White Paper

Missing Links in the Evolving Distribution Markets

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Shareables

1. DER total value can be realized by customers and its value to the power system. This paper focuses on DER value to the power system, specifically the distribution system.
2. No single market or operational mechanism can address needs of the bulk power system. It requires a spectrum of economic and control mechanisms to develop grid services and pricing.
3. Ultimately, ICF sees distribution markets following an evolutionary path that maximizes net value to all customers, starting from the largest and most tangible value potential, and over time adding incremental and more complex opportunities.

Executive Summary

Discussions are taking place across the industry exploring the value in distributed energy resources (DER) and the potential market mechanisms that can enable them in the future. Many of these proposed mechanisms, however, are not grounded in a manner that addresses the needs of the bulk power system or market participants. We learned from the past evolution of the wholesale markets that establishing a spectrum of economic and control mechanisms

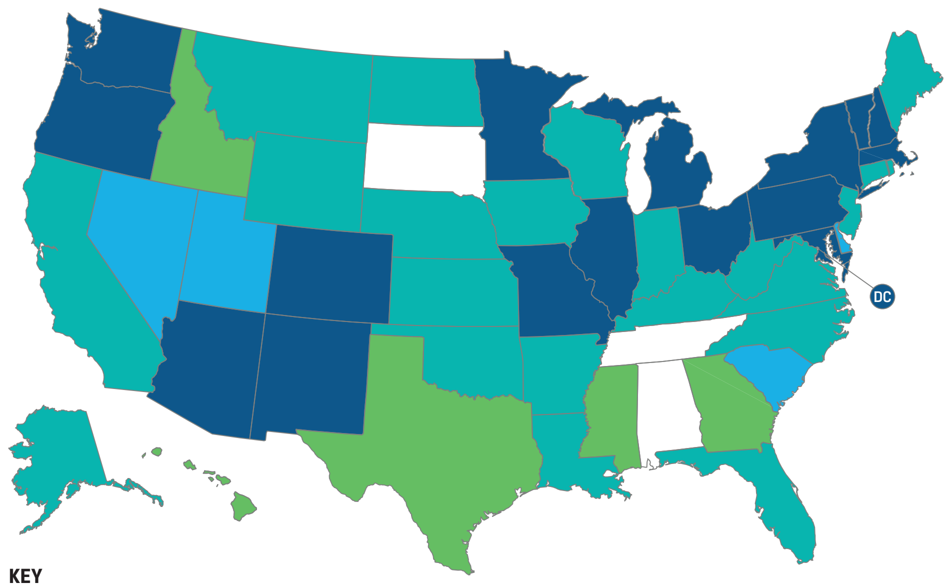
is needed in order to meet operational requirements. Drawing from these best practices, we believe the distribution market will need to evolve in a similar order, starting with long-term solutions (e.g., distribution capacity deferral), moving into operational controls (e.g., voltage management), and eventually reaching development of short-run operational services (e.g., congestion management). As DER adoption continues to increase, future distribution markets accounting for DER locational value may involve a variety of mechanisms from forward contracts to spot markets with granular locational marginal pricing. Several states are already beginning to develop distribution markets for grid services. It is therefore important to understand the path distribution markets may take and determine which mechanisms are appropriate to implement and at what stage of the distribution market's evolution.

This paper takes a deep dive into the spectrum of market mechanisms and operational controls—looking at long-term infrastructure mechanisms and real-time operational controls to address the needs of a power system accommodating high amounts of DERs. We introduce an old concept of the Pareto approach to the discussion of the locational value of DERs to explain the evolutionary pathway distribution markets may take as they maximize the largest and most tangible value potential first, and incrementally add smaller and more complex DERs over time. What we find is a potentially optimal sweet spot where optimal value can be derived from DERs along this evolution. The increasing adoption of DERs across the distribution system will require sophisticated methods for integrated distribution planning and valuing customer DER as distribution system resources. We elaborate on these points below.

An Industry in Flux

Understanding and fully realizing the value of DERs is becoming an increasingly important issue for utilities, regulators, and other energy industry leaders. Pressures to integrate DERs onto the grid are growing, given declining costs, heightened customer adoption, and supporting federal and state policies. Integrating a growing array of DERs onto the distribution grid presents a complex set of challenges, which is compounded by policies that require utilities to develop a market for products and services at the distribution system level. We are seeing this happen already in states like California and New York, where the New York Reforming the Energy Vision (NY REV) process continues to transform major investor-owned distribution utilities into distributed system platform providers (DSPP). While initiatives in California and New York represent the leading edge of this paradigm shift, it is already the case that most states have either a form of nonlocational feed-in tariff, such as net energy metering (NEM), and/or a renewable portfolio standard (RPS) that includes DER, as illustrated in Exhibit 1.

EXHIBIT 1: DISTRIBUTED RESOURCE ENABLING POLICIES



KEY

- Renewable Portfolio Standard with solar/distributed generation (DG) provision + State mandatory NEM rules
- Renewable Portfolio Goal with solar/DG provision with no state mandatory NEM rules
- State-developed mandatory NEM rules for certain utilities (41 states + DC)
- Distributed generation compensation rules other than mandatory net metering (6 states)

Source: DSIREUSA.org

NEM is Inappropriate

Administratively-determined value for DER, such as NEM, is increasingly recognized as an inappropriate method to value DER and also as not beneficial for all customers.[1] Industry experts have been exploring methods to fully measure the value of DER. In our previous whitepaper "The Value in Distributed Energy: It's All About Location, Location, Location,"[2] we discussed how increasing amounts of DER joining the grid could create real and substantial net benefits for stakeholders (e.g., lower system costs, better resiliency, greater savings for customers, and robust emissions reductions) while at the same time presenting utilities with new operational challenges and costs (e.g., greater variability in net load, challenges managing distribution voltage, integration costs, and cost allocations). The "true" value of DER should be able to reflect the net benefits and operational challenges. However, this requires analysis of DER's locational net benefits within the distribution system while also taking into account wholesale system impacts. How these values are delineated and realized will evolve as distribution systems allow greater granularity around system dynamics and pricing.

