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Selection of Distribution Feeders for Implementing Distributed and Renewable Energy Applications

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SELECTION OF DISTRIBUTION FEEDERS FOR IMPLEMENTING DISTRIBUTED AND RENEWABLE ENERGY APPLICATIONS

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Abstract - Climate change concerns, mandated renewable portfolio standards, lucrative government incentives, and accelerated cost reduction in renewables and distributed energy applications are driving steep growth in system installations. Distributed energy resources (DER) are not commonly connected to a bulk power transmission system, instead are interconnected near the load in the electric power distribution system. DER includes renewable energy such as wind and solar, fossil-fuel based generation such as microturbines, small gas turbine units and distributed energy storage. In this paper, a novel methodology is developed that ranks utility feeders for implementation of DER systems. This performance index is based on peak load reduction, increased system capacity, load-generation correlation, and feeder load growth. This is based on a statistical measure that quantifies the relationship between loads and the stochastic nature of renewable resources. This allows the utility to gain insight into improved benefits from non-dispatchable renewable resources such as solar and wind technologies as well as dispatchable DER technologies.

***Index Terms*— Distributed Energy Resources, Distributed Generation, Distributed Storage, Optimization, Distribution System, Distribution Feeder**

I. INTRODUCTION

TODAY's electric power system is designed to deliver high-quality and highly reliable electricity to customers. A century of development has lead to massively interconnected system that brings power from central-station generators via transmission and distribution to end-use customers. Although this system has been providing relatively inexpensive power, issues remain such as increasing and volatile fuel costs, green-house gas emissions, meeting the mandated renewable portfolio standards, and increasing customer needs for higher reliability power. One potential solution to these issues is the use of strategically installed distributed and renewable energy sources integrated at the distribution level.

Distributed energy resources (DER) are sources of electric power that are not commonly connected to a bulk power transmission system, instead are interconnected near the load in the electric power distribution system. Typically, the individual DER unit ratings are less than 10MVA and include both fossil-fuel and renewable generation as well as energy storage technologies. Because DER are sited at customer load locations, they can be more efficient than central station generators because lower transmission and distribution system losses. Targeted deployment of DER can also relieve loads on a utility's transmission, sub-transmission, and distribution systems, and effectively increase available T&D capacity and relieve undesirable congestions.

The wide variety of DER, however, also causes complexity when installed, applied and operated in electrical distribution systems. Traditional radial distribution systems are not designed for two-way power flow. Adding additional sources into distribution systems can affect system performance such as operations, protection, and system costs. Currently, no industry standard exists to determine the amount of DER that can be installed on a feeder without causing adverse effects.

In this paper, a novel methodology is developed that ranks utility feeders for implementation of DER systems. This is determined by calculating an index based on peak load reduction, increased system capacity, load-generation correlation, and feeder load growth. This value is also based in part on a statistical measure that quantifies the relationship between loads and the stochastic nature of renewable resources. This would allow the utility to gain insight into improved benefits from non-dispatchable renewable resources such as solar and wind technologies as well as dispatchable DER technologies. Once the feeder that benefits the most from DER is identified, a second method is used to optimize the placement of the DER.Based on the screening methodology, it was found that feeders with a high peak load compared with the average load are good candidates for DER. For nondispatchable DER, it is important to have good correlation between the load and the DER output. The full methodology quantifies the factors that influence the performance and costs of the electrical distribution system and the characteristics of the DER. This work will be specifically useful to electric power utilities and end-use customers wanting to site DER systems.

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II. BACKGROUND

Past researchers [1]-[5] have described numerous potential benefits of DER for both the utility and the customer. The benefits depend on many factors, including site-specific resources for renewables, DER penetration level, distribution system characteristics, load density, reliability and power quality. The benefits of variable, non-dispatchable sources are also influenced by energy storage. Traditionally, the major benefits of DER to customers and utilities are energy production and capacity displacement, but there are additional non-traditional benefits to both the utility and customer.

A number of references have examined the economics of integrating DER into the electric power system and methodologies to determine such benefits. Ma[6] presented a methodology for distribution planners and operators to assess the technical and economic effects of variable power production. Vachtsevanos[7] developed a methodology for simulation studies for various levels of PV penetration. Chinery[8] described a methodology to estimate the value of PV to electric power systems. Hoff[9] provided a method to calculate the value of PV to a utility system that focuses on traditional values of energy and capacity. Rahman[10] conducted a study of the economic effect of integrating PV with conventional electric utility operation. Bouzguenda[11] evaluated the economic and operational effects of incorporating large PV and wind systems into the electric utility generation mix with the availability of existing hydroelectric generation. As part of the Photovoltaic's for Utility Scale Applications Project, Pacific Gas and Electric built the Kerman 500-kW PV[2] power plant. To site the Kerman system, Shugar[12] proposed a methodology that examined three selection criteria: correlation of PV system output with peaks, expected growth rate of the feeder, and sufficient land area. Zaininger[13] compared central versus distributed PV systems from an economic cost perspective. Leng[14] conducted a study to determine the value of PV with a daytime summer peaking utility. Chowdhury[1] presented a new methodology for assessing the reliability of utility systems that include PV. Dugan[15] discussed a way to capture incremental capacity provided by DER. El-Kattam[16] proposed a new integrated model for solving the distribution planning problem of load growth by implementing DER as an attractive option in a distribution utility's territory. Borges[17] presented a methodology for optimal DER allocation and sizing in distribution systems to minimize electrical losses and guarantee reliability and voltage profiles. Quezada[18] presented an approach to compute annual energy loss variations when different penetration and concentration levels of DER are connected to a distribution network. Payyala[19][20] presented a techno-economic feasibility assessment for distributed biomass plants that addresses DER optimization with economic and technical considerations. Le[21] provided a new methodology to optimize the capacity and location of DER based on the level of power loss reduction. Kuri[22] presented a method using genetic algorithms that helps determine the optimal rating and placement of DER.

