Achieving a Robust Market on the Distribution Grid

Mark B. Lively
Utility Economic Engineers
Gaithersburg, MD USA
301-428-3618
MLively@LivelyUtility.com

SUMMARY

This paper presents a cost basis for achieving a fungible commodity market for using the distribution grid. Markets are more robust when they deal with a fungible commodity and when many participants are interested in buying and selling that fungible commodity. A robust commodity market will lead to various forms of futures or forwards markets. These futures markets are likely to be more robust than they might be without an underlying fungible commodity market. For the market on the use of the distribution grid, these futures markets may take some form of a capacity market. The standard utility tariff generally has such a capacity market.

BACKGROUND

Most markets for the use of the distribution grid have yet to develop the concept of a fungible commodity.[1] The standard approach to the distribution grid market relies on the utility's planning program. Under this standard approach, a distributed energy resource (DER) is considered to be worthwhile **only** when it allows the utility to defer an investment in the distribution grid. Such investments may include adding transformer capacity at the distribution station and replacing existing wires with larger diameter wires along the street.

The planning approach to valuing DER is rarely fungible. Distribution investments are lumpy. Such investments occur infrequently and must be made in standard sizes. Each DER will generally be of the wrong size to defer or replace the upgrade exactly. Often the DER will be too small to result in a change of the distribution system planning process. Occasionally, the DER will be too large for the distribution system planning process to make full use of its contribution to the capacity of the distribution system.

Consider the case where DER comes in uniform standard sizes, say 1 MW, and that the utility needs to upgrade the distribution grid for 3 MW. Without 3 MW of DER, the

---

[1] Fungible—Being of such a nature or kind that one unit or part may be exchanged or substituted for another unit or equal part to discharge an obligation. *The American Heritage Dictionary, Second College Edition*, 1985.

utility must expand the distribution grid under the standard planning paradigm. The addition of 1 or 2 DER units will produce 1 or 2 MW of capacity, but will not allow the utility to defer the expansion. However, the addition of a 3rd DER unit allows the utility to defer the expansion, reduce its capital budget and pay the 3rd DER for its presence. This provides no payment to the 1st or 2nd DER units, or to a 4th or 5th DER unit. The planning process does not result in a fungible financial plan for DER.

This paradigm tying DER payments and planning demonstrates the Goldilocks syndrome. Most things at the home of the Three Bears were either too big or too small, too hot or too cold, too hard or too soft, but seldom just right. Goldilocks did not find fungible commodities at the home of the Three Bears. Everything was poorly planned for her, except for those things belonging to Baby Bear.

Electricity has been treated at retail as the ultimate fungible commodity. For most customer classes, the same tariff price is charged to all consumers for all the energy taken during a month. This constant price occurs despite wholesale prices that vary throughout the day, sometimes throughout an hour, and that vary by location. The value to the consumer of the distribution system obviously varies throughout the day. But it is often difficult to devise a method to show that the cost of the distribution system varies throughout the day.

SETTING RATES

During the rate setting process, costs are often classified as being demand related, commodity related, or customer related. Demand related costs then often lead to demand or capacity charges. Demand and capacity charges are monthly prices per kilowatt (or kilovolt-ampere) of maximum usage or of requested capacity. This rate setting procedure typically begins with the related concepts of book cost, embedded cost, or average cost, none of which is appropriate for a competitive market.

A competitive market looks at the cost of making an additional sale. To the extent that the sales decisions are being made on a daily basis, the seller can only evaluate the seller's own short run cost of making the sale. For electricity, short run costs generally include only the cost of fuel. Any sale arranged on a daily basis would cause the seller to incur some identifiable additional cost of fuel. The fuel cost includes the effect of the electrical losses on the transmission and distribution system between the generator and the customer.

More sophisticated costing systems also recognize that additional generation will also increase the maintenance for the generators, even though the maintenance might not occur until months or years after the sale. Some sophisticated costing systems will differentiate this maintenance costs between time periods, depending on the loading levels. For instance, some generators can be operated, with some risk, at levels in excess of their nominal maximums. The risk of such operation is more rapid degradation of equipment, most obviously of turbines and boilers but also of transformers and wires.

Marginal cost is an alternative approach to rate setting that builds on the incremental costs identified above. During most days of the year, the marginal cost of using the distribution grid is limited to the electrical losses on the distribution lines and transformers. Such electrical losses are often considered to be trivial relative to the full cost of owning the distribution grid.

One exception is during periods of extremely high prices for electricity delivered to the distribution grid. These periods are also often during periods of high electrical losses on the distribution grid. Another exception is during extremely high loading, perhaps even dangerously high, on the distribution grid.

Occasionally the marginal cost of using the distribution grid involves the degradation of the life of the equipment. The higher marginal cost associated with the potential degradation of the life of the equipment can be used to set prices for the use of the distribution system.