[1] Herman Trabish, "The Solar Industry Responds to Utility Attacks on Net Metering," Greentech Media, Jul. 18, 2013. http://www.greentechmedia.com/articles/read/The-Solar-Industry-Responds-to-Utility-Attacks-on-Net-Metering

[2] Steve Fine, Paul De Martini, and Samir Succar, "The Value in Distributed Energy: It's All about Location, Location, Location," 2014. http://www.icfi.com/insights/white-papers/2015/value-in-distributed-energy

The Value of DER to Customers and the System

As we dive deeper into the true value of DER, the "total value of DER" can be viewed from two main perspectives: customers' derived value of DER and incremental system value of DER.

Customer-Driven Value of DER. The customer's derived value of DER comes from tangible and perceived benefits that buying or leasing of DER technology will provide to a customer through electric bill savings, including those related to NEM tariffs as well as potential enhanced reliability and environmental attributes. These benefits represent about 70% of the value needed to justify a solar photovoltaic (PV) investment for a customer; the remainder is provided by federal and state tax incentives and rebates. When the federal investment tax credit expires in 2022, a 30% gap in benefits will need to be addressed. Today, the discussion is how that gap will be filled by revenues from providing wholesale and distribution grid services. Also, for other distributed resources (e.g., behind the meter storage), customer value and existing incentives fall short of providing the revenue needed to justify a sale or develop a project. In these instances, the DER developer is also seeking additional revenue from power system services.

The challenge with this is that the NEM tariffs already provide more value to the customer than their solar PV system provides to the power system—hence the cross subsidization problem that has grown over the past 5 years. To make matters more complicated, some DER developers are seeking additional administratively-determined compensation, often described as the intrinsic value the DER provides to the power system by reducing energy consumed or other proposed inherent attributes. This "I exist therefore I should get paid" perspective lacks a direct linkage or recognition as to what is needed on the bulk power system, let alone being necessarily aligned with the engineering needs and economic impacts on the local distribution system and net value for all customers. As several states are beginning to reconsider net energy metering tariffs and successor rate designs, it is becoming clear that the most sustainable path forward is compensating customers correctly and fairly for their DERs based on a valuation method tied to planning and operational needs of the electricity system—both at the bulk power system and local distribution level.

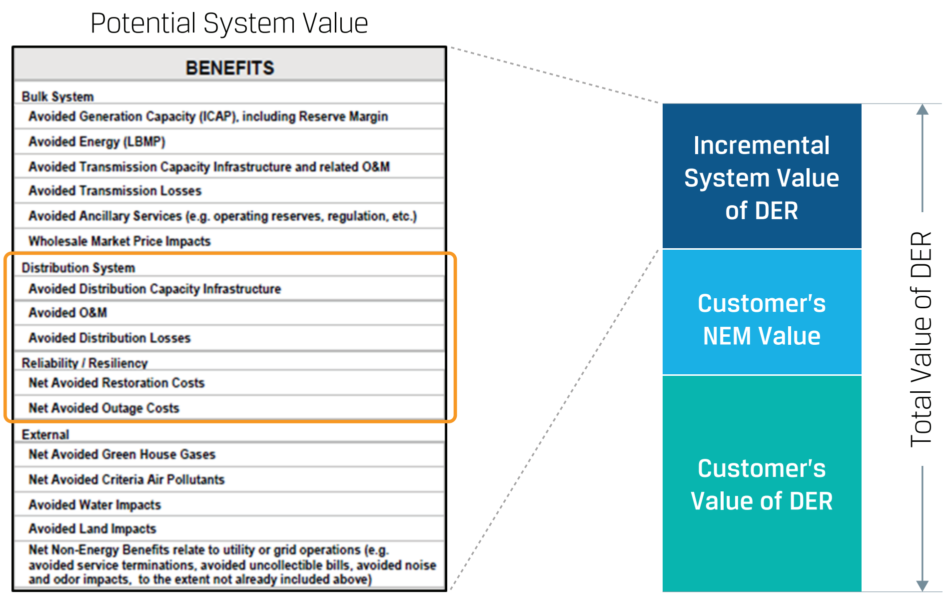
Incremental System Value of DER. The incremental system value of DER can be broken down into benefits within three main categories: bulk power system, distribution system, and external (e.g., customer and societal).[3,4] Bulk power system value derived from DERs includes components such as avoided generation and transmission, increased flexible capacity, and reduction of

3 CPUC, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769 - Rulemaking 14-08-013, Feb. 2015.

4 YPSC Order Establishing the Benefit Cost Analysis Framework, REV Proceeding, Case 14-M-0101, Jan. 2016.

transmission congestion and losses. Distribution system value (the focus of this paper) includes deferred/avoided distribution capital, improved voltage management, improved reliability and resilience, and reduced losses. Customer and external societal value derived from DERs include reduced emissions, increased energy autonomy and security, and decreased water and land use. The focus of this paper is on the development of distribution operational markets to realize the potential benefit of DER directly linked to planning and operational values based on avoided costs, as shown in Exhibit 2. More specifically, we focus on the methods and evolution of monetizing the incremental distribution system locational value of DER.

