ELECTRIC POWER
RESEARCH INSTITUTE

MAKING THE CONNECTION: THE IMPORTANCE OF DER VISIBILITY TO GRID SUPPORT AND MODERNIZATION

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Introduction

The penetration of distributed energy resources (DER[1]) is growing across the country. With this increase, utilities are faced with the new challenge of managing these resources in concert with central generation. Taking the grid from a traditional central control to a future with increased reliance on DER through distributed control requires the DER to shift to being active grid participants. To enable this transition, utilities are modernizing the methods and tools used to operate and plan the grid in a more integrated way with fast and effective use of DER. A necessary step to achieving grid integration and enabling DER contribution is for utilities to have visibility of the DER.

Currently, with many DER being behind the meter, visibility is lacking creating a situation where DER is not visible to grid operators. This impacts both the effectiveness of modernization efforts as well as the DER's opportunity to participate. For example, DER may be an impediment to FLISR schemes as the system tries to optimize restoration of service and load is "masked[2] by the DER." In cases with grid enhancements to optimize voltage regulation and reduce losses, unaccounted DER may conflict or may be overlooked when actively regulating and compensating voltage at the point of connection.

If DER penetration continue to rise and visibility is not addressed, examples like these will only become more complex and frequent. This points to the need to rethink DER monitoring requirements, particularly where methods to address visibility are lacking jurisdictions with net energy metering. IEEE 1547 now requiring the availability of grid support functions only makes this more timely. Lacking visibility, the return on many ongoing investments in grid support and grid modernization will be impacted. Therefore, addressing this need now is all the more critical.

This paper provides insights into the need for visibility, the current state of visibility across the country, as well as provides examples of the implications to grid operation and DER participation if visibility is not gained. It also provides considerations for utilities, DER industry, and regulators moving into the future on DER visibility.

Identifying the Realities

Grid Support from Distributed Energy Resources is Coming Soon

Additions of solar photovoltaic (PV), electric vehicles and energy storage to the power system continues to be on the rise driven by economics, customer behavior, and regulatory conditions. The increase in generation on the distribution system is causing shifts from the traditional model with all generation being centralized to an increased contribution by distributed generation. With this shift, utilities are making changes to the planning and operation of the grid to integrate DER and its capabilities.

Inverters, used to connect PV and battery systems to the grid, are capable of providing grid support. However, original requirements assumed a low DER penetration which led to restrictions on most grid support capabilities and monitoring requirements. With DER technological and economic advances and much higher levels of deployment, the need for grid support from DER became evident. In the newly revised IEEE 1547 standard,[3] the inverters are *required* to be capable of supporting the grid for specific functionality.

With installations of these technologies continuing to rise, utili-

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[1] DER in this white paper refers to distributed generation and energy storage. Load management and demand response, often considered as part of DER, is excluded in this discussion.

[2] Masking is used to refer to situations where load is being supplied by DER, and therefore not showing up in load monitoring device.

[3] Since 2003, DER interconnection performance requirements have been primarily governed by the IEEE Standard 1547 ™ in conjunction with utility connection agreements, DER certification (by UL Std 1741), and installation technical screening or studies.

CONNECTION STANDARD NOW REQUIRES DER GRID SUPPORT

The newly revised IEEE 1547 standard is expected to be adopted in most jurisdictions to define requirements for connection to the public power supply. In May 2014, restrictions for DER to actively participate in grid support were removed and in March 2018, a number of specific grid support requirements were added:

FUNCTION TYPE	AVAILABLE GRID SUPPORT FUNCTIONS
Static Response	Synchronous power generation with adjustable trip settings
Frequency Support	Ride through with frequency rate of change and frequency-watt control
Voltage Support	Ride-through low/high voltage and phase jump, dynamic voltage support, fixed reactive power, options to set volt-var or volt-watt response
Controllable Support	Real and reactive power and ramp rate control

ties are moving from accommodating these resources to integrating them into grid operations and planning.[4] Planned integration will enable DER to become a more active participant on the distribution grid and cost-effectively serve all electricity customers. The grid's readiness to integrate and effectively use DER capabilities will be essential to realizing the full value.

