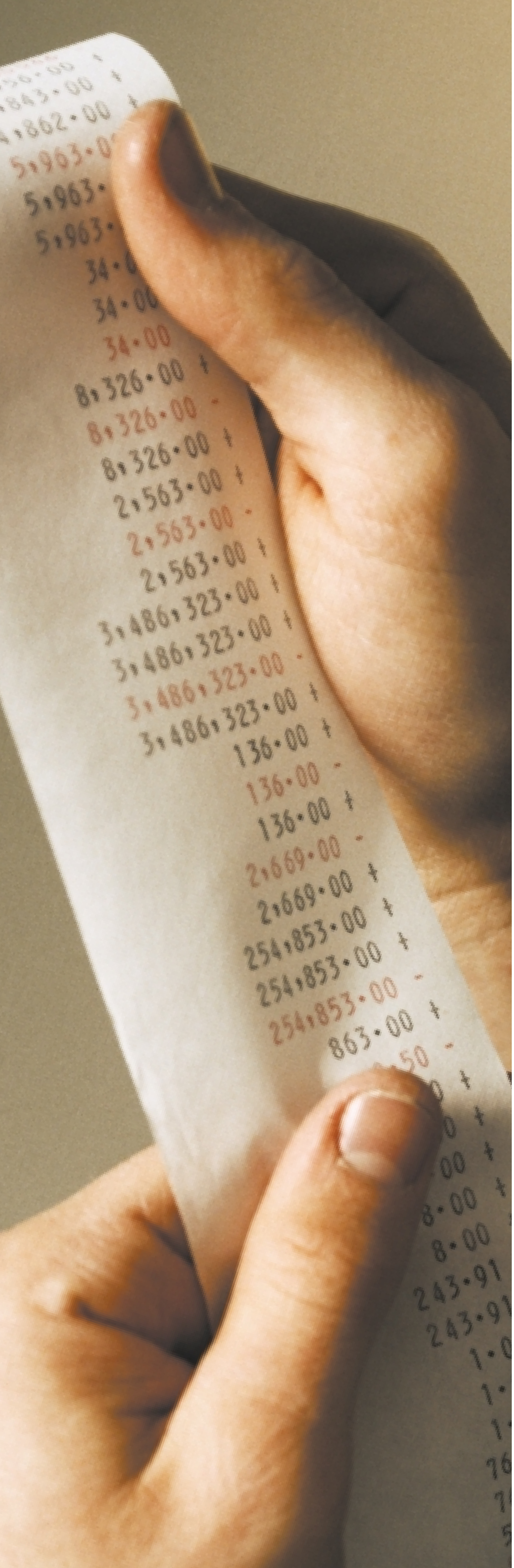


Distributed Generation

Benefit Values In Hard Numbers

In the second of three articles, Oak Ridge National Laboratory reviews the economics and financial issues related to DG.

Economic assessment methods for customer-owned distributed energy resources (DER) typically compare the cost of purchased power and fuel with the cost of owning and operating a DER system.[1] However, largely because of current market structures, these assessments disregard a host of other DER benefits, such as reliability and power quality—often described in nebulous terms, if at all. A good review of the full range of DER benefits addresses the difficulty in assigning values to these more esoteric factors.[2]

Moreover, DER benefits often are enjoyed by parties other than the DER owner.[3] For example, a DER system that provides voltage support improves electric-service quality for many nearby customers on the grid and reduces the load on the long-distance transmission system as well. The question of valuing DER benefits is obviously more complex than is reflected by the traditional cost-benefit analysis.[4] Recognizing this com-

By S. W. Hadley, J. W. VanDyke, and T. K. Stovall

plexity, the Department of Energy's Distributed Energy Program is examining DER benefits from multiple perspectives.

The issue is especially pertinent in this time of evolving market mechanisms precipitated by deregulation. As the markets accept, or even invite, broader participation, DER owners may be able to generate additional revenue streams by selling ancillary services.[5] Market instruments may motivate new operating strategies for DER systems that reflect their optimal performance from a broader system perspective. In another vein, a more concrete understanding of societal benefits, such as reductions in regional pollution, may lead to increased public support for technology development or other publicly funded incentives.

FIGURE 1 **THE PJM REGION TODAY**

Source PJM

Methodologies to quantify several DER benefits—in particular, economic values for power supply, reserves, emissions, and transmission and distribution (T&D) deferrals, and the effect of DER on utility revenues and system reliability—will not give a definitive answer as to whether a particular DER project in a given location provides benefits outweighing costs; no broad study could, given the site-specific nature of DER. However, by analyzing the effect of DER and combined heating and power (CHP) on a large power pool, we can gain insight regarding system-wide changes.