EXHIBIT 2: VALUE OF DER TO THE DISTRIBUTION SYSTEM



Source: Source: NY PSC Benefit Cost Analysis Framework Order, January 2016

Discussion of the potential for development of distribution-level energy markets is beyond the scope of this paper. However, we recognize that in a post-NEM environment and with the rise of multiuser microgrids, there will increasingly be the potential for bilateral energy commodity transactions across the distribution system. However, there are significant regulatory, technical, and operational issues to resolve before such an energy market develops. Given these gating issues, we do not expect the first of such energy markets to develop until well into the next decade.

How DERs Can Benefit the Distribution System

DER-supplied grid services such as distribution capacity, voltage support, and reliability (laid out in Exhibit 3) can provide value to the distribution system based on the locational value of DER. The distribution locational value of DER can be realized through potential long-run avoided costs related to infrastructure upgrade investments and short-run avoided costs related to operational expenses. However, it is important to consider that nearly all DER is located behind the meter and is commercially and operationally considered load-modifying.

Several states, including California, Hawaii, Minnesota, and New York, have begun considering the use of DER as an alternative to long-run costs related to distribution system "wires" investments, often referred to as non-wires alternatives (NWA). Deploying DER in a specific location can reduce or defer the need for incremental distribution upgrade investments. Short-run avoided costs are another potential locational value derived from operational and control services. This includes services related to the real-time operation of the distribution system (e.g., distribution voltage/reactive power support and reduced real-time distribution losses).

This past year, the California Public Utility Commission (CPUC) and stakeholders recognized that an initial set of services represented the logical starting point for DER to provide services to the distribution system, particularly distribution capacity deferral and potentially reliability and resiliency. In Exhibit 3, the initial set of grid services identified and developed for California were the result of a CPUC-directed stakeholder working group[5]. These services represent the near- and intermediate-term services called out in the CPUC's guidance in 2015.[6] A staged implementation, such as the "walk/jog/run" approach in California to sequentially incorporate the value potential for the whole stack, reflects several practical implementation considerations. For example, utilizing smart inverters to provide voltage support is dependent on 1) a revision to the IEEE 1547 standard, 2) regulatory changes to state interconnection rules, and 3) conversion of solar PV and battery inverters to smart inverter capability.[7] California, at the forefront of this effort, does not expect these changes to be completed and systems operational until about 2018 or 2019.

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[5] Mark Esguerra, "Distribution Services, Attributes and Performance Requirements." California IDER and DRP Working Groups, Jul. 11, 2016. http://drpwg.org/wp-content/uploads/2016/07/CSFWG-Sub-Team-1.-Summary-Conclusions-and-Recommendations.pdf

[6] CPUC, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769 - Rulemaking 14-08-013, Feb. 2015.

[7] Phase 2 and 3 capabilities identified by the CA smart inverter working group recommendations that have not yet been adopted by CPUC

EXHIBIT 3: CPUC IDENTIFIED GRID SERVICES[8]

Distribution Service	Definition
Distribution Capacity	Load-modifying or supply services that DERs provide via dispatch of output (MW) or reduction in load that is capable or reliably and consistently reducing net loading on desired distribution infrastructure.
Voltage Support (Voltage control through real and/or reactive power)	Improved steady-state voltage to avoid voltage-related investment. Dynamic voltage management to keep secondary and primary voltage within interconnection rule limits.
Reliability	Load-modifying or supply service capable of improving local distribution reliability and/or resiliency. Service provides fast reconnection and availability of excess reserves to reduce demand when restoring customers to service during abnormal configurations.
Resiliency	Load-modifying or supply service, including microgrids, capable of improving local distribution reliability and/or resiliency. Service provides fast reconnection and availability of excess reserves to reduce demand when restoring customers to service during abnormal configurations. Service also provides power to islanded end-use customers when central power is not supplied and thus reduce the duration of outages.

DER value potential from providing distribution grid services is likely to be modest in comparison to the potential to be derived from DERs participating in wholesale markets, as noted by New York PSC Chair Zibelman.[9] While Con Edison's Brooklyn Queens Demand Management (BQDM) initiative is often cited as a leading example of DER-derived distribution system services, it is also likely the "unicorn" of distribution project deferral opportunities for NWAs. To put BQDM's $1.2 billion capital estimate into perspective, consider Con Edison's capital spend and forecast in Exhibit 4[10] The sum total of distribution upgrades ("system expansion") across Con Edison's system over the 10 years

