SOLUTIONS TO THE UTILITY INFORMATION PROBLEM

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INTRODUCTION

In our SEPA 51st State Concept Paper, *An Adaptive Approach to Promote System Optimization*,[1] we articulated principles for rate design and market structure that would incent the utility and provide price signals for distributed energy resource (DER) providers to optimize the system around public policy goals and economic efficiency. Our approach was to ensure that regulation itself allowed the utility and marketplace to adapt quickly and innovate to integrate new technologies and policy goals like customer choice and clean energy. Throughout the paper, we maintained that market structure decisions including the scope of the regulated utility monopoly could be tailored to each state's preferences. The scope of the monopoly is just one means to an end to make utilities ownership-agnostic enablers of system optimization.

New technologies and power system goals demand a distribution system optimizer (DSO) function that enables all DERs to participate on par with generation and other infrastructure in serving customers. Whether that role should fall with existing electric distribution companies or some other entity is unclear without more information about the optimal locations and types of DER and how they interact dynamically with distribution infrastructure. Similarly, the boundaries of utility ownership of DERs can't be known without fixing underlying incentives to maximize capital investment and devalue DERs. The difficulty untangling these functions suggests a major role for distribution utilities, however. It's also likely that multiple approaches are workable.

This paper focuses on pathways to reveal the information necessary to answer SEPA's prompt questions on the boundaries and functions of the utility monopoly. Both approaches examined require integrated distribution planning – an analysis of DERs' potential contribution to grid services – to reveal latent value and flexibility on the distribution system. Having that information and making it available to the optimizer or platform provider and third-party service

[1] Available at https://sepapower.org/our-focus/51-state-initiative/phase-1/.

providers is a sine qua non for achieving distribution system optimization and defining the scope of the utility's natural monopoly functions.

The paper then examines parallel approaches. First, it explores an information-intensive approach where utilities are asked by a DSO to reveal system needs and the DSO makes markets for DERs and the monopoly infrastructure provider to compete. The information-intensive approach is consistent with cost-of-service regulation (COSR), but it does not necessarily imply COSR is the best approach. Its main downside is that it never addresses the utility's capital bias, maintaining the utility's incentive to keep information from regulators. The second approach is outcome-focused, retaining the DSO function with the distribution utility, but instead focusing on compensating the utility for performance on key public policy goals and reducing capital bias. This approach is more novel and holds tremendous promise, but there are risks pursuing a relatively untested approach and with setting targets for performance with imperfect information. These approaches are meant to sit on a spectrum, meaning neither is mutually exclusive, and a combination of these approaches is likely needed.

THE SCOPE OF A NATURAL MONOPOLY

Electricity infrastructure can be roughly divided into four layers: generation, transmission, distribution, and retail. To answer the questions posed by SEPA, it's important to draw lines where they are clear. However, each layer is currently being subjected to some form of competition, and the scope of the monopoly is in flux in each area, making line drawing difficult in this context. Because the results are mixed for competition elsewhere on the system, we can equally conclude that there is no certainty for what competition would bring to the distribution system.

For example, the bulk transmission system is subject to competition. At first glance, no potential benefits seem to manifest from two overlapping systems of redundant infrastructure, given the costs. But on the transmission system, competitive lines compete with utility lines that recover their revenue through cost-based tariffs. While most transmission lines recover their costs through regulated rates, merchant transmission lines take on the risk of investment and recover their costs through negotiated rates. Several of these lines are able to create a viable business model by building in valuable, congested areas.

Experience shows electricity generation is not a natural monopoly, though the jury is out on whether restructuring, on its own, leads to lower prices or higher customer satisfaction. Even before the proliferation of DERs, wholesale markets managed by independent system operators (ISOs) have proven that competitive generation keeps the lights on while maintaining a similar cost of service.[2]

[2] For example, studies show that when PJM incorporated Midwest utilities, it immediately led to a boost in inter-regional trading, suggesting that the larger trading area allowed for more cost-effective transactions. Erin T. Mansur and Matthew W. White, "Market Organization and Efficiency in Electricity Markets," 2012, 56.

