Distribution System Regulation

Introduction

The MADRI Regulatory Subgroup has been tasked with addressing issues related to distributed resource-related regulation of distribution utilities. This document addresses potential reporting and cost valuation methodologies regulators can use to help quantify the value of distributed resources in terms of avoided or deferred distribution level costs. These values can be used to the amount of payments or credits for distributed resources that deliver these values to the distribution system.

Section 1 – Description of the reporting and process requirements for revealing the values of distributed resources in the distribution system.

Magnitude of Distribution Investments

Collectively, utilities in the US typically invest over $5 billion per year in their distribution systems. Unlike investments in generating and transmission facilities, which can be somewhat erratic (or lumpy) in both timing and magnitude, investment in the distribution system is typically an on-going process in which the annual investments are relatively more consistent and predictable. Year to year investment levels may be variable, but when averaged over three to five years, investments by individual utilities are likely to appear relatively constant.

Nominal vs. Effective Cost of Distribution Investments

While overall investment levels may appear relatively constant, the *effective* costs of distribution investments, on a per-MW or per-MWh basis, are not homogenous. They are highly dependent on granular conditions within the distribution system. Important factors that impact the effective cost of distribution investments include geographic topography (i.e. whether the location is urban or rural, mountainous or plains, etc.), technical topography (i.e. whether the facilities are underground or overhead, outside or inside a building, radial or networked, etc.), and end-use topography (i.e. customer density, consumption and growth patterns of end-use, and types of end-use loads such as the presence of motors or other equipment that may affect local power quality or present other special needs). The highest effective costs are seen in locations where load growth is relatively slow and the costs of solutions are high (because of any combination of geographic, technical or end-use topography).

For example, when confronted with a substation that is nearing its capacity, the utility might install a new 40 MW transformer at a "nominal" cost of, say, $30/kW, for a total investment of $1.2 million. If installation of this transformer coincided with 40 MW of new load, then one could say that the $30/kW cost was the same as its effective cost. Using reasonable simplifying assumptions (a 65% load factor, a thirty year life and a weighted after tax cost of capital of 8% for this new load and ignoring distribution plant O&M), we can see this results in an effective cost/kWh of approximately $0.00084/kWh in the first year.

On the other hand, if the load does not match the capacity of the upgrade but is some smaller amount, say 5 MW per year, the effective cost jumps to $0.00674/kWh – 8 times higher than the nominal cost of the transformer. If load growth is only 0.5 MW per year, the cost would be $0.6744/kWh, or 80 times higher than the nominal cost of the transformer. In other words, rather than $30/kW, the transformer can have an effective cost of between $240 and $2400/kW, an amount which is, alone, sufficient to justify the installation of many forms of demand-side resources.

Of course, the same analysis applies to the differential between the required capacity and the rated capacity of a distributed resource alternative. However, distributed resources often do not come in the larger "lumps" that distribution hardware does. This will depend heavily on the assortment of options considered and how they might be combined to deploy an optimal alternative to distribution system upgrades.

But even the nominal cost of distribution system investments can vary widely on a rated capacity cost per kW. While our example uses a nominal cost of $30/kW for the distribution system "solution," real-life nominal costs can be much higher – often running as high as $60/kW and sometimes as high as $300/kW.[1] In these situations the effective costs of these solutions can be has high as $480 to $48,000 per kW (using the same assumptions from our previous example)! Even exotic alternatives to traditional distribution solutions, such as solar and energy storage, can be deployed at these effective costs and these high cost projects can be as much as a third of the projects facing a distribution utility.

Potential Deferral Values for MADRI Utilities

Although we lack specific data for individual distribution system projects for each utility in the MADRI footprint, we are not without useful company-specific aggregate data that can suggest the potential values for deferring distribution investments. Specifically, the annual distribution system investments and system load growth for most utilities filing a FERC Form 1 during the period 1994-1999 has already been compiled for this very purpose.[2]

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[1] For example, in data set of distribution projects for Commonwealth Edison for the year 2000, out of a total of 65 projects, 22 had a nominal cost of $60/kW or more, 10 projects cost more than $100/kW and the highest cost project came in at $300/kW.