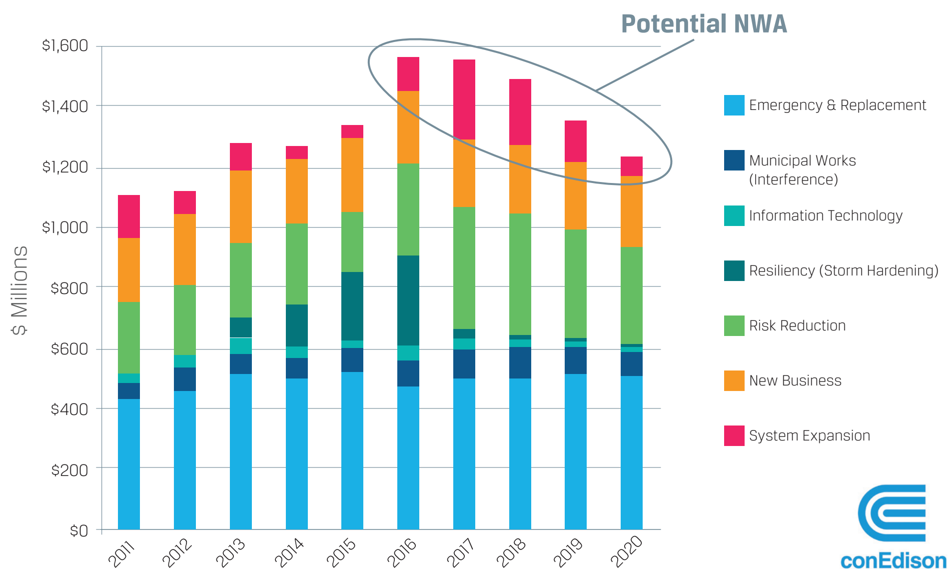
[8] Adapted from Mark Esguerra, "Distribution Services, Attributes and Performance Requirements." California IDER and DRP Working Groups, Jul. 11, 2016. http://drpwg.org/wp-content/uploads/2016/07/CSFWG-Sub-Team-1.-Summary-Conclusions-and-Recommendations.pdf

[9] Davide Savenije, "In New York, Utility of the Future Will Be 'air Traffic Controller'" Latest News. Utility Dive, Mar. 12, 2015. http://www.utilitydive.com/news/in-new-york-utility-of-the-future-will-be-air-traffic-controller/373342/

[10] Con Edison presentation at IEEE-ISGT Conf., Sep. 8, 2016.

presented in Exhibit 4 is substantially less than BQDM alone. Thus, while BQDM may provide a unique platform for demonstration of various commercial applications of DER to defer forecast distribution system upgrades, it is not representative of the NWA cost-deferral potential on the typical utility distribution system. In the Con Edison example, the annual ratio of system expansion costs that are potential NWA opportunities to total distribution spend is roughly 5–15%. This is consistent with outcomes from similar discussions in California and other states that have also suggested that roughly 5–10% of distribution capital spend is related to capital upgrades suitable for potential NWA.

EXHIBIT 4: ConEd CAPITAL SPEND FORECAST



Source: Con Edison presentation at IEEE-ISGT Conf., Sep. 8, 2016.

Distribution "Market Animation"

The primary objectives for distribution operational market animation have been described as twofold: 1) enable innovative, cost-effective solutions from competitive providers and 2) provide a means to price the services that DER may provide to the power system.[11,12] Distribution operational markets also need to consider the requirements of both buyers and sellers of grid services if they are to be sustainable and result in net benefits for all customers. As such, market animation should align to the utility's identified grid needs and the commercial needs of the DER providers. This may seem obvious, but often the industry discussion ignores the basic economic principle for transactions and markets requiring both a willing and able buyer and seller.

11 NY REV, Order Adopting Regulatory Policy Framework and Implementation Plan for a Reformed Retail Electric Industry, Feb. 2015.

12 CPUC, Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning and Evaluation of Integrated Distributed Energy Resources, § R1410003 - Proceeding (Oct. 2, 2014).

Lessons Learned from Wholesale Markets

Since the early 2000s, wholesale markets in the United States have focused on developing products, procedures, and controls using longer-term planning approaches and forward contracts to encourage investment in new generation plants and development. More robust spot markets began to emerge to manage the residuals surrounding forward contracts and daily/hourly/real-time load variations. Independent system operators (ISOs) recognized the need to introduce key services to provide operational control needed within very short time frames. They recognized that a transactional market would be an impractical and expensive way to provide such services. In fact, these services often became a necessity for market participants (i.e., AGC control capability) or were developed as tariffed services (i.e., ancillary services), which further highlighted the need for cost-effective and efficient ways to deliver them. A related set of learnings has been experienced in New York as the New York Independent System Operator (NYISO) has developed over the past 20 years.

As seen across the United States, no single market or operational mechanism can address the needs of the bulk power system or market participants. Establishing a spectrum of economic and control mechanisms,[13] each evolving in a timeframe that matched the operational needs and evolution of the wholesale market mechanisms, continues to be the best practice. These insights offer guidance for the development path regarding services and market mechanisms on distribution systems.

Distribution Operational Market Structure

As distribution-level operational market structures evolve, they need to include distribution-level economic and control mechanisms to address the range of NWA services identified to date. Similar to the wholesale market mechanisms described above, these distribution market mechanisms will need to align with distribution grid operational services that involve very different attributes, including transaction timeframes ranging from years to potentially sub-seconds, which requires both operational and control mechanisms in addition to pricing methods.[14] For example, forward-market contracts are often preferred to provide finance-ability for DER investments and manage operational risk for long-term capital deferral. Spot market transactions help in real-time operations to manage grid operational needs. Dynamic operational control may be needed on very short time cycles that are practically not supported by a real-time, bid-based market but more efficiently provided as a condition to participate or paid for under a subscription tariff, akin to similar services on the transmission system. Exhibit 5 shows the temporal regions for two types of markets—long-term forward and

The California Wholesale Market Failure

In the early stages of wholesale market deregulation in the United States, policy makers primarily focused on creating price transparency and paid less attention to the economic and operational needs of the power system. In the mid-1990s, for example, California's focus on establishing wholesale markets to increase competition and motivate investment in generating plants provided some benefits. Its execution, however, was fatally flawed. The new energy spot market was operated independent of the physical transmission grid operation. The California market failure and its impact took years to recover.