From a utility perspective, it is important to evaluate the feeders in a distribution system that will receive the best value from the installation of DER. The main economic factor for DER is based on the actual energy that the system produces. The basic energy production value occurs because the amount of electricity that must be generated at other plants is reduced by the amount of DER energy production, which thus decreases the fuel consumed and the operations and maintenance (O&M) costs associated with the electricity-generation equipment [23]. It can be compared with the cost of providing that energy via traditional methods. DER are often used to produce energy when costs from the utility are at their highest. Renewable sources that produce energy during times of peak demand when electricity rates are higher may have more value. This is both a customer and utility benefit. The customer reduces electricity usage from the utility and this reduces the electricity the utility must generate.

Another benefit of DER is capacity displacement which is the system peak capacity that can be freed by using generation at the load. Capacity displacements can increase system operations efficiency and reduce the run time of expensive power plants. To the utility, the generation capacity is the economic value of the avoided cost of electricity (typically produced by natural gas turbines), while to the customer the generation capacity is seen as demand reduction if the DER output coincides with times of high load. DER effectively provide generation capacity by reducing demand-side consumption. Generation capacity value is the product of an economic value of an ideal resource (represented by a natural gas turbine) and a technical adjustment to reflect the DER actual peak load reduction value to the utility system.

Peak electrical demand is a concern to utilities because of its role in peak generation availability, price, environmental quality, and stress imposed on the system. DER can be used to provide peak generation, provided that they are reliably available at peak time. For dispatchable DER, the effective capacity is the unit's rating. However, for nondispatchable DER, another way must be used to account for the fact that the DER may not always be available. Industry has used a method call effective load carrying capability (ELCC) to determine the capacity of nondispatchable DER. The ELCC of a generating unit in a utility grid is defined as the load increase that the system can carry while maintaining the designated reliability criteria (e.g., constant loss of load probability). Results indicate that a DER, depending on system configuration, is worth between one-half to two-thirds the value of an equivalently-sized ideal resource.

Targeted deployment of DER can also relieve loads on a utility's transmission, sub-transmission, and distribution systems, and effectively increasing available T&D capacity [23]. This relief allows utility T&D planners to defer capital investments in the transmission and distribution (T&D) system.

DER systems also produce energy at the point of consumption. By locating energy sources at the point of use, losses in the T&D system are reduced because the energy produced by DER does not have to pass through the T&D systems. Losses are a function of the current squared, and DER can provide a benefit by producing power at the point of load. This reduces the real and reactive losses through the T&D system to the utility. Another possible benefit from DER would be phase balancing to help reduce losses and unbalances at the distribution level. These benefits may contribute to improving the local reliability of the feeder if a DER can provide backup power to the customer.

Additional benefits to the utility of using DER are environmental such as fossil fuel emissions (e.g., NO_x, SO_x, heavy metals, and CO_2,) reductions. This is becoming a higher priority in the future if carbon taxes are implemented.

Another important utility benefit is the deferment of equipment upgrades. Adding extra generation in the utility circuit may allow utilities to defer upgrades to feeders/conductors, transformers, load-tap-changers, and other equipment on the distribution system if they are running near capacity for short periods of time.

III. FEEDER RANKING METHODOLOGY

Initial studies[12] that identified good feeders for DER relied on a few factors (e.g. peak-load reduction, load growth, and available land). The following methodology builds on this work and fully evaluates the feeders and DER in terms of peak-load reduction, feeder capacity, load-generation correlation, and feeder load growth rate. This method can be used to screen all distribution feeders in a utility service territory and rank them according to their potential to add value to the utility.

To conduct the analysis, the following information is needed for each feeder:

- A full year of hourly (8,760 points) feeder load data
- The feeder transformer capacity (in MVA)
- The projected 5 year load growth of the feeder (in percentage per year).

Other important variables are the DER type and operational characteristics. DER can be classified as dispatchable or nondispatchable. This is important for understanding the run profile of the DER. If the run profile for the DER is known (e.g., there is a plan to run the unit from 4 p.m. – 7 p.m., Monday - Friday), then that can be used. If no run profile is given for a dispatchable DER, then it is assumed to run for only the top $(n)_r$ hours of the *Load Duration Curve* (LDC) in order to maximize value to the utility system. For this research n_r was chosen to be 100hrs., because the highest value for capacity is embedded in the top 100 (load) hours. Figure 1 shows the relationship between the LCC and LDC hour for Pacific Gas & Electric (PG&E) from 1985 to 1988 [9]. The LCC is the incremental load that the generating unit permits the system to carry [24]. This graph shows, that for the PG&E system, capacity is of greatest benefit during the top 100 hours of load. This graph should be determined for the specific utility being studied. The DER capacity is then determined using Equation 1. For these studies, n_r = 100 based on the research from PG&E.

$$\text{DER Capacity} = \text{Peak Load} - \text{Load at Hour } n_r \text{ of LDC} \quad (1)$$

