Distributed Energy Resources and their Interaction with Grid Operations

Whitepaper

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1. EXECUTIVE SUMMARY/INTRODUCTION

> ***"We want to get to a 21st-century grid, but we're still running 20th-century computer systems. We're still running 20th-century metering.[1]"***
>
> ***Michael DeSocio, NYISO***

This paper takes contemporary information and reports from both the Independent System Operator (ISO) and distribution levels, and attempts to define a path to integration – not from a policy or conceptual viewpoint, but from an operational, reliability and market standpoint. The paper attempts to identify issues that have or may arise as DER growth develops and integration with the transmission grid increases. Issues and potential solutions are covered at a high level with the hope that this paper may lead to more detailed discussion on specific issues.

Distributed Energy Resources (DERs) have grown at an exponential rate over the past decade. This growth is due to several factors including lower costs, government subsidies, clean energy initiatives and regional regulatory efforts (ISO and state). Certain ISOs, notably NYISO, CAISO and ERCOT, have launched major initiatives to deal with this growth. Many states have also independently developed initiatives.

A major concern of DER penetration in many regions of the country is the potential effect on grid reliability, both for bulk systems and local distribution systems. DERs will have an effect on reliability at every level, from the end-use customer through the Transmission and Distribution System Provider (TSDP) and finally the ISO.

System reliability is highly dependent on accurate forecasting. Although all load is present whether supplied by conventional generation or DERs, load served by resources "behind the meter" appears as reduced load to the ISO. This has become known as "phantom load." Dispatch control, load studies and reliability forecasting, ancillary service levels, and transmission planning are all dependent on accurate forecasting, both short- and long-term. "Phantom load" distorts this forecasting and must be accounted for since it is served by intermittent or transient resources.

[1] https://www.rtoinsider.com/new-york-wholesale-markets-der-47273/

Interconnected transmission systems are sensitive to variations in frequency and voltage. Variations outside of prescribed tolerances can cause stability issues and, if uncorrected, system collapse. As the grid has developed, baseload generation has provided VAR support to maintain transmission level voltage and spinning mass (inertia) regulated by governors to maintain system frequency. As conventional baseload generation retires, frequency and voltage control is slowly being shifted towards passive and solid-state devices (non-spinning) on the transmission level (capacitors, reactors, SVCs, etc.) and new technology near the distribution level, such as smart inverters.

Control issues regarding over-generation and ramp will loom larger with increased DER penetration. During low load periods, over-generation has always been an issue and ISOs have developed methods of dealing with it. However, over-generation during midday peak periods is becoming a relatively new phenomenon. In California, this has become particularly acute and load net of PV generation has become known as the "Duck Curve." Like over-generation, ramp has always been an issue during morning and evening load increases. With the sudden disappearance of PV energy during the evening peak, this has become a greater issue. ISOs will need to work amongst themselves and with their DSO partners to resolve these control issues going forward.

As new resources attach to the grid, certain metering and communication requirements must be met. Metering is required for reliability, growth planning (as discussed above), and market participation. DERs represent both load and generation, therefore it will be preferable to meter load and generation separately, and calculate net load and net injection. The degree of DER granularity visible becomes important for load modeling, forecasting, market product distribution and price formation. Data from DERs is currently received by the host TDSP and will be transmitted to the ISO through the Distributed System Platform/Provider (DSP)/DSO. Data required will be similar to that required of conventional resources, but some data unique to DERs, such as invertor capacity, may also be required. The radial aspect of most distribution load and its potential ability to transfer from node to node at the transmission level will need to be recognized as DER penetration increases. In all, DER metering requirements will be similar to existing requirements with modifications for the unique qualities of DERs.

At the ISO level, DERs will need to respond to and settle at prices formed at the dispatch level, nominally 5-minutes. DERs are unique in that they are often a combination of load and generation. Often, resources are settled at the generation bus price while load is settled at a zonal price. Individual ISO pricing mechanisms may need to be revisited as DER penetration increases.

As DERs grow, their initial impact will be in reliability at the distribution level. As they increase in size, their impact will begin to be seen at the ISO level. At this point, they will begin to have an effect not only on grid reliability, but also market issues. DERs may appear as passive load reduction or take a more active part in the market as dispatchable demand response or directly dispatchable injectable energy. How DERs are integrated into the market as a resource will become an issue for ISOs and DSPs to resolve.

Not only will DERs participate in ISO energy markets, DERs will also have the potential to participate in ancillary service (AS) markets. As wind and PV resources are used more in conjunction with storage devices, DERs gain the ability to both absorb and inject energy from the grid and gain the ability to provide AS such as reserve and regulation. Advances in technologies and cost reductions will only increase this ability. Issues such as aggregation, control and quality of service will need to be addressed.

Conventional load and generation are subject to certain compliance issues and the distribution of charges for uplift and ancillary services. Some of these are regulatory in nature and administered by the ISO, while others are developed by, and may be unique to, a particular ISO. Oftentimes, if a Market Participant (MP) is responsible for causing a cost, that MP is charged for that cost. This is known as the "cost causation" principle. What new costs will DERs cause in the future and what will they be held responsible for? As DERs grow, ISOs will need to revisit compliance issues and their methods of distributing charges.

As DERs grow, DSPs will evolve into DSOs to interact with their host ISO. The structure of the ISO-DSO relationship will become an issue. What will the structures look like? How will the ISO and its DSO(s) relate to each other? Regions may form a one-to-one relationship (one DSO to ISO in a region) or many DSOs to one ISO. In some regions, individual TSPs may each form a separate DSO to interact with the ISO. In others, individual TSPs may band to form a single DSO, especially if there is one dominant TSP. Geographic issues may come into play: is a region mostly rural, urban or both; is it a single state region (NYISO) or multi-state (MISO)? Complexity of the organization and economics will also come into play. As DERs evolve and further penetrate the grid, formal ISO-DSO structures will develop.

Finally, the industry needs to articulate a path forward to integrate and enable DERs across DSPs, DSOs, TSPs, and ISOs. This will provide new business opportunities for providers and utilities as well as challenges for collaboration across data needs, planning, forecasting, operations, systems, and market structure. This paper concludes with a suggested "strawman" to facilitate such discussions.

2. DERS AND THEIR CURRENT RELATIONSHIP WITH THE GRID

While there may be more than one definition for Distributed Energy Resources (DERs), the NYISO version may have the most comprehensive: "a resource, or a set of resources, typically located on an end-use customer's premises that can provide wholesale market services but are usually operated for the purpose of supplying the customer's electric load. DER can consist of curtailable load (demand response), generation, storage, or various combinations aggregated into a single entity."[2] Over the past decade, the penetration of DERs at the distribution level has grown exponentially. This growth can be attributed to the following factors:

- **Lowered cost:** Technological advancements over the past several years in solar generation and energy storage have lowered the cost of such devices designed for residential use.
- **Subsidies:** Currently, subsidies are available at the federal, state and levels to encourage development of wind, solar and storage technologies. As the markets mature, costs lower and these technologies develop further, consumers should expect these subsidies to be reduced and eventually disappear.
- **Clean energy:** A desire to move away from carbon based generation has increased demand for clean energy including small wind and solar.
- **ISO and State efforts:** ISOs, notably NYISO and CAISO, with encouragement from their respective state governments have begun to actively promote DER integration into the transmission grid (Appendix A lists various state initiatives).

NYISO, CAISO and ERCOT are the ISOs in the U.S. currently undertaking the most initiative in grid integration of DERs. The following is the current state of these initiatives:

NYISO

[2]Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets - *A Report by the New York Independent System Operator*; January 2017; p.5

In 2015 New York State, under Governor Mario Cuomo, launched a major energy initiative known as Reforming the Energy Vision (REV). Two 2030 goals of the REV will have a major impact on both the NYISO system and market operations: a 40% reduction of greenhouse gas (GHG) emissions from 1990 levels and that 50% of electricity must come from renewable energy sources. One intent of the REV is to spur development of DERs in New York State.

In January 2017, the NYISO published a "Distributed Energy Resources Roadmap for New York's Wholesale Energy Markets." This "roadmap" details how DERs may be integrated into the existing NYISO market. The NYISO is focusing its efforts on dispatchable (or controllable) DERs that have the ability to participate in the wholesale market. A basic premise of the NYISO is to treat DERs as similar as possible to conventional generating resources, while recognizing unique characteristics and limitations. As such, NYISO realizes that enhancements will be required in market design, system planning and grid operations.

CAISO

In 2013, Governor Brown approved Assembly Bill 327 which required the reform of utility distribution planning, investment, and operations to "minimize overall system cost and maximize ratepayer benefits from investments in preferred resources, while advancing time- and location-variant pricing and incentives to support distributed energy resources."[3] Senate Bill 350 was approved by Governor Brown in 2015 and commits California to reduce GHG emissions by 40% below 1990 levels, increases to 50% the share of electricity to be produced by renewable generation, doubles targets for energy efficiency, and encourages widespread transportation electrification.

