21, rue d'Artois, F-75008 PARIS
http://www.cigre.org

CIGRE US National Committee
2018 Grid of the Future Symposium

A Direct Calculation of Locational Marginal Value of Distributed Energy Resources

M. NDRIO[1], N. M. ABDULLAH[1], F. MAIGHA[1], A. PAASO[1], A. KHODAEI[2], E. NTAKOU[3], F. FARZAN[3]
[1]Commonwealth Edison
[2]University of Denver
[3]Quanta Technology
USA

SUMMARY

There is a growing world-wide interest in the integration of distributed energy resources (DERs) into electric power grids due to their potential economic and environmental benefits. Broadly defined, a DER represents any electric power resource, such as solar or combined heat and power, installed and operated in the distribution system at voltage levels below the typical bulk power system levels. The increased DER installations provide an opportunity for distribution utilities to view such resources as non-wire alternatives that enable network investment deferrals. However, this brings considerable challenges in the development of methodologies and evaluation algorithms to determine the value of DERs to the distribution grid. In this paper, we provide mathematical formulation for the direct calculation of the value of DERs based on the AC power flow equations. The mathematical framework is incorporated into a generalized algorithm for the assessment of the locational and temporal value of a generic DER to the distribution grid. Preliminary study results are provided to demonstrate the locational nature of the value of DERs and the impact of the magnitude of violations and network losses in the value. The proposed methodology can be applied to any planning horizon and enables the consideration of the DER value in terms of managing voltage levels, circuit power factor, as well as real and reactive power.

KEYWORDS: Distributed energy resources (DERs), locational marginal value (LMV), programming tools, power system simulations

fnu.maigha@comed.com

1. INTRODUCTION

The electric power industry is entering a period of fundamental transition due to growing climate change concerns, the integration of intermittent renewable generation and the emergence of distributed resources that offer the potential for additional resilience. In this changing environment, electricity customers have more choices and control over their electricity service, such as ownership of generation systems (solar PV, combined heat and power), leveraging demand response opportunities, as well as, energy efficiency measures. Collectively, these load-altering measures are referred to as distributed energy resources or DERs. For distribution grid operators, DERs can potentially provide value to the grid in terms of deferred capacity upgrades or reduced operating expenses.

DERs have markedly different characteristics from conventional generation resources. Specifically, DERs are located near end-use customers and can incorporate renewable generation of intermittent and stochastic nature that can provide significant environmental benefits resulting from their operation and aggregation. DERs bring a wide range of values to the electricity grid [1]. From the increase in usage of low-carbon energy, reduction in the customer's payments in terms of energy costs and electric rates, to improvement of power quality, reliability and resilience. While DERs provide a wide range of environmental, economic and societal benefits, the focus of this paper is only on the value that DERs bring to the distribution grid. This value is defined in terms of the avoided costs for providing delivery capacity, which is primarily peak load shaving or other loading reduction on parts of the system that would otherwise require investment to increase capacity. DERs provide voltage control and power quality benefits in terms of avoided costs to maintain voltages within ANSI or state specific standards. Furthermore, DERs may conceivably in the future provide reliability and resilience benefits via not only behind-the-meter backup generation but also via local or community microgrids that provide, in effect, a form of backup generation to one or multiple customers. DERs can provide these benefits via the supply of real power, reactive power, and reserve capacity. Once DERs become a significant part of the distribution system portfolio, some DERs may also provide a reliability benefit in terms of local reserves; that is, additional real and reactive power capacity available to provide capacity, voltage, or reliability in case the DERs primarily providing that service become available.

DERs pose opportunities as well as challenges. Uncontrolled DERs are often a source of power quality problems, especially high voltage and flicker if power electronically-coupled, and possibly circuit ampere overloads in cases of extreme reverse flow [2], [3]. DERs can, however, be a means to manage and mitigate these problems, even increasing hosting capacity for other DERs, including EV charging by providing local real and reactive power to mitigate the adverse effects of locally high amounts of PV or other variable DG. In this paper, we focus on the avoided costs of traditional investments to evaluate the benefits of DERs to the grid.

We first discuss the fundamental aspects of the value of DER and the nature of the problem. Although DERs may provide multiple value streams and benefits, the quantification of those benefits is beyond the scope of this work. The key contribution of this work is to provide a generic algorithm for direct calculation of the value of DER that is technology agnostic and is based on the AC power flow formulation. We present preliminary results of a test system.