DISTRIBUTION PHYSICS

A piece of electrical equipment typically has two rating limits. The equipment can operate indefinitely below the lower rating limit with no apparent long term effect. There are, of course, the electrical losses associated with I Squared R. These electrical losses heat the equipment, even when the equipment is being operated below the lower rating limit.

When equipment experiences loading above the lower rating limit, the equipment has a greater chance of failing and a significant degradation of life. During such emergency overload conditions, wires may stretch and sag into trees, as occurred during the precursor events to the 2003 Northeast Blackout. Transformers may overheat and fail. In extreme cases, wires melt. Circuit breakers are set to prevent such problems associated with overloads.

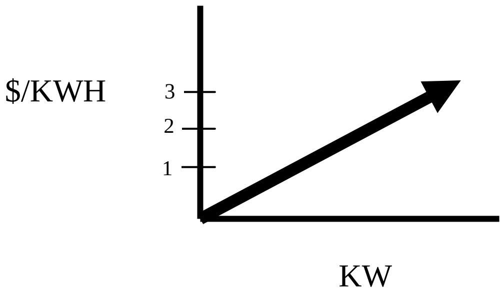
Total electrical losses are given by the I Squared R formula. These electrical losses can be evaluated at the unit cost of electricity delivered by the grid to the distribution station. Calculus shows that a minor change in the load carried on the distribution grid will change electrical losses by 2 * I * R. Thus, the marginal fuel cost of operating the distribution grid is nominally directly proportional to the load being carried on the distribution grid. The load is represented by the “I” term for current in the formula.

The marginal fuel cost is also dependent on the location, since the “R” term depends on the distance from the distribution station to the customer’s meter. Again, these losses would be financially evaluated based on the unit cost of electricity delivered by the grid to the distribution system.

This linear cost associated with the marginal loss formula of 2 * I * R is illustrated in Figure 1. Note that when the load on the distribution grid is zero then the price is zero. A doubling of the load on the distribution grid results in a doubling of the price. The slope of the line changes with the price of electricity delivered by the transmission grid to the distribution substation and with the distance between the substation and the customer meter.

Marginal Cost Associated
With Electrical Losses

Figure 1

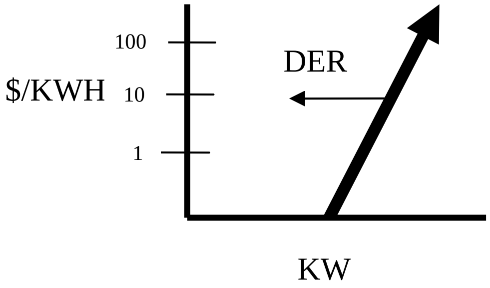


The cost associated with the degradation in the life of the distribution grid is less certain than is the cost associated with electrical losses. Relatively few studies are available on this topic. An indication of the degradation cost of overloading the distribution grid can be inferred from the relay settings for the circuit breakers that prevent damage to the distribution grid. Small overloads are tolerated for long periods of time, occasionally as long as several days. Larger overloads are tolerated for shorter periods of time, such as hours, minutes, or seconds.

One simplifying approach is to assume that the marginal cost is exponential with respect to the loading on the line, as is illustrated in Figure 2. The vertical scale for an exponential graph would be equal vertical distances for equal multiples of the price. Thus, in Figure 2, the equally spaced cross hatching of the pricing axis are for prices that change by multiples of ten (10). The graph becomes vanishingly small at a loading that is equal to the lower rating limit on the distribution grid.

Marginal Cost Associated
With Life Degradation

Figure 2



`

INCREMENTAL CONCEPTS

Marginal cost involves very small theoretical changes in the loading on the distribution grid, such as changing the loading from 25.000001 MW to 25.000002 MW. The changes are so small that they are beyond the measuring accuracy of the system. DER and many customer loads are significant, certainly in the KW range and often in the MW range. Marginal costs can vary significantly depending on the presence of a specific customer. This is especially true when the load on the distribution system is high, that is, when the load is close to or above the lower limit. Below that limit, the marginal cost is limited to line losses. Above that limit, marginal cost involves the degradation of the equipment.

Figure 2 includes an arrow indicating the potential impact of DER. Without the DER operating, the utility might be incurring degradation costs of $10/KWH. This is suggested by the DER arrow originating on the price curve at a height of $10/KWH. The DER capability is illustrated by the length of the arrow. With the DER running at its maximum capability, degradation costs become vanishingly small. The small cost is illustrated by the head of the arrow extending to the left of where the cost line intercepts the KW axis. Thus, without the DER operating, the utility is incurring degradation costs of $10/KWH. With the DER operating, the utility is incurring only nominal degradation costs, degradation costs that are too small to measure.