Generation restructuring's cousin, retail choice, has an even more opaque record of performance. A recent exhaustive empirical study by Morey and Kirsch indicates that while green choices and innovative rate designs have proliferated under retail choice, retail rates and customer satisfaction remain largely unchanged when comparing states with retail choice to those without.[3] On the other hand, Texas has one of the most robust and unencumbered retail competition markets, and electricity rates have fallen 15 percent since 2009 while U.S. rates have increased 6 percent over the same time.[4]

The distribution system, the last miles of wires connecting substations customers, has been historically the least subject to competition, but even that is changing. Pilots such as the Brooklyn Queens Demand Management project indicate DERs can effectively replace or defer not only generation, but distribution assets such as substation upgrades.[5] New business models for distributed energy resources as grid infrastructure indicate DERs are increasingly up to the task,[6] but their cost effectiveness in doing so will vary widely.

Given the breadth of issues at play and SEPA's focus on the distribution system, this paper limits the scope of discussion to the distribution monopoly. But an open admission underlies the paper that without clear empirical data and more testing, we won't know where the "natural monopoly" boundaries lie. The complexity of subjecting generation and transmission to competition indicates no clear answer exists even after almost two decades of experimentation. Furthermore, there are likely multiple ways to skin the cat. We can take advantage of the laboratory of democracy we have in the U.S. under more adaptive regulatory frameworks to experiment and iterate in real-time to get it right. Finding states and utilities willing to generate and test new models will be key to advancing the conversation.

That being said, two key unanswered questions underpin the rest of the paper:

1. What is the distribution utility's role in owning, operating, and marketing distributed energy resources like storage, efficiency, distributed generation, and demand response?[7]
2. Should the distribution system optimizer role be separated from ownership of distribution assets and DERs?

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[3] Mathew Morey & Laurence Kirsch. *Retail Choice in Electricity: What Have We Learned in 20 Years?* Christensen Associates. Prepared for the Electric Markets Research Foundation. Feb. 2016.

[4] U.S. Energy Information Administration Electricity Data Browser, accessed October 6, 2017.

[5] See Walton, R. *Straight Outta BQDM: Consolidated Edison looks to expand its non-wires approach*. UtilityDive. July 19, 2017. http://www.utilitydive.com/news/straight-outta-bqdm-consolidated-edison-looks-to-expand-its-non-wires-appr/447433/.

[6] See, e.g., SolarCity. *A Pathway to the Distributed Grid*. 2016. http://www.solarcity.com/sites/default/files/SolarCity_Distributed_Grid-021016.pdf.

[7] The first issue is addressed in part with some case studies in Energy Innovation's Addendum to our Phase 1 Concept Paper, *Who should own and operate distributed energy resources*? http://energyinnovation.org/wp-content/uploads/2017/09/20150824_APPSEPA_utility-ownershipDERs.pdf.

THE ROLE: A DISTRIBUTION SYSTEM OPTIMIZER

We know that demand-side resources are waiting to be unlocked to make electricity service cleaner, cheaper, and more reliable – demand response, energy efficiency, storage, and distributed solar each provide value to the system that exceeds the cost in different contexts. But institutional factors, particularly utility business models and the regulation driving them, stand in the way of unleashing these products to make the system cleaner, cheaper, and more reliable. As such, defining and pursuing a role for utilities as distribution system optimizers is a win for consumers, businesses, and the environment.

In the *Adaptive Approach to Promote System Optimization*, we articulated four principles of market structure that promote the full and fair valuation of distributed energy resources:

1. Create a level playing field for competition between all resources, regardless of their type, technology, size, location, ownership and whether or how they're regulated, allowing supply and demand resources to compete head-to-head.
2. Ensure the grid's stability and health while incentivizing integration of cost-effective centralized and distributed resources. Allow infrastructure owners and grid operators to capture a fair portion of the value of optimizing new technologies to deliver an affordable, reliable, environmentally clean electricity system.
3. Foster innovation in energy services delivery by allowing procurement to adapt quickly to technological innovation. Allow any resource—single or aggregated—to compete to provide energy services (energy, capacity, and ancillary services).
4. Maximize the transparency of energy procurement and markets.