Modernization Improves Grid Readiness for DER Participation

Improving the grid's readiness to integrate DER, especially PV and energy storage, is at the center of many grid modernization investment discussions, Figure 2. Across the US, significant investments are being made to deploy advanced metering infrastructure, distribution automation solutions, distribution management systems and other advanced operational capabilities that are increasing the visibility and controllability of the grid.

While utilities share many common drivers for modernization, they are in different places. Some are beginning to study the most important investments, while others are in the process of deploying and commissioning new systems. Still others have made investments in years past, but are evaluating how to best leverage them as new resources come on line. Successfully leveraging these grid investments points to the importance and opportunity for DER's visibility in grid operations. The challenge - current visibility into DER operation is limited and based on different state, utility, and regulatory requirements.

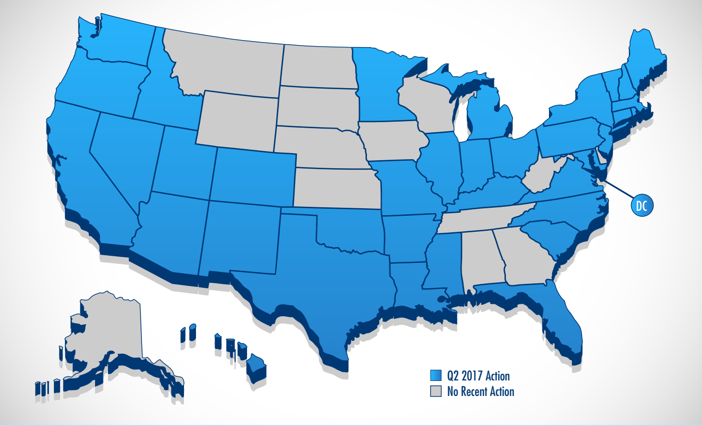

Figure 2 – States that Currently Have Grid Modernization Activities Underway[5]

Visibility and Measurement Set the Stage for Effective Integration

As grid modernization continues, and DER penetration levels increase, measurement and visibility will become even more critical. This leaves the industry faced with questions:

1. How can grid modernization investments move forward if DER is treated as a reduction in load?
2. Will existing tariff structures such as net metering need to evolve to enable more effective grid support and use?
3. What metering and measurement are needed for DER to be recognized as a grid participant?

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[4] *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources.* EPRI, Palo Alto, CA: 2014. 3002002733.

[5] https://nccleantech.ncsu.edu/the-50-states-reports/

Effective integration occurs when DERs are in grid planning, in day-to-day operations as well as involved with economic power dispatch, delivery and end use. Progress toward this integration must start with visibility and measurement of the distributed resources. Also, a successful long-term relationship will hinge on visibility and measured participation. In this context, "behind the meter" may be a barrier to accounting for and recognizing DER.

Current State of DER Visibility

Currently, utility visibility into DER operation is minimal and largely driven by approaches to metering DER that vary across jurisdictions depending on regulatory requirements and policy drivers. For solar PV, metering approaches tend to vary not only by tariff, utility type, and jurisdiction, but also by the size of the PV system. Regulated utility options also depend on tariffs approved by state commissions or other regulation bodies. Unregulated utilities may have more flexibility, but still will be limited by economic considerations and municipality or coop board oversight.

In many locations net-metering is the required approach resulting in no visibility into DER operation because it appears as a reduction in the customer load to the utility. In some cases, utilities are able to require a second meter that separately measures DER providing visibility to the utility. A hybrid approach is bi-directional metering that measures energy from the grid and the difference between generator production and the load. However, it does not provide direct visibility by measuring the generator production. Table 1 summarizes the differences for each metering type. In each of these cases, meters are configured to capture real power (watt-hours) to account for energy delivered and can also monitor voltage and reactive power with the same accuracy.[6]

In the case of the single meter approaches, utilities have no visibility into the DER generation, volts or vars, and therefore DER is not recognized as a grid participant that can provide grid support. In the case of the separate meter solution, the utility could have visibility into DER operations in two ways:

1. ***Measurement Visibility*** – Monitor DER (including real and reactive power as well as voltage) and accurately know its generation output. If the utility has communication enabled meters, there will be visibility into how the DER is operating and current levels. The utility can adjust feeder operating decisions based on this information, and the DER can be recognized as a grid participant. The DER owner can also benefit from the metered generation data.
2. ***Management Visibility*** – Monitor and call on DER (including real and reactive power as well as voltage) to change operation and provide grid support[8] with high degree of accuracy. With this capability, utilities can optimize the operation of the grid assets and the DER in coordination.