This article looks at the PJM power pool (*see Figure 1*—although at the time of the study, the PJM power pool was smaller than it is currently, containing most of Pennsylvania, New Jersey, Maryland, and Delaware) because the deregulation process and electricity market development in this pool are well under way and appear to be functioning well. Second, PJM includes regions with transmission congestion and relatively high electricity prices. PJM also includes electricity supply and load concerns common to many other parts of the country.

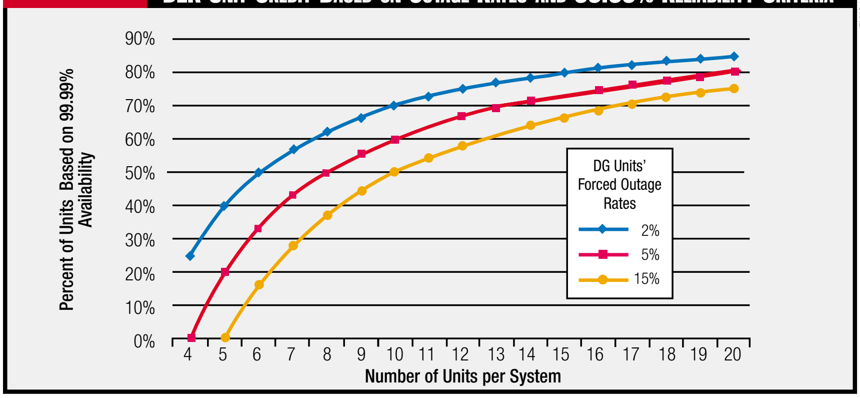
Moreover, utilities typically assess the T&D potential of DER using a site-specific approach and focus on opportunities where planned expansions or upgrades of the distribution system can be avoided or deferred. This analysis looks at the potential of DER to avoid T&D costs from a different perspective—that of a long-run equilibrium in which DER is planned and coordinated fully with other T&D resources. The premise is that in the long run, T&D resources must be maintained, replaced, and usually augmented to accommodate system growth. Therefore, in the long-term view, DER should contribute to a reduction in T&D expenses. Taking this perspective provides a generalized framework in which to estimate the long-term value of DER as opposed to its situation-specific value. It should be emphasized that (even as a bounding case) the approach taken here will shed little light on the value of specific DER installations, which can range from zero to very high values in the near term.

The methodology employed here first estimates the diversified coincident effect of DER on the system, considering unit size, unit forced outage rate, and number of DER units. The diversified DER contribution is then combined with the marginal costs of T&D assets to give an estimate of potentially avoided T&D capacity costs.

The Marginal Cost of Transmission And Distribution Capacity

Utilities report the breakout value of distribution equipment on Federal Energy Regulatory Commission (FERC) Form 1. Accounts 360 through 368 include distribution equipment potentially affected by DER. This includes 82 percent of the total value of distribution-equipment book value in 1998. The end-of-year balances (EOYBs) for total distribution plant "in service" measure an embedded value of distribution capital that is part of the electric utility's rate base. Therefore, the EOYB divided by the total MVA for distribution-line transformers provides an average embedded value of distribution capacity. In 1989, the average EOYB for 105 major utilities was \$104/kVA; by 1998, it was \$137/kVA. The increase reflects the fact that, on average, new distribution capacity costs more than the installed base. However, because the purchases each year are only about 5 percent of the installed base, the installed average will change slowly. Costs for the 11 PJM utilities were significantly higher than the national averages.

FIGURE 2 **DER UNIT CREDIT BASED ON OUTAGE RATES AND 99.99% RELIABILITY CRITERIA**



Source: ORNL

the diversified demand would be 4 kW; *i.e.,* there would be no credit for diversification in calculating the peak transformer capacity required. However, as more customers with electric ranges are added to the transformer, the diversified demand per customer approaches 1 kW (*i.e.*, the average) at the coincident peak.