To make these principles real, the system needs a central coordinator that either procures energy services on behalf of customers or creates a market for demand and supply-side resources, while balancing and maintaining physical integrity of the distribution system in real time. The DSO would call on available resources to meet system needs based on their costs and physical constraints, while integrating public policy as well. The DSO would meet local demand with a technology-agnostic, policy-mindful, reliable, low-cost combination of distributed resources, like rooftop solar, storage, or price-responsive demand, compared against transparent real-time prices from the bulk system and distribution and transmission infrastructure. eah

It's worth mentioning that this DSO role is possible without central control over the resources – it could be enabled entirely by a platform provider that merely handles dispatch based on price signals. This model would be closer to a transactive energy framework, enabled by what many refer to as a distribution system platform provider. This model still accomplishes optimization, but relies on individual agents to optimize their behavior around prices. Still, the platform would require management, ensuring the resources that participate meet reliability standards and do not unduly disrupt or manipulate the market.

Who owns what?

There are some benefits to having the same entity own the physical system and operate the resources—it can streamline decision-making about where to expand or improve the distribution network to dynamically accommodate cost-effective DERs and avoid unnecessary infrastructure investments. Additionally, the brand and customer data utilities own can help identify and connect customers to cost-effective DER providers, if utilities are properly motivated to partner with these providers.

On the other hand, compensating the utility based on a rate of return on prudent capital expenditures under cost-of-service regulation, while asking it to also create a neutral platform for DERs that obviate utility infrastructure creates inherent conflicts of interest. These conflicts are amplified when the utility can own and operate the DERs themselves. We see this playing out at the wholesale level, even when generators have been separated from transmission owners and grid operators, but wield significant influence over the RTOs. The generators have managed to reward incumbency and resist accommodating changing resource mixes, state policies, and technologies.[8]

In addition, disentangling the two functions is an immensely complex task, particularly in the context of regulatory dockets. The orchestrator and build/operate functions currently reside with distribution utilities in every state, but unlike the bulk system, distribution system restructuring is complicated by at least five significant issues:

1. Potential value from the existing utility-customer interface and utility brand.
2. Lack of experience with non-wires alternatives, particularly how they interact dynamically with options for managing outages and system configuration.
3. Presence of less sophisticated customers.
4. New public policy mandates, and;
5. Inexperience with price-based dispatch and system use charges on the distribution system.

As an example of the complexity, New York's Public Service Commission (NYPSC) created a matrix of the functions shared by a company owning and operating distribution infrastructure, and company coordinating resources on the distribution system. It is worth noting that the multitude of areas where the utility and distribution system platform (DSP) functions overlap led the NYPSC to retain the distribution utility to undertake both functions.

[8] See, e.g., R. Orvis & E. Gimon. *The state of wholesale power markets: What's wrong with proposed changes in Eastern RTOs?* UtilityDive. June 20, 2017. http://www.utilitydive.com/news/the-state-of-wholesale-power-markets-whats-wrong-with-proposed-changes-in/445417/.

Utility and DSP Roles and Responsibilities	Utility	DSP
Market Functions		
Administer distribution-level markets including:		
- Load reduction Market		X
- Ancillary services		X
Match load and generator bids to produce daily schedules		X
Scheduling of external transactions		X
Real-time commitment, dispatch and voltage control		X
Economic Demand Response		X
Demand and Energy Forecasting	X	X
Bid Load into the NYISO	X	
Aggregate Demand Response for sale to NYISO	X	X
Purchase Commodity from NYISO	X	
Metering	X	
Billing	X	X
Customer Service	X	X
System Operations and Reliability		
Monitor real-time power flows	X	X
Emergency Demand Response Program	X	X
Ancillary Services	X	X
Supervisory Control and Data Acquisition	X	X
System Maintenance	X	
Engineering and Planning		
Engineering	X	
Planning / Forecasting	X	X
Capital Investments	X	
Interconnection	X	X
Emergency Response		
Outage Restoration / Resiliency	X	X

Source: DPS Staff Straw Proposal on Track One Issues, New York Public Service Commission, Case 14-M-0101, August 22, 2014.

The key question for utilities is how they make money as a DSO role emerges. The DSO framework will shift the way that distribution utilities collect revenues and earn rates of return. Rate base shrinkage from investments displaced by DERs will cut into long-term growth prospects for incumbent utilities, but the provision of the platform provides new value to the system, which ought to be shared between customers and the utility to motivate the animation of DER markets. Providing these system benefits should likewise directly influence the profitability of the DSO.