When it comes to metering DER output, the capabilities of existing metering infrastructure and communication systems may limit visibility options. What is clear is that the metering approach required has implications on not only visibility from a grid operators stand point but on the ability for DER to participate in grid operations, Figure 3. Recognizing this relationship will inform grid investment decisions and allow infrastructure to be put in place and configured properly now, to support future utilization of DERs. Both accounting for the role of DER, and providing the necessary visibility will be needed.

Table 1 – Metering Approaches and Visibility

Metering	Approach	Visible for billing[7]	Visible to grid operator
Single Meter (net-metering)	No separate meter installed to measure DER. DER generation is behind the meter.	No	No, DER production appears as a reduction in customer load.
Single Meter (dual register, net-billing)	Single meter setup to measures energy from the grid and difference between generator production and load.	Yes	No, DER not directly measured.
Separate Meter	Separate meter installed to measure DER production separate from load.	Yes	Yes, DER and load measured directly

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[6] *Preparing Smart Meter and AMI Systems for Solar Integration.* EPRI, Palo Alto, CA: 2017. 3002009731.

[7] Note that separating DER generation from load with a meter, does not, by default, impact the determined value of DER being credited to the customer.

[8] For protection reasons, utilities may require the ability to disconnect/reconnect DER from the grid to prevent unintended island conditions.

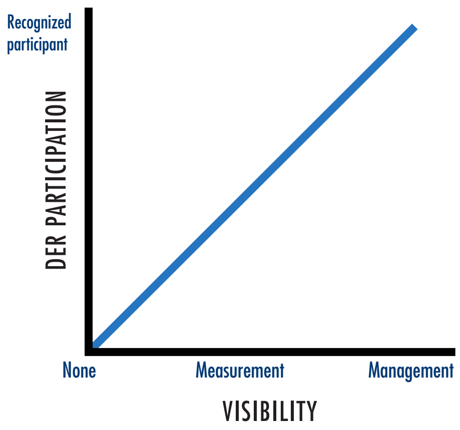

Figure 3 – Relationship between Visibility and DER Participation

If these are not taken together, investments decisions may limit potential benefits of DERs and their ability to contribute. As grid visibility into the DER operation increases, so does the ability for higher levels of DER to be accommodated and recognized as a grid participant. At the same time, as DER participation increases, so too does the capability of the grid operator. Inherent in this relationship, as one improves, so does the other. Said another way – if you can't see it you can't manage it, and if you can't manage it you can't optimize it. Taken together DER visibility and measurement enables grid modernization investments to obtain full benefit.

Achieving Modernization Objectives with DER

As DER penetration increases all aspects related to effectively integrating these resources will have increased priority and impact. There is a long list, from determining hosting capacity, setting grid support functions, and adapting feeder protection to operating in normal and contingency conditions. Perhaps most critical to grid modernization and effective integration is the initial connection and metering of these resources. This is particularly the case in areas where there is no visibility because net-metering is the norm. It is important to consider that grid modernization investments present opportunities for utilities to enable DER access and to better serve their customers by:

1. ***Improving reliability*** – efforts to improve reliability typically include deployment of distribution automation (DA) and utilization of fault location, isolation and service restoration (FLISR) methodologies. Automation with FLISR can greatly improve the speed at which utilities can restore power after faults, or other events. The objective is to reduce the duration of customer outages by isolating the fault and reconfiguring the feeder.
2. ***Optimizing operations to increase utilization and reduce losses*** – efforts to optimize distribution operations typically include application of distribution management systems (DMS) and other more advanced techniques such as employing smart inverter functions. These enable the utility to manage grid assets more effectively such as reducing losses, improving capacity factor, and improving asset utilization over its lifetime. The goal being to optimize the operation of the grid in a cost-effective manner leading to asset life extension and efficiency gains. In addition to these more traditional goals, this optimization is also a potential tool to increase DER hosting capacity by having more flexibility in how the grid can be operated.
3. ***Realizing full participation of grid resources*** – efforts to realize full value of grid support from DER includes monitoring of the resources, requiring smart inverter grid support capabilities, managing DER in coordination with other grid assets and utilizing DER as a non-wires solution to meet an identified grid need.