2. VALUE OF DER FUNDAMENTALS

The first principle in determining the value of DER to the distribution grid in terms of avoided costs is that all DER value is locational [4]. That is because all avoided costs for capacity and voltage are investment costs in response to actual forecasted needs of the system, which are always based on specific grid issues in specific locations. On a given circuit the ability of a DER to avoid capacity or voltage costs by providing real or reactive power depends very much upon the location relative to the grid constraint to be addressed. Generally, for radial distribution circuits the DER must be downstream of the location of a loading issue to help mitigate the problem. Figure 1 illustrates the DER overload mitigation concept through a simple example. The DER downstream of the congested line provides more benefits in comparison to the DER upstream of the congestion. Similarly, voltage problems on circuits are typically local in nature. Low voltage at the end of the circuit does not imply low voltage near or at the station. Indeed, attempting to cure a low voltage at one location by raising overall circuit voltages may cause too high a voltage in another location. Traditional mitigation to voltage issues are to deploy local apparatus that affects voltage locally, such as capacitors or voltage regulators.

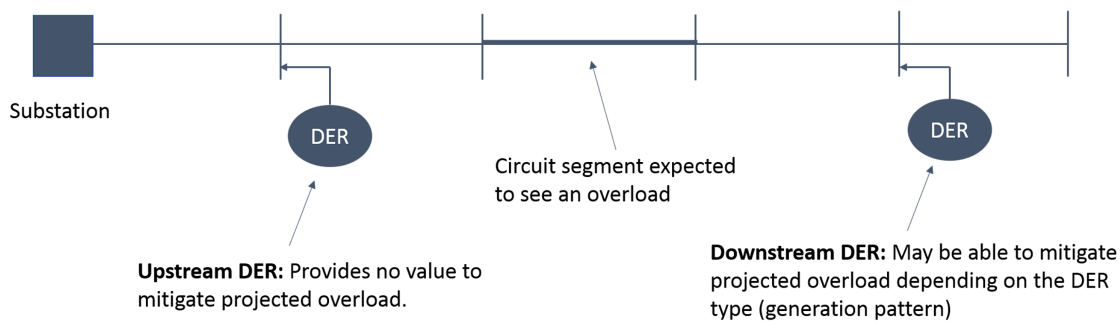

Figure 1. Illustration of DER Overload Mitigation.

If we examine the simple case of a radial feeder shown above where the first mile of a circuit needs to be reinforced and the argument that DER only affects loadings on the upstream portions of the circuit, then this introduces the concept of how to place a locational value on the DER. If the DER midway on the overloaded portion of the circuit deferred the need to upgrade capacity on the first half of the circuit – conceivably it could at maximum avoid half of the cost. The DER located at the downstream end of the affected portion of the circuit could, by contrast, avoid all the cost. So conceptually, the second DER is worth twice the first DER in terms of value to the distribution grid. This concept can be generalized. For any DER, its locational value is affected by the sensitivity of the circuit condition requiring capacity or voltage investments to the real and reactive power from that DER.

Another concept is important when we evaluate the value to the distribution grid of specific DER technologies. Circuit capacity and voltage problems typically do not happen to the same extent across every hour of the year, and in fact may only occur for a limited number of hours a year. An effective and efficient DER technology would essentially provide real and reactive power when and where they are needed. As such, the DER value is both locationally and temporally granular. Therefore, there are three elements to valuing DER: First is the avoided cost of required circuit upgrades and how that cost is apportioned among affected parts of the circuit; and second is how effective real and reactive power input from the DER is at a given location in reducing or avoiding that cost. Third is how different DER technologies align with the temporal value of DER and how much of the generic DER value a given technology can realize.

An accurate and efficient methodology for valuing DERs would compensate such resources for services they provide to the distribution grid by addressing different characteristics /capabilities of the DER technologies, as well as, taking into consideration their locational and temporal value. Moreover, such methodology would be fair and equitable to limit impact on non-participating customers and avoids under and over-compensation. The double compensation of DERs from other existing markets would be avoided. The methodology would support the value provided by the DERs to the grid based on when and where they are functional.