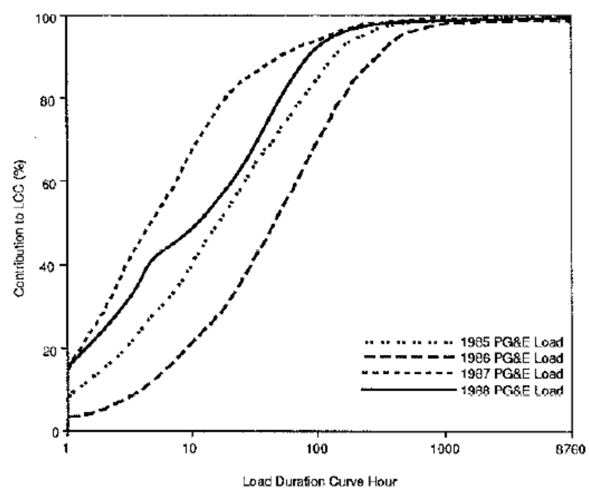

Figure 1. LCC as a Function of LDC Hour[9]

The value to the utility of each DER feeder is based on the objective function shown in Equation 2. Once this is determined for all feeders, the next step is to rank-order and screen the feeders based on the value. To determine the final feeder value, the feeder transformer capacity (MVA), the projected 5-year load growth of the feeder (in percentage per year), and a full year of hourly feeder load data (8,760 points), are used in conjunction with Equation 1.

$$f_{val}(n) = c_1 PLR + c_2 CAP + c_3 COR + c_4 LGV \quad (2)$$

Where:
PLR= Percent peak load reduction
CAP = Percent capacity gain for the top nr load hours with DER
COR = Correlation between the generation and load
LGV = Load growth value
c_1-c_4 are some weighting coefficients

Equation 2 includes four important factors (i.e., peak-load reduction, capacity gain, correlation between load and generation, and load growth value) to determine the relative value of DER on the proposed feeder. The weighting coefficients ($c_1 - c_4$) are arbitrary numbers that help the user define the importance of each part of the equation. These values may differ from utility to utility based on what the user believes are the most important aspects of the value.

Peak-load reduction (PLR) is the percent by which feeder load is reduced during a year as a result of using DER. This value is determined by calculating the new peak load with DER and comparing it with the original peak load as shown in Equation 3.

$$P_{plr} = \frac{\left(Peak\ Load_{\ without\ DER} - Peak\ Load_{\ with\ DER}\right)}{Peak\ Load_{\ without\ DER}} \times 100 \qquad (3)$$

Where:

$Peak\ Load_{\ without\ DER}$ = Peak hourly load from the original 8,760-point hourly data set

$Peak\ Load_{\ with\ DER}$ = Peak hourly load from the 8,760-point hourly data with DER installed.

This is an important parameter because utility distribution systems are designed to carry peak load. A reduction in peak load can defer system upgrades and therefore reduce operating costs for the utility.

The *CAP* factor in Equation 2 is the capacity that is released through the use of DER. For this factor, the value of n_r needs to be established by the utility. In this research, n_r is equal to 100 hr. based on Figure 1. Therefore, *CAP* (Equation 4) is defined as the percentage of energy released during the top 100 load hours with the DER running.

$$CAP = \frac{Energy(n_r)_{\ without\ DER} - Energy(n_r)_{\ with\ DER}}{Energy(n_r)_{\ without\ DER}} \times 100 \qquad (4)$$

Where:

$Energy(n_r)$ = total energy (kWh) from the top n_r load hours; in this case $n_r = 100$

The next factor in Equation 2 deals with the correlation between the generation and load. This is important if the DER is nondispatchable such as a wind or PV systems. If the DER can provide energy during the peak demand periods, it is more valuable to the utility. This is because peak electricity is more expensive for the utility to produce than off-peak electricity.

The factor (*COR*) describes the correlation between generation and load for the time period when the energy is most valuable, the peak load period. The *COR* factor between the load and generation is computed using Equation 5.

$$COR = \frac{\sum_{1}^{n_r} DER_{kw}}{DER_{kw-rating} \times n_r} \qquad (5)$$

Where:

DER_{kw} = the power produced at a specific hour

$DER_{kW\text{-}rating}$ = the rating of the DER

n_r = the total hours above a specified load (in this case $n_r = 100$)

COR is the percent of rated power produced during the top n_r hours of operation. The value of *COR* ranges from 0 to 1. For this study n_r is equal to 100 because this also equates to the top hours the utility would be concerned about. Figure 2 shows how this value changes based on generation conditions. The peak load conditions happen between the hours of 15 and 19. Generation scenarios are shown for three different DER. PV Output 1 is a normal system that peaks during the noon time. PV Output 2 is a system that has been pointed west so that its peak output is a little later in the day. Finally, a dispatchable DER is designed so that it runs when the peak load is reached. For these scenarios, the correlation between generation and load ranges from 0.37 with PV Output 1 to 1.0 for the dispatchable DER.

