Promoting Innovation in Electricity Distribution Networks: New Tools for Regulators and Planners

by

Max N. Luke

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Signature of the Author: Signature redacted
Institute for Data, Systems, and Society
August 29, 2016

Certified By: Signature redacted
Ignacio Pérez-Arriaga
Visiting Professor, Sloan School of Management
Thesis Co-Supervisor

Certified By: Signature redacted
Richard Lester
Japan Steel Industry Professor of Nuclear Science and Engineering
Associate Provost, Massachusetts Institute of Technology
Thesis Co-Supervisor

Accepted By: Signature redacted
Munther Dahleh
William A. Coolidge Professor, Electrical Engineering and Computer Science
Director, Institute for Data, Systems, and Society
Acting Director, Technology and Policy Program

PROMOTING INNOVATION IN ELECTRICITY DISTRIBUTION NETWORKS: NEW TOOLS FOR REGULATORS AND PLANNERS

By Max N. Luke

Co-supervised by Ignacio Pérez-Arriaga and Richard Lester

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Abstract

Recent years have seen an unprecedented increase in the adoption of distributed energy resources (DERs) in distribution networks around the world. In most jurisdictions the increase in DERs has been met with a "fit and forget" network management approach whereby grid planners accommodate these resources by expanding the capacity of the network with conventional technologies. However, the continued use of a "fit and forget" network management approach will lead to large inefficiencies compared to a network management approach in which DERs play an active role in the planning and operation of distribution networks. The transition to actively managed distribution networks, however, will require the development and deployment of a variety of new technologies and systems, and a sea change in the roles of electricity distribution utilities and in the ways in which utilities are regulated.

The objective of this thesis is to equip regulators and network planners with a set of tools that, if adopted, will aid these organizations in transitioning from a passively managed to an actively managed network management paradigm. First, tools are presented for enabling network utilities to invest in the least-cost mix of conventional and unconventional network resources. These include regulatory tools for equalizing incentives for operational and capital expenditures, as well as a quantitative methodology that can aid planners in assessing the least-cost mix of conventional and unconventional investments. Second, regulatory tools are presented for enabling network utilities to adequately invest in specific outcomes that are not directly linked to economic efficiency but that will nonetheless be important for the transition to actively managed networks. Finally, regulatory tools are presented for encouraging distribution utilities to engage in long-term innovation – that is, investment in demonstration projects, as well as the technological learning that emerges from those projects and dissemination of knowledge and best practices between network utilities, technology providers, technology users, and other market participants.

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1 A NEED FOR NEW DISTRIBUTION NETWORK MANAGEMENT PARADIGMS

Recent years have seen an unprecedented increase in the adoption of distributed energy resources (DERs) – including distributed solar photovoltaics (PV), electric vehicles, demand side management systems, distributed battery storage, and gas-fired distributed generation – in electricity distribution networks around the world. These resources are characterized by relatively small capacities (a few kilowatts to a few megawatts), and are connected to lower voltage electricity distribution grids (as opposed to transmission and high voltage distribution systems).[1]

Among distributed energy resources, distributed solar PV has seen particularly robust deployment. In Italy, in 2015 the installed capacity of distributed solar PV reached nearly 19 gigawatts (GW), approximately equal to total off-peak electricity demand in all of Italy (Lo Schiavo, 2016). In Germany at the end of 2015, the installed capacity of solar PV was 40 GW, representing 1.5 million distributed power plants and with a total potential output that is about half of Germany's peak electricity demand (Fraunhofer, 2016; RAP, 2015). In the United States, the numbers are smaller but are nonetheless significant (and increasing). In California, where one in ten homes now has rooftop solar PV, the installed capacity of distributed PV is about 3.2 GW. In Hawaii, where one in four homes now has rooftop solar PV, the installed capacity of distributed PV is about 500 megawatts (MW) (EIA, 2016).

Other distributed energy resources are also significant and growing. In the United States demand side management resources have achieved significance in the PJM Interconnection (the largest electricity market in the United States). In PJM's 2019/2020 capacity market auction, nearly 11 GW of demand-side resources were cleared, representing about 6% of the total capacity that was cleared in the auction (PJM, 2016). In addition, roughly 450 MW of demand-side resources provided secondary operating reserves in PJM's ancillary services markets in 2015. In all, flexible demand-side resources in PJM earned roughly $825 million in revenues from participating in PJM's various markets in 2015. PJM is not the only electricity market that is home to significant quantities of demand side resources (NYISO, ISO-NE, CAISO, MISO, and ERCOT all utilize these resources) but it is by far the largest. It is expected that these resources will play an even more significant role in electricity markets in the years to come.

Deployment rates of distributed storage and electric vehicles (EVs) are also expected to increase in the coming years. For instance, while the deployment of behind-the-meter storage has been small in recent years (e.g. in the US, less than 50 MW of behind-the-meter storage capacity was installed in 2015, and the amount of energy deployment from behind-the-meter storage was less than 100 MWh), it is

[1] In this thesis wind power that is connected in high voltage distribution networks are not considered to be a distributed application, although these systems are certainly more "distributed" than traditional coal or natural gas plants.

expected that the installed capacity of behind-the-meter storage could increase to more than 600 MW by 2020 as a result of declining storage costs and subsidy support for behind-the-meter storage (GTM Research, 2015). Likewise, EV deployment rates are low but increasing. Year-over-year global demand for EVs increased by 80% in 2015. It is projected that EVs could reach 20% of new global vehicle sales by 2030 and 35% by 2040 (BNEF, 2016). This implies that 16 million EVs could be traveling U.S. roads by 2030 (of a total of more than 280 million light duty vehicles), comprising on the order of 1,000 gigawatt-hours (GWh) of battery storage capacity. Some pioneering countries have already achieved these levels of deployment in percentage. For example in Norway, nearly 19% of all new light duty vehicle sales in 2015 were EVs and conventional vehicle sales will be banned by 2025.

In summary, electricity resources are becoming increasingly distributed -- that is, DERs are increasingly the providers of a range of electricity services that were traditionally provided by centralized resources, as well as locational services that were traditionally provided by distribution network utilities. This has been facilitated by the increasing digitization of the power sector through the deployment of information and communications technologies (ICTs), advanced metering infrastructure (AMI), real-time sensors, and a variety of other technologies and systems that contribute to the automation of distribution networks and enable the participation of DERs in the operation and planning of the system (for a concise taxonomy of these so-called "smart grid" technologies and their functions, refer to Appendix A).

1.1 New distribution network management paradigms and the changing role of the utility

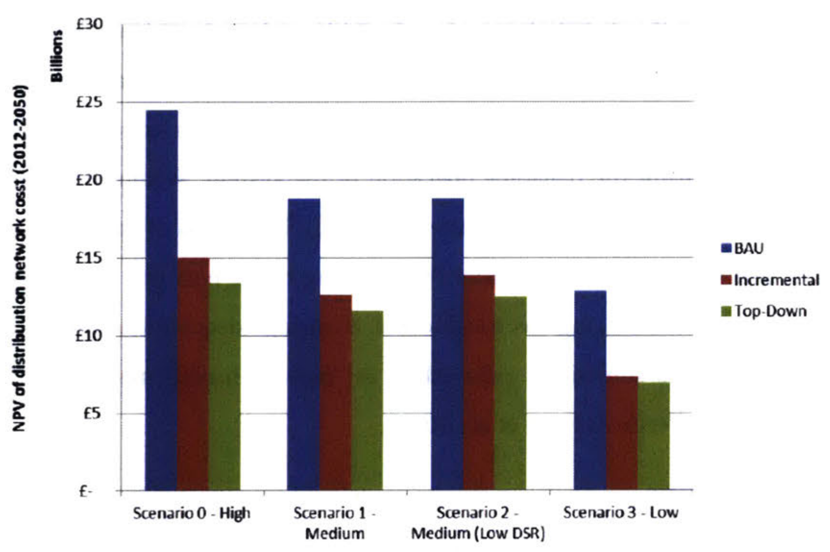
The integration of DERs into electricity distribution networks necessitates a sea change for the planning and operation of these networks. Distribution planning and operation has historically been carried out independently by the distribution network utility as largely independent tasks. Long-term network planning has entailed forecasting regional peak demands over a planning horizon and reinforcing the grid accordingly. The main goal of this process was to ensure that no physical constraints were violated during the real-time operation of the system. Within this framework, during real-time operation the network utility has required relatively low levels of monitoring and control to ensure that services that are critical to the smooth functioning of the network (e.g. maintaining voltage levels within a certain band, minimizing electrical losses, ensuring adequate levels of reliability, etc.) are maintained.[2] This paradigm is sometimes referred to as "passive management" or a "fit and forget" approach (Eurelectric, 2013; Pérez-Arriaga et al., 2013).

[2] While planning and operation have historically been largely independent, some degree of coordination has nonetheless usually occurred between the two. For example, the operation department typically indicates impending network investment needs to the planning department, while the planning department tries to reproduce the operating conditions when estimating future planning scenarios.