3. DIRECT CALCULATION OF THE LOCATIONAL MARGINAL VALUE OF DERs

This study extends the work provided in [4] and presents a methodology to directly compute the locational marginal value (LMV) of a generic DER. The concept of marginal cost of capacity (MCC) was first introduced in [4] and is defined as the marginal cost of grid upgrades required to mitigate overloads and voltage violations in the network. To calculate the MCC, the branch ampere overloads are obtained for each hour of the specified study period (8760 for a year) from the results of a series of unconstrained distribution load flows. The MCC values are used to establish the penalty functions for the ampere overloads in each branch of the study system. The LMV evaluation requires the solution of an optimal power flow problem with the objective to minimize the total cost of supplying real and reactive power at the substation and the total costs of overloads or voltage violations. The dual variables of the real and reactive power equality constraints at each node are the LMVs since they represent the marginal impact on the total MCC of an increment of real and reactive power at that node. The details of LMV and MCC formulation can be found in [5]-[6].

In this section, LMV has been formulated as the partial derivative of the total MCC penalty on all the branches of the network with respect to the real and reactive power at each node. This alternative LMV formulation can be easily reconciled with the dual variable definition from the theory of Lagrangian optimization [7]. The real and reactive power injections at node i are denotes as $P(i)$ and $Q(i)$ respectively. The LMV of a kW of DER located at node i, i.e., $LMV_P(i)$, is given by:

$$LMV_P(i) = \frac{\partial MCCT}{\partial P(i)} = \sum_j \frac{\partial MCC(j)}{\partial P(i)} \quad , \tag{1}$$

where $\boldsymbol{MCCT}$ is the total penalty function summed across all branches and $\boldsymbol{MCC(j)}$ is the penalty for branch $\boldsymbol{j}$. A similar equation can be written for the reactive power LMV. At this step in the formulation, the form of the $\boldsymbol{MCC(j)}$ is very general. The MCC may be formulated to explicitly represent the branch current overload, nodal voltage, branch real/reactive power, or any electrical variable in the network. In this paper, the LMV is derived for MCCs representing branch current overloads. In fact,

$$MCC(j) = MCC_{pu}\left(I_{mag}(j) - I_{lim}\right) \; , \tag{2}$$

where $I_{mag}(j)$ is the current magnitude flowing on branch j, I_{lim} denotes the ampacity limit of the branch and MCC_{pu} is the total cost of the grid upgrade required to mitigate the branch overload divided by the total number of hours in the study period. Using the AC power flow equations and the Jacobian matrix terms as well as the phasor expressions for branch current, nodal voltages and branch admittance, we can rewrite the $LMV_P(i)$ as follows:

$$LMV_P(i) = IO^T \left[\left(\frac{\partial MCC}{\partial v, \theta} \right)^T * J^{-1} \right] \tag{3}$$

where, J^{-1} is the inverse Jacobian matrix, and IO^T is a vector with entries equal to one if there is a current overload on branch j and zero otherwise. When the MCC is based on voltage variations beyond limits, then the partial derivative is trivially MCC_{pu} for the same node voltage and zero for other nodes or for the nodal angle θ. The above LMV formulation can be applied to a DC load flow model as well. The advantage of an AC formulation is that it enables consideration of DER value streams in terms of managing voltage levels, circuit power factor, and conceivably voltage flicker as well as the real power, which is the only variable evaluated in the DC model.

4. GENERALIZED ALGORITHM FOR THE DIRECT LMV COMPUTATION

The generalized algorithm for the calculation of the LMV for generic DERs is provided in this section. The overall process contains six major steps as shown in Figure 2. The timeframe of procedure is one hour. The entire planning horizon can be defined by a set of hours and can vary according to the study or the application at hand. Typically, the planning period is assumed to be one year. The first step in the process is to implement a "reduction" in the specified distribution network considered in the study. The reason for this pre-step is that the proposed method is designed for balanced, single-phase networks and as such, elimination of two-phase or three-phase elements is required for the appropriate power flow solution. The "network reduction" step also aims to simplify the network and remove redundant elements and loops to expedite the computation procedure. Furthermore, the removal of very small element impedances is required to avoid numerical issues in the computation of the admittance matrix and the Jacobian elements. The "network reduction" step is particularly useful when dealing with large-scale realistic distribution feeder topologies.