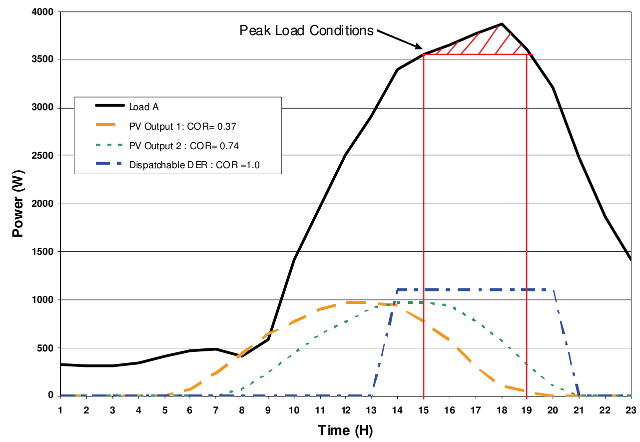

Figure 2. *COR* Factor with Various DER

The final factor in Equation 2 is the load growth value (LGV). This accounts for expected load growth (G_f) of the feeder and the percentage at which the feeder is loaded at peak conditions (*XMR*). Feeder load growth rate is important to a utility because feeders with high growth rates are upgraded to accommodate the growth. DER can delay upgrades to feeders, but this is best realized on feeders with slow load growth. The DER can be used to defer feeder upgrades such as increasing wire size, voltage, or transformer capacity. Equation 6 defines the *LGV* as the exponential of the *XMR* value divided by the growth factor of the feeder (G_f). The exponential of the *XMR* term is used to match the exponential properties of the load growth factor.

$$LGV = \frac{EXP(XMR)}{G_f} \qquad (6)$$

Where:

XMR = Peak load divided by transformer rating

G_f = Percent load growth for feeder (percentage per year).

Because the G_f term is in the denominator, the higher the load growth factor, the smaller the overall value to the utility will be. Transformers that often operate near their peak rating may be candidates for upgrades if project load growth is high. The addition of DER to reduce the peaks may allow utilities to defer transformer upgrades. The *XMR* value (Equation 7) is the percentage at which the distribution feeder transformer is operated at its rating during peak loading.

$$XMR = \frac{Peak\ Load\ Value(MVA)}{Transformer\ Rating(MVA)} \qquad (7)$$

The objective of this process is to rank a set of distribution feeders in the order of the value that DER will bring to the utility. The following is a step-by-step process to determine each feeder's value based.

IV. STEP-BY-STEP RANKING PROCEDURE

Step 1: Obtain the following information about each feeder in the study:

- Hourly feeder load data for an entire year (8,760 points)
- The feeder transformer capacity (MVA)
- The projected 5-year load growth (in percentage per year).

Step 2: Construct an LDC based on a specific year of data.

- Determine n_r of study set (assumed, $n_r = 100$)
- Determine the peak load and load at hour n_r of the LDC.

Step 3: Determine the capacity of the DER. If the value is known, use that value. If the value is unknown, use the value determined by Equation 1. Determine the DER run schedule for dispatchable units or a specific year of resource data for nondispatchable renewable units.

Step 4: Simulate an 8,760-point hourly run profile for the DER. A variety of simulation and modeling programs can simulate the output of DER technologies. For this step, HOMER[25] or PVWatts[26] is acceptable for simulating solar, wind, and other DER systems.

Step 5: Construct a new LDC and determine the new peak load

Step 6: Compute *PLR*, *CAP*, *COL*, and *LGV* for each feeder. Compute the feeder value using Equation 1 and rank-order the feeders based on their feeder value numbers. The highest value is assigned to the feeder that can provide the best value with DER.

V. CASE STUDIES

A set of ten distribution feeders was selected randomly to evaluate the feeder screening methodology. The data from these feeders are based on actual feeder and load data from a utility, but they have been modified to remove any identification marks. Although modified from the original data, the objective of rank-ordering the feeders to determine the value of DER to the utility has not been compromised. The sample feeders will show a range between good value fits for DER and poor fits for DER. Table 1 lists the feeders used to test the feeder selection methodology. For each feeder, the transformer ratings, projected percent load growth per year, peak load, load factor, average load, and utilization factor are given. The *load factor* is the average load divided by the peak load over the time period. The *utilization factor* is the peak load divided by the rated system capacity (in this case, the feeder transformer capacity).

TABLE 1
DISTRIBUTION FEEDER LIST

Feeder Name	XFMR Size (MVA)	% Load Growth /year	Peak Load (MVA)	Average Load (MVA)	Load Factor	Utilization Factor
A	10	1.0	6.13	4.44	0.724	0.61
B	10	1.5	4.83	4.01	0.831	0.48
C	10	1.5	4.80	3.36	0.701	0.48
D	5	1.5	3.87	0.73	0.189	0.77
E	5	2.5	2.83	0.73	0.258	0.57
F	5	2.5	3.32	0.83	0.250	0.66
G	5	3.0	2.12	0.53	0.250	0.42
H	5	2.5	2.12	0.68	0.321	0.42
I	10	2.5	6.70	1.90	0.284	0.67
J	5	2.5	2.75	1.32	0.479	0.55

The feeders listed in Table 1 include various capacity feeders, projected load growth, and peak loads. To get an overview of the feeders, their loads were normalized to the peak load of Feeder A. The normalized LDCs for feeders A through J are shown in Figure 3. Feeders A and B are commercial feeders that use demand side management (DSM) to manage peak loads. The DSM operates on a time setting to reduce loads during peak usage time. These feeders show a relatively flat LDC. Because of the DSM, these feeders typically do not have good correlation between the load and a solar system output. Feeders C, I, and J are commercial feeders that show a step function in the LDC. This is because loads are either on (during the day) or off (at night and on weekends). Feeders D, E, F, and G are residential loads with high peaks in the morning and afternoon and relatively low loads during midday and at night. These loads show a highly peaked LDC.