The same principle of diversification can be applied to DER. As more DER units operate on a given component of distribution capacity, the diversified effect will tend to approach the average operating capacity of the DER units for that period. This suggests that for T&D equipment that accommodates many DER units of similar size, the reduced need for capacity would approach the average operating capacity of DER during the peak demand period. Furthermore, because they affect relatively large increments of load, DER units can be provided with incentives to operate during capacity-critical periods. If these incentives induce the customers to operate their DER systems at their maximum output during periods of peak demand, the effect would be to displace the need for distribution capacity equivalent to the maximum output capacity of the DER, adjusted for their characteristic forced outage rates. It follows that, if the loads and DER units on the distribution system are known, the system capacity can be adjusted to account for the reduction in load resulting from DER operation during capacity-critical periods.

In such a market, where DER is operated to maximize power production during periods of peak demand—and if each DER unit is the same size and all units have the same forced outage rate—then an equation can be solved to calculate the number of DER systems that can be counted upon to operate coincidently at the selected reliability criteria (results shown in Figure 2). For example, if the reliability criterion is 99.99 percent (reflecting an outage probability of less than 1 hour/year), there are eight DER units on the same feeder, and each DER unit has a forced outage rate of 5 percent, then the distribution utility can count on at least four of the units operating at the same time. If each of these DER units were rated at 400 kW, the distribution utility would be able to reduce its planned feeder capacity by 1,600 kW. This example is for the simplified case where all DER units are the same size and have the same unit forced outage rates. However, for more complicated cases, it would be straightforward to estimate the avoided capacity effects of DER using other statistical techniques.

Taking the difference in the account EOYBs for 1998 and 1989 and dividing by the change in the distribution capacity for the same period gives an approximation of the marginal cost for new equipment. Over this period, the marginal cost of distribution capacity was $290/kVA nationally and $375/kVA for the 11 PJM utilities. In other words, the average marginal cost of distribution capacity over this period was more than double the average embedded cost. The marginal cost for transmission for the same period was $81/kVA for the 105 nationwide utilities and $65/kVA for the 11 PJM utilities.[6]

DER Reliability, the Effect of Diversified Coincident Operation

DER capacity connected to a local distribution system has the potential to reduce the demand on the upstream distribution system by an amount equivalent to the total DER capacity, and therefore has the potential to displace T&D service provided by local utilities. The local utility's T&D resources are not needed to serve a load while the DER is operating, but they still must provide backup capacity. Such uncertainty, related to the availability of the DER, is a key factor in determining the difference in T&D capacity requirements with and without DER.

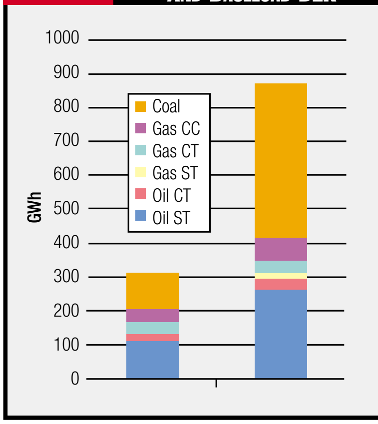
For instance, utilities routinely make probability assumptions in sizing distribution transformers that serve utility customers. The transformer size is selected to accommodate the peak simultaneous demand (coincident peak) based on a probability estimate of the coincident maximum of the individual loads on the transformer. Because appliances will not all be in operation at the same time, credit can be taken for "diversification" of the individual loads. As a distribution transformer serves more customers, the transformer capacity required per appliance will tend to approach a level characteristic for that type of appliance. An example is an electric range that typically requires a maximum of 4 kW of power and an average of 1 kW during the peak period. For one customer on a transformer,

The Value of T&D Investments Avoided by DER

Only a portion of the T&D equipment will experience the reduction in load resulting from the DER operation, depending on the DER units' location relative to the upstream distribution feeder and sub-feeder equipment. An illustrative example, using conservative assumptions for the physical distribution of DER, is shown in Table 1. The diversified capacity of the DER would be greater on the transmission level, which would see a greater number of DER units than would any single substation or feeder (see the "Trans total" line in Table 1 where the DER receives 80 percent capacity credit based on 20 downstream DER units). In fact, the diversified DER capacity credit grows smaller as you progress outward through the distribution system (see the credit reduced from 60 percent for "Dist land" with 10 downstream units to 20 percent for "Dist poles & towers" with 5 downstream units in Table 1). At the line transformer level, the diversified capacity would be zero because that level would likely see a single DER unit. The avoided cost of DER based on the marginal cost for 105 nationwide utilities would be about $119/kVA of DER capacity. The similar calculation for the 11 PJM utilities would be $134/kVA of DER capacity (see the sum at the far right column in Table 1).