But more information is needed before we can outline a sensible framework distinguish whether the utility should exclusively be the DSO and whether it should be able to own and operate DERs. First, we need to know that the utility or DSO has sufficient data to identify non-wires alternatives and the optimal mix of DERs to balance its system, particularly as the share of variable renewables grows. Second, we need to either publicly expose this information and create transparent markets to reveal the optimal mix of DERs, or we need to create incentives for utilities to become optimizers. Today we are woefully short on answers.

THE INFORMATION PROBLEM

SEPA asks a crucial pair of questions: "Which other functions, if any, should the regulated utility be allowed to provide under regulated, cost-of-service business models, in competition with so called "non-regulated" third party providers?" and "Which functions, if any, should the regulated, cost-of-service utility monopoly be prohibited in offering to utility consumers?" The easy answer would be – whatever is in the best interest of customers and public policy. Problem solved, right?

But the key problem that engenders such fierce debate over this topic is that utilities and third parties still don't know enough about how the distribution system might operate with millions of connected devices, rapid technological change, evolving environmental imperatives, and two-way power flows in order to maximize these goals. What's more, distributed energy resource management systems (DERMS) are in their infancy, and have yet to be synced up with the transmission system at the T-D Interface. Without more information about the locational value of DERs, how this might change dynamically, and the ability of DERs to provide infrastructure as a service, the extent of the distribution grid's natural monopoly will remain unknown.

Further complicating the information problem, traditional COSR rewards utilities that grow their capital asset base and increase their sales volume. But distributed options for reducing costs, improving customer service, and increasing reliability antagonize this business model.[9] And so any utility claim to the right answer that involves a modicum of utility ownership or prefers the status quo to innovation is not only subject to an absolute lack of information, but a distrust of their motivations by regulators and stakeholders. Combine this lack of information with the new options for optimizing the power system that complicate prudency review, and COSR fails to provide confidence in utility ratemaking.

Former California PUC Commissioner Mike Florio explained the information problem in a 2016 ruling in the Integrated Distributed Energy Resources docket:[10]

> *"One might ask: why provide the IOUs with any incentive at all? Why not just direct the utilities to choose DERs whenever they are less costly than traditional distribution investments? The problem is that, given the complexity of the distribution system, this Commission is ill-equipped, at least at present, to determine with the necessary specificity exactly when and where such DER deployment opportunities may exist. . . . Practically*

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[9] See D. Aas & M. O'Boyle. *You Get What You Pay For: Moving Toward Value in Utility Compensation, Part 2 – Regulatory Alternatives*. America's Power Plan. 2016. http://americaspowerplan.com/wp-content/uploads/2016/08/2016_Aas-OBoyle_Reg-Alternatives.pdf.

[10] California Public Utilties Commission, Assigned Commisioner's Ruling Introducing a Draft Regulatory Incentives Proposal for Discussion and Comment. R 14-10-003. April 4, 2016. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M159/K702/159702148.PDF.

speaking, command-and-control regulation faces major challenges in this context. Instead, if our objectives are to be achieved, we should create the appropriate utility incentives, such that the IOUs will affirmatively seek opportunities to deploy DERs in the pursuit of their own shareholders' interests."

As such, defining a pathway to obtaining this information is a crucial first step toward achieving a new definition of the natural monopoly. The next section focuses on pathways to obtaining information about the optimal mix of DERs, as a foundation to deciding the market structure that best achieves economic efficiency and public policy goals.

Know that the utility knows: Integrated distribution planning

Right now, distribution utilities don't even know enough about their distribution systems to properly value and plan around distributed energy resources. According to the SEPA and Black & Veatch report:

> "*The growth of DERs is challenging many of the assumptions upon which traditional distribution planning relies. DERs are creating two-way power flows on the distribution system that legacy distribution equipment was not designed for. DERs are also confounding conventional load forecast methodologies and complicating the modeling of distribution feeders by introducing new kinds of generation sources or modifying load profiles*."

Recent conversations among utility and industry stakeholders at the Utility Business Models Pathways pod at Rocky Mountain Institute's eLab Summit have confirmed this lack of system visibility and understanding.