[2] See *Distribution System Cost Methodologies for Distributed Generation*, The Regulatory Assistance Project, September 2001 available at: http://www.raponline.org/showpdf.asp?PDF_URL=%22Pubs/DRSeries/DistCost.PDF%22 and the accompanying *Appendices* available at: (http://www.raponline.org/showpdf.asp?PDF_URL=%22Pubs/DRSeries/DCAppndx.pdf%22) and the associated *Distribution System Cost Deferral Lookup Table*, available at: http://www.raponline.org/Pubs/DRSeries/CostTabl.zip.

Figure 1 shows the potential deferral values of distributed resources for a number of utilities within the MADRI footprint. These data are based on the actual average marginal distribution costs per MW of average growth in system peak for the five year-to-year periods from 1994 to 1999. The values reflect an assumed "high cost" case that is 1.94 times the average cost per MW experience by each utility.[3]

Figure 1

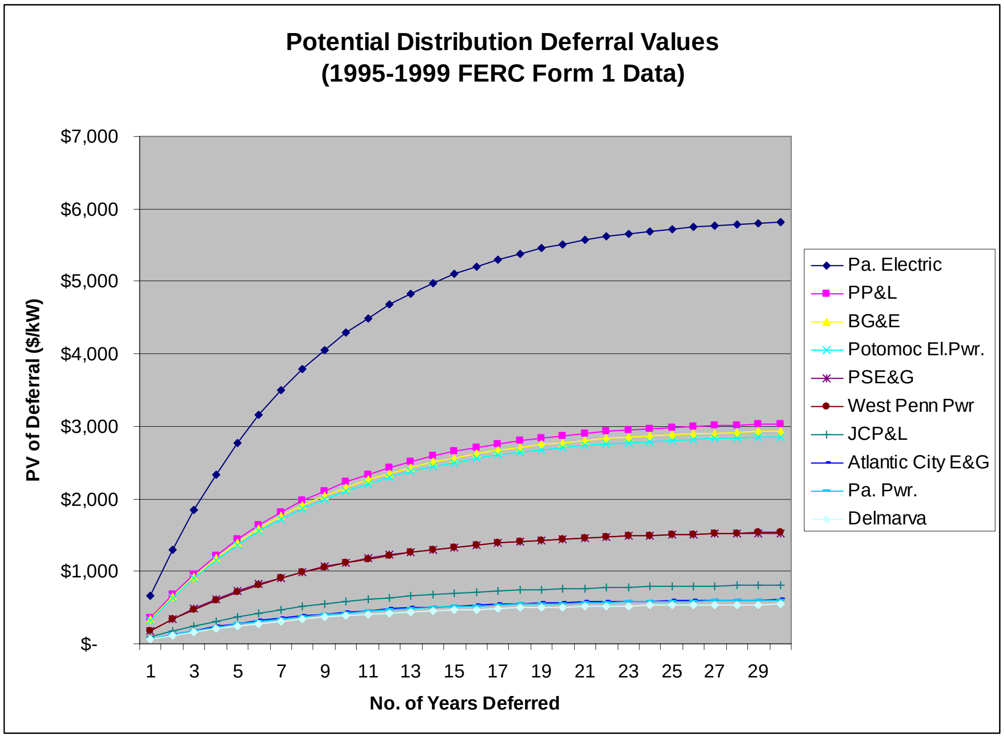

Figure 1 answers the question, "How much money (expressed in $/kW) should a utility being willing to pay (equivalent to an up front cash payment) to defer or avoid its distribution system investments?" The answer is the sum of the present value revenue requirement for the distribution system investment for each year that it might be deferred.

Figure 2 reflects data for Potomac Edison which would appear to be a special case because the experienced cost levels are more than six times higher than even the highest of the rest of the utilities. One should not conclude that these values would be typical or expected for Potomac Edison going forward – indeed, one would expect some extraordinary project, accounting entry or other special circumstance to have generated such large values. Variations from the "norm" such as this only reinforce the notion that actual forward-looking data for this company (as for all of the companies) should be analyzed and understood before reaching any conclusions.

