] \tag{14}$$

EQUATION VALIDATION

This section validates the economic portion of Equation (14) using economic data from two separate studies. These two studies were selected because one represented a DSM evaluation and the other a DG evaluation and because the author had no involvement in performing either of these studies. Technical data (*M* and *E*) are taken from these two studies as inputs.

Delta Area Case Study

Equation (14) can be validated using results from the Delta Model as applied to the Delta Area Case Study. It is accomplished by using the raw economic input data and the same technical inputs as used by Orans, et. al. (1992).

The thirty year distribution and sub-transmission capacity expansion plan present value cost for the Delta Area is \$112,300,000 (X), its cost is escalating at a rate of 6 percent per year (i), the utility has an 11 percent discount rate (r), and 9,000 kW in area peak reduction capacity are required to defer the plan for one year (L).[8] According to Equation (9) and these assumptions, the marginal T&D system capacity cost equals \$562/kW.

The marginal generation and bulk transmission system cost and marginal energy cost are not determined by the Delta Model but are inputs. Although these raw data are not specified directly in the report, it is deduced that the marginal generation and bulk transmission capacity cost is \$521/kW. It is also deduced that the initial average marginal energy cost (V_0) is \$0.024/kWh and is escalating at a rate of 6.0 percent for 30 years (e).[9] Based on these inputs, Equation (12) suggests that the present value marginal variable cost is \$0.40/kWh.

F equals 1.0 since DSM programs are treated as expenses. Thus, based on Equation (14) and these inputs, the break-even price for any DSM program in the Delta Area Case Study equals

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[8] Delta's optimal plan assumes that 9,000 kW of capacity are needed even though the load is only projected to grow at a rate of 7,700 kW per year. This number may be the optimal number due to limits on the penetration rate of the DSM programs.

[9] Other combinations of current marginal energy cost and energy escalation rates are possible to arrive at the same result.

$$P = (\$562 / kW) M^D + (\$521 / kW) M^G + (\$0.40 / kWh) E \tag{15}$$

where M^D is the demand reduction in the T&D system, M^G is the demand reduction in the generation and bulk transmission systems, and E is the energy savings associated with a particular DSM program. These three pieces of technical data are taken form the Delta Area Case Study and are presented in Appendix B. Also presented in Appendix B are the total benefits (i.e., the break-even price) for each program calculated by the Delta Model.

Figure 2 plots the break-even price for the 18 DSM programs using Equation (15) and the data in Appendix B versus the break-even price (i.e., the total benefits) calculated by the detailed Delta Model; the results would be identical if all of the points were directly on the dashed line. The figure suggests that Equation (15) is a good approximation of the detailed Delta Area Case Study result for each of the 18 DSM programs.[10]

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[10] A detailed comparison of the Delta results with Equation (15) results will show that the difference in results varies some by measure. This is because the Delta study uses marginal energy costs that vary by season and time of day (summer and winter seasons, and peak, partial-peak, and off-peak periods) while Equation (15) uses only an annual average marginal energy cost. This difference could be eliminated by expanding Equation (15) to have marginal energy costs that vary by season and time of day.