What follows explores the three main opportunities driving grid modernization decisions and the impact different visibility approaches have on those opportunities. It also outlines important considerations for leveraging the relationship between DER and grid modernization.

Modernizing for Improved Power Reliability[9]

One opportunity being pursued by grid modernization investments is to improve the reliability of the grid through deployment of distribution automation and employment of fault location isolation and service restoration schemes. These ultimately improve ability to restore customers after an outage and improve reliability metrics such as System Average Interruption Duration Index[10] (SAIDI). Automation can typically reduce customer outage time from cutting it in half to reducing by an order of magnitude. For example, an average outage time of 100 minutes/year without any automation can be reduced to 20 minutes.

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[9] *Advanced Distribution Management System with Distributed Energy Resources: Distribution Automation/Fault Location Isolation and Service Restoration.* EPRI, Palo Alto, CA: 2016. 3002007990.

[10] EIA currently requires reporting of reliability indices in their 861 Annual Report. They include for both SAIDI and SAIFI (an interruption frequency per customer index). Different values are reported if including "Major Event Days" and with "Loss of Supply." In 2015, For large utilities > 250k customers, and using the IEEE Standard 1366 for reporting reliability, the SAIDI's ranged from ~30 to 360 minutes on average, per customer. The average SAIFI ranged from .3 to 2 events per customer. Major event days are excluded, highest and lowest of the 93 utilities reporting are excluded.

The concept of distribution automation/FLISR can be laid out in three steps including:

1. ***Fault Location*** – The location of faults between any two DA devices is automatically identified by fault detection sensors.
2. ***Fault Isolation*** – Based on the location of the fault, DA devices open to isolate the faulted section between two open switches.
3. ***Service Restoration*** – Once the fault has been isolated normally open ties to adjacent feeders are closed to restore as much service as possible until repairs are completed.

The process involves switching options for servicing customers via different grid configurations. Line and substation reclosers and relays are employed in FLISR to carry out automated restoration steps. With all of these moving pieces, one of the key components of successfully executing is having an accurate representation of the load and DER on the system.

A common issue that arises is what is referred to as "masked load" – load that is being supplied by DER, and therefore not showing up in load monitoring from devices. Without any enhanced logic or monitoring of DER, the DA FLISR algorithm may make the wrong restoration decisions, perhaps leading to an overload of the alternate source(s). The issue of masked load can be demonstrated when modeling a feeder with several DER installations and then applying a fault to simulate a DA automated restoration event.

Reliability Considerations with DER

Modeling DER scenarios has shown it is critical to have monitoring data that makes distribution automation algorithms aware of the presence of, the status of, and the contribution of any installed DER. By including measurements of the DER (lost generation), and thereby unmasking the load to be served, the FLISR system can determine the optimum restoration solution. Without this visibility, DA/FLISR algorithms may fail either by restoration that leads to a trip on overcurrent, restoration that leads to an overloaded asset, or failing to restore altogether. In doing so, the goal of improved reliability is at risk. This represents an opportunity to meter DER and provide visibility for operations.