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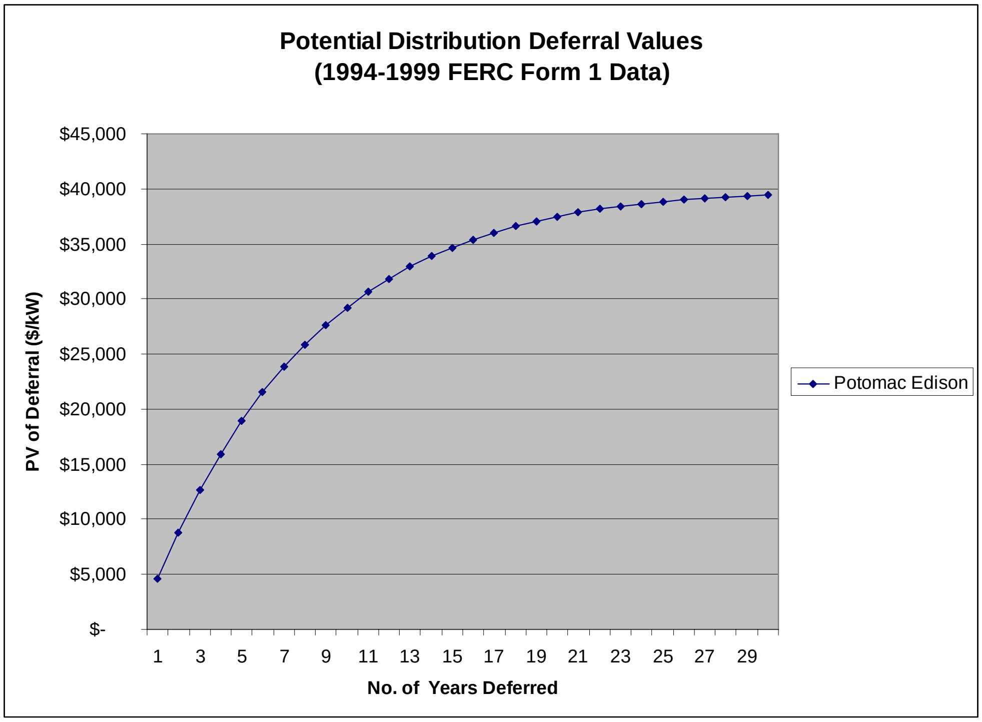
[3] A range of variability was developed based on the Commonwealth Edison data to derive low and high cases for each utility, based on one standard deviation from the average. The resulting percentage ranges were then applied to other utilities to compute a potential high and low case based on each utility's average for the study period.

Figure 2



While individual analyses of each of these utilities' systems is required to identify actual deferral values on individual projects or specific locations on the distribution system, the magnitude of these potential values suggests that many forms of distributed resources, including load control and distributed generation, might be economically justified without relying on their use for economic dispatch purposes (i.e. without relying on energy and capacity values relative to wholesale power supply costs). This is especially true where these resources can defer investments for 5-10 years or longer.