To obtain this information, distribution utilities should engage in integrated distribution planning (IDP), a practice in which demand-side and distribution-level investments are considered in conjunction with bulk-system resources to achieve an optimized, integrated system.[11] This includes understanding the potential contribution from DERs, by first conducting a general assessment (and ideally a locational assessment) of a cost-effective portfolio of resources.

Of course, IDP is a large undertaking and doesn't have to be all-or-nothing. Some pieces of information are more relevant in less mature markets. More than Smart has created a "walk-jog-run framework to IDP that lines up with market development, allowing utilities and stakeholders to prioritize.[12] In addition, SEPA released a summary of best practices.[13]

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[11] For a definition of IDP, see Electric Power Research Institute, *The Integrated Grid*, accessed January 26, 2016, http://integratedgrid.com/; SolarCity, "Integrated Distribution Planning," 2015.

[12] See "More Than Smart," *Greentech Leadership Group*, August 2014. See also ICF International, *Integrated Distribution Planning*. Prepared for the Minnesota Public Utilities Commission. August 2016.

[13] For examples and best practices, see Coleman, Amy et al., "Planning the Distributed Energy Future: Emerging Electric Utility Distribution Planning Practices for Distributed Energy Resources", Smart Electric Power Alliance, 2016.

Once IDP is complete, it produces useful data to help align utility incentives and reveal market information. Data about what efficiency, reliability, and environmental goals are possible through better integration of demand-side resources provides a rational basis for regulators and stakeholders to measure and set targets for utility performance. Locational value data indicates what performance characteristics would be needed to rely on DERs as infrastructure-grade service providers, laying the foundation for long-term contracts and real-time pricing, enabling greater competition and price transparency on the distribution system. Smart customer-facing rate design, DER procurement, and technology deployment can then be used to improve overall environmental and economic performance, regardless of the market structure.

CREATING BUSINESS MODELS FOR THE DSO

Once the utility demonstrates its knowledge of where DERs can be most valuable, additional work is required to ensure utility incentives align with system optimization. Two parallel paths can lead to a DSO role – an information-intensive approach and an outcome-focused approach. The information-intensive approach is compatible with COSR and separation of the optimization & ownership functions. The outcome-focused approach represents a new regulatory compact that seeks to shift the role of existing distribution utilities into drivers of low-cost, reliable service that achieves public policy. These are ends of a spectrum, and some combination of both is likely the best path forward.

Information-intensive approach

DERs provide a stack of benefits including transmission, generation and distribution capacity deferral, as well as societal benefits and operational efficiencies including greater reliability. IDP reveals these values, allowing a neutral DSO to define services and create markets for the distribution utility, third-party providers, and customers to provide grid services. A well-functioning distribution-level market would maximize net benefits to consumers by ensuring regulators, stakeholders and system planners have adequate information to determine the combination of centralized investment and DER deployment is in the public interest.

A data- or information-intensive approach demands utilities accumulate and process customer usage data in conjunction with location-based assessments of infrastructure needs. This is no small task for businesses built under the safe assumption traditional distribution infrastructure investment was always the most economical solution to reliability concerns.

The California Public Utility Commission's (CPUC) distributed resource planning (DRP) proceeding[14] demonstrates the heavy lifting required to acquire this information through an information-intensive approach to utility planning and regulatory review, even without disentangling the system operator role from the utility itself. In response to the CPUC's 2016

See also Bode, Josh et al., "Addressing the Locational Valuation Challenge for Distributed Energy Resources," Solar Electric Power Alliance in partnership with Nexant, September 2016.

[14] http://www.cpuc.ca.gov/General.aspx?id=5071

DRP roadmap straw proposal, the state's investor-owned utilities indicated they needed upward of five years to accumulate data and complete demonstration projects to accurately compare DER investments against distribution infrastructure investments, although some stakeholders disputed this timeline.[15]

In its 2016 *Distributed Energy Resources Action Plan*,[16] the CPUC gave a clear sense of the sheer scope of the undertaking, which would last into 2020:

> ***Continuing Elements***
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> 1. Distributed Resource Plans (DRP) (R.14-08-013) proceeding, including consideration of:
>   a. DRP demonstrations including establishing and testing integrated capacity and locational net benefit methodologies
>   b. DER data needs
>   c. Distribution infrastructure deferral framework, including reforms to consider DRP results in GRC Phase 1 proceedings (e.g., A.16-09-001)
>   d. Grid modernization definition and characterization
>   e. DER growth scenario forecast methodologies, including implementation risk assessments as inputs to integrated resource planning.