In September 2016, a multi-agency effort of the California PUC with CAISO, the CA Energy Commission and the CA Air Resources Board published "California's Distributed Energy Resources Action Plan: Aligning Vision and Action." This "Action Plan" accomplishes four objectives: 1) Provides a long-term vision for DER and supporting policies; 2) Identifies continuing efforts in support of the long-term vision; 3) Assesses and directs further near-term action needed to support the long-term vision; and 4) Establishes a DER steering committee responsible for sustained coordination of DER activities. To accomplish the purpose of the "Action Plan" its scope includes: 1) Rates and tariffs; 2) Distribution grid infrastructure, planning,

[3] California Public Utilities Code §769(c)

interconnection and procurement; and 3) Wholesale DER integration and interconnection.

ERCOT

In 2015, ERCOT formed the Distributed Resource Energy and Ancillaries Market (DREAM) task force to explore many potential policy and technical issues associated with introducing DERs to the ERCOT market. ERCOT issued a concept paper to the DREAM task force in August 2015. This paper addressed at a high level the reliability concerns that may result from a large deployment of DERs, which would require mapping these resources to the grid. The paper also outlined proposed transition activities and provided recommendations. Recommendations included more detailed collection of DER related data, with better mapping to the grid and new settlement options for DERs. The DREAM task force was disbanded in the first quarter of 2016.

In March 2017, ERCOT issued a paper on DER reliability impacts and recommended changes. ERCOT is currently planning to collect additional data on existing registered DERs and inserting them into the network model, with binding language to incorporate mapping of future registered DERs. A process will be established for monitoring overall growth of non-registered DERs and to work with TDSPs for future mapping.

3. RELIABILITY ISSUES

When we begin to discuss and evaluate the relationship between the ISO/RTO and the DSP/DSO for integrated or coordinated management of DERs, we must keep in mind the various levels of drivers and issues across such a relationship. We see four distinct levels:

1. The **end-use customer** (residential, commercial or industrial) who exercises a choice to install a distributed resource on their premises. This choice is driven by various factors from economics to societal/environmental concerns.
2. The **Distribution System Operator (DSO)** who is responsible for interconnecting the customer's distributed resource in a way that maintains the safety and reliability of the distribution grid, as well as be the conduit to potential participation in the wholesale market. In 2015, the New York State Department of Public Service (NYSDPS) formalized the DSO as a **Distributed System Platform (DSP)**[4]. DSO and DSP will be used interchangeably in this paper.
3. The **Transmission Service Provider (TSP)** who is responsible for the safety and operation of the bulk transmission grid that serves the DSPs, and will be affected as the penetration of DERs grows on the DSP grids. In this paper, TSP and **Transmission Operator (TO)** will be used interchangeably.
4. The **ISO** who is responsible for a) the safety and reliability of the bulk electric grid operation, and b) the reliable and economic operation of the wholesale electric market.

This helps to understand the dynamics of how DER growth will take time to penetrate each level since it is driven by 'grass roots' adoption. It also provides a framework to understand that what might be considered of negligible impact at one of the higher levels could very well be significant at a lower level. Several kilowatts of DERs on a distribution feeder could be significant to the safe and reliable operation of that feeder and the interconnected distribution grid, but negligible at the bulk wholesale

[4] CASE 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. ORDER ADOPTING REGULATORY POLICY FRAMEWORK AND IMPLEMENTATION PLAN. Issued and Effective: February 26, 2015

level where it might take 10+ megawatts to have any impact on reliability and market operations.

3.1 Forecasting Issues

Grid and local reliability is highly dependent on accurate forecasting. As DERs penetrate the grid to a greater and greater degree, the unmetered, or "phantom", load becomes more of an issue. Phantom load can result in forecasting errors which can affect dispatch and control at the grid level. Price formation, contingency analysis, voltage and frequency control are all dependent on accurate short-term forecasting. At the distribution level, control becomes more granular and accurate forecasting becomes more critical. At both the grid and distribution level, medium and long-term planning and design relies strongly on accurate planning which takes into account the growth of phantom load.

3.1.1 Bulk Grid / ISO Level

Depending on current installed capacity and projected rates of growth, DERs may not pose an immediate or near-term reliability concern for the transmission grid. In some ISOs, the environment for DERs is characterized by a combination of low energy prices and an absence of region-wide regulatory incentives, leading to a penetration growth rate that is much slower than has been witnessed in other regions such as New York, California, and Hawaii. Regardless of the current state, several important drivers — including customer desire for independence, environmental consciousness, and declining costs of DER acquisition — point to continued growth.

There are different categories of DERs to consider: those that are dispatchable, either self-dispatched/self-scheduled or dispatched by a grid operator, and intermittent resources, primarily rooftop solar. Dispatchable resources are historically units that use diesel fuel or natural gas and provide backup power to critical infrastructure. An emerging dispatchable resource is distribution-connected energy storage. In contrast, intermittent resources generate automatically and are typically offsetting native load, with the potential to export excess generation. Importantly, data suggests that rooftop solar adoption tends to concentrate in neighborhoods, creating clusters on various distribution feeders, which in turn are connected, to single transmission load points.[5]

An emerging trend is to aggregate smaller solar and/or energy storage resources. This larger resource then may be able to provide certain market products/services, but not without navigating complex guidelines and protocols related to telemetry, data, performance, and Measurement & Verification (M&V).

Local integration of DERs is the responsibility of the DSP. As DER penetration levels increase, especially in concentrated clusters, the DSPs can be expected to see the first level of impact to their systems such as voltage and feeder capacity, which are not visible to the ISO.[6]

The real-time operations of these DERs can affect the grid as non-conforming power, or "phantom load." With higher penetration over time, this DER activity can affect grid operations through increased error in net load forecasting, less accurate inputs for managing bulk transmission line loading, over-operation of voltage control equipment, and uncoordinated system restoration after a load shed event.

ISO operations are attempting to track and identify this "phantom load." Typically, a significant portion of load 'disappears' at an unexpected time, where net load has fluctuated without any signal or notification to the ISO. With fluctuating prices, some of this may be accounted for as voluntary load reduction in response to price signals. However, it is surmised that it is due to load being served locally by solar rooftop clusters or other DERs. This uncertainty creates inefficiency in ISO operations in terms of forecasting and acquiring ancillary services and other reserves, forecasting and managing transmission, and in wholesale price formation. These "phantom load" events highlight the increasing importance of DER visibility to the ISO.

Data Visibility

Many of the concerns associated with larger self-dispatched DERs could be alleviated if the ISO were to acquire real-time visibility of the units' locations and real-time or near- real-time data in the form of telemetry. Other concerns could be addressed by

[5] **DISTRIBUTED ENERGY RESOURCES (DERS) Reliability Impacts and Recommended Changes**, pg. 3, ERCOT, March 22, 2017

[6] Ibid

allowing larger self-dispatched DERs the option of active wholesale market participation.[7]

The foundation to the reliable and efficient management of this future distributed grid is visibility, in the form of more detailed collection of static DER data from DSPs and TSPs to support various ISO grid monitoring functions.[8]

Grid Support

As higher levels of DER penetration begin to impact the power grid, the need for DERs to provide reactive power and improved response to disturbances and faults on the electrical system will become important. Efforts are already underway to address some of these reliability concerns via new standards being developed by the Underwriters Laboratory (UL) and the Institute of Electrical and Electronic Engineers (IEEE).[9],[10]

ISOs and DSPs should seek to identify appropriate standards for interconnected equipment and resources, and to provide the ISO with visibility to assure that system planning, load forecasting and ancillary service requirements are sufficient to manage the benefits and risks of large scale DER deployment. This visibility, coupled with appropriate resource information, will support the ISO's ability to manage or mitigate reliability issues as DERs become a significant part of the resource mix. This anticipates the need to account for intermittent DERs in procuring Ancillary Services (AS) and to build models correlating weather conditions and DER output.[11]

Dispatch Control

As a rule, ISOs are not seeking to acquire the ability to control these intermittent DERs directly, however, as DER penetration levels rise, the ability to control such DERs for transmission constraint management through DSP communications and control systems may be necessary.