Figure 4 provides an example of this modeling. The feeder one line on the top left shows what happens immediately after a fault occurs with the breaker opening and PV disconnecting. In the upper right the

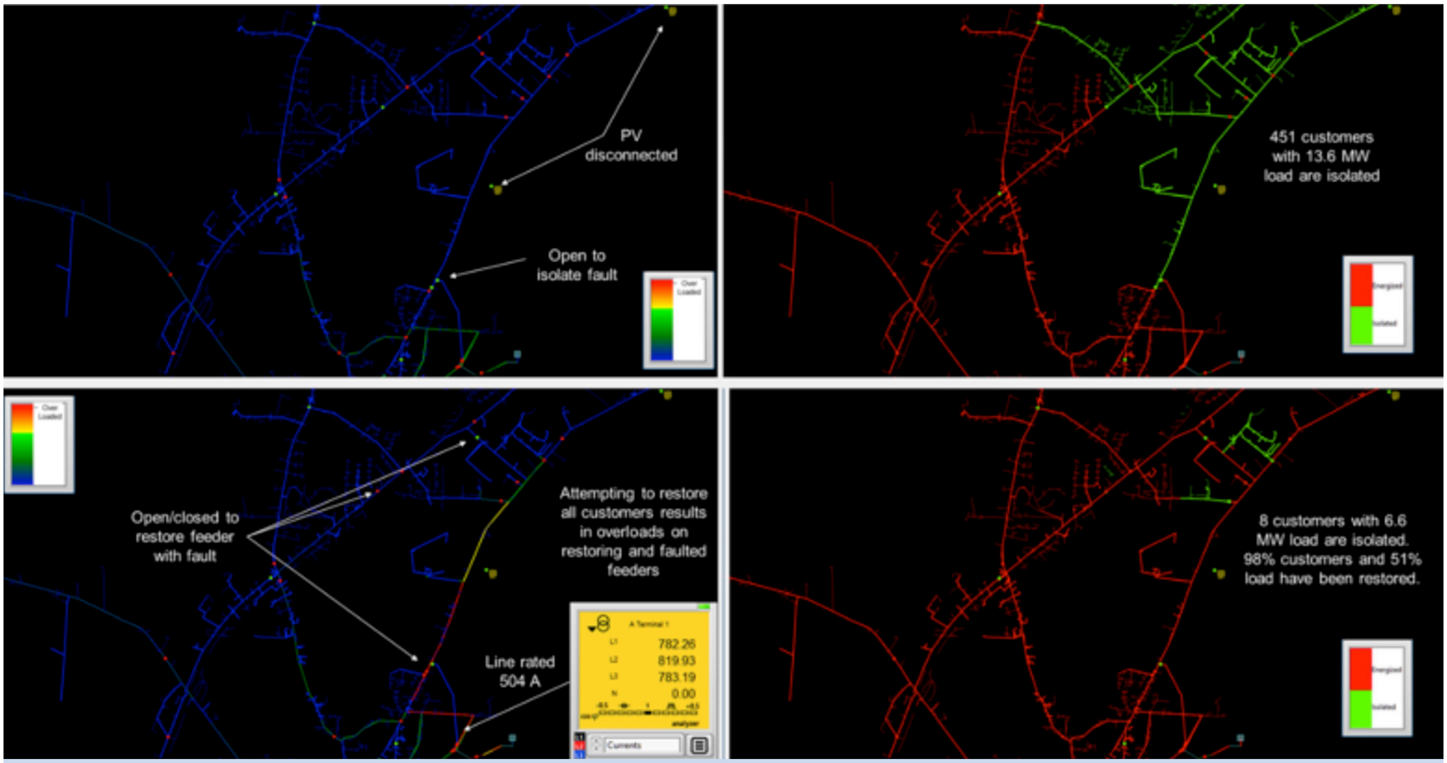

Figure 4 – Example DA/FLISR Scheme with DER[11]

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[11] https://www.youtube.com/watch?v=cbftwt5dOpE

red represents the portion of the feeder that is energized, while green shows what is isolated. In the lower left, the DA/FLISR algorithm restores service except where overloads or under voltages that are present. Finally, in the lower right, the majority of customers are restored through adjacent ties to other feeders. Those remaining are those that would cause overload. Once the DER comes back online, remaining customers can be restored. This case clearly shows the value of having knowledge of DER location and status at the time of fault.