Step 2 of the process is to specify the real and reactive nodal demand in the network to solve the AC power flow. This is accomplished by first computing the Jacobian matrix around an initial state of the system. The Newton-Raphson method is implemented for the AC power flow solution at each iteration and the desired solution is derived when the mismatch error is below a certain threshold. The solution or the power flow are the state variable, i.e., the nodal voltage magnitudes and angles are used. In Step 5 of the computation procedure, the *unconstrained* power flow solution to identify the location, number and the magnitude of violations in the system (voltage violations or overloads) is determined. Since the MCC can be readily obtained from the power flow solution as indicated by equation (2), the LMV for real and reactive power can be computed in Step 6, based on equation (3). The process can be repeated for each hour in the planning horizon.

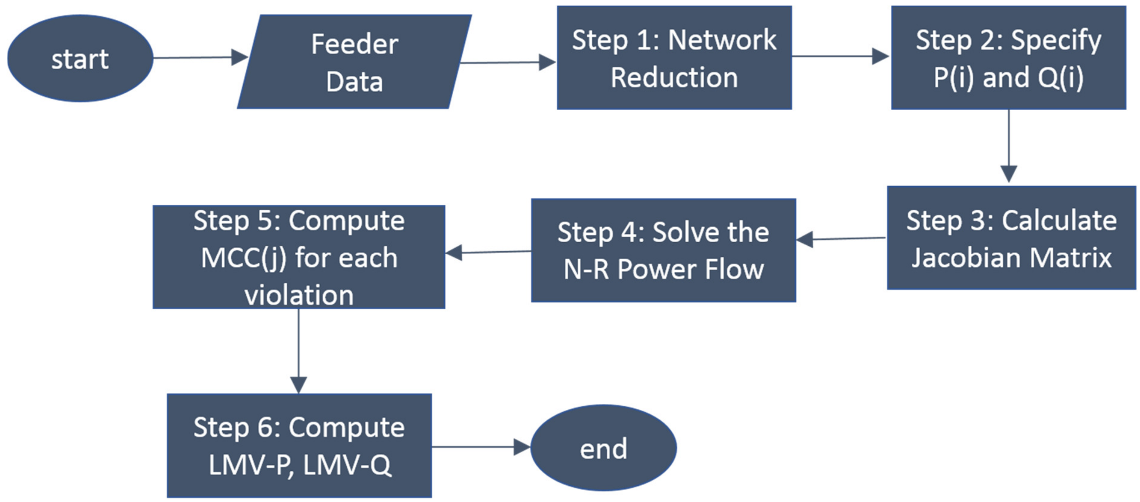

Figure 2. Computational procedure of the LMV calculation for every (hourly) simulation.

5. TEST CASE RESULTS

The preliminary results from a simple three-bus network shown in Figure 3 are presented in this section. The network has two PQ buses with specified complex load values. Note that the load values are given per unit for simplicity of representation. The purpose of this application is mainly for demonstration purposes. Applicability and scalability of the proposed LMV computation scheme will be provided in subsequent work.

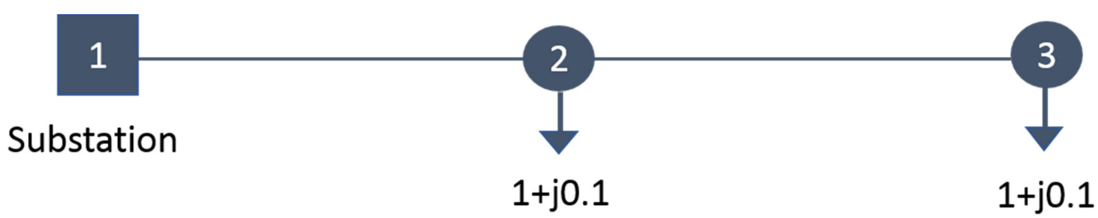

Figure 3. The case study system with given load values (in p.u.).

The power flow results and the branch flow overloads are provided in Tables 1 and 2. The tolerance for the solution is equal to 1E-5. In Table 1 we impose branch current limits such that there is an overload only on branch 1-2.

Table 1. Direct LMV calculation results for overload on branch 1-2.