[7] Ibid, pg.4
[8] Ibid, pg. 5
[9] Ibid, pg. 6
[10] Note that NERC Standards apply to BAs. As such, they set requirements for the BAs to meet. It is up to each BA to set standards or policy for its participants such that NERC Standards are met.
[11] [11] **DISTRIBUTED ENERGY RESOURCES (DERS) Reliability Impacts and Recommended Changes**, pg. 9, ERCOT, March 22, 2017

Load Studies & Reliability Forecasting

ISOs utilize IT applications to determine an estimate of the state of the system (bus voltage magnitude and angle, and transformer taps), given the network model and available measurements. The results are used in creating a power flow study case describing the current state of the system, which is used in real-time reliability analysis programs, and detecting structural errors in network configurations and erroneous breaker status.[12]

A process of load adaptation uses estimated values for each load to feed into numerous ISO-generated studies used to manage system reliability and market operations. A significant increase in the penetration of DERs could result in more bi-directional flow of energy from the distribution system. This becomes a concern when the DER injection is driven by a factor other than time of day — for example, cloud cover over clustered solar photovoltaic (PV) sites — leading to erroneous results for some studies but not others. Erroneous load adaptation estimates could mask potential reliability issues in these studies.[13]

For ISO-level forecasting tools that rely on neural networks and linear regression-based algorithms, the accuracy is highly dependent on the consistency of changes in load. With higher penetration of DERs across various geographic locations in the ISO, net load reductions caused by DERs will look sporadic. Within geographic regions DER penetration can be expected to be inconsistent, due to the observed tendency for DER adoption to occur in clusters, leading to concentrations of DER activity at specific substations and network modeled loads. These inconsistencies will affect the accuracy of the ISO's load forecast and any downstream operational or planning studies based off the forecast.[14]

The mapping of DERs to ISO network models is assumed to be static – that is, a static relationship will be established by the DSP/TSP between a DER (or more likely, depending on the TDSP, the distribution feeder associated with the DER) and its modeled load(s). Distribution system facilities are primarily radial and are therefore subject to switching by the DSP in order to allow for necessary maintenance. At any given time, a small percentage – typically less than 5% - of a distribution system's load will be switched to different feeders for this purpose. This could result in

[12] Ibid, pg. 10
[13] Ibid, pg. 10-12
[14] Ibid, pg. 13

inappropriate LMP price signals being provided to certain DERs. However, a certain level of inaccuracy in price formation may be tolerable at relatively low DER penetration levels. To ensure modeling accuracy as DER penetration increases, this issue should be revisited periodically and if required, analyzed and enhancements to the mapping of DERs to applicable network loads developed.[15]

Ancillary Services Uncertainty

DERs can offset local load, thereby causing significant changes in the ISO system's apparent demand patterns. These unanticipated load variations in real time can be expected to result in additional reliance on ancillary services. The ISO will deploy a regulation service to maintain the balance of supply and demand; however, as the penetration of DERs continues to grow, current levels of a regulation service may not be sufficient.[16]

If the ISO lacks visibility to the quantity and availability of DERs on the system in near- real time conditions, the ISO's ancillary service requirements will need to have higher safety margins to manage this uncertainty. The CAISO, which operates a system with high levels of DER penetration, has examined the effects of DERs on its reserve requirements and quantified benefits and costs associated with gaining visibility and control of DERs. The CAISO study observes that with higher DER penetrations and no added visibility in the longer term, the ISO's Regulation-Up requirements could triple. Conversely, the same study found that with improved visibility, forecasting and monitoring, at conservative error margins Regulation-Up requirements could actually decrease by as much as 8%, even in a high DER penetration scenario.[17]

Transmission Planning

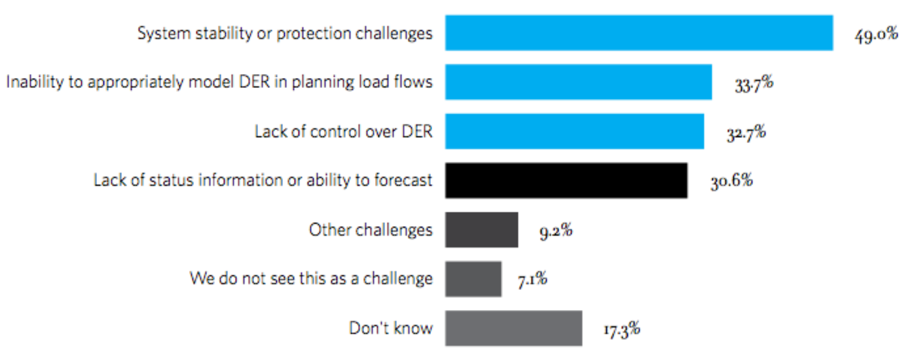
The forecasted growth of DER will have an impact on planning decisions. Inaccuracies in long-term load forecasting due to over- or under- forecasting of DER in an area could lead to building too little or too much transmission. Further, the dynamic behavior of DERs can affect stability study results, which could also lead to less than optimal transmission planning decisions.[18]

[15] ERCOT Concept Paper on Distributed Energy Resources in the ERCOT Region, August 2015
[16] **DISTRIBUTED ENERGY RESOURCES (DERS) Reliability Impacts and Recommended Changes**, pg. 13-14, ERCOT, March 22, 2017
[17] Ibid, pg. 14
[18] Ibid, pg. 15

3.1.2 Distribution Grid Level

Similar issues affect forecasting at the distribution level, though at a different scale and with more granular impacts. At the distribution level, the impacts of net load changes from DERs can have a more significant effect at the feeder and substation level, creating critical reliability issues. Planning and modeling become more complex as DSPs attempt to forecast the implications of higher DER penetration and dynamic load flows on their system.

Figure 1: MOST SIGNIFICANT CHALLENGES FOR A TSP SUPPORTING A HIGH PENETRATION OF DERS [19]



Planning & Forecasting Issues

Regulatory compliance and operational necessity are the two most important factors driving utilities towards proactive distribution planning for DERs. Every utility is pursuing a different mix of new methodologies and tools for DER planning, based on its own unique circumstances and concerns, including:

- Methods and tools for assessing the DER hosting capacity of distribution circuits
- Valuing the locational costs and benefits of DERs
- Guiding DER installations to preferred interconnection locations

[19] Beyond the Meter, PLANNING THE DISTRIBUTED ENERGY FUTURE, VOLUME I: EMERGING ELECTRIC UTILITY DISTRIBUTION PLANNING PRACTICES FOR DISTRIBUTED ENERGY RESOURCES, Black & Veatch, Smart Electric Power Alliance, May 2017

- Assessing the need for rate restructuring
- Monitoring and control of DER assets[20]

New modeling software capabilities are emerging to address the needs around grid modeling in an age of increasing DER penetration, and leading utilities are beginning to take advantage of the new analytical tools. However, a number of open questions remain around DER planning processes, modeling approaches, and monitoring/control methods. No utility has yet put into practice a comprehensive framework for utility planning that incorporates the far-reaching impacts of DER growth.[21]

Utilities can realize numerous benefits from better DER planning, including more efficient interconnection processes, expanded capacity to accommodate DERs, reduced total infrastructure costs, and improved forecasting of DER impacts on load and utility revenues. However, a number of issues must be considered when implementing a proactive DER planning process, including:

- Ownership and control of DER assets
- DER markets and procurement
- Data sharing and confidentiality
- Rate impacts
- Interactions with other utility regulatory proceedings
- IT infrastructure
- Staff resources
- Preferences of local customers and policy-makers.[22]

Figure 2: PROACTIVE DER PLANNING PROCESS SUMMARY[23]

Step #	Name	Description
1	Load and DER Adoption Forecast	Develop load forecast, assess technical/economic/achievable potential for DER deployment and estimate customer adoption, and determine net load profile.

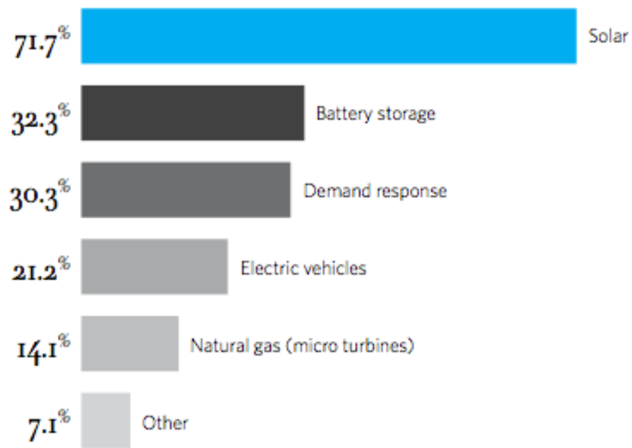
[20] Ibid
[21] Ibid
[22] Ibid
[23] Ibid

2	T&D Grid Impacts	Run dynamic distribution system model to identify and quantify all grid impacts from load/DER growth.
3	Bulk Power Impacts	Run full model of bulk power system (generation and transmission), including impacts from distribution level.
4	Finance, Rates and Regulation	Quantify locational costs and benefits of DERs, determine if/how DERs can defer or avoid traditional utility distribution investments, calculate financial and rate impacts of DER deployment, and develop appropriate policies (e.g., incentives, tariffs, standard contracts, competitive solicitations) to encourage DERs at the right place and right time.
5	Strategy and Operations	Decide on utility's overall DER strategy and any related changes to the business model, as well as modifications to utility operations to support effective DER integration.