If the CPUC approves the utility proposals, which have since moved into the rate case phase, demonstration projects and the multitude of parallel proceedings would occur in conjunction with $5-6 billion in proposed grid modernization investment, approximately half of which is driven by investments to collect and process locational data. While significant evidence suggests some data could be acquired more cheaply from non-utility sources,[17] the scale of investment requested by utilities and the regulatory back-and-forth suggests significant financial and regulatory costs to enabling, among other things, comparison of DERs and centralized investment.

However, to move to a model that separates the distribution utility and DSO function, and independent DSO (IDSO), even more will need to be done. Once sufficient information is known about the most valuable locations for DER deployment, the IDSO will be tasked with developing an algorithm to optimize procurement and dispatch of DERs within public policy constraints such as reliability standards, low-income service, and environmental goals. This will be significantly more complicated than security-constrained economic dispatch on the bulk system, with many more connected devices behaving in new ways and responding to different signals.

Engaging in a comprehensive effort to reveal the locational and time-varying value of providing energy, capacity, and other services at the distribution level will be necessary to enable DERs to

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[15] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M156/K128/156128642.PDF

[16] http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Commissioners/Michael_J._Picker/2016-09-26%20DER%20Action%20Plan%20FINAL3.pdf

[17] http://www.solarcity.com/sites/default/files/SolarCity_Distributed_Grid-021016.pdf

efficiently compete against utility infrastructure. Though it is a significant lift, it creates a level playing field that can enable significant efficiency within the constraints of public policy goals.

Outcome-focused approach

On the outcome-focused side of the spectrum, regulators can prioritize creating utility incentives to pursue the most efficient system optimization solutions without relying so heavily on a line-by-line review. Performance-based regulation ties utility shareholders' returns on equity investments to achieving outcomes.[18, 19] If calibrated correctly, utilities' primary avenue for increasing the value of their company no longer lies in capital investment -- it lies in system optimization.

In this scenario, the regulatory role shifts to defining system goals and calibrating incentives to elicit desired utility behavior. This starts with defining outcomes for system optimization, figuring out what combination of transparent metrics can track utility performance fairly, and defining reasonable targets (e.g., peak demand reduction) for performance.[20] This alone requires significant regulatory resources.

But even goals, metrics, and targets may be insufficient. Focusing on outcomes can help regulators and stakeholders overcome information asymmetry and hold utilities accountable, but measurement alone does not correct inherent problems with COSR, namely that DER investments, partnering with third-parties, and other non-wires alternatives antagonize utility profit maximization. Utilities and other stakeholders eager to embrace a DER future where utilities drive the transition can consider performance-based regulation (PBR).

PBR is an umbrella term that encompasses a variety of regulatory mechanisms to motivate performance against a number of different outcomes.[21] Tools to promote affordability and reduce capital bias and the throughput incentive include multi-year rate plans, revenue caps, price caps, and revenue decoupling. Other un-monetized goals for the power sector are incorporated into the PBR framework as targeted financial incentives that offer combinations of upsides and downsides based on performance in areas of concern like customer service, environmental performance, or reliability.

[18] For a list of resources on performance-based regulation, visit http://energyinnovation.org/resources/our-publications/going-deep-performance-based-regulation/.

[19] See D. Littell et al. *Next-Generation Performance-Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation*. Regulatory Assistance Project & National Renewable Energy Laboratory. September 2017.

[20] For a detailed outline of this approach and relevant case studies, see Whited et al., *Utility Performance Incentive Mechanisms: A Handbook for Regulators*, 2015. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf.

[21] These tools are described at length in D. Aas & M. O'Boyle, *You Get What You Pay For: Moving Toward Value in Utility Regulation, Part 2 – Regulatory Alternatives*. June 2016. http://americaspowerplan.com/wp-content/uploads/2016/08/2016_Aas-OBoyle_Reg-Alternatives.pdf.