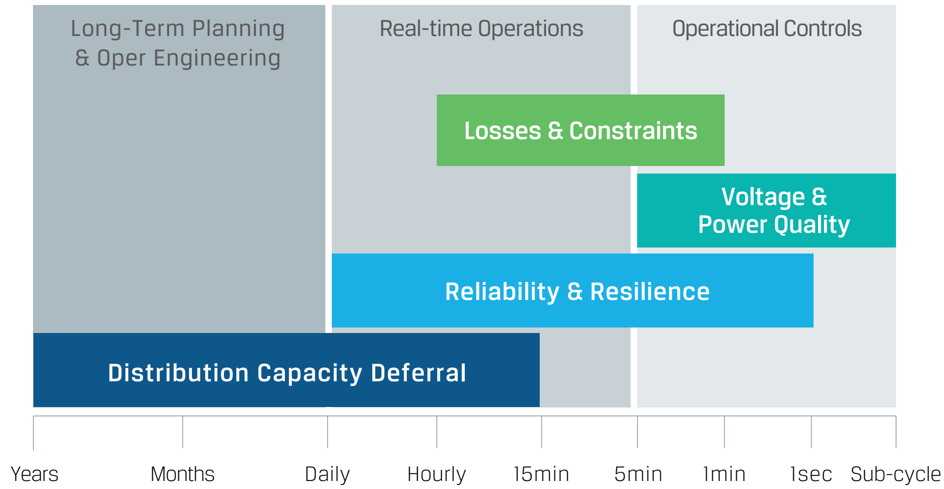
This market setup is similar to some distribution market proposals, suggesting a separate economic market independent of the physical operation of the distribution grid. Among the lessons learned from the wholesale markets, experts recognized the need to carefully consider and understand the intimate link between economic markets and electric system operations. ***Moreover, after 15–20 years of experience in wholesale markets, we have seen that market evolution begins when we recognize the full spectrum of power system needs and match the development of processes, systems, products, and services to the stage of market development.***

[13] L. Kristov, P. De Martini, and J. Taft, "Two Visions of a Transactive Electric System," CAISO-Caltech-PNNL, 2016.

[14] J. Mathieu, T. Haring, J. Ledyard, and G. Andersson, "Residential Demand Response Program Design: Engineering and Economic Perspectives," IEEE, 2013.

real-time spot—as well as the dynamic operational control system.[15] Exhibit 5 also highlights the temporal aspects of several key distribution grid services identified in California and New York.

EXHIBIT 5: DISTRIBUTION MARKET STRUCTURE



Source: Paul De Martini/ICF

The evolution of distribution operational markets will develop to address the potential grid requirements and DER value monetization in three categories: long-term infrastructure, real-time operations, and operational controls.

Long-term Distribution Planning. The annual distribution planning process common to many utilities identifies infrastructure upgrades. These capital upgrades—and associate avoided cost—are the basis for considering NWA from DER providers/aggregators. The distribution network operator will source these services through pricing and procurement methods that align with desired performance requirements as well as commercial risk mitigation. Currently, this is being pursued through open competitive procurements but is anticipated to also include pricing and programs. The ceiling price for these services is the respective incremental long-run avoided cost of the "wires" alternative.

Real-Time Operations. In the future—beyond 2025—high levels of DER will be providing services to wholesale markets, distribution network services, and energy transactions across distribution. In this future, the distribution operator may have a need for local resources to manage congestion and losses due to dynamic changes in power flows on the distribution network. These operations could involve intraday markets for services priced at a short-run marginal cost.

Operational Controls. Over the next 10 years, distributed solar PV penetration in several states will require operational controls to manage voltage and reactive power on the distribution system, particularly as more intermittent sources are interconnected to the system. The need for increased voltage/reactive power

[15] J. Taft," Grid Architecture 2", Pacific Northwest National Laboratory, 2016.

control is identified in the long-term planning process (i.e., forecasted hosting capacity analysis). Use of smart inverters on rooftop solar and battery storage could be called upon to provide these services. Due to the nature of control needed, a bidding market for these services is impractical and services may be priced at an administratively-determined long-run marginal cost and likely will be provided under a tariff and/or subscription structure.

Distribution Operational Market Evolution

Based on the experience of the wholesale markets, we expect distribution operational markets for grid services to pursue a net value maximizing approach that addresses utility grid needs and DER providers' commercial interests. As such, the evolution will follow a path that seeks to address the largest and most tangible value potential first and then add those incrementally smaller and more complex opportunities over time as makes sense in terms of yielding net value for all customers and potential market participants. These practical commercial considerations will ultimately determine the timing, shape, and viability of distribution operational market structures.