Taken one step further, modeling has shown additional value in being able to manage DER during a restoration event. In other words, having the ability to call on DER and set its operation as part of the FLISR algorithm. Value likely comes from restoring the DER exactly as necessary to enable full restoration rather than a random setting or a 5-minute wait. The intent would not be to keep the DER offline, but to bring it on within the 15-minute DA window when system conditions are improved or to bring the DER on immediately after restoration occurs to mitigate the overload condition. Table 2 and Figure 5 summarize the impact of the degrees of DER visibility and minimum visibility requirements in the example of improving reliability. Management of the DER's operation will require a data connection from the utility to the DER's smart inverter possibly passing through the dedicated meter.

Table 2 – Role of DER Visibility in Improving Reliability

Degrees of Visibility	Improved Reliability
None	DER causes concerns in automated restoration because load is masked
Measurement	DER availability is visible and considered in restoration process
Management	DER capabilities are considered and used when needed in restoration process

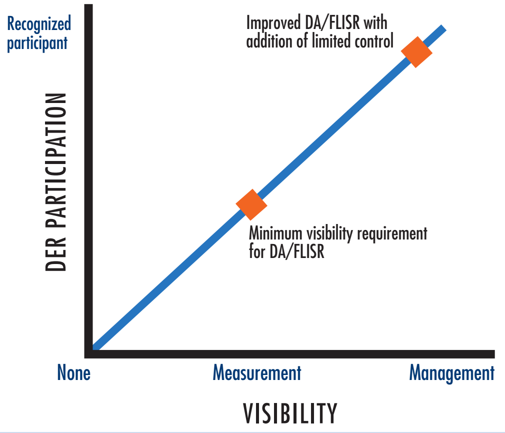

Figure 5 – Minimum Visibility Requirements when Improving Reliability

As is clearly shown here, in order for DA/FLISR algorithms to successfully operate and achieve their desired reliability improvements, DER capability must be well defined and visible. Without this, DA/FLISR algorithms will be stymied and cannot be optimized, ultimately limiting return on modernization investment.

Modernizing to Optimize Power Delivery[12]

Another opportunity for DER in grid modernization comes from optimizing distribution operations. In this case, utilities are deploying DA, DMS or other advanced operational solutions to improve their capabilities to managing grid voltage, particularly around volt/var optimization (VVO). While not a new functionality, VVO traditionally has been used to maintain voltage levels by monitoring (such as via AMI) and controlling grid devices (such as regulators) typically owned by the utility.

Optimizing grid voltage has existed as a driver for modernization. When deploying VVO, utilities are typically driven by the need to improve efficiency/reduce losses and implement conservation voltage reduction[13] (CVR) strategies. However, allowing higher DER penetrations is a new aspect for consideration. With DER the ability to optimize grid operations has become more complicated and points to new requirements to be able to effectively achieve. Table 3 provides a summary of the optimization objectives, control devices, and actions with and without DER.

Table 3 – Volt/Var Optimization With and Without DER

	VVO without DER	VVO with DER
Optimization Objective Functions	• Loss minimization • Demand reduction	• Loss minimization • Demand reduction • Reduce voltage fluctuations • Increase DER hosting capacity • Absorb VARS to mitigate voltage rise
Controllable Devices and Actions	• Capacitor bank – increase or decrease VAR supply • Adjust voltage regulator and LTC	• Capacitor bank – increase or decrease VAR supply • Adjust voltage regulator and LTC • Adjust smart inverter output

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[12] *Advanced Distribution Management System with Distributed Energy Resources Volt/VAR.* EPRI, Palo Alto, CA: 2015. 3002006130.

[13] CVR is a technique to reduce demand by lowering feeder voltage. Locally this can reduce power delivery losses without noticeable customer impact. Wide area it is used to reduce demand with the grid capacity is limited.

With the introduction of DER, optimizations currently being utilized are not considering or including all assets on the grid. As of DER penetration increases, a growing number of optimization levers will not be available if visibility is limited.