Conventional distribution planning works within the premise of delivering electricity to end-use customers after it has been generated in a centralized power plant and often moved over long distances via high-voltage transmission lines. Conventional distribution assumes that power moves in a single direction from generation through transmission and distribution lines to the end user—from "turbines to toasters" as pioneers of the electric grid would say. The main focus of distribution planning is to ensure safe, reliable and cost-effective delivery of electricity.[24]

FIGURE 3: DISTRIBUTED ENERGY RESOURCES THAT WILL IMPACT ELECTRIC UTILITIES MOST[25]

[24] Ibid
[25] Source: Black & Veatch: Strategic Directions Smart Utilities/Smart Cities Survey Results, Black & Veatch Global Insights, February 2016



Net Load Profile Uncertainty

The growth of DERs is challenging many of the assumptions upon which traditional distribution planning relies. DERs are creating two-way power flows on the distribution system that legacy distribution equipment was not designed for. DERs are also confounding conventional load forecast methodologies and complicating the modeling of distribution feeders by introducing new kinds of generation sources or modifying load profiles. Utilities may find that the traditional distribution planning framework is no longer able to accurately predict net load profiles and guarantee grid reliability once DERs reach a significant level of penetration on their system.[26]

Voltage/Frequency Stability

In addition to cost and performance improvements that have made DER technologies more attractive to customers, it now offers capabilities that can provide benefits to utilities – see Sections 3.2 & 3.3.

Some of the new planning tools emerging are:

Geographic/Spatial: Maps of Preferred Interconnection Locations:

As a way to incentivize locational deployment, the use of this tool demonstrates that the utility has begun attempting to direct DER projects to more optimal locations. Utilities are working to direct DERs to more optional locations to avoid

[26] Beyond the Meter, PLANNING THE DISTRIBUTED ENERGY FUTURE, VOLUME I: EMERGING ELECTRIC UTILITY DISTRIBUTION PLANNING PRACTICES FOR DISTRIBUTED ENERGY RESOURCES, Black & Veatch, Smart Electric Power Alliance, May 2017

interconnection applications in locations where they will not be approved (and thereby saving time for the utility and developer), or because of a regulator mandate. Although only one utility has made its preferred interconnection location maps publicly available, two other utilities have also provided more limited maps of optimal or unsuitable interconnection locations. More utilities are expected to pursue this type of map in the future to track DER installations and guide project siting.

Dynamic Modeling: Advanced DER Modeling Tools: This includes system-wide asset models (including bulk generation and/or T&D), forecasting of DER output and dynamic distribution modeling capabilities.

Control: Active DER Management: Some utilities are exploring active management with demonstration-stage DERs (inclusive of solar, energy storage and demand response resources). A few of these utilities have established plans and begun implementation, beyond demonstration, of remote control systems to manage DERs. As an example, one utility has mapped all customer-sited DER installations and is currently testing feeder auto-sectionalized protection plans to increase reliability under a variety of load/DER scenarios.[27]

The first step in traditional distribution planning is forecasting load growth in the various sub-regions of a utility's service territory. With increasing penetration of DER technologies utilities also need to forecast growth in the penetration of DERs. While utilities have been developing load forecasts for many decades and have well-established methodologies for such studies, the methodologies for DER adoption forecasting are in their infancy today and the necessary techniques and software tools are still under development by various consultants and software vendors. For the most precise results, utilities should model DER adoption at the individual customer or site level.

Most utilities have historically performed distribution grid modeling by examining static "snapshots" in time corresponding to peak load periods to identify where system limits were being violated and where upgrades were required to accommodate load growth. However, increasing DER deployment means the net load problem will become much more variable than before. As a result, dynamic modeling of load and DER technologies on an hourly or sub-hourly basis is required to capture all potential impacts on the distribution system. In addition to modeling peak load

[27] Ibid

periods, periods of minimum load and peak solar PV generation may also need to be investigated.

Once the model is complete, new modeling tools have the capability to simulate individual distribution circuits or the entire transmission and distribution system—including all customer loads and DERs down to the level of the secondary side of the service transformer—in order to comprehensively quantify all positive impacts (e.g., reduction in peak load) and negative impacts (e.g., increased voltage fluctuations) on the grid. In particular, the modeling should identify at what time, or at what level of DER penetration, a violation of thermal/voltage/power quality/protection/safety limits occurs on the system. This analysis also determines the DER "hosting capacity" of the existing distribution system (e.g., what the system can handle without decreasing reliability). Ideally, this information would be compared with the utility's aggregated load and DER adoption forecast to determine where customers are most likely to install an amount of DERs that could cause violations.

Once the grid impacts of load/DER growth are known, utility planners must list possible mitigation solutions to address the violation(s), and select the most cost-effective option. Mitigation solutions traditionally included options such as:

- Re-conductoring
- Transformer upgrade/replacement
- Installation of voltage regulators and capacitor banks
- Reconfiguration of protection scheme settings

In addition to traditional methods, some DER technologies, like advanced solar PV inverters, battery storage, demand response, and electric vehicle (EV) charging infrastructure, may now be feasible alternatives to address certain types of violations—assuming the utility is convinced (though some are not yet fully) that DERs are sufficiently reliable to defer or avoid the need for traditional options. As a result, utility planners must now compare traditional and DER options on a common basis, and select the optimal mix of mitigation solutions to cost-effectively address the violation(s).[28]

At low DER penetration levels, there are few, if any, impacts on the bulk power system because any excess generation from DERs on various circuits is consumed by other customers connected to the same distribution substation. However, in areas with rapidly increasing DER penetration, some utilities are beginning to see

[28] Ibid

noticeable bulk system impacts. This occurs when excess DER generation begins to back-feed onto the transmission grid. In these areas, utilities are working to develop methodologies for assessing these impacts.[29]

Other regions that have already experienced high DER penetration have found it necessary to adopt a common set of interconnection requirements. This provides a level of consistency that could provide value to DER entities, TDSPs, and the ISO. Germany, Hawaii, and California — all of which are managing rapid growth in DER penetration — have either adopted or are in the process of adopting a common set of technical requirements for distributed PV, particularly requirements for smart inverters for PV. Based on the experience of these regions, particularly California's Rule 21, requirements for a DER installation could include:

1) Two-way communication/control between DER and remote entity (TDSP, Scheduling Entity if applicable);
2) Anti-Islanding Protection;
3) Low and High Voltage Ride-Through;
4) Low and High Frequency Ride-Through;
5) Dynamic Volt-Var Operation;
6) Ramp Rates;
7) Fixed Power Factor; and
8) Soft Start Reconnection.[30]

Below is a summary of DER forecasting and reliability issues for ISOs and DSPs. It is not surprising that there are significant common and overlapping issues. Because DER growth will be organic on the distribution systems, these issues will be tackled and solved there first. As DER penetration grows and these issues flow over into the bulk system, visibility, coordination, and operational control will become more complicated:

ISO – Bulk Grid	**DSP – Distribution Grid**

[29] Ibid
[30] ERCOT Concept Paper on Distributed Energy Resources in the ERCOT Region, August 2015

• Data visibility	• Data visibility
• Grid support	• Grid support (voltage, frequency)
• Dispatch control	• Dispatch control
• Load studies / reliability forecasting	• Net load studies / reliability forecasting
• Ancillary services uncertainty	• Dynamic modeling
• Transmission planning	• Distribution planning
	• System stability & protection

3.2 Frequency and Stability Control

As DERs become more prevalent, frequency control becomes more critical. NERC Standard BAL-003 has a stated purpose of "To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value."[31] Each ISO or RTO, acting as a BA, sets their own protocol to operate to NERC Standards. Generally, generator governors react to frequency excursions and maintain system frequency. Historically, this rotational mass (inertia) has been relied upon to provide frequency and stability control. As DERs penetrate the system, larger baseload resources are retired and system inertia decreases. At higher DER penetration levels, a significant amount of DERs disconnecting from the system just when their energy is needed could potentially cause cascading effects. In addition, due to the fluctuating nature of DERs, they could cause a sudden surge in output with resulting high frequency.

New storage and regulating technologies, including batteries and flywheels, can be used to compensate for this loss of control at the transmission level. Both resources can provide near instantaneous energy in the event of sudden DER disconnection. In the event of a sudden surge, they can provide near instantaneous absorption of energy. Due to their limited energy storage capability, flywheels would be used almost exclusively for regulation and frequency control. Flywheels, due to their size, will likely be located at the transmission level while smaller battery storage devices

[31] NERC Standard BAL-003-1.1 — Frequency Response and Frequency Bias Setting

would be located at lower voltage levels and distributed across the system. Smart inverters, by responding to sudden PV output fluctuations, will also help in smoothing frequency deviations. Properly controlling frequency at the transmission level will require coordination by DSPs and the ISO will need to communicate with and coordinate DSP operation.