Accordingly, the price for service should reflect both the actual loading on the distribution system and the load reduction associated with the presence of DER. For instance, under the situation that DER is not operating and the distribution system is overloaded, the marginal cost of the distribution grid is very high. Changing the operating status of DER will dramatically reduce the marginal cost of the distribution grid, perhaps even eliminating the degradation costs.

To the extent that DER owner knows the loading on the distribution system, it can maximize its revenue by gaming the system. Instead of fully operating the DER, the owner can operate the DER at part load, such that the marginal degradation cost is still significant, such as the $10/MWH shown in Figure 2. The utility would prefer for the DER to be operated fully at such times, to eliminate the marginal degradation cost. But there is a trade off between the payment to the DER and the savings in degradation cost. A sharing of the savings in degradation cost provides benefit to both the DER and to the utility. The savings to the utility will reduce the cost to other utility customers.

The potential for DER to maximize revenue without maximizing production is illustrated in Table 1. The example assumes that the distribution system is overloaded by 8 MW. The price (in $/KWH) set for overloads is given by the exponential formula ($10^{MW/4}$). At 0 MW, the price is $1/KWH. At 4 MW, the price is $10/KWH. At 8 MW, the price is $100/KWH. Any DER production reduces the overload from the stated 8 MW. The overload reduction results in a lower price. The DER revenue is shown in the last column as the amount of production times the price. In this example, the DER owner maximizes revenue by operating at 1.7 MW, leaving the distribution grid overloaded by 6.3 MW.

PROBABILITY COSTING—AN ALTERNATIVE CONCEPTUAL SUPPORT

Prices help allocate resources, especially scarce resources. When the load on the distribution system is in excess of the nominal capacity of the distribution system, high prices will discourage consumption and encourage DER.

When the distribution grid is overloaded, the distribution grid is more likely to shut down, either as the result of equipment failure or due to the operation of safety equipment.

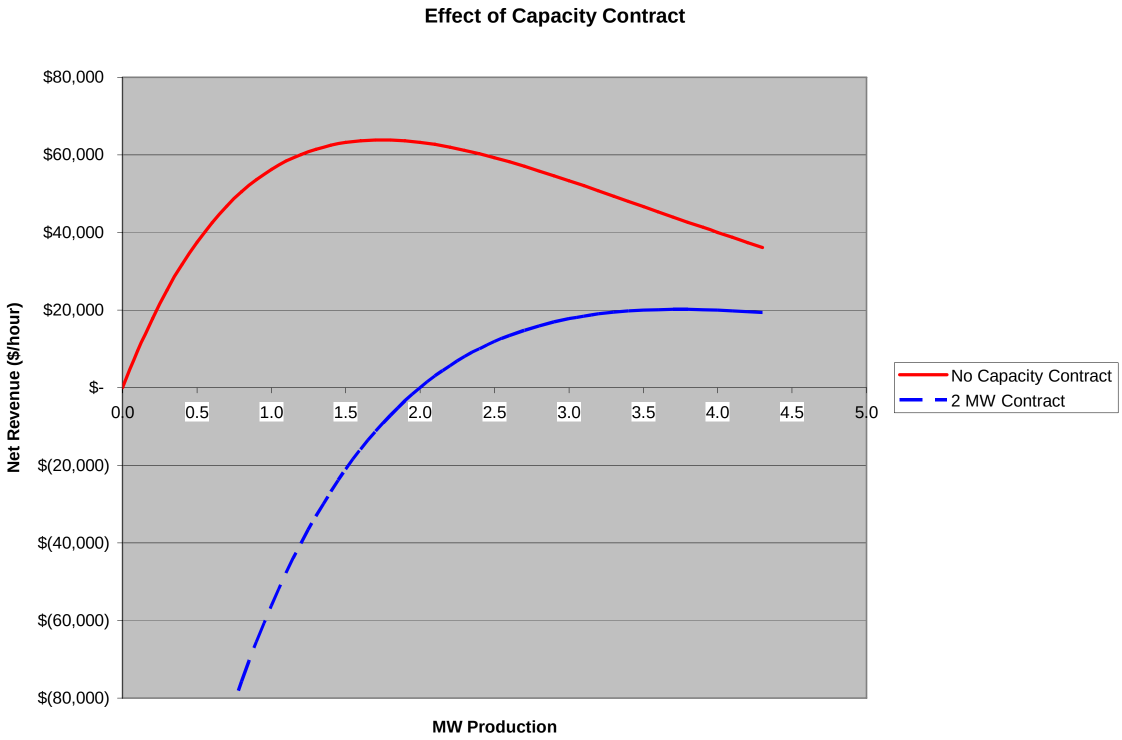
When the grid is being shut down, the value to consumers associated with the use of the grid is very high. When there is ample capacity on the grid, the value associated with the use of the grid is very low. When the grid is overloaded, the value associated with the use of the grid is some weighted average of those two values: The smaller the overload, the lower the value of the use of the distribution grid; conversely, the greater the overload and the nearer the grid is to shutting down, the greater that value of the use of the distribution grid.