Power Delivery Considerations with DER

Modeling and analysis has shown that it is not possible to optimize feeder voltage with multiple sources of power that are largely doing their own thing. Real and reactive power are likely to flow in any direction at different times of the day or season increasing line losses. In order to realize the maximum value of a VVO investment grid resources need to be visible and available to be called on to participate. This can be best illustrated when looking at the case of a single home. Figure 6 depicts that voltage on a circuit over the course of the day. The blue line is the baseline with no PV and the orange line shows the voltage with a 20% PV penetration added along the feeder. In this case, voltage increases with PV generation through the day. The green line, shows the same PV penetration, but with an appropriate volt/var response from each smart inverter. In doing so, the voltage is more consistent (flat) throughout the day. This example is helpful in illustrating the value in volt/var control. The challenge is to extend this idea to many points along multiple feeders and to account for other DER that may be actively responding to local conditions. This is where visibility and coordination of DER responses enables optimization.

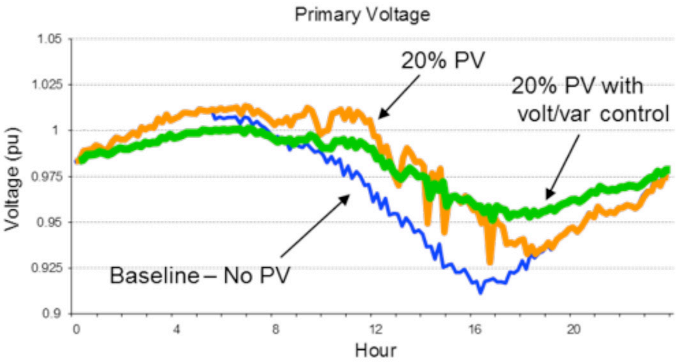

Figure 6 – Voltage at a distribution feeder with and without voltage optimization

In order to make best use of this advanced operational solution, there is an opportunity to further integrate DER. With a lack of visibility into the status and operation of DER, the optimization is not able to consider its impact on the system and inevitably any adjustments made to the controlled devices will not be optimal. If monitoring is in place, the optimization can be informed by the operation of the DER, but it will still be limited in its ability to effectively operate the system to meet the objectives. When management is possible, full optimization of all resources can be achieved. Table 4 and Figure 7 summarize the impact of the degrees of DER visibility and minimum visibility requirements in the example of optimizing operations.

Table 4 – Role of DER Visibility In Optimizing Operations

Degrees of Visibility	Optimization
None	DER not recognized in optimizations.
Measurement	DER status and operation able to be considered in optimizations.
Management	DER operation can be called on and optimized in coordination with other grid assets.

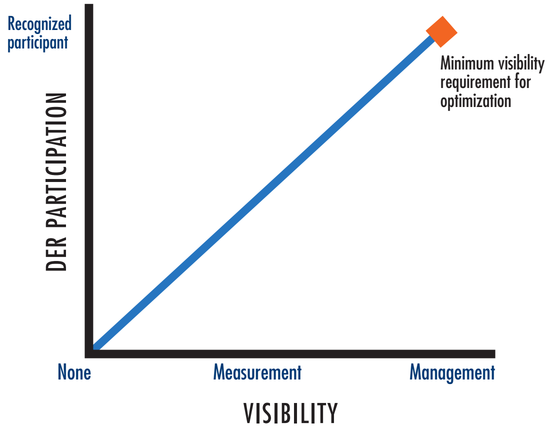

Figure 7 – Minimum Visibility Requirements when Optimizing Operations

Limits on visibility and control means the system operation is not fully optimized and may not employ the most cost-effective operation long term. This has a significant impact on the successful implementation of major investments into DMS and other advanced operational solutions. With limited DER visibility, DER contribution to providing grid support will be limited.

Realizing Full DER Participation

Another objective in modernizing the grid is to specifically leverage the relationship with DER to realize its full value. All future DER will be able to provide grid support through new functionalities,

such as smart inverters. Many aspects of grid modernization are needed to enable utility planners and distribution operators to effectively use DER as grid resources.