Market Mechanism for Long-Term Infrastructure NWA

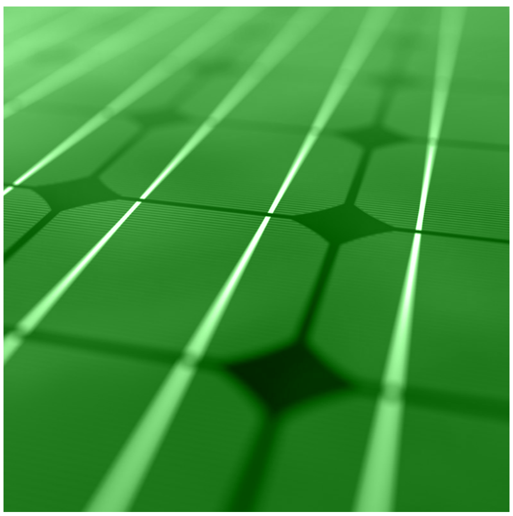
To capture the largest and most tangible value potential, distribution system markets have started focusing on opening opportunities for non-wires alternatives to long-term capital upgrades involving potential long-run avoided costs. Distribution upgrades such as substation transformers or feeder reconductoring represent typical deferred/avoided investments. As noted earlier, these long-term upgrade investments also represent the largest potential value of the three categories. In New York, California, and elsewhere, DER-provided services are being sourced through a combination of three types of mechanisms:

- Pricing—locational price overlays (not unlike critical peak pricing/peak time rebates) and/or service tariffs
- Programs—targeted DSM rebates based on locational avoided cost
- Procurements—competitive solicitations and procurements

During the distribution planning process, the distribution utility identifies needs for these grid operational services. These distribution services are priced based on the long-term locational avoided cost of traditional utility investments or through competitive procurements using avoided cost as a ceiling price. This starting point may evolve over time to optimally assess a bundle of services that may be provided by DER. This would require a more complex optimization model for developing long-run marginal cost (or price) of such a portfolio, given the differences in grid needs or attributes for each identified investment in the portfolio to be deferred/avoided.

Real-Time Operational Controls with Long-Run Avoided Costs

As previously described, DER grid services such as voltage/reactive power management involve both real-time operational controls and potential long-run avoided costs associated with NWA. This means that the value of service is capped at the avoided cost of long-term investments, such as capacitor banks or grid-based power electronics for voltage management. In this case, determining the price of service begins with long-term avoided costs (as described above). Also, there are inherent real option value characteristics to several operational control-based services that may make sense to value by using a subscription tariff for services linked to a specific locational need and administratively derived pricing. Such a tariff could be offered on a first-come basis, up to the maximum amount of services required. A tariff may offer a better approach to procurements, given the smaller capital deferral/avoidance value potential for these types of services. Procurements for these services are not likely to be cost effective for utilities or DER providers.[16]



Real-Time Operations with Short-Run Avoided Costs

The third category of real-time operations with short-run avoided costs represents the smallest distribution avoided cost potential. These opportunities are largely related to dynamic operational constraints and losses.

Distribution feeder constraints due to thermal limits are quite different from transmission, and the changing nature and flexibility of the distribution system means that mitigation can be accomplished without any material incremental expense. For example, grid operators/engineers can reconfigure feeder topology through switching sections of a line to an adjacent circuit or substation to reduce losses. Or, constraints caused by phase imbalance can be addressed by moving service transformers to a different phase of a circuit. Constraints due to voltage limits are already addressed through operational controls as noted above. Persistent distribution constraints are within the scope of the long-term, investment-based avoided costs.

Real-time operational management of distribution losses is a very complex problem to manage. While distribution losses average less than 4%, they can reach 14% or higher under certain loading situations—these periods are relatively short and are increasingly more random in terms of when they occur. This is due to the random nature of distribution power flows, given the increasing variable DER and impact on net load and multidirectional power flows on the grid. In addition, any short-run avoided cost method would need to determine the short-run marginal cost in real time similar to LMP at wholesale or determine the price based on previously provided supplier bids.[17] A challenge with a short-run

[16] Distribution System Planning Engagement Group, "Summary of Stakeholder Engagement Group Meetings on NWA Suitability, NY REV Distributed System Implementation Plan," Joint Utilities of New York, Jul. 2016.

[17] D. Cai, E. Malladay, and A. Wierman, "Distributed Optimization Decomposition for Joint Economic Dispatch and Frequency Regulation," Proceedings of IEEE CDC, 2015.

marginal price type approach such as distribution marginal pricing (DMP) is that it requires accurate distribution grid state information and the means to estimate power flows in the next time increment (e.g., 5 minutes or less). This prerequisite is needed before a DMP-type economic optimization model[18] can be applied.

These approaches to determine short-run marginal cost/price assume that:

1. An accurate digital grid model exists that correctly reflects the topology.
2. Asset information and connectivity of customers and DER is known.
3. An extensive distribution grid sensor network exists with appropriate communications network infrastructure in place (i.e., low latency and high bandwidth communications network).
4. A distributed computing platform at each substation exists to run complex real-time optimization models.

These capabilities are the foundation requirements of these short-run market structure approaches and may not realistically come into fruition until well beyond 2020. While the investments have value for other purposes in a high DER environment like California, it is not clear if they would be cost-beneficial if used only for short-run marginal pricing of grid services, such as constraint management, for which there are other potentially less costly solutions.