A key point in this evaluation is that DER has capacity value for a distribution system to the extent that it reduces the need for upstream capacity. Therefore, it makes sense to first calculate the potential value of DER as if it could be centrally dispatched. Then this potential value can be systematically exploited. Among other things, the distribution system can be designed or adapted to technically accommodate DER. Finally, market designs, such as incentives for operating DER during capacity-critical periods, can provide the basis for avoiding distribution capacity costs while meeting system reliability goals, even when DER is not owned and/or controlled by the distribution utility.

Figure 3 Displaced Energy by Peak and Baseload DER



Source: ORNL

Looking at marginal production values

The economic value for many DER benefits is tied to the time-varying wholesale power price, which is fundamentally based upon the marginal cost of production. Therefore, we used a regional bulk power market model to evaluate the impact of DER on the rest of the electric grid, including generation costs, emissions, and reserve requirements.[7] This analysis used 1999 utility data (including the hourly demand and power generation portfolio) to evaluate the selected region.[8] The results from that study are summarized in Table 2.[9] Even though oil-fired capacity is only 7 percent of total generation, it is on the margin 34 percent of the time. Natural gas is on the margin only 14 percent of the time, while coal is the marginal source 52 percent of the year. Note that low variable cost and non-dispatchable units are never on the margin. The type of power production displaced by DER can be sensitive to factors such as the price of fuels for the grid's power plants or other external factors. Changes in relative prices can alter the order of plants on the margin and change the marginal emissions and prices.

The addition of DER to a system could be modeled from either a supply-increase or demand-reduction point of view. There are two main arguments for using the demand-reduction approach. First, the DER is typically on the customer side of the meter; so from the

Table 1 Long-Term Marginal Cost Approach for Calculating the Value of Transmission and Distribution Equipment Costs Avoided by Distributed Generation

Equipment	1989 to 1998 Marginal cost ($/MVA)		Downstream DER units (Number)	Capacity credit	Avoided capacity value of DER based on marginal costs ($/MVA)	
	Nationwide (105 utilities)	11 PJM utilities			Nationwide (105 utilities)	11 PJM utilities
Dist land	2,639	5,653	10	60%	1,583	3,392
Dist structures	2,481	5,538	10	60%	1,488	3,323
Dist station equip	32,869	57,248	10	60%	19,722	34,349
Dist battery storage	2	0	10	60%	1	0
Dist poles & towers	50,390	50,746	5	20%	10,078	10,149
Dist overhead conduct	52,059	63,363	5	20%	10,412	12,673
Dist undgr conduit	13,815	23,739	5	20%	2,763	4,748
Dist undgr conduct	44,226	65,121	5	20%	8,845	13,024
Dist transformers	40,787	39,757	0	0%	0	0
Dist services	26,553	34,494	0	0%	0	0
Dist meters	13,625	14,045	0	0%	0	0
Dist installations	2,854	4,858	0	0%	0	0
Dist leased property	-131	1	0	0%	0	0
Dist street lights	8,034	10,175	0	0%	0	0
Trans total	80,650	64,876	20	80%	64,520	51,901
Total	**370,853**	**439,613**			**119,412**	**133,557**

Source: ORNL

TABLE 2 PRODUCTION STATISTICS FROM BULK POWER MODEL BASE CASE WITH NO DER

Source: ORNL

Generation type*	Generation TWh	% of Total generation	% of Total capacity	%Time on margin	Carbon kTonne	SO_2 lb/MWh	NOx lb/MWh
Oil St	17.6	7%	14%	30%	4,025	8.60	2.10
Oil CT	1.0	0%	7%	4%	255	0.00	1.49
Gas ST	0.3	0%	1%	1%	50	0.67	1.14
Gas CT	1.2	0%	7%	5%	182	0.15	1.16
Gas CC	18.9	7%	8%	8%	2,582	0.00	1.05
Nuclear	97.2	37%	23%	0%	0	0.00	0.00
Coal	115.9	45%	35%	52%	29,985	18.54	4.50
Hydro	3.6	1%	5%	0%	0	0.00	0.00
Renewable	4.1	2%	1%	0%	0	0.15	0.25
Totals	259.7	100%	100%	100%	37,078		

* ST: steam turbine, CT:

the load because their variable costs were too high were assigned to meet the reserves.

However, for spinning or supplemental reserves, these plants must run at some minimum level, *e.g.*, 10 percent of capacity. That minimum capacity requirement (which varies by plant type), in turn, will cause plants that would otherwise have run to reduce their power level. However, as they back down in energy, they free up the equivalent amount of reserves, since they could ramp back up to provide the power in the event of an emergency. If a plant reduces its electrical output, then it forgoes the profit that is the difference between its variable cost and the market-clearing price. The last plant that backs down has the biggest difference between the two and so sets the market price for this ancillary service.