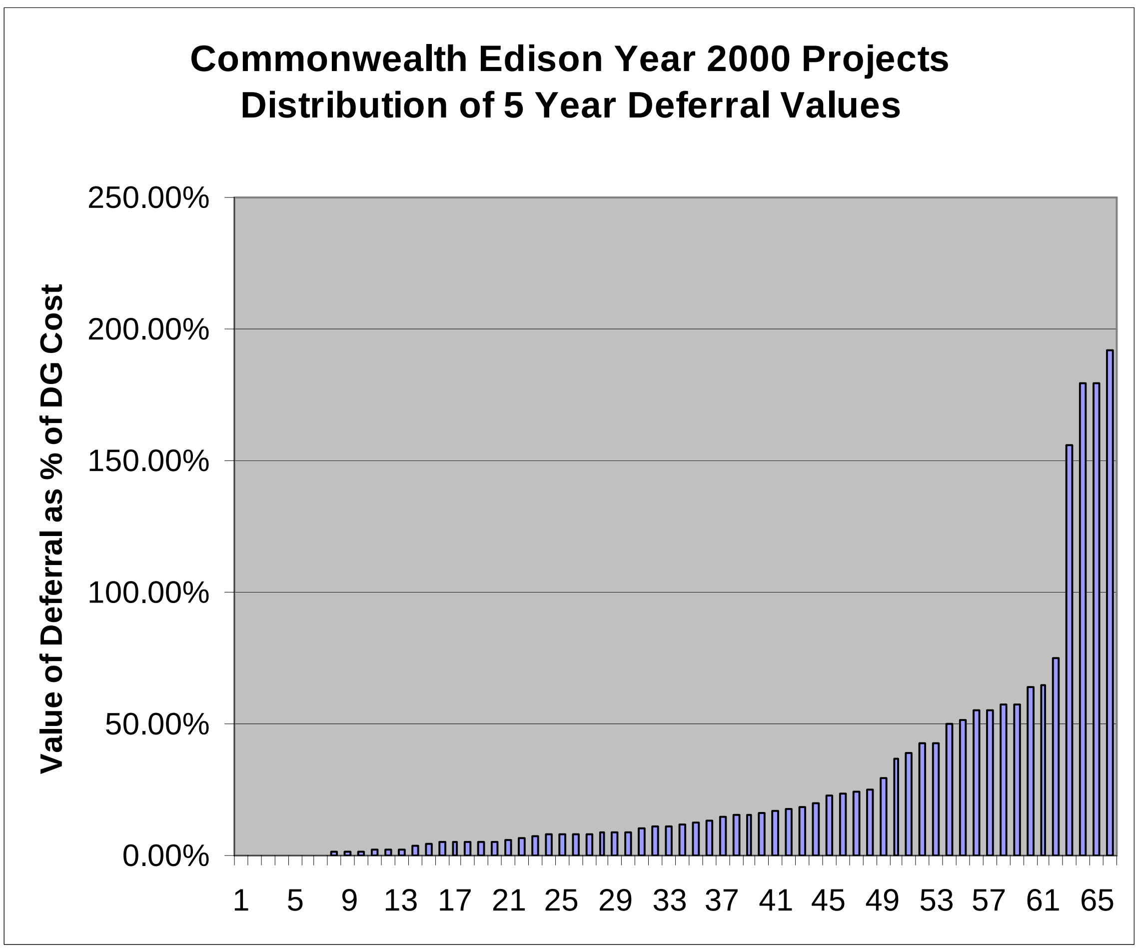
Finally while some of these companies have higher cost curves (Pennsylvania Electric, PP&L, BG&E, Potomac Electric Power and PSE&G) and others have lower cost curves (West Penn Power, JCP&L, Atlantic City Electric & Gas, Pennsylvania Power and Delmarva), this does not lead to the conclusion that the companies with lower overall costs would not have high value potentials. Because of the large variability in the effective cost of specific distribution system problems and solutions, even low cost utilities can have zones of high cost problems and solutions. Again, access to good data about the distribution system is the key to understanding these potential values.

Assessing the Significance of the Indicated Values

There is considerable skepticism that the suggested deferral values for the MADRI companies are an accurate reflection of reality. In part this is because these values appear, at first blush, to be higher that those found in a similar analysis done for the Business Model Subgroup, which generally found a significant "gap" in the expected values for DG. In fact, these are different kinds of analyses and appear to be largely consistent with another. The effective capacity costs appear so large because the denominator is not the capacity of the new installation, but rather the incremental load that it would serve.

Fortunately, we a large data set of individual distribution project for one (non-MADRI) company from the year 2000 for comparison which enable a calculation of the levelized annual deferral value if each distribution project could be deferred for five years. With a data set having an "n" of 66, on average the annual levelized value of deferring a distribution project was about$13/kW, albeit with a very high standard deviation of ± $20. Fourteen of the projects (21%) yielded deferral values of $20/kW or higher and four of the projects (6%) yielded values of $75/kW or higher. These correspond to *effective* costs of as much as $5,300/kW and higher.

The analysis done for the Business Model Subgroup was expressed in terms of the percentage of the cost of the DG unit that could be realized through distribution system deferrals. The following chart reflect the distribution of the Commonwealth Edison data, assuming the projects are deferred for five years.



The distribution of these values appears to be consistent with the analysis done for the Business Model Subgroup. The average value for these data is approximately 28% of the cost of a DG unit. However, a sizable number (13 or 20%) of the projects have deferral values that are approximately 50% of the cost of the DG unit or higher and four would have values that exceed the cost of the DG unit. Of course, we have no way knowing if DG units could, from a pragmatic standpoint, be deployed in any of these particular situations.