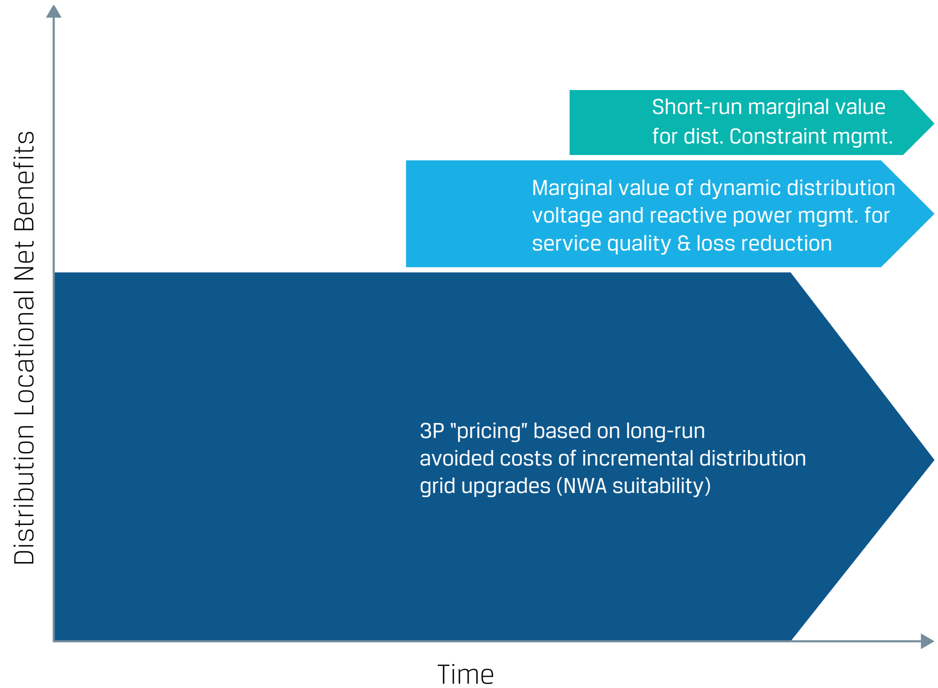
Evolutionary Pathway

Distribution markets for grid services are currently under development in several states. We believe that these markets and mechanisms will follow a Pareto-based pathway to maximizing the net value for all customers. This pathway is based on pursuit of the highest value potential with the simplest, least cost to implement approach to market development. For these reasons and those described earlier, we believe that the market will develop sequentially for long-term solutions (e.g., distribution capacity deferral), operational controls (e.g., reliability, resilience, and voltage management), and perhaps ultimately short-run operational cost savings from services such as congestion management and dynamic loss reduction, as illustrated in Exhibit 6.

[18] Caramanis, et al., "Co-Optimization of Power and Reserves in Dynamic T&D Power Markets with Nondispatchable Renewable Generation and Distributed Energy Resources," Proceedings of the IEEE, 2016.

Regulators and developers of distribution-level markets should view markets as tools rather than ends in themselves and should carefully assess any given distribution system requirement or policy objective, whether the proposed market achieves incremental net benefits for all customers.

EXHIBIT 6: DISTRIBUTION MARKET EVOLUTION



Source: Paul De Martini/ICF

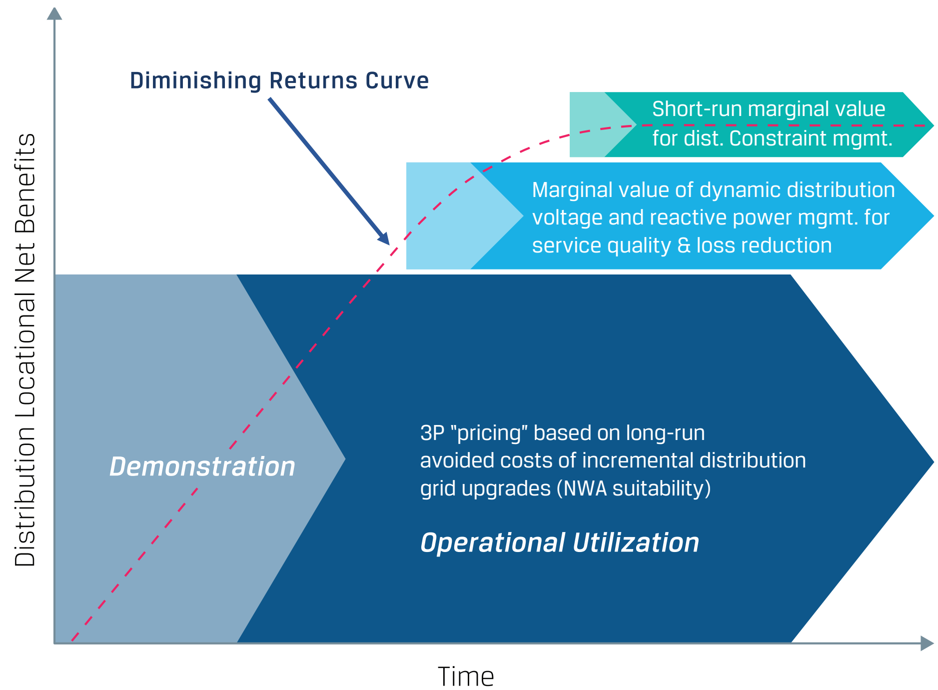
The value of distribution grid services follows a diminishing returns curve that reflects the rising incremental costs and operational risks with each increment of potential economic efficiency gain. It is, therefore, essential to assess this incremental value from additional operational market mechanisms and related complexity/cost in the context of realizing net customer benefits. Operational market development, therefore, requires a thorough evaluation of the operational risks[19] associated with increasing complexity of the market system for each increment of expected efficiency gain. It is not clear to us that pursuit of DMP-type markets as described in academic papers and transactive energy literature will provide net benefits for customers and support a commercially-viable market for DER providers or not impose material operational risks on grid operators.