Two key questions must be answered when comparing this outcome-focused approach to the information-intensive approach: how much do we pay for these outcomes, and what design elements can help ensure success and minimize risk?

Paying for performance

Evidence suggests utilities may be motivated to consider DER alternatives even with a relatively small amount of revenue at stake. Recent research surveyed utility financial analysts to determine that a 10 percent improvement (e.g. increasing from 10 percent to 11percent) of the utility's earned return on equity should be at stake in order to grab the attention of investors.[22] As additional anecdotal evidence, the paper also cites FERC's increase in ROE for transmission that is 10-20 points above the average regulated ROE for distribution utilities, which has resulted in a marked increase in transmission investment.[23]

In *Beyond Carrots: A National Review of Performance Incentives for Energy Efficiency*,[24] the American Council for an Energy Efficient Economy (ACEEE) conducts an exhaustive case study of energy efficiency (EE) PIMs, and provides insights into the relationship between incentive amounts and performance. ACEEE's data suggest well-designed efficiency performance incentives can be effective motivators even when they are in the range of 0.1-1 percent of total revenue.

Other states have experimented with PBR, but those experiments are still in the early days, making it hard to tell whether the performance incentives have been impactful. Still it is worth noting that utilities in these states have been willing participants in shaping the scope of incentives, and most utilities have been able to achieve regulatory performance targets and increase their returns for shareholders:

State	Incentive size & status
Illinois	50 basis point adjustment to return on rate-base.[25] Downside-only incentives for reliability and customer service as part of the formula-based ratemaking enacted in 2013.

[22] P. Kind & D. Lewin. *Lower Spending Higher Returns.* Dec. 2016.

[23] It's worth noting that while the transmission ROE adder was cited as successful at motivating additional transmission development, it was criticized by Synapse in its Performance-based Regulation Handbook for poor policy design, particularly on cost containment. See Whited et al., *Utility Performance Incentive Mechanisms: A Handbook for Regulators*, 2015. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf.

[24] http://aceee.org/sites/default/files/publications/researchreports/u1504.pdf

[25] See *Ameren Illinois Company Modernization Action Plan: Multi-Year Performance Metrics 2016 Annual Report* & *Commonwealth Edison Company's Multi-Year Performance Metrics Annual Report for the Year Ending December 31, 2015*. Accessed via https://www.icc.illinois.gov/electricity/utilityreporting/InfrastructureInvestmentPlans.aspx

Massachusetts	Maximum penalties of 2.5 percent of utility revenue requirement.[26] Fully implemented.
New York	90-110 basis points of upside-only incentives based on achievement of system efficiency, market animation, and customer service outcomes.[27] Cost of non-wires alternatives may also be included into rate base. Some have been approved, while others are currently under consideration.
United Kingdom	250 basis points adjustment on return on equity using symmetrical incentives based on a series of performance metrics. A higher baseline ROE is available for companies that submit well-justified business plans. Additional incentives available for reducing expenses against a revenue cap (200 basis points symmetrical). [28]
California	Cost of DER alternative receives 4 percent rate of return. Pilot phase.

These revenue adjustments range from a high-end of 450 basis points of symmetrical incentives (900 basis points at stake) in the United Kingdom down to a mere 50 basis point one-sided adjustment to return on equity in Illinois. The three jurisdictions with performance records (Massachusetts, Illinois, and the U.K.) indicate the performance incentives have had their intended effects. Utilities in each of the jurisdictions have routinely met or exceeded their goals, with some limited exceptions, and each plans to continue the PBR approach. Those companies falling short were penalized, better simulating competitive pressure.

Potential pitfalls of performance-based regulation

However, none of the programs was designed perfectly, and each had some unintended consequences undermining the claim that PBR aligns utility incentives with public policy goals. Illinois' Ameren and ComEd were able to meet most of their performance targets for 2013-2015, but the relatively lax baselines cast doubt into to whether the targets have been effective motivators.[29] In another case, a baseline set with only one anomalous year of data made

[26] See Order Adopting New Service Quality Guidelines, D.P.U. 12-120-D, December 18, 2015. http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=12-120%2f12120D_Order_121815.pdf

[27] See, e.g., Consolidated Edison Joint Settlement Proposal. Matter No. 16-00253/16-E-0060, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service. Filed September 19, 2016. Pp 77-81.