In conclusion, one can have a relatively high degree of confidence distribution deferral values are likely to be significantly large enough to warrant data gathering and disclosure. In so doing, it would not be unreasonable for regulators to "triage" the distribution system into low, average and high cost zones in order to target rate credits for DG.

Recognizing Locational Values on the Distribution System

Deploying distributed resources in high cost areas would be a win-win situation for consumers and distribution utilities. The challenge is to develop policies to concentrate the use of distributed resources in high-cost areas. De-averaged distribution credits and distributed resource development zones meet this challenge.[4]

On the one hand, distributed resources seem ideally suited to be delivered in a competitive fashion. They represent the antithesis of economies of scale. Distributed resources may be the ultimate form of retail competition because they can be used by consumers with or without industry restructuring.

On the other hand, if distribution prices are geographically uniform, monopoly distribution utilities will have an unbeatable competitive advantage and distribution utilities will be the only entities positioned to “see” the distribution value of distributed resource deployment. States that wish to encourage competitive delivery of distributed resources are compelled to either 1) de-average distribution prices on a geographic basis - unlikely for a long list of reasons, 2) prohibit distribution utilities from owning distributed resources - also unlikely, plus it levels the field at the cost of eliminating all suppliers, or 3) adopt geographically de-averaged distribution credits - a low-cost, low-risk strategy that might yield large benefits.

Under a program of geographically de-averaged distribution credits, the utility would establish financial credits for distributed resources installed in a given area. The amount of the credit would be a function of the distribution cost savings that would be generated through deployment of the distributed resources. Credits would be limited in duration and magnitude, in order to match the timing and need for distribution system reinforcements. For example, credits might be available to the first 20 MW of distributed resources installed in the next year, because, after that period, loads are expected to grow to make construction of new distribution lines unavoidable.

[4] In theory, regulators could simply geographically de-average distribution prices, requiring the utility to charge something approaching zero in areas that have excess distribution capacity, and the deferral value in areas with constrained distribution facilities. De-averaged marginal cost prices would send the “right” price signals to consumers and would ensure that distributed resources would be installed precisely when and where they make the most sense. De-averaging prices along these lines, however, is unlikely and undesirable for compelling practical and political reasons.

The amount of the credits should reflect the value (savings) derived from deferring or avoiding the distribution upgrade. Credits would also vary by location of the distributed resources. Credits would be highest in areas of greatest need and would be zero in low-cost areas. For example, customers in an area with 20¢ distribution costs might be offered a 15¢ credit. This would certainly produce a strong economic incentive for customers and others to invest in distributed resources. Because the credit is 15¢ instead of the 20¢ the utility would incur to upgrade facilities, there is an opportunity for savings to be shared.

The term “de-averaged credits” is being used as shorthand for a family of related policy options that provide cost-effective economic incentives to concentrate distributed resources in high cost areas. Distributed resource development zones, for example, would designate geographic areas and set a standard credit for all qualifying distributed resources that locate in the area. One could use a Distribution Value Bidding scheme to invite competitive proposals from distributed resource vendors. The amount of the credit requested in the bids would be one of the criteria used to select winning distributed resources.

Implementing Distributed Resource Credits

Step one: Identify high cost areas.

The first step is to examine capital investment plans and identify parts of the distribution system that could most likely benefit from the deployment of distributed resources. The earlier the areas can be identified the better. It is best to look for areas that will require investment in the next 24 to 36 months rather than areas that need investment in the next 30 to 90 days. This allows enough lead time to seek distributed resource alternatives.

Step two: Address design issues.

Designing a de-averaged credit, market-based program requires consideration of a number of important practical questions. For most issues there is not a single right or wrong answer. The best way to proceed is to ask the distribution utility and the interested distributed resource vendors and users to collaborate on program design. The top six issue areas that need to be considered are described below.

Type of distributed resources that can qualify

Not all distributed resources are created equal. The utility and regulators need to decide which distributed resources can participate in a credit program. For example, the most common distributed resource today is an internal combustion (gasoline or diesel) engine connected to a generator. Environmentally, many of these types of units are very bad, yet because of their small size and historically very limited hours of operation they currently require no environmental permits.