The reserves market price, therefore, varies as the system's marginal price varies. This cost in turn depends on which generating units are on the margin. Looking separately at the peak season (summer) and the off-peak season (the rest of the year), the wholesale price for each hour of the year was determined by correlating the price curve from the base case to the load duration curve. We performed a similar calculation with the reserves price curve from the model. Figure 4 shows the load duration curve for each season with the corresponding marginal price curve. For most of each season, the price stays below 3 cents/kWh; but when the system demand is at its greatest, *i.e.*, from 0 to 10 percent on the load duration curve, the price rises rapidly because production is more expensive and start-up costs for plants (which are factored into their bids) become a more significant factor. The reserve prices in Figure 4 refer to the payment made for having production available in standby, according to the stand-by logic described earlier.

The average purchase price of the power displaced by the DER supply was 3.2 cents/kWh for the peaking strategy and 2.7 cents/kWh for baseload DER. These results can be compared with the average of the actual published prices for 1999, as shown in Table 3. The actual prices ran up to 99.9 cents/kWh

grid's point of view, it appears as a reduced demand for that customer. Second, in today's market, the utility typically has little or no control over the DER, which is again characteristic of a demand, or load. A moderate amount of DER capacity, 100 MW, was selected for these analyses because it is small enough to avoid any significant change to the regional power supply mix and yet large enough that the marginal changes in the system can be measured. All results are given per megawatt-hour, so the absolute size of the DER capacity in the model is not important. For this study, we considered two DER deployment options: a weekday-only system that ran from 8 a.m. to 8 p.m. (peaking DER) and a system that ran 100 percent of the time (baseload DER). The key results for the system operations are shown in Figure 3 and Table 3. In the peaking mode, the DER displaces more oil and gas generation; in baseload operation, it displaces more coal.

Reliability Reserves and Marginal Prices

An important new feature was added to the bulk power-market model during this project: the capability to calculate the time-varying value of reserves. Utilities maintain reserve generation to meet any unplanned power plant outages or unexpected large demands. Reserves are subdivided into different categories; but, for our analysis, we have combined the spinning and supplemental reserves into a single reserve category, typically on the order of 7 percent of the expected load.[10] A new reserves element was added to the bulk power model by calculating the additional capacity needed in each block of time over the year to meet this requirement. Plants that were not called upon to meet

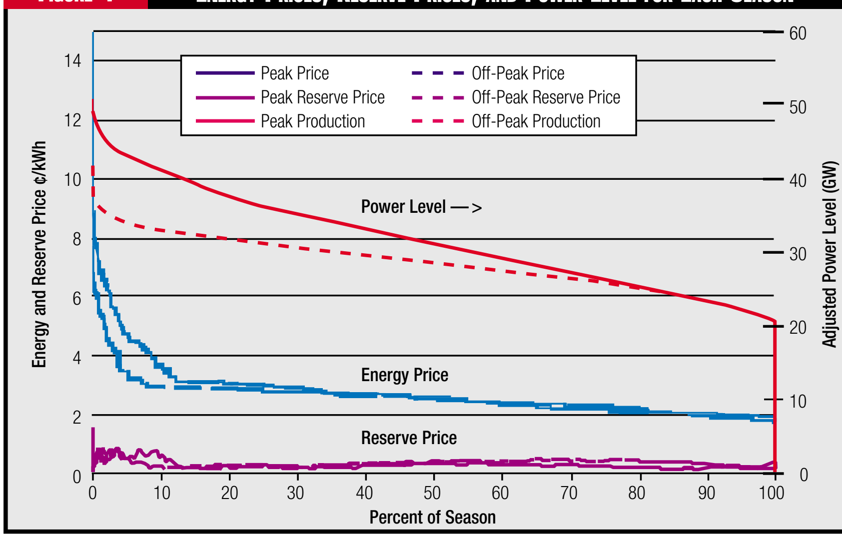
TABLE 3 DISPLACED SYSTEM POWER PARAMETERS