[28] See generally: https://www.ofgem.gov.uk/sites/default/files/docs/2013/02/riioed1decoutputsincentives_0.pdf

[29] See *Ameren Illinois Company Modernization Action Plan: Multi-Year Performance Metrics 2016 Annual Report* & *Commonwealth Edison Company's Multi-Year Performance Metrics Annual Report for the Year Ending December 31, 2015*. Accessed via https://www.icc.illinois.gov/electricity/utilityreporting/InfrastructureInvestmentPlans.aspx.

compliance virtually impossible.[30] Still, the compliance reports make it clear the PIMs have helped to focus utility operations toward meeting these targets, particularly as they increase in stringency over time.[31]

In the U.K., setting the right revenue cap was very challenging in a world of growing uncertainties. Though the total expenditures (totex) revenue cap model creates clear incentives to choose cheaper DER options over capital expenditures, utilities received large profits not necessarily due to their own efficiency, but rather outside factors such as economic depression. Thankfully, Ofgem designed the cap to share gains or losses between utilities and customers, but still, over the last few years, it is possible the utilities earned more than efficient business practices would have yielded alone under better-calibrated revenue caps.[32]

Experience so far suggests that revenue caps with totex and carefully calibrated outcome-based performance incentives can drive innovation, stabilize or improve utility profitability, and focus utility attention on the outcomes customers most want. For example, in the first performance year of the U.K.'s PBR scheme, many distribution utilities beat forecasts for customer bills, exceeded most of their performance targets, and achieved returns on equity averaging just over nine percent – 300 basis points more than their estimated six percent cost of equity. Beyond performance numbers, anecdotal evidence also suggests that utilities have shifted their focus toward performance under PBR. There is no indication that Ofgem and other U.K. utilities will move away from this regulatory structure after testing it over the last four years.

CONCLUSION

As DERs get cheaper, the conflict between COSR and potential contribution of demand-side resources is becoming clearer, blurring previously established boundaries of the electric distribution utility's natural monopoly. But before we can make unequivocal claims as to how that monopoly has shifted, we need more information. First, we must be sure that utilities indeed possess the knowledge needed to optimize their distribution systems. IDP is an emerging tool to obtain this information, laying the foundation for more fundamental changes to the utility business model toward distribution system optimization.

As the DSO role becomes possible, the next question becomes how to regulate the DSO and ensure it achieves its purpose. This question can be pursued simultaneously, and need not wait for IDP to be complete. The first path is an information-intensive approach to transforming the

[30] For example, the ComEd has missed its Service Reliability target by at least 3x in 2013-2015, and over 10x in 2013. *Commonwealth Edison Company's Multi-Year Performance Metrics Annual Report for the Year Ending December 31, 2015*, at 14-15.

[31] See the performance reports above.

[32] Ofgem. Open letter on the RIIO-2 Framework. July 12, 2017. https://www.ofgem.gov.uk/system/files/docs/2017/07/open_letter_on_the_riio2_framework_12_july_final_version.pdf

utility business model, which creates regulation-driven processes for quantifying and sharing distribution system needs with third parties, contracting with DERs as system resources, and valuing un-monetized policy goals such as reduced pollution and reliability to interact with those markets. This path is consistent with COSR, and is well suited to separating the DSO model from the poles and wires monopoly.

The second path is outcome-focused. Under this model, the DSO is not regulated using cost-of-service, but rather by adjusting its earnings based on performance against key outcomes. In particular, the utility will be rewarded financially for choosing cheaper non-wires alternatives, and will be encouraged to maximize public policy outcomes such as environmental performance, customer service, and reliability. It is worth noting these two approaches are on a spectrum, and are not mutually exclusive.

And so the answer to SEPA's original questions about the scope of the natural monopoly remains, "it depends." Without undertaking IDP and adjusting utility regulation to accommodate new business models, we cannot know that the utility is empowered as a distribution system optimizer. Once a DSO role becomes fleshed out, and the optimal mix of DERs and a modernized grid become knowable, the boundaries of the utility's natural monopoly will become clearer. But there will be more than one way to achieve the DSO. Utilities and stakeholders' priority should be testing DSO models and iterating, taking an adaptive approach to promote system optimization.