In many jurisdictions, the fit and forget approach has simply been applied to accommodate increased penetrations of DERs; the network is reinforced by the distribution utility whenever the existing grid capacity is insufficient to ensure that even the most extreme conditions can be accommodated. Due to these reinforcements, the real-time operation of the network remains a largely passive exercise.

However, while the traditional network management paradigm has proven to be effective and cost-efficient in a conventional centralized context, it will not be cost-efficient in a future with high penetrations of DERs. For example, a recent analysis estimated the cost of distribution network investment required to accommodate DERs in the United Kingdom in the year 2050, under different scenarios of DER penetrations, and under different network management paradigms (EA Technology, 2012). The analysis found that regardless of the level of DER penetration in 2050, under a business as usual (BAU) network management paradigm, where only conventional investments are made (i.e. a fit and forget management approach), total network costs associated with accommodating increased DER penetrations are significantly higher than if innovative distribution grid solutions are deployed alongside conventional network upgrades either in an incremental fashion or in an aggressive ("top-down") fashion. These results are shown in Figure 1. One of the reasons for this result is that high penetrations of passively managed DERs lead to situations that occur relatively infrequently (e.g. extremely high levels of solar irradiation that occur a few times per year) but that necessitate costly grid reinforcements that could be substituted by lower-cost innovative solutions.

Figure 1. Total distribution network investment costs in different scenarios about DER penetration in the U.K. in 2050, and under different network management paradigms (EA Technology, 2012)



It is imperative, therefore, that the electricity distribution network management paradigm shifts from one in which increasing penetrations of DERs are accommodated by conventional network upgrades and do not participate in real-time operation, to one in which DERs actively participate in both the planning and operation of networks. Under this new, "active network management" paradigm, network planning and operation will be coupled so that network constraints are managed not only at the planning and connection stage but also during real-time operation. This active network management approach ultimately relies on the extensive utilization of ICT-enabled monitoring and control capabilities.

Under the active network management paradigm distribution utilities will no longer manage the network alone, but rather will facilitate the participation of DERs in the planning and operation of the distribution grid. Distribution utilities will likely continue to bear the responsibility of the smooth and efficient operation of distribution networks, but will become "market platform providers" for various electricity services and will become agnostic with respect to the technologies deployed for the delivery of services and the market participants that deploy them, as long as cost minimization is achieved. Moreover, distribution utilities will be required to become much more savvy with respect to real-time monitoring and operation of distribution networks, since the planning and operation of these networks will become more coupled and therefore the built-in capacity margins in networks will be smaller.

More specifically, these new roles will require three fundamental shifts in the incentives and activities of distribution utilities. *First*, to ensure economic efficiency in the short- to medium-term, distribution companies must be inclined to deploy the economically efficient mix of conventional network solutions versus unconventional solutions. That is, regulatory incentives must be set such that the distribution company, when trying to maximize its own benefit, contributes to the maximization of global social welfare by deploying the least-cost mix of network solutions. Companies must also possess the requisite analytical tools for making assessments about the optimal mix of conventional and unconventional resources. *Second*, distribution companies should be incentivized to deliver specific outputs that are not directly related to economic efficiency but that will contribute to incremental innovation and to the transition to actively managed electricity networks. *Third*, distribution companies must be incentivized to engage in long-term innovation, that is, demonstration projects whose outcomes are inherently uncertain but that will contribute to new technical knowledge and to long-term (dynamic) economic efficiency.

The objective of this thesis is to equip regulators and network planners with a set of tools that, if adopted, will aid these organizations in transitioning from a passively managed to an actively managed network management paradigm. This thesis presents a compilation of regulatory best practices from the United States and Europe that can be adopted by regulators to promote innovation in distribution networks and that will contribute to the transition to actively managed networks. Moreover, this thesis presents a novel quantitative methodology that can help network planners determine the economically efficient mix of conventional and innovative resources for network planning needs.

The thesis proceeds as follows. First, the remaining introductory Chapter discusses why it is important for the distribution utility to adopt new roles, and the regulatory and other challenges associated with adopting these new roles. These Chapter sections are focused on utility's roles in: 1) deploying the economically efficient mix of conventional and unconventional resources (Chapter 1.2); 2) delivering specific outputs that are not directly related to economic efficiency but that could contribute to the transition to actively managed networks (Chapter 1.3); and 3) promoting long-term innovation via demonstration projects and the new technical knowledge that such projects result in (Chapter 1.4).

Chapters 2, 3, and 4 are focused on specific regulatory and other solutions that will be required in order for network utilities to adopt these new roles and for the transition to actively managed networks. Chapter 2 presents examples of state-of-the-art regulatory approaches for equalizing utility incentives to invest in operational expenditures (OPEX) and capital expenditures (CAPEX). Chapter 2 also presents a novel quantitative methodology that can be used by network planners to help assess the economically efficient mix of conventional and unconventional resources. Chapter 3 is focused on regulatory approaches for the promotion of investments in outcomes that are not directly linked to economic efficiency but that are nonetheless important for driving incremental innovation. Finally, Chapter 4 is focused on state-of-the-art regulatory practices for the promotion of long-term innovation in electricity distribution networks.

1.2 Utilities must become agnostic with respect to conventional and unconventional solutions

In order to ensure short- to medium-term economic efficiency, i.e. maximization of global social welfare, distribution utilities must be agnostic with respect to least-cost network management solutions, whether those solutions are conventional or unconventional. The emergence of DERs and smart grid capabilities will heighten tradeoffs between capital expenditures (CAPEX), such as investments in new distribution lines or substations, and operational expenditures (OPEX), such as active system management programs or contracts with DERs to avoid or defer network investments.[3] For example, distribution utilities can achieve important cost savings by adopting an active system management approach, especially as DER penetration increases (Cossent et al., 2010, 2009; Eurelectric, 2013; Olmos et al., 2009; Poudineh and Jamasb, 2014; Pudjianto et al., 2014; Strbac et al., 2012; Trebolle et al., 2010). Setting up ICT and advanced grid management infrastructure that allows distribution utilities to more actively manage distribution network configuration and make use of DERs for their daily grid operations will entail substantial upfront CAPEX. However, such investments will in turn enable distribution utilities to increasingly contract with or procure system operation services from DER

[3] These operational expenditures are sometimes referred to as "non-wires" alternatives, in contrast to traditional investments in distribution "wires" and other network assets.

owners or aggregators, including CAPEX deferral, volt-var support, loss reduction, congestion management, or reliability improvement (Meeus and Saguan, 2011; Meeus et al., 2010; Poudineh and Jamasb, 2014; Trebolle et al., 2010). These contractual arrangements or new markets for distribution system services can increase utility OPEX while reducing CAPEX. Alternatively, CAPEX related to new smart grid capabilities can enable an improved workforce and reduce truck rolls, leading to OPEX savings. In short, the most efficient tradeoff between CAPEX and OPEX is likely to change significantly and evolve over time.

Both traditional cost of service and price- or revenue-cap approaches to the economic regulation of distribution companies will need to be updated to fully exploit new opportunities to effectively balance increasingly important tradeoffs between these two expenditure categories. Under cost of service regulation, utilities traditionally only earn a regulated return on capital investments. Allowed returns are calculated based on the utility's "rate base" or regulated asset base which includes the cumulative, non-depreciated share of capitalized expenditures. Under cost of service regulation, utilities can thus be discouraged from reducing CAPEX, as this may impact their rate base and allowed returns. At the same time, the intrinsically poor incentives for cost saving under cost of service approaches make it unlikely that firms will fully exploit the most efficient tradeoffs between capital and operational expenditures.

While multi-year revenue trajectories or revenue caps will reward firms for efficiently reducing total costs, this form of regulation can also distort incentives between savings achieved via reductions in CAPEX versus OPEX. While incentive regulation will reward the utility equally for saving a dollar of CAPEX or a dollar of OPEX, if only CAPEX is capitalized into the utility's regulated asset base, then that dollar in reduced CAPEX will also involve a reduction in the regulated asset base and thus a reduction in the allowed return on equity and a corresponding decline in net profit for shareholders. This decline in net profit will offset some portion of the efficiency-related income, distorting tradeoffs between OPEX and CAPEX and potentially encouraging over-investment (Ofgem, 2013a, 2009). Conversely, if only CAPEX is capitalized and the rate of return on CAPEX is very low, and OPEX costs are fully remunerated, the utility may have an incentive to spend on OPEX to avoid investments in CAPEX that would incur a loss (e.g. to meet a reliability target). This, too, would distort tradeoffs between OPEX and CAPEX. Regulatory strategies for addressing this challenge are discussed in Chapter 2.1.

Additionally, regulators and planners will need quantitative methodologies to assess the efficient mix of conventional and non-conventional resources to meet future network needs. Expected changes in network use – i.e. changes in distribution generation and changes in electricity demand – may require investments in either conventional network reinforcements (e.g. transformers, copper wires, etc.) or non-conventional solutions that have the same effect as conventional network reinforcements (e.g. active management technologies that can increase DG hosting capacity, demand response solutions that can curtail load, etc.). In order to determine the economically efficient mix of conventional and non-conventional resources, regulators and planners will need quantitative methodologies that can help assess the relative costs of these two classes of resources, and the optimal mix of the two. A novel analytical methodology that can be used for this purpose is presented in detail in Chapter 2.2.