However, at this stage of distribution system market evolution, it is clear that tangible value can be derived from the deployment of DER, particularly where there are opportunities for NWA to replace long-term capital upgrades and provide potential long-run avoided costs through the use of "3-P's" for sourcing DERs. As more DER is deployed on the distribution system, real-time operational controls will be required, and that value can be delivered from deployed or new DERs with the required attributes. By this point, around 60–80% of the available distribution locational net benefits may be captured. As discussed earlier, the cost to

[19] P. De Martini, "Risky Business," Transmission & Distribution World, 2013.

achieve capture of the remaining locational net benefits may be substantial. The evolutionary path we envision certainly does not preclude moving toward this last increment of value, but it does recognize and suggest that our focus in the near term should be toward developing tools, processes, and technology to efficiently capture the largest value components in the near term. If we are successful in this regard over time, we may determine that the optimal value to be derived from DER may not require investments to determine and capture all of the short-run operational cost savings from services, such as congestion management and dynamic loss reduction, as shown in Exhibit 7.

EXHIBIT 7: NET VALUE MAXIMIZING PATHWAY FOR DISTRIBUTION MARKETS



Locational Net Benefits = Locational Value of DER – (System Integration Costs + Operational Risks)

Source: Paul De Martini/ICF

Conclusion

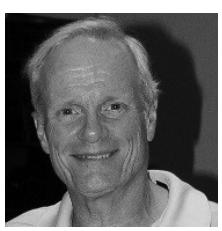
The increasing deployment of DER across the distribution system will require more sophisticated methods of integrated distribution planning and valuing customer DER as potential system resources. An important first step is realizing the potential for NWA services to defer distribution infrastructure investments. This is beginning to occur through demonstrations in California, Hawaii, Minnesota, and New York. However, these demonstrations will need to transition into institutionalized practices over the next 2–5 years. There is considerable effort and investment required to do so, as reflected in California and New York working group discussions and recent utility distribution plans and rate cases. Getting this right is important, as the largest potential avoided cost is in long-term distribution upgrade deferrals. The additional value from smart inverters for voltage management is dependent on changes in interconnection standards, regulatory rules, and technology upgrades by 2020. Value realization related to complex real-time operations are highly dependent on sophisticated infrastructure investments that may occur over the next decade, if cost effective.

As states transition away from simple NEM feed-in tariffs, the ability to accurately value the net benefits of DER on the distribution system will become increasingly important. But, this value is just one of four potential components of a post-NEM tariff structure that may include a distribution access charge, customer charge, energy price for purchases and sales, and a locational value. As such, the role of markets is important to consider in context. Markets are not an end in themselves but an enabling mechanism that have a role, when accompanied by proper operational controls, in valuing DER and realizing their "true" value for all customers.

Additionally, assessing and realizing the potential value of DER will require an evolution in distribution planning as well as significant investments in grid modernization. In our next paper, "Enabling the Value of DER Through Grid Modernization," we draw on our extensive experience supporting distribution system investment planning and related regulatory filing development. This grid modernization paper will lay out the capabilities and systems that need to be deployed along different stages of DER adoption and distribution market development and valuation addressed in this paper.

About the Authors

Paul De Martini has more than 35 years of experience in the power industry. He supports ICF's global strategy in the evolving electricity sector. He is also a visiting scholar at the Resnick Institute at Caltech. Previously, Mr. De Martini held several executive positions focused on strategy, policy, and technology development, including chief technology and strategy officer for Cisco's Energy Networks Business Unit and vice president of advanced technology at Southern California Edison (SCE).



Dale Murdock Dale Murdock has over 38 years of experience in the utility and energy industry sectors. Mr. Murdock has a deep background in electric utility industry operations, wholesale and retail electric and natural gas market development and participation, utility strategic planning & business analysis, utility-scale information systems and technology needs assessments, procurement strategy, vendor proposal evaluation and procurement contract negotiations. Significant engagements have included solicitation, evaluation for Southern California Edison's Distributed Energy Resource Management System, and grid modernization platform roadmaps for SCE, Hawaiian Electric and First Energy.

Dale was previously an officer at PG&E Corp in both unregulated and regulated wholesale and retail natural gas and electric market operations and earlier in generation operations. He holds an MBA from St. Mary's College and BSME from CSU-Chico. He is a California licensed professional engineer.

Steve Fine is a Vice President with ICF and leads the Distributed Energy Resources Team. Steve has particular expertise in evaluating the economics of conventional and renewable energy resources—both central station and distributed generation—within the context of developing technologies, market design and environmental regulations. He works with many of the major U.S. power companies and developers in evaluating the impact of distributed energy resources (DER) on their system and the implications for their business models and their distribution system planning and operations.

He has published numerous whitepapers on the Value of Solar and Distributed Resources and is actively working with the DER team to develop innovative analytical frameworks that can be used by utilities and third parties to more accurately assess the value of these resources in the context of system planning and operations.

Brenda Chew is an Associate with ICF's Energy Advisory and Services practice and supports the Integrated Demand Side Resources (iDSR) Team. Brenda assists clients with national and state level grid modernization efforts, as well as supports clients' customer-centric strategy planning efforts assessing future utility business models, services, and metrics. Currently, Brenda serves as Deputy Project Manager for a national effort to define the next generation's distribution system (DSPx) in conjunction with the Department of Energy, key state commissions, national labs, and other industry stakeholders. Brenda has previously worked on projects analyzing distributed energy technology trends and manages ICF's SolarFlare model, which evaluates impacts of solar PV economics and regulatory environments. Brenda holds an MSc in Sustainable Development from the University of St. Andrews and a BA in Economics and Environmental Studies from Emory University.

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