Source: ORNL

	Peaking DER	Baseload DER
Displaced energy, GWh	313	876
Displaced source		
Oil ST	36%	31%
Oil CT	7%	4%
Gas ST	2%	1%
Gas CT	10%	5%
Gas CC	11%	8%
Coal	35%	52%
Avg displaced efficiency	31%	32%
NO_x, lb/MWh	3.03	3.59
SO_2, lb/MWh	9.67	13.1
CO_2, lb/MWh	1,938	1,972
Avg. marginal cost¢/kWh	2.99	2.62
Avg. purchase price, ¢/kWh		
Using model	3.23	2.70
Using PJM published	4.43	2.83

for short periods during the summer months. The modeled marginal prices are somewhat lower than the actual prices because: (1) the model uses a single marginal cost for each plant, while actual plants will have marginal costs that vary depending on their load level; (2) PJM interaction with other regions may provide supplies at lower prices or demands that raise prices; and (3) plants may vary their bid prices to take advantage of market conditions.

FIGURE 4 ENERGY PRICES, RESERVE PRICES, AND POWER LEVEL FOR EACH SEASON



If there is an open market for reserves as ancillary services, then DER may be able to earn additional revenue during times it is not operating. Using the reserves prices shown in Figure 4 and tracing the prices back to the original demand load duration curve, we can determine the reserves price for any hour of the year. Applying these prices to the 100 MW of DER available for reserves during the off-peak hours, we find that the DER could earn an additional $16/kW/year. If the DER were a simple backup unit and so were available for 100 percent of the year, it could earn $26/kW/year. Since there are no variable operating costs while the DER is in standby and available as a reserve, these funds can be used to offset the fixed cost of the DER. Of course, the equipment will not be available 100 percent of the time, so the actual payment will be somewhat less depending on the time and duration of any outages.

If the utility does not own the DER, the lost revenue from lower sales will likely be higher than the reduction in power supply costs (estimated using modeled marginal costs). Considering only displaced power production costs and revenue (estimated using 1999 rate schedules) in our example, Public Service Electric and Gas (PSE&G) would have net annual losses of $140/kW for peaking DER and $370/kW for baseload DER. Because of its different rate structure, Baltimore Gas and Electric would lose only $50/kW and $40/kW for the same two cases. However, the lower loss for this utility corresponded to lower savings for the DER owner and a consequently longer payback. Modeling DER as a reduction in load rather than an addition to the power supply implies that the customer controls the DER and decides what hours it should run. If the utility or system operator were controlling the DER, or if the customer were trying to sell the production on the wholesale market, then the DER would be dispatched as power from other power plants and is based on its variable cost or bid price. The variable cost will depend on several factors, most notably the fuel price, the technology used, and whether the thermal exhaust is used.

The addition of CHP can greatly change the variable cost, as reflected by the total CHP efficiency in Table 4. Microturbines change from the highest variable cost without CHP, at around $63/MWh, to the lowest cost at $26/MWh with CHP,[11] because of the combination of relatively low electrical efficiency but high utilization of thermal energy. At a variable cost of $26/MWh, the DER would be dispatched within the system roughly 48 percent of the year, while at $63/MWh it would only be called upon 1 percent of the year.

Meanwhile, one of the principal societal benefits of DER is the potential for improved air quality. A DER system will reduce net emissions if a cleaner fuel is substituted for a more-polluting fuel, as shown in Figure 5, or if the overall system efficiency is improved, usually via CHP. If the DER operates as CHP, emissions become a function not only of the cleanliness of the DER technology and the displaced industrial boiler, but also of the electrical and heat exchanger efficiencies summarized in Table 4. Table 5 shows the net emissions savings for each technology after subtracting the DER system emissions. Our analysis showed that baseload DER in the PJM region, especially as CHP, could reduce NOx emissions by as much as 7.3 lb/MWh, SO_2 by as much as 13 lb/MWh, and CO_2 by almost 1,500 lb/MWh. Assuming market values for the SO_2 and NOx of $200/ton and $1,500/ton (with the NOx market limited to the summer months), the savings can be as much as 0.3 cents/kWh.