1.3 Utilities must deliver specific outcomes that are conducive to active management

In addition to being agnostic about least-cost network management solutions, which will contribute to ensuring short- to medium-term economic efficiency in networks with high penetrations of DERs, distribution utilities must also be incentivized to deliver specific outcomes that are not directly related to economic efficiency but nonetheless that drive incremental innovation and contribute to the transition to active management. These outcomes include traditional ones such as improving the quality of electrical service, reducing energy losses, ensuring workplace and public safety, and others. They may also include non-traditional outcomes that are more directly related to the transition to actively managed networks, such as deploying smart grid technologies, increasing DER hosting capacity, and reducing the time that a distributed generator must wait to be connected to the network.

These outcomes are generally not achieved via economic efficiency incentives, since achieving them may impose additional costs on distribution companies, and therefore may be at odds with cost-saving economic efficiency measures. Therefore, many regulatory authorities have created additional incentives of one form or another to maintain and improve upon these critical outcomes. Best practices for the design of these types of incentives are discussed in Chapter 3.

1.4 Need for increased levels of long-term innovation

Finally, to keep pace with a rapidly evolving electricity landscape, electricity distribution utilities will need focus on harnessing increased long-term innovation – that is, investment in demonstration projects, as well as the technological learning that emerges from those projects and dissemination of knowledge and best practices between network utilities, technology providers, technology users, and other market participants. Uncertainty about how networks will evolve implies that the technological solutions that will lead to the greatest levels of productive efficiency in the medium- to long-term (i.e. in periods that extend beyond the regulatory period) are also uncertain. The technologies and systems that will be most efficient for facilitating active network management in distribution networks with high penetrations of DERs are simply not known today. Therefore there is a need for greater investment in demonstration projects and accelerated knowledge sharing or "spillovers" between utilities, technology provides, and technology users. This will involve undertaking experimental projects whose potential cost savings are inherently uncertain and may only be realized in the medium- to long-term, if at all.

Despite the need for increased levels of long-term innovation, spending on research, development, and demonstration (RD&D) by network utilities has been declining (Meeus and Saguan, 2011). Today's regulatory frameworks, including both cost of service and incentive regulation, do not adequately incentivize these types of risky projects and the technological learning that emerges from them.

Under cost of service regulation, utilities are only incentivized to engage in innovation to the degree that short-term cost savings can be retained by the utility until the next regulatory review or rate case (Bailey, 1974; Malkin and Centolella, 2014). Since this period of "regulatory lag" generally lasts for up to a few years at most, utilities are only rewarded for very low-risk measures that can generate savings quickly – hardly the kind of long-term innovation required in an evolving electricity landscape. In some jurisdictions, regulators allow longer-term RD&D costs to be capitalized into the utility's rate base, allowing companies to earn a rate of return on these costs, providing an additional incentive to engage in innovation. However, in practice regulators do not blindly accept all costs (Joskow, 1989) and many innovative projects are unlikely to be approved during the regulatory process due to their inherent riskiness. Indeed, the majority of regulatory authorities in cost of service jurisdictions are risk averse, contributing to low levels of RD&D expenditures amongst electric utilities in those jurisdictions (NSF, 2011).

When multi-year revenue-cap, or RPI-X, regulation, was first proposed (Beesley and Littlechild, 1989), the assumption was that the multi-year revenue trajectory established under this form of regulation was superior to cost of service regulation both in promoting short- and long-term productive-efficiency (Armstrong et al., 1994; Clemenz, 1991; Littlechild, 2006). Nonetheless, the actual results of incentive regulation on promoting long-term innovation are ambiguous (Kahn et al., 1999). Unlike with cost of service regulation, under a revenue cap, the company is exposed to more risk: the company bears the cost of a failed RD&D investment. Therefore the company is more inclined to engage in incremental innovations that are very likely to lead to cost savings within the regulatory period rather than higher-risk but potentially higher-reward innovations that may take longer to bear fruit. Moreover, under this form of regulation, companies benefit if they outperform the revenue trajectory set by the regulator. Companies are thus incentivized to minimize costs in the short term, which may incentivize reductions in RD&D expenditures as well. The result is that the short-term productive efficiency that can be stimulated by incentive regulation may work against long-term productive efficiency improvements that can be achieved by RD&D investments (Bauknecht, 2011).

In summary, additional mechanisms must be implemented within the regulatory framework to adequately incentivize network utilities to invest in RD&D projects that are inherently risky and uncertain but that are necessary for achieving dynamic efficiency in electric power systems. In the US and Europe a small number of jurisdictions are deviating from the trend by encouraging network utilities to propose innovative projects that will be included in their regulated asset bases. Chapter 4 presents the case studies of three of these pioneering jurisdictions: the United Kingdom, Italy, and New York.

2 LEVELING THE PLAYING FIELD BETWEEN CONVENTIONAL AND UNCONVENTIONAL RESOURCES

2.1 Regulatory strategies for equalizing incentives for operational and capital expenditures

Regulatory frameworks must be updated to incentivize network planners to invest in an efficient mix of network resources. Specifically, regulatory mechanisms should take care to avoid distorting a utility's incentives to invest in capital assets rather than operational expenditures. As discussed in Chapter 1.2, utilities are facing increased tradeoffs between traditional capital investments in network assets and novel operational and network management strategies that harness DERs. To encourage utilities to find the most efficient combination of capital and operational expenditures, financial incentives related to CAPEX and OPEX need to be equalized.

Incentives are typically skewed by conventional regulatory approaches, which add approved capital expenditures directly to a utility's regulated asset base or rate base, while operational expenditures are expensed annually. Even if utilities are properly incentivized to pursue cost-savings via a profit sharing incentive, under this financial framework, a dollar in reduced CAPEX will also involve a reduction in the utility's regulated asset base and thus a reduction in the allowed return on equity and a corresponding decline in net profit for the utility's shareholders. This decline in net profit will offset some portion of any efficiency-related income awarded by the regulator, distorting tradeoffs between OPEX and CAPEX and potentially encouraging over-investment in conventional network assets (Jenkins and Pérez-Arriaga, 2014; NYDPS, 2016; Ofgem, 2013b, 2009).

The regulatory authority in the UK, Ofgem, has developed one mechanism for equalizing these incentives, known as the total expenditure or "TOTEX-based" approach (see Ofgem, 2013b, 2009). Under a TOTEX-based approach, introduced by (Ofgem, 2009), the regulator establishes a fixed portion of total utility expenditures (TOTEX), referred to as "slow money," which will be capitalized into the utility's regulated asset base (from which depreciation and cost of capital revenue allowances are calculated). The remainder of TOTEX is designated as "fast money," which is treated as an annual expense. Critically, the regulator fixes these shares at the *start* of the regulatory period based on an estimate of the efficient split between CAPEX and OPEX in total expenditures. As such the share of CAPEX and OPEX in actual utility expenditures is free to depart from this expected share without impacting the utility's return on equity. Under this approach, both OPEX and CAPEX savings will thus face the same efficiency incentives –that is, a dollar of OPEX savings and a dollar in CAPEX savings will result in the same improvement in utility earnings – freeing the utility to fully exploit the expanding frontier of cost-saving tradeoffs between both types of expenditure.[4]

Alternative measures have been enacted by the New York Department of Public Service (NYDPS, 2016, 2015a) consistent with their cost of service-based regulatory framework and U.S. accounting practices. New York establishes allowed revenues or "base rates" based on a "forward test year" or a forward-looking estimate of expected utility costs. This estimate is based in part on a capital investment plan submitted by the utility and reviewed by the regulator in each rate case. Once base rates are set for a given year, a utility could conceivably increase earnings by withholding funds from capital projects included in the base rates. While this provides an efficiency incentive, New York regulators were historically concerned that this incentive could lead to underinvestment and degradation of network quality or reward utilities for inflating their estimates of future expenditures during rate cases. As such, a "clawback" provision was established wherein regulators automatically reduce a utility's allowed revenues if capital expenditures fall below approved levels, returning all such earnings to ratepayers. In contrast, New York's new "Reforming the Energy Vision" framework aims to incentivize utilities to "pursue cost-saving DER-based alternatives to capital expenditures" (NYDPS, 2016). Recognizing the inherent disincentive to pursue such cost-saving measures created by the clawback mechanism, the NY DPS reformed this mechanism in 2016, explicitly pledging to allow utilities to retain earnings on capital included in the base rates for the regulatory period, freeing the utility to pursue cost-effective operational expenditures and DER alternatives to planned capital projects. During the next rate case, any such DER expenses would be incorporated into base rates and the earnings associated with avoided capital projects would be removed, allowing ratepayers to benefit from any net savings in total expenditures achieved.