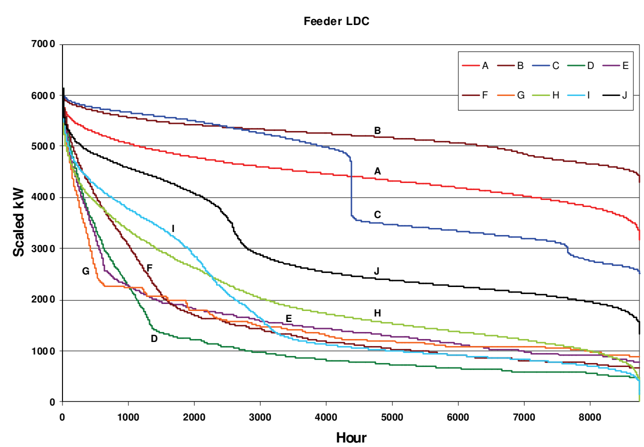

Figure 3 Normalized LDCs for All Feeders

To examine the results of the methodology, ten case studies were performed. These case studies evaluated how several variables affect the ranking of the feeder value of DER to the utility. The main variables were the dispatchability of the DER source and the DER capacity. Nondispatchable cases used a modeled PV system performance. The PV system output was derived from solar resource data from calendar year 2003 for Sacramento, California. The dispatchable DER was modeled as a fossil-fuel based DER (FFDER) that is turned on when a preset load threshold is reached. The capacity of the DER was determined three ways. The first was to size the DER based on the capacity gained during the top 100 hours of the LDC. The second was to use a fixed percentage of the peak load (% DER penetration), 15% and 30% were used. The third was to size the DER to a fixed value. 200kW and 1,300kW were used. This is useful if the size of the DER has been predetermined. Table 2 lists the cases evaluated.

TABLE 2
RANKING METHODOLOGY CASES

Case Number	Case Name	DER Dispatchable	DER Capacity	DER Penetration
1	PV	No	Equal to load during top 100 hours	4% - 22.5%
2	PV15	No	Equal to 15% of peak load	15%
3	PV30	No	Equal to 30% of peak load	30%
4	PV200kW	No	200kW	3% - 9.4%
5	PV1300kW	No	1,300kW	19.4% - 61.4%
6	FFDER	Yes	Equal to load during top 100 hours	4% - 22.5%
7	FFDER15	Yes	Equal to 15% of peak load	15%
8	FFDER30	Yes	Equal to 30% of peak load	30%
9	FFDER200kW	Yes	200kW	3% - 9.4%
10	FFDER1300kW	Yes	1,300kW	19.4% - 61.4%

Table 2 shows that in some of the cases the value of the DER penetration changes, while in other cases it remains fixed. The following sections will show that this is not an important factor in overall feeder rankings, but the dispatchability of the DER is. Table 3 gives the weighting factors used in this study to determine the relative importance of the four factors of Equation 1. The *COR* weighting factor (*c3*) is set to 5 to make the correlation factor have a similar importance to the *PLR* and *CAP* factors.

TABLE 3
WEIGHTING FACTORS

Weighting Factors	*c1*	*c2*	*c3*	*c4*
All Cases	1	1	5	1

VI. RESULTS

In Cases 1 though 5, a nondispatchable DER is used. These cases examine the value that nondispatchable DER such as PV or wind systems could provide to the utility. In these cases, a solar PV system is simulated using solar resource data that have been time-correlated to the actual load data.

Case 1: Nondispatchable DER Sized to Peak Load Minus 100th Hour Load

If the capacity of the DER is not known, then Equation 1 is used to size the DER based on the top n_r hours of the LDC. Although this makes the actual value of the DER vary with each feeder (DER penetration levels ranged from 4% to 22.5%), this is a reasonable starting assumption. Figure 4 shows the peak load day from Feeder A with a nondispatchable DER that has been sized to the peak demand minus the load at the 100th hour of the LDC for the feeder. In Figure 4, one can see that the PV system produces energy during the day but none at night as would be expected. The peak load on this feeder occurs at night, so there is no reduction in peak load from the DER.

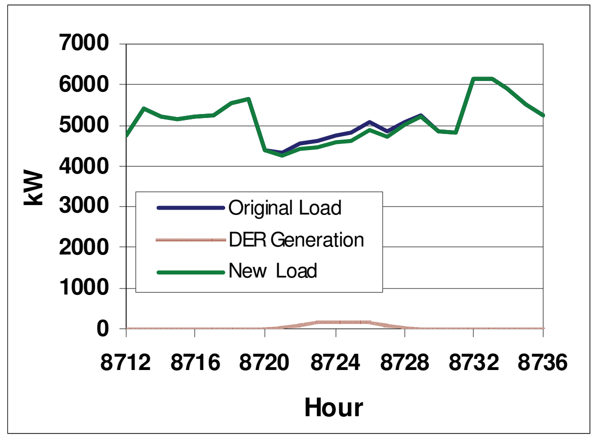

Figure 4. Feeder A – Peak Load Day with PV

Figure 5 depicts the lack of any peak load reduction in the LDC for Feeder A with and without the DER. This shows the top 100hrs. of the LDC. Because there is poor correlation between the peak loads and nondispatchable generation, there is relatively little change (lines are on top of each other) in the top 100 hours of the LDC with the addition of DER.