3.3 Voltage Control

Voltage control is also critical to maintaining system stability. NERC Standard VAR-001 has a stated purpose "To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection."[32] Each ISO or RTO, acting as a BA, sets their own protocol to operate to NERC Standards. Generators participating in voltage control, i.e. providing VARs as an ancillary service, are equipped with Automatic Voltage Regulators (AVRs) and can maintain bus voltage levels within prescribed limits. In addition, generators can provide additional leading or lagging VARs at the request of TSP or ISO Operators when conditions warrant. As DERs penetrate the grid and conventional generation is retired, this ability to control voltage at the transmission level decreases. Reliance on reactors, capacitor banks and static var compensators (SVCs) at the transmission level will increase.

Sudden fluctuations in PV output can cause voltage spikes (up or down) at the distribution level, which can ripple through to the transmission system. Smart inverters for solar PV systems and other DERs, which can instantly provide or absorb VARs, can help support voltage on the distribution system and help in maintaining stable voltage at the transmission level. As with frequency control, properly controlling voltage at the transmission level will require coordination by DSPs and the ISO will need to communicate with and coordinate DSP operation.

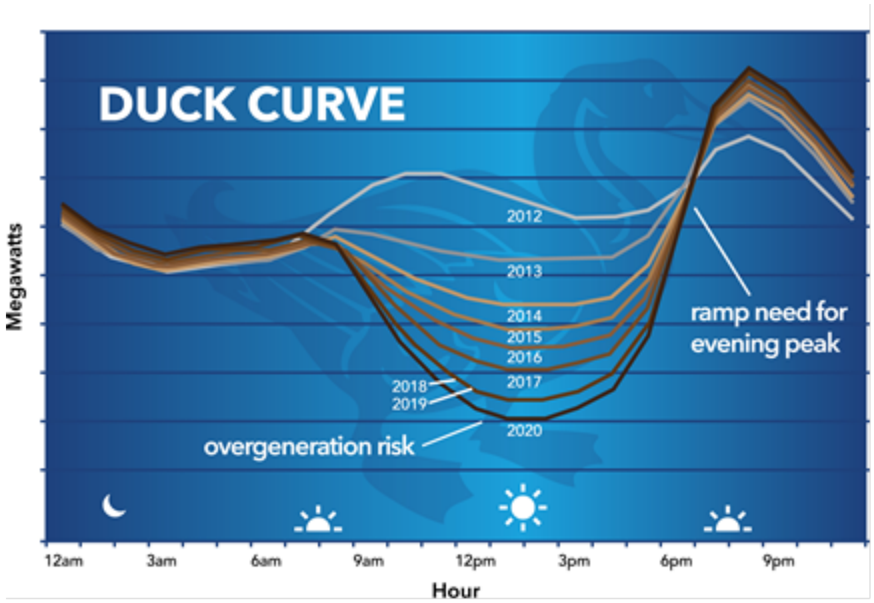
3.4 Ramp and Control Issues

With higher penetration of DERs, ramp and control issues begin to arise. Two notable issues concern overgeneration and lack of ramping ability. During peak periods, a high penetration of solar generation located "behind the meter" effectively reduces apparent measured load and the risk of overgeneration increases. In the evening, as the sun sets, solar generation begins to disappear just as the evening load increases, as does the possibility of ramp shortage. The combined effect of on-peak

32 NERC Standard VAR-001-4.1 – Voltage and Reactive Control

overgeneration and evening ramp shortage has come to be known as the "duck curve."[33]

Figure 4: The "Duck Curve"



Below, these issues will be discussed in more detail.

3.4.1 Overgeneration

Overgeneration has typically occurred during off-peak periods where extreme light loads are likely to occur. However, with the increased penetration of DERs into the generation resource mix, two things have occurred:

- During light load periods, DER generation (especially wind and solar) can add to an overgeneration problem; and
- During peak periods, an excess of solar generation can also create an overgeneration risk, as illustrated by the "belly" of the above "duck curve."

While techniques are currently available to deal with overgeneration, creative use of these techniques or new techniques will need to be developed as DER penetration increases.

[33] https://www.utilicast.com/media/A-Market-Solution-to-Renewables-Final_032116_FINAL-final.pdf

Among current techniques available are negative pricing, load shifting, use of hydro storage or ponding, and forced curtailment. Some ISOs, such as NYISO, CAISO and PJM, have historically used negative pricing as an economic solution to discourage unwanted generation. Negative pricing forces generation to pay to operate during overgeneration events and can reduce unwanted generation. However, it does have drawbacks. Baseload steam units do not have the ability to shut down and restart within a certain time frame (which may be 12 hours or longer). As a result, they will find it economic to remain on and pay to run. To promote renewable generation, the Federal government and some states provide incentives for wind and solar generation in the form of direct payments or tax credits. As a result, these resources may offer in at negative prices and remain economically feasible during periods of overgeneration. Caught in a Catch-22 situation, the ISO will increase negative price signals in an attempt to force this generation off while increasing the penalty on baseload generation.

Due to increased PV penetration during mid-day hours, the CAISO has noted a dramatic increase in the occurrence of negative prices: “For the first time, negative prices were relatively frequent in the day-ahead market. Prices fell below zero in over 50 hours in the first quarter (of 2017), around 10 percent of hours between hours ending 11 and 15. The frequency of negative prices increased in the real-time market as well, reaching about 10 percent of intervals in the 15-minute market and 13 percent of intervals in the 5-minute market. Lower prices during the middle of the day corresponded to periods when low-priced solar generation was greatest, and net demand was lowest.”[34]

Another current technique is load shifting. Often, load shifting will occur automatically in response to economic signals. If low or negative prices occur regularly or are anticipated, large industrial customers may reschedule certain processes to off-peak, low load periods. Ideally, this would occur through the Day-Ahead scheduling process of the particular ISO. Operators also have the option of modifying pump-storage schedules during overgeneration events. To some extent, load shifting also occurs at the residential level through time-of-day pricing provided by the local utility. However, since marginal pricing does not yet occur at the retail level, this does not occur as a direct result of low or negative prices during periods of overgeneration. Possibly, financial incentives could be provided in the future to

[34] California ISO: Q1 2017 Report on Market Issues and Performance, July 10, 2017

encourage certain customers to reschedule loads to off-peak periods, a kind of mirror image of demand response products.

Advances in storage technologies will provide new solutions to overgeneration issues. In addition to pump storage mentioned above and currently used to time shift load during light load periods, new types of storage including batteries and flywheels are beginning to make inroads. Almost all of these types of resources have been added since 2010. Half of the United States' 540 MW of batteries are in California, Illinois, and West Virginia. Flywheels provide electricity storage through rotational kinetic energy, and almost all the nation's 44 MW of utility scale flywheels are located in New York and Pennsylvania.[35] During light load periods and the belly of the duck curve, these resources would have the ability to store excess generation produced by renewables and base load generation. It should be noted that flywheels have a limited energy storage capability and would be used primarily for regulation and frequency control. An advantage of battery storage is that batteries can be relatively compact and placed at existing substations electrically close to concentrations of distribution level DERs. As noted previously, batteries could also be used for regulation and voltage control at both the distribution and transmission levels of the grid.

3.4.2 Ramp

Ramp has historically been an issue during "shoulder" periods of rapid load increase or decrease, such as morning and evening load pickups and early morning load decreases. With the addition of DERs, especially PVs, ramp has become a larger issue during periods of a sudden drop in DER output. These output drops can be predictable, such as during sunset, or unpredictable, such as sudden cloud cover or wind loss.

During the sunset hours, load has historically increased due to both the increase in lighting and, especially during colder months, heating load. To meet evening ramp requirements, operators would pre-commit quick start resources in order to increase headroom and ramp capability on steam units and also make use of high ramping resources, such as hydro, during the load increase. With the penetration of PVs and the sudden loss of generation that also occurs during this period when it is most needed, ramp constraints that were already difficult to meet can become severe. An efficiently designed market can aid in meeting ramp constraints during these periods. Proper scheduling and planning in the DA market can commit additional resources to

[35] Today in Energy, May 25, 2017 U.S. Energy Information Administration

be available for these peak periods. While energy may be at a surplus, reserve and regulation can experience shortages during periods of ramp constraint. In the NYISO, demand curves are used to price reserve and regulation during periods of shortage. These shortage constraints will also be reflected in the energy price. Resources will tend to modify bidding behavior throughout the day in order to maintain sufficient energy and ancillary services to offer in during these shortage periods and take advantage of high prices. CAISO has introduced the Flexible Ramping Product,[36] which offers award payments to resources that can provide ramping capability in the face of demand uncertainty and forecasting errors. Which approach may be desirable in a given market is open for discussion.