FUTURES CONTRACTS

The prevalent approach to DER is a capacity payment reflecting the reduction in fixed costs to the utility derived from the planning process. The capacity payment concept can also be consistent with a robust commodity market on the distribution grid. The capacity payment would be part of a futures market.

Normally, a DER capacity payment is associated with a guarantee by the DER to produce a specified amount of electricity. A distribution grid commodity market provides a price to evaluate DER performance, a way to charge DER for not performing up to specifications and a way to pay DER for performing in excess of the specifications.

The utility should contract with some DER. The amount of DER that should be under contract will depend on the utility's expectations of overload on the network, the price being demanded by DER, and the commodity prices for the overloads. The DER would then have some form of contractual obligation to operate when there is an overload on the distribution grid. The amount of capacity included in the contract will determine the optimum operating level for the DER. This concept is shown in Figure 3.



Under this concept, the DER would be charged the marginal degradation cost of the distribution grid for any DER shortage relative to its contract demand. Any surplus production by the DER would be paid the marginal degradation cost of the distribution grid. This pricing plan allows the DER to dispatch itself against the cost of the distribution grid as well as the cost of central station power.

MAKING THE MARKET EVEN MORE ROBUST WITH RETAIL RATES

The presence of a commodity price for DER deliveries to the utility will provide the utility and the DER with financial tools to evaluate the contracts being proposed by each other. The concept that the DER would pay the utility for deficiencies can be extended to retail rates.

A DER that fails to deliver the capacity to which it has contracted is effectively taking electricity from the grid. A retail load can be viewed in the same way and can be priced the same way. Retail consumers can evaluate its potential power bill under the standard utility tariff versus its potential power bill under the pricing plan illustrated in Figures 1 and 2. In Figure 1, the customer is paying the utility for energy losses incurred on the distribution grid. In Figure 2, the customer is paying the utility for overloads on the grid, providing the utility revenue to offset its capital and non-energy related distribution costs.

CONCLUSIONS

Utilities can achieve a robust market for the use of the distribution grid by having a formula for the price for using the distribution grid. The formula would be driven by the loading of the distribution grid, such as the MW being delivered from the transmission system to the distribution grid. The price would apply to DER that helps the distribution grid and could be used for traditional loads.

The concept of a pricing formula for the use of the distribution grid can be supported by the engineering cost associated with degradation of the life of the distribution grid due to overloads. The concept is also supported by economic theory associated with the rationing of a scarce commodity, where the scarce commodity is the capability of the distribution grid.

The formula driven commodity market would facilitate futures markets. Such futures markets would likely take the form as capacity markets. Such capacity markets are consistent with a planning approach to paying for DER.

The market formulas need to reflect the actual loading on the distribution grid and the amount that DER has been able to unload the grid. This is to provide incentives for the DER providers to game the system in ways that help the utility.

DER Revenue Optimization
Table 1

DER Production (MW)	Distribution Overload (MW)	Price ($/KWH)	DER Revenue ($/HR)
0.0	8.0	$100.00	$ -
0.1	7.9	$94.41	$ 9,441
0.2	7.8	$89.13	$ 17,825
0.3	7.7	$84.14	$ 25,242
0.4	7.6	$79.43	$ 31,773
0.5	7.5	$74.99	$ 37,495
0.6	7.4	$70.79	$ 42,477
0.7	7.3	$66.83	$ 46,784
0.8	7.2	$63.10	$ 50,477
0.9	7.1	$59.57	$ 53,610
1.0	7.0	$56.23	$ 56,234
1.1	6.9	$53.09	$ 58,397
1.2	6.8	$50.12	$ 60,142
1.3	6.7	$47.32	$ 61,510
1.4	6.6	$44.67	$ 62,536
1.5	6.5	$42.17	$ 63,254
1.6	6.4	$39.81	$ 63,697
1.7	6.3	$37.58	$ 63,892
1.8	6.2	$35.48	$ 63,866
1.9	6.1	$33.50	$ 63,643
2.0	6.0	$31.62	$ 63,246
2.1	5.9	$29.85	$ 62,693
2.2	5.8	$28.18	$ 62,004
2.3	5.7	$26.61	$ 61,197
2.4	5.6	$25.12	$ 60,285
2.5	5.5	$23.71	$ 59,284
2.6	5.4	$22.39	$ 58,207
2.7	5.3	$21.13	$ 57,064
2.8	5.2	$19.95	$ 55,867
2.9	5.1	$18.84	$ 54,626
3.0	5.0	$17.78	$ 53,348