A better correlation between load and DER generation is found on Feeder H. Figure 6 shows the output of the PV system correlating extremely well with the load profile. This graph clearly shows the reduction in peak load for this particular day. This is also shown in the LDC in Figure 7. Here, a drop occurs in peak load for the feeder, and there is a significant lowering of the overall LDC for the top 100 hours.

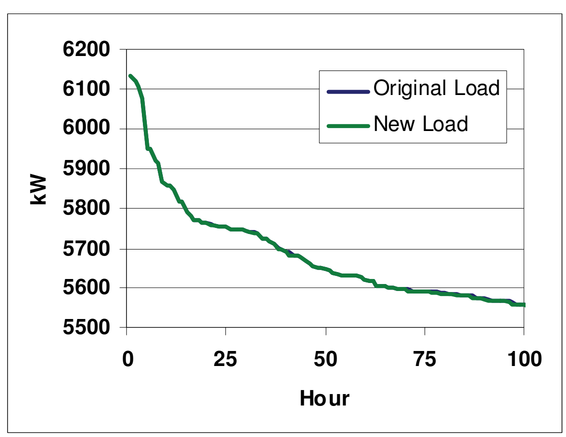

Figure 5. Feeder A - LDC Top 100 hours

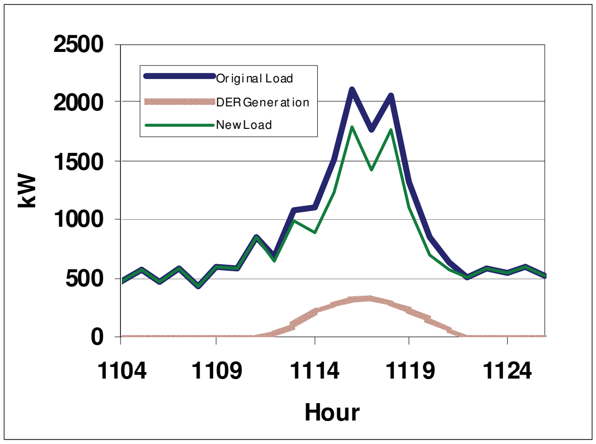

Figure 6. Feeder H – Peak Load Day

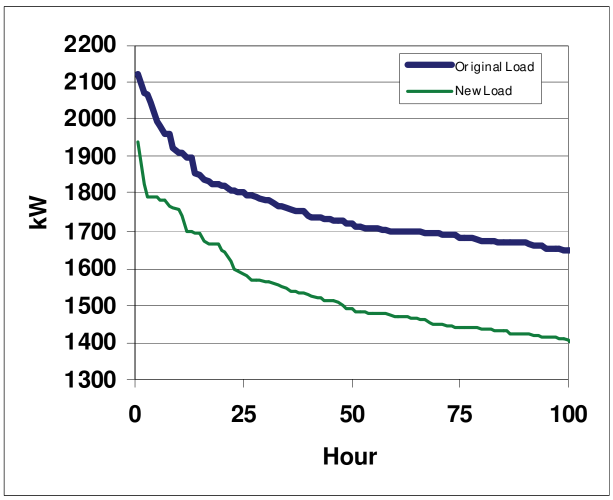

Figure 7. Feeder H – LDC Top 100 Hours

Data from feeders A through J were run through the screening methodology and the results for Case 1 are given in Table 4. For each feeder four components (peak load reduction, capacity, correlation, and load growth value) make up the final feeder value. Each of these values is weighted by the appropriate weighting coefficient. The totals are given in the Feeder Value column and ranked from the highest to lowest value.

TABLE 4 CASE 1: FEEDER RANKING RESULTS

Feeder Name	DER Size (MVA)	Peak Load Reduction	Capacity	Correlation	Load Growth Value	Feeder Value	Rank
H	0.471	8.37	12.6	2.74	0.61	24.31	1
I	1.302	4.93	8.6	2.27	0.78	16.59	2
J	0.389	2.32	5.6	2.31	0.69	10.89	3
D	0.667	0.70	3.7	1.11	1.45	6.95	4
G	0.476	0.37	4.9	1.12	0.51	6.91	5
C	0.191	0.86	1.5	2.37	1.08	5.77	6
E	0.585	0.20	3.0	0.78	0.70	4.64	7
A	0.573	0.00	0.0	0.01	1.85	1.87	8
B	0.223	0.00	0.0	0.04	1.08	1.16	9
F	0.484	0.00	0.2	0.08	0.78	1.10	10

Figure 8 shows that Feeder H was the best candidate for implementation of DER. If one standard deviation from the best case is used to make the decision, only Feeder H meets this criterion. The next closest was Feeder I, which was close to being within one standard deviation from the best case. Feeders J, D, G, C, and E all show some level of value but not a strong case for DER. Feeders B, A, and F show little if any benefit from using nondispatchable DER using the criteria in Case 1.