As noted above, sudden losses or surges of DER output can create frequency and voltage problems. Slower fluctuations, such as from storms or cloud cover, may not lead to stability problems but can create ramp issues. Excursions such as these are largely unpredictable and do not lend themselves to DA planning and scheduling. Unexpected use of quick-start or hydro resources to chase these excursions can lead to RT uplift, which will be discussed in more detail below. Storage devices, such as batteries and flywheels, may offer a better solution for smoothing these excursions.

3.5 Metering and Communication

Basic metering functions are:

1. Data for reliability and growth planning; and
2. Control for market participation.

In simple terms, DERs will either reduce load or inject power on the grid. For an intermittent DER, its ability to do either is uncertain, creating uncertain net load flows. This uncertainty around load and injection requires net metering to be more precise in terms of understanding the components contributing to net load or net injection. The preferred method is to meter total load and total generation separately, and calculate net load and net injection. This provides the necessary visibility to the grid operator of the total potential load that may flow onto the grid on a cloudy day, for instance.

[36] California Independent System Operator Corporation, Fifth Replacement FERC Electric Tariff, Section 44

The need to for ISOs to build cases representing the behavior of the grid is probably even more sensitive for "dynamics" study cases. Power engineering "dynamics" studies use arrays of differential equations describing the millisecond by millisecond changes in electrical output of resources, alternating with solutions to power flow equations to analyze time-dependent stability of the power grid. These studies are highly sensitive to topology changes and additional electrical injections. The results of these studies are likely to be very sensitive to DER injections.

ISO market products use load distribution characteristics to appropriately assign weather forecast data or bid data to individual network modeled Loads. The use of load distribution characteristics to appropriately assign reasonable MW values to the network modeled loads for performing power flow and contingency analysis is impacted if DER injections at the network modeled load level are not properly accounted for. These inaccuracies may be unacceptable as DER penetration becomes significant.

The ISO's load data collection process should ensure accurate and uniform reporting of DER data, so that DER penetration is accounted for consistently across all TDSPs.

For these reasons, the ISO will over time require additional and more granular information related to DERs, including the location of these sources and data describing their time-dependent interaction with the larger electric grid.

A typical ISO real-time market produces thousands of LMPs every five minutes, of which, a subset of LMPs correspond to the electrical buses associated with network modeled loads. This network model system typically models the electric grid down to the high side of load-serving substation transformers. The network modeled load construct can be determined by each TDSP. Typically, the network modeled load represents the load on an individual substation transformer. This load modeling may be subject to TSP discretion and may be more or less discrete depending on both the load being modeled and the TSP practice. Each network modeled load is connected to an electrical bus. Substations may contain a single network modeled load while others may contain multiple network modeled loads, which may or may not be owned by the same TSP.

DER data to be provided by TDSPs to the ISO includes:

- Load interval data via revenue grade meter
- Generation technology (type) and fuel source
- Interconnection agreement effective date

- Generation capacity in kW DC or kW AC as applicable
- Stored energy
- Invertor capacity in kW AC? (if applicable)
- Inverter's published peak efficiency rating
- Network modeled load identifier (substation?)

For DER aggregations, rules and procedures will need to be developed to validate the list of meter identifiers on an ongoing basis. The process will involve coordination between the TDSP, the resource owner and the ISO.

The mapping of DERs to network modeled loads in order to enable market pricing is assumed to be static — that is, a static relationship will be established by the DSP/TSP between a DER (or more likely, depending on the TDSP, the distribution feeder associated with the DER) and its network modeled load(s) (typically 1:1 mapping). Distribution system facilities are primarily radial and are therefore subject to switching by the DSP in order to allow for necessary maintenance. At any given time, a small percentage of a distribution system's load will be switched to different feeders for this purpose. This could result in inappropriate market price signals being provided to DERs. However, a certain level of inaccuracy in price formation may be tolerable at relatively low DER penetration levels. To ensure modeling accuracy as DER penetration increases, this issue should be monitored and if required, analyzed and enhancements to the mapping of DERs to applicable network modeled loads developed.

Typically, ISOs receive periodic data, ranging from 5 to 15 minutes, representing net energy consumed or net energy injected into the transmission or distribution grid, as measured at the meter location. For meters with executed Distributed Generation interconnection agreements, TDSPs may be responsible for reporting bi-directional energy flows to the ISO as separate channel reads — "generation/injection" channel and "load/consumption" channel.

Metering scenarios relevant to the DER discussion are described in the following table:

Metering Type	Description
Unidirectional	Measures load (consumption) only

Traditional Net Metering	Single-channel non-directional - Single data point representing net load minus net on-site generation over a billing period, typically monthly (could be a negative number)
Bi-Directional	Two data points for each interval: measures net in-flow to the service delivery point (i.e., may be reduced by on-site DG), and net exports to the grid from the service delivery point
Dual Metering	Two bi-directional meters, two data points for each interval, configured to measure gross native Load and gross generation behind the service delivery point

Dual metering will be necessary in instances where load at the service delivery point may be settled differently than the on-site generation.

Communication requirements will depend on the dynamics of the net load flow and provision of any market products or services. For the distribution operator, as the net load flow dynamics increase, the need for accurate, near real-time communications will increase. This will be a function of the characteristics of the DER penetration on the distribution grid (feeder, substation, etc.) and the design of the grid itself. The distribution grid will be more sensitive to DER growth than the bulk grid, therefore requiring more data and communication for reliable operations at an earlier stage. Data communications may be limited depending on the meter system (power line carrier, mesh, fiber, etc.).

For DERs electing to actively participate in the market, their scheduling entities would need to provide the ISO with appropriate data, including status and MW output in real-time or near real-time, via ICCP telemetry or other approved communications medium.

Any DER that is passively participating in the energy market may be required to respond to ISO instructions under emergency conditions.

For market products and services, communications will be modeled after requirements for typical thermal generation resources, which is real time telemetry with a data cycle of just a few seconds. Some products and services that have been developed for demand response products will provide for after-the-fact performance data, such a Meter Before, Meter After, or Baselines. These M&V requirements and performance requirements will likely require some modifications to adapt them to the characteristics of DERs and DER aggregations.

4. MARKET ISSUES

4.1 Pricing Issues

Under FERC Order 825, ISOs are required to settle "(1) … energy transactions in its real-time markets at the same time interval it dispatches energy; (2) … operating reserves transactions in its real-time markets at the same time interval it prices operating reserves; and (3) … intertie transactions in the same time interval it schedules intertie transactions."[37] Dispatch intervals are nominally 5-minutes and transaction intervals may range from 5 minutes to 1 hour. At the time of the Order, NYISO, CAISO and SPP were substantially in compliance and settlement rules required only minor modifications. MISO complied in early 2017 and PJM expects to be in compliance by early 2018. ERCOT is not under the jurisdiction of the FERC and settles at 15-minute intervals. Settlements are generally made at the LMP of the respective bus of the load or resource. Resource LMPs are usually specific to the bus, but load bus LMPs may be specific to the zone. As DER penetration trends accelerate, individual ISO pricing mechanisms may need to be revisited.

4.2 Integration Issues

For integrating DERs into the distribution grid, the DSP's requirements may be different for reliability purposes than the requirements for DERs to offer into the ISO market. The DSP's reliability requirements will more than likely be linked to the DSP's existing infrastructure for communications, data management, modeling, etc. When the DERs reach a critical size where they begin to affect the ISO bulk grid and market, then the ISO's protocols and infrastructure will dictate the participation requirements. This will apply regardless of whether the participation is net load fluctuations, which is a passive participation or a more deliberate participation via net injection or dispatched load reduction. The former will have an impact on planning, forecasting, grid support and operating reserves. The latter will be treated like a market resource.

DERs as a market resource will be expected to meet the same requirements as typical thermal generation resources. In reality, DERs will have limitations that need to be

[37] UNITED STATES OF AMERICA FEDERAL ENERGY REGULATORY COMMISSION; 18 CFR Part 35; Docket No. RM15-24-000; Order No. 825: Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators (Issued June 16, 2016)

recognized and accommodated, if possible. Intermittent solar resources cannot be dispatched. Energy storage resources will have a fast response time, a limited duration, and a defined re-dispatch limitation to recharge.

Since individual DERs are small, a minimum size requirement will need to be determined. For demand response, most ISOs have a 100kW minimum size. DERs lend themselves to being aggregated, which provides a larger size to the market. However, this adds additional complexity related to data transfer, communications/telemetry, dispatch control and M&V. In some ISOs, this ground has already been plowed for demand response resources and products, where the DER characteristics may fit easily into those requirements.

While the current requirements for small DERs is minimal, ISOs should consider the likelihood of eventual high penetration of small DERs – for instance, hundreds of thousands of residential premises with solar that are not visible to the ISO – and their potential impact on markets and reliability.