The NY DPS Commission recognizes that the clawback reform discussed herein is "not a complete solution to issues around capital and operating expenses" and that a TOTEX-based approach that eliminates the distinction between capital and operational expenditures is "a more comprehensive way to address the potential capital bias" (NYDPS, 2016, pp. 100-101). In addition, the NY DPS restricts waiver of the clawback mechanism specifically to cases "directly linked to a demonstration of the DER alternative that replaced the capital project." This implies increased regulatory risk for utilities, as they must demonstrate, on a case by case basis, the particular measures undertaken to harness DERs in lieu of network investments. A multi-year revenue trajectory with profit sharing incentives and a TOTEX approach to capital bias would thus provide greater regulatory certainty, reduced regulatory burden, and enhanced efficiency incentives.

[4] For additional discussion of this TOTEX-based approach and resulting incentives for utility cost-savings, see (Ofgem, 2009), pp. 117-120, and (Ofgem, 2013b), pp. 30-32.

Whatever mechanism is pursued, the goal is important: utilities should be freed to find the most cost-effective combination of conventional investments and novel operational expenditures (including payments to DERs) to meet demand for network services at desired quality levels.

2.2 A quantitative methodology for evaluating the economically efficient balance of conventional and unconventional resources in network planning

In addition to the critical need for regulatory frameworks that equalize incentives of operational and capital expenditures, there is a need for quantitative methodologies and tools for helping network planners determine an economically efficient mix of conventional and innovative solutions. The objective of the methodology described herein is to enable regulators and network planners to determine the least-cost balance of traditional network reinforcements and innovative ("non-wires") solutions for a given expected peak load growth (or decline) and/or peak distributed generation growth.

The methodology itself makes use of two independently-developed quantitative tools or softwares. The fist software is an engineering-based electricity distribution network planning tool known as a Reference Network Model (RNM). The RNM is a computer program that takes as inputs detailed information about the geographical and physical (electrical) characteristics of an electricity distribution network, as well as information about expected growth (or decline) in electricity demand and distributed generation, and constructs a network that minimizes the network equipment costs associated with meeting those changes in demand or generation, while also meeting reliability constraints. The RNM can be run either in "greenfield" mode, in which it builds an entirely new network from scratch, or in "brownfield" mode, in which it builds only the incremental additions to an existing network necessary to meet expected network demands. Importantly for the purpose of this discussion, the RNM does not utilize innovative or "non-wires" solutions to meet new network demands. Rather, it only utilizes conventional network equipment. Therefore, results obtained from the RNM can be likened to an efficient outcome under a fit and forget network management paradigm but not necessarily under an active network management paradigm. A richer description of the RNM can be found in Box 1 and in (Mateo et al., 2011).

The second tool that this methodology employs is Matpower, a Matlab package used for solving power flow and optimal power flow problems in electricity networks (Zimmerman et al., 2011). The methodology proposed herein utilizes Matpower's alternating current (AC) optimal power flow (OPF), or ACOPF, functionality. In qualitative terms, an OPF finds the solution that minimizes the operational costs of the network subject to standard power flow constraints and other operational constraints, such as generator minimum output constraints, distribution/transmission stability and voltage constraints, and limits on switching mechanical equipment. The mathematical formulation that the ACOPF in Matpower uses is presented in Box 2.

Upon running an OPF in Matpower on a given distribution network, if the OPF does not solve (converge) under the initial network conditions (i.e. the initial demand and/or distributed generation in the network), then it will attempt to shift the network conditions such that the OPF can converge. For example, if there is a high concentration of distributed generation in a certain part of the distribution network that would otherwise lead to a voltage violation, the OPF will shift or curtail generation in this part of the network to relieve the voltage constraint (from this point forward I will use the phrase "generation curtailment" to refer to both generation shifting and generation curtailment). Likewise, if high electricity demand is leading to constraint violations in a certain part of the network, the OPF will attempt to curtail load in this part of the network to relieve the constraint (unlike with generation, load cannot be shifted, so the use of the phrase "load curtailment" always refers to actual load curtailment). Importantly for the present discussion, this property of the OPF can be used to determine the amount of curtailment (in load or generation) that would be necessary to relieve constraints that are associated with a given increase in electricity demand or generation (respectively). In other words, the OPF solution reveals the level of curtailment that would be necessary to avoid the conventional network upgrades that would be required to mitigate the constraints. Moreover, as will be discussed shortly, curtailment (in both load and generation) can be considered a proxy for any innovative or "non-wires" solution or technology that is capable of providing load and/or generation curtailment.

Finally, with these two tools in hand (the RNM and the Matpower ACOPF), I have built a script in Matlab that serves as an architechture or "user interface" (UI) that enables a user to run a large variety of experiments that can aid regulators and utilities in making decisions about the deployment of conventional and unconventional solutions to meet future network demands. The UI is designed such that the only inputs/parameters that a user needs to provide are done so upfront, at the beginning of the Matlab script. After the user has specified these initial parameters, the script runs autonomously and generates a set of outputs that correspond to the initial parameters that were specified by the user. The initial parameters that the user must specify include parameters such as: the distribution network (or the part of the distribution network) that the user would like to run an experiment on; change in peak load/generation or the range of changes in peak load/generation; the distribution voltage level(s) (i.e. low voltage and medium voltage) in which these changes occur; and others. A list of user-specified inputs/parameters is provided in Table 1.

Box 1: How does a reference network model (RNM) work?

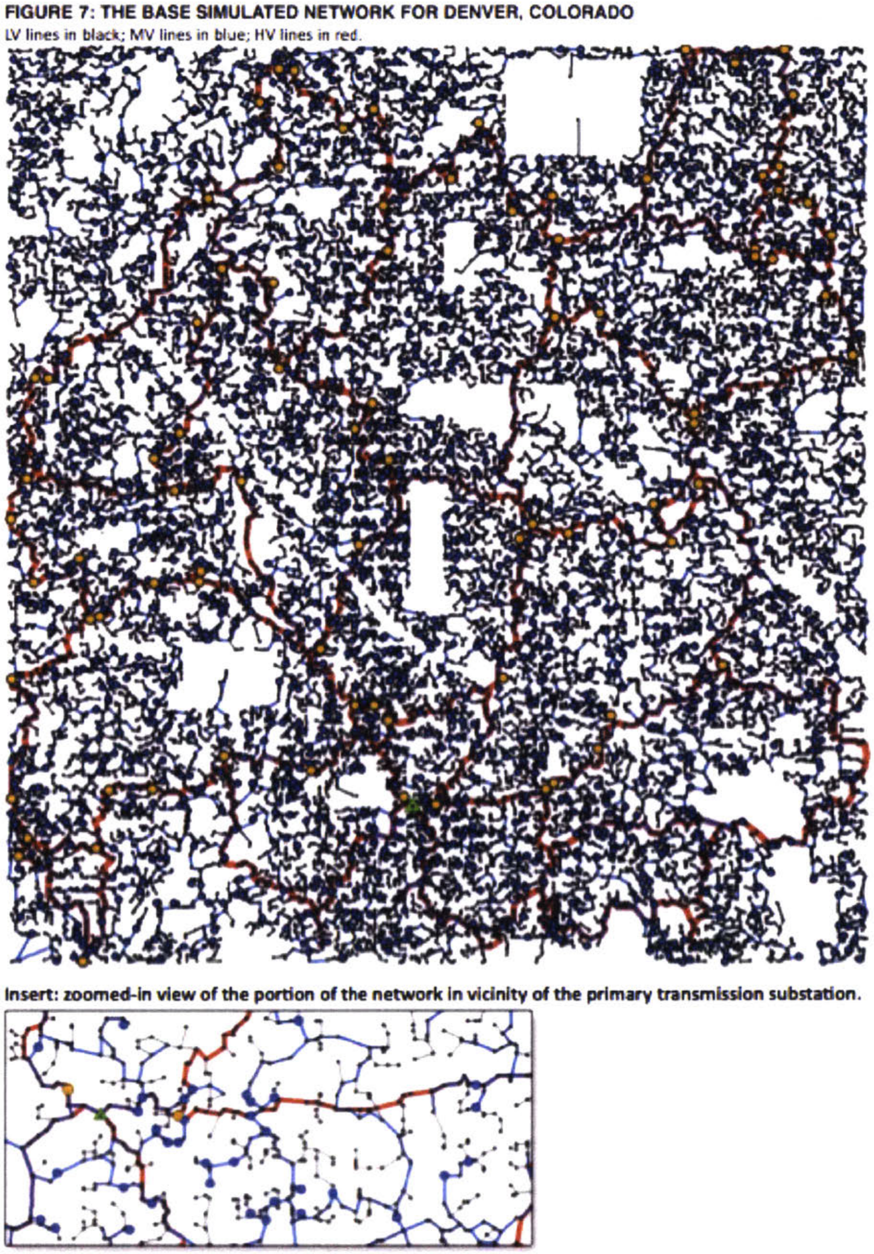
An RNM typically takes as input the location and power injection/withdrawal profile of all network users as well as a catalog containing technical and cost information about available equipment, probability of component failure, and the cost and time burden of maintenance actions. Given these inputs, the RNM constructs a network to serve all network users while minimizing total network costs (including capital expenditures, operational expenditures, and a specified penalty for ohmic network losses) and meeting three specified quality of service constraints: (1) maximum system average interruption duration index (SAIDI); (2) maximum system average interruption frequency index (SAIFI); and (3) maximum acceptable voltage range at every node. An example of an RNM-produced network is provided in Figure 2.