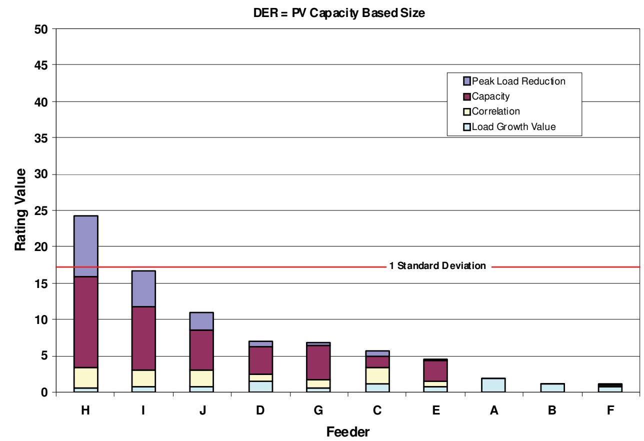

Figure 8. Case 1: Feeder Value and Ranking

In Case Studies 6 through 10, a dispatchable fossil-fueled DER (FFDER) is used. In this case, the fossil-fueled DER could be an engine, a microturbine, or a fuel cell. The run profiles in these cases are significantly different from the run profiles under the nondispatchable cases, in which the DER operates only when sufficient resources were available. In Cases 6 through 10, the DER is dispatched to reduce peak load. The DER is run only during the top 100 hours of load based on the original load profile.

In Case 6, the DER is again sized to the peak load minus the 100th hour load of the load profile, as was done in Case 1. Figure 9 shows the peak-day load profile for Feeder A. Notice that the DER now operates during the peak demand periods around 5 a.m. and 9 p.m.

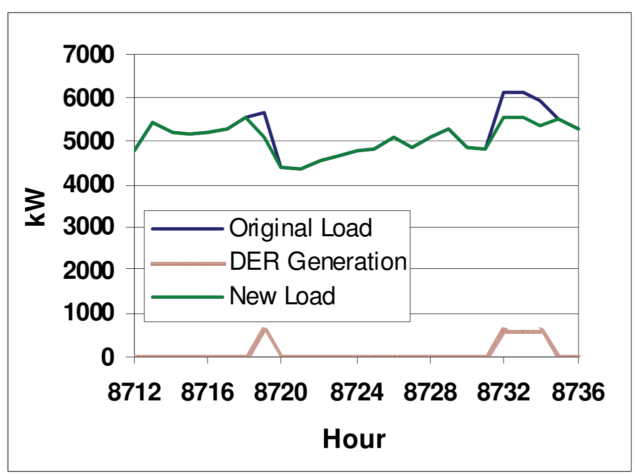

Figure 9. Feeder A – Peak Load Day with Dispatchable DER

Figure 10 shows the LDC for the original load and the new load with the DER running on Feeder A. Because the DER is dispatchable and runs during peak demand, it significantly reduces peak load and increases capacity on the system.

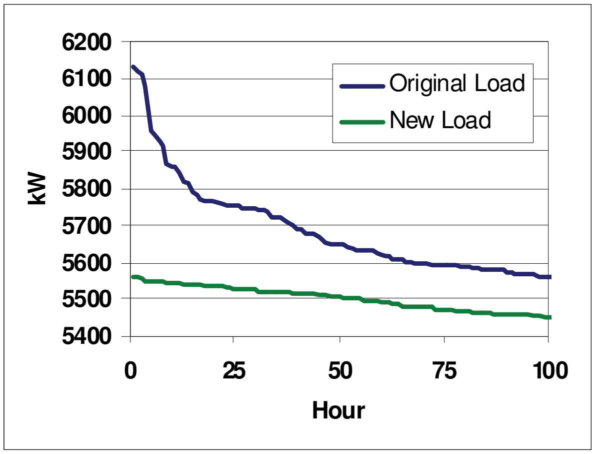

Figure 10. Feeder A – LDC with Dispatchable DER

Figure 11 shows the peak-day load for Feeder H, which was the top-ranked feeder for Case Studies 1 through 5. Again, the DER operates during the peak-demand periods but is no longer restricted to the times when the solar resource is available. Figure 12 shows the LDC Feeder H for the original load and new load with DER. This shows that the peak load is significantly reduced.

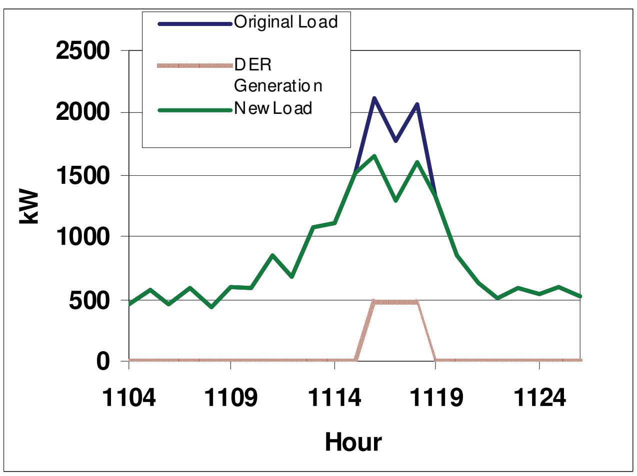

Figure 11. Feeder H – Peak Load Day with Dispatchable DER

Table 5 and Figure 13 provide the results for Case 6. In this case, because the DER can be run when the load exceeds a threshold, increases in peak-load reduction and capacity are seen on all the feeders. Note that for the dispatchable cases the correlation factor is always equal to 5. This is because the DER always operates when it is needed, and then this value is multiplied by the weighting coefficient 5 to remain consistent with the nondispatchable cases. There are also more feeders that are within one standard deviation of the top ranked feeder. Feeders G, E, H, D, and I are all within one standard deviation of the top. This means that for dispatchable DER, the number of candidate feeders increases. Also note that these feeders have high peak loads in relation to average loads and low utilization factors).