Large single-site DERs or aggregations could participate passively in energy markets, or could elect to participate actively in energy and ancillary services markets and be settled at the LMP if they are mapped into the network model. For the latter, the DER resource would be treated similarly to conventional generation resources in the relevant market construct.

Energy storage DERs would need to have well-defined metering configurations to ensure that the electrical energy used to charge the storage device can be measured separately from native and auxiliary load, since these loads may be settled differently.

4.3 Ancillary Service Issues

Much of the discussion to date around DERs has been concerning their participation and effect on current energy markets. However, over the past few years both the market and regulators have expressed interest for non-traditional resources to participate in the Ancillary Service (AS) markets. For example, in 2011 FERC issued and Order which stated: “Resources such as large-scale battery systems, flywheels, electric vehicle-to-grid (V2G) systems, and demand-side processes have the ability to ramp up or down faster than some traditional resources and, as such, are able to provide frequency regulation services more accurately than traditional resources” and “the Commission proposes to require regional RTOs and ISOs to adopt tariff revisions that will ensure that resources providing frequency regulation service are appropriately compensated." [38] ISOs and RTOs have since filed Responses to comply with the Order.

As DER penetration increases, there will be increased pressure on ISOs for their participation in the AS markets. This pressure will be more increased as storage technology advances. This will raise a number of issues that will need to be resolved:

- **Quality of Service:** As technology advances, how will the quality of service of storage devices used with DERs compare to conventional resources. Regulation and reserve response may be quicker (on the order of cycles rather than seconds or minutes). However, energy output cannot be sustained as long as a conventional resource. Solid-state voltage devices may offer quicker and steadier voltage response. How will quality be measured? Will products be priced based on degree of quality?
- **Participation in contingency reserve markets:** Storage devices, whether flywheels or batteries, have the ability to inject power on short notice. As such, they have the ability to participate in contingency reserve markets. Could these devices be permitted to provide 10-minute synchronized (spinning) reserve, the contingency reserve product of highest quality and market value?
- **Aggregation, Size and Control:** As noted, DERs at the distribution level are small and will need to be aggregated by DSPs for visibility to and control by the ISO. If AS are to be offered into the market by the DERs, will supply be aggregated similar to Energy? Or will the DSP act as a single aggregator and AS provider?

4.4 Compliance Issues

Conventional generation resources qualified to participate in a security constrained economic dispatch system are subject to numerous compliance metrics, including but not limited to the following:

- Base point deviation charges
- Deployment performance
- Primary frequency response
- Reactive power
- Outage reporting

[38] 134 FERC ¶ 61,124; UNITED STATES OF AMERICA; FEDERAL ENERGY REGULATORY COMMISSION; Frequency Regulation Compensation in the Organized Wholesale Power Markets; Docket Nos. RM11-7-000, AD10-11-000,

- Telemetry data accuracy

Those DERs actively participating in the energy and ancillary services market will have compliance criteria and compliance metrics that will closely mimic the existing metrics for conventional generation resources.

For DERs who are passively participating in the energy market, there would be two areas to consider developing compliance metrics:

- Validation of telemetry or near real-time data communication if required to support real-time price formation
- Response to ISO instructions during emergency conditions

4.5 Uplift and Distribution of A/S Charges

Typically, ancillary service and uplift charges are distributed in two ways: 1) in accordance with load share ratios; or 2) based on deviation from DA schedules and commitments. DER penetration will influence both methods. Not only will DERs reduce apparent RT load, they can cause unpredictable deviations from DA scheduled and forecasted load.

4.5.1 Apparent RT Load Reduction

Charges for many ancillary services, including voltage, reserve and dispatch and control, are often distributed based on load ratio shares. With the penetration of DERs, apparent RT load measurement is reduced. This raises the question: Should charges be based on actual measured load or on load plus DER output? (Or something in between?) Proponents of basing charges on actual measured load argue that load should be charged only for the amount that they are actively drawing from the grid. On the other side, it is argued that DER participants are beneficiaries of ancillary services provided through the grid whether they are withdrawing power or not. While arguments on both sides have merit, as DERs increase penetration ISOs will need to investigate new methods to allocate ancillary service charges to the consumers of those services.

4.5.2 Deviation from DA in RT

Any RT deviations from DA commitments can result uplift charges. Unaccounted for load, unexpected ramp increases, unexpected generation and transmission losses are among the reasons for committing resources not scheduled in the DA market. As these resources are committed, charges not recovered through the normal market are incurred. Among these charges are: start-up costs, minimum generation and run-time costs and production costs from requirements to operate at a point on the offer curve above the bus LMP. These costs are recovered through RT uplift.

Historically, uplift costs have been allocated to load, those parties that may have caused a deviation from DA, or some combination of both. However, on January 19, 2017 FERC issued a NOPR "to require that each regional transmission organization (RTO) and independent system operator (ISO) that currently allocates the costs of real-time uplift due to deviations should allocate such real-time uplift costs only to those market participants whose transactions are reasonably expected to have caused the real-time uplift costs."[39] This adheres to the FERC "cost-causation" principle that states that those MPs that cause a cost to occur pay for that cost. Due to their intermittent nature, DERs can result in the scheduling and commitment of additional RT resources above DA requirements. Should these additional uplift costs be allocated to DERs per cost causation principles? If so, how would the additional causation and resultant cost be measured and allocated?

[39] FERC Docket No. RM 17-2-000 "Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators" issued January 19, 2017

5. ISO/DSO INTEGRATION

As can be seen from the issues enumerated in this paper so far, the intersection between the ISO and DSP as it relates to managing DERs connected at distribution voltage is complex. As the DER penetration grows, there will be a need for individual DSPs to either merge together or independently form distribution versions of an ISO: a Distribution System Operator, or DSO. Any DER connected to the distribution grid will need to report to the DSO. If, and when, DSOs begin to emerge, the question becomes should there be one DSO to one ISO or many to one? The following scenarios provide some structure to explore this question:

- **One DSO** (per ISO region): this would be the most efficient structure in terms of both communications and cost. With one DSO for the region the communications would be centralized for both reliability operations and the coordination of market operations with the ISO. This option would have to overcome natural geographic issues (e.g., rural versus urban), and regional political issues (private versus public).

- **Each Individual DSP, or TSP, as a DSO**: this would be a costly option. Each DSO would have to invest in the required IT systems and add staff to include critical subject matter experts. This option would also be inefficient and burdensome for the ISO in terms of communications to many DSOs and the system modifications required to support data and operational interfaces with many DSOs. The might be a concern that numerous critical interfaces could compromise grid reliability and safety.

- **Hybrid DSOs**: this option could address some of the issues raised under the two scenarios above, where DSPs aggregate into political or regional DSOs. A viable option under the current utility industry structure would be to create a public power/municipalities DSO, an electric cooperatives DSO, a DSO for each large IOU DSP, and a DSO for an aggregation of smaller IOU DSPs.

How these potential scenarios may actually play out will depend on the complexity of forming a DSO in a particular ISO region in terms of IT systems investments and HR investments. As DERs penetrate deeper into the grid, they will need to be incorporated into existing lines of communication.

6. SUMMARY: A PATH FORWARD

In the utility industry today, the question is rapidly shifting from "should DERs be allowed to expand across the grid?" to "how can the growth of DERs be enabled in a manner that supports customer demands, maintains grid reliability, and ensures reasonable costs?" This shift is creating new business opportunities, and many utilities are considering whether to offer new services, such as:

- Community shared solar
- Investing in customer- or third-party-owned DER portfolios
- On-bill financing for customer-owned DERs
- Online tools to support customer decisions about DER adoption
- Operations and maintenance services for customer- owned DERs
- Utility ownership of customer-sited DERs
- Utility-owned DER assets to meet grid needs (e.g., utility control of advanced inverters, or microgrids where high reliability is needed)
- Rate structures that allow utilities to recover costs while equitably sharing those costs among ratepayers, and fairly compensating DER customers for the services they provide to the utility

Formulating a coherent strategy around enabling DERs will involve utility management asking fundamental questions about their business model.

Utilities are caught between competing demands to increase transparency by sharing more data with interested grid/DER stakeholders and mandates to ensure high levels of physical security and cyber security for grid assets. Clearly, DER customers and developers can benefit from greater grid data, but utilities can also benefit from data on DER performance and costs, and requirements for data sharing in both directions will need to be defined. This is still an area of very active debate. Each jurisdiction will have to determine what data is appropriate to share and what should be kept confidential. One potential compromise is allowing greater grid data access to a limited stakeholder group that can review utility assessments and provide objective, outside feedback. Perhaps the most robust example to-date of public grid data sharing is the California IOUs' Distribution Resources Plan that includes online maps showing estimated DER hosting capacity by circuit.[40]

Clearly, as DER penetration grows, the intersection between DSP/DSO management and ISO management will emerge and require attention in order to maintain a reliable electric grid. Below is a suggested path forward for resolving this DSO/ISO interface:

ISO/DSP Collaboration: As DSPs increase in influence and evolve into DSOs, the importance of collaboration between the DSP and their host ISO will grow. Key areas, which have been discussed in detail above, include:

- Data visibility;
- Net load thresholds and dynamics that will impact bulk grid planning, forecasting, and operations;
- DER participation in wholesale Energy and Ancillary Service markets; and
- Effects of DER penetration on system stability (voltage, VAR and frequency thresholds).