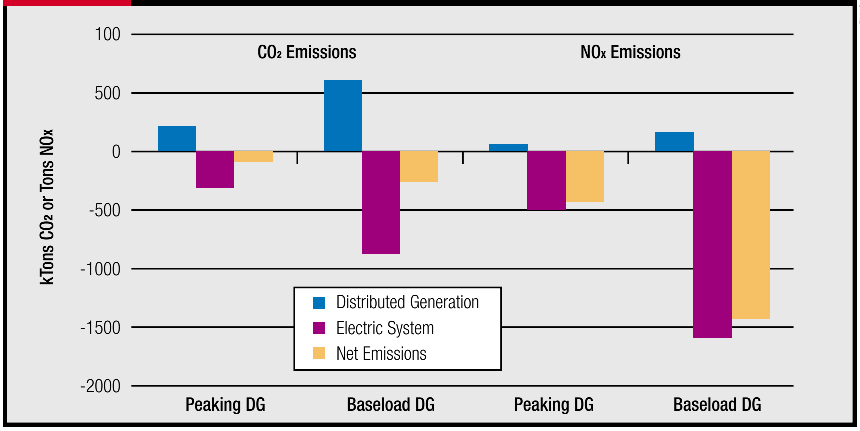
Reliability: Loss of-Load-Probability

Reliability at the customer's site is determined by the reliability of many electric system components, including the generating units and the T&D system. The generation aspect of system reliability changes attributable to DER was evaluated within the bulk power model using a probabilistic model for forced outages. Multiple smaller DER units, if of equivalent availability, can provide increased reliability compared with an equivalent capacity from a single larger unit. If a large unit goes down, then an equal amount of capacity is needed to replace it; but with multiple plants, it is much less likely that all would be down at the same time. Less backup capacity is needed, and it would run more often. This further improves the economics compared with a large amount of backup that is used only when the single large source is down.

Based on this reliability analysis, there is a small but positive value to having capacity added at typical DER unit sizes as opposed to typical central station sizes. This conclusion is based on a series of paired scenarios in which a large plant addition was compared with the addition of ten smaller units, each with 1/10 the capacity of the large unit. In the first scenario, we used the originally reported system demand data and added either a single 100-MW plant or 10 10-MW plants. The change in the loss-of-load probability (LOLP) between the two reflects the higher reliability provided by the multiple small plants. Since 100 MW is such a small fraction of the total demand in the PJM region, the change was small (Table 6). Other scenarios were established to explore the sensitivity of the results to the size of the reserve margin, as well as to the size of the new plant. For these four scenarios, the energy needs were increased by 10,000 GWh, which increased the peak demand from 51 to 53 GW. As the size of the added capacity increased from 100 to 1000 MW, the change in LOLP grew more pronounced.

In conclusion, utilities have the potential for significant long-term T&D savings if they recognize and take advantage of the diversified reliability of DER resources. We calculated a representative set of values for the utilities in the PJM region based on their system-wide marginal costs and considering

FIGURE 5 Net CO_2 and NO_x Emissions From 100 MW of Combustion Turbine-6B Without CHP



Source: ORNL

TABLE 4 Distributed Generation Technologies

Technology	Size kW	Capital cost $/kW	O&M cost $/MWh	Electrical efficiency (HHV)	Heat exchanger efficiency	Total efficiency	NOx emissions lb/MWh	CO2 emissions lb/MWh
Microturbine-2B	60	1,093	10	25%	67%	75%	0.541	1584
Combustion Turbine-2D	5,200	670	13	27%	62%	72%	1.388	1463
Combustion Turbine-6D	5,200	850	15	27%	62%	72%	0.278	1463
Combustion Turbine-6B	9,450	785	15	29%	62%	73%	0.263	1391
Natural gas Engine-2C	330	670	9.7	34%	52%	68%	2.37	1166
Natural gas Engine-6C	1,750	870	11.5	34%	52%	68%	0.25	1166
Non-CHP boiler					72%	72%		

Source: J. Iannucci, Distributed Utilities Associates, 2002

TABLE 5 Net Emissions Savings (lb/MWh) From 100 MW of DER

Technology	Peaking DER				Baseload DER			
	CO2		NOx		CO2		NOx	
	w/o CHP	with CHP	w/o CHP	with CHP	w/o CHP	with CHP	w/o CHP	With CHP
Fuel cell-2	1,002	1,375	3.02	4.49	1,036	1,409	3.50	4.97
Microturbine-2B	354	1,457	2.48	6.82	388	1,491	2.96	7.30
Combustion turbine-2D	476	1,391	1.64	5.24	510	1,425	2.12	5.72
Combustion turbine-6D	476	1391	2.75	6.35	510	1,425	3.23	6.83
Combustion turbine-6B	548	1401	2.76	6.12	582	1,435	3.24	6.60
Natural gas engine-2C	772	1326	0.66	2.83	806	1,360	1.13	3.31
Natural gas engine-6C	772	1326	2.78	4.95	806	1,360	3.25	5.43

Source: ORNL

the diversified reliability of a projected DER population. The potential capital cost savings to the 11 utilities in the PJM region were about $150/kW of DER capacity. Using costs for 105 utilities across the country, the capital cost savings were about $130/kW of DER capacity.