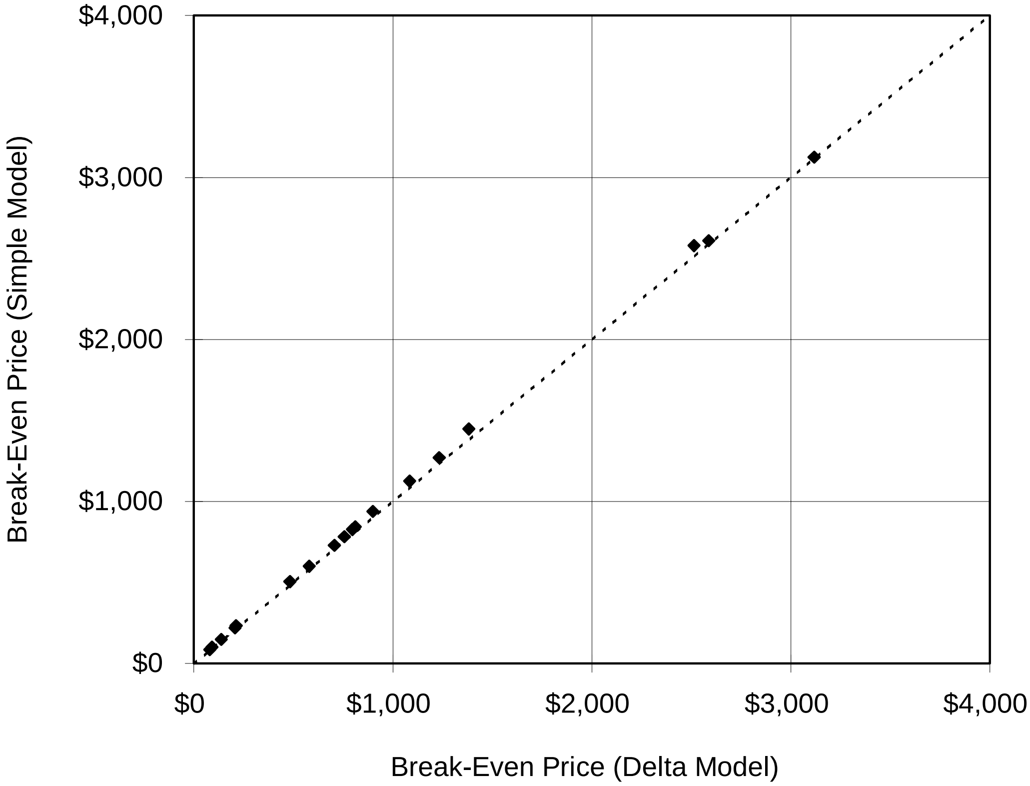

Figure 2. Break-even price comparison: simple model vs. Delta Model ($/program).

Arizona Public Service Distributed PV Generation Case Study

Another validation of the break-even price equation is to calculate the break-even price using data from the distributed PV generation study by Lambeth (1992). The study was jointly funded by Arizona Public Service and Sandia National Labs.

The distribution and sub-transmission capacity expansion plan present value cost for the area is $2,311,000 ($X$), the cost is escalating at a rate of 3.5 percent per year (i), the utility has an 11.2 percent discount rate (r), and 200 kW in area peak reduction capacity are required to defer the plan for one year (L). According to Equation (9) and these assumptions, the marginal T&D system capacity cost equals $800/kW. The present value marginal generation cost is $851/kW and the present value bulk transmission system cost is $462/kW. Lambeth (1992) calculates a capacity increase of 0.83 kW per kW of PV for the generation, transmission, and T&D systems. Thus, the total capacity cost savings equal the marginal costs of $800/kW plus $851/kW plus $462/kW times the 0.83 kW per kW of PV, or $1,754/kW of PV. This is the first summation in Equation (14).

The initial average marginal energy cost is $0.024/kWh and is escalating at a rate of approximately 8.0 percent per year (*e*). The study implies that the initial average marginal environmental cost is $0.022/kWh and is escalating at a rate of approximately 3.5 percent year. PV plant life is 30 years. Based on these inputs, Equation (12) suggests the present value marginal energy costs equal $0.49/kWh and the present value marginal environmental costs equal $0.28/kWh. Lambeth (1992) assumes a 14 percent reduction in system losses and a 32 percent PV plant capacity factor, which translate to an annual energy production of 3,195 kWh per year per kW of PV (1.14 * 0.32 * 8,760). Thus, the total variable cost savings equal $0.49/kWh plus $0.28/kWh times of 3,195 kWh per year per kW of PV, or $2,460/kW of PV. This is the second summation in Equation (14).

The factor that converts the capital cost of a PV system to a present value cost for Arizona Public Service's system is 1.30. Thus, the break-even PV price equals $1,754/kW plus $2,460/kW divided by 1.30, or $3,241/kW. This result is within about 5 percent of the detailed study's break-even price of $3,440/kW.

CONCLUSIONS

Distributed generation technologies and targeted demand side management programs offer electric utilities an alternative to large system capacity investments. This paper presented an evaluation method to determine how much a utility can afford to pay for these distributed resources.