It would be short-sighted to design and implement a distributed resource credit program if the result was to substantially increase the use of these types of distributed resources. It would not only be bad for the environment, but it would probably hasten new environmental regulations that could undermine the value of the units to the utility and to the customer. A more prudent course would be to designate a class of qualifying distributed resources that would be eligible for the program and exclude distributed resources that may cause environmental or other problems. Another option is to provide for graduated payments with higher payments to clean resources on the basis that these resources are more likely to result in the desired cost savings.

Qualifying resources should also include demand- and supply-side options. Some demand-side options, mostly load management options, will be easy to incorporate. Indeed, many utilities already have credit approaches that offer customers a payment or reduced electricity price if they agree to have part of their load under direct control. These programs, however, have generally been designed with an eye toward reducing system peak energy and capacity costs rather than avoiding or deferring upgrades to the distribution plant. Changing the focus to distribution cost savings means that the loads may have to be curtailed during the distribution peak instead of the system peak.

Operating and performance standards

Distributed resources can save money if they either generate power or reduce demand during the high cost periods. Thus, the terms of a de-averaged credit program should specify that the credit is tied to the distributed resource's ability to deliver its value during the hours that the substation or feeder is at or near peak load.

Several approaches can be taken depending on the size and nature of the distributed resource. For the smallest units that are not directly under the user's control, such as PV, wind, CHP units, or units that are designed to run whenever available, this requirement should be determined in an aggregate, probabilistic manner. Some combination of load studies, manufacturer's availability data, and warranty information can be used to estimate the likely contribution during peak periods. If, for example, only 60% of the installed generation is likely to be on-line during the peak periods, the credits paid to this class of facilities would be discounted. Special metering and individually determined credits could be options but they should not be required.

For small units that are directly under the user's control such as back-up generators, it may be necessary to require some type of metering to show that the unit operated. For larger units installed on the premises of customers who are likely to have more sophisticated metering, credits could be paid on a metered time-of-use basis. This would result in higher credits paid to the distributed resources that are operating more when needed.

Also, many distributed resources are capable of being in direct two way communication with the utility. Microturbines, fuel cells, and radio-controlled loads can all be placed under direct utility control or at least can be monitored by the utility in real-time. This provides the best opportunity to manage the distributed resources to reduce distribution costs, and distributed resources with this type of capability should receive the highest possible credit.

Installation time, milestones and amount of response

Distributed resources can save money by avoiding or deferring distribution upgrades if enough distributed resources are in place in time to avoid conventional upgrades. Conventional distribution system upgrades are planned and installed in a fairly short time period; one to three years is common.

This has several implications for a de-averaged credit program. First, it means the utility should have a well developed distributed resource credit program prepared, approved by regulators, and ready to deploy in a given area as soon as it appears an upgrade will be needed.

Second, deploying distributed resources will take some time. How the market reacts to a credit program will only be known with certainty after the programs have been in use for some time. The most likely scenario is that distributed resource vendors, rather than retail customers, will be the main users of the credit program. Once the availability and size of credits are known, vendors will begin the job of marketing their goods and services to end users. The credit will allow a distributed resource vendor to discount equipment and reach agreements quickly with end use consumers.

Third, there may be some minimum amount of distributed resources that must be made available before distribution savings can be realized. It seems reasonable that a de-averaged credit program would state the minimum amount of distributed resources that must apply and qualify for the credits before any credits are paid. To protect against the situation of sufficient distributed resources signing up for the credits but then not materializing, a reasonable set of milestones could also be established. If a project fails, another should be allowed to step into its place.

To avoid paying for more distributed resources than are needed, the program could also state the maximum amount of distributed resources that will receive the credits.

Duration of distributed resources performance

In some cases, the value of distributed resources will be the ability to postpone distribution upgrades for a few years. In this situation, the persistence of the distributed resources should not be much of an issue. In other cases, the value may be in a more permanent substitution for distribution investment. This results in the long term reliability of the distributed resources being more important.