Recognition of these issues before they cause system reliability problems will take cooperation between the DSP and ISO as DERs increase in penetration. Cooperation among DERs, DSPs and the host ISO at an early stage becomes essential. ISOs should rely on their governance structure to invite DSPs, as current or potential MPs, to actively participate in the revision of current or formation of new market or operational rules that will affect DERs and the structure of DSOs. DSPs should investigate the formation of working groups to insure the fair and equitable treatment, as an MP, in the overall wholesale market.

Metering and Communication Issues: As DSPs begin to form DSOs, they will need to work with their host ISO to resolve metering and communication issues. ISOs will need to work with DSPs within their control to develop rules and standards for any required metering and communication. While these rules should meet standards that apply to existing MPs, they should strive to not impose undue financial burdens upon the evolving DSPs and existing systems hosted within the DSPs.

Price Response Issues: As DERs grow in the market, how will they respond to price signals? Today, dispatch interval pricing signals do not reach to the retail

[40] Beyond the Meter, PLANNING THE DISTRIBUTED ENERGY FUTURE, VOLUME I: EMERGING ELECTRIC UTILITY DISTRIBUTION PLANNING PRACTICES FOR DISTRIBUTED ENERGY RESOURCES, Black & Veatch, Smart Electric Power Alliance, May 2017

level. Renewable DER response is dependent on the input received, whether it be available sunshine or wind. In the future, as price signals reach the DERs, whether directly or through their DSO, how will they respond? In many markets today, such as the NYISO, DERs can aggregate and participate as Demand Response Providers (DRPs). DRPs respond to incentives that generally occur when prices are high. Load will disconnect and rely on on-site resources. In the case of wind and PV DERs, incremental costs are low and these resources will already be on line in times of high loads and prices. Response as a DRP will not occur.

Advances in the development of storage devices will help drive price responsiveness of DERs. Working in conjunction with advanced storage devices, DERs will have the ability to inject or absorb from the grid in response to price signals. For this to occur, DSOs will need to aggregate DERs under their control into "virtual" resources with the ability to respond to grid prices at ISO pricing nodes or zones. To encourage participation, incentives will need to flow to the retail level.

These and other issues will arise as DER penetration increases. These should not be viewed as obstacles to development, but rather as opportunities. Since the time of Edison's first generator and simple grid in NYC, the North American power grid has evolved into the largest and most complex machine in the world. Development and growth of DERs is just one more step in that evolution.

7. APPENDIX A: ACRONYMS AND ABBREVIATIONS

AVR	Automatic Voltage Regulator
CAISO	California Independent System Operator
DER	Distributed Energy Resource
DREAM	Distributed Resource Energy and Ancillaries Market (ERCOT)
DRP	Demand Response Provider
DSP	Distributed System Platform (NYISO) / Provider (ERCOT)
DSO	Distribution System Operator
ERCOT	Electric Reliability Council of Texas
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
IEEE	Institute of Electrical and Electronic Engineers
ISO	Independent System Operator
IT	Information Technology
LMP	Locational Marginal Price
MP	Market Participant
M&V	Measurement & Verification
NERC	North American Electric Reliability Corporation
NYISO	New York Independent System Operator
NYSDPS	New York State Department of Public Service
PV	Photovoltaic

REV	Reforming the Energy Vision (NYISO)
RTO	Regional Transmission Organization
SVC	Static VAR compensator
TDSP	Transmission and Distribution Service Provider
TO	Transmission Operator
TSP	Transmission Service Provider
UL	Underwriters Laboratory
V2G	Vehicle-to-Grid
VAR	Volt-ampere Reactive

8. APPENDIX B: VARIOUS STATE DER INITIATIVES[41]

State	**Policies Relevant to Distribution Planning**
California	State Renewable Portfolio Standards (RPS) requires electricity retail sales procured from renewable energy resources as 33% by 2020, and 50% by 2030 (75% must come from resources located within, and/or states connected to, California). In July 2015, State Assembly Bill 327 required investor-owned utilities to submit individual Distribution Resources Plans (DRPs) for approval that included: DER integration capacity within current distribution system down to circuit level; Methodology for quantification of DER locational value; and Growth scenarios of 10-year deployment siting at the substation level and impacts on distribution. CAISO will allow aggregated DER portfolios to bid into wholesale markets beginning in late 2016. "Integrated Demand-Side Resources" (IDSR) proceeding is exploring new procurement models,

[41] Beyond the Meter, PLANNING THE DISTRIBUTED ENERGY FUTURE, VOLUME I: EMERGING ELECTRIC UTILITY DISTRIBUTION PLANNING PRACTICES FOR DISTRIBUTED ENERGY RESOURCES, Black & Veatch, Smart Electric Power Alliance, May 2017

	tariffs, and contracts for DERs to meet grid needs. In January 2016, the California Public Utilities Commission voted to the retain retail-rate Net Energy Metering (NEM) tariff, while requiring NEM customers to pay more in non-bypassable charges and switch to time-of-use rates (NEM tariff will be reviewed again in 2019).
Hawaii	State RPS requires renewable penetration to ramp up according to the following schedule: •15% by 2015 •25% by 2020 •40% by 2030 •70% by 2040 •100% by 2045 – In 2014, the Hawaii Public Utilities Commission directed the Hawaiian Electric Companies (HECO) to develop and implement a fully integrated portfolio for demand response programs (Order No. 320542, Docket No. 2007-0341), along with a comprehensive Distributed Generation Interconnection Plan (DGIP) for accelerating grid integration of DERs. In early 2015, HECO was the first utility to enable advanced PV inverter functionality on a large scale, which allowed it to raise the threshold for detailed interconnection studies from 120 to 250% of minimum daytime load (highest in the nation). In October 2015, the PUC adopted two new NEM programs (Order No. 332583, Docket No. 2014-0192): •"Grid supply" program resembles traditional NEM with customers receiving wholesale instead of retail for energy exported to the grid •"Self-supply" does not pay for grid exports and encourages customers to align generation with load profile using energy storage and load management •Next phase of the proceeding will focus on growing competitive markets for DER to maximize the value of grid- supported DER systems
Massachusetts	RPS requires up to 25% renewable generation by 2030; State law requires >25% load satisfied by demand-side resources by 2020. Senate Bill 2214 established a solar and net metering task force to focus on planning solutions to reduce effects of outages; optimize demand (reduce system and customer costs); integrate distributed resources; and improve workforce and asset management. The Department of Public Utilities also ordered distribution utilities to develop and execute a 10-year Grid Modernization Plan (GMP), including marketing, education, and outreach plans, with a five-year capital investment plan to achieve advanced metering functionality within five years of

	GMP approval.
Minnesota	Stakeholders requested the 21st Century Energy System, or e21 Initiative (docket 14-1055), to realign issues at odds between the traditional utility model, technology advancement, and public policy: •DER growth identified as main drivers of change in the electricity industry •Phase I examined and called for more transparent and integrated system planning process (December 2014) •Phase II will map out a new regulatory system to develop an economically viable utility business model for DER initiatives
New York	Reforming the Energy Vision (REV) initiative changes the role of the distribution utility via two tracks: •**Track 1:** Utilities are to efficiently integrate behind-the-meter DER into the grid; utilities are distributed system platform provider, or "market enabler" of DERs and third-party services. Utilities are not expected to primarily own DERs (except where the market is not responding in cost effective ways). This includes DER participation in the NYISO market. •**Track 2:** Financial support of Track 1 via ratemaking to raise capital for infrastructure improvement and upgrades, and aligning utility financial incentives with societal goals (e.g., reducing emissions, improving reliability).
Texas	Distributed Resource Energy and Ancillaries Market Task Force (DREAM TF) approved by Electric Reliability Council of Texas (ERCOT) to allow appropriate DER market participation through: •Investigation of current and future DER development opportunities at transmission substation level and up •Development and recommendation for regulatory framework, including rules for DERs to bid into the wholesale market

9. APPENDIX C: REFERENCES

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ABOUT UTILICAST

Utilicast is a premier management, regulatory, and solutions consulting firm that specializes in the electric utility industry. Our consultants deliver a powerful combination of experience, management, and subject matter expertise in markets, system operations, compliance, metering, retail and other industry areas. Since 2000, we have provided our customers with an expert level of service that brings results from both a business practices and information technology perspective. Our experience spans the entire U.S. region, as well as several international entities.

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