The method is based on the simplification that the economic analysis of distributed resources can be uncoupled from the technical analysis. One first estimates the cost savings associated with a perfect distributed resource and then modifies the result by the operational characteristics of the particular investment. The simplification results in a substantial reduction in the data necessary to perform an analysis. This simplification becomes less valid if the change in system capacity associated with the distributed resource is not constant from year to year. This situation can occur when peak load timing is uncertain, when the peak load shifts from summer to winter early in the planning period, or when there is a large penetration of distributed resources on the constrained portion of the system.

Initial validation efforts using two extensive case studies suggest that the simplification does not result in a loss of much accuracy. Thus, analysts who want to screen distributed resource investment opportunities with a minimal amount of effort will find the method particularly useful.

One set of attributes not addressed in this research are related to risk and uncertainty. As Logan, et. al. (1995) and others point out, these uncertainties include: demand growth, fuel price, environmental requirements, technology cost, plant output, and industry structure. While much work remains to be done in this area, a brief comment is in order on how these uncertainties may affect the results presented in this paper.

Demand uncertainty is likely to have the greatest effect on the results presented in this paper; it may either increase or decrease the value of distributed resources. On the one hand, value may increase if the distributed resources have short lead times relative to the T&D upgrade because they provide the utility with the option to wait closer to the time when added capacity is actually required before investing (Hoff and Herig 1996). On the other hand, value may decrease if larger distributed resource investments are required to prepare for worst case peak load conditions. Fuel price and environmental requirements uncertainties may increase or decrease the value and are likely to be technology specific and depend upon what alternatives the distributed resource is displacing. Uncertainty in distributed resource costs may increase the value of distributed investments relative to the T&D upgrades because of the modular nature of the investments (Hoff, Wenger, and Farmer 1996). In any case, how to incorporate each of these uncertainties into the method presented in this paper deserves further investigation.

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APPENDIX A: NOMENCLATURE

C = marginal capacity cost

ΔD = change in area load due to all DSM programs

Δd = change in area load due to particular DSM program

e = energy cost escalation rate

E = annual energy output / energy savings

F = conversion of DG / DSM capital cost to present value capital cost

h = hour

i = capacity cost escalation rate

I = DG / DSM investment capacity

k_t = annual growth related capacity investment in year t

L = annual load growth

M = capacity increase / demand reduction

P = break - even DG / DSM investment price

r = discount rate

S = capacity expansion plan salvage value

t = year

T = capacity expansion plan life or DG / DSM investment life

V_0 = current marginal variable cost

V = present value marginal variable cost

W = weighting factor based on hourly loads

X = capacity expansion plan present value cost

APPENDIX B: DELTA AREA CASE STUDY DATA

Table A-1. Capacity and energy reductions and total benefits for Delta Area (Orans, et. al. 1992, pp. 5-5 to 5-6).

Program	Area Peak Reduction (kW)	System Peak Reduction (kW)	Energy Savings (kWh)	Total Benefits ($)
Residential Retrofit				
Lighting	0.09	0.02	100	91
Infiltration Repair	0.14	0.09	56	138
Insulation and Shading	1.03	0.64	531	1,083
Air Cond. Tune-up	0.21	0.13	84	208
Air Cond. Duct Repair	0.48	0.30	195	485
Air Cond. Early Changeout	0.89	0.56	363	900
Air Cond. Replacement	0.79	0.49	321	796
Refrigerator Rebate	0.04	0.02	132	80
Residential New				
Lighting	0.21	0.04	233	213
Shading and Air Cond. Upgrade	2.19	1.53	1,449	2,588
High Perf. Win. and Air Cond.	2.53	1.77	1,944	3,116
Commercial Retrofit				
Air Cond. Tune-up	0.33	0.40	971	756
Lighting	0.63	0.95	4,327	2,512
Refrigeration Curtain Door	0.47	0.38	2,462	1,382
Air Cond. Upgrade	0.36	0.43	1,042	812
Commercial New				
Window Film	0.22	0.27	841	579
Lighting	0.31	0.47	2,126	1,234
Air Cond. Upgrade	0.31	0.37	906	706