TABLE 6 **LOSS-OF-LOAD PROBABILITY CHANGE WHEN ADDING MULTIPLE SMALLER PLANTS VERSUS A SINGLE LARGER PLANT**

	Reserve margin	Single plant LOLP (day/10 yr)	Ten plants LOLP (day/10 yr)	% Improvement In LOLP
Added 100 MW supply	12.4%	0.057	0.057	0.07%
Added 2 GW demand and:				
100 MW supply	7.3%	3.40	3.40	0.0007%
200 MW supply	7.5%	3.08	3.08	0.0014%
500 MW supply	8.1%	2.13	2.13	0.19%
1000 MW supply	9.0%	1.11	0.92	16.7%

Source: ORNL

The utility may realize benefits from having an additional supplier of ancillary services, and multiple DER projects can provide additional reliability compared with the same capacity in a single central station. The reliability improvements considered here were only those due to additional power generation sources. Additional reliability improvements should be defined relative to the ability of the DER to function during transmission or distribution system disturbances.

It is more difficult to assess the short-term value of DER to the utility (unless it is the DER owner as well). While the utility will not have to purchase or produce as much electricity, it also will receive lower revenue from the DER owner. The amount of the difference depends strongly on the utility's rate structure, including energy, standby, and demand charges during the peak and off-peak periods. For the two utilities examined here, net annual revenue would decline from $40/kW to $370/kW of installed DER capacity. Location-specific savings are available in the near term to the utility through the deferral of T&D additions.

As noted earlier, one of the principal societal benefits of DER is improved air quality. To the extent that cogeneration is used to improve the overall system energy efficiency, and to the extent that cleaner fuels are substituted for more-polluting fuels, DER will reduce net regional emissions. Our analysis showed that DER would reduce net emissions in the PJM region even without the use of CHP. Other regions with similar mixes of central generation fuel, *i.e.*, largely coal with smaller amounts of oil, gas, and nuclear, would have similar results. Regions without the nuclear power resources of PJM likely would receive even greater air quality benefits from DER. Who reaps these benefits depends on the regulations involved in calculation and sale of emission permits (as well as the location of the DER and the displaced central generators), but in the end, all of society has the benefit of cleaner air.

Financial benefits to the owner from reduced utility purchases and cogeneration are easily calculated, but other factors can play a role. If the system owner is allowed to sell ancillary services at their market value, that will increase the owner's revenue and profitability. For the cases examined here, the addition of ancillary services (in the form of reserves) or emissions credits reduced the payback period by roughly one year for those projects that were economically viable.

Based on this evaluation, market rule changes that would enable better realization of DER benefits are the use of diversified reliability values in setting stand-by rates and access to the emissions savings and ancillary services markets for DER owners.

Endonotes

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4. S. W. Hadley *et. al.*, The Effect of Distributed Energy Resource Competition with Central Generation, ONRL/TM-2003/236, Oak Ridge National Laboratory, Oak Ridge, TN, 2003.
5. B. Kirby, "Restructured Electricity Markets Offer Increased Complexities and Opportunities for Cogeneration," Cogeneration and Competitive Power Journal, Vol. 16, No. 4, 2001.
6. Source: The data are from 105 utilities for whom these accounts were available in both 1989 and 1998 in the POWERdat database (Resource Data International, Inc.). These data were originally collected in FERC Form 1.
7. S. Hadley and E. Hirst, ORCED: A Model to Simulate the Operations and Costs of Bulk-Power Markets, ORNL/CON-464, Oak Ridge National Laboratory, Oak Ridge, TN, June 1998, <*http://www.ornl.gov/orced/index.html*>.
8. More recent data are available but not as complete. In addition, electricity and fuel prices were highly volatile in 2000 and 2001, making any conclusions based on that period problematic. Note that in 1999, oil prices were relatively low compared with natural gas prices. The result is that oil-fired plants played a significant role in the marginal production for the PJM region in 1999.
9. S. W. Hadley *et. al.*, Quantitative Assessment Of Distributed Energy Resource Benefits, ORNL/TM-2003/20, Oak Ridge National Laboratory, April 2003.
10. Contingency reserves for typical system operators are also defined by the loss of the single largest generating unit or transmission line. DER would not reduce the contingency reserve on that basis.
11. With a $4/mmBtu gas price.