At the same time the DER industry and DER owners are seeking to participate as grid assets on the distribution system. This includes not only operationally, but in the way the system is planned considering DER as a non-wires alternative. As stated previously, changes to the visibility that exists today are required in order to reach this goal. If the operator does not have the ability to monitor DER and know the status of its operation, its ability to contribute and be called upon for grid support is not possible. If the planner does not have information about DER to be able to make informed decisions to rely on it, DER cannot be considered as a potential solution alongside traditional grid-side upgrades. Lacking visibility into what DER is doing and when it is doing it, it cannot be considered as a lever for grid use. Much like that of the volt/var optimization case, lacking control, DER cannot be coordinated with other resources on the grid and therefore its ability to contribute to meet grid needs when and where it is needed is limited. Table 5 summarizes the impact of the degrees of DER visibility in the ability to realize full DER participation.

Table 5 – Role of DER Visibility In Optimizing Operations

Degrees of Visibility	DER Participation
None	DER not recognized as grid participant.
Measurement	DER provides autonomous preset grid support, but not active participant.
Management	DER participates in grid optimization when called upon, grid support capability when and where it is needed.

IMPACT OF LACK OF VISIBILITY ON GRID PLANNING

Similar to operating the system, the level of DER visibility has an impact on a planner's ability to design the system to meet future needs. These impacts include the ability to:

- Maintain accurate representation of system load – peak and minimum – because true obligation to serve could be masked due to DER not being accounted for separately.
- Forecast system needs due to lack of clarity in terms of breakdown between load and DER operating on the system.
- Count on DER or DER portfolios as a non-wires solution to meet a grid need rather than traditional upgrades.
- Utilize DER's grid support ability as an option in planning and interconnection decisions.

In the future, credit for grid support may become a possibility in some electricity markets. Just like the bulk system, this can't happen without DER visibility and a way to measure response. Also, changes from a behind the meter approach to an accountable resource status will be needed. For optimization, ways to engage DER as a grid contributor will trump that of improving reliability.

Conclusion

The connection between DER visibility and grid modernization presents an opportunity to better leverage DER. Gaining visibility is an important step to reaching a future where DER is an active grid participant. It is also critical to planning and operating the grid in a more integrated way in the future. The industry must look holistically at DER growth and potential for grid support in light of ongoing grid modernization investments. Currently, this logical synergy cannot be fully utilized in some jurisdictions because DER visibility is lacking due to metering.

This paper provides examples of why grid modernizations need to consider DER including the impact to monitoring and control decisions and ability to call on DER for optimizing use of all grid resources. It highlights the necessity of DER visibility – accounting for and making good use of it – for cost effective grid modernization investments as well as DER participation. All this points to the need to revisit metering options realizing that expectations for DER – both by the utility and by the customer - have evolved. In doing so, the following are important considerations:

1. ***Maintain grid flexibility to serve the changing needs of electricity consumers.*** Both the capacity for adding DER (hosting capacity) and effective grid operation with high penetrations of DER will depend on the ability of utilities to operate the grid flexibly.

2. ***Ensure that grid modernization investments consider making the best use of DER.*** Grid investments need to both include, and to enable, the use of DER.
3. ***Develop metering and monitoring requirements for effective DER integration.*** Syncing up metering approaches with DER visibility needs will further enable grid flexibility and participation of DER. This will require development of methods to determine requirements across a system – recognizing unique grid conditions – as well as weigh costs and benefits.
4. ***Identify "no regrets" strategies to fully realize the benefits of DER.*** Calling on DER when needed, for example smart inverters, is likely a least cost mitigation alternative. Experience from jurisdictions where market conditions have driven rapid deployment of DER, for example Germany and Hawaii, offer clear lessons on the need to consider DER participation. Development of methods to manage level of control – autonomous, decentralized, centralized – will be critical to achieving this.
5. ***Develop new grid capabilities that effectively and rapidly employ distributed resources.*** Taking the grid from the traditional central control and distributed load serving to a future with fast and effective use of DER is a very big step. Modernizations are needed to enable this transition. As this transition increases reliance on the DER rather than central generation, DER will need to become an active participant in operating the grid thus increased visibility needs.

EPRI RESOURCES

Lindsey Rogers, *Senior Project Manager*
865.218.8092, lirogers@epri.com

Tom Key, *Senior Technical Executive*
865.218.8082, tkey@epri.com

Distribution Operations and Planning (P200)
Integration of DER (P174)

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Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com