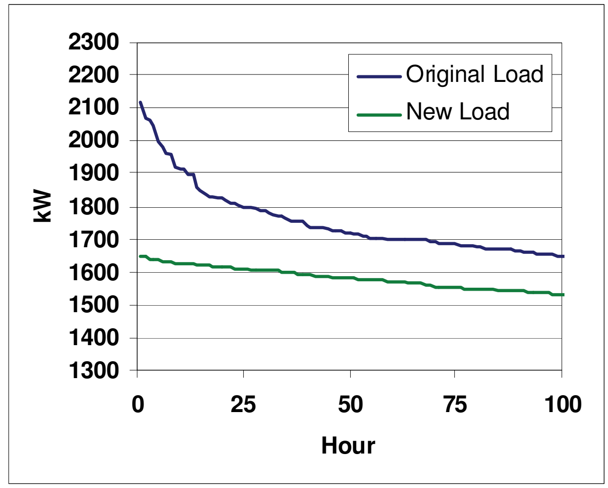

Figure 12. Feeder A – LDC with Dispatchable DER

TABLE 5
CASE 6: FEEDER RANKING RESULT

Feeder Name	DER Size (MVA)	Peak Load Reduction	Capacity Value	Correlation	Load Growth Value	Feeder Value	Rank
G	**0.476**	22.50	15.1	5.00	0.51	43.09	1
E	**0.585**	20.67	12.7	5.00	0.70	39.07	2
H	**0.471**	22.25	9.9	5.00	0.61	37.75	3
D	**0.667**	17.24	11.8	5.00	1.45	35.45	4
I	**1.302**	19.44	9.1	5.00	0.78	34.30	5
F	**0.484**	14.57	9.3	5.00	0.78	29.65	6
J	**0.389**	14.13	5.0	5.00	0.69	24.85	7
A	**0.573**	9.34	3.3	5.00	1.85	19.50	8
B	**0.223**	4.61	1.6	5.00	1.08	12.29	9
C	**0.191**	3.98	1.4	5.00	1.08	11.44	10

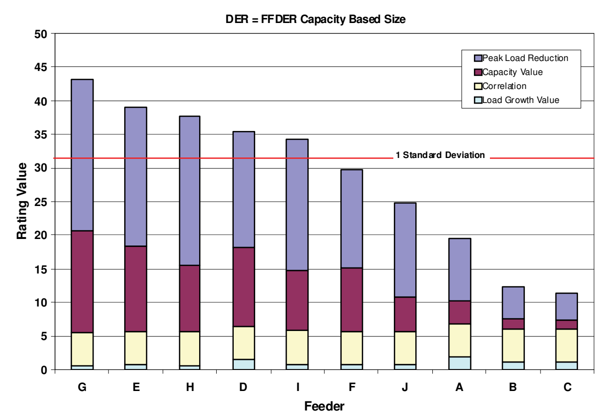

Figure 13. Case 6: Feeder Value and Ranking

VII. CONCLUSIONS

Based on the screening methodology, it was found that feeders with a high peak load compared with the average load are good candidates for DER. For nondispatchable DER, it is important to have good correlation between the load and the DER output. In the nondispatchable Case Studies (1 through 5), the relative ranking of high- and low- value feeders was maintained under various DER penetration levels and sizes. The one standard deviation from the top ranked feeder criterion was useful in determining the top feeders for value of

DER to a utility. In the dispatchable Case Studies (6 through 10), the relative ranking of high- and low-value feeders was maintained under various DER penetration levels and sizes. It was found that, in these cases, using the one-standard-deviation criterion produced more candidate feeders for DER implementation.

Table 6 gives the ranking results for all the case studies. The feeders that meet the one-standard-deviation criterion are highlighted. The methodology shows that the top-ranked feeder remained constant for all dispatchable and nondispatchable case studies. These results show that the feeder selection methodology works well for a variety of conditions and can successfully rank-order feeders based on the value of DER to the utility.

TABLE 6
FEEDER VALUE RANKING RESULTS FROM ALL CASES

			Feeder Ranking									
			1	2	3	4	5	6	7	8	9	10
Case	1	PV	H	I	J	D	G	C	E	A	B	F
	2	PV	H	I	J	C	D	G	E	A	B	F
	3	PV	H	I	J	D	C	G	E	A	F	B
	4	PV	H	J	I	C	G	D	E	A	B	F
	5	PV	H	J	I	G	D	C	E	A	F	B
	6	FF	G	E	H	D	I	F	J	A	B	C
	7	FF	G	D	E	F	H	I	J	A	B	C
	8	FF	G	E	H	D	I	F	J	A	B	C
	9	FF	G	H	E	J	F	D	A	I	B	C
	10	FF	G	E	H	D	I	F	J	A	B	C

within 1 standard deviation of top
PV - Photovoltaic DER
FF - Fossil Fueled DER

This paper described a novel methodology to rank distribution feeders by value for using distributed energy resources based on peak load reduction, increased system capacity, load-generation correlation, and feeder load growth. This value is based in part on a statistical measure that quantifies the relationship between loads and the stochastic nature of renewable resources. The advantage of this methodology over prior work is that capacity and generation-load coincidence are assessed. This allows the utility to gain insight into improved benefits from nondispatchable renewable resources such as solar and wind technologies.

VIII. ACKNOWLEDGMENT

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