Node	Voltage magnitude (p.u.)	Voltage angle (deg)	Branch	Current Magnitude (p.u.)	Current limit (p.u.)	LMV-P ($/kW)	LMV-Q ($/kVAr)
1	1	0	1-2	2.0729	1.1	-	-
2	0.9757	-0.0287	2-3	1.0429	1.1	644.1	88.3
3	0.9636	-0.0436				661.0	90.2

As it can be observed from the reported results, the LMV for real power is much higher than that for reactive power. This is due to the load power factor. The branch overload can be relieved when real and reactive power is injected downstream the location of the violation, as shown in Figure 1. Moreover, the LMV for both real and reactive power seems to be increasing as the electric distance from the violation increases. This is intuitively correct, as more power needs to be supplied by the DER to relieve the congested network component and account for additional losses. It is further noted that there is no LMV computed for the substation bus as this is the reference bus for the calculations and no DER is expected to be connected at the substation. In Table 2, the simulation results for modified current flow limits such that only branch 2-3 experiences violation have been presented. A few interesting observations can be made here. First, the LMV for real and reactive power has dropped significantly at node 2 because the current limit for branch 1-2 has more than doubled compared to Table 1; and the amount of violation has dropped to zero, implying that the per unit MCC value has decreased accordingly. The LMV is not exactly zero because it accounts for the losses in the network. As expected, the LMV for real and reactive power are significantly higher for DER located at node 3 where it can contribute to alleviate the overload.

Table 2. Direct LMV calculation results for overload on branch 2-3.

Node	Voltage magnitude (p.u.)	Voltage angle (deg)	Branch	Current Magnitude (p.u.)	Current limit (p.u.)	LMV-P ($/kW)	LMV-Q ($/kVAr)
1	1	0	1-2	2.0729	2.5	-	-
2	0.9757	-0.0287	2-3	1.0429	0.9	7.4	10.5
3	0.9636	-0.0436				653.0	84.8

6. CONCLUSION

In this paper a novel methodology and algorithm for the direct calculation of the locational marginal value of real and reactive power by DERs has been presented. The focus of the paper is to calculate the value of DERs to the distribution grid taking into consideration the locational and temporal nature of such value. A general mathematical formulation of the direct LMV calculation for both real and reactive power based on the AC power flow equations has been presented. The methodology was implemented as a generalized algorithm providing a framework for the consistent evaluation of the LMV of any DER regardless of its type or technology. Preliminary demonstration results were provided for a small test system where the impact of the location and the magnitude of violation of the DER were clearly illustrated in the LMV. Future work will include simulation results of the methodology for large-scale realistic distribution feeders and investigate the impact of the different DER technologies on the LMV.

BIBLIOGRAPHY

[1] R. Tabors, G. Parker, P. Cantonella and M. C. Caramanis, “White Paper on Developing Competitive Electricity Markets and Pricing Structures” (*April 2016*).

[2] R. J. Bravo, R. Salas, T. Bialek and C. Sun, “Distributed energy resource challenges for utilities”, (*IEEE 42nd Photovoltaic Specialist Conference (PVSC)*, June 2015).

[3] P. D. F. Ferreira, P. M. S. Carvalho, L. A. F. M. Ferreira and M. D. Ilic, “Distributed Energy Resources Integration Challenges in Low-Voltage Networks: Voltage Control Limitations and Risk of Cascading” (*IEEE Transactions on Sustainable Energy*, Jan. 2013, pages 82-88).

[4] J. Smith, B. Rogers, J. Taylor, J. Roark, B. Neenan, T. Mimnagh and E. Takayesu, “Time and Location: What Matters Most When Valuing Distributed Energy Resources” *(IEEE Power & Energy Magazine*, March 2017, pages 29-39).

[5] P. Adrianesis, M. C. Caramanis, R. Masiello, R. Tabors, S, Bahramirad, “Locational Marginal Value of Distributed Energy Resources as Non-Wires Alternatives” *(Submitted for per review in IEEE Transactions on Power Systems*).

[6] E. Ntakou and M. C. Caramanis “Distribution Network Spatiotemporal Marginal Cost of Reactive Power” *(IEEE Power and Energy Society General Meeting, July 2015*).

[7] D. P. Bertsekas, “Nonlinear Programming”, 3rd Edition (Athena Scientific, 2016)