There are at least two approaches to matching the performance of the distributed resources to the needs of the distribution system: contractual requirements and payment terms. Contract, including standard contracts for small units, could specify performance requirements including long-term availability. Failure to meet the requirements could result in reduced or lowered payments or, if needed, fines and penalties.

For larger units with time-of-use metering, long-term availability can probably best be addressed through credit payments. Credits are paid on the basis of measured performance relative to the needs of the distribution system. For example, if the distribution system experiences its peak loads on weekday afternoons during the summer, payments could be made based on the measured performance of individual distributed resources during these designated periods. If the credits were based on three years worth of deferrals, the performance-based payments should be spread out over the entire three year period. If the credit payments have been in the form of large up front payments, the contract may provide for repayment of excess payments if the distributed resource ceases operation.

Standard Contract

To reduce transaction costs, it makes sense to have a simple, standard contract setting forth the duties and responsibilities of all parties. Having a standard contract also provides an opportunity for regulatory oversight and input from vendors and users into important contract terms.

Experience with small scale wind and interconnected PV facilities and net metered facilities provides substantial experience on reasonable and unreasonable contracts. Contract terms covering metering and insurance can be made too onerous to be successful.

Bidding or standard payments.

Credits could be paid on the basis of fixed preset credits, such as $/kW/year, for qualifying distributed resources. The fixed credits could be the same for all types of distributed resources, or they could differ for different classes of distributed resources. Higher credits for cleaner distributed resources or distributed resources using CHP would be one way to encourage these types of facilities.

The level of the payments could range from very low up to the estimated value of the distributed resources. The credits could also be the same in all designated areas or they could differ based on the relative need for distributed resources and the potential distributed resource cost savings. Offering different levels of credits in different locations (which is probably justified by differing distribution cost savings) would help create a supply curve for distributed resources.

Alternatively, payments could be made on the basis of competitive bids with the winning bids being the distributed resources requesting the lowest credits. This approach has the appeal of offering the most value to consumers, but it also may have the highest transaction and administrative costs.

Step three: Develop a monitoring and evaluation plan

To determine the performance of a distribution credit program, the regulator may wish to require measurement, verification and reporting by the utility. This may include the following items:

1. Distribution plant performance.

How does the operation of the distributed resources affect substation and feeder loadings? How is distribution affected during high load periods? During low load periods? Are there any unanticipated affects on the distribution plant? Would direct control of the distributed resources by the utility add any value?

2. Distributed resource performance.

How well do distributed resources perform individually and in the aggregate? How many distributed resources does it take before aggregate performance is reliably predictable? How do distributed resources perform over time? Does the method of payment affect performance? How do different technologies perform? How well has distributed resource operation matched the needs of the distribution equipment? What types of distributed resources are able to be dispatched by the utility?

3. Distributed resource supply curve.

What is the relationship between the quantity of distributed resources and the level of the credits? Can supply curves for distributed resources be constructed? Can they distinguish between distributed resource technologies?

4. Distributed resource response time.

How long does it take from the time the need for distributed resources is determined to the time distributed resources can be installed? How does the response time vary with the credit approach taken (bidding versus standard offer)? How does the response time differ for different types of distributed resources? How does the response time differ based on varying levels of credit?

5. Service quality and outage performance.

Have the distributed resources had a discernable effect on outages, frequency, restoration times, or power quality?

6. Environmental performance.

What are the emission characteristics of the distributed resources? Did the operation of the distributed resources raise environmental concerns for local residents or local environmental agencies? Was there any relationship between the level of the credit and the type of distributed resources deployed?

7. Distributed resource vendor and user feedback.

What problems did the pilot pose to distributed resource vendors and users? What suggestions were received to improve the program? Did the siting and operation of distributed resources cause local noise, pollution, or other complaints? Did the distributed resource provide any other benefit to the user such as power quality, back-up service, heating, cooling, or motor drive?

8. Customer profiles.

What types of customers installed distributed resources? What types of customers were able to use CHP distributed resources? What kind of customer allowed the utility to dispatch the distributed resource?

9. Tracking cost savings and credit payments.

Have the estimated savings been achieved? At what cost to the utility? At what cost to the customer?

Section 3 – Model tariff for credits or payments to DR for distribution values

Section 4 – Example Case