FUTURE ELECTRIC
Utility Regulation

DISTRIBUTION SYSTEMS IN A HIGH DISTRIBUTED ENERGY RESOURCES FUTURE

Planning, Market Design, Operation and Oversight

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[1] Ideas presented in this report are for discussion purposes only and do not reflect the views or policies of the California ISO.

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Foreword by U.S. Department of Energy

The provision of electricity in the United States is undergoing significant changes for a number of reasons. The implications are unclear.

The current level of discussion and debate surrounding these changes is similar in scale to the discussion and debate in the 1990s on the then-major issue of electric industry restructuring, both at the wholesale and retail level. While today's issues are different, the scale of the discussion, the potential for major changes, and the lack of clarity on implications are common to both time periods. The U.S. Department of Energy (DOE) played a useful role during the 1990s' discussion and debate by sponsoring a series of papers that illuminated and dug deeper on a variety of issues being discussed at that time. Topics and authors were selected to showcase diverse positions on the issues, with the aim to better inform the ongoing discussion and debate, without driving an outcome.

Today's discussions have largely arisen from a range of new and improved technologies, together with changing customer and societal desires and needs, both of which are coupled with possible structural changes in the electric industry and related changes in business organization and regulation. Some of the technologies are at the wholesale (bulk power) level, some at the retail (distribution) level, and some blur the line between the two. Some of the technologies are ready for deployment or are already being deployed, while the future availability of others may be uncertain. Other key factors driving current discussions include continued low load growth in many regions and changing state and federal policies and regulations. Issues evolving or outstanding from electric industry changes of the 1990s also are part of the current discussion and debate.

To maintain effectiveness in providing reliable and affordable electricity and its services to the nation, power sector regulatory approaches may require reconsideration. Historically, major changes in the electricity industry came with changes in regulation at the local, state or federal levels.

The U.S. Department of Energy (DOE), through its Office of Electricity Delivery and Energy Reliability's Electricity Policy Technical Assistance Program, is funding a series of reports, of which this is a part, reflecting different and sometimes opposing positions on issues surrounding the future of regulation of electric utilities. DOE hopes this series of reports will help better inform discussions underway and decisions by public stakeholders, including regulators and policy makers, as well as industry.

The topics for these papers were chosen with the assistance of a group of recognized subject matter experts. This advisory group, which includes state regulators, utilities, stakeholders and academia, work closely with DOE and LBNL to identify key issues for consideration in discussion and debate.

The views and opinions expressed in this report are solely those of the authors and do not reflect those of the United States Government, or any agency thereof, or The Regents of the University of California.

Key Definitions

Throughout this report we use the following key terms, italicized in the first use:

Balancing Authority (BA) is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within an electrically-defined Balancing Authority Area (BAA), and supports Interconnection frequency in real time. A utility TSO or an ISO/RTO may be a balancing authority for an area.

Distributed Energy Resources (DERs) include clean and renewable distributed generation systems (such as high-efficiency combined heat and power and solar photovoltaic systems), distributed storage, demand response and energy efficiency. Plug-in electric vehicles are considered as part of distributed storage. While not included in the formal definition of DER, this report also considers the implications of customer back-up generation on grid operations given that over 15 percent of U.S. households have either a stationary or portable back-up generator to enhance their reliability.[1]

Distribution System is the portion of the electric system that is composed of medium voltage (69 kV to 4 kV) sub-transmission lines, substations, feeders, and related equipment that transport the electricity commodity to and from customer homes and businesses and that link customers to the high-voltage transmission system. The distribution system includes all the components of the cyber-physical distribution grid as represented by the information, telecommunication and operational technologies needed to support reliable operation (collectively the "cyber" component) integrated with the physical infrastructure comprised of transformers, wires, switches and other apparatus (the "physical" component).

Distribution grids today are largely radial, with sectionalizing and tie switches to enable shifting portions of one circuit to another for maintenance and outage restoration. Some cities have "network" type distribution systems with multiple feeders linked together to provide higher reliability.

Distribution System Operator (DSO) is the entity responsible for planning and operational functions associated with a distribution system that is modernized for high levels of DERs. The term DSO is not intended to imply the need for a different entity from the existing utility. Although the term is becoming more widely used in industry discussions, it does not yet indicate a single, well-defined business model, organizational structure or complete set of functional capabilities, nor does it need to. Rather, we adopt the term DSO simply to recognize that distribution operations of the future will have some functional capabilities beyond those of utility distribution operators today, if for no other reason than to be able to plan and operate the system reliably with large amounts of diverse DER and multi-directional energy flows. Depending on policy choices in each jurisdiction, the DSO may be limited to the minimal functions needed for high-DER operations, or may expand to a more proactive role in guiding DER deployment to meet locational needs or facilitating or "animating" markets for DERs and prosumer energy-related transactions. In this report, we assume that the practicality of real-time operation requires that there

[1] Generac, Inc., Generac Investor Day presentation, slide 9, May 20, 2015: http://investors.generac.com/phoenix.zhtml?c=232690&p=irol-presentations.

can only be one DSO for each LDA. Thus, the DSO is a regulated entity for the LDA it operates. A given DSO entity may likely operate more than one LDA within a specific geographic area.

Distributed System Platform (DSP) and DSP provider[2] are the terms used in the New York REV proceeding to refer, respectively, to a set of distribution system functions and a distribution utility that is responsible for those functions, including distributed resources planning, distribution market operations, and operational coordination of DERs on an open and non-discriminatory basis to enable wholesale and distribution market opportunities for DERs.

Distribution Utility or Distribution Owner (DO) is a state-regulated private entity, locally regulated municipal entity, or cooperative that owns an electric distribution grid in a defined franchise service area, typically responsible under state or federal law for the safe and reliable operation of its system. In the case of a vertically integrated utility, the distribution function would be a component of the utility. Although the regulatory frameworks of these different types of distribution utilities may have considerable differences, by focusing first on the operational and planning functions related to the physical distribution wires system, we hope to identify impacts and requirements of DER expansion that would be common to all.

This definition excludes the other functions that an electric utility may perform depending on the applicable regulatory structure. This is done in order to concentrate on the distribution wires service without confounding it with other issues such as retail electricity commodity sales or other potential customer services, and ownership of generation for a vertically integrated utility.

Integrated Grid is an electric grid with interconnected DERs that are actively integrated into distribution and bulk power system planning and operations to realize net customer and societal benefits.

Independent DSO (IDSO) is an independent, state-regulated entity established to plan an integrated distribution system, procure DER services to operate the distribution system, and facilitate distributed energy markets in a non-discriminatory, open-access manner that ensures the safety and reliability of the distribution system. “Independent” means that the DSO is not affiliated with the buyers or sellers of wholesale or retail energy or capacity, or with the owners of the physical distribution assets. IDSO is a concept being discussed and not yet in operation.

Independent System Operator (ISO) or Regional Transmission Organization (RTO) is an independent, federally regulated entity that is a Transmission System Operator, a wholesale market operator, a Balancing Authority and a Planning Authority.

Local Distribution Area (LDA) consists of all the distribution facilities and connected DERs and customers below a single transmission-distribution (T-D) interface on the transmission grid. Each LDA is not electrically connected to the facilities below another T-D interface except through the transmission grid. For purposes of our analysis, each LDA will have a single DSO responsible for safe and reliable real-time operation, though a given DSO may operate multiple LDAs.

[2] New York PSC, Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

Markets as referred to generically in this report include any of three types of markets: wholesale, distribution, and retail customer energy services. Markets for sourcing non-wires alternatives for distribution may employ one of three general structures: prices (e.g., spot market prices based on bid-based auctions, or tariffs with time-differentiated prices including dynamic prices); programs (e.g., for energy efficiency and demand response) or procurements (e.g., request for proposals/offers, bilateral contracts such as power purchase agreements).

Net Load is the load measured at a point on the electric system resulting from gross energy consumption and production (i.e., energy generation and storage discharge). Net load is often measured at a T-D Interface and at customer connections.

Regulator is the entity responsible for oversight of the essential functions of the electric utility, including funding authorizations for power procurements, investments and operational expenses. This oversight extends to rate design, planning, scope of services and competitive market interaction. Throughout this report we use the term regulator in the most general sense to include state public utility commissions, governing boards for publicly owned utilities and rural electric cooperatives, and the Federal Energy Regulatory Commission (FERC).

Scheduling Coordinator is a certified entity that schedules wholesale energy and transmission services on behalf of an eligible customer, load-serving entity, generator or other wholesale market participant. This role is necessary to provide coordination between energy suppliers, load-serving entities and the transmission and wholesale market systems. This entity may also be a wholesale market participant.

Transactive Energy as used in this report refers to the Gridwise Architecture Council definition:[3] techniques for managing the generation, consumption or flow of electric power within an electric power system through the use of economic or market-based constructs while considering grid reliability constraints. Transactive energy refers to the use of a combination of economic and control techniques to improve grid reliability and efficiency.

Transmission-Distribution interface (T-D interface) is the physical point at which the transmission system and distribution system interconnect. This point is often the demarcation between federal and state regulatory jurisdiction. It is also a reference point for electric system planning, scheduling of power and, in ISO and RTO markets, the reference point for determining Locational Marginal Prices (LMP) of wholesale energy.

Transmission System Operator (TSO) is a federally regulated entity responsible for the safe and reliable operation of a transmission system. A TSO may be a functional division within a vertically integrated utility, a separate agency such as the Bonneville Power Administration and Tennessee Valley Authority, or a function of an ISO or RTO.

[3] GridWise Architecture Council, GridWise Transactive Energy Framework, Version 1.0, January 2015.

Executive Summary[4]

A. Objectives and Summary

The growth in volume and diversity of distribution-connected, distributed energy resources (DERs) is driving an evolutionary process that is reshaping infrastructure planning, grid operations, energy markets, regulatory frameworks, ratemaking, and utility business models across the nation. To state regulators and policy makers trying to guide DER growth to maximize net benefits for ratepayers and society as a whole, these changes raise disparate issues that may appear to need to be addressed all at once. This report offers a practical framework to consider DER growth and address its impacts in a logical sequence, in order to guide *distribution system* evolution with clear lines of sight to overarching regulatory and public policy objectives.

An emphasis throughout this report is the need to ensure reliable, safe and efficient operation of the physical electric system, including the distribution system itself as well as its interfaces with interconnected customers, DERs and the bulk electric system.

The framework described here uses several complementary approaches to analyze possible versions of a future high-DER electric system from both a static structural perspective and an evolutionary perspective:

Evolution Based on Creating Net Value for Customers

- A three-stage evolutionary structure for characterizing the current and anticipated future state of DER growth in a given jurisdiction, with stages defined by the volume and diversity of DER penetration plus the regulatory, market and contractual framework in which DERs can provide products and services to the distribution utility, end-use customers and potentially each other
- Various models for re-thinking the value of the distribution system in a high-DER future, to explore the incentives for end-use customers to remain connected to the grid rather than defect
- Descriptions of the major categories of markets that could be created at the distribution level for DER participation in each of the three evolutionary stages

Structured Architectural Orientation

- A whole-system architecture framework that begins with the high-level public policy objectives of greatest importance to the jurisdiction and then derives the qualities (e.g., performance characteristics, observable outcomes) the electric system must embody to achieve those objectives
- Descriptions of the functional capabilities a distribution utility will need—starting with real-time operation and distribution system planning—to provide reliable and safe distribution service in each of the three evolutionary stages

[4] Key terms are italicized in the first use and explained in the Key Definitions section at the beginning of this report.

- Examination of the interface between the high-DER distribution system and the bulk electric system and wholesale market, specifically to consider how best to specify roles and responsibilities for DER coordination and wholesale market participation between the distribution system operator (DSO) and the transmission system operator (TSO, ISO or RTO)
- Discussion of key criteria and trade-offs for regulators and policy makers to consider in determining the appropriate organizational structure for the DSO in their jurisdiction at higher levels of DER penetration—in particular, criteria for addressing whether to enhance functional capabilities of the existing distribution utility or create a separate, independent DSO entity

Building on these approaches and tools, the report offers a structured sequence that state regulators and policy makers can use to assess options and develop a preferred high-DER system for their jurisdictions:

1. Start with a clear statement of the state and local policy objectives for the jurisdiction.
2. Using the three-stage system evolution scheme, identify which stage the system is in currently and, based on the policy objectives, identify which stage is anticipated or desired in the near term (next five years or so) and in the longer term (beyond five years).
3. From the policy objectives, derive the system qualities the high-DER system must exhibit to achieve the objectives.
4. Determine the functional capabilities the distribution system must have to produce the required system qualities. Specifying the current and future evolutionary stages is crucially important for making the more detailed policy, design and implementation decisions needed to achieve the desired outcomes. Such decisions determine how to provide the needed functional capabilities: who are the key actors and what are their roles and responsibilities, what regulatory and business processes are needed, what technologies are needed, at what points would standards be most effective, what roles should markets play and what are the best types of markets to meet the needs, and more. All of these choices should be made in the context of the specific evolutionary stage the jurisdiction is starting in and the one to which it wants to move.
5. Building on these decisions and specifications, undertake the policy and design activities described above in the following sequence:
    - Step 1: physical capability and operation of the distribution system
    - Step 2: market structures and development
    - Step 3: organizational structure for realizing policy objectives

In undertaking this process, it is important to recognize that the growth of DERs in the electric system, unlike previous major shifts in the industry, is being largely driven by customer choice enabled by technological advancement. That means there are limits to the ability of regulators and policy makers to control outcomes. Many DER technologies will continue to get more powerful and less costly, and customers will adopt them for a variety of reasons. Local jurisdictions, for both physical and economic resilience, will take advantage of new ways to achieve synergies between electric service and municipal functions including water supply, wastewater treatment and local transportation. At the same time, overarching state and national policy objectives will continue to have significant impact.

In this combined top-down and bottom-up transformation process, the tools and approaches of system architecture can be of immense value. The architectural problem is to design the high-DER distribution

grid of the future to provide reliable, safe and efficient operation of the whole system, from regional interconnections to customer premises, while allowing for the maximum degree of flexibility for individual customers and local areas to adopt DER-based solutions that best meet their needs. The key questions for utility regulators, then, are how best to define the value of the distribution network and related operational structure for a high-DER future in their jurisdictions, and how to structure the regulatory framework and rules to enable that future. The authors hope this report will be helpful for addressing those questions.

B. Structure of Report

This report is organized as follows:

Section I (Introduction) describes the objectives of the report and the analytical approach and holistic perspective employed. It also explains how this report relates to the first report in the series, on the institutional arrangements or industry structures that may develop with high DER penetration.

Section II (Distribution System Evolution) provides a three-stage framework for understanding the potential evolution of the distribution system based on the extent of DER expansion driven by policy decisions, technological advancements and individual customer choices. This section also discusses the potential future value of the distribution grid under several models and discusses distributed market constructs. Last, we introduce the concepts of structured versus unstructured evolution as a useful way to characterize the transitions from Stage 1 to Stage 2 and from Stage 2 to Stage 3, respectively.

Section III (DSO Development Criteria and Issues) provides a framework for linking policy objectives with system qualities, to derive criteria for evaluating distribution system development. These criteria are extended though introduction of fundamental trade-offs regarding reliability versus economic efficiency, and deciding between an independent DSO versus the distribution utility as the DSO.

Section IV (Specification of the Distribution System Operator) provides a detailed discussion of the evolving distribution system functions, including integrated distribution planning, operations and markets. An overview of bulk power system and wholesale market operations is provided as a reference for introducing three distribution operational models with respect to the *transmission-distribution interface*. This section also explores the foundational functions of the distribution utility to reliably operate and maintain the grid as well as the new functions that a DSO may be required to perform as the distribution system evolves through the three stages.

Section V (Perspectives on Future Operational Models) evaluates the three distribution operational models to consider how the power system may be operated differently in jurisdictions with different policy objectives. This framework can be used to clarify existing roles and responsibilities and suggest potential pathways for the roles of utilities and the relationship between the transmission system and DSO in later stages of evolution. This DSO framework combined with the three-stage evolution framework of Section II provides structure for a context-based comparison of the pros and cons of an independent DSO versus the distribution utility as the DSO. This section concludes with a schematic diagram that summarizes the functional entities and their interactions in a high-DER electric system.

Section VI (Considerations and Recommendations) presents a set of summary considerations and recommendations for policy makers, regulators, utilities and other stakeholders.

I. Introduction

A. Context and Objectives

Customer adoption of distributed energy resources (DERs), public policy objectives, and rapid improvements in technology costs and capabilities are driving changes in uses of the distribution system. A system originally designed and built for one-way energy flows from central generating facilities to end-use customers will see greater variability and more multi-directional flow patterns as a result of a continuing increase in the amount and diversity of DERs on the system.

Also, engineering standards are changing to allow customer premises to move smoothly and frequently between production and consumption modes. This evolutionary process will require substantial changes to distribution system planning and operation to accommodate new uses of the distribution system and to realize the value that DERs can provide.

In parallel to developments at the distribution level, environmental regulations and other public policy objectives, nationally and in individual states, will lead to greater amounts of renewable energy and capacity on the transmission grid and participating in wholesale markets, combined with retirements of certain fossil-fuel power plants[5] that have been relied on for operational flexibility. Thus, on both the distribution and transmission systems we expect a central focus will be to modernize operating procedures to maintain reliable operation with a more diverse and variable set of resources.

Additionally, the modern grid is increasingly converging with other critical infrastructure such as water[6] and the electrification of transportation. We believe that it is essential to consider electric system evolution in this larger context. Too often, the discussion of distributed resources, markets, operations, regulations and standards narrowly views electricity as if it were disconnected from its uses to support other essential services and could be redesigned apart from these broader societal implications.

This second report in the Future Electric Utility Regulation series focuses on planning, market design, operation and regulatory oversight of the distribution system in a high DER adoption scenario. The report takes a bottom-up approach to reflect that DER adoption is mainly driven by local needs and decisions, and that the impacts of DER proliferation will be felt first at the lower levels of the integrated electricity system. The report assesses alternative ways to structure roles and responsibilities of entities to address technical and operational requirements of the high-DER electric system. We intend this assessment to help inform regulatory decisions. Specifically, this report will provide technical pros and cons for an independent entity or utility-based distribution system operator (DSO)[7] in a manner that is

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[5] This includes older power plants that are functionally obsolete or those retiring for cost or environmental reasons, including those in California affected by once-through cooling water regulation.

[6] Water-related services including municipal water supply, wastewater treatment, and high-volume pumping for irrigation—and in the near future desalination in some areas—are large users of electricity. At the same time, the operation of this equipment can be flexible and offer significant demand response capability to help manage variability and peak system loads. This is one example of increased convergence between electricity and other essential services.

[7] Throughout this report we use the term distribution system operator (DSO) simply to convey the fact that distribution systems in an increasing-DER context will require enhanced operational and planning capabilities beyond what is required under today's paradigm of one-way energy flows from the transmission system to the end-use customer. Our use of the term DSO is not intended to imply the need for a new entity to perform the needed functions; rather, that is a question we

relevant for areas with vertically integrated utilities as well as restructured areas with an *Independent System Operator* (ISO) or *Regional Transmission Organization* (RTO).

In summary, the objectives of this report are to:

1. Provide a logical framework for *regulators* to consider potential changes needed to electric distribution utility operations, infrastructure planning and oversight, starting with early stage grid modernization up to high levels of DER penetration.
2. Describe the major enhanced functional requirements for distribution operations and planning that will be required with increasing DER levels.
3. Compare the pros and cons of creating an Independent DSO (IDSO) versus enhancing the existing distribution utility, under different industry structure contexts and plausible DER scenarios.

To keep the focus on the above objectives, this report considers a scope of distribution utility functions that is limited to those of a distribution wires company—i.e., real-time operation, infrastructure planning and maintenance, and interconnection of loads and resources. This report sets aside the retail load-serving function typically bundled with the distribution wires service. The report does not explore the potential for a distribution utility to provide competitive energy services to customers, to own and operate DER on their systems, or other "new business model" questions that go beyond essential distribution wires company functions. There are active discussions underway in several states about the possibility of removing some of the barriers to utility participation as highlighted in the New York Public Service Commission (NY PSC) Reforming the Energy Vision (REV)[8] proceeding and most recently in decisions by several state regulatory commissions. These questions, while timely and important, are beyond the scope of this report.

B. Anatomy of the Analytical Approach

Although this report is primarily focused on the distribution system, it is important to maintain a whole-system perspective, from the highest level of the regional interconnection[9] down to the end-use customer. The proliferation of DERs in both volume and diversity is having impacts in all aspects of the electricity system and industry. The discussion and recommendations in this report take such impacts into consideration.

The term integrated distributed electricity system[10] is used to denote the high-DER system, to recognize that energy sources and operating decisions will be broadly decentralized and localized, while customers, microgrids and larger DERs continue to benefit from connections to the transmission grid and wholesale markets operated by Balancing Authorities (BAs) such as an ISO, RTO or traditional integrated utility *transmission system operator* (TSO).

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examine later in this report. While this report focuses on distribution systems with high levels of DERs, some parties may have other reasons to consider an independent or utility DSO.

[8] New York PSC Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

[9] A regional interconnection is comprised of all the balancing authority areas (BAAs) that are physically connected to each other to allow electric energy to flow between them.

[10] Staff, The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources, Electric Power Research Institute, 2014.

While maintaining a whole-system perspective, our emphasis on the operational and planning requirements of the high-DER system requires that we focus first on the physical operation and architecture of the basic building block of the new power system—namely, the set of distribution facilities that radiates from each transmission-distribution interface point, plus the DERs and customers connected to those facilities. We refer to this building block as a *local distribution area* (LDA). In today's electric system each LDA must function as a separate operational sub-system with no electrical connection to other LDAs except through the bulk electric system. For purposes of this report we assume this basic fact does not change in the high-DER electric system. Each LDA must be operated reliably to meet local needs, relying on its own functional capabilities, local DER services and its interface with the transmission system.[11]

There also is a higher-level logical sequence that should be followed in developing the design of the future high-DER system, in order to achieve the intended policy objectives most effectively and efficiently. The logical sequence is built on systems engineering and grid architecture principles,[12] which are discussed in more detail in the next section. In brief, the sequence is as follows:

1. Start with articulation of a set of high-level public policy objectives the electric system should achieve.
2. Based on the policy objectives identify the qualities the system should have to achieve those objectives. These qualities should typically be specified in terms of performance characteristics or observable outcomes of the system.
3. Next, consider how to structure the system in terms of basic components or functional elements and the interrelations among them to achieve the desired qualities. At this level, we are specifying the functions the various elements of the system need to perform and how the various functions interact with one another. In terms of the central focus of this report, this step will emphasize the operational and planning functional requirements of distribution systems in the high DER context.
4. Finally, consider who does what—the organizational structures and roles that would be best suited to perform the needed functions addressing a central question framed for this report—whether an independent DSO or utility DSO would be the more appropriate organizational structure.

To illustrate the above logic, this report considers several possible future electric system scenarios, or cases, based on the degree of DER expansion and alternative ways to define the functional roles and responsibilities of the DSO. Given ongoing changes in the industry, changes proceeding at different rates in diverse jurisdictions, and the likelihood that the end-state of the changes will differ by jurisdiction, different conclusions can be reached for the cases we explore.

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[11] DSOs may switch some distribution circuits from one LDA to another to manage distribution system loading and certain real-time operational situations. However, the point for this report is to exclude permanent connections between LDAs to avoid the potential complication of parallel energy flows on the distribution and transmission systems.

[12] J. Taft and AS Becker-Dippmann, Grid Architecture, PNNL-24044, Pacific Northwest National Laboratory, 2015.

II. Distribution System Evolution

A. Stages of Distribution System Evolution

DER adoption in the U.S. is uneven; certain areas have significant adoption while others have nearly none. This is true within a state and even within a utility service area. This patchwork of adoption is currently driven by policy, technological cost-effectiveness, local economic factors and consumer interest. The adoption patterns observed in several states and countries[13] over the past 10 years, along with the related impacts to distribution system operation, can help identify the key issues and decisions. For example, growth in customer adoption of DERs and back-up generation may begin to change the amount, shape and predictability of *net load*, and at higher levels may introduce local multi-directional power flows.

However, high levels of DERs also may provide an opportunity to leverage these resources to optimize grid investments and improve overall power system performance and economic efficiency. For purposes of this report, answers to questions about needed distribution system functionality, optimal design of a DSO and whether an *independent DSO* is desirable will depend on the current and anticipated DER development stage.

Figure 1 shows a three-stage evolutionary framework for the distribution system. This framework is based on the assumption that the distribution system will evolve in response to both top-down (public policy) and bottom-up (customer choice) drivers. Thus, each stage represents the effects of both a set of public policies and increasing customer adoption of DERs. Each level includes additional functionalities to support the greater amounts of DER adoption and the level of system integration desired. Each level expands on the capabilities developed in the earlier stage. The result is an increasingly complex system.

[13] Experience in Hawaii, California, New Jersey and Australia, for example.

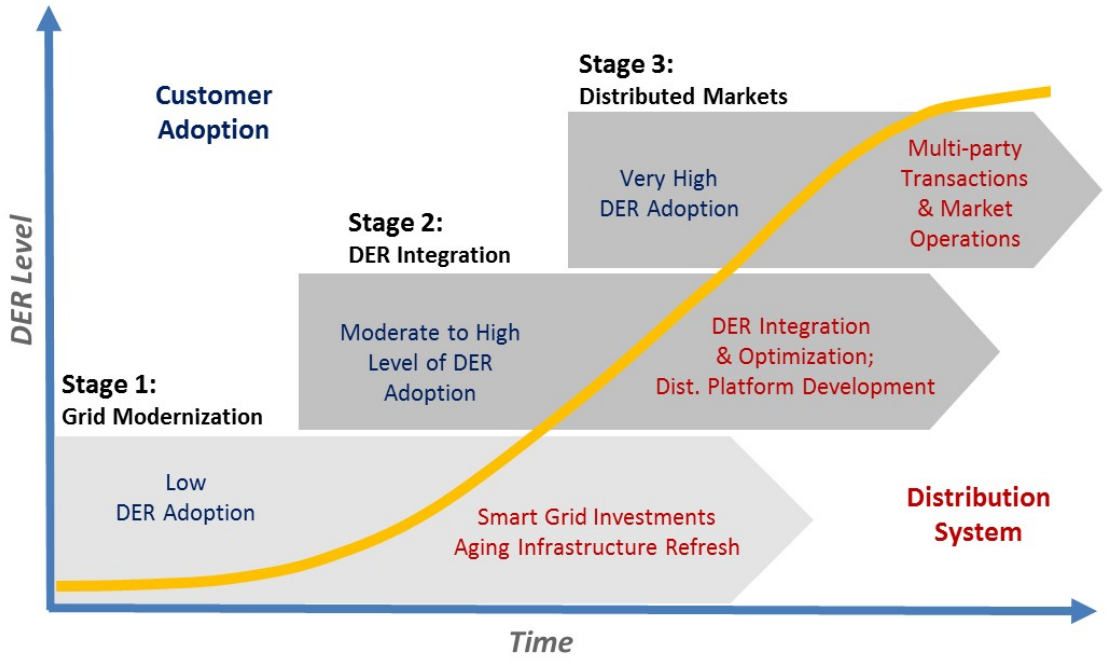

Figure 1. Distribution System Evolution.
We developed a three-stage evolutionary framework for the distribution system driven by its aggregate growth of DERs. The stages are related to the required distribution system changes and potential for DER service transactions at certain thresholds of DER adoption, as experienced in the U.S. and globally to date.

Stage 1: Grid Modernization – This stage represents the state of *distribution utility* grid modernization and reliability investments currently underway or soon to be made. In this stage, the level of customer DER adoption is low and can be accommodated within the existing distribution system without material changes to infrastructure or operations. Most distribution systems in the U.S. are currently at Stage 1. Distribution systems prior to Stage 1 had little automation beyond a substation and largely analog systems. This was the state of distribution systems over 10 years ago.

States in Stage 1 should anticipate customers' propensity to adopt DERs and the implications for growth in interconnection requests and needed changes to distribution planning. States can begin by assessing and streamlining rules and procedures for interconnecting DERs to the system, where barriers to DER implementation can easily arise. As part of these revised procedures, they should consider performing regular engineering assessments of distribution system capacity to integrate DERs ("DER hosting capacity"). Hosting capacity is the amount of capacity on any given portion of the distribution system to accommodate additional DERs with existing and already-planned facilities. In California, for example, this is quantified for individual segments of a feeder.

States wishing to take the next step should consider performing locational value assessments, to identify areas of the distribution system where the addition of DERs would benefit the system by providing real-time operational services or deferring infrastructure investment. Such assessments would help prepare for entering Stage 2.

Stage 2: DER Integration – In this stage, DER adoption levels become material and reach a threshold level that requires enhanced functional capabilities for reliable distribution operation. At these levels,

DERs also have the potential to provide system benefits. For both of these reasons, changes to grid planning and operations are required. The Stage 2 DER adoption threshold, based on DER adoption experience in the U.S. and elsewhere, appears to be when DER adoption reaches beyond about 5 percent of distribution grid peak loading system-wide. This level of adoption typically results in pockets of high customer adoption in some neighborhoods and commercial districts, which creates the need for enhanced functionality inherent in Stage 2.[14] PG&E and other utilities' experience with DER adoption illustrate this situation. Today, installed DER capacity interconnected to the PG&E distribution grid is about 8 percent of peak load system-wide,[15] and the following adoption pattern has emerged:

- 1 percent of all feeders may have DER capacity levels at or near 100 percent of the feeder peak load;
- 3 percent of all feeders may have DER capacity levels exceeding 30 percent of the feeder peak; and
- 8 percent of all feeders may have DER capacity levels greater than 15 percent of the feeder peak.

Bi-directional power flows will begin to be problematic on high DER circuits. In response, more advanced protection and control technologies and operations capabilities will be required to manage these parts of a distribution grid in a safe and reliable manner.

Additionally, the increased level of DERs may provide an opportunity to leverage their value for bulk power system and distribution grid efficiency. Distribution utilities can source services from flexible DERs to support reliable operation or as qualified alternatives to traditional investments. If DERs also can provide services to the bulk power system (which many are doing already via an ISO/RTO market), then the distribution operator and the TSO must also coordinate with each other to ensure reliable operation of the *integrated grid*.

California and Hawaii are in Stage 2 based on DER adoption and public policy decisions. While some jurisdictions are envisioning *markets* at distribution level, in Stage 2 we only need to think about procurement mechanisms for the distribution operator to procure services from DERs. Thus, Stage 2 markets would have a single buyer—the distribution operator—and would not involve distribution-level energy sale-for-resale transactions that could raise federal-state jurisdictional issues.

The New York REV proceeding is also instituting policies to integrate the value of DERs into bulk power system and distribution system optimization. The near-term markets being discussed in New York are effectively the same as those discussed in California and Hawaii. That is, the distribution operator will obtain services from DERs to support reliable operation and cost-effectively defer or avoid distribution infrastructure investment and expenses.

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[14] System penetration of DERs to 5 percent of peak load is a nominal guide. Individual portions of the distribution grid may encounter higher levels of DER penetration and will require targeted mitigation and potentially application of advanced solutions to maintain required reliability and safety of the network.

[15] PG&E presentation at CPUC DRP workshop in September 2014: http://www.cpuc.ca.gov/NR/rdonlyres/139F207F-041D-4B7E-92A5-87282537DF63/0/DRPWorkshop_PGE_Distribution_Final.pdf.

Stage 3: Distributed Markets – This conceptual stage results from a combination of high DER adoption and policy decisions to create distribution-level energy markets for multi-sided ("many-to-many" or "peer-to-peer") transactions. Stage 3 is conceptually when DER providers and "prosumers" go beyond providing services to the wholesale market and the distribution utility and seek to engage in energy transactions with each other. This will require regulators to institute changes to allow retail energy transactions across the distribution system, including transactions that are still within a *local distribution area* (LDA) defined by a single T-D interface substation, thus not relying on transmission service.

Enabling such a multi-sided market will require a formal distribution-level market structure to facilitate peer-to-peer energy transactions. In addition to local markets within each LDA, prosumers may also want to transact between LDAs using both the transmission system and the distribution system, placing greater emphasis on coordination between DSOs and TSOs at the T-D interfaces. In this context the DSO role may evolve to include additional market facilitation services such as financial clearing and settlement. Given the regulatory changes and high levels of DER adoption required for Stage 3 to be viable, Stage 3 activities will likely begin in select areas that already have high DER penetration. It is also possible that regulators in areas without significant levels of DERs may want to proactively explore, perhaps initially on a pilot basis, potential efficiency gains and local resilience benefits of such markets.

B. The Value of the Distribution Grid

The value of the distribution grid, and more broadly the interconnected power system, is a timely question. In view of the increasing ease and falling cost with which customers can "defect" from the grid,[16] it cannot be taken for granted that customers will continue indefinitely to find it desirable to remain connected. Because the value of any network is proportional to the number of interacting entities or facilities connected to it,[17] if defection picks up momentum the value of the grid could drop precipitously. Thus, a question for policy makers to consider is whether a vibrant, beneficial distribution grid is important to their policy objectives and, if so, how to modernize it so that customers will prefer to stay connected rather than exit.

Current national and state level discussions are focused on the following three potential paths,[18] on a continuum in terms of increasing value of the grid.

Current Path: This model is based on the current evolutionary path of utility planning and grid modernization roadmaps for replacement of aging electric distribution infrastructure and adoption of smart grid technology. The model assumes an incremental approach, investing in infrastructure as needed to accommodate increases in distributed resource adoption. The model also allows for a proactive jurisdiction that wishes to facilitate DERs to begin streamlining interconnection procedures and performing regular planning studies to quantify hosting capacity and communicate results to customers and the marketplace. Lack of coordination or collaboration among regulators, utilities, DER

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[16] P. Bronski, et al., The Economics of Load Defection, Rocky Mountain Institute and HOMER Energy, 2015.

[17] A formal statement of this principle is known as Metcalf's Law, which characterizes the value of a network in terms of the transaction opportunities among entities attached to the network. For example, if there are N entities on the network, then there are N*(N-1) directional transaction opportunities, so the value of a network of size N is roughly proportional to N^2. Metcalf's Law may be relevant for Stage 3 peer-to-peer markets, but even in Stage 2 the ability of aggregators to aggregate DERs into virtual resources to provide grid services will be greater with more entities connected to the system.

[18] Adapted from P. De Martini, More Than Smart, Greentech Leadership Group-Caltech, 2014.

developers and customers can create gaps in system planning and investment. This may create risk of misalignment of the timing and location of advanced technology investment or substantive changes in distribution design with the pace of DER adoption and preempt future opportunities to realize value from DER integration. Section IV describes new types of planning studies distribution utilities can add to their current planning practices to minimize such risks while maintaining a current-path trajectory.

Grid as Enabling Platform: This model builds on the current investments through accelerated implementation of advanced technology for the grid, along with an evolution of distribution system designs to create a node-friendly or "plug-n-play" grid that enables seamless integration of DERs and independently owned and operated microgrids. The enabling platform concept also supports the principle of "technology-neutral" regulation and market design, which seeks to design rules and opportunities in terms of needed performance and avoids "picking winners" from an evolving field of technologies that might provide the needed performance.

Interactive networks have a unique property in that a greater number of points of interactive connectivity results in nonlinear value creation, or "network effects." An interactive distribution grid has the potential to yield network effects through increasing the number of responsive devices and users of the system. This interaction involves at least three aspects:

- Better alignment of DER locational adoption to shape net load profiles and thereby improve system efficiency and load predictability,
- DERs providing services to the distribution grid and bulk power system, and
- Potential for DERs to engage in transactions across the distribution system.

This type of electric distribution platform is envisioned in New York. Failure to seize this potential in the face of accelerating customer DER adoption may lead to an erosion of value if customers seek to self-optimize more fully than the existing regulatory framework allows and then substantially reduce their use of the distribution system or, in more extreme situations, disconnect from the grid.

Convergence: This model envisions the convergence[19] of an integrated electric network with water, natural gas, transportation systems, and other municipal services such as wastewater treatment and solid waste management, to create more efficient and resilient infrastructure, enable long-term economic vitality, and meet environmental and other public policy objectives of the jurisdiction. Convergence of networks is the integration of two or more networks into a unified system to create value that is intrinsically synergistic. The current California regulatory proceeding on the water-energy nexus[20] is an example of exploration of the potential synergies. Also, many "smart city" initiatives are designing integration of multiple essential services to enhance long-term resilience and sustainability.[21] In such initiatives the modernized distribution system and the DSO can play a crucial role as enabling infrastructure.

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[19] P. De Martini and J. Taft, Value Creation through Integrated Networks & Convergence, Caltech-PNNL, 2015.

[20] CPUC R.13-12-011; Water/Energy Nexus proceeding: http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Water-Energy+Nexus+Programs.htm.

[21] Smart Cities Council: http://smartcitiescouncil.com/.

C. Distributed Markets

In its Reforming the Energy Vision proceeding, the New York PSC stated:[22]

> *"REV will establish markets so that customers and third parties can be active participants, to achieve dynamic load management on a system-wide scale, resulting in a more efficient and secure electric system including better utilization of bulk generation and transmission resources. As a result of this market animation, distributed energy resources will become integral tools in the planning, management and operation of the electric system. The system values of distributed resources will be monetized in a market, placing DER on a competitive par with centralized options. Customers, by exercising choices within an improved electricity pricing structure and vibrant market, will create new value opportunities and at the same time drive system efficiencies and help to create a more cost-effective and secure integrated grid."*

This statement and similar discussions in other states encompass three types of markets that should be clarified in order to understand potential market evolution and consider the functions of a DSO and related jurisdictional issues over time:

1. **Wholesale energy and operational markets:** DER opportunities to participate in wholesale markets exist today to various degrees across the U.S. under the jurisdiction of the Federal Energy Regulatory Commission (FERC). DERs are increasingly providing a number of wholesale services including energy, generation capacity, transmission capacity deferral, and ancillary services necessary to operate the system. DER participation may occur as supply side or load modifying resources[23] depending on the nature or configuration of the DER and market rules, may be connected to the utility's distribution grid or at end-use customer premises, and may be aggregated to comprise larger "virtual" resources.

2. **Distribution operational market:** This is a new structure that involves creating opportunities for DERs to be considered as alternatives to utility capital investment or operational expense. The potential types of services may include distribution capacity deferral, steady-state voltage management, transient power quality, reliability and resiliency, and distribution line loss reduction. The distribution utility would procure these services, in lieu of traditional expenditures, to meet its statutory obligations for a safe, reliable distribution grid. The distribution planning process defines the need for these operational services. This type of market is contemplated to become viable as a characteristic feature of Stage 2 of the grid evolution.

3. **Distribution energy market:** This is a conceptual structure that involves DER providers, energy services providers, and customers or prosumers buying and selling energy commodity across a local distribution system—at delivery points that bypass the transmission system, if both sides

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[22] NY PSC, Case 14-M-0101, Order Adopting Regulatory Policy Framework and Implementation Plan, Feb. 26, 2015, at p. 11.

[23] The California PUC's "bifurcation" policy for demand response resources distinguishes "load modifying" resources whose impacts are quantified and taken into account in formulating the state's demand forecasts to be used for procurement and planning purposes, versus "supply side" resources that become part of the total portfolio of resources to meet forecasted needs and are required to be available to the CAISO for commitment and dispatch when and where needed to manage system conditions.

of the transaction are within the same LDA, or using the transmission system if the two sides are in different LDAs. Such a peer-to-peer market may involve two structures: a) bilateral forward energy transactions, and b) the creation of an organized residual energy spot market. Both types of structures would likely require statutory and regulatory changes, because some energy transactions of this type—for example, when the buyer is a load-serving entity rather than an end-user—may be considered to be sales for resale and therefore FERC-jurisdictional.

Section IV identifies the new functions and capabilities that will be required of distribution operators to support these types of markets.

D. Structured Versus Unstructured System Evolution

To better understand the implications of the three developmental stages just described, it is useful to distinguish between what we consider "structured" and "unstructured" industry evolution. These are two very different models for how change can occur in a large-scale complex system: a) gradual change guided by policy, regulation and adaptation on the part of the existing system structure ("structured") and b) dramatic change driven by customers and external forces such as technology and business innovation that disrupts the existing structural elements and their relationships and requires more systemic reorganization of the system ("unstructured"). In the electricity industry context, these two models have different implications for operations, planning and markets, and for how regulators think about the reforms needed to their regulatory framework.

Structured evolution occurs without significantly disrupting the existing industry structure, through measured policy and regulatory changes that affect the pace of DER adoption to a considerable degree. The growth of DER adoption in Stage 1 is an example of structured evolution. It is more a process of adaptation to changing conditions, or accommodation or integration of new entrants and technologies, rather than a dramatic change in paradigm. Structured evolution in the electricity industry includes keeping pace with demographic shifts and economic factors, as well as integration of new technologies that may alter how energy is produced and used, provided such technologies do not challenge the structural paradigms that characterized the industry and its major players.

In today's electricity industry, utilities plan for and accommodate demographic and economic changes and trends, and integrate all sorts of new technologies, including smart meters, utility-scale variable renewable generation, and diverse new end uses such as electric vehicles and computers and other energy-intensive electronics. Structured evolution through policy and regulation enables orderly growth of DERs to align with overall net customer value, including DER participation in the wholesale market and DER provision of services to the distribution utility. These structured changes do not substantially alter the predominance of central station generation, one-way energy delivery, and clear delineation between wholesale markets (for energy and capacity at the transmission level) versus retail markets (for electricity supply to end-use customers).

In contrast, the revolutionary step to Stage 3—a high-DER, more decentralized power system with peer-to-peer energy trading across the distribution system—is what we call unstructured. This will become more apparent when we discuss the Market DSO later in this report. To meet the needs of a Stage 3 system, the DSO must either expand its functions dramatically to include operation of energy spot markets at distribution level and complex coordination with the TSO at the T-D interface, or leave these functions to another entity. These new market functions should be designed from a whole-system architecture perspective—as an explicit paradigm shift—rather than allowing them to develop through a process of gradual accretion of new activities.

Each state and locality will experience customer adoption at a different pace based on the structured parameters for DERs and if and when the cost-effectiveness of a DER solution equals or is less than the customer's cost of electric service. Reaching such retail parity is a function of increases in retail electric rates for end-use customers and declines in cost of DER technology over time as well as efficiency improvements. For example, much attention is paid to the declining price of solar, but less so to the equally important fact that the efficiency of solar panels has been steadily increasing. Similarly, energy storage has made significant gains in cost-effectiveness. With such technology-driven improvements, the ability for policy makers and regulators to shape the pace and dispersion of customer DER adoption will diminish. At the same time, as the cost of DERs reach parity, they become more attractive to the system for operational services and infrastructure deferral. This should make it attractive for regulators and distribution utilities to accelerate DER deployment in the near term where net benefits can be achieved while leveraging the existing distribution grid.

The immediate point, however, is that most participants from all corners of the industry seem to perceive the current process of change as the structured variety. They tend to think of managing the evolutionary process through incremental changes to current structural elements and processes, rather than recognizing a need for entirely new approaches to operations, planning, markets and regulatory frameworks. In the next few sections we offer a detailed framework for considering the changes that may be needed, anticipating continued acceleration of technological innovation and rising customer expectations.

As Bill Gates observed, "*We always overestimate the change that will occur in the next two years and underestimate the change that will occur in the next ten.*"[24]

III. DSO Development Criteria and Issues

A. Criteria for Evaluating Distribution Systems

The electricity system in the U.S. is a complex, ultra-large scale machine.[25] This complex system has many interdependent components that must work harmoniously to ensure safe and reliable service. Any material changes to the system need to be considered holistically, while still paying sufficient attention to the crucial building blocks of the system such as the LDA and the T-D interface. This report therefore employs a systems engineering approach to questions about distribution system development, including new functionality and roles.

The first step starts with identifying policy objectives and customer needs to define system qualities and, by extension, the distribution system design and operational requirements. Some policy objectives may seem to be universal at the abstract level, such as safety and reliability. But as we probe more deeply to consider how to implement them, they reveal local flavors and nuances based on the unique jurisdictional preferences, local societal and environmental concerns, customer mix and adoption rates, and existing distribution system capabilities. Just as each distribution feeder is unique due to

[24] Bill Gates, The Road Ahead, Penguin Books, 1996.
[25] P. Schewe, The Grid: A Journey Through the Heart of Our Electrified World, Joseph Henry Press, 2007.

configuration and load characteristics, there will not be a singular DSO model that is preferred or optimal for all jurisdictions.

In its 2015 Grid Architecture report,[26] the Pacific Northwest National Laboratory (PNNL) identified a list of policy categories useful for specifying more refined, locally defined objectives for each policy category and their implications for specific system requirements:

- Safety
- Robustness (reliability and resilience)
- Security
- Affordability
- Minimum environmental footprint
- Flexibility (extensibility and optionality)
- Financeability (utility and non-utility asset)

This list reflects objectives that regulators in virtually all jurisdictions consider important, though to varying degrees and with varying priorities. Regulators and stakeholders will need to establish priorities and specify more refined and possibly more localized sub-objectives (or system qualities in the terminology of grid architecture), in order to make these high-level objectives concrete enough for regulatory decision-making and implementation. An architectural approach can be used to align the specific aspirational requirements—in the form of desired system qualities—to the jurisdiction's unique local policy objectives and priorities. As noted in the Grid Architecture report, "A good set of qualities … should be as nearly discrete as possible, should be as specific and quantifiable as possible, and should be prioritized...."[27] Figure 2 illustrates examples of system qualities grouped under the policy categories listed above.

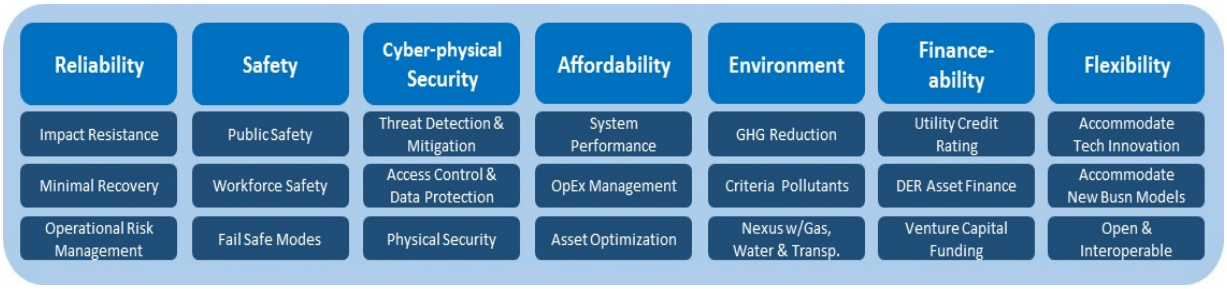

Figure 2. Distribution System Objectives and Qualities[28]
Grid architecture starts by identifying policy objectives and customer needs at a high level, as shown in the top row of this figure. From these objectives regulators establish more refined sub-objectives and desired system qualities, listed below the top row, that are customized to the circumstances and needs of their jurisdictions.

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[26] J. Taft and AS Becker-Dippmann. Grid Architecture. PNNL-24044, Pacific Northwest National Laboratory, 2015.
[27] *Id.*, p. 5.2.
[28] Adapted from P. De Martini, More Than Smart, GTLG-Caltech, 2014.

It is essential to start from the necessity of safe and reliable operation. The system behind electric service is first and foremost a system of wires and other physical equipment, which must obey the laws of physics. It must work safely and reliably, or else the other objectives of change will be at risk. Thus, the first design task is to identify what kinds of functional capabilities the system must have in the high-DER world in order to maintain safe and reliable operation, and then determine how best to provide those functional capabilities—i.e., tools, structures and processes, actors and their inter-relationships (see Section IV for more details).

B. Reliability Versus Economic Efficiency Tradeoff

A central consideration for modernizing the distribution system for high-DER levels, including creation of distribution level markets, is the inherent trade-off between reliability and economic efficiency, as Figure 3 illustrates. Competitive market forces are widely relied on to achieve economic efficiency, so with the expansion of DERs there is growing interest in creating markets at distribution level. Yet while competition may yield net economic benefits, the market structures employed should be carefully evaluated against potential reduction in system reliability.[29] At a minimum, it is essential that physical reliability not be displaced by a desire for "hyper-efficiency" or an untested theoretical belief that ubiquitous implementation of markets will meet all needs of the high-DER electric system.

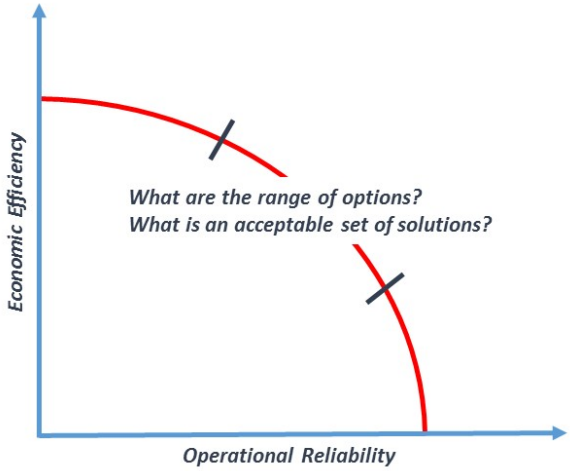

Figure 3. Economic Efficiency Versus Operational Reliability.
A central consideration is the inherent trade-off between economic efficiency and reliability. Maximizing economic efficiency may introduce undesirable operational risks. Conversely, over-investment may create a robust distribution system that is prohibitively expensive. An architectural approach based on clear objectives can achieve desired results through coordinated market designs and control mechanisms.

[29] As an illustration, the restructured spot markets first implemented in California in 1998 were based on large electrical zones that ignored internal grid constraints in order to have "deep and liquid" markets for trading energy. As it turned out, the zonal markets frequently cleared energy transactions that could not feasibly be delivered due to congestion and required costly re-dispatch payments to generators in real-time to maintain reliable operation.

The principle of diminishing returns to complexity is another way to understand this tradeoff. Integrated grid economic efficiency gains through the use of increasingly complex DER markets will follow a diminishing returns curve that reflects the rising incremental costs and operational risks with each increment of potential economic efficiency gain.

Market development therefore requires a thorough evaluation of the operational risks[30] associated with increasing the complexity of the market system for each increment of expected efficiency gain. In other words, regulators and developers of distribution-level markets should view markets as tools rather than ends in themselves and should carefully assess for any given distribution system need or policy objective whether the proposed market is the best solution and can be implemented to exhibit effective competition and technology neutrality. For instance, concepts such as creating spot energy prices on a distribution circuit may create increased complexity, market power opportunities and operational challenges that can lead to fragility. Regulators and system designers should therefore be diligent in defining clear objectives and system qualities they are trying to achieve and should carefully evaluate whether an energy market based on distribution-level locational spot prices is the best way to achieve those objectives.

For these reasons it is important to consider the interrelationship between physical operation of the distribution grid and the use of distribution-level markets to meet specific operational needs.[31] These matters need to be considered holistically when designing the high-DER distributed system.

C. Independent DSO Versus Distribution Utility DSO

A central question posed as a focal point of this report is whether the new functional requirements of a distribution utility in the high-DER context are best provided by a new independent entity or by adding additional responsibilities and capabilities to the existing distribution utility. A new independent entity, generally referred to as an independent DSO or IDSO,[32] would be separate from and unaffiliated with the entity that performs most traditional utility functions, including retail electric service to end-use customers and ownership of the distribution system assets.

As our analysis in a later section explains in detail, we approach this question through the following logic. The first step is to identify the policy or regulatory attributes that guide the choice of an independent or utility DSO. We propose the following key attributes for consideration:

- *Non-discrimination* – Are all types of DERs and DER developers treated in an equivalent and non-discriminatory fashion? This is relevant to the operations functions—scheduling and dispatch[33]—as well as to infrastructure planning and interconnections.[34]

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

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

[32] J. Tong and J. Wellinghoff, Rooftop Parity, Public Utilities Fortnightly, August 2014.

[33] The term dispatch as used here refers to direct and indirect control through economic or control system signals consistent with transactive energy. These signals may be on a range of time dimensions.

[34] Although the focus in this section is on non-discrimination in performance of the DSO's functions, discrimination by either utility or independent DSO can occur in other, more subtle ways that regulators should also be concerned about. For example, opportunities for DERs to provide services to the distribution system might be specified so as to favor certain

- *Transparency* – Are the processes and related decisions for planning, sourcing, operational dispatch and resource interconnection objective, open to impartial audit, visible and understandable to participants?
- *Market power* – Would a utility performing the DSO functions be advantaged in its or its affiliate's retail and wholesale market activities over its competitors? Is an independent DSO more effective in resolving competitive market power issues?
- *Oversight* – Are regulatory provisions that address potential utility discrimination, non-transparency and market power effective in ensuring utility compliance? Do regulatory authorities have the capacity to oversee the expanded functionality and increased complexity of the DSO in a high-DER context?
- *Timing of major decisions* – When in the adoption of DERs and related evolution of the distribution system do the above concerns take on greater urgency? How might an early decision on any of these questions unduly constrain the ability to adapt to changing circumstances or result in stranded investment as system evolution proceeds?

The second step is to identify the industry scenarios in which the question of independent DSO becomes important. Referring to the stages of industry evolution described in the previous section, we will assess this question in the context of Stages 2 and 3 of the evolutionary scheme. In the next section we describe the new functions that will be required in the high-DER system. We suggest that in Stage 1 the additional functions needed are only incrementally greater than what distribution utilities perform today. As we discuss in greater detail in section IV, some of these new functions could be addressed adequately within existing regulatory provisions. However, as regulators anticipate growth of DERs in their jurisdictions with a view toward transition into Stage 2, additional proactive functions they direct their regulated utilities to undertake should be accompanied by careful consideration of the associated regulatory provisions to ensure transparency and non-discrimination related to customer adoption of DERs and grid interconnections.

Today's utilities are subject to FERC interconnection rules for DERs that intend to participate in wholesale markets, and many states have uniform interconnection technical standards, procedures and agreements, mitigating much of that concern. Still, state-jurisdictional interconnection processes typically coexist with FERC-jurisdictional processes in many areas where DER growth is now testing the formerly clear boundaries between them. That said, we believe there are good reasons to support treating the needed new Stage 1 functions under the current regulatory framework as we discuss in section IV.

Another element that we will use to define industry scenarios is the choice of the preferred DSO functional model. In the next section we define three main types of DSO models a given jurisdiction could adapt to its local needs and policy objectives, which differ based on the allocation of roles and responsibilities between the DSO and the TSO in managing the T-D interfaces.

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resource types or providers, rather than in a technology-neutral manner that guards against picking winners or tilting the playing field.

One further element of the scenario specification is whether the area is under an ISO or RTO with wholesale spot markets or under another structure where the TSO is a separate entity from the distribution utility, versus under a vertically integrated utility structure.

Based on the logic just described, we will address the question of independent DSO versus utility DSO, focusing on the ability to ensure the regulatory attributes we specified above, in the context of specific combinations of: a) the stage of industry evolution, b) the choice of DSO model, and c) the existing market or utility structure prevailing in the jurisdiction. For these scenarios, we ask whether an independent DSO is necessary to ensure non-discrimination, transparency, absence of market power, regulatory oversight and optimal timing of major decisions, or whether these attributes can be effectively achieved through other means like functional separation within the utility, standards of conduct, and establishment of fully transparent distribution planning and resource interconnection processes (see Section V).

IV. Specification of the Distribution System Operator

A. Distribution System Functions

Evolution of distribution systems to support the integration of DERs will require changes to grid planning, interconnection procedures and electric system operations, plus the expansion of market opportunities for DERs, to provide services for the operation of the grid and, in some areas, engage in transactions between DERs, other market participants and end-users. The following discussion summarizes emergent and future planning, operational and market functions.

Integrated distribution planning and interconnection

Where distribution systems experience significant levels of DER interconnection, utilities and state regulators will need to consider an evolution to an integrated grid planning process because the existing methods and processes are functionally deficient to address scope and scale required. This need is recognized by laws in California[35] and Hawaii[36] and by regulators and utilities in other states. This integrated planning approach involves a wider and more complex range of engineering and economic valuation issues in a cohesive and multi-disciplinary fashion, with stakeholder participation.

The first step is development of a standardized planning framework, like EPRI's Integrated Grid approach. Such a planning framework would involve several changes and additions to traditional distribution planning, including the following:

- Use DER adoption scenarios linked with a shift from deterministic to probabilistic engineering methods.
- Evolve interconnection studies and update interconnection procedures for DERs based on revised planning methods and to accommodate an expanded volume of requests.

[35] California Public Utility Code §769 and regulation: http://www.cpuc.ca.gov/PUC/energy/drp/.
[36] Hawaii Grid Modernization Law HB1943: http://www.capitol.hawaii.gov/session2014/bills/HB1943_CD1_.htm.

- Establish baseline capacity of the distribution grid to host DERs ("hosting capacity") and link to DER interconnection processes.
- Identify the locational net value of DERs to the grid, which may be positive or negative.
- Integrate transmission and distribution (T&D) planning and specify linkages of these activities to the jurisdiction's demand forecasting and procurement proceedings.

We describe these planning functions below.

Scenario-based, probabilistic distribution planning – The uncertainty of the types, amount and pace of DER expansion make singular forecasts ineffective for long-term distribution investment planning that often spans up to a 10-year horizon. A better approach is to use at least three DER growth scenarios to assess current system capabilities, identify incremental infrastructure requirements and enable analysis of the locational value of DERs (described below). Because many local jurisdictions are now viewing DER development and convergences among essential services as potential elements of climate action and resilience plans, distribution planners can work with these entities to align distribution system planning with emerging local needs.

Additionally, as customer DER adoption grows the distribution system will increasingly exhibit variability of loading, voltage and other aspects of power characteristics that affect the reliability and quality of power delivery. Traditional distribution engineering analysis based on deterministic methods will need to evolve to include probabilistic methods that take account of the random variability associated with intermittent supply resources and net customer load due to DER use.

Interconnection studies and procedures – Interconnection studies for DERs should evolve based on revised engineering methods and should be consistent with the planning criteria listed above. Process reforms also should be implemented, such as rules for managing interconnection queues to accommodate increasing volumes of requests seeking to connect to the utility distribution system.

A DER interconnection issue for regulators relates to the appropriate interconnection regime for DERs intended for "multiple-use" applications, where DERs are providing services to and receiving compensation from more than one entity. For example, DER developers are seeking to aggregate behind-the-meter energy storage and vehicle charging stations over multiple locations, each installed under state-jurisdictional rules, to create virtual resources that can provide grid services at distribution level and participate in the wholesale market while providing services to end-use customers at each individual location. These types of scenarios raise questions for regulators about interconnection, dispatch priority, metering and compensation that will need to be addressed as DER penetration increases within the jurisdiction.

Hosting capacity – The maximum DER penetration for which a distribution grid (from substation through feeder) can operate safely and reliably is the hosting capacity. Hosting capacity methods[37] quantify the engineering factors that increasing DER penetration introduces on the grid within three principal constraints: thermal, voltage/power quality and relay protection limits. These analyses should go

[37] Staff, The Integrated Grid: A Benefit-Cost Framework, EPRI, 2015, and T. Lindl, *et al.*, Integrated Distribution Planning Concept Report, Interstate Renewable Energy Council, Inc. and Sandia National Laboratory, 2013.

beyond simply cataloguing operating limits; they should consider how structured, optimized locational adoption of DERs by customers within an LDA could enhance the hosting capacity of the existing grid by, for example, smoothing net load profiles, improving phase balance, managing voltage variability and increasing capacity utilization.

Locational net value of DERs – The value of DERs on the distribution system is locational in nature—that is, the value may be associated with a distribution substation, an individual feeder, a section of a feeder, or a combination of these components. Based on an analysis of near-term and long-term uses of the distribution system, incremental infrastructure or operational requirements may be met by sourcing services from DERs, as well as optimizing the location of DERs on the distribution system. The objective is to achieve net positive value for all utility customers. These net values may include avoided or deferred utility capital spent on distribution assets and avoided operational expenses. There may also be environmental and customer benefits based on a specific location. Locational value of DERs is not always net positive, as it depends on any incremental distribution system costs (not including costs to the DER developer/owner) to integrate the DER. A California multi-stakeholder working group for the California Public Utility Commission's (CPUC's) Distribution Resources Plan proceeding developed the list of potential DER value components in Figure 4.

	Value Component	Definition
Wholesale	WECC Bulk Power System Benefits	Regional BPS benefits not reflected in System Energy Price or LMP
	System Energy Price	Estimate of CA marginal wholesale system-wide value of energy
	Wholesale Energy	Reduced quantity of energy produced based on net load
	Resource Adequacy	Reduction in capacity required to meet Local RA and/or System RA
	Flexible Capacity	Reduced need for resources for system balancing
	Wholesale Ancillary Services	Reduced system operational requirements for electricity grid reliability
	RPS Generation & Interconnection Costs	Reduced RPS energy prices, integration costs, quantities of energy & capacity
	Transmission Capacity	Reduced need for system & local area transmission capacity
	Transmission Congestion + Losses	Avoided locational transmission losses and congestion
	Wholesale Market Charges	LSE specific reduced wholesale market & transmission access charges
Distribution	Subtransmission, Substation & Feeder Capacity	Reduced need for local distribution upgrades
	Distribution Losses	Value of energy due to losses bet. BPS and distribution points of delivery
	Distribution Power Quality + Reactive Power	Improved transient & steady-state voltage, harmonics & reactive power
	Distribution Reliability + Resiliency	Reduced frequency and duration of outages & ability to withstand and recover from external threats
	Distribution Safety	Improved public safety and reduced potential for property damage
Customer & Societal	Customer Choice	Customer & societal value from robust market for customer alternatives
	Emissions (CO2, Criteria Pollutants & Health Impacts)	Reduction in state and local emissions and public and private health costs
	Energy Security	Reduced risks derived from greater supply diversity
	Water & Land Use	Synergies with water management, environmental benefits & property value
	Economic Impact	State or local net economic impact (e.g., jobs, investment, GDP, tax income)

Figure 4. DER Value Components and Definitions.[38]
This list of mutually exclusive and collectively exhaustive potential DER value components, including avoided costs and societal and customer benefits, can serve as the basis for system-wide and locational net benefits analysis. The More Than Smart working group developed the list in support of California's Distribution Resources Plans.

[38] Developed by California's More Than Smart working group in support of the CPUC Distribution Resources Plan proceeding (R.14-08-013) in 2015.

Integrated T&D planning – At high levels of DER adoption the net load characteristics on the distribution system can have material impact on the transmission system and bulk power system operation.[39] Therefore, transmission and distribution planning should be integrated. This may be accomplished through an iterative approach that involves, for example, using the output of distribution planning as an input into the transmission planning assumptions, and using any DER alternatives for needed transmission upgrades as inputs into distribution planning. The tools to perform a truly integrated engineering analysis are under development, for example, by PNNL with GridLab-D and commercial grid simulation software vendors.

An important extension of integrating transmission and distribution infrastructure planning with each other is to integrate these activities into the jurisdiction's long-term demand forecasting and procurement processes. Assuming the jurisdiction has an established recurring process for forecasting long-term (10 to 20 years) electricity demand, the validity of the resulting forecasts and decisions based on them will depend on how well the expansion of DERs can be forecasted and these forecasts integrated into projections of peak demand, annual energy and system load shape. Such forecasts are used, for example, to assess future generating capacity adequacy to guide procurement decisions for those utilities with load-serving responsibilities. For transmission planning, the DER forecasts will need to be locationally granular to the T-D substation level, which can be built up from the feeder-level forecasts developed for distribution planning. The point is that a jurisdiction that anticipates DER growth should begin to think about how to align the recurring cyclical processes for long-term load forecasting, resource procurement, and T&D planning so as to specify the timing and content of essential information flows among these processes.

To a large extent, the operational management of net load on the transmission grid will depend on how the DSO model in the jurisdiction allocates roles and responsibilities between the DSO and the TSO. Thus, an important consideration in designing the DSO for the high-DER system is to assess the pros and cons of managing DER-related variability locally within the LDA versus exporting it to the transmission grid.

Distribution operations[40]

Today, the distribution utility is responsible for safety and reliability of the local distribution system (including non-FERC jurisdictional sub-transmission facilities). This involves regular reconfiguration or switching of circuits and substation loading for scheduled maintenance, isolating substation and distribution feeder faults, and restoring electric service. Distribution utilities are also responsible to ensure local voltage, power factor and power quality are maintained within engineering standards.

With a greater number of DERs, the potential for multi-directional power flows across the distribution system has emerged and is likely to become prevalent as adoption grows. In addition, as independently owned and operated microgrids develop and electrical standards change to allow seamless islanding,

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[39] "Net load" here refers to the amount of load that is visible to the TSO at each T-D interface, which can be expected to be much less than the total or gross end-use consumption in local areas with high amounts of DERs. The term "net load" is also used at the transmission system level to refer to the total system load minus the energy output of utility-scale variable renewable generation, as illustrated by the CAISO's well known "duck curve." In this report we are focusing mainly on the first sense of the term—i.e., the impact of DERs on the amount of load seen at each T-D interface.

[40] L. Kristov and P. De Martini, 21st Century Electric Distribution System Operations, Caltech, 2014.

system operations will need to include physical coordination of DER and microgrid operation and interconnections to ensure safety and reliability. This includes physical coordination of scheduled and real-time flows between the DSO and its TSO counterpart on the other side of the T-D interface. Thus, in addition to the full suite of traditional operational functions, a new minimal set of functional responsibilities will be required. Although these changes will make distribution system operation much more complex than it has been in the past, they appear to reflect the direction that technology, public policy and customer preferences are taking the industry.

Another aspect of an integrated distributed electricity system is managing reliability through a distributed set of resources and microgrids. Enabled by diverse, small-scale generating systems, energy storage, power flow control devices, demand response and other DERs combined with advanced information and control technologies, a federated system of DSOs, microgrids, and self-optimizing customers will have responsibility and accountability for the reliable, real-time operation of the respective electric systems under their operational control. Elements of this federated system may adopt islanding capability to enhance local resilience in order to maintain electric service under stress conditions on other parts of the electric system. Such a system requires integrated operational processes and distributed control systems to ensure reliability.

Another required distribution operational function is coordination of DER services at the T-D interface. DER-provided services must be properly coordinated through scheduling and real-time management so that the TSO—who will typically view DERs as if they were located at the T-D substation—has predictability and assurance that DERs committed to provide transmission services will actually deliver them across the distribution system to the T-D interface. The distribution operator must be able to manage situations where DERs scheduling reliability services have potentially conflicting service commitments, such as offering the same capacity to serve the needs of the transmission and distribution operators during the same operating interval. This physical coordination also involves ensuring that DER dispatch (via direct control or economic signal) does not create detrimental effects on the local distribution system. Both of these require schedule and dispatch coordination at the T-D interface between the transmission and distribution operators. At a minimum, the distribution operator will likely be the best positioned entity to forecast net load in each LDA and net power flows across its T-D interface, based on visibility to all interconnected loads and DERs and the real-time status of all distribution facilities in the local area.

Figure 5 illustrates the key participants, potential operational functions and relationships.

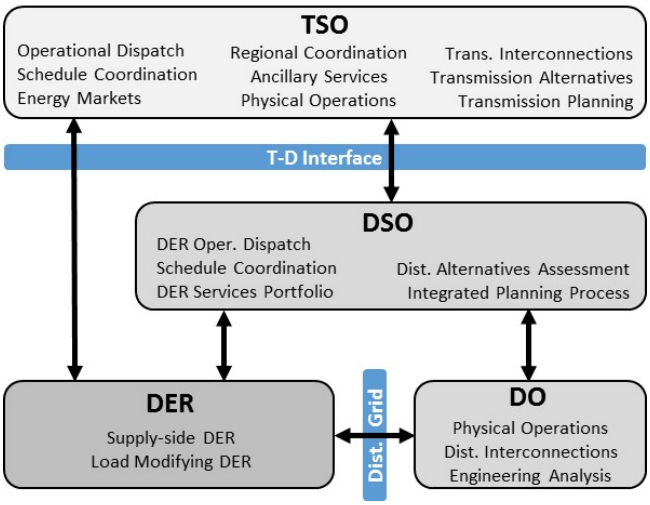

Figure 5. Integrated Systems Operations Framework.
The high-DER electric system will require new or enhanced functional capabilities that can be grouped into four interrelated functional entities: owners/operators of distributed energy resources (DERs); the distribution owner (DO) responsible for safe, reliable operation and maintenance of the distribution grid; the distribution system operator (DSO) responsible for coordinating the activities of DERs and the interface with the transmission system; and the transmission system operator (TSO) responsible for reliable transmission service and, in ISO and RTO areas, operation of the wholesale markets. Depending on the model adopted by a particular jurisdiction in the future, the existing utility may serve all of these functions, except for wholesale market and transmission operation in ISO or RTO areas. Refer to the "Key Definitions" section at the beginning of this report.

Markets and market services

In Section II we described three basic types of markets: wholesale energy and operational markets, distribution operational markets and distribution-level energy markets. Development of these markets starts with clear service definitions with specific operational and commercial performance requirements. This is true for both wholesale/transmission and distribution services as highlighted in the analysis of the value of storage by Sandia National Laboratories.[41] While developed for storage, the services and high level performance requirements identified by Sandia are applicable to any type of DER or combination of DERs that can satisfy the requirements.

Many types of DERs will be able to provide operational services to the distribution system as envisioned in Stage 2. These services need to be defined, their performance requirements and measurement rules specified in a technology-neutral manner, and sourcing and compensation mechanisms established. Customers and services firms should know what types of services and benefits they can provide to the grid through access to relevant information, as compensation for these services may comprise a necessary element of the DER providers' business plans to obtain project financing. This also includes rules for the physical interconnection of new resources, whether principles of "open access" should apply and, if so, how they are specified and enforced. Boundary questions need to be addressed, such as

[41] J. Eyer and G. Corey, Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide, Sandia National Laboratories, 2010.

whether DERs can participate in the wholesale transmission-level market directly, or must go through a distribution operator or load serving entity (LSE)[42] that would provide the wholesale market interface.

The animation of distribution operational markets should consider the commercial and operational interest of the buyers and sellers of DER services. For example, medium- to long-term contracts will likely be needed to finance distributed generation, energy storage and some energy efficiency projects; expectations of spot market revenues will not be sufficient. Likewise, grid operators will want well-defined service agreements with specific availability and performance requirements for DERs they procure in lieu of capital investment. Reliance on DER responses to dynamic spot pricing[43] will not provide the DSO with sufficient confidence that the DER will perform as needed, when needed.

It is also not clear that highly granular locations (feeder line sections or service transformers) and short time-period pricing (sub-hourly or sub-minute), as proposed by some transactive energy advocates, is the appropriate level to start developing markets for distribution operational services in Stage 2 or even distributed energy markets in Stage 3. The level of complexity can be massive given that most distribution feeders are operated unbalanced, meaning there could be a price for each of the three phases of each feeder and then for each line section or individual service transformer. It will likely be more tractable and effective to start more simply with substation transformer level or whole feeder pricing and compensation determined by contract, rather than spot pricing. Also, pricing time periods do not need to be as granular as the response time required for performance. For example, a fixed price can be provided to a smart inverter to provide voltage service that involves second-by-second response. In fact, this may be preferable due to control system issues identified earlier in this report. The efficiency-reliability tradeoff discussed previously should be borne in mind in these design considerations.

Distribution market development must also consider issues of potential market power. This is especially an issue in Stage 2 of the distribution system evolution, when DER services are likely to be concentrated among a few firms on any individual distribution feeder subject to frequent local constraints.[44] This assumes continuation of the current pattern of over 60 percent of DER asset ownership remaining with the services firm through customer power purchase agreements or leasing arrangements.[45] For example, a distribution feeder may have at most three DER services firms with sizable amounts of aggregated dispatchable DERs and any one would be able to influence a local market.

Market services

Beyond establishing such markets, a DSO could provide market facilitation services as identified in New York.[46] The specific services and potential applicability of each additional role will depend on regional

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[42] Staff, The Evolution of Demand Response in the PJM Wholesale Market, PJM Interconnection, October 2014.

[43] Spot pricing as discussed in this report refers to day-ahead up to real-time pricing of any grid service and energy, temporally aligned for the most part with the wholesale spot markets operated by ISOs and RTOs. It does not necessarily mean locational marginal pricing or any specific degree of locational granularity unless specifically identified as such.

[44] C. Wu, S. Bose, A. Wierman, H. Mohesenian-Rad, A Unifying Approach to Assessing Market Power in Deregulated Electricity Markets, Tsinghua University, California Institute of Technology and University of California, Riverside. This paper addresses market power issues related to local constraints on transmission, which are analogous to issues at the distribution level.

[45] D. Feldman and T. Lowder, Banking on Solar: An Analysis of Banking Opportunities in the U.S. Distributed Photovoltaic Market, National Renewable Energy Laboratory, 2014.

[46] NY REV Working Group 1: DSPP Markets, Staff Report on the Work of the DSPP Markets Committee, July 8, 2014.

and local considerations. Market facilitation service may include:

- Aggregation and dispatch coordination
- "Park-and-loan" energy storage-based services
- Micro-transaction clearing and settlement services

Aggregation and dispatch coordination is a possible DSO market facilitation service that could provide a consolidated offer to the TSO and wholesale market at each T-D interface. The DSO would formulate an aggregated virtual resource on the distribution side of the interface to coordinate market bidding and operational dispatch of all DERs in the LDA that intend to participate in wholesale energy, capacity and ancillary services markets. This includes wholesale markets managed by the TSO for the T-D Interface and broader regional markets that are increasingly available through arrangements such as the new energy imbalance market in the western U.S.[47] As we discuss below, this arrangement has some desirable properties from a system architecture perspective.

The incorporation of energy storage on the distribution system and at customer sites may enable distribution operators to offer new, non-core market-enabling services similar to those provided by natural gas distribution utilities. Such services may include "park and loan," where parties may store energy with the DSO that cannot be delivered immediately and schedule it for delivery at another time. Similarly, distribution operators may sell or loan short-term energy as needed to make up for deficiencies in scheduled deliveries, or they may use stored energy to smooth an LDA's net load shape to minimize variability exported onto the transmission grid.

As the number of energy transactions rises across the distribution system and into the bulk power system, it may be desirable for distribution operators to offer additional non-core micro-transaction clearing and settlement services. Transactions involving DERs may involve complex pricing structures and terms and very small dollar amounts per transaction. These types of micro-transactions will more closely resemble the special tariff and other operating revenue transaction structures that utilities currently support, albeit at a fraction of the volume of transactions contemplated for a high-DER future.

B. Distribution System Functional Evolution

Distribution systems will evolve in complexity and scale over time as the richness of their functionality increases to integrate greater numbers of DERs and intelligent grid devices. Figure 6 lists the planning, operational and market functions described above and indicates the evolutionary stage at which each one becomes necessary.

The Stage 2 distribution grid requires a proactive management approach to align cyber-physical grid[48] investment with customer adoption of DERs. This involves changes to the physical engineering designs of the grid and the operational systems. Such systems may be completely distributed, or they may involve distributed elements with centralized management and coordination.

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[47] See http://www.caiso.com/informed/pages/stakeholderprocesses/energyimbalancemarket.aspx.

[48] "Cyber" refers to the information and communication technology that is integral to a modern electric grid. Cyber-security is the security related to the information and communication technology in the grid.

Distribution Functions	Stage 1	Stage 2	Stage 3
1. Planning			
A. Scenario based, probabilistic distribution engineering analysis	✓	✓	✓
B. DER Interconnection studies and procedures	✓	✓	✓
C. DER Hosting capacity analysis	✓	✓	✓
D. DER Locational value analysis		✓	✓
E. Integrated T&D planning		✓	✓
2. Operations			
A. Design-build and ownership of distribution grid	✓	✓	✓
B. Switching, outage restoration & distribution maintenance	✓	✓	✓
C. Physical coordination of DER schedules		✓	✓
D. Coordination with ISO at T-D interface		✓	✓
3. Market			
A. Sourcing distribution grid services		✓	✓
B. Optimally dispatch DER provided distribution grid services		✓	✓
C. Aggregation of DER for wholesale market participation		✓	✓
D. Creation & operation of distribution level energy markets; transactions among DER			✓
E. Clearing and settlements for inter-DER transactions			✓
F. Market facilitation services			✓

Figure 6. Distribution Functions by Evolutionary Stage.
Distribution systems will evolve in complexity and scale over time as their functionality increases to integrate greater numbers of DERs and intelligent grid devices. This list summarizes the planning, operational and market functions described in this report and indicates the evolutionary stage at which each function becomes necessary.

C. Overview of Bulk Power System and Wholesale Market Operations

The purpose of this subsection is to provide a basic overview of how the bulk electric system and wholesale spot markets work, both in restructured areas operated by an ISO or RTO as well as for vertically integrated utilities. There are two reasons why this is important for this report. First, in the next subsection we will describe three DSO models that vary based on how roles and responsibilities are defined and allocated between the DSO and the transmission/wholesale market operator, focusing on

the transmission-distribution interface substation. Understanding these models will require understanding the TSO's functions as well as the DSO's functions. Second, some participants in state and national discussions on a high-DER future electric system have suggested the creation of an ISO equivalent for the distribution system, similar to the Independent DSO (IDSO) model considered in this report against the utility distribution service provider. In order to evaluate the merits of an ISO at distribution level, it is necessary to have a clear sense of the key roles and responsibilities of a TSO, and in particular an ISO or RTO. FERC has jurisdiction over the bulk electric system, wholesale markets and transmission, among other areas.[49]

Some of the entities described below were defined in the Key Definitions section at the beginning of this report. Here we go into some details on their roles and responsibilities.

Balancing Authority (BA). In ISO/RTO areas, the transmission assets of each constituent utility (called a participating transmission owner) continue to be owned and maintained by the utility. However, operational control, allocation of grid services for moving energy, and BA functions are performed by the ISO/RTO. In non-ISO/RTO areas, vertically integrated utilities that own transmission may be the BA for a defined balancing authority area (BAA). In most of the U.S.—Alaska, Texas and Hawaii are the exceptions—each BAA is interconnected with other BAAs that comprise a regional interconnection, and adjacent BAAs manage flows of imported and exported energy across their points of interchange.

BA functions include continual real-time balancing of supply and demand, maintaining reliable operation of the grid under both normal and contingency conditions, and supporting interconnection-wide system frequency.

Transmission service provider. Federal legislation and regulatory rulemakings in the 1990s required transmission-owning utilities to provide open-access transmission service. A primary goal behind these laws and regulations was to ensure that all generators would have fair and equal access to the grid to supply energy to wholesale buyers. In general this was intended to shift the risk of generation over investment from ratepayers to private investors and ultimately to lower generation costs. Utilities met federal requirements by either joining or forming an ISO or RTO, or filing open-access transmission tariffs (OATT).

Wholesale spot market operator. In areas that formed ISOs or RTOs in response to the open-access regulations of the 1990s, the ISO or RTO became the operator of competitive spot markets for generators and marketers to sell energy to load-serving entities, in addition to being the transmission service provider or TSO. Spot markets operated by the ISO/RTO would provide the real-time price of the delivered electricity commodity against which parties could formulate forward bilateral contracts.

Although some ISOs and RTOs in the U.S. started with zonal markets in which wholesale energy was traded with little or no regard to the transmission grid that might constrain its delivery, eventually all of them adopted the locational marginal pricing (LMP) paradigm. Under LMP the market-clearing algorithm is subject to grid constraints and creates a locational price at each transmission-distribution interface, generator interconnection point, and import-export point with an adjacent BAA. This approach ensured

[49] See http://www.ferc.gov/ for applicable orders.

that energy trades executed in the spot markets would conform to the physical structure and limitations of the grid and therefore could feasibly be delivered.

One under-appreciated result of adopting the LMP paradigm is that there is no longer any meaningful distinction between these seemingly disparate functions: spot market for trading wholesale energy, open-access allocation of grid use to suppliers and buyers, and reliable operation of the grid, including management of congestion and contingencies and supply-demand balancing. The spot market becomes the vehicle by which buyers and sellers bid to buy or sell energy at the same time as they bid to move energy over the grid, as well as the tool with which the ISO/RTO aligns price incentives with the operational needs of the grid to manage congestion and maintain reliable operation. This is an important insight to keep in mind as we discuss the idea of applying an ISO model to the distribution system.

Transmission planner. In restructured markets, the ISO/RTO is the transmission planner for the area. Although the participating transmission owners participate in the planning process and perform some of the needed studies, ultimately the ISO/RTO makes the decisions about what upgrades are needed and which upgrade solutions—including the potential use of non-wires alternatives—are the most cost-effective to meet the identified needs. One reason for giving this role to the ISO/RTO is that it provides transparency, removing any concern that a participating transmission owner might wish to implement upgrades that benefit its own generating resources in an anti-competitive manner. Another reason is that separating the planning of upgrades from the ownership of assets mitigates concerns that a participating transmission owner might invest simply to increase its regulated earnings opportunities. Current discussions of the independent DSO model mention the same reasons for separating distribution planning from ownership of distribution assets.

New generator interconnection procedures. The TSO (ISO/RTO or utility BA) also manages the interconnection procedures for new generators seeking to interconnect to the transmission grid, although the participating transmission owners participate in the process by performing some of the needed studies and ultimately constructing many of the needed interconnection facilities. Just like open-access transmission services, interconnection procedures are subject to non-discrimination requirements and provisions to ensure transparency.

To create some basis for considering how roles and responsibilities may be allocated between a TSO and distribution operator, Figure 7 reviews each of the above TSO functions and compares them to functions that utilities perform today.

Function	Transmission System Operator (TSO)	Distribution Operator (DSO or DO)
Balance supply and demand	Balances for its area, including net load of all LDAs and interchange with adjacent BAAs	Distribution operator does not balance - only delivers energy to and from T-D interface
Maintain frequency	Supports frequency for its system or at regional interconnections, along with other BAs	Distribution operator does not maintain frequency. However, DER may provide frequency support to TSO
Grid scheduling and coordination	TSO is responsible for the scheduling and coordination of transactions across its area	New function as may be required of distribution operator depending on volume and types of transactions
Open-access transmission service	All TSOs provide open-access pursuant to federal law	Analog does not currently exist at distribution level
Operate spot market	ISO/RTO clears wholesale spot market for residual energy; spot market may not exist in integrated utility area	No spot market clearing at distribution level at this time. Distribution operator only delivers wholesale spot market energy to or from customer/DER provider.
Infrastructure planning	ISO/RTO plans for all constituent Participating Transmission Owners (PTO); PTOs own, maintain and physically operate assets. For non-ISO/RTO areas - Integrated utility is the planner.	Distribution operator plans distribution asset replacements and system upgrades
Interconnection	ISO/RTO manages generator interconnection for DER that will inject energy into the grid and participate in the wholesale market. In an integrated utility, the utility is the PTO and manages the interconnection process	Distribution operators have open-access FERC-jurisdictional interconnection procedures for DER that will inject energy into the bulk power system. Also, have distinct state-interconnection processes for loads and DER located behind the customer meter.

Figure 7. Functional Roles and Responsibilities: TSO Versus Distribution Operator Today.
Under the traditional electric system paradigm, in which electricity is produced predominantly by transmission-connected generators and delivered one way over distribution systems to end-use customers, the responsibilities of the distribution operator are limited to reliable but passive delivery of energy and interconnection of new customers. Responsibilities that are now assigned only to the transmission system operator (TSO)—such as supply-demand balancing, resource scheduling and spot market operation—may have distribution-side counterparts in a high DER future. Today, the utility is both the distribution system operator (DSO) and the distribution owner (DO) and may also serve as the transmission system operator (TSO).

D. Distribution Operational Models

This section describes the functional requirements of distribution system operations for the high-DER electric system. The three distribution operational models discussed here reflect different ways to divide roles and responsibilities around the T-D interface between the DSO and the TSO and, thus, imply different functional requirements and capabilities between the two entities. These three models are arranged in sequence starting with a maximal role of the TSO in the coordination and operation of DERs, and consequently a minimal role for the DSO in these areas (model A), and ending with a minimal role for the TSO with regard to DERs and a maximal role for the DSO (models C1 and C2). Thus models A and C are at the opposite extremes, while model B (minimal DSO) is an intermediate model.

In all these operational models the focus is on the distribution system component of the utility, as distinct from other utility functions such as supplying retail energy to end-use customers, administering energy efficiency programs or providing other energy-related services for customers. The point is not to

exclude or preclude DSOs engaging in such activities; rather, it is simply to set such matters aside for the present inquiry so as to focus acutely on the challenges of distribution planning, market design, operations and oversight within the context of a future high-DER electricity system.

Following are descriptions of the three operational models.

Total TSO (Model A)

In Model A, the TSO operates a fully integrated electricity system and performs an economic dispatch, including DERs down to a relatively low size threshold.[50] The TSO's economic dispatch algorithm includes distribution circuits and represents DERs at their actual locations on the distribution system, so that the TSO can take account of distribution system impacts in determining its optimal dispatch. The DSO has only minimal new functional responsibilities to ensure distribution system reliability. Although these functions may be significant from an operational perspective, the DSO has little or no role with regard to any distribution-level market for DER services. As we discuss in Section V, the Total TSO model may be conceptually interesting and even technically plausible, but will likely be a suboptimal way of allocating roles and responsibilities between the TSO and DSO.

Minimal DSO (Model B)

The Minimal DSO provides non-discriminatory distribution service, in terms of both interconnection to the distribution system and coordinating wholesale market participation. Additionally, the DSO sources distribution grid services from many of the same wholesale market-participating DERs. Thus, the DSO is responsible for physical coordination of the activities of the DERs, particularly their potential impacts on the distribution system and responses to TSO dispatch instructions.

Model B is similar to model A, except that the TSO's economic dispatch algorithm stops at the T-D Interfaces where DERs are assumed to be located for dispatch purposes, rather than modeling the distribution circuits and the actual physical locations of DER participating in the dispatch. Under model B, the TSO still has telemetry and dispatch control over potentially tens of thousands of wholesale market-participating DERs, but has no visibility to distribution circuits and system conditions and has only limited information at best about the impacts its dispatches of DERs may have on distribution system conditions. This requires communications and real-time operating procedures between the DSO and the TSO, and between the DSO and the DER providers in the DSO's local area.

Market DSO (Models C1 and C2)

The Market DSO model represents a simplification for the TSO by requiring that DERs be aggregated to a minimum size (such as 10 MW) for participating in the economic dispatch or wholesale market. Under this model the TSO relies on the DSO either to: (1) provide coordination among the DER aggregators and their constituent DERs within each local distribution area, to ensure safe and reliable response to TSO dispatches, and potentially to serve as such an aggregator itself (model C1); or (2) perform <u>all</u> aggregation and coordination of DERs in each LDA and provide the TSO with a single resource at each T-D Interface (model C2). In either case, the TSO sees only one or a few aggregated resources at each T-D Interface, includes them in its economic dispatch as if they were located at the T-D Interface, and then

[50] In an ISO/RTO area, the economic dispatch is the same as clearing the wholesale spot market. In areas with vertically integrated utilities, the TSO still performs a comparable economic dispatch of those resources under its control to manage congestion and real-time balancing of supply and demand.

leaves it to the DSO to coordinate the responses of these resources and their constituent DERs to its dispatches.

In version C1 of the Market DSO model, the DSO's coordination function is complicated by the presence of multiple scheduling coordinators or aggregators, each having aggregated resources in the same LDA, with each aggregator submitting bids to the wholesale market and responding independently to wholesale market dispatches. Thus, model C1 may be more complicated from an operational perspective than model C2.

In model C2, the DSO functions as the sole scheduling coordinator to submit a single bid to the TSO at each T-D Interface reflecting the aggregation of all DERs within the LDA. In this version, the DSO takes on many of the characteristics of a local ISO at the distribution level, as well as the scheduling coordinator function with respect to the TSO markets. For example, as the scheduling coordinator for the wholesale market and the coordinator of DER operations, the DSO upon receiving a TSO dispatch would determine which DERs in the area are able to respond to the dispatch most economically with manageable impact on the distribution system. And, in analogous fashion to a BA, the DSO would effectively balance supply and demand in the LDA, relying as needed on imports or exports with the TSO across the T-D substation. Thus, model C2 represents a substantial simplification of the operational relationships between DSO, TSO and DERs within each LDA. At the same time, model C2 also precludes direct participation by DERs in the wholesale spot market and therefore increases concern about the regulatory attributes of non-discrimination and transparency, discussed earlier.

E. Distribution Owner (DO) Functions

This section considers whether some of the distribution system operational and planning functions should remain with the owner of the distribution system assets (the distribution owner, or DO), irrespective of the entity responsible for the other functions under the various DSO models we describe. The resulting implication for those functions listed in Figure 6, where we can decide affirmatively to leave them with the DO, is that the question of independent DSO versus utility DSO becomes moot.

The rationale here draws upon an analogy with the relationship between an ISO or RTO and its member-participating transmission owners in restructured areas. In the planning phase, the ISO or RTO is responsible for the transmission planning process, which includes conducting stakeholder activities and determining the preferred solutions for identified needs. The participating transmission owners contribute substantially, however, by performing reliability engineering studies and proposing mitigations for the needs they identify. A similar relationship applies with regard to generator interconnection procedures.

In the operational sphere, the ISO or RTO performs the centralized scheduling and dispatch of the transmission system comprised of the participating transmission owners' assets, but the participating transmission owners are responsible for the maintenance and operation of the physical transmission facilities. Thus, the basic question here is whether there is a set of DO functions for the high-DER distribution system comparable to the participating transmission owner functions under an ISO or RTO.

Referring to Figure 6, this analogy suggests that Planning functions A, B and C, and Operations functions A and B, are candidates for DO responsibilities across all DSO models and DER development stages. On the pro side, these functions are so intrinsically connected to the physical assets that it could be both overly complicated and inefficient to try to separate them from the DO and assign them to a different entity.

On the con side, one potential concern is that the DO could perform Planning functions A, B and C in a manner that tends to favor its own rate-based investment in distribution assets. If we continue the analogy with the ISO/RTO relationship, however, the DO would perform the studies under Planning functions A, B and C as part of larger planning and interconnection processes for which another entity—the DSO or TSO with regulatory oversight—would be responsible.[51] In other words, the DO would not be the entity that makes investment decisions based on the Planning A, B and C studies it performs; it would only provide these studies as input to the appropriate planning or interconnection process that has stakeholder review and regulatory approval. Thus, the focus for ensuring the desired regulatory attributes, such as non-discrimination and transparency, would need to be on these larger processes as defined, for example, in California's Distribution Resources Plan order.[52]

Similarly, another concern could arise with regard to Operations function A, design-build and ownership of the distribution grid. Concern about the DO performing this function may be mitigated if the decisions about what upgrades should be built are not made by the DO, but are under a similar planning or interconnection process. Today, distribution utilities' infrastructure expenditures are subject to prudency review by state regulators. In moving toward higher levels of DERs, these proceedings will likely need some refinement to ensure sufficient transparency.

Finally, with regard to Operations B functions—switching, outage restoration and distribution maintenance—these are functions the DO performs today. We believe that whatever oversight, standards, and other processes ensure the proper performance of these functions today should be equally effective in maintaining reliable operation in the high-DER future and can be enhanced by the regulator to address non-discrimination concerns. Therefore, we recommend keeping these functions with the DO. There is a close relationship between this function and Operations C—physical coordination of DER schedules—but such schedule coordination entails activities beyond current DO scope. Therefore, we keep Operations C as a separate item and include it in our detailed assessment of independent DSO versus utility DSO in Section V.

These five DO responsibilities—Planning functions A, B and C, and Operations functions A and B—address the basic functions needed to ensure operational safety and reliability of the distribution system. They also address the legal obligations that a DO may have regarding safety and reliability under a state's public utility code, as noted by Southern California Edison (SCE) in its comments in the CPUC Distribution Resources Plan proceeding:[53] "Accordingly, a utility is 'responsible for operating its own electric distribution grid, including . . . owning, controlling, operating, managing, maintaining, planning, engineering, designing, and constructing its own electric distribution grid.' See Pub. Util. Code §399.2(2)."

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[51] An additional complexity here, for which there is no analogy in the ISO/RTO context, is the coexistence of state-jurisdictional and federal-jurisdictional interconnection procedures on the distribution system, discussed earlier. As we noted, the growth of DERs and appearance of innovative DER aggregations for multiple-use applications are now testing the previously clear specification of which procedure applies to any given interconnection request. A proper treatment of this topic, relevant to either an independent DSO or utility DSO, is beyond the scope of this report.

[52] CPUC R14-08-013, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769, Aug. 14, 2014.

[53] SCE's Comments on CPUC R14-08-013 DRP Order Instituting Rulemaking, at p. 16, http://www.cpuc.ca.gov/NR/rdonlyres/1F33B67D-6D38-4361-87A6-C86ED4FAEF5F/0/105626157sce.pdf.

Further, proponents of an Independent DSO recognize this role for the DO. For example, in their recent "51st State" paper,[54] Wellinghoff, Tong and Hu affirm that, "Regulated utilities still own and maintain T&D infrastructure—the only aspects of the electric system that are truly natural monopolies." Similarly, SolarCity in its NY REV comments[55] recommends that the DO "should continue to manage physical operations and asset management functions."

With Planning functions A, B and C, and Operations functions A and B assigned to the DO—in part to simplify our assessment of the merits of an ISO at the distribution level—we can focus on options for assigning the remaining functions with the expansion of DERs on the system. The need for these other functions depends on the specific stage of DER development and the particular jurisdiction's vision of the desirable mature end-state of the distribution system—i.e., evolutionary Stage 2 or Stage 3. In addition, depending on the choice of DSO model, some of these functions could be performed either by the DSO or by the TSO. The next subsection provides an overview of how to assign the various functions based on the DSO model and stage of system evolution and sets the stage for our assessment of the independent DSO versus utility DSO alternatives in Section V.

F. Responsibilities for Distribution Functions

Figure 8 summarizes the discussion thus far to provide the framework for the assessment in Section V. It lists the distribution functions we have discussed, and for each function indicates which entity—DO, DSO, TSO or in some cases another entity—would be responsible. The color-coding of the rows indicates whether a function is needed in all three stages of distribution system evolution (grey), only in Stages 2 and 3 (blue), or only in Stage 3 (purple).

[54] J. Wellinghoff, J. Tong and J. Hu, The 51st State: Market Structures for a Smarter, More Efficient Grid, Stoel-Rives and Clean Power Finance, 2015.

[55] Comments of SolarCity Corporation, p.2, NY REV Track 1 Case 14-M-0101, July 18, 2014.

Distribution Functions	Total TSO	Minimal DSO	Market DSO
1. Planning			
A. Scenario based, probabilistic distribution engineering	DO	DO	DO
B. DER Interconnection studies and procedures	DO	DO	DO
C. DER Hosting capacity analysis	DO	DO	DO
D. DER Locational value analysis	TSO	DSO	DSO
E. Integrated T&D planning	TSO	TSO/DSO	TSO/DSO
2. Operations			
A. Design-build and ownership of distribution grid	DO	DO	DO
B. Switching, outage restoration & distribution maintenance	DO	DO	DO
C. Physical coordination of DER schedules	DO/TSO	DSO/TSO	DSO
D. Real-time Coordination with ISO at T-D interface	DO/TSO	DSO/TSO	DSO
3. Market			
A. Sourcing distribution grid services	TSO	DSO	DSO
B. Optimally dispatch DER provided distribution grid services	TSO	DSO	DSO
C. Aggregation of DER for wholesale market participation	TSO	Aggregators	DSO (C2)
D. Creation & operation of distribution level energy markets; transactions among DER	TSO	TSO/Others	DSO
E. Clearing and settlements for inter-DER transactions	TSO	TSO/Others	DSO
F. Market facilitation services	TSO	TSO/Others	DSO
	Stages 1-3	Stages 2-3	Stage 3

Figure 8. Future Possible Operational Models in a High DER Scenario.
The assignment of roles and responsibilities for the various functions to a distribution operator (DO), distribution system operator (DSO), transmission system operator (TSO), aggregators and other entities will depend on both the jurisdiction's choice of operational model (one of the three columns on the right—Total TSO, Minimal DSO or Market DSO, described above) and the stage of distribution system evolution. Depending on the model adopted by a particular jurisdiction in the future, the existing utility may serve many of these functions.

V. Perspectives on Future Operational Models

We turn now to a comparative assessment of the alternative operational models and the pros and cons of creating an independent DSO to perform the DSO functions versus expanding the responsibilities of the distribution utility to include these functions. As discussed in Section III of this report, our assessment focuses on five key regulatory attributes for a high-DER system: non-discrimination in operations and interconnection, transparency, absence of market power, effective oversight, and timing of major decisions.

First, we identify the industry contexts in which new operational functions are needed or desirable. For this purpose we turn to Figure 8, showing both the distribution functions that become necessary at each stage of distribution system evolution and the entity that would be responsible for each function under the operational models we developed for our assessment.

Second, we consider the positives and negatives for each operational model (Total TSO, Minimal DSO and Market DSO) as well as any preconditions. Based on issues described in the following section, we eliminate the Total TSO (model A) from further consideration. For the remaining two DSO models, we focus on the question of the independent DSO versus the distribution utility as DSO by looking at the specific functions and the entity that would be responsible for them in accordance with Figure 8, to consider the pros and cons of each.

A. Total TSO Model

We consider the Total TSO to be an interesting conceptual model for defining the range of possibilities, but not a practical one in most cases. The problems with the Total TSO stem first and foremost from the complexities and operational vulnerabilities of a whole-system optimal dispatch that encompasses the whole range of facilities from the high-voltage transmission system down to the individual distribution circuits. The Total TSO construct places all new functional needs that arise with high presence of DERs under the scope of responsibility of the balancing area TSO. As we discuss in the next section, the utility DO would probably retain some of the basic planning and operational functions it does today, but beyond that the Total TSO would expand its capabilities to encompass all functions required at Stage 2 and Stage 3 of DER development. This model, therefore, makes any separate new DSO functions unnecessary and renders the independent DSO versus utility DSO entity question moot.

The following discussion summarizes the problems we see with the Total TSO model. This assessment is most relevant in restructured states with an ISO/RTO or areas with generation and transmission (G&T) entities separate from publicly-owned distribution utilities (municipalities and rural electric cooperatives). The Total TSO may appear attractive in restructured regions where DERs already participate in wholesale markets, including in planning processes and economic dispatch. In such regions, moving to a Total TSO may appear to be a natural and relatively simple and inexpensive extension of today's regime. The ISO/RTO is an independent entity in these jurisdictions, and that same independence from market participants and infrastructure asset owners could be extended to the distribution level. Unfortunately, this apparent simplicity does not bear closer scrutiny.

One area of concern has to do with the policy objectives of facilitating DER expansion. In both the New York and California proceedings, a great deal of emphasis is placed on the potential for DERs to provide net load reduction at the T-D Interface, thereby reducing wholesale costs. DERs are also anticipated to provide location-based services to the distribution system, including operational services like voltage support and power quality, as well as deferment of distribution infrastructure investment. These

distribution-level values are economically very significant; utilities are projected to spend about twice as much on distribution investment as they do on transmission investment.[56] One implication is that new types of distribution studies to measure hosting capacity and identify locational benefits of DERs will be a valuable undertaking, requiring capabilities (people, processes, technologies) that are not simply extensions of transmission planning. Thus, these activities would require more than just incremental enhancements to existing TSO functions.

A significant issue is that scheduling and dispatch of DERs in ISO/RTO markets today is done without consideration of the impacts on the distribution grid. Depending on the location of DERs on the distribution grid and DER concentration on various circuit phases, this may result in reliability issues such as phase imbalance and increased losses, as well as over/under voltage and equipment loading issues.[57] As DER penetration increases, visibility to and management of DER impacts on the distribution grid in response to ISO/RTO dispatches will be essential. The question is, can all this be integrated into the TSO's management of the transmission system?

Starting from the technical aspects, the Total TSO would require that the market model and optimization algorithms of the TSO incorporate all the distribution circuits and place the participating DERs at their actual locations on those circuits. It would be a major increase in complexity to incorporate the whole range of facilities from extremely high voltage (e.g., 500 kV) down to distribution voltages (e.g., 4 kV to 35 kV) into a single network model to be used in a global dispatch algorithm. The TSO would track distribution system outages, circuit switching and other relevant status details to update the network model, and monitor real-time flows on distribution circuits to ensure that dispatches of DERs are feasible on the distribution system with a high degree of certainty.[58] The TSO's settlement rules would account for the DER's location, real-time response, and other factors affecting the value of the resource in a manner comparable to settlement of other grid-connected resources.

Considerations from the theory of ultra-large scale systems and system architecture indicate that such complexity makes the system more fragile and vulnerable to relatively small or local disturbances.[59] The same considerations further suggest that in trying to optimize the electric system from the highest level of the regional high-voltage interconnection down to the local low-voltage facilities that serve local areas and sub-areas, the most stable approach is to design a layered or hierarchical optimization. As discussed below, this approach is consistent with Market DSO model C2.

Turning to another aspect of real-time operation, the Total TSO model would require the TSO, which may be operating a very large BA, to coordinate field operations with the multiple DOs who manage local circuit switching, outage restoration and similar functions. The TSO's model of the distribution

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[56] M. Chupka, R. Earle, P. Fox-Penner and R. Hledik, Transforming America's Power Industry: The Investment Challenge 2010-2030, Brattle Group – Edison Foundation, 2008.

[57] F. Rahimi and S. Mokhtari, From ISO to DSO, Public Utility Fortnightly, June 2014.

[58] Some parties involved in discussions of various DSO models express strong concerns about whether it is desirable or even technically feasible to incorporate this degree of granularity into the network model and central optimization algorithms of the TSO. One concern raised with regard to technical feasibility has to do with the shorter response times required to address operational issues arising in the distribution system compared to the transmission grid, suggesting that a layered or hierarchical optimization structure—as exemplified by model C2, for example—would be more resilient and stable than a single grand optimization.

[59] L. Northrup, et al., Ultra-Large-Scale Systems, Software Engineering Institute, Carnegie Mellon University, 2006.

system used in the economic dispatch would need to continually reflect current conditions, so that the TSO has high confidence that its dispatches will elicit the needed responses. This is a massive issue given the very large number of devices (e.g., DERs, transformers, switches, reactive power controllers, sensors, etc.) on a distribution system as well as the dynamically changing topology of the distribution circuits due to switching. Also, a TSO may need to manage multiple distribution systems in a state or region. This type of operational structure raises significant safety and reliability concerns.

Finally, with respect to regulation, the states have jurisdiction over distribution systems and retail markets, and FERC has jurisdiction over transmission and wholesale markets, including distributed generator interconnections if the generator plans wholesale transactions. The Total TSO model discards this long-standing regulatory boundary by giving the TSO vastly expanded control over distribution-level activities. Such activities would include, for example, the TSO performing distribution planning and evaluating distribution expenditure proposals, thereby bringing this TSO activity under state regulatory jurisdiction. A considerable amount of the value of DERs is from reducing wholesale power costs through lower net demand. The ISO/RTO revenue model is based on wholesale market participant fees and transmission access charges. A likely concern is that an ISO/RTO could tend to favor centralized resource and transmission options as opposed to distributed solutions that reduce transmission revenues. Combined with a lack of state jurisdiction over ISO/RTO planning, this presents a significant issue for both inherent bias toward centralized resources and transmission solutions, as well as regulatory oversight conflict between state and federal jurisdictions regarding distribution and transmission planning, respectively. Resolving these issues seems needlessly complex and controversial and would take years to figure out a workable ratemaking and regulatory framework, if one could be figured out at all.

Our sense, then, is that the concerns identified ultimately make the Total TSO unattractive and impractical. This may be why no party in the New York REV proceeding, including the NYISO, has advocated for this model. Thus, while the Total TSO model is useful to examine as a concept, it is not likely to be a practical arrangement for the high-DER electric system. Alternative DSO models discussed below offer similar benefits without all the problems of the Total TSO.

B. Distribution DSO Alternatives and Independent DSO Versus Utility DSO Models

The following discussion is based on considering a distribution level DSO in either a Minimal DSO or Market DSO construct depending on the relevant stage of evolution. We also consider these in relation to the question of an independent DSO versus a utility DSO. Following the approach laid out at the beginning of this section, we address the issues on a function-by-function basis, for those functions in Figure 8 not assigned to the DO. We start with Planning functions D and E, then move to Operations functions C and D, then lastly to Market functions A through F. Most of the discussion should be equally applicable to restructured ISO/RTO areas and other areas where the TSO is a separate entity from the distribution utility, as well as vertically integrated utility areas. Where there are differences we will address them. Our discussion also highlights parties' comments in recent and current state proceedings, as well as recent industry articles and papers where relevant. This provides context for discussions at the state and national levels and for assessing the various points within the operational framework and analysis in this report.

1. Planning functions: DER locational value analysis and integrated T&D planning

Earlier we assigned certain planning functions to the DO/utility based on the rationale that the DO would perform the engineering studies and provide the results as input into planning and

interconnection processes that have an adequate regulatory framework to ensure the attributes of transparency, non-discrimination, etc. Now we need to consider the pros and cons of assigning those larger processes to an IDSO versus a utility DSO.

In the high-DER system, and perhaps even more so during the evolution from relatively low DER penetration to much higher levels, distribution planning and interconnection processes will need to undergo significant enhancement. Traditional planning and interconnection procedures and study methods were designed for a system that transmits energy one way from the transmission grid to end-use customers and, more important, were structured to address only gradual load growth and occasional addition of new supply resources. As we learned when California first adopted a renewable portfolio standard, the existing processes for transmission planning and interconnection were not well suited to deal with the arrival of large volumes of proposed renewable generation projects, the uncertainty about which projects would ultimately succeed, and the choice of which geographic areas should be the focus of transmission upgrades. In response, the California ISO redesigned these transmission-level processes beginning in 2010.

For the distribution system, as recognized in Hawaii,[60] similar process redesign and enhancement is needed for moving to a high-DER system. In Section IV we described the needed enhancements, as summarized in Figures 6 and 8. The enhanced planning processes must include:

A. scenario-based, probabilistic power engineering reliability analysis;

B. new interconnection studies and procedures;

C. DER hosting capacity analysis;

D. DER locational value analysis; and

E. integrated T&D planning.

To address the independent DSO versus utility DSO question, it is helpful to distinguish the responsibility to perform studies in the above areas from the responsibility for a process that interprets the results of the studies and makes decisions on such things as infrastructure upgrades and the assignment of costs to DERs interconnecting to the system. In Section IV, we suggested that it would be appropriate for the DO/utility to perform studies based on its engineering expertise and knowledge of its own system. We discussed this idea, which is a corollary of the relationship between an ISO/RTO and its participating transmission owners today, in terms of items A, B and C above. But we could readily extend the principle to the studies required for D and E, with the same proviso that these studies would feed into a parent process for decision-making that met the required regulatory attributes.

Although the comments of stakeholders in state proceedings and other writers on this topic do not seem to make the distinction between performing the technical studies and responsibility for the overall processes, there are several comments that suggest an independent DSO should be the responsible decision maker.

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[60] A. Nelson, A. Hoke, S. Chakraborty, J. Chebahtah, T. Wang, and B. Zimmerly, Inverter Load Rejection Over-Voltage Testing SolarCity CRADA Task 1a Final Report, National Renewable Energy Laboratory - SolarCity Corporation, February 2015.

For example, in its NY REV comments, SolarCity proposed that an IDSO would "Plan and design a safe and reliable distribution system in a manner that integrates DER as a primary means of meeting system needs."[61] SolarCity and others make the argument that an independent DSO would not be biased in decisions involving interconnections and viability of DERs as alternatives to traditional distribution system investments and operating expenses.

NRG, another independent DSO advocate, proposed that utilities initially have responsibility for planning, including assessing the locational benefits: "Utilities know best where on the system investment is needed, even if they are unsuited to determining the what."[62] [Emphasis in original.] In other words, the utility would be the best entity to determine what the system's needs are, but should not decide what types of facilities—wires, substation upgrades or DER portfolios—would best meet those needs.

NRG further states, "As we have learned at the wholesale level, the ISOs are adept at leveraging existing utility resources, and many grid planning and operations tasks continue to be done by the regulated utilities with oversight from the ISO."[63]

Transmission planning in ISO markets is a two-tier structure with the participating transmission owners performing the local power engineering reliability studies that identify the local transmission grid needs and propose mitigation measures including potential infrastructure investments. These engineering studies consider the impacts of generation interconnections as well as changes in system loading. The ISO, which is responsible for the overall planning process, incorporates these studies and proposals into an engineering-economic analysis of alternatives, including generation and DERs, through a stakeholder process to arrive at a regional transmission plan. The ISO effectively has authority from FERC under transmission tariffs to direct a participating transmission owner, or to solicit proposals from qualified independent entities,[64] to build new transmission as may be selected under this plan and recover the associated revenue requirements through a regulated rate for transmission service. The actual monetary amounts of each such entity's transmission revenue requirements must, however, be approved by FERC as prudently incurred.

This supports our idea that the primary issue is not who performs the power engineering analyses, but rather who is responsible for the overall planning process and for making recommendations and funding decisions for expenditures, including DER services that substitute for an infrastructure upgrade. Adapting the ISO transmission planning model suggests that a DSO would be responsible for conducting a transparent process with stakeholder involvement, within which the DO would perform the engineering studies and identify needs. The DSO would then evaluate a set of alternatives to mitigate the identified needs, with stakeholder input into the range of alternatives considered. The DSO also would determine the preferred mitigation for each need. Ultimately, however, the state commission

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[61] Comments of SolarCity Corporation, p.7, NY REV Track 1 Case 14-M-0101, July 18, 2014.

[62] NRG Response to Track One Policy Questions and Issues Surrounding the Rethinking the Energy Vision Proceeding, p. 5, NY PSC REV proceeding, 14-M-0101.

[63] Id., p. 8.

[64] Under the California ISO tariff, an independent entity that builds transmission in accordance with the transmission plan and then turns that infrastructure over to ISO operational control and recovers its costs through the regulated transmission access charge becomes an ISO participating transmission owner.

that regulates the DSO would have responsibility for ensuring an effective and transparent process and for authorizing the funding and implementation of the distribution plan.

Thus, we believe the questions to be addressed are as follows:

Is an independent DSO necessary to ensure the planning process is transparent and includes effective stakeholder involvement?
This question was considered in California in the context of new public utilities code §769, which was the driving motivation behind the CPUC's Distribution Resources Plan proceeding. The CPUC guidance ruling[65] explicitly assigns responsibility to the utility for all five planning functions, but clearly linked to requirements for increased transparency in the planning process, stakeholder review and regulatory oversight. This oversight extends to the authorization of subsequent decisions regarding the use of DERs as alternatives to utility investment through rate cases and other rate-setting proceedings.

In its Track 1 final order,[66] the New York PSC also assigned responsibility for distribution planning to the utilities and will likely have similar requirements for transparency, stakeholder participation and oversight. Transparency and openness of the planning process could be ensured under a utility DSO model if state regulatory oversight is incorporated into the process. This could adapt the current process transparency requirements used in several restructured states for utility default supply portfolio procurement.

Is an independent DSO necessary to assess alternatives for identified distribution system needs, including non-utility DER services as well as utility grid investments, and to perform unbiased selection of the preferred alternative for meeting each need?
This question relates to how the alternatives will be identified and assessed, how the preferred solution will be selected and sourced, as discussed next.

Who should be responsible for identifying and assessing distribution investment alternatives?
A key focus in California, Hawaii[67] and New York is optimizing distribution system economics and reliability through the use of DERs as alternatives to utility infrastructure expenditures. The process to identify alternatives starts with clearly defined distribution needs and performance requirements resulting from the DO's and DSO's planning analyses. The DSO would define a set of discrete services to meet the operational requirements which, if provided by DERs, could effectively substitute for an infrastructure upgrade. These services must be defined in a neutral manner, in terms of the technical or performance requirements that potential solutions must meet, rather than specifying a pre-determined DER technology solution to offset the grid infrastructure upgrade. Under this construct, the technical assessments that identify the distribution system needs and the performance requirements that a viable solution must meet would all be available to stakeholders in a transparent planning process. DER providers, the DO and others would then have the opportunity to propose solutions to the DSO that meet the requirements. The DSO as the party responsible for the planning process would assess the

[65] Issued Feb. 6, 2015, in the CPUC Distribution Resources Plan Proceeding, R14-08-013.
[66] NY PSC Reforming Energy Vision proceeding, 14-M-0101.
[67] Hawaii PUC, Instituting a Proceeding to Investigate Distributed Energy Resource Policies. Docket No. 2014-0192 Order No. 32269, Aug. 21, 2015.

alternatives, determine the preferred solution for each need, and then report and explain its recommendations for stakeholder comment and regulatory approval.

It is expected that the potential alternatives to any identified need will involve a range of solutions that may be sourced through one or more of these mechanisms:

a. **Prices** – DER response through time-varying, regulated rates and market-based prices
b. **Programs** – DERs developed through programs operated by the utility or third parties with funding by utility customers through retail rates or by the state
c. **Procurements** – DER services sourced through competitive procurements

Determining an optimal mix from these three categories, plus any grid infrastructure investments, requires both a portfolio development approach and a means to establish a comparative basis for these alternatives in terms such as firmness, response time and duration, load profile impacts, and value (net of the costs to integrate DERs into grid operations). Traditional methods of valuing energy efficiency and demand response alternatives are not adequate for distribution operational or infrastructure requirements.[68] Similarly, the operational firmness of DER response to time-varying rates needs be considered in developing a portfolio of alternatives to traditional investment. To date there has been limited procurement of DER services through competitive processes to defer transmission and distribution investments.[69]

The portfolio assessment to determine the preferred solution for each particular need would use a pre-approved methodology through a transparent regulatory process involving stakeholders. Approval of a portfolio would be the responsibility of the regulator in the context of its approval of the comprehensive distribution plan. These issues are being considered in California's Integration of Distributed Energy Resources proceeding (formerly called the Integrated Demand Side Management proceeding), which recently adopted an expanded scope that includes all types of DERs,[70] and which will be linked to the Distribution Resources Plan proceeding to create a new end-to-end process for identifying distribution system needs and values and then selecting and procuring DER solutions.

Should an independent DSO conduct the alternatives assessment and develop the portfolio of solutions?

The benefit of an independent entity is impartiality in conducting the analysis and developing the recommended portfolio for regulatory approval. Impartiality regarding recommendations on alternatives and the portfolio composition could be a concern if the DSO is also the DO and the alternatives have material impacts on the DO's profit or net operating revenue.

A utility DSO could perform this function given a transparent process overseen by the regulator and using analytic methods approved by the regulator, with the range of potential DER solutions open to market-based competitive proposals and inclusive of regulator-approved portfolio implementation

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[68] P. De Martini, DR 2.0: Future of Customer Response, LBNL, 2013,
[69] New York PSC Case 14-E-0302 approved the Con Edison Brooklyn/Queens Demand Management (BQDM) Program.
[70] CPUC R14-10-003, Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Demand Side Resource Programs. See particularly decision D.15-09-022, issued Sept.22, 2015, which adopts the new name and details the expanded scope of the proceeding.

plans. Additionally, a neutral consultant under contract to the regulator could perform a review of the portfolios and even the entire distribution plan. Stakeholder review also provides an important check on the key process attributes.

2. Operations functions: DER scheduling and coordination at T-D interface

Who should be responsible for physical coordination of DER schedules across the distribution grid and real-time coordination with the ISO at the T-D interface?
The DSO will need to coordinate all DER scheduled activity across the distribution grid to ensure distribution grid safety and reliability. The DSO will also need to have visibility and coordination responsibility with the DO and TSO to satisfy its responsibilities. This will include coordination of the physical schedules of DERs participating in wholesale markets and communication with DER aggregators. This specific function would not require the DSO to perform DER dispatch or aggregation, though it could require the DSO to direct some re-dispatch of DERs to manage real-time conditions on the distribution system.

There are two basic considerations related to these functions:

Does having an independent DSO introduce a new organizational layer in the operations of the integrated grid and add undesirable complexity into real-time operations?[71]
The answer to this question is currently being researched at PNNL in relation to grid operational and control architecture. The expectation is that technical analysis and operational simulations will help address this question. It is important to remember that functional division of responsibilities introduces additional interfaces (human and machine) that can add time and coordination issues into the operational control of the grid that may present undesirable operational risks.

Does a distribution utility have inherent conflicts related to coordination of schedules, and therefore might it perform these functions in a discriminatory manner or exert market power?
Scheduling involves three basic aspects: development of a coordinated distribution schedule, reconciliation of distribution and transmission schedules, and managing real-time distribution level curtailments. Potential issues may arise with reconciliation of distribution and transmission schedules as some DER supply-side services for transmission may not be able to flow due to distribution constraints. Additionally, real-time coordination may involve curtailments of previously scheduled services or transactions by supply-side DERs. As a starting point, distribution scheduling and curtailments should be governed by a clear set of regulatory rules and operating procedures and criteria.

If a distribution utility does not own supply-side DERs and does not perform wholesale procurement to serve retail load, it is not clear that it has inherent conflicts regarding scheduling and curtailments. If a distribution utility has an unregulated affiliate with supply-side DERs, then there may be a potential bias. The question then is whether affiliate codes of conduct and regulatory oversight are sufficient to ensure non-discriminatory scheduling and curtailment decisions. If a distribution utility owns supply-side DERs, then potential bias is clearer. In this case, the materiality (location and amount) of the supply-side DERs should be considered. If the distribution utility is also the load-serving entity and procures wholesale

[71] P. De Martini, M. Chandy and N. Fromer, Grid 2020: Towards a Policy of Renewable and Distributed Energy Resources, Caltech Resnick Institute, 2013, at p. 12.

energy for its load, there may be a tendency to favor the procured resources. This may become a greater concern where load-serving entities are subject to a renewable portfolio standard and wish to maximize the energy received from their contracted renewable generators. This scenario is discussed further in connection with the market functions of a DSO further below. In all cases, careful consideration should be given to whether functional separation and additional operational compliance requirements or performance-based regulation would sufficiently address the issues.

If an independent DSO is desired for other functions discussed in this section, these two operational functions—DER scheduling and coordination at T-D interface—should also be assigned to the independent DSO, as they are an integral part of the incremental operational processes.

3. Market functions

Who should be responsible for sourcing and pricing distribution grid services?
Once a DER portfolio has been selected and approved as the preferred alternative to a distribution or transmission upgrade, for example, there must be a process for sourcing and implementing the needed DER services. The question of who should do this is complicated by the fact that one entity may not be the most appropriate in all cases to source the needed services. In some instances it may be the DO; in others, the DSO or perhaps a load-serving entity responsible for serving retail load.

To begin with, we note that the DSO function does not involve designing retail rates or implementing energy efficiency and other demand-side programs. The regulator has oversight over retail rates, and load-serving entities, states and third parties implement demand-side programs. So, if these elements comprise part of the preferred solution to a need, the sourcing would not be completely in the hands of either the DO or the DSO. Setting aside these cases for the moment, we consider the sourcing of DER portfolios that do not include rate mechanisms or demand-side programs.

Perhaps the most clear-cut case is procurement of grid operational services to support reliable delivery of electric energy within defined power quality requirements. For DER services needed to support distribution operations but not associated with infrastructure deferral, the DSO as the party responsible for reliable grid operation would be the appropriate buyer.

In contrast, for DER services selected as the preferred solution to an infrastructure need, there are at least two possible approaches, with a third, hybrid approach in the early stages of discussion. None of these approaches places the sourcing in the DSO's hands (unless the DSO and the DO are the same entity). One approach is that DERs would be procured as distribution assets to be fully compensated through regulated distribution rates. In this case the DO would procure the DERs, analogous to the role of the participating transmission owner under the ISO transmission planning construct. Another approach would be for the DERs to participate as market facilities, compensated via bilateral power purchase agreements or capacity contracts with a load-serving entity, plus revenues the facilities might earn by participating in wholesale markets. In this case, the LSE would procure the bilateral contract. Under a conceptual hybrid approach, a facility could earn a portion of its revenues as a distribution asset via the regulated distribution rates, and another portion via a combination of wholesale bilateral energy contracts and spot market participation.

For any of these procurement variants, the resulting DER price would be determined by competitive offers from DER providers. Thus, the regulated buyer—who may be the DO, DSO or load-serving entity—does not set the market value. In the case of infrastructure deferment, however, there is an economic

ceiling set by reference to the cost of the needed infrastructure upgrade identified by the DSO in the planning process. This is also comparable to transmission planning, where a proposed non-wires alternative would need to be equal to or more cost-effective than the transmission upgrade in order to be selected.

Depending on the nature of the specific need for DERs and whether the DO, the DSO or the load-serving entity is the buyer of these services, the source of funding may be through distribution system rates paid by end-use customers and others using distribution service, or through retail energy rates. Either way, rates are determined through a regulatory process. In some cases, funding may be supplemented by the DER developer through participation in the wholesale market or, in some future scenarios, participation in distribution-level energy markets.

Who should be responsible for operational dispatch of DERs to maintain reliable distribution system operation?

In the wholesale market, the ISO or RTO dispatches resources, not the transmission owner. Similarly, DSO operational dispatch of DERs to maintain reliability, including DERs procured for operational services or infrastructure deferment, requires impartial use of these resources to meet safety and reliability objectives and constraints. This function is somewhat more complicated than the procurement function, however, because real-time dispatch coordination may include merchant DERs and DER aggregations that participate in the wholesale market and are responding to wholesale market dispatches in addition to meeting distribution grid needs. It may also include DERs procured by a load-serving entity to comply with renewable portfolio standards, which typically seek to maximize their energy output at all times.

Dispatch should be guided by clear rules that establish non-discriminatory dispatch priorities that enable the DSO to maintain safe, reliable operation, supported by effective compliance enforcement. For those resources procured by the DO or DSO and subject to dispatch by the DSO, there may be a preferred dispatch order established by the regulator as part of portfolio development and approval. One question often raised is whether a utility DSO would be biased against the use of DERs in real-time operations in favor of utility distribution assets. In practice, this is unlikely to occur because once the decision is made to adopt the given DER portfolio as an alternative to traditional distribution system infrastructure there will be no back-up infrastructure built or available. The DER solution would be the only resource available to meet the identified need. So, if the utility DSO doesn't optimally dispatch the sourced DERs, unacceptable, non-compliant, unsafe operating conditions or outages may result. Also, once regulators approve decisions in the planning and portfolio development process regarding the use of DER alternatives in lieu of utility infrastructure, investment concerns effectively become moot. However, this points to why regulatory oversight and approval of the distribution plan and portfolio of DER alternatives are vitally important.

There may still be latitude for the DSO to select or curtail certain resources or providers over others in operational practice—for example, when two or more DERs are equally effective in meeting a real-time operating need. Such latitude should be exercised on an impartial basis and in accordance with transparent processes and criteria established by the regulator. The exercise of operational discretion is at issue for whether an independent DSO is required. Thus, the challenge for a potential utility DSO is establishing and maintaining its impartiality regarding operational decisions that can only be evaluated by regulators after the fact. A key issue is whether a utility DSO has a potential conflict of interest through: a) an affiliate firm that is providing DER services; b) functional responsibilities related to dynamic rates or DSM programs in the portfolio that have a dispatch aspect; or c) an affiliate load-

serving entity that has procured renewable resources whose output it wants to maximize. If a distribution utility has none of these potential conflicts, then there is seemingly no inherent motive for a bias in resource dispatch.

If a utility has a competitive affiliate, then regulatory consideration should be given to whether existing code of conduct rules governing affiliate transactions with the utility have been effective in the past in mitigating potential bias and are adequate for the high-DER context or need to be expanded. Additionally, to address potential internal utility conflicts related to DSO functions and market-oriented functions, new state standards of conduct may need to be developed to ensure independence of distribution functions. These new standards could be adapted from FERC's Standards of Conduct for Transmission Providers. Similarly, such a distribution standard could deter undue preference by: (1) requiring utilities to functionally and physically separate employees engaged in distribution and marketing functions, and (2) prohibiting the disclosure of non-public distribution system information to marketing employees. If a regulator determines that codes of conduct can be effectively developed, applied and monitored, then an independent DSO may not be necessary for operational dispatch.

Utility load-serving entities with time-varying rates or demand-side programs (and utility performance incentive mechanisms) may have a bias in the preferred use of these resources in operational dispatch over other sourced DER services. Such programs entail explicit dispatch priorities, which should be considered in the development and sourcing of a DER services portfolio. Another potential conflict may arise if a utility has a load-serving role and a renewable portfolio standard obligation that includes distributed generation. Under typical constructs, a load-serving entity wants to get as much renewable energy as possible from eligible owned or contracted resources, often signing take-or-pay contracts, so that it will rarely if ever want to curtail the renewable generator. Thus, a utility DSO with an affiliated load-serving entity may have a conflict. These potential conflicts involving demand-side programs and renewable portfolio standards are largely driven by regulation. In these instances, any portfolio of DERs would need to consider the impact of existing regulatory priorities in the creation of a distribution-level dispatch priority order. DER portfolio dispatch priority is needed for an independent DSO as well. A dispatch priority approved by the state regulator may sufficiently mitigate dispatch bias when combined with the other measures described above. These considerations and potential mitigations should be considered in assessing whether the creation of an independent DSO is necessary.

Who should be responsible for aggregation of DERs?

Aggregation of DERs by a DSO to simplify the interface with the TSO is part of the Market DSO (see Section IV, Model C). In Stage 2, given a relatively modest amount of DERs participating in wholesale markets, it is not necessary to consider a single aggregator, as the number of entities aggregating DERs will be small. In this stage, the DSO may also provide aggregation services under a regulated tariff as one alternative, among other entities, for customers and DER providers seeking to participate in wholesale markets.

However, in Stage 3 of our distribution system evolution, with significant DER adoption and market participation, the distribution utility regulator and ISO may decide it is operationally more effective to simplify the T-D Interface and have a single aggregation of DER at each T-D node (Model C2 described in Section IV). In this case, the discussion of an independent DSO may be highly relevant. Regulators will need to ensure that DERs in a given LDA, which have no other access to the wholesale market except through the DSO, are treated in a transparent and non-discriminatory manner. Thus, any consideration of the Market DSO under Model C2, which we argued has great appeal due to the whole-system stability and control benefits that the system architecture perspective reveals, leads into a discussion of

transparent distribution-level energy markets or some comparable mechanism that can ensure non-discriminatory scheduling and dispatch within each LDA.

Who should be responsible for developing and operating a distribution-level energy market?
In Stage 2, as DER penetration increases, it is likely that distribution utilities, DER providers and prosumers will want to have greater temporal and locational granularity reflected in energy prices to capture the value of distribution grid constraints and losses. As the system evolves, it may be possible to combine the wholesale locational marginal price (LMP) for energy and the distribution constraint/loss value to a particular point on the distribution grid to create a distribution marginal price (DMP). This is also referred to as "LMP+D." While this may be useful to signal locational value through a dynamic locational retail rate or smart contract,[72] it would not in itself create a multi-sided market, with multiple buyers as well as sellers. Absent a multi-sided market, the process, roles and responsibilities described above for sourcing distribution grid services would still apply.

Distribution level, multi-sided energy markets may emerge in Stage 3 of our distribution system evolution framework. These multi-sided energy markets may involve three basic structures: a) bilateral forward energy transactions; b) an organized residual energy spot market; and c) an over-the-counter secondary, multi-sided market that buys and sells services, like displacement transactions to mitigate the real-time DMP.

For market types (a) and (c), the DSO could be focused on physical coordination, and another entity could manage the market pricing, scheduling and settlement functions. Thus, a bilateral distribution level market may evolve by parties transacting among themselves with little or no involvement by the DSO except to manage schedules for energy injections and withdrawals and maintain system reliability by dispatching DER services, analogous to wholesale energy markets. This is the predominant wholesale transaction type in the U.S., facilitated by firms like the Intercontinental Exchange. These types of firms, and not an independent DSO, may manage a distribution-level energy market.

Alternatively, if the desire is to create temporally and locationally granular ISO/RTO-type market auctions using distribution-level marginal energy prices, organizing and coordinating these markets at the distribution level will be very complex.[73] For example, in California the investor-owned utilities have a combined 9,500 distribution circuits. Most of these circuits' three phases are unbalanced, because most customers and DERs are connected to a single phase along the circuit through tap lines. This means a DMP may be needed for each phase to reflect the constraint/loss differences—a total of over 27,000 DMP nodes. Also, some have suggested that DMP have more locational and temporal granularity. For example, if the feeder breaker and a mid-point on a circuit were used for pricing nodes, this would involve over 50,000 discrete DMP nodes in California. Further, hourly pricing of distribution constraints and losses (i.e., to create a distribution adder to a LMP) would equate to over 36 million

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[72] C. Brandstätt, G. Brunekreeft and N. Friedrichsen, Locational signals to reduce network investments in smart distribution grids: what works and what not? Bremer Energie Instut, April 2011.

[73] This complexity involves both scaling the market functional dimensions cost-effectively and addressing the separation of physical law related to power flows and economic market decisions to simplify the decision process by removing mathematical difficulties that are presently a barrier to distributed spot markets. A comprehensive survey of the state of the art is in the following two-part tutorial: S. H. Low. Convex relaxation of optimal power flow. Part I: formulations and equivalence. IEEE Trans. Control of Network Systems, 1(1):15-27, March 2014. Part II: exactness. IEEE Trans. Control of Network Systems, 1(2):177-189, June 2014.

prices to calculate and at least as many micro-transactions to settle monthly in this example. In addition, there are issues with obtaining clean data and performing calculations (state estimation and optimal power flow analysis) to support development of these prices.

These numbers become astronomical if more DMP nodes and shorter time cycles are considered. In a scenario with five pricing nodes per circuit and five-minute pricing, this would equate to *over 1.4 billion DMP prices to clear and micro-transactions to settle monthly*. To put this into business operations context, Visa processes about 5 billion transactions globally each month.[74]

So what level of granularity is needed to achieve overall system efficiency objectives and provide net benefits to all customers? In considering this question, recall the discussion in Section III on the reliability versus economic efficiency tradeoff and the diminishing returns to complexity. If such a market is desirable, then an independent entity may be needed to operate a market and manage the transactions of this scale. But, it is unlikely to be a nonprofit, independent DSO—as currently envisioned—given the expertise in distributed market management and transaction processing required. Also, the economics of each state building multiple versions of these platforms is unlikely to be cost-effective especially since for-profit firms already exist in energy commodities and in other industries that could provide similar distributed market and micro-transaction settlement functions.

C. DSO Functional Model Summary

A foundational premise in this report is that the functional operation of the grid will change as DER adoption grows, because DERs use and interact with the grid in ways that are beyond traditional uses of the grid and related operations. Also, among the key policy objectives in a number of states is to realize the net value of DERs for all customers toward the goals of overall system efficiency and greenhouse gas reduction. In this context, DERs may provide non-wires alternatives for the distribution system in Stage 2 of our evolution framework and potentially intra-distribution level transactions in Stage 3. The presence of DERs is a fundamental prerequisite for stage 2 and 3 operational functions such as schedule coordination, portfolio dispatch, aggregation and settlements. Without high levels of DERs on a distribution system, these functions would not be necessary. By extension, the issues that arise in considering one DSO structure versus another, as described in this report, relate in two parts: a) the required functions related to Minimal (Model B) versus Market DSO (Model C) and b) scale of DERs in relation to evaluation of Total TSO (Model A) and the trade-off with Minimal versus Market DSO. This is why the timing, pace, and locational diffusion of DERs on a distribution system matter with respect to decisions about DSO functional evolution and structures.

As such, we chose to identify specific issues rather than try to provide definitive answers to the questions of which of the DSO models—B, C1 or C2—is best and whether an independent DSO is preferred to a utility DSO or vice versa. We chose this approach because we believe there may legitimately be different answers for different jurisdictions. It is more valuable for regulators and policy makers to work with their constituents to define objectives and envision their preferred future end state, and for industry participants and stakeholders to wrestle with these design questions and issues, than it would be for us or some other experts to tell them what we think are the right answers.

[74] Visa processed 64.9 billion global credit card transactions in fiscal year 2014, according to its 2014 Annual Report.

The key points that emerge from the discussion in this section are as follows:

1. Total TSO (Model A) is interesting as a conceptual bookend, but is not practical for a high-DER system. As the amount and diversity of DERs on the system increase, the distribution utility or DSO will need to assume new or enhanced planning, operations and market functions and capabilities. Even in areas where the utility TSO or ISO/RTO expands its functions to include such things as DER dispatch, there are practical limits to the feasibility of having the TSO take on all the new requirements of the high-DER system.
2. Regulators should focus on enhancing transparency and stakeholder participation in their earliest considerations of DER expansion. Stage 1 of the evolutionary process does not in itself impose significant new requirements on the distribution utility. However, forward-looking regulators and utilities may want to begin to prepare for DER expansion by initiating regular engineering studies to measure DER hosting capacity and consider regulatory and process reforms to clarify and streamline their DER interconnection procedures.
3. The question of independent DSO versus utility DSO becomes relevant as DER expansion moves into Stage 2 and beyond. The potential for bias and barriers to DER development could occur in the areas of distribution planning, DER interconnection procedures, and real-time operations. Due to the diversity of new players entering the DER landscape and the rapidity of changes in technologies and customer demands, attributes such as transparency, non-discrimination, and minimizing risk of stranded investment are crucially important. Each jurisdiction will need to assess its ability to sustain these attributes under a more traditional, regulated-utility framework with modifications, versus creating an independent DSO.
4. In Stage 2, when DERs can provide real-time operational services and increasingly offset distribution infrastructure investments, system needs should be defined in a technology-neutral manner. Sourcing mechanisms should be non-discriminatory to encourage competition and innovation that provide net positive benefits for all customers.
5. Clear, transparent operating procedures will be needed to ensure the DSO performs its real-time operational functions in a non-discriminatory manner. Development of distribution level operating standards of conduct may be appropriate to address potential conflicts of interest that may arise with regard to real-time re-dispatch of DERs to maintain reliability, if the DSO owns or is affiliated with the owner of DERs on the system, or serves load or is affiliated with a load-serving entity that wants to maximize the use of its preferred supply resources.
6. As this report has emphasized throughout, the expansion of DERs into Stage 2 will require substantial enhanced functional capabilities on the part of the DSO. The functional roles, responsibilities and relationships derived from the detailed discussion above, irrespective of independent or utility DSO, would result in a very complex integrated operational structure as Figure 9 illustrates.[75] This illustration shows in a single frame how complicated the operational requirements of a high-DER future are likely to be. At the same time, power systems have always been complicated. Portraying the complexity in such a diagram

[75] J. Taft, L. Kristov and P. De Martini, A Reference Model for Distribution Grid Control in the 21st Century, Pacific Northwest National Laboratory, 2015.

demonstrates the possibility of approaching industry evolution logically, architecturally and, most important, manageably. Figure 9 represents the structure implied by the functional requirements of the high-DER system, as described in this report and currently being considered in California and New York. This set of interactions at scale will need to be coordinated between wholesale/transmission operations and those at distribution level to ensure reliable operation.

Three DSO models (B, C1 and C2) are distinguished by the solid and dashed green lines at the left-hand side of the diagram. The dashed line labeled B furthest to the left indicates direct participation by diverse merchant DERs and prosumers in the wholesale market, which is associated with the Minimal DSO Model B. The second dashed line, labeled C1, indicates direct participation by aggregators in the wholesale market, with all individual prosumers and DERs participating through the aggregators, which is associated with Market DSO Model C1. Finally, if both dashed lines are removed, then all wholesale market participation by DERs, aggregated or individually, is through the DSO illustrated by the solid green line labeled C2, for Market DSO Model C2. Other than these distinctions, the functions and interactions shown in the diagram reflect the foundational operational and planning requirements of a high-DER electric system.

The set of functions and interactions illustrated would be replicated for each T-D interface and its related distribution substations and feeders within a utility's service territory. Also, assigning certain responsibilities of this operational structure to an independent entity introduces another dimension of complexity that needs to be considered. Whether an independent DSO or utility DSO is pursued, careful attention to architecture and design, using tools such as schematics like Figure 9, is required to address the complexity and operational risks[76] inherent in such a system at the scale anticipated in Stage 2 of distribution system evolution.

7. Before a jurisdiction decides to move into Stage 3, we recommend resolving the issues identified in point 6 above, starting with the choice of the preferred DSO model and its role in managing the T-D interface and DER participation in the wholesale markets. Allowing peer-to-peer transactions at scale across distribution adds significant complexity to an already complicated operational model. The principal issues with peer-to-peer transactions involve development of cost-effective market constructs for imbalance energy and balancing net load and supply. For example, the temporal and spatial granularity of locational spot prices for imbalance energy, or distribution losses and constraints on the distribution system, can quickly escalate to the hundreds of thousands given the number of potential nodes and normal phase imbalances, and the volume of small transactions to the hundreds of millions. It is not yet clear what level of locational and temporal granularity yields net benefits for all customers.

[76] P. De Martini and L. von Prellwitz, Risky Business, Transmission & Distribution World, 2013.

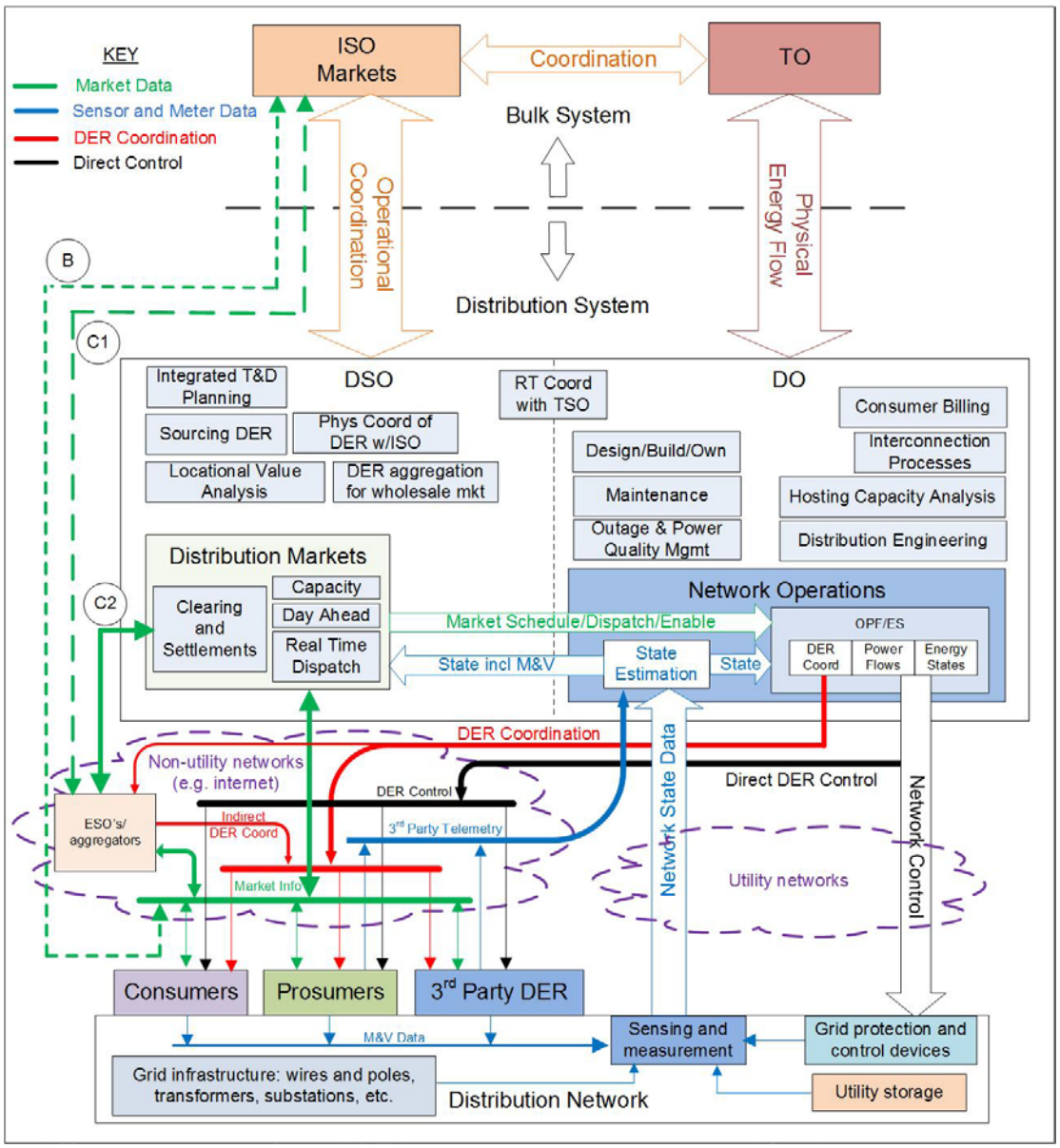

Figure 9. Map of Core Functions & Interrelationships in a High-DER Electric System.
Representation of the complex structure and coordinated set of interactions required between wholesale/transmission operations and distribution level operations for a high DER system. Three distribution system operator (DSO) models (B, C1 and C2) are distinguished by the solid and dashed green lines at the left-hand side of the diagram. These represent different modes of DER participation in wholesale markets.

VI. Considerations and Recommendations

This report provides a framework for comparing possible ways to structure the roles, responsibilities and incentives for operators of distribution systems, for a future electric system that features high penetration of diverse DERs. The framework is intended in particular to be useful for state utility regulators and policy makers, to help them think about distribution system planning, operation, markets and oversight for the 21st century. A key regulatory goal in this context is to plan and operate reliable

and cost-effective distribution systems incorporating the optimal potential of DERs to help achieve these objectives and other energy and environmental policies.

A. Structured Sequence for Addressing the Issues

The following steps provide a logical sequence of considerations for regulation of electricity distribution systems in a future with high DER penetration.

Step One: Ensure physical capability and reliable operation of the distribution system

The first, and primary, considerations derive from the fundamental question of how to plan and operate an electric system with significant amounts of customer and merchant DERs in order to ensure safety, reliability, resilience and affordability. Design choices must respect the physical laws governing the electric distribution system while achieving public policy objectives. Planning and operational concerns are primary not because they are more important, but because they provide a foundation for subsequent decisions about market design and organizational structure, which must be made to align with the operational needs of the high-DER distribution system.

Step Two: Develop market and regulatory structures to fully realize DER value

The second set of considerations related to fully realizing the value of DERs for distribution (and bulk power) systems requires that they can effectively and substantially reduce T&D operational expenses and offset investment in T&D infrastructure and utility-scale generation. This in turn requires a market and regulatory framework to ensure DER availability and performance when and where needed. Different types of procurement and compensation mechanisms and market structures should be considered, with careful attention paid to determining the best tool for the job in all instances. Where DERs are proposed to avoid distribution or transmission investments, the much longer lead time for building the foregone traditional grid upgrade requires enforceable assignment of accountability for the DERs to be operational, and with the needed performance characteristics, by the time the grid upgrade would have needed to be in service. This means that market structures and associated regulatory frameworks need to consider the whole life-cycle, from identifying the needs that DERs could fulfill, to determining the best portfolio of DERs to meet each specific need, to procuring, implementing, dispatching and operating the DERs to meet real-time grid operating requirements.

Step Three: Design organizational structure to realize policy and regulatory objectives

Questions of organizational structure comprise the third step in our sequence. We start with the high-level policy objectives for the system, then derive the attributes or qualities the system must have to achieve those objectives, determine the operational capabilities or functions the system must perform, and assess how to plan the system to embody those capabilities and functions while maintaining safe and reliable operation (see step one). On this basis, we design the tools required, likely a combination of control and communication systems; markets of different types (procurements, bilateral contracts, spot prices); retail rate designs; and DER programs, products and services (see step two). The last step involves determining the organizational structure that will work best—specifying the functions to be performed by distribution utilities, the boundaries between the utilities' regulated monopoly functions and competitive functions, whether there is a need for an independent DSO to perform some functions, and how best to ensure the regulatory attributes of non-discrimination, transparency, absence of market power, effective oversight and optimal timing of major decisions. Throughout the entire process, regulators and stakeholders should maintain clear lines of sight between the design decisions being made at each step and the end-state vision toward which the electric distribution system is evolving.

B. Evolution of Regulatory Decision-making

The first fundamental observation the reader should take from this report is that traditional modes of distribution system planning and operation are not adequate for a high-DER power system. New York's REV proceeding, California's Distribution Resources Plans and Hawaii's Grid Modernization proceedings have initiated major activities to develop the needed enhancements. For regulators in other jurisdictions, the question is not whether but when the new capabilities will be required.

There is probably not much need for advanced planning and operations in a distribution system in Stage 1 of our evolutionary framework, where DER presence on the grid is relatively small and manageable. But even in a Stage 1 system there may be forces at work that will drive DER expansion and related requirements in the near future, suggesting that it may be time to consider and plan for system evolution. Such forces would include policy objectives and bottom-up interest on the part of customers and local jurisdictions—for example, to build greater individual or community resilience to electric system disturbances through microgrids, or to improve the environmental footprint by developing local renewable energy resources.

At Stage 2, the system will definitely need enhanced capabilities. The central feature of Stage 2 is a framework for leveraging the value of DERs to provide services to support distribution system operation and to defer or avoid costly distribution system upgrades. This means developing methods to identify needs of the system by location, determine hosting capacity, assess potential benefits of DERs on a particular feeder and distribute DERs optimally within an LDA. The new framework must also define DER services that the system needs, including the performance characteristics required of DERs in order to provide those services, as well as approved mechanisms for distribution utilities to procure and compensate such services. The Stage 2 system will also need advanced grid platform technologies and operating procedures for the distribution utility to call upon the DERs when needed in real time and track performance. Such a framework would essentially create an initial market for DER services in which the distribution utility or DSO would be the sole or primary buyer, perhaps in the form of request for offer-based procurement under bilateral contracts between the DSO and DER providers.

The Stage 3 system will require more elaborate market enhancements, as discussed in sections II and IV in this report.

The point for state regulators and policy makers is that the need for enhanced capabilities on the part of distribution utilities will depend not only on the current stage of DER development, but also on expected future needs due to trends of customer adoption and the intended impacts of specific policies. How should regulators think about these future needs?

The first question to ask is what level of DER expansion and what forms of DER participation does the jurisdiction want to allow or enable, both in the near term (five years or sooner) and in the longer term (five to 10 years and beyond). The answer should draw upon higher-level policy objectives, translated into clear system qualities upon which to design changes in regulations and programs.

We categorize several possibilities for DER participation below. We anticipate the later categories 4 and 5 of DER participation to be implemented on top of categories 1 and 3, and to be potentially viable in both restructured and vertically integrated utility jurisdictions. Category 2 depends on the existence of ISO/RTO market opportunities for DERs.

1. *Behind-the-meter services to end-use customers only.* For example, rooftop solar PV, possibly augmented with battery storage and automated controls, can serve customers' own premises, as well as electric vehicle charging at residences and commercial and municipal sites.
2. *Participation in wholesale markets.* In ISO/RTO regions where demand response resources already participate in the markets, it may be natural to allow all types of DERs to participate in wholesale energy, capacity and ancillary services markets—if they meet requisite availability and performance requirements.

For the most part, steps 1 and 2 are already in progress. As long as the amounts of DER are small, regions that are in Stage 1 of our evolutionary framework may require little enhancement of distribution utility functional capabilities beyond what they have today. At higher levels of DER wholesale market participation, however, management of the T-D interface may require new coordination capabilities between the DSO and ISO.

3. *DERs provide operational and infrastructure deferment services to the distribution utility.* This objective moves the system into Stage 2 and will require utilities to enhance some functional capabilities.
4. *DERs and prosumers engage in transactions for energy, capacity and other services, using the distribution system as a platform.* The DSO must be able to coordinate such transactions to maintain reliable and safe operation, and likely provide scheduling and settlement services. This is clearly Stage 3 of our evolutionary framework, the stage at which the core issue of independent DSO versus utility DSO is most meaningful. Given the cumulative effects of all four categories of DER activities (this category and the three above) occurring concurrently, the entry into Stage 3 will be the most far-reaching in terms of the functional capabilities required of the DSO.
5. *Local jurisdiction objectives, such as convergences among municipal services (e.g., water, wastewater treatment, transportation), local resource development for economic development and environmental reasons, and local resilience objectives.* In this realm of policy objectives, strategic planning is needed to translate high-level objectives into specific ways DERs and the distribution system can be used to meet local objectives. The distribution utility could be a valuable collaborator with the local jurisdictions in this process.

As regulators decide whether to implement a DSO, it's prudent to give due consideration to a number of factors. The next section describes several principles to consider in the process.

C. Analytical Framework Principles for Regulators

The framework developed in this report follows the logic of the following principles:

1. The transformation of the electric system to accommodate high penetration of DERs, changing customer service expectations, and other change drivers must start from a clear statement of state and local policy objectives. From those objectives we derive the distribution system attributes or qualities required in order to achieve those objectives.
2. Design of a future distribution system with the needed qualities starts from the basic necessity of reliable and safe operation. The system that provides electric service is first and foremost a system of wires and other physical equipment, plus operating and control procedures, all of which must obey the laws of physics. Thus, the first design task is to

identify the functional capabilities the system must have in order to maintain reliable and safe operation. Then we determine how best to provide those functional capabilities by defining the key structures, actors, processes, and technologies and their inter-relationships.

3. The answer to how best to provide needed capabilities will depend on the stage of distribution system evolution in any particular jurisdiction, considering both the current stage and the desired end stage.

    a. The desired end stage should be linked clearly to the state and local policy objectives.

    b. Different jurisdictions may have different end stages in mind, to reflect a combination of their objectives or aspirations and the realities of resources, conditions, customer mix and capabilities.

    c. Despite the best intentions of state and local policy makers, there are limits to their ability to control outcomes given customers' increasing ability to choose technology-driven alternatives. This is particularly true in the evolution to a high-DER electric system because it is driven largely from the bottom up, by technological innovation (and resulting cost reductions) and the decisions of individual energy users and local communities.

4. Distribution level markets should be considered carefully. Markets are not ends or objectives in themselves. They are potential tools to elicit system qualities necessary to achieve desired objectives. For any given need, quality or objective, a particular market structure may or may not be the best tool, and may or may not be achievable. Thus, it is critical to compare market tools against other ways to achieve the objectives as described in this report and examine their relative pros and cons for the given context.

5. Some industry participants and experts assert that if we "get the prices right" and allow decentralized market participants to act autonomously, concerns like system reliability, real-time operation and infrastructure investment will occur in an optimal fashion without the need for any central entity with responsibility and accountability in these areas. It is crucial to realize that this belief is based largely on theory rather than empirical evidence. We know of no instance where a complex, physically-based, highly technical system has worked reliably and consistently simply through the actions of autonomous participants responding to prices, without the services of a central entity responsible for certain essential coordination and operational functions.

    We do not deny the importance of establishing prices that reflect actual costs and conditions that allow for efficient competition and the autonomous actions of individual actors. Our point is simply that getting the prices right is not a *sufficient* strategy for enabling the high-DER electric system of the future and ensuring that its performance aligns with public policy objectives and maximizes societal and customer benefits. In particular, good pricing alone cannot eliminate the need in a complex system for certain critical coordination functions to be performed by a central entity like a DSO.

One final point this report does not discuss in any detail: Electric service cannot be viewed in isolation from the uses of electric service in a society, and therefore should not be viewed simply in terms of provision of a kWh or kW commodity for a price. In particular, an aspect of the industry transformation now in progress with the growth of DERs is the convergence of electric service with other essential services, including water supply, wastewater treatment and transportation. As state and local

jurisdictions encounter tightening budget constraints and impacts of climate instability, there is an increasing need to explore potential synergies of convergence of these systems. A question for policy makers to consider, then, is how best to leverage the distribution utility of the future to support state and local interests beyond basic electric service, in order to enhance the quality of life and economic vitality of residents and businesses who depend on electric service.