For regulatory benchmarking purposes, it is important to take into account the established layout of the utility's network and sunk investments in network components. The RNM should thus be run in a "brownfield" or network expansion mode taking as inputs the existing network layout and location of the utility's existing network users and specifying the layout of network reinforcements and extensions necessary to serve projected changes in network use over the regulatory period. Therefore if regulators were to use this tool utilities would be required to report information on their existing networks in a standard format including: the location, voltage level, contracted capacity, and injection/withdrawal profile of all existing network connections (loads and DERs); the layout, impedance, and capacity of the electrical lines and protection devices; and the capacity and location of transmission interconnection substations, high voltage/medium voltage substations, and transformers.

Box 1 continues on the next page.

Box 1 (continued)

Figure 2. Example output of a reference network model (Jenkins and Pérez-Arriaga, 2014)



Upon specifying these parameters the user is prepared to run an experiment on a distribution network or a portion of a network. The basic architecture of the proposed methodology is shown in Figure 3. The methodology begins with the user specifying the network that she or he is performing an experiment on and specifying the values of the inputs/parameters presented in Table 1. Aside from data post-processing and statistical analysis, which occurs after the experiment has completed, this initial step is the only manual function that the user must perform. What follows is a description of the automated steps that occur between parameter specification and data post-processing. These automated steps are shown in boxes that have borders with dashed lines in .

First, the Matlab script reads the distribution network into the Matlab workspace by reading either (or both) a greenfield RNM network file and/or a Matpower network file that have been placed into a specified directory prior to running the experiment. Once the network has been read into Matlab, the Matlab script calls a recursive function that divides the network into zones, where each zone is a specific feeder. This recursive function defines a feeder as any aggregation of consuming and/or generating nodes for which there is only a single connection point to a MV-LV substation. Using more colloquial terminology, the function defines a feeder as any one "tree branch" that is connected to the "tree trunk" of the network, where the "tree trunk" is the collection of power lines that connect each of the MV-LV substations.

After the network has been divided into zones, the Matlab script then proceeds to what is labeled in Figure 3 as "RNM loop" and "OPF loop". Whether the script proceeds to either or both of these loops depends upon whether the user has set *set.runtype* equal to 1, 2, or 3. Beginning with the RNM loop, the first step is to assign each zone a new peak withdrawal and/or peak injection value(s). Whether a peak withdrawal value, or peak injection value, or both is/are assigned will depend upon whether the user has set *set.loadgen* equal to 1, 2, or 3. The first new peak withdrawal and/or peak injection value(s) that is/are set for each zone will depend upon the value that the user has specified for *set.start.load.rnm* and *set.start.gen.rnm.* For example, if the user has set *set.start.load.rnm* to 1.1 and *set.start.gen.rnm* to 0.1, then a given zone will be assigned a new peak load level and peak generation level that is approximately equal to 1.1x that zone's pre-existing peak load level, and 0.1x that zone's pre-existing peak load level, respectively. To introduce some variation into this process, these zonal peak withdrawal and peak injection values are drawn from a normal distribution with a specified standard deviation. Moreover, depending on the values that the user has given to *set.cf.load* and *set.cf.gen* (recall that these parameters control the level of concentration of load and generation in the network, respectively), the distribution from which the zonal peak withdrawal and peak injection values are drawn will be normally distributed with no skewedness (*set.cf* = 0) or contain some degree of skewedness (*set.cf* > 0). The effect of drawing from a very skewed normal distribution (e.g. *set.cf* = 1) rather than from a normal non-skewed distribution is that a few select zones will have relatively large loads and/or generation while the majority of zones will have relatively small loads and/or generation.

Box 2: Matlab alternating current (AC) optimal power flow (OPF) formulation

Matpower includes code to solve both alternating current (AC) and direct current (DC) versions of the optimal power flow problem. The standard version of each of these takes the following form:

$$\min_x f(x) \tag{1}$$

subject to

$$g(x) = 0 \tag{2}$$

$$h(x) \leq 0 \tag{3}$$

$$x_{min} \leq x \leq x_{max} \tag{4}$$

The AC version of the standard OPF problem is a general non-linear constrained optimization problem, with both non-linear costs and constraints. In a system with n_b buses, n_g generators, and n_l branches, the optimization variable x is defined in terms of the $n_b \times 1$ vectors of bus voltage angles Θ and magnitudes V and the $n_g \times 1$ vectors of generator real and reactive power injections P and Q as follows:

$$x = \begin{bmatrix} \Theta \\ V \\ P \\ Q \end{bmatrix} \tag{5}$$

The objective function (1) is simply a summation of individual polynomial cost functions f_P^i and f_Q^i of real and reactive power injections, respectively, for each generator:

$$\min_{\Theta,V,P,Q} \sum_{i=1}^{n_g} f_P^i(p_i) + f_Q^i(q_i) \tag{6}$$

The equality constraints (2) consist of two sets of n_b non-linear nodal power balance equations, one for real power and one for reactive power:

$$g_P(\Theta, V, P) = 0 \tag{7}$$

$$g_Q(\Theta, V, Q) = 0 \tag{8}$$

The inequality constraints (3) consist of two sets of n_l branch flow limits as non-linear functions of the bus voltage angles and magnitudes, one for the *from* end and one for the *to* end of each branch:

$$h_f(\Theta, V) \leq 0 \tag{9}$$

$$h_t(\Theta, V) \leq 0 \tag{10}$$

(Box 2 continues on the next page)

Box 2 (continued)

The variable limits (4) include an equality limited reference bus angle and upper and lower limits on all bus voltage magnitudes and real and reactive generator injections:

$$\theta_{ref} \leq \theta_i \leq \theta_{ref}, \quad i = i_{ref} \tag{11}$$

$$v_i^{min} \leq v_i \leq v_i^{max}, \quad i = 1 \dots n_b \tag{12}$$

$$p_i^{min} \leq p_i \leq p_i^{max}, \quad i = 1 \dots n_g \tag{13}$$

$$q_i^{min} \leq q_i \leq q_i^{max}, \quad i = 1 \dots n_g \tag{13}$$

Here i_{ref} denotes the index of the reference bus and θ_{ref} is the reference angle.

Source: (Zimmerman et al., 2009)

Table 1. Descriptions of user-defined input parameters for the proposed quantitative methodology

Input/parameter name	**Function/description**
Global parameters	
set.network	The name of the distribution network that will be loaded into Matlab. Depending on whether the user is running brownfield RNM, Matpower OPF, or both, this parameter will instruct the script to load either a greenfield RNM network file, a Matpower network file, or both, into the Matlab workspace.
set.runtype	A numerical value indicating whether the user is going to run RNM (1), Matpower OPF (2), or both (3).
set.loadgen	A numerical value indicating whether the user is going to vary peak load (1), peak generation (2), or both (3).
set.vlvar	A numerical value indicating whether the user is going to vary load/generation in the low voltage part of the distribution network (1), the medium voltage part of the network (2), or in both voltage levels (3).
set.pf.load *set.pf.gen*	A percentage value ranging from 0 and 1 (e.g. 1, corresponding to 100%) that sets the power factor for electrical loads (*set.pf.load*) and generators (*set.pf.gen*) in the distribution network.
set.sf.load *set.sf.gen*	A percentage value ranging from 0 to 1 (e.g. 0.4, corresponding to 40%) that sets the "simultaneity factor" for electrical loads (*set.sf.load*) and

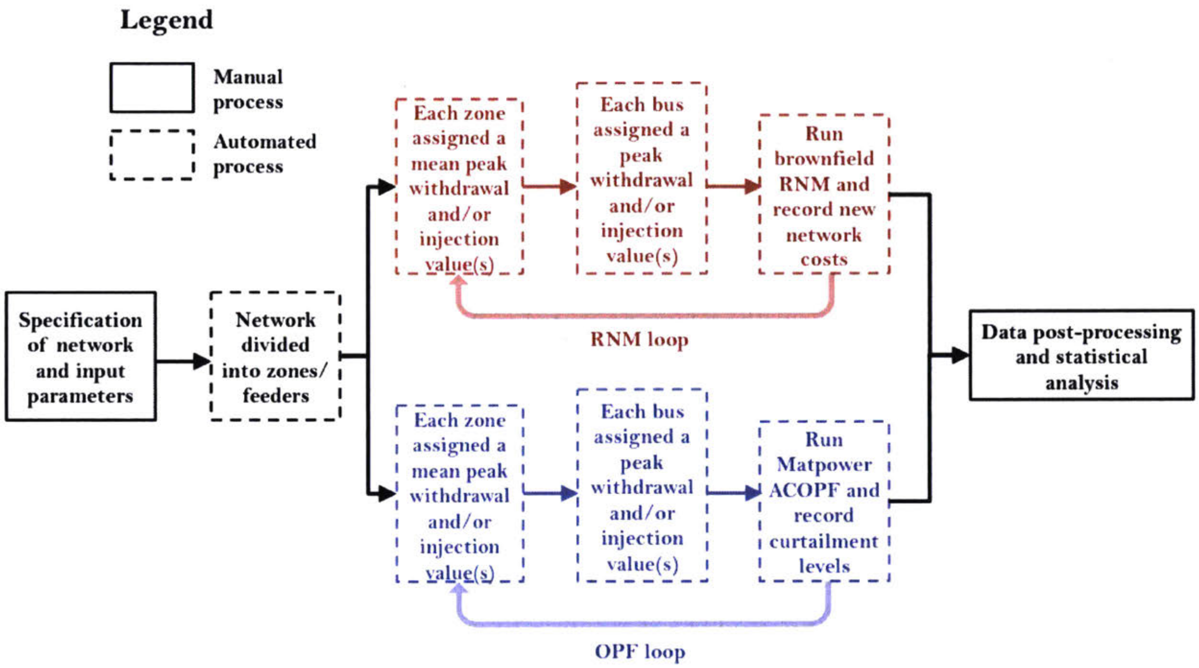
	generators (*set.sf.gen*) in the distribution network. The simultaneity factor is the probability that a given network user will be operating at maximum load or generation (for loads and generators, respectively) in a given hour.
set.cf.load *set.cf.gen*	A percentage value ranging from 0 to 1 (e.g. 0.5, corresponding to 50%) that sets the "concentration factor" for electrical loads (*set.cf.load*) and generators (*set.cf.gen*) in the distribution network. The concentration factor is the concentration of large loads and/or generators in a given network zone/feeder. For example, a given network feeder may contain 10 MW of distributed generation. If *set.cf.gen* is 0, then this generation will be distributed evenly throughout the feeder. Conversely, if *set.cf.gen* is 1, then the majority of the 10 MW of generation will be highly concentrated at a relatively small number of buses (i.e. there will be a small number of buses with high generation and a large number of buses with low generation).
RNM-specific parameters	
set.start.load.rnm *set.start.gen.rnm*	A percentage value (e.g. 1.1, corresponding to 110%) that sets the initial level of peak demand (*set.start.load.rnm*) and peak generation (*set.start.gen.rnm*) that will be an input into brownfield RNM runs.
set.end.load.rnm *set.end.gen.rnm*	A percentage value (e.g. 1.2, corresponding to 120%) that sets the final level of peak demand (*set.start.load.rnm*) and peak generation (*set.start.gen.rnm*) that will be an input into brownfield RNM runs.
set.inc.load.rnm *set.inc.gen.rnm*	A percentage value (e.g. 0.01, corresponding to 1%) that sets the increments by which peak load (*set.inc.load.rnm*) and peak generation (*set.inc.gen.rnm*) are increased (or decreased) between each brownfield RNM run.
set.maxruns.load.rnm *set.maxruns.gen.rnm*	A numerical value indicating the maximum number of RNM runs that the user will allow for variation in peak load (*set.maxruns.load.rnm*) and peak generation (*set.maxruns.gen.rnm*). If *set.maxruns* (for either load or generation) is smaller than the number of runs that are specified via *set.start*, *set.end*, and *set.inc*, then the Matlab script will randomly sample from the full (larger) list of runs so that the total number of runs is equal to *set.maxruns*.
Matpower ACOPF-specific parameters	
set.start.load.matpower *set.start.gen.matpower*	A percentage value (e.g. 1.1, corresponding to 110%) that sets the initial level of peak demand (*set.start.load.matpower*) and peak generation (*set.start.gen.matpower*) that will be an input into Matpower ACOPF runs.
set.end.load.matpower	A percentage value (e.g. 1.2, corresponding to 120%) that sets the final level

set.end.gen.matpower	of peak demand (*set.start.load.matpower*) and peak generation (*set.start.gen.matpower*) that will be an input into Matpower ACOPF runs.
set.inc.load.matpower *set.inc.gen.matpower*	A percentage value (e.g. 0.01, corresponding to 1%) that sets the increments by which peak load (*set.inc.load.matpower*) and peak generation (*set.inc.gen.matpower*) are increased (or decreased) between each Matpower ACOPF run.
set.curtzone	A numerical value indicating whether load and generation curtailment are allowed to occur only in the low voltage part of the network (1), only the medium voltage part of the network (2), or in both voltage levels (3).

Following the assignment of zonal peak withdrawal and peak injection values, the script then proceeds to assign each node or bus specific peak injection and/or peak withdrawal values. The procedure by which this occurs is straightforward. Simply stated, specific node or bus values are assigned in proportion to the peak load values of those specific buses in the pre-existing network. This is best illustrated with a simple example. Suppose that a specific network zone contains two consumers A and B, and no generators. In the pre-existing network, consumers A and B had peak loads of 60 kilowatts (kW) and 40 kW, respectively, and therefore a total peak load of 100 kW. Now suppose that this zone has been assigned a new peak load value that is equal to 1.1x the pre-existing peak load value, or 100 kW x 1.1 = 110 kW. In this case, since customer A's peak load in the pre-existing network accounted for 60% of that zone's total peak load, customer A's new peak load is 0.6 x 110 kW = 66 kW, whereas customer B's peak load is 0.4 x 110 kW = 44 kW. The procedure for distributing new peak generation is exactly the same as the procedure for distributing new peak load so I will not provide an analogous example.

After each node has been assigned new peak load and/or generation value(s), the next step is to run brownfield RNM with these new peak load and/or generation value(s). As previously described in this section, the function of brownfield RNM is to reinforce an existing network in a manner that is sufficient to accommodate new peak load and/or peak generation growth, and to do so in the most cost-effective way using only conventional network equipment. The output of RNM is a series of data tables detailing the network costs associated with these reinforcements. Therefore, after brownfield RNM has run, the Matlab script automatically compiles the relevant cost data from the RNM output and sends this data to a specified output directory. Finally, after brownfield RNM has performed an initial run using the values that the user has specified for *set.start.load.rnm* and *set.start.gen.rnm*, the Matlab script returns to the step in which new zonal peak withdrawal and injection values are set, but this time using values that are incrementally higher than *set.start.load.rnm* and *set.start.gen.rnm* (the increments by which this loop proceeds will depend upon the values that the user has set for *set.inc.load.rnm* and *set.inc.gen.rnm*). The loop will continue until it reaches the end values (which are also user defined), *set.end.load.rnm* and *set.end.gen.rnm*. The user will be left with a data set that contains the costs of conventional network expansion associated with incremental increases in peak load and/or peak generation and/or combinations thereof. An example of such a cost curve will be presented in the following section.

Figure 3. Architecture of proposed quantitative methodology



The OPF loop proceeds in a nearly identical manner to the RNM loop, but the input parameters that end in "*rnm*" replaced with new, analogous parameters that end in "*matpower*". The critical difference between the OPF loop and the RNM loop, of course, is that instead of building network reinforcements to accommodate new load and/or generation, the OPF loop utilizes load curtailment and generation curtailment to avoid constraint violations that would otherwise occur if curtailment were not possible. Therefore, just as the RNM loop generates a cost curve associated with a range of increases in peak load and/or generation, the OPF loop provides an analogous "curtailment curve" associated with that same range of increases in peak load/and or generation. Therefore, these two curves together can be thought of as substitutable: for a given level of increase in peak load and/or peak injection, a network planner may either invest in conventional network upgrades at a given cost (RNM cost curve) or invest in non-wires alternatives that are capable of providing a given level of load and/or generation curtailment (Matpower OPF curtailment curve). This concept will be explored further in the following section.

The final step shown in Figure 3, which I will not discuss at length, is the manual post-processing and statistical analysis that the user will conduct following the experiment. For example, the user may want to define a statistically sound function for both the RNM cost curve(s) and the load and generation curtailment curves so that substitutions between the two functions can be easily performed and/or so that the results of the experiments can be condensed into simplified functions that can serve as inputs into other models and processes. The user may also wish to visualize the curves for presentation.

2.2.1 A illustrative case study of how the proposed methodology can generate insights

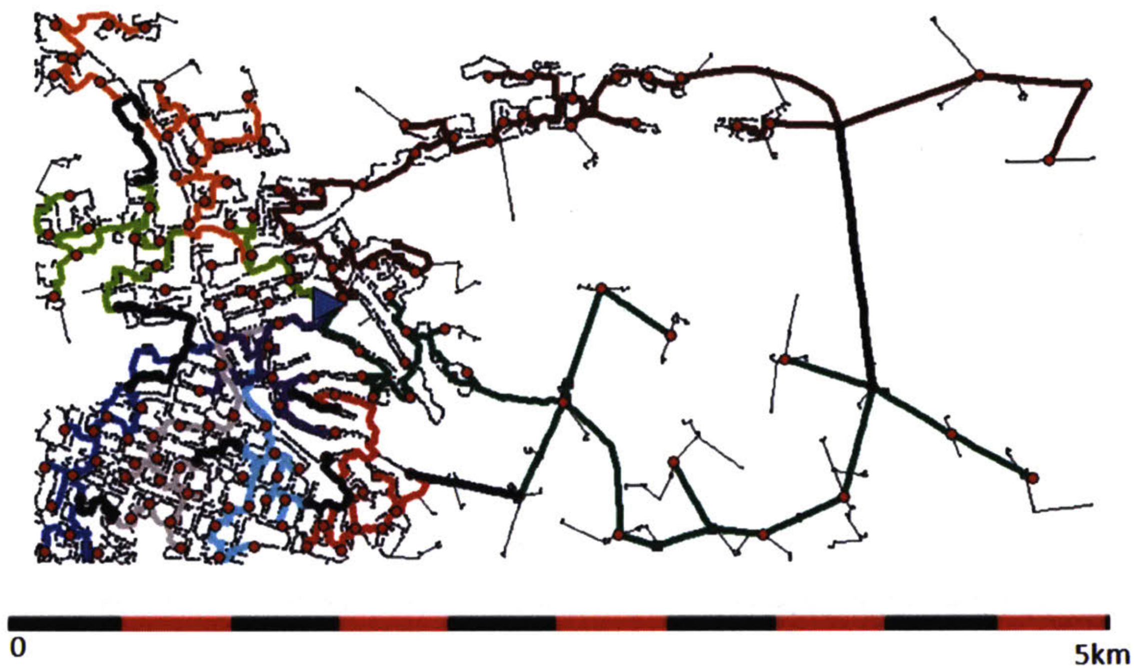
In this section I present a hypothetical case study that illustrates how the quantitative methodology presented in Chapter 2.1 can generate insights for a network planner/utility to help assess the least-cost mix of conventional and unconventional (innovative) resources to meet the needs of future growth in peak network load and peak distributed generation. The case study and the results that follow are intended to illustrate how the quantitative methodology presented in Chapter 2.1 can provide general insights – rather than specific ones – about how to assess the efficient mix between conventional and unconventional investments. The methodology presented in 2.1 was designed as an input into a bulk power system capacity expansion model that requires generalized functions that characterize the relationship between increases in peak demand/peak generation, and network investment costs and levels of load and generation curtailment. Thus, the case study that follows presents results in which peak demand and peak generation growth have been evenly spread across an entire electricity distribution network.

In practice, to generate insights that would be of specific relevance to a network planner, the granularity of the methodology presented in Chapter 2.1 would need to be increased. Specifically, the methodology would need to be able to simulate increases in peak load and peak generation in specific feeders or network sections, and to produce network cost and network curtailment curves that are specific to these feeders or network sections (rather than curves that apply to average growth across the entire network). This functionality could be relatively easily implemented into the existing methodology and will be a research priority immediately following the submission of this thesis. However, for the purposes of illustrating the functionality of the methodology and how it might be applied at a more granular level, a more general methodology is sufficient.

The case study makes use of a synthetic network that was developed using greenfield RNM by researchers at the Instituto de Investigación Tecnológica (IIT) in Madrid, Spain. The network in question is a modestly sized (approximately 14,000 LV customers and 40 MV customers) semi-urban network that was designed to be representative of other semi-urban networks in the European Union (Prettico et al., 2016). The network was built for a LV peak demand of 68.5 MW and a MV peak demand of 6 MW. Figure 4 shows the topology of this network. The thick colored lines in Figure 4 are the MV feeders of the network, that is, the electricity lines that connect the various MV-LV substations.

The red dots are the MV-LV substations themselves. The very thin black lines that "dangle" from each of the MV-LV substations are the LV feeders, and each LV customer is represented by a very small black dot. Finally, the blue triangle represents the HV-MV substation that connects this network to the transmission system.

Figure 4. Topology of a representative European semi-urban distribution network



Suppose that the planner of this network is anticipating significant peak load growth over the next ten years – on the order of 10% in both voltage levels – as well as modest increases in peak distributed generation, and would like to gain general insights with respect to deployment of conventional network upgrades vis-a-vis more innovative solutions that integrate DERs into network operations. The planner could utilize the methodology presented in Chapter 2.1 or one similar to it to gather such insights. The first step that the planner would take is to compile detailed data about its network (if it did not already have such a compilation) and organize this data into files that would serve as inputs to brownfield RNM or a similar engineering-based distribution network planning tool. This itself would be an arduous task if the planner did not already have detailed and organized data pertaining to the characteristics of its network; nonetheless it is a necessary first step.

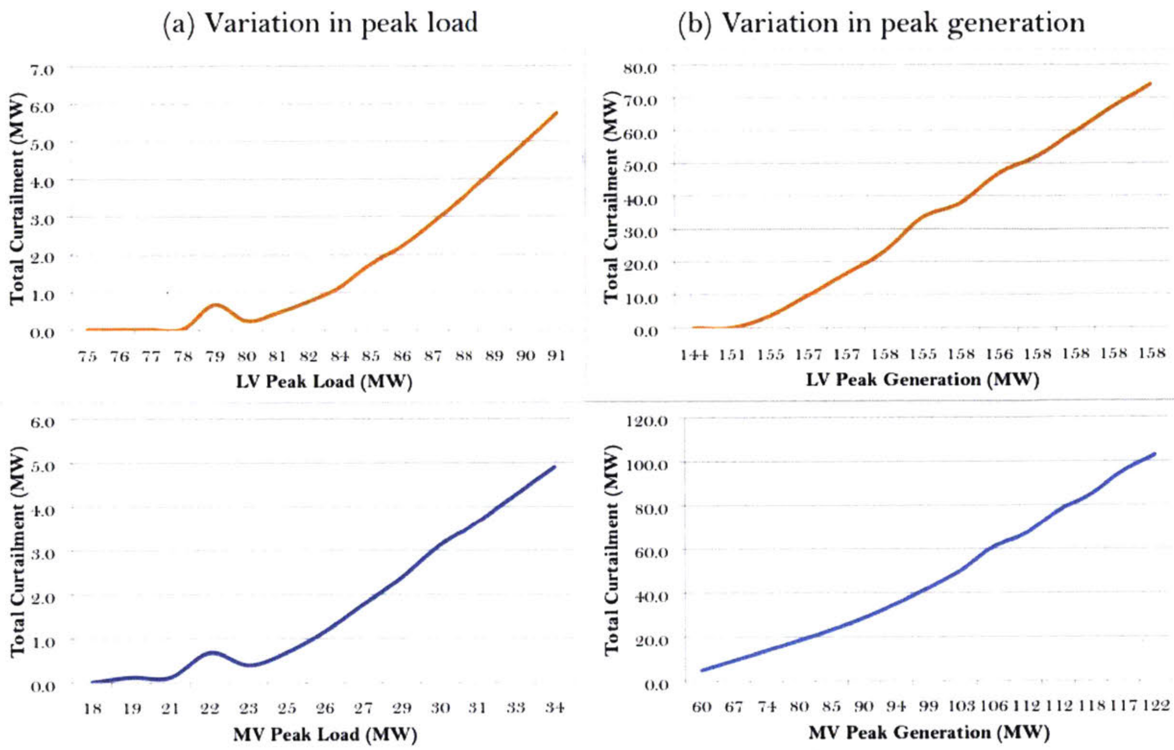
Following this initial step the network planner would be in a position to run both brownfield RNM and Matpower ACOPF[5], and therefore to construct system-wide RNM cost curves and system-wide

[5] Compiling network data into formats that can be used as inputs into brownfield RNM also means that the network can be read by and manipulated in Matlab/Matpower, since there is a version of brownfield RNM that generates a Matpower-format distribution network as one of its outputs.

Matpower OPF curtailment curves (by system-wide I am referring to the fact that incremental peak load and generation growth are evenly distributed across the network; for more granular curves the planner would increment load and generation in specific feeders). The network planner could first estimate the amount of load and generation curtailment that would be necessary to accommodate system-wide or average increases in peak load and peak generation, using the "OPF loop" described in Chapter 2.1 and illustrated in Figure 3. The curtailment curves that would be obtained by the planner are shown in Figure 5. Panel (a) in Figure 5 shows the levels of load curtailment that would be necessary to accommodate increasing average levels of peak demand in low voltage (top curve) and medium voltage (bottom curve); whereas panel (b) shows the levels of generation curtailment that would be necessary to accommodate increasing average levels of peak generation in low voltage (top curve) and medium voltage (bottom curve).

Panel (a) in Figure 5 shows that peak demand in the low voltage part of the network would have to reach about 78 MW (representing a 14% increase in average peak demand in this part of the network) before curtailment would be necessary. Peak load in medium voltage would have to reach about 21 MW (a 250% increase) before curtailment would be necessary. Moreover, panel (b) shows that peak distributed generation would have to reach very high levels in both low voltage and medium voltage before any generation curtailment would be necessary. Therefore, the first general insight that the planner would glean is that the part of the network that is as most risk of becoming constrained is the low voltage part of the network. Moreover the planner would recognize that some combination of investments in conventional network upgrades and non-wires solutions would be required in this part of the network in the coming decade if the planner hoped to accommodate load and maintain a significant margin.

Figure 5. Total curtailment necessary to accommodate increasing levels of average peak load (panel (a)) and average peak demand (panel (b)) in the low voltage and medium voltage parts of the network



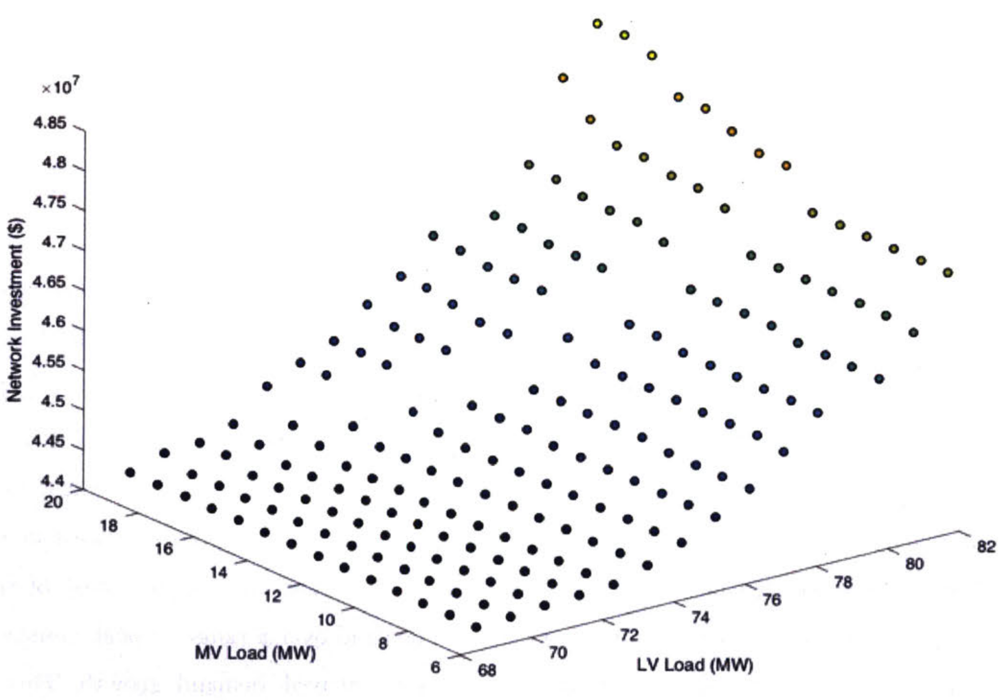
In practice, at this stage, the planner would likely want to conduct a more granular investigation of the particular low voltage feeders that are most likely to be constrained in the coming decade. This could be achieved using a similar but more granular methodology as that proposed in Chapter 2.1. However, since this example utilizes a more general methodology (in which increases in load and generation are evenly distributed), we will proceed with the case study and assume that at this stage, the planner could become interested in exploring specific solutions to accommodating expected increases in peak load growth.[6] Thus, the next step for the planner would be to estimate the marginal cost of traditional network reinforcement associated with increases in peak demand over a range of peak demand growth scenarios that are near to the planner's best estimate of actual peak demand growth. This could be accomplished using the "RNM loop" described in 2.1 and illustrated in Figure 3.

The incremental network cost curve that results from this type of exercise is shown in Figure 6. Figure 6 shows how incremental network costs (vertical axis) vary with increasing average levels of peak load in the low voltage and medium voltage parts of the network. As with the previous load and generation curtailment curves, Figure 6 yields general insights for the network planner. The Figure shows that

[6] In practice, it would not become interested in doing this until it had honed in on specific LV feeders that it expected would become constrained in the next decade.

increases in average LV peak demand are the most significant driver of network cost increases, but that increases in average MV peak demand can also drive investment costs if those increases are large enough and if there are also increases in average LV peak demand. Moreover, Figure 6 reveals that over a range of average peak demand increases that are similar to what the planner anticipates (i.e. 10% ± 2%, corresponding to about 75.3 MW ± 13.7 MW in LV and about 6.6 MW ± 1.2 MW in MV), the marginal cost of network expansion is relatively linear with respect to increases in LV peak demand. The linearity of the network investment cost curve over this range is almost certainly a result of the fact that this is an aggregate cost curve corresponding to average system-wide increases in peak load. The shape and smoothness of the curve would change if the planner were to investigate smaller network sections or feeders.

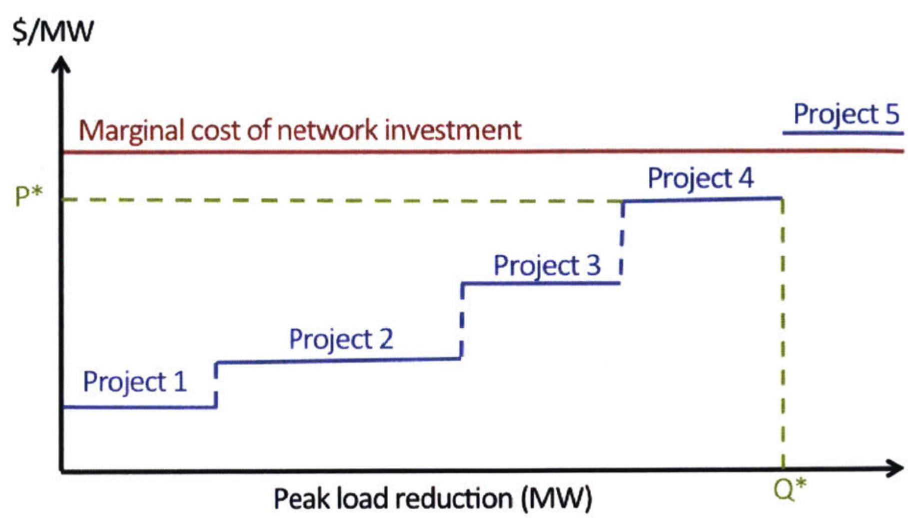
Figure 6. Total distribution network costs as a function of increases in average peak demand in the low voltage and medium voltage parts of the network



Given that it now has an estimate of the marginal cost of conventional network expansion over a range of expected peak load growth, the planner might now be interested in comparing these conventional network costs to the costs of "non-wires" or innovative solutions that are capable of curtailing LV load. Assume for the present example that the network cost curve displayed in Figure 6 is indeed the cost curve associated with increases in peak load in a particular set of feeders rather than average increases across the entire network. With the information that the planner had about the marginal cost of conventional network expansion associated with peak load increases in these feeders, the planner could animate a market for innovative solutions by sending a price signal to market participants (technology providers) that is equal to the marginal cost of network expansion at the expected level of future peak load. If the planner was effective in sending this signal, technology providers with solutions that cost less (per MW of peak load curtailed) than the marginal cost of network expansion (per MW of peak load added) would ostensibly respond to the price signal to offer those solutions to the planner. One way in which the planner could animate these markets is through the use of a competitive bidding or auction process. The planner could submit a competitive tender for technology solutions that were capable of curtailing LV peak load. The planner would accept a set of proposals totaling no more than the total amount of load curtailment that it expected would be required for mitigating the constraints in the feeders, and would only accept proposals with per-MW costs lower than the marginal cost of network expansion.

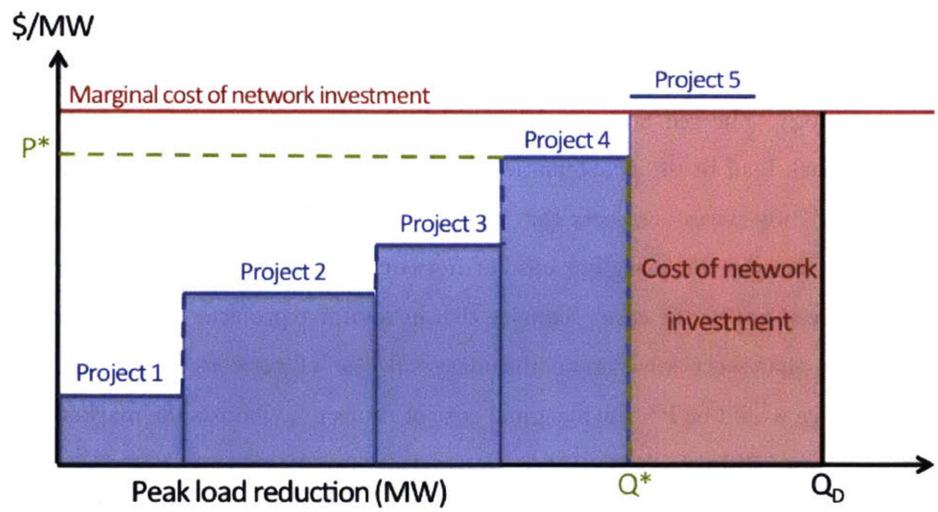
Figure 7 illustrates what the outcome of such an auction might look like. The vertical axis of Figure 7 corresponds to the per-kW cost of either the marginal network investment or a given "non-wires" solution or technology. The red horizontal line gives the marginal cost of network expansion at the level of expected peak load in the problematic feeders. The solid blue lines give the marginal costs of each of the specific "non-wires" projects that might submitted to the network planner in the auction (note that in this example the marginal cost of network investment, and of each of the projects, is constant, but this need not be the case). Suppose that in total five projects were submitted but only four had marginal costs that were lower than the marginal cost of network expansion. In this case, the market-clearing price would be P*, the marginal cost of Project 4, whereas the market-clearing quantity would be Q*.

Figure 7. Price and quantity outcomes of a theoretical auction in which four "non-wires" solutions provide a quantity Q* