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Restructuring Revisited: Competition and Coordination in Electricity Distribution Systems

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Abstract

This paper addresses the implications of the emergence of distributed energy resources (DERs) for industry structure in the electric power sector. Regulations on industry structures dictate which actors can perform which roles in the power sector and play a key role in enabling or preventing efficient power sector planning, investment, and operation. However, the structures in place today were designed in an era characterized by centralized resources, unidirectional power flows, and relatively price inelastic demand. In light of the decentralization of the power sector, regulators and policy makers must carefully reconsider how industry structure at the distribution level affects system planning, coordination, and operation, as well as competition, market development, and cost efficiency. To address this critical issue, we analyze the economic characteristics of the actors necessary for efficient and reliable distribution system planning, investment, and operation: distribution network owners and operators, DER owners, aggregators and retailers, and data managers. We translate the foundational theories in industrial organization and the lessons learned during the previous wave of power system restructuring to the modern context in order to analyze the implications of these characteristics on the potential for competition in the roles of DER ownership and aggregation. This analysis provides deep insight into questions such as whether or not monopoly distribution utilities should be allowed to own distributed resources. We then analyze how the mechanisms for coordinating vertically and horizontally disaggregated actors need to be updated, focusing on the need to improve the price signals present at the distribution level. We argue that the price signals governing transactions at the distribution level must increasingly internalize the cost of network externalities, revealing the marginal cost or benefit of an actor's decisions. This will require a dramatic rethinking of electricity tariffs.

1 INTRODUCTION AND FRAMING

The emergence of distributed energy resources (DERs)[1], digital technologies, and innovations in power electronics and network technologies are creating new options for the delivery of electricity services and the potential for more affordable and resilient power systems. However, these developments are also placing new strains on electric power industry structures that were established in a time of static distribution networks and relatively inelastic demand. DERs and digital technologies dramatically expand the number of potential investors in and operators of power system infrastructure, challenging traditional means of planning and coordinating the construction of generation, storage, and network assets. Further, DERs are connected to electricity distribution systems. Distribution-connected resources have historically not participated in traditional means of executing least cost, security-constrained dispatch of generation and typically face regulated tariffs as opposed to market-determined prices. Thus, the emergence of DERs is challenging the structures historically used to coordinate investments in power system infrastructure and to coordinate supply and demand to ensure reliable operations of power systems in real time.

During the wave of restructuring that swept through the electricity industry in the 1980s, 1990s, and 2000s, regulators grappled with questions about the value of enabling or encouraging competition in the generation and (to a lesser extent) retail sectors. This spawned a set of questions over how to assign the roles of transmission system ownership and operation, generation ownership, bulk power market operation, and retailing to power system actors in order to ensure efficient pricing and the development of an affordable mix of transmission and generation assets in the short and long run (European Commission, 2009; FERC, 1999; Joskow, 1996; Joskow and Schmalensee, 1983).

Today, the challenges described above have spurred regulators to engage in analogous debates over which actors should perform which roles within the distribution system. The primary objectives of these debates are two-fold. First, regulators are interested in ensuring the efficient utilization of and investment in both DERs and the system's conventional suite of network, generation, demand, and storage resources. Second, regulators are interested in maintaining or enhancing competition in the horizontal segments of the power

[1] A DER is any resource capable of providing electricity services that is located in the distribution system. DERs include distribution-connected demand response, generation, energy storage, and energy control devices.

sector (e.g., generation and retailing) where it exists, while potentially fostering more competitive provision of "non-wires" or operational alternatives to investment in conventional network assets.[2]

Existing industry structures do not adequately achieve these goals, prompting a need to revisit the challenge of industry structure once again. Efficient coordination of investments and operations of a mix of generation and energy storage devices at various scales, demand-side flexibility, and transmission and distribution network assets holds the potential to reduce overall electricity costs relative to a system with uncoordinated investments (Baldick and Kahn, 1993; MIT, 2016). In power systems where actors remain vertically integrated across generation, transmission, distribution, and retail, this coordination requires a set of internal planning and operating decisions and appropriate price signals, incentives and/or communications with electricity users. In systems with competition in generation and/or retail, this coordination requires multilateral arrangements between monopoly network providers and market actors and, in many cases, market-facilitated price signals and contracts for energy, capacity, and ancillary services. In light of the decentralization of the power sector, regulators and policy makers must carefully consider how industry structure impacts the ability of power sector stakeholders actors to efficiently and reliably plan, coordinate, and operate distribution networks and connected devices while evaluating implications of today's and potential future industry structures for competition, market development, and cost efficiency.

To facilitate this critical task, this paper begins in Section 2 by defining and reviewing the core activities and economic characteristics of six key industry roles: distribution network ownership (DNO); distribution system operation (DSO); DER ownership and operation; distribution-level markets; aggregation of demand and DERs; and data management. We also discuss the monopoly nature of the DNO and DSO roles, and consider the implications of their monopoly characteristics on adjacent roles that may be suitable for competition: DER ownership and aggregation. Section 3 of this paper then discusses the arrangements needed to coordinate actions between the distribution network owners and operators and DER owners and electricity consumers. We conclude in Section 4 with a summary and raise a series of additional research questions. Throughout this document, our analysis focuses primarily

[2] We recognize that power sector stakeholders may have additional goals, including ensuring universal and affordable electricity access, decarbonizing the power sector, and ensuring cyber-physical security, etc. For a review of state-level regulatory and policy goals, see (DOE DSPx, 2017).

on whether a given structure is likely to lead to the least-cost[3] mix of network and generation resources in the short and the long run.

This paper has implications for five questions that are currently being debated by regulators and policy makers globally.

1. Should distribution system operations be separated from distribution network ownership in order to ensure the neutrality of the DSO role?
2. Should DNOs be allowed to own and operate DERs, or should DER ownership be left exclusively to competitive actors?
3. Does the emergence of DERs necessitate a reconsideration of the role of competition in the provision of aggregation services such as retailing[4]?
4. What is the role of the distribution system operator (DSO) – independent or otherwise – in future power system operations?
5. What, if any, market mechanisms might be needed under different institutional arrangements to coordinate efficient investment and operational decisions across various actors?

We find that separating distribution system operations and network ownership would likely result in a decrease in system efficiency relative to a system in which the DNO and DSO are a single entity. However, a combined DNO and DSO must be sufficiently separated from any competitive activities, given that the future DSOs will be responsible for a much greater degree of system operation and planning and given that DSOs will increasingly procure services from a variety of distributed network users and aggregators. If DNOs and DSOs are barred from owning and operating DERs, price signals must be dramatically improved to ensure that network users adopt and operate DERs in a way that maximizes the welfare of the power system as a whole, rather than for any one network user at the expense of others. This will likely require significant improvements in electricity tariff design that align individual incentives with

[3] We note that least-cost implies least-*societal* cost. Societal costs include the costs of blackouts, externalities, and other social costs. A least cost system should therefore balance the cost of increasing reliability and resiliency with the costs of failing to deliver power during certain times (after accounting for any minimum reliability standards for all customers). A least-cost system should also, in theory, incorporate the costs of environmental externalities such as greenhouse gas emissions. Thus, in the context of this paper, efficient implies that the least-cost system meets reliability standards and properly accounts for environmental and other externalities.

[4] Retailers are a subset of the broader category of aggregators. Retailers aggregate consumers (and, in some cases, producers) and procure power on their behalf. These retailers also comply with power system regulations, perform hedging functions, and other activities on consumers' behalf (Burger et al., 2017). We refer to retailers as aggregators or retail aggregators throughout this paper, and only specify differences between DER aggregators and retailers where relevant.

cost-savings opportunities for the system as a whole as well as new market mechanisms such as auctions for procuring non-wires alternatives.

1.1 LITERATURE REVIEW

The bulk of the literature on electric power industry reform and the ensuing structure – developed during the 1980s, 1990s, and early 2000s – focuses on the use of transaction cost economics and comparative institutional analysis, and centers around the assignment of responsibilities for bulk power generation, transmission system ownership and operation, and, to a lesser degree, retailing functions. The transaction cost economics framework states that the structure of the power sector – that is, the extent of vertical and horizontal integration – is the efficient outcome of attempts to coordinate the sector's many interlinked roles and to manage the complexities introduced by the network externalities (losses and congestions) that are pervasive in power systems (Joskow and Schmalensee 1983).

Transaction cost economics, first articulated by Williamson (1979, 1975, 1971) dictates that firms face choices to perform certain activities or functions (e.g. production of a good) within the firm or to contract with external parties for these activities or functions. Where contracting involves highly complex activities, is infrequent, involves durable and specific assets, large degrees of uncertainty over the value of these assets, and where the quality of the assets is difficult for the contracting party to verify, firms will typically seek to integrate these activities into their operations. In this context, integration can increase efficiency by minimizing transaction costs, Vertical integration can also increase efficiency by preventing double marginalization[5] (Spengler, 1950) and enabling more efficient investment in infrastructure (Hart and Moore, 1990; Williamson, 1975). Thus, setting aside the potential for negative impacts on competition and market power, the efficient outcome under some conditions is vertical integration.

Substantial empirical evidence validates these theories across a number of industries (Lafontaine and Slade, 2007) and within the power sector in particular (Joskow, 1987, 1985). Alternative theories of vertical integration based on evaluation of property rights (Hart and Moore, 1990) or moral hazard (Lafontaine and Slade, 2007) exist, but transaction cost analyses, such as those performed by Joskow and Schmalensee (1983), Joskow (1996), and Newbery (2002) have dominated the literature on vertical integration and the introduction of competition in power generation and retail aggregation.

[5] Double marginalization is the phenomenon of multiple firms in different vertical segments of an industry charging prices above the marginal cost of provision.

However, vertical integration is not costless. It creates the possibility for the vertically integrated firm to foreclose (that is, raise the costs of) competitors (Rey and Tirole, 2007). This is especially true in the electric power industry, where certain horizontal segments of the sector (transmission and distribution) are natural monopolies (Joskow, 1996) and control physical access between suppliers and consumers. Where vertically integrated firms act as monopolies, they do not face the incentives for efficiency created by competition. Regulators attempt to create incentives for efficiency, but regulation is never perfect and often fails to create effective incentives (Cicala, 2015; Laffont and Tirole, 1993). Thus, when considering any given industry structure, we must consider the potential for both costs and benefits from various degrees of integration.

Previous analyses of the role of distribution utilities in power systems with significant penetrations of DERs focused primarily on the benefits of improved coordination of investments in network infrastructure and DERs that may potentially be achieved through integration (Bauknecht and Brunekreeft, 2008; Brunekreeft and Ehlers, 2006). However, previous work has not considered the multitude of potential structures at the distribution level and the potential efficiencies gained through competition in a given horizontal segment.

More recent literature on distribution-level organization has concentrated on three broad issues:

1) the evolving roles of the DNO and DSO;
2) the value of separating or integrating the DNO and DSO functions;
3) coordination of the DSO and bulk system balancing authorities (BAs)[6] and power markets.

We briefly summarize the literature on each of these three dimensions below.

The evolving roles of the DNO and DSO. For example, van Werven and Scheepers (2005) argue that the emergence of DERs creates the need for more active distribution system operations, and that enabling such operations requires stronger unbundling and better incentive regulation. Eurelectric (2016a) highlights the need for the DSO to remain neutral in future power systems. The U.S. Department of Energy's DSPx Initiative (2017) defines many of the capabilities and functions of future distribution network, system, and market operators in a descriptive fashion, focusing on the actions required to ensure reliable system operations. Martini et al. (2015) and Kristov et al. (2016) discuss alternative models for

[6] We refer to the actor responsible for bulk power system balancing and real-time dispatch as the Balancing Authority or BA. The BA can take many forms. In the U.S., vertically integrated utilities, independent system operators (ISOs), and regional transmission operators (RTOs) perform balancing in different geographies. In the European Union, balancing is performed by transmission system operators (TSOs). Where it is important to do so, we distinguish between a vertically integrated utility, an independent RTO or ISO, or a TSO.

assigning distribution level roles to power system actors and advocate for increasing the responsibility of the DSO in power system operations. Similarly, Corneli et al. (2015) compare two high-level visions of the future, but do not compare the potential efficiency of these visions or the key economic tradeoffs. Bahramirad et al. (2016) describe a vision for a DSO that takes primary responsibility over scheduling resources and demand within its service territory, but do not compare this structure to other potential structures. MIT (2016) reviews the lessons learned from restructuring conversations in the 1990s and 2000s and discusses the pros and cons of three potential options for distribution level institutional arrangements. The primary options discussed by MIT (2016) are: 1) a distribution system operator independent from the distribution network owner, 2) a combined distribution network owner and operator that is independent from all competitive activities, and 3) a vertically integrated and closely regulated utility.

The value or cost of an independent DSO. Drawing parallels to established independent system operators at the bulk power system level, Wellinghoff and Tong (2014) argue that separating the DSO and DNO roles creates the best environment for competitive distributed energy resource deployment. Friedrichsen (2015) similarly argues for separating distribution system operations and ownership due to the increasing responsibilities of DSOs and the practical challenges of unbundling DNOs from other market activities. Friedrichsen's analysis is based on transaction cost economics, but does not describe alternatives to the independent DSO (IDSO) model in detail. Helm (2017) also describes the functioning of an independent DSO in the UK context without describing structural alternatives.

DSO-BA coordination. Finally, a number of authors have focused on coordinating DSO activities with bulk system balancing authorities. Ruester et al. (2014) highlight the changing nature of the DSO vis-à-vis the bulk system BAs and argue for increased regulatory oversight to ensure that DSOs do not abuse their monopoly positions in aggregation and DER markets. CAISO et al. (2017) provides a near term roadmap for coordination in the California context, focusing on ensuring that distribution network constraints are respected in market and balancing operations. Many other industry reports and academic papers have focused on this issue, primarily outlining different methods for ensuring operational feasibility in the near term.

This paper advances the state of the art on this subject by considering the full range of industry roles necessary to plan and electricity distribution systems, and highlighting the considerations for competition, coordination, and efficiency of different industry structures through a transaction cost framework. By translating the foundational theory and modern work in markets and hierarchies to the present situation, this provides a more holistic framework with which to make informed structure decisions.

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2 INDUSTRY STRUCTURE AND COMPETITION

In the subsequent sections, we discuss each of the key roles at the distribution level. The focus of this section is on the implications for competition of potential industry structure decisions governing the assignment of each key role and varying degrees of integration with other roles in the power system.[7]

2.1 ACTORS, ROLES, AND VERTICAL INTEGRATION

To aid in our analysis, we distinguish between actors, roles, and activities. An actor is a legal entity (i.e. a company or institution) that performs certain roles in the power sector. A role is a set of activities in a given horizontal segment of the power sector. The six roles under discussion in this paper are distribution network ownership, distribution system operation, DER ownership and operation, aggregation, market operation, and data management. If a single actor performs more than one role, we consider this actor to be vertically integrated between these roles. In horizontal segments of the power sector where competition has been introduced, such as aggregation, generation, and/or DER ownership and operation, multiple actors perform the roles in this segment and compete for market share.

It is important to distinguish between fully vertically integrated actors, vertically integrated actors with different degrees of legal or regulatory separation between roles, and fully unbundled (i.e., financially independent) roles. In some jurisdictions, actors remain fully vertically integrated, and no legal or organizational barriers exist between roles. However, in certain jurisdictions, regulators and policy makers seeking to promote competition and efficiency during the previous wave of restructuring created "barriers" between certain roles (primarily between monopoly and competitive roles). These separations take a variety of forms. Primarily, regulators may separate vertically integrated actors into a set of legally distinct companies corresponding to different roles but owned by a single parent actor (typically a holding company or similar corporation). This is referred to as "legal unbundling." Legal unbundling involves the separation of costs and revenues, independent management, and rules governing sharing and dissemination of information dissemination between the legally unbundled roles. In contrast, full "ownership unbundling" prevents an actor from having any financial or commercial interest in other roles

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[7] Section 3 then discusses the mechanisms needed to coordinate any vertically and horizontally disaggregated actors.

open to competition. These distinctions are important given the multiple implications and challenges of full ownership unbundling.

2.2 DISTRIBUTION NETWORK OWNERSHIP

In many systems, DNOs are vertically integrated with the other power sector roles discussed in this paper. In particular, the DNO is currently vertically integrated with the DSO role in every power system, although we will discuss the key considerations in potentially establishing an independent DSO in Section 2.3. Nonetheless, it is important to develop an understanding of the key characteristics and the core responsibilities of the DNO role on its own, as this understanding builds useful intuition for the remainder of the discussion. In the majority of power systems globally, DNOs are responsible for the following activities[8] (and any supporting activities required to perform these primary activities):

1. Procuring, constructing, and proactively maintaining network assets (wires, transformers, etc.) in coordination with network expansion plans performed by the DSO.
2. Repairing assets and restoring service after any major or minor damages or disruptions.
3. Operating distribution network infrastructure in response to DSO or balancing authority directives.

2.2.1 Economic characteristics of the DNO

The DNO has strong network effects and economies of scale within a given geographic area. DNOs tend to own and maintain hundreds of thousands to millions of medium and low voltage network assets. These assets tend to have high fixed costs, long lifespans, and relatively low operating costs. These characteristics lead to sub-average marginal costs, meaning the cost of adding additional customers to a given network is typically low compared to average network costs.[9] As a result, the DNO is considered a "natural monopoly." This has given rise to a "regulatory compact" in which the actor performing the DNO role is subject to revenue or price regulation with varying degrees of performance-based incentives while being granted an exclusive franchise monopoly license for a specific territory of operation. Under such a scheme, regulatory authorities also specify the types of activities in which DNOs can engage while proscribing other activities left to competitive agents or other regulated actors.

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[8] Installing, maintaining, and reading metering infrastructure is also potentially an activity of the DNO. While all DNOs in the U.S. and the majority of DNOs in the E.U. own and operate meters and manage the meter data, some exceptions apply (for example, Germany and the United Kingdom).

[9] Exceptions may occur where potential network users are located far from existing network infrastructure.

The infrastructure owned and managed by DNOs is critical to the ability of DER providers and conventional generators to deliver electricity services to end-users. This network infrastructure provides the physical connection between providers and consumers of electricity services and can be a critical bottleneck between these actors.

2.2.2 Independence of the DNO from market activities

Where competition in generation, DER ownership, or retailing/aggregation exists, the characteristics of the DNO have important implications for competition and efficiency in these horizontal segments. Should the monopoly DNO have commercial interest in performing competitive roles (either directly or, more commonly, through a legally unbundled affiliate), the DNO would experience two primary anti-competitive incentives. Firstly, the DNO may cross-subsidize its competitive businesses with regulated revenues or resources (either directly or by, for example, procuring lower cost financing than would be competitively available due to the holding company's common balance sheet). Second, the DNO may build or maintain its network in a way that benefits its affiliates over competing businesses (e.g. engage in some degree of vertical foreclosure).[10]

During the wave of deregulation that took place in the 1980s, 1990s, and 2000s, the regulatory commissions in the U.S. and E.U. recognized the potential for anticompetitive behavior in establishing the independence of transmission network owners (TNOs). For example, FERC noted that when monopoly TNOs "also have power marketing interests, they have poor incentives to provide equal quality transmission service to their power marketing competitors… The inherent characteristics of monopolists make it inevitable that they will act in their own self-interest to the detriment of others by refusing transmission and/or providing inferior transmission to competitors in the bulk power markets to favor their own generation, and it is our duty to eradicate unduly discriminatory practices" (FERC, 1999). Similarly, the European Commission noted that failing to properly separate monopoly network providers from competitive roles creates "an inherent risk of discrimination not only in the operation of the network but also in the incentives for vertically integrated undertakings to invest adequately in their networks" (European Commission, 2009).

Monitoring and ensuring the neutrality of the DNO is a perennial challenge. While this challenge exists at the transmission level, differences between transmission and distribution networks makes the challenge

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[10] For example, the DNO may first respond to outages affecting its competitive retail affiliate's customers before responding to outages affecting other business' customers, or provide differing quality customer service or interconnection times to unaffiliated retailers or DER providers.

far more significant at the distribution level. Table 1 highlights these differences. The continuous investment cycles, orders of magnitude greater number of discrete assets and decisions, and the greater degree of complexity at the distribution level make monitoring and contesting the actions of distribution utilities challenging, which underscores the need for incentive regulation and structural arrangements that ensure their neutrality.

Table 1: Selected differences between transmission and distribution networks

TRANSMISSION NETWORK	DISTRIBUTION NETWORK
○ Hundreds to thousands of assets.	○ Thousands to millions of assets.
○ A few large, discrete investments needed annually.	○ Many smaller investments needed on a continual basis.
○ Network expansion and maintenance decisions easily supervised and contestable.	○ Network expansion and maintenance decisions more difficult to supervise or contest.
○ Meshed network structure.	○ Meshed and radial network structure.

Distribution network ownership remains a natural monopoly. It follows that the DNO must be sufficiently separated from any roles open to competition. The complexity of distribution systems increases the challenge of ensuring DNO neutrality in system planning and operation, highlighting the need for regulations governing structure and remuneration to provide efficient incentives for the DNO.

2.3 DISTRIBUTION SYSTEM OPERATION

DSOs independent from DNOs remain a hypothetical concept today, as throughout the world, integrated DNO-DSOs (referred to as DNO/SOs in this paper) currently perform all operational and planning functions. Nonetheless, it is worth discussing the activities of the DSO in isolation, as this will shed light on questions regarding the possible independence of the DSO from the DNO and from other potentially competitive roles. Mirroring the responsibilities of bulk power system operators (that is, ISOs and TSOs), we assume that distribution system operators are responsible for the following activities:

1. Planning long-term distribution network development.

2. Defining and procuring any security-related services such as distribution network constraint management (thermal and voltage constraints) and ensuring the delivery of these services in real time.
3. For all distribution-connected resources and loads, coordinating dispatch and operation in advance of real-time (e.g. day-ahead) and dispatching resources – including network infrastructure and DERs – and accommodating non-dispatchable resources or unscheduled demand in real-time to ensure the feasibility of power flows within the distribution system. We discuss this function in Section 3 of this paper.

Demand-driven binding congestions in radially operated distribution feeders lead to demand curtailments or blackouts (supply-driven constraints may also result in demand curtailment, for example in situations in which circuits are disconnected due to overvoltage conditions). DNO/SOs have historically had limited if any operational recourse respond to such constraints in real-time. As such, DNO/SOs to date design distribution networks to handle all expected power flows while maintaining a robust operating margin to account for uncertainty. In addition, the vast majority of connected DERs are solar photovoltaic (PV) generators that have historically not been equipped for dispatch by system operators.[11] The vast majority of DNO/SOs today therefore do not engage in significant levels of DER dispatch or demand control, and the majority of DNO/SO actions involve scheduling maintenance and responding to contingencies and routine network failures (for example, isolating faults and restoring service). DNO/SO's do engage in some close to real-time and real-time system circuit reconfiguration and volt/VAR control.

The proliferation of DERs has the potential to change this relatively passive management paradigm in two primary ways. First, peak network usage in high DER areas could occur during times of net power *production*, not *consumption*. Such a situation is happening in many locations in Europe today, including in the north of Germany (Schermeyer et al., 2018), Italy (Lo Schiavo, 2016), and parts of the UK (Anaya and Pollitt, 2017). DSOs will therefore be required to find the most economic ways to minimize generation curtailment within network constraints. Second, DERs may increasingly be deployed as alternatives to investments in network capacity, meaning that network infrastructure alone may no longer be designed to meet peak power withdrawals—or at least traditional network operating margins may be substantially reduced, as operational recourse increases. In such instances, coordinated DER dispatch and/or demand

[11] Solar PV is curtailable and PV inverters are technically capable of providing certain services such as voltage control or reserves (Hulle et al., 2014). In certain locations, grid codes for distribution-connected solar PV (von Appen et al., 2013) or wind (Anaya and Pollitt, 2017) have been modified to require resources to provide services in an automated or dispatchable fashion. These developments are relatively recent, and DERs have not historically been available for dispatch or curtailment.

control may be required during peak demand hours, providing operational recourse to comply with network voltage or thermal constraints. Both potential active system management strategies have led to debate over the role of the DSO vis-à-vis the bulk system BA (ISO/RTO/TSO) and which actor should be responsible for dispatching resources at the distribution level. In addition, some observers have begun to debate whether distribution system operation needs to be independent from network ownership in order to ensure the independence of the system operator function.

We will first discuss the economic characteristics of power system operators. We then discuss the potential for separating the DSO role from the DNO. Finally, given the DSO's likely increasing role in DER dispatch, we introduce different structural models for clarifying the role of the DSO vis-à-vis the bulks system BA, and highlight the tradeoffs inherent in different DSO arrangements.

2.3.1 Economic characteristics of power system operators

Within a given geographic area, system operators show clear natural monopoly characteristics. Power systems within an interconnection[12] operate at a common frequency; maintaining this frequency requires power production and consumption to be in balance at all times.[13] Second, the physical realities of power networks mean that power flows over these networks create network externalities (i.e. losses and congestions)[14] that market parties cannot accurately internalize in bilateral trades without knowledge of all other relevant bilateral trades. Thus, only an operator with complete knowledge of the underlying network and all networked transactions can maximize the efficiency of dispatch to match supply and demand. Mansur and White (2012) provide empirical evidence of the challenges that network externalities present in the power system context. Furthermore, centralizing operation eliminates free ridership in the procurement of reserves and capacity (Chao et al., 2008). Therefore, in the absence of computational or jurisdictional constraints on the geographic scope of the system operator, a single system operator with complete knowledge within a given geography would maximize efficiency. Of course, in reality, jurisdictional and operational challenges exist – an issue discussed in Section 3.1.

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[12] In the U.S., there are three interconnections, the Eastern Interconnection, the Western Interconnection, and the Texas Interconnection. The majority of the European continent is comprised of a single interconnection; however, some nations have relatively little interconnection capacity.

[13] Note that the presence (or lack thereof) of energy storage does not change this basic fact. Energy storage resources help match supply and demand, but do not change the basic need for power balance.

[14] The alternating current power that energizes distribution networks is characterized primarily by the magnitude, frequency, and phase angle of the power's voltage and current waves. Injecting or withdrawing power from a network at one location may impact these characteristics elsewhere along interconnected network branches and thus impact the ability of other network users to inject or withdraw power from the same network (e.g. by causing constraints that prevent otherwise mutually beneficial transactions). To the extent that these impacts are not priced into an individual network user's decisions, these impacts are considered network externalities.

The system operator role at the transmission level also shows significant economies of geographic scope. The experience of the geographic expansion of system operation in the U.S. demonstrates the benefits achieved through common market operations and balancing over large geographies. See, for example, the results of the expansion of PJM market (Mansur and White, 2012), the MISO market (MISO, 2017), U.S. markets more broadly (Cicala, 2017), and the results of the creation of the Western Energy Imbalance Market in the U.S. (CAISO, 2017). The bulk of these benefits emerge from enabling welfare increasing gains from trade, although improving the efficiency of dispatch and decreasing transaction costs has also contributed to increased welfare. Recent experience from the Western Energy Imbalance Market in the U.S. also demonstrates how geographic expansion can decrease emissions by decreasing renewable energy curtailment (that is, by identifying buyers of low marginal cost renewable close to real time that displaces higher marginal cost fossil generators) (CAISO, 2017).

The economic characteristics of the system operator – natural monopoly, geographic economies of scale, network economies – have important implications for assigning the role of balancing within the distribution system. These facts indicate that: 1) it would be most efficient for a single entity to be responsible for balancing power within a given geography, and 2) efficiency will be improved as the geography across which a given operator balances increases. Thus, who should be responsible for balancing power at the distribution level?

2.3.2 Independence of the DSO from market activities

System operators hold the authority to choose which resources to dispatch (and accordingly remunerate) to supply various electricity services. System operators also contract for services from generators and play a significant role in developing (non-binding) plans for network expansion. These positions can clearly be used to favor certain (affiliated) actors over others. This has led to a near universal recognition of the need to ensure the independence of the system operator role from any competitive roles.

Experience from bulk system restructuring shows that in order to enable effective competition in the horizontal segments in which competition has been introduced, system operation and planning should be structurally separated from market activities. Indeed, upon reviewing progress in establishing competitive generation and retail markets, the European Commission stated that the "rules on legal and functional unbundling of [TSOs]… have not led to effective unbundling" (European Commission, 2009). In response, the European Commission strengthened their unbundling rules in an effort to "remove the incentive for vertically integrated undertakings to discriminate against competitors as regards access to the network, as regards access to commercially relevant information and as regards investments in the network" (European Commission, 2010). Citing the need to minimize real and perceived conflicts of interest between the system operator and any other actors, the U.K. Office of Gas and Electricity Markets (OFGEM) has recently taken steps to further unbundle the system operator from all competitive activities (UK Ofgem, 2017). In the U.S., bulk system operators were made independent from competitive functions for the same reasons (FERC, 1999).

While structural unbundling of distribution system operation has not been universally required to date, the potential for anticompetitive behavior by the DSO is likely to increase substantially as the penetration of DERs increases. Further, due to the complexity of distribution systems relative to transmission systems, the ability for regulators to sufficiently monitor DSO behavior is likely to be even more limited than at the transmission level. This has led many state and national regulators to recently reexamine the independence of the DSO from competitive activities. In the E.U., where regulators have established competitive markets for retailing and have mandated legal unbundling between DNO/SOs and retailers, regulators are re-emphasizing the need to ensure a "sufficient level of unbundling between suppliers and associated DSOs" (CEER, 2016). Similarly, the Agency for the Cooperation of Energy Regulators (ACER) and the Council of European Energy Regulators (CEER) "support the [European Commission's] prohibition on DSO ownership/operation of energy storage and electric vehicles' charging infrastructures" (ACER and CEER, 2017). Ofgem has concurred, citing the increasingly active role of the DNO/SO, and noting that DNO/SO ownership of storage could "lead to distortions, and impede the development of a competitive market for flexibility services" (Ofgem, 2017, p. 14). In supporting the separation of the DNO/SO and DER Ownership and Operation roles, the New York Department of Public Service stated that "markets will thrive best where there is both the perception and the reality of a level playing field" (NYDPS, 2015, p. 67).

There are two basic models for ensuring independence between the DSO and any competitive roles. Regulators could either establish a DSO that is independent from all other roles including the DNO, or they could maintain the current DNO/SO structure and ensure the separation of the combined DNO/SO from competitive roles.

2.3.3 Should the DSO be independent from the DNO?

Proponents of an independent DSO (IDSO) argue that only an IDSO can plan and operate a distribution system in a transparent and neutral way (Friedrichsen, 2015; Tong and Wellinghoff, 2014). In many markets, vertically integrated DNOs compete with other retailers and DER providers to provide electricity services. In addition, DERs may compete with network assets, and a poorly regulated DNO/SO may opt for less efficient network investments over procurement of services from DERs. This can be solved with certain models of incentive regulation (Jenkins and Pérez-Arriaga, 2017),[15] but an IDSO is an alternative. The IDSO concept is intellectually appealing, as it parallels well-established independent system operators at the bulk system level. The model could, in theory, eliminate the potential for anti-competitive behavior by the DNO without requiring changes to the DNO's remuneration and without requiring the DNO to unbundle from any competitive roles. However, the IDSO concept would split the responsibility for maintaining reliability at the distribution level between the DNO and DSO, and we argue that this would dramatically increase transaction costs.

In today's regulatory environment, DNO/SOs are typically held responsible for system reliability through regulated standards and/or incentives (and penalties) for meeting (or missing) reliability targets. Regulators of these firms face significant information asymmetries compared to the regulated firm, and regulators cannot thoroughly monitor DNO/SO's managerial effort to ensure reliability or other desirable outcomes (Laffont and Tirole, 1993). Rather, DNO/SOs submit information regarding their cost of service to regulatory authorities and negotiate for the remuneration of these costs in some manner.[16] Meanwhile, regulators observe outcomes related to the metrics of their interest, such as duration or frequency of service disruptions.

Under an IDSO model, assigning responsibility for ensuring reliable system operation through effective planning and procurement becomes very challenging. The IDSO would ideally be incentivized to plan its distribution network to maximize efficiency – that is, plan the network balancing the costs of increased reliability and resiliency against the cost of network failures, service disruptions, and blackouts. The DNO would then be responsible for implementing IDSO network expansion and maintenance plans, although the IDSO may not have the legal authority to force a legally distinct DNO to make any specified investment. The DNO will retain some autonomy in implementing network development plans.[17] Under this structure, neither the IDSO nor DNO is solely responsible for ensuring reliability, which creates a "moral hazard in teams" problem, in which both parties have an incentive to free ride off of the other party's efforts to ensure reliability (Joskow and Tirole, 2005).

[15] The key regulatory reforms include implementation of strong incentives for overall cost-efficiency and neutralization of any incentives for utilities to favor investment in capital expenditures rather than operational expenditures. Unfortunately, traditional distribution network regulation in the United States and many other jurisdictions lacks both features at this time.
[16] This can take many forms. See (Joskow, 2014; Pérez-Arriaga et al., 2013).
[17] The IDSO cannot reasonably specify every project down to the nut and bolt.

In order to coordinate IDSO and DNO actions and align incentives, the IDSO would have to rely on either market arrangements or contracts. Given the durability and specificity of the assets involved and the complexity of the system, bilateral contracts between the DNO and IDSO would likely be more efficient than market-based mechanisms (Williamson, 1975).

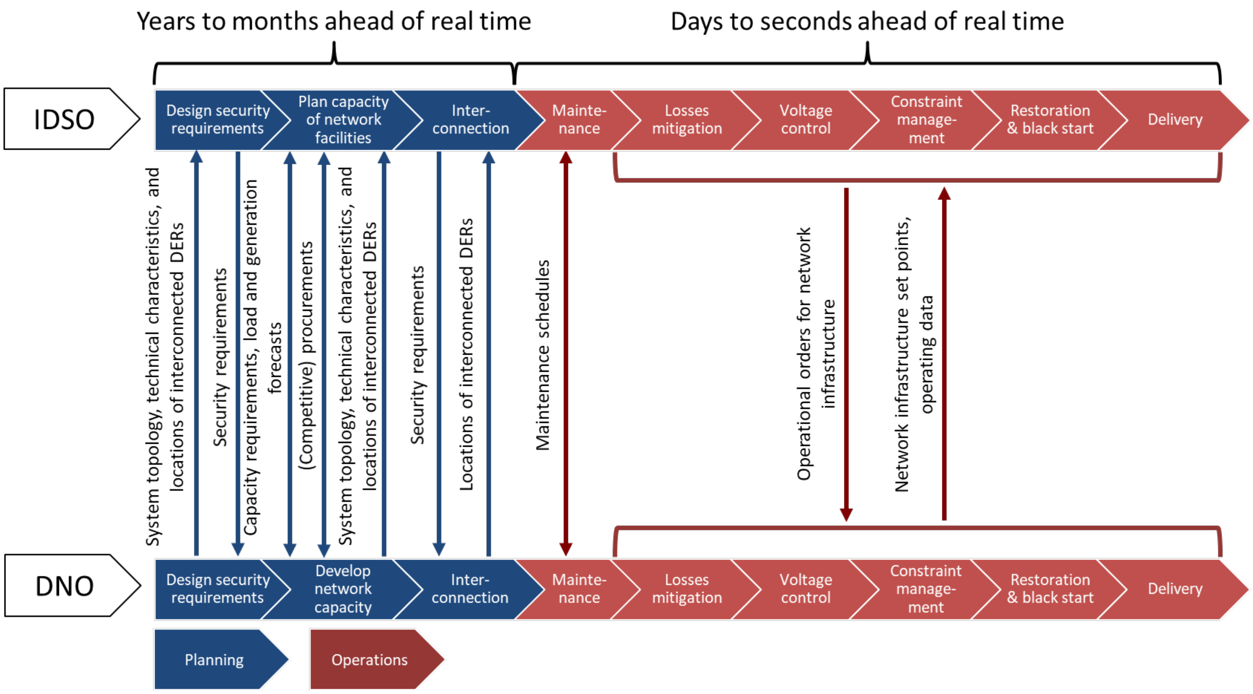
The durable network assets involved would have high degrees of locational specificity (they must be located in the right area), capital specificity (they would have little value outside of the power system), and temporal specificity (they must be available when needed). The IDSO and DNO would negotiate these contracts in the face of significant uncertainty over load growth, DER penetration, etc. Arrangements with such high degrees of asset specificity, uncertainty, and long lifetimes have been demonstrated to be more efficiently procured via long term contracts or, in many cases, vertical integration (Joskow, 1985; Lafontaine and Slade, 2007).

The DNO would likely attempt to create contracts that limit its liability in contingencies that result from poor planning on behalf of the IDSO. Likewise, the IDSO will attempt to limit its liability in contingencies that emerge from flaws in the DNO's execution of its plans. The cost of negotiating either general operating contracts or contracts between the IDSO and the DNO for deployment and maintenance of millions of distribution network assets would dramatically increase transaction costs over an integrated DNO/SO model. Given the complexity of system planning and operations, such contracts would likely be incomplete and contingencies would result in ex-post haggling and re-negotiations. The most efficient outcome from a transaction cost perspective is therefore to integrate distribution system operation and ownership.

ISO/RTOs at the bulk system level experience similar challenges given the separation between network ownership and operation. However, the relatively small number of assets makes it possible for the efficacy of planning decisions and the execution of these decisions by transmission developers and owners to be scrutinized in detail on an individual basis. That is, ISO/RTO monitoring of transmission network owners is significantly less costly than IDSO monitoring of DNO behavior would be.

The challenge of coordinating DNO and IDSO operations and investment would be immense. DNOs today deploy maintenance and repair crews daily and consistently change network topologies for maintenance purposes, requiring continuous information flows between the parties. Furthermore, the IDSO would need to send real-time information control signals to the DNO to manage set points of voltage controllers, transformer tap changers, and any other DNO assets. Figure 1 highlights the various types of information exchanges that would be required between the DNO and IDSO over different time scales. Failures in any of these communication channels could result in significant costs and potential service disruptions.

Figure 1: Information flows between the IDSO and the DNO



While ISO/RTOs exchange similar information with transmission network owners at the transmission level today, the number of assets and the more dynamic nature of distribution network maintenance and topology creates much greater challenges than are routinely faced by ISO/RTOs. While efficient information flow is possible, the IDSO model would almost certainly increase coordination and transaction costs relative to an integrated DNO/SO model.

While the IDSO model has the benefit of preventing the need from any additional unbundling between the DNO and any competitive roles, it would almost certainly increase costs relative to an integrated DNO/SO model.

Given the likely inefficiencies of the IDSO model, we view it as an unlikely outcome for future industry structure.[18] We therefore refer primarily to the DNO/SO throughout the remainder of the paper.

[18] MIT (2016) discusses the potential for an "extended ISO" model, in which the bulk system BA takes operational control over any meshed portions of distribution networks. This would emulate some elements of the IDSO model

2.3.4 The integrated DNO/SO and the importance of regulatory incentives and separation from competitive activities

The primary alternative to the IDSO model is to maintain the current combined DNO/SO structure while both establishing appropriate regulatory incentives and sufficient separation of the DNO/SO from competitive activities. Given the inefficiencies of the IDSO model and the currently universal reality of joint system operation and ownership at the distribution level, it is highly likely that the DNO and DSO roles will remain integrated in most (or nearly all) jurisdictions.

Combining the DNO and DSO into a single role raises the importance of efficient incentive (or performance-based) regulation. Under traditional cost-of-service regulation, in which utilities earn a regulated return on prudently invested and capitalized assets, DNOs have a natural incentive to systematically favor owning infrastructure over contracting with third-party actors for the services provided by that infrastructure. Yet the DSO function should seek to efficiently optimize tradeoffs between investments in network infrastructure and non-wire alternatives (NWAs) or other operational expenditures. Under a DNO/SO arrangement, regulatory mechanisms that align DNO/SO incentives with cost savings and equalize financial incentives for capital and operational expenditures will be critical (Bauknecht and Brunekreeft, 2008; Jenkins and Pérez-Arriaga, 2017; MIT, 2016). We stress that these reforms are important regardless of whether or not the DNO/SO is vertically integrated into retailing or DER ownership.

As highlighted in the sections above, both the DNO and DSO roles hold the potential to engage in anticompetitive behavior. Combining the DNO and DSO – as the bulk of regulators across the U.S. and Europe are proposing[19] – also increases the importance of effectively separating the DNO/SO and any competitive roles.[20] This concept has been generally supported by regulators in both the U.S. and E.U. In practice, this may involve more stringent legal unbundling provisions or full ownership unbundling of the DNO/SO from any competitive roles. As noted by the European Commission, where legal unbundling is already in place, new "regulatory safeguards are necessary to guarantee the DSOs' neutrality in their

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in that an independent operator would be responsible for operating and planning certain portions of distribution systems. This would still leave a significant role for DSOs in operating radial portions of their systems. We discuss the need for operational coordination between BAs and DSOs in Section 3.1.

[19] The New York Department of Public Service notes that while it plans to integrate the DNO and DSO (referred to by the NYDPS as the DSP) roles, they also note that they must be "prepared to make changes in direction, including the role of individual utilities as the DSP, if warranted by the facts" (NYDPS, 2016).

[20] As noted by MIT (2016), the DNO/SO could perform competitive roles *outside* of the DNO/SO's service territory, so long as the DNO/SO's competitive affiliates do not influence the DNO/SO's planning and operation decisions within the service territory.

new functions, e.g. in terms of data management and when using flexibility to manage local congestions" (European Commission, 2016, p. 5).

2.4 DER OWNERSHIP

DERs can either be co-located with demand or separately connected to the distribution system without demand colocation. DER owners may be individual homeowners, businesses, financial institutions, specialized DER developers, or a complex combination of these groups. Furthermore, the owner, operator, and maintainer of a DER may not always be the same actor. Broadly speaking, DER ownership entails responsibility for developing, installing, and ensuring the maintenance of DER assets or contracting for these services. We discuss the role of operating DERs in Section 3 of this study.

From an industry structure perspective, the key question is whether monopoly DNO/SOs should be permitted to own DERs, or whether this activity should be left exclusively to competitive actors. The answer to the question of DER ownership depends on three primary factors:

1. The minimum efficient scale of DER ownership and operation relative to the market size.
2. The magnitude of economies of vertical integration between the DNO/SO and DER ownership.
3. The potential for anti-competitive behavior by the DNO/SO vis-à-vis competitive DER providers/owners.
4. The ability for price signals to coordinate independent DER owners with the DNO/SO and other actors.

This section focuses on the first three factors, while Section 3 focuses on the fourth.

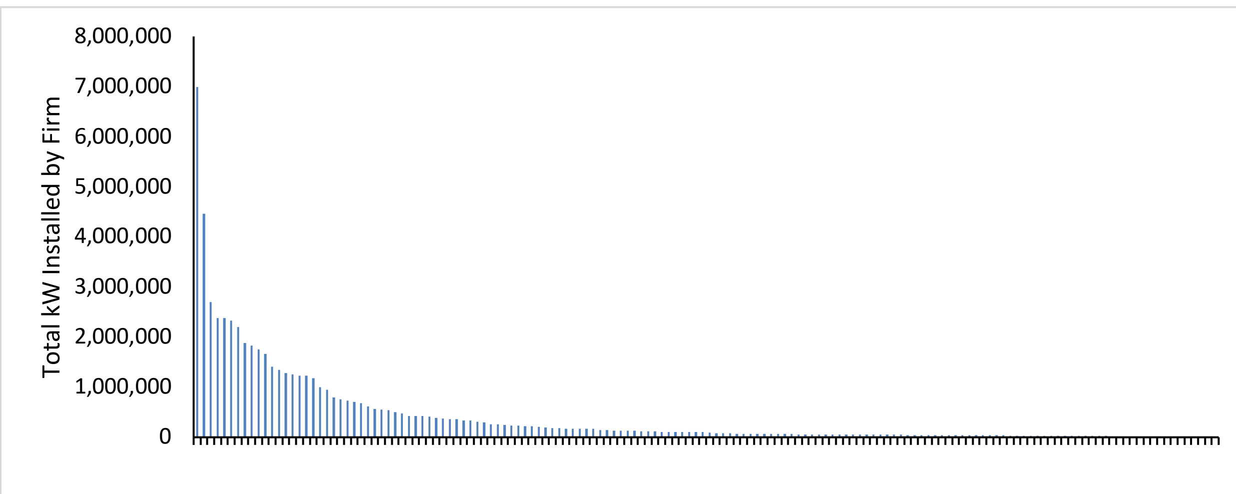
For competitive DER markets to emerge, the minimum efficient firm size must be small relative to the market size. That is, the market size must be sufficiently large for many firms to compete without exhibiting sufficient market power to raise prices well above long-run marginal costs. Regulated monopoly ownership of DERs may be justified where such conditions cannot be met, as the appropriate conditions for competition would not be present.

Minimum efficient firm size is not a well-studied phenomenon for DER providers. However, two pieces of the limited evidence exist that indicates that developing and owning solar PV – the most commonly deployed DER today – is suitable for competition and thus is not a monopolist activity.

First, the market size for the primary services that DERs provide – that is, energy, firm capacity, ancillary services – is quite large (MIT, 2016, chap. 2). During the previous wave of deregulation, scholars found that economies of firm scale for generators were not prohibitively large, implying that competition in the generation sector was likely workable in most locations (Joskow and Schmalensee, 1983). Given their modular nature, DER ownership would be expected to exhibit even smaller minimum efficient firm sizes than their traditional bulk generation counterparts.

Second, by plotting the distribution of installed capacity of the largest 150 solar PV installers in the U.S. (Figure 4), we can see a small number of large installers followed by a very long tail of small installers, indicating that barriers to entry in the DER provision market are also relatively low. In addition, Nemet et al. (2016) found that low priced residential and commercial solar PV systems were more likely to be installed by experienced but *small* firms with *low* market shares, indicating that greater competition in the installer market leads to lower system prices. While other DER technologies are less well studied than solar PV systems, there is no reason to believe that the economic characteristics of other DER technologies, including distributed storage and demand response, are dramatically different.

Figure 2: Distribution of the total kW installed by the top 150 solar PV contractors in the U.S.



While the evidence indicates that DER ownership is a role well suited for competitive actors, some regulatory agencies have taken steps to allow DER ownership by DNO/SOs. For example, the CPUC has granted DNO/SOs the authority to own and operate up to 50% of the 1.325 GW of energy storage that the California legislature mandated be procured under AB 2514 (CPUC, 2013). The NYDPS has indicated that DNO/SOs can own certain DER resources under four conditions:

"1) procurement of DER has been solicited to meet a system need, and a utility [DNO/SO] has demonstrated that competitive alternatives proposed by non-utility parties are clearly inadequate or more costly than a traditional utility infrastructure alternative;

2) a project consists of energy storage integrated into distribution system architecture;

3) a project will enable low or moderate income residential customers to benefit from DER where markets are not likely to satisfy the need; or

4) a project is being sponsored for demonstration purposes" (NYDPS, 2015, p. 70).

The CPUC's arguments for enabling DNO/SO ownership of DER assets largely echoes the NYDPS's. Despite the fact that the NYDPS and CPUC have stated desires to minimize DNO/SO participation in DER markets in the long-term, the above criteria provide many opportunities for DNO/SO ownership of DERs.[21] Furthermore, the logic for DNO/SO ownership of DERs articulated by both regulatory commissions is not entirely clear.

The NYDPS argues that DNO/SOs can own DERs when non-DNO/SO providers fail to offer a cost-competitive alternative. DER assets deployed for reliability purposes will likely exhibit temporal, locational, and capital specificity, all of which, all else equal, tends to favor vertical integration (Joskow, 1985; Lafontaine and Slade, 2007; Pirrong, 1993). Should DNO/SOs contract with third parties for reliability services, these contracts would likely involve long time horizons and terms navigating significant uncertainty, which again favor vertical integration. It is plausible, therefore, that the cost of contracting would prevent non-utility developers from being cost competitive with DNO/SOs. Using these arguments, Brunekreeft and Ehlers (2006) conclude that preventing DNO/SO ownership of DERs will lead to insufficient investment in DER capacity.

However, three factors necessitate that regulators proceed with allowing DNO/SO ownership of DERs with caution.

First, DNO/SO ownership of DER infrastructure could lead to the underutilization of DER assets in markets with competitive generation and ownership unbundling rules between generators and monopoly network utilities. In markets with competitive generation, regulatory authorities determine which assets monopoly network utilities can own. Regulators typically classify a given asset as generation, transmission, or distribution. An asset classified as generation cannot be owned by monopoly DNO/SOs, and assets classified as transmission or distribution typically cannot earn revenues by providing services in competitive markets (Usera et al., 2017). FERC (2017) clarified that DERs (in particular, energy storage systems) can earn revenues from providing services to transmission and distribution utilities while also earning revenues from providing services in competitive energy markets, so long as the system

[21] Note that exception 2 outlined above is referring to storage used for reliability purposes. The NYDPS echoes the CPUC's sentiment that DNO/SOs should be able to own energy storage resources that are deployed "to support and enhance reliable system operations" (NYDPS, 2015, p. 69).

operator maintains its independence from the DER owner. However, FERC (2017) also clarified that DERs cannot earn market-based revenues if the asset is to recover all of its costs by providing services to monopoly network owners and operators.

These rules exist primarily to prevent network owners and operators from inefficiently foreclosing competition, and follow from the "Bell Doctrine," which states that monopolies should be "quarantined" from any competitive segments of an industry (Joskow and Noll, 1999). Under these rules, should a DNO/SO own a DER facility and recover its costs from regulated rates, it would not be able to use this facility to simultaneously provide services to wholesale electricity markets. In contrast, an independent competitive actor could earn revenues providing an identical service to the DNO/SO via contractual relationship, and, when not needed by the DNO/SO, could also earn revenues in competitive markets. Revenues from these competitive activities would then lower the cost of providing network services to the DNO/SO. Thus, in many cases, the benefits of a DER asset earning revenues from competitive services may outweigh the transaction costs associated contracting for service provision with the DNO/SO. In such cases, DNO/SO ownership would lead to an inefficient underutilization of DER assets and would be ill advised.

Second, it will likely be difficult to closely monitor DNO/SO cost saving efforts with respect to DER infrastructure procurements, which increases information asymmetry challenges and is likely to yield some degree of inefficiency in DER investments. Information asymmetries between monopoly DNO/SOs and their regulators make it impossible for regulators to ensure that the utilities they regulate are pursuing all cost saving possibilities (Laffont and Tirole, 1993). This dynamic has been demonstrated to lead to higher cost procurements by regulated utilities than competitive generators (Cicala, 2015). This is particularly true when the goods that regulated utilities are procuring are non-homogenous. If regulators are unable to effectively monitor the procurement decisions of the utilities they regulate or establish sufficient incentive-compatible performance incentives for the regulated utility, DNO/SO ownership of DERs could lead to higher cost procurements than would otherwise be efficient. In contrast, competition between DER providers would impose price discipline without regulatory oversight.

Finally, enabling DNO/SO ownership of DERs opens the possibility for anti-competitive behavior on behalf of the DNO/SO in two key ways. The DNO/SO may:

1. favor DERs owned by itself or its affiliates in dispatch or in procurements of services.
2. provide greater service to its affiliates relative to other agents (for example, in maintenance of network assets or in settlement).

The risks of monopoly engagement in competitive roles were detailed in Section 2.3.1 and 2.3.2. Legal unbundling and incentive regulation may be insufficient. The DNO/SO will face a natural incentive to self-provide or procure services from its affiliates over other competitors, even if these options are less competitive than other providers. If the profits gained by the DNO/SO or its affiliate outweigh any reduction in regulated profit relative to procurement from a competitor,[22] the DNO/SO will be incentivized to favor its own assets.

Given the risks of enabling DNO/SO ownership of DERs, regulators would be wise to ask the question of whether third parties could provide these same services as a vertically integrated DNO/SO with reasonably competitive terms. Many examples of third-party ownership and operation of resources used for reliability purposes exist. For example, in systems with competitive generation markets, BAs use reliability must-run contracts to secure generation from non-BA owned resources in critical regions. Furthermore, the bulk-system BAs rely on non-BA owned resources for providing reserves to prevent failures on very short timescales. DERs have demonstrated their efficacy in providing these short-term security-related services (see, for example, (Hulle et al., 2014) and (Mathieu et al., 2012)). If the most cost-effective or only available location for DER deployment is on DNO/SO property (for example, locating energy storage or distributed generation at a substation in a dense urban area), the DNO/SO could lease this space to competitive DER providers.[23] Given competitive pressures for cost-efficiency, it is also reasonable to assume that competitive actors are likely to deliver least cost DERs, and evidence from solar PV markets (e.g. Nemet et al., 2016) support this hypothesis. The limited evidence that exists therefore does not indicate that DNO/SO ownership is strictly required for reliability purposes.

Both the CPUC and NYDPS also highlight "market development" as another rationale for allowing DNO/SO ownership of DERs. Relatedly, the NYDPS notes that DNO/SOs may own DERs in demonstration projects. Ownership of DERs in small demonstration projects likely doesn't pose a threat to competition, although regulators should beware of "slippery slope" situations in which DNO/SOs corner a significant portion of a market by repeatedly engaging in demonstration projects. DNO/SO

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[22] Increased costs of procuring DER services may result in a reduction in regulated profit under incentive regulation with sharing of cost savings (e.g. various forms of multi-year revenue cap regulation) or if the regulator deems a specific investment imprudent and disallows cost recovery. Otherwise, the utility may actually financially *benefit* from higher cost DER procurement (e.g. under cost-of-service regulation where returns are based on capitalized assets).

[23] This offers an alternative to DNO/SO ownership of "energy storage integrated into distribution system architecture" as outlined by (NYDPS, 2015, p. 70).

development of DER assets may enable them to develop learning and other advantages that could crowd out competition in future years. Furthermore, while DNO/SOs may be able to leverage their monopoly position and stable balance sheets to stimulate under-served markets, other mechanisms – such as subsidies for third-party providers – may also be able to stimulate these markets with greater transparency.[24] New mechanisms – such as enabling utilities to add rebates provided to stimulate activities by non-DNO/SO DER providers to their regulated asset base[25] – could also enable DNO/SOs to profit from market stimulation without requiring direct ownership.[26] Another alternative would be to design DNO/SO remuneration incentives within an incentive regulation framework for reaching certain deployment targets for high priority technologies.[27]

So while monopoly DNO/SOs may act as effective stimulants for early DER market development, there is no clear reason why they must own DER assets to do so. In addition, if DNO/SOs spur competitive market formation without owning DERs, it avoids the need to make the eventual transition to competitive provision once markets are sufficiently mature. Indeed, one could also argue that if DNO/SOs develop DER markets through direct ownership, it may retard the development of the kind of competitive procurement that the CPUC, NYDPS, and other regulators and policy makers envision as the eventual goal, as competitive DER providers will not have sufficient opportunity to mature and gain experience in service provision in markets initially dominated by regulated utilities.

The logic for DNO/SO ownership of DERs is not clear, as DER ownership does not exhibit monopoly characteristics and the benefits of DNO/SO ownership of DERs can likely be achieved through other methods.

In sum, there are likely a myriad of ways to stimulate market development without direct DNO/SO ownership of DERs. The ideal position from a competition standpoint is thus to bar DNO/SO

[24] Indeed, there are many strong parallels here to stimulation of energy efficiency markets, in which utilities in many jurisdictions regularly contract with (or are required by regulators to procure services from) third party firms specializing in energy efficiency programs.
[25] This is a method currently being debated in Illinois. See Trabish (2017).
[26] Again, there are parallels to successful energy efficiency programs here, where utilities can profit under various performance-based incentives from successfully stimulating adoption of efficient appliances and other energy saving measures.
[27] While such a model has been implemented in Europe and the U.K., it has risks, as many factors that affect DER deployment fall outside the control of the DNO/SO. Ideally, DNO/SO incentives should be based on factors directly within the DNO/SO's control.

participation in DER markets. The benefits of DNO/SO participation in DER markets are uncertain, while, as discussed in Sections 2.2.2 and 2.3.2, the potential for DNO/SO abuse of monopoly power or anticompetitive behavior is significant.

We discuss DER operation and coordination through system operator commands and price signals in Section 3. As we will highlight, coordinating DER installation and operation will require dramatically improved price signals, as well as new operational models for the DNO/SO and bulk system balancing authorities.

2.5 RETAILING AND AGGREGATION

The value of competition in the electricity retail[28] sector has long been a subject of contentious debate (see, for example, the public debate between Paul Joskow and Stephen Littlechild (Joskow, 2000; Littlechild, 2000)). After years of experience with competition in the retail supply sector, the realized benefits of having competitive actors perform retail aggregation are not decisive.[29] While the evidence does not display dramatic benefits, it clearly demonstrates that retail aggregation is not inherently a monopoly activity; that is, there is no conclusive evidence that introducing competition into retail *increases* costs. DER aggregation shares many of the same traits as retail aggregation. While this is an area for further research, we argue that DER aggregation (including demand response aggregation[30]) is not a monopoly function either. This section highlights some of the key ways that the emergence of DERs may change the relationship between aggregators and the DNO/SO.

We focus primarily on systems with competitive retail aggregation. Given the inconclusive results of retail competition, there is insufficient evidence to argue that competition in retail should be implemented in systems where it does not already exist. However, we note that new metering technologies, increasingly cost-reflective rate design, and wider adoption of DERs may increase the potential for competitive retail

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[28] As noted in Section 1 (see Footnote **Error! Bookmark not defined.**), we consider retailers to be a subset of a broader category of aggregators. Retailers and DER aggregators perform essentially the same functions (and indeed, many retailers are beginning to offer DER aggregation services). Both: 1) schedule power procurements or production in energy markets on behalf of aggregated customers, including establishing hedging positions on behalf of customers and signing and managing any long-term contracts for the provision of energy or security-related services; 2) balance market positions on behalf of aggregated customers; 3) settle market transactions with the appropriate counterparties and settle transmission and distribution network-use-of-system charges with TNOs and DNOs on behalf of aggregated customers; and 4) bill customers for services rendered.

[29] See (Littlechild, 2009), (Swadley and Yücel, 2011), (Borenstein and Bushnell, 2015), and (Morey et al., 2016) for recent reviews of the status and results of electricity retail competition.

[30] While many definitions of DERs exists, we consider demand response to be a DER, as per MIT (2016)

to create value, as each of these changes increase the ability for retailers to provide differentiated services and service qualities. This view is supported by CPUC (2017)[31], and is an important subject for further research.

Before turning the role of DER aggregators, it is worth taking stock of the current status of demand aggregation in U.S. and European jurisdictions. In the majority of U.S. states today, retail aggregation is not open to competition and DNO/SOs exclusively perform the retail aggregation role. Nonetheless, competitive DER aggregators – primarily demand response providers – are active in many of these states providing services to DNO/SOs and BAs (Burger and Luke, 2017). In 18 U.S. states and all European nations, retail aggregation is open to some form of competition. Still, in the majority of the U.S. states with competitive retail markets and in most European nations, DNO affiliates compete with other retailers to provide aggregation services. In other cases, DNO/SOs serve as the default retail aggregator when customers do not select a competitive retailer or when a consumer's retailer can no longer serve that consumer (Pérez-Arriaga et al., 2013, chap. 9).[32] In some U.S. states and all European nations, the competitive retail affiliate is legally unbundled from the DNO/SO. However, in some U.S. states (such as Massachusetts), legal unbundling is not in place and the DNO/SO directly competes with other competitive retailers.

The price elasticity of demand in the short and long term is likely to increase as the penetration of DERs and digital technologies increases. Aggregators – both retailers and DER aggregators – are therefore likely to become more active participants in energy markets, and both bulk system BAs and DNO/SOs are likely to procure services from these aggregators more frequently. Just as BAs must maintain their independence from competitive service providers, it will therefore become increasingly important that DNO/SOs procure services from aggregators in a neutral manner. Additionally, monopoly DNO/SOs may be barred from providing services in competitive markets due to the competitive concerns highlighted in Sections 2.2.2 and 2.3.2.

Vertically integrated DNO/SOs will face natural incentives to leverage its monopsony position to procure services from its affiliates over other competitors. Ownership unbundling between distribution utilities and aggregators – as has been implemented in Texas, the UK, and Australia, among other locations – is one structural model for preventing the DNO/SO from acting upon these incentives;

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[31] For example, CPUC (2017) notes that the state's solar and energy storage programs have "empowered customers to choose new energy options and enabled new market entrants… to serve customers with innovative solutions" (pg. 3). CPUC (2017) goes on to say that these trends require the CPUC to reexamine the role of the distribution utility as the retailer for all customers within a geographic region.

[32] There are many alternatives to this model, such as periodically auctioning the right to serve as the default retailer.

however, as noted in Section 2.1, ownership unbundling is a challenging task in many locations. Legal unbundling is a second model, although this may be insufficient in cases where aggregator profits may be large; indeed, in moral hazard models of vertical integration, when the marginal return on effort is large, vertical disaggregation is often more efficient than vertical integration (Lafontaine and Slade, 2007). An alternative to legal or ownership unbundling would be to require the DNO/SO to operate its bundled retail affiliate as a profitless cost pass through entity (Joskow and Noll, 1999).

Proponents of legal unbundling argue that a legally unbundled DNO/SO under incentive regulation would seek out least-cost options when procuring any services, and thus would not inefficiently favor its retail affiliate. These arguments are bolstered by the fact that there is little empirical evidence of anti-competitive behavior involving DNO/SOs and their retail affiliates.

The UK government's Competition and Markets Authority found that consumers served by incumbent retailers paid systematically higher rates than customers served by new entrants, as these incumbents did not switch "inattentive" customers on high cost legacy rates to lower cost options (Competition and Markets Authority, 2016). However, this is an incumbency effect and not the result of anti-competitive behavior driven by vertical integration. Defeuilley (2009) finds similar incumbency effects, and the European Commission cites incumbency effects as a reason for high retail rates, but does not cite specific data (European Commission, 2016).

Recent empirical evidence from the airline industry demonstrates that joint ownership of legally distinct competing firms can create anti-competitive incentives and yield higher prices than would be expected without joint ownership (Azar et al., 2017). The literature on the competitive effects of joint ownership is relatively nascent. While Azar et al. demonstrate anti-competitive behavior among firms under common ownership competing in a single horizontal segment of a sector, it is not unreasonable to expect similar effects could be observed when considering firms jointly owned in different horizontal segments of a given industry.

At this stage, direct evidence for anticompetitive behavior exhibited by DNO/SOs vis-à-vis their affiliated aggregators is merely anecdotal, and it remains to be seen if practical outcomes warrant concerns raised by industrial organization theory. To err on the side of caution, where competition is in place, regulators should strengthen and strictly monitor legal unbundling requirements between aggregators and DNO/SOs. Where competition is in place without unbundling, regulators should explore options for implanting structural reform or neutralizing any financial incentives for anti-competitive behavior. However, the increasing penetration of DERs and digital technologies increases the ability for DNO/SOs to take advantage of their network monopoly position vis-à-vis retail and DER aggregation and their monopsony position in distribution network services markets, increasing the urgency for reform.

2.6 A DATA HUB AS A SECOND-BEST SOLUTION TO STRUCTURAL REFORM

In all of the institution arrangements discussed above, data ownership and access remains a critical and unresolved issue. Herein, we adopt Eurelectric (2016b)'s distinction between three classes of data: meter data, grid data, and market data. Meter data contains information on customer consumption or production obtained from metering infrastructure. Grid data contains information related to the topology of networks, any planned investments in these networks, the ability for these networks to benefit from or host DERs, and all network-deployed sensor measurements (e.g. of voltage and frequency). Finally, market data contains information on market outcomes, such as clearing prices. Different parties will naturally produce and consume these different classes of data. This section outlines the reasoning for establishing an independent data hub to manage certain classes of data.

Regardless of which actors ultimately manage which classes of data, the data manager for each class will need to aggregate and distribute – in a non-discriminatory manner – all relevant data to the appropriate recipients on timespans meaningful to make productive use of these data. For example, the recipient of smart meter data will likely be the customer, the customer's aggregator(s), and, if eligible under the relevant regulatory framework, any other market parties. Furthermore, data managers will need to protect and secure all relevant data.

Is an independent data necessary to maintain certain classes of data and ensure timely and non-discriminatory access to these data? To answer this question we must first examine the motivations of the party that originally generates, and thus first manages, data. In theory, non-discriminatory access to regulatorily-approved data should not be an issue in structures where the data manager's incentives are aligned with the data-requesting party (that is, where providing the data is either financially beneficial or neutral to the data manager). This will occur in scenarios where the data manager is independent from the activities of the data-requesting party. If, however, the data manager has commercial interests that are in competition with the activities of the data-requesting party, the data manager may be incentivized to discriminate or otherwise exercise foreclosure, such as by providing lower quality data, delaying access, or other means. If a potential conflict exists, it is therefore critical to ensure that the manager of each class of data is independent from the market activities related to that data.

Meter and grid data will be collected by the DNO/SO.[33] Should regulators allow competition in DER ownership or aggregation, and should the DNO/SO not be independent from these activities, it may be necessary to establish an independent data hub to manage grid and meter data (Brandstätt et al., 2016). When applicable, market data will be collected by the market operator (either the BA, the DNO/SO, or an independent market operator). Where market operators are not independent from market participants, it may be beneficial to establish an independent data hub for market data (we discuss the need for market independence in Section 3.2). Creating a data hub will likely be costly, and the flow of information between the various data collecting parties, the data hub, and the data requesting parties will create transaction costs.

If an independent data hub cannot be established and the manager of a given class of data has commercial interests in that data, clear regulatory guidelines (i.e. timelines, sharing formats, etc.) – with appropriate penalties for failing to meet these guidelines – is a third-best solution.

Creating an independent data hub is a second-best solution in systems where the system operator, market operator, or network operator are not financially independent from any market parties.

2.7 SUMMARY: INDUSTRY STRUCTURE AND COMPETITION

This section has discussed the implications of different industry structure options on competition in the power sector. The lessons and theories applied in our analysis largely echo lessons and theories applied in the restructuring of the bulk power sector. We considered the economic characteristics of distribution network owners and operators and the new and changing actors in the power sector – DER owners and aggregators. We find that DER ownership is likely an activity best left to competitive actors. We note that, as retailers and other forms of aggregators become more active participants in the power sector, regulators should also ensure that DNO/SOs maintain their neutrality in planning and operation.

Just as the independence of transmission network planning and operation and bulk system balancing authorities from generators was a prerequisite for competitive wholesale markets, the independence of distribution network ownership and operation will be essential to enable competition between centralized and decentralized resources, as well as between traditional network investments and NWAs.

[33] In a small minority of systems, such as the UK, actors independent of the DNO/SO supply meters. In these markets, the meter provider would be responsible for collecting meter data.

Well-established regulatory principles dictate that the best solution from a competition perspective is structural reform that establishes full independence between the DSO and any affiliates in competitive markets. However, regulators must contend with the implications of existing industry structure and the costs of any proposed transitions (e.g. requiring ownership unbundling of integrated DNO/SOs or establishing IDSOs). Second best solutions include legal or functional unbundling, although these solutions have historically proven insufficient at the bulk power system level (European Commission, 2009; FERC, 1999), and are likely face similar (if not more severe) challenges at the distribution level.

Whatever structure regulators and policy makers choose, if responsibility for different horizontal segments is vertically and horizontally disaggregated, mechanisms for efficiently and reliably coordinating the actors in different horizontal segments of the power sector will be required. We turn to this issue in Section 3.

3 INDUSTRY STRUCTURE AND COORDINATION

The power sector was historically dominated by either a regional monopoly generator (i.e. a vertically integrated firm) or a relatively limited number of power producers investing in large plants. Entry into the generation sector in this paradigm was relatively easy to monitor and control. However, today, there are relatively few barriers preventing consumers or other investors from adopting DERs in most developed power systems. Indeed, many DERs (for example, "smart" HVAC units and water heaters) look more like consumer electronics than power sector resources. Consumers do not need to coordinate with the DNO/SO to install and operate these devices, despite the fact that these devices can have significant impact when considered in aggregate (see, for example, (Mathieu et al., 2012)).

Some DER owners are motivated to invest in and operate DERs at least partially by non-economic factors such as peer effects (Bollinger and Gillingham, 2012). However, for the majority of customers and investors, economic incentives significantly influence (if not wholly determine) DER adoption and operation decisions. Price signals are thus one of best means to coordinate DER investment and operation decisions by influencing where and when DERs provide electricity services (MIT, 2016).

The majority of DNO/SOs are mandated to interconnect DERs upon request.[34] Thus, even in systems in which the DNO/SO is vertically integrated into the DER ownership segment, the DNO/SO must have

[34] Interconnection is typically required as long as these DERs meet local interconnection standards, pay any associated interconnection fees, or pay the cost of network upgrades required to accommodate interconnection.

mechanisms to coordinate with other DER owners. In vertically integrated environments, a well-regulated DNO/SO would, in theory, seek welfare maximizing DER deployment opportunities in coordination with network investments, accounting for consumer adoption of DERs (that is, making investments above and beyond what independent network users may already be doing). Planning and investment in a vertically integrated utility benefits from improved coordination (Baldick and Kahn, 1993; Brunekreeft and Ehlers, 2006; Meyer, 2012).

Outside of vertically integrated environments, price signals are one of the primary tools for coordinating DNO/SO network investment and operation decisions with DER owners and operators investment and operation decisions. For strict unbundling between the DNO/SO and DER ownership roles to deliver net benefits relative to vertical integration, the efficiencies gained by competition must outweigh any lost economies. This will critically depend on the formation and communication of efficient and cost-reflective prices to electricity consumers, DER owners, and aggregators thereof.

The price signals that influence DER investment and operation decisions can be summarized in four broad categories that are not mutually exclusive:

1. Energy price signals
2. Network use of system price signals
3. Ancillary services and capacity price signals
4. Subsidies and other policy and regulatory costs

These four categories are not mutually exclusive. For example, the price of energy in a given area often reflects the scarcity of network capacity, which can signal the need for network capacity investments. Nonetheless, it is useful to distinguish between these four categories of price signals, as they will be impacted in different ways by different industry organization decisions.[35]

In the remainder of this section, we discuss the price signals that will be needed to coordinate investments and operations in DERs and network assets in the short and long term and highlight how different structural arrangements impact the need for these price signals. We begin with a discussion of the entity responsible for coordinating and dispatching resources on operational timescales in order to ensure reliable power system operations, as the actions that this entity takes play a key role in determining the prices that coordinate the behavior of other actors. We then discuss the role of short-term price signals

[35] Subsidies and policy and regulatory costs emerge from policy decisions to support certain classes of technologies or customers. We do not discuss subsidies further, as industry structure questions are only loosely related to these costs.

in the planning and operation of the distribution system and the power system more broadly. Finally, we conclude with a discussion of the price signals needed to coordinate long term planning and investment.

3.1 THE ROLE OF THE DSO VIS-À-VIS BULK SYSTEM BALANCING AUTHORITIES

As discussed in Section 2.3.1, bulk system balancing authorities (BAs)[36] today balance power at the transmission level by:

1. Ensuring the feasibility of power flows scheduled by generators, storage providers, aggregators, and retailers in the weeks- to day-ahead time frames.
2. Issuing security-related dispatch orders to generators in real time to match supply and demand within system operating constraints.

Security-related dispatch orders are the shortest timescale operational decisions in the power system (aside from automatic inertial response and generator control). The final production and consumption schedules that result from generator and consumer schedules and system operator dispatch decisions result in a set of marginal prices for energy and operating reserves that are related to the marginal cost of the resources providing these services (Hogan, 2013). Making welfare maximizing security-related dispatch decisions requires the system operator to have a robust knowledge of the network and the constraints and marginal costs of the resources connected to it. However, today, BAs have little or no visibility into: 1) the network conditions of the distribution networks connected to their system, 2) any DER or aggregator dispatch orders issued by DSOs, or 3) DER operation or consumption decisions made by users connected to the distribution system.[37]

As a result, BAs run the risk of issuing suboptimal dispatch decisions. BAs also run the risk of issuing dispatch orders to DER providers or aggregators that are infeasible due to distribution system constraints or that conflict with dispatch instructions sent by the DSO to consumers, DER providers, or aggregators. Conflicting DSO and bulk system BA orders result from "tier bypassing," wherein an actor in the

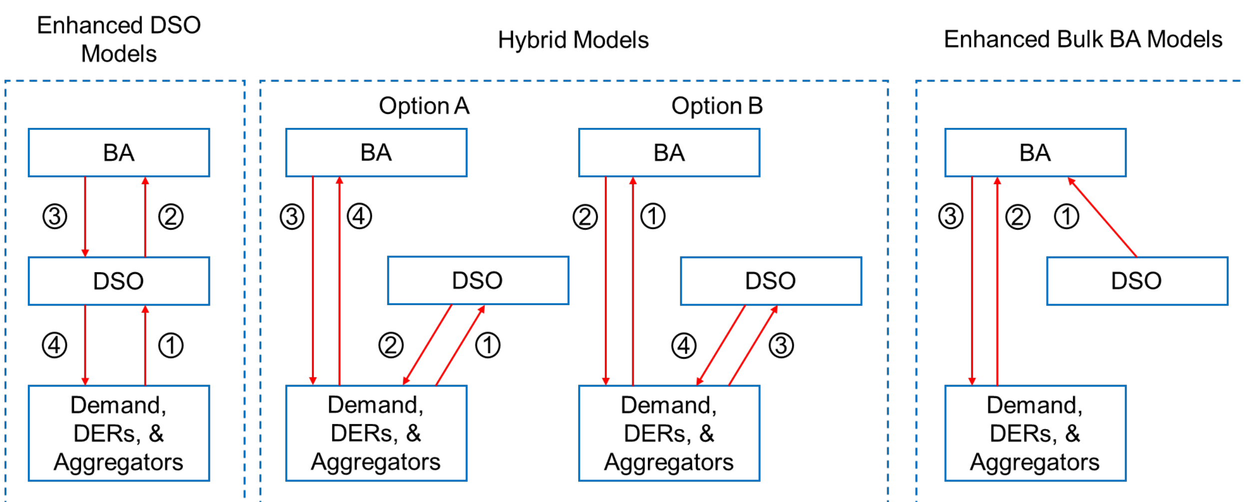
[36] Depending on the local industry structure and context, the bulk system balancing authority in question may be an independent system operator (ISO) or regional transmission organization (RTO), a transmission system operator (TSO), or a vertically integrated utility with balancing responsibilities.
[37] This is not true in cases where the BA is a vertically integrated utility, as, in theory, the vertically integrated utility has visibility over its entire network. Such visibility may not be true in practice given technological shortcomings (for example, limited smart meter deployment or lack of SCADA coverage in lower voltage distribution feeders).

distribution network makes a physical commitment without incorporating distribution-level network externalities (Taft and Becker-Dippmann, 2015).

DSOs, on the other hand, have visibility into distribution system conditions but have little to no visibility into bulk system conditions. In many cases, DSOs also lack visibility into the investment or operation decisions of DER owners and, as a result, lack knowledge of the potential for DERs or demand to take action to support system operations. This has led to a variety of discussions over how to coordinate DSO operations with demand, DER providers, aggregators, and bulk system balancing authorities (Eid et al., 2016; ENTSO-E, 2017).

At the highest level, there are three basic models for coordinating these roles, as depicted by Figure 2 below. The numbers in Figure 2 correspond roughly to the order of the flow of information in each model. In each model, the BA and DSO coordinate to some degree to ensure that demand and supply are balanced within transmission and distribution constraints. The goal of all of these methods would be to limit any price differences at the "seams" between transmission and distribution that do not result from losses or congestions – that is, to maximize all welfare improving trades across the widest possible geography.

Figure 3: Three basic models for coordinating DSOs and bulk system Balancing Authorities



Enhanced DSO models: In enhanced DSO models, the DSO has sole responsibility for distribution level power balancing. The DSO would first aggregate all demand, DER, and aggregator bids. The DSO would also make or aggregate any necessary forecasts of unscheduled demand or DER production (such as from solar PV). The DSO would then ensure the feasibility of these potential power flows under a range of different assumptions about potential transmission-level power flows and prices (step 1). The DSO would then provide the transmission-level BA with an aggregate demand or supply bid for energy and ancillary services that is a function of power flow and price at the transmission-distribution interface (step 2). For this process to be run in one step, this bid would need to contain price-quantity pairs at the transmission-distribution interface(s)[38] for all potential prices and power flows that would result from the bulk system BA's optimal power flow problem. The BA would then incorporate the DSO's supply-demand function into its transmission-level security-constrained economic dispatch decisions and communicate the resulting price and flows at the transmission-distribution interface to the DSO (step 3). Upon receiving BA dispatch orders, the DSO would dispatch all distribution level resources and perform any security-related re-dispatching to ensure that network flows in distribution are feasible and that the flow across the transmission-distribution interface is equal to the level in the BA's economic dispatch solution (step 4). Under this setup, the bulk system BA would, in theory, have and need relatively little information regarding the status or topology of the distribution system, other than the DSO supply-demand function submitted in each time period.

Some algorithms, such as those proposed by Caramanis et al. (2016), jointly clear energy and ancillary services while accounting for both transmission and distribution resources and constraints. These models often "decompose" the system into transmission and distribution level problems. In such methods, the distribution level problems are solved and iterated with the transmission level problem until an equilibrium solution is found. This is effectively an implementation of an enhanced DSO model, as the bulk and distribution system scheduling problems are solved independently and coordinated. The difference is that this distributed solution method seeks a globally-optimal solution via an iterative convergence strategy, whereas the process described above relies on a sequential process.

Hybrid models: In hybrid models, the BA and DSO share responsibility for real time power balancing. In this model, the DSO clears demand, DER, and aggregator schedules either before (Option A in Figure 1) or after (Option B in Figure 1) these schedules have been cleared with the BA. This effectively involves the DSO and BA sharing information to avoid the infeasible or conflicting dispatch order scenario described above.

Consumer, DER, and aggregator positions will depend on transmission-level outcomes and a variety of exogenous factors. Likewise, transmission-level outcomes will depend on the aggregate demand or supply at all transmission-distribution interfaces. Therefore, the process of clearing positions with the DSO and BA would need to involve (perhaps very rapid) iteration. Alternatively, the DSO and BA could accept sub-optimal but feasible solutions. That is, the DSO and BA may accept solutions that do not maximize total

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[38] This type of arrangement may only be feasible if the distribution system downstream of the transmission-distribution interface is radial. This has led some scholars to argue that it may be necesssary to consider re-assigning the proper boundary between transmission and distribution to the meshed-radial boundary (MIT, 2016, Ch. 6).

system welfare but that do meet all system constraints. In such an instance, either the DSO or BA would have primacy in the case of conflicts. One mechanism for establishing primacy would be to assess the marginal value of the two conflicting dispatch options to determine which dispatch order should be executed, with the second actor then finding a feasible but potentially suboptimal alternative dispatch decision. In systems with low penetrations of DERs and few operational measures required of the DSO, this model may be workable without substantial efficiency loss. Indeed, variations of this model are proposed by CAISO et al. (2017) and ENTSO-E (2017) as intermediary solutions for the near term. In these cases, no single entity retains full responsibility for dispatch of resources in a given geography. However, with high penetrations of DERs and frequent operational measures taken by the DSO, the infrastructure and the arrangements necessary to enable such a model may increase transaction costs and prove more costly or challenging than alternatives.

Enhanced bulk BA models: In enhanced bulk BA models, the DSO cedes the responsibility for ensuring the feasibility of power flows and power balancing at the distribution level to the bulk system BA. The DSO would provide the BA with complete information regarding the status of the distribution network (step 1). All network users – whether distribution or transmission connected – would submit bids for production or consumption to the bulk system BA directly or through an aggregator (step 2). The BA would also forecast any unscheduled generation or load (step 2). The BA would then dispatch all transmission and distribution level resources accordingly (step 3).[39] As discussed below, this option would likely prove computationally infeasible using the algorithms currently used by BAs to clear security-constrained economic dispatch of bulk power systems.

Tradeoffs and considerations: With perfect information flows and zero transaction costs between the DSO and the BA, enhanced DSO and enhanced BA models are effectively identical. However, in reality, information flows are imperfect and not costless. Regulators must therefore consider several key tradeoffs when determining which system to implement.

Without sophisticated and as-of-yet unproven mechanisms for coordinating power exchanges between BAs and DSOs, enhanced DSO models could significantly decrease trade between resources at the transmission level and demand and DERs at the distribution level (and between DERs in one distribution system with demand in another). This could dramatically decrease power system efficiency. For context, there are over 3,000 DNOs in the U.S. today. If each DSO acted as an independent balance authority

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[39] A variant of this model would have the BA issue dispatch orders to the DSO who would then execute these orders.

within its service territory, this would increase the number of BAs operating in the U.S. by two orders of magnitude (the U.S. had 66 BAs as of July 2016).

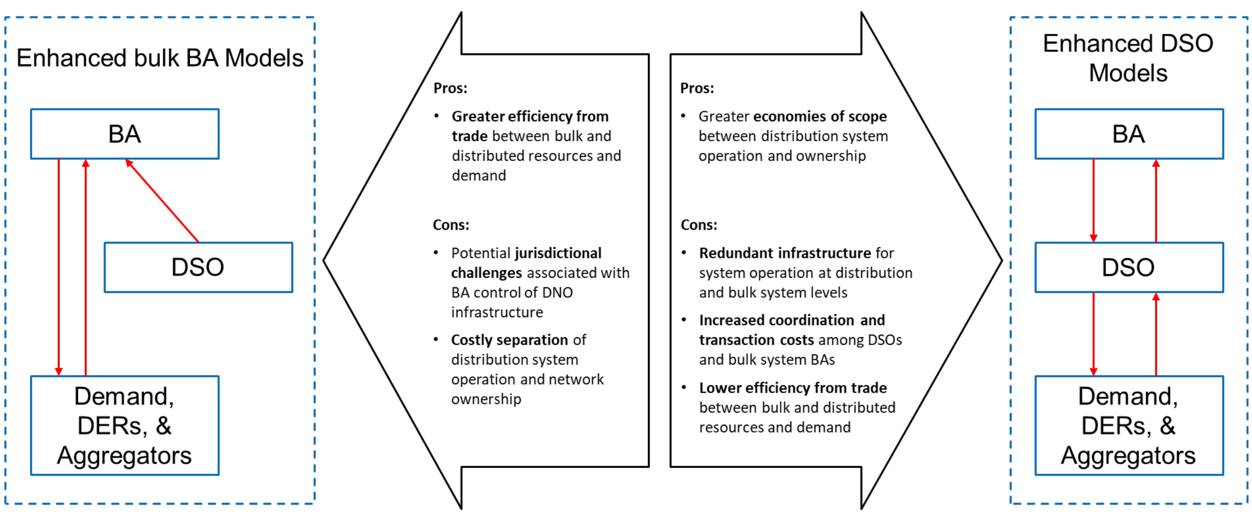
Proponents of enhanced DSO models note that BA-DSO coordination could mimic today's inter-ISO coordination (Kristov et al., 2016). However, inter-BA trading has historically been very limited; a review of hourly U.S. trading data reveals that roughly 90% of all power produced in a given BA's territory was consumed in that territory between 1999-2012 (Cicala, 2017, p. 18). This can be interpreted in one of two ways. One could interpret this as meaning that balancing authorities do not effectively coordinate to maximize the benefits of potential trades between their areas. Alternatively, one could interpret this as the result of balancing authorities expanding their geographies to the point that maximizes the achievable gains from trade.

Neither interpretation would lead one to believe that DSOs are the optimal scope for balancing responsibility, as a single distribution system is unlikely to be the ideal size to maximize gains from trade, and the enhanced DSO model would necessitate significant cross-seams trading. Furthermore, the existing evidence indicates that the first interpretation is correct: that is, that inter-BA coordination is sub-optimal, at least under the U.S. model where market operations are largely defined by the balancing authority area. For example, the development of the Western Energy Imbalance Market (EIM) yielded many benefits by coordinating real time dispatch among previously independent BAs in the Western Interconnect in the U.S. (CAISO, 2017). The EIM was established in 2014, indicating that gains from trade were available but uncaptured at the time of EIM formation. Furthermore, the recent expansion of the Midcontinent ISO in the U.S. also yielded benefits, primarily from gains from trade (MISO, 2017). In Europe, the benefits of greater market integration have been estimated to be on the order of several billion dollars per year (Newbery et al., 2016). While this evidence is not definitive, it indicates that methods to coordinate markets and balancing areas are not yet fully developed, and that dramatically increasing the balkanization of markets may be very costly.

In addition to creating a need for novel and sophisticated DSO-BA coordination mechanisms, each DSO would have to develop the computing infrastructure and knowledge required to assess the feasibility of power flows and balance power across many time scales. However, the cost of this infrastructure is not likely to be a major barrier. For example, the total expenses of PJM – the largest balancing authority in the U.S. by generation capacity – were roughly $277 million in 2016 compared to total billings of over $39 billion (roughly 0.7% of the total system costs) (PJM, 2017).

Enhanced bulk BA models require the BA to have a complete understanding of the DNO network and the resources and demand connected to this network. BAs have substantially greater experience than distribution utilities at efficiently and dynamically operating electricity systems. However, accounting for all distribution system conditions and DER characteristics would require a significant increase in the complexity of BA operations. For example, the California Independent System Operator (CAISO) system contains 26,000 miles of transmission lines, while the three largest DNOs in California together manage over 255,000 miles of distribution lines (CAISO et al., 2017). A BA-led system would require modeling the constraints of more than one order of magnitude more lines and network users. Further, it would require new computational techniques, as many distribution circuits are unbalanced 3-phase circuits. It is unlikely that such a system would be computationally feasible or practical with today's technology. Furthermore, there may be jurisdictional impediments to an enhanced bulk BA model in the U.S., given that distribution utilities are regulated at the state level, while ISOs/RTOs are regulated at the federal level. Finally, enhanced bulk BA models effectively emulate IDSO models, as, in non-vertically integrated markets, the BA (serving as distribution system operator) would be independent from the DNO. A BA-led model would therefore create many of the inefficiencies discussed in Section 2.3.3. These potential inefficiencies must be weighed in considering a BA-led model.

Figure 4: Tradeoffs between distribution system operational models



Many open questions remain about the future role of the DSO. Enhanced DSO models will require new methods for BA-DSO coordination that maximize the potential benefits from trade in order to prove viable. If such coordination mechanisms cannot be established, the benefits of enhanced bulk BA models must be compared against the increase in transaction costs that result from separating distribution system operation and ownership. The complexities of the issues at hand justify further research into the costs and benefits of the potential implementations of these models. In the near term, it is likely that Hybrid models with suboptimal outcomes will prevail. However, if DER penetration increases, regulators and policy makers may benefit from reconsidering the mechanisms that coordinate DSOs and bulk system BAs.

3.2 ENERGY, ANCILLARY SERVICES, AND CAPACITY PRICES

The prices of energy, ancillary services, and capacity products are related to the marginal cost of providing these services. In systems with organized wholesale markets, these prices emerge from a combination of: 1) market operations that match the least cost set of generation resources with demand, and 2) any security-related actions taken by the system operator. In vertically integrated systems, these prices emerge from internal dispatch decisions by the vertically integrated utility. Marginal prices already serve to coordinate investment and operation decisions in generation, storage, and network resources at the bulk system level. As the penetration of DERs increases, it will become increasingly important that DERs are included in the processes – whether market-based or otherwise – that determines the prices for energy, ancillary services, and capacity products. While the owners of some DERs, such as homes with rooftop solar PV or smart HVAC systems, may not schedule their production or consumption decisions in markets, the impacts of these resources must be accounted for in any dispatch processes in order to maintain system stability (these resources may participate in markets via aggregators).

It is theoretically possible to extend the marginal cost-based price formation process used in bulk power systems into the distribution network to create prices for DERs and consumers reflective of network constraints and marginal costs of supply at a given time and place. As discussed in Section 3.1, different organizational decisions will determine the entity responsible for accounting for DERs and distribution level constraints in system operations. Accounting for DERs and distribution level constraints in detail would likely require a dramatic increase in the complexity of system operations. Furthermore, the true price of energy and ancillary services at different locations in the distribution system would likely be significantly more volatile than prices for the same services at the transmission level, potentially reducing their efficacy as an investment and operation signal (MIT, 2016, chap. 4). We view it as unlikely that these signals will be the sole means of coordinating decisions in the near term (as is sometimes envisioned by proponents of "transactive energy" systems, e.g., Kristov et al., 2016). Instead, DNO/SOs will likely need to rely on proxies for the true value of energy, ancillary services, and capacity at the distribution level, such as the price of energy at the relevant transmission node adjusted to reflect estimated marginal losses in each distribution voltage level. As we will discuss in Section 3.3, the price signals that the vast majority of distribution network users see are tariffs, which are, in the majority of cases, proxies for the real prices of energy and network services.

Nonetheless, in unbundled systems that pursue an enhanced DSO model, DNO/SOs may wish to rely on market mechanisms to identify the lowest cost resources for relieving distribution system constraints on operational timescales. The key question from a structural perspective is whether these markets should be organized by the DNO/SO or by an independent market operator. To ensure transparency and prevent foreclosure, the market operator must maintain complete independence from market activities. This has been a key design feature in both the European and U.S. contexts. Thus, in systems with competition in the DER and/or aggregation roles and where the DNO/SO is downstream integrated into these roles, a third party market operator may be critical for short-term operational markets. The European market context demonstrates the possibility of independent market operators ("power exchanges") working in coordination with network owners and operators. However, such a structure can require the system operator to make out-of-market congestion management payments, which can harm efficiency (Neuhoff et al., 2011). This strengthens the argument for ensuring the independence of the DNO/SO, so that the DNO/SO may also act as a neutral market operator.

Some power system stakeholders have highlighted the potential for local or peer-to-peer markets to replace existing system operators and market mechanisms. These stakeholders argue that these decentralized markets will, among other things, create greater value for DER owners and enable consumers to procure power that better matches their preferences (NYDPS, 2014; Parag and Sovacool, 2016). We note two challenges that these peer-to-peer markets must overcome. First, network externalities – losses and congestions that result from the aggregate behavior of all network uses – may make truly peer-to-peer architectures reliant on bilateral transactions infeasible as all transactions would need to account for underlying network realities (Mansur and White, 2012). Second, as noted in Section 2.3.2 and 3.1, power markets deliver the greatest benefits when run over the largest possible geographies. Restricting markets to specific geographies to enable peer-to-peer markets can decrease market liquidity, which can increase the ability of certain participants to exercise market power and can result in suboptimal market outcomes. An alternative to peer-to-peer markets is ensure DERs are capable of participating in other more geographically diverse market mechanisms, such as existing wholesale markets, multilateral markets for distribution-level services, or distributed globally optimal market clearing processes.

3.3 THE ROLE OF TARIFFS

At the distribution level, the price signals for energy, network access, and ancillary services are typically bundled in retail tariffs along with other power system costs. The vast majority of residential and commercial electricity consumers do not buy and sell electricity in markets and negotiate for network access with transmission and distribution utilities. Rather, a retailer – competitive or monopoly – assumes financial responsibility for the customers, procuring and scheduling energy consumption and production in markets and with the relevant system operator and network owners. Network users in turn pay retailers a tariff for energy use or are paid at a tariff-determined rate for energy production. As a result, tariffs are one of the primary investment and operation signals for DERs (Carley, 2009).

Given that tariffs will influence DER adoption and operation decisions in all industry structures, cost-reflective tariffs are necessary to align the incentives of network users with the incentives of the system writ large (MIT, 2016, chap. 4). Tariffs that do not reflect the short run marginal cost of energy consumption and production decisions have two deleterious effects. First, they distort investment and operation signals for DERs and electricity consumers. Second they shift costs between network users, as any time a user saves more in reduced tariffs than they reduce system costs, another system user inevitably pays for the remaining system costs. Borenstein (2017) highlights this phenomenon in the case of rooftop solar PV.

The magnitude and structure of the retail tariff may be determined by a regulatory agency, by the retailer, or both.[40] These retail tariffs typically bear relatively little relation to the marginal costs of providing electricity services at any given time and location. Further, these tariffs tend to bundle the cost of energy, network and generation capacity, and policy costs and subsidies into a volumetric price that artificially inflates the marginal cost/value of energy seen by ratepayers. It is critical that tariffs be designed in a way that reflects marginal costs and does not favor private net benefits over system wide welfare benefits.

Changes to industry structure at the distribution level do not fundamentally alter incentives for creating efficient, cost-reflective tariffs. Improved incentive regulation schemes reward DNO/SOs for pursuing cost savings that may result from improved network tariffs. Retailers settled at efficient prices for the actual consumption and production profiles of their consumers have the incentive to pursue cost saving opportunities (Borenstein and Bushnell, 2015; Joskow and Tirole, 2006). Thus, changes to retailing settlement rules could lead to more efficient tariffs. However, these are primarily regulatory decisions that are not directly linked to industry structure decisions.

Efficient tariffs that reflect the short run marginal cost of energy delivery will help consumers or businesses identify the optimal locations for DER deployment, and the optimal operating schedules at these locations. In the absence of efficient tariffs, the DNO/SO may wish to signal the optimal locations for DER investment through other means, such as long-term contracts. We turn to this issue next.

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[40] For example, in some competitive retail markets, the network tariff is regulatorily determined while the retailer is free to structure the energy tariff.

3.4 THE ROLE OF LONG TERM CONTRACTS FOR DISTRIBUTION SERVICES

Efficient tariffs will play a major role in driving investments towards the locations in the power system that deliver the most value to the system writ large. However, given the risk aversion of network utilities and the long planning horizons required for network investments, long term mechanisms may be needed in order to encourage the development of the optimal mix of network assets and DERs.

The traditional network planning process involves forecasting future demand and designing the network infrastructure necessary to meet this expected demand. Now, however, DNO/SOs must plan their networks accounting for changing load and the potential for electricity production from DERs. Cost minimizing DNO/SOs may wish to procure services from DERs – either through ownership or contracting – as opposed to investing in network infrastructure. Similarly, DER owners and operators may wish to receive revenue from providing network services or to curtail injections or withdrawals rather than pay for network upgrades.

The retail tariff may include forward looking elements that signal the impact of network user's consumption or production decisions on future network investments. In such a case, the DNO/SO could, in theory, rely on the distributed response of network users to curtail demand or production to avoid congestions or system failures. However, the DNO/SO must make network investments in anticipation of consumer response. Baldick and Kahn (1993) note that uncertainty over generator locations impedes optimal network investment decision making, exacerbating the challenge for the DNO/SO. In addition, using forward-looking network price signals raises questions over when the DNO/SO (or the bulk system BA) would have the authority to curtail demand or production if network users fail to respond to price signals as anticipated when network investments were made.

Network investment decisions are typically made months to years in advance of real time. DER investment decisions are typically made weeks to months in advance, and, finally, operational decisions are made days to seconds in advance. Should the DNO/SO fail to build sufficient network capacity or contract for DER services, binding demand-driven congestions could result in demand curtailment or localized blackouts. A risk neutral or risk averse DNO/SO that is subject to regulatory standards for reliability is unlikely to rely solely on the potential for real time response, and will likely wish to establish contracting mechanisms to coordinate investment across these timeframes. Harvey et al. (2013) describe a similar logic for establishing capacity markets (although the authors note that forward financial contracts without physical commitments do not adequately serve this coordination function).

DNO/SOs are therefore more likely to rely on long term contracts secured well in advance of real time with strict performance requirements for delivery. This practical observation is bolstered by theoretical and empirical research that predicts that transactions that navigate significant uncertainty (future demand or supply) and rely on highly specific assets tend towards long term contracts (Joskow, 1985; Lafontaine and Slade, 2007; Williamson, 1979). The most high profile non-wires alternatives programs – such as the BQDM project in New York City – have relied on such forward contracts (Coddington et al., 2017). It is unlikely that the DNO/SO will enter into such arrangements with all DER owners (that is, it is unlikely that every home solar system owner will negotiate network access with the DNO/SO). There are many such designs for these commitments. For example, Anaya and Pollitt (2017) describe a method that relies on interconnection agreements.

Contracts for non-wires alternatives will require complex, long-term forward contracts with strict performance requirements. These contracts are likely to be procured in the network planning phase.

Competitive procurement mechanisms may be used to procure these forward contracts. In systems in which the DNO/SO is not fully unbundled from DER ownership, a third-party market operator may be necessary to create a level playing field between monopoly and non-monopoly providers. Alternatively, the DNO/SO could manage the procurement process subject to closely monitored open standards and with third-party review of the bids. Open procurement mechanisms could mirror those leveraged by some vertically integrated utilities today. For example, to ensure transparency, Pacific Gas and Electric (PG&E) in California uses a third party to solicit bids for non-wire alternatives to distribution network infrastructure and an "independent evaluator" to review these bids (PG&E, 2017). As replacing network infrastructure with non-wires alternatives becomes more commonplace, the DNO/SO may wish to run many auctions per year. Communicating auction requirements to a third party operator or engaging in thorough regulatory oversight will likely increase transaction costs significantly. In this case, it may become advantageous to address concerns about potential anti-competitive practices through structural reforms by barring DNO/SOs from participating in DER ownership and aggregation.

4. DISCUSSION AND CONCLUSIONS

The emergence of DERs provides new opportunities to lower power system costs. Achieving this potential requires regulators to ensure that the industry structure at the distribution level aligns the incentives of the various roles at the distribution system towards efficiency. This paper supports this revisiting of restructuring by considering the implications of different industry structures for competition and coordination in the power sector. Our conclusions are five-fold.

First, we find that separating distribution system operation and ownership is likely a second best solution to an integrated utility that is fully financially unbundled from any competitive activities. Where competition is a priority, the monopoly nature of the DNO and DSO roles and their potential to abuse this position necessitates their independence from any competitive activities. If the DNO is not fully unbundled from any competitive activities, the independent DSO concept is intellectually appealing. However, separating the DNO and DSO roles would require complex and costly arrangements between these two parties to align incentives and actions. A more efficient model would be to combine the DNO and DSO and ensure that this actor is strictly separated from any market activities, including generation, DER ownership, and aggregation services. While structural regulations can ensure that the DNO/SO acts as a neutral market facilitator, these regulations do not fundamentally alter the DNO/SOs incentives to leverage DERs when and where they reduce costs. It is therefore critical that the DNO/SO be regulated under an incentive regulation scheme that encourages it to make efficient tradeoffs between wires and non-wires assets, or they will face financial incentives that consistently bias decisions towards investment in rate-based capital assets.

Second, in systems in which competition for generation has been introduced, there is insufficient evidence to argue that distribution utilities should be allowed to own DERs. Rather, we show that there is evidence that DER ownership is an activity best left exclusively to non-monopoly actors. Experience from the restructuring of the bulk power sector provides examples of the negative impacts of allowing monopoly participation in competitive activities. Furthermore, in systems with competitive generators, enabling monopoly ownership of DERs will likely result in an inefficient utilization of DER capacity.

Third, the emergence of DERs and digital technologies means that aggregators – and the loads and DERs they serve – will increasingly be active and impactful participants in power systems. Where competition has been introduced in retail aggregation, regulators interested in ensuring the neutrality of the DNO/SO must take steps to more effectively unbundle DNOs and DSOs from affiliated aggregators. Where unbundling is not an option, regulators should strengthen the barriers that prevent anti-competitive collusion between DNO/SOs and their competitive affiliates.

The above conclusions all point to stronger separations between the DNO/SO and any competitive actors, and thus an increasingly vertically and horizontally disaggregated power system. This necessitates a renewed focus on the mechanisms that coordinate vertically and horizontally disaggregated actors in the power sector. This is especially true as price signals – the primary mechanism for coordinating these actors – have historically not been designed with efficiency and coordination in mind. We thus provide two key conclusions regarding coordination and price signals at the distribution level.

First, as the penetration of DERs increases and as DNO/SOs increasingly rely on DERs as alternatives to traditional network infrastructure, power system stability and reliability will be increasingly tied to how distribution-connected resources are dispatched. However, today, no single entity has visibility over distribution network constraints and authority to modify dispatch according to these constraints. This requires a reconsideration of the entity that is responsible for maintaining balancing power on operational timescales. Two potential models emerge: one in which the DSO takes full responsibility for distribution-level balancing, and one in which the bulk system balancing authority takes responsibility. Both models have tradeoffs. A DSO-led system will require as-of-yet unproven coordination mechanisms with the bulk system balancing authority. Without such coordination mechanisms, a DSO-led system could significantly reduce overall trade. A bulk system balancing authority-led system would eliminate significant economies of scope between the system operator and the DNO. However, given that the BA-led system would enable balancing and coordination over the widest possible geographic area, such a system would likely maximize the possible gains from trade. The costs and benefits of different options for power balancing at the distribution level is a key area for further research. In the short term, suboptimal but feasible arrangements involving increased communication between DSOs and BAs and shared responsibility will likely prevail.

Finally, price signals at the distribution level – retail tariffs in particular – must be dramatically improved to better reflect the marginal cost of consuming or producing a given service at a given time and location. The emergence of DERs dramatically expands the potential number of owners and operators of electricity resources. Price signals must be dramatically improved in order to coordinate these distributed decision makers. In addition, competitive procurements for DERs and flexible demand as alternatives to network assets will likely increase efficiency in all market structures (that is, structures with and without competition for generation and aggregation). Should the DNO/SO not be, at a minimum, legally unbundled from aggregator or DER owning/operating affiliates, third-party monitoring or operation of these competitive procurements may create a more competitive environment and increase transparency and efficiency of the auctions. Similarly, in vertically integrated power systems, standardized, open solicitations or third-party run solicitations may be required if an incentive regulation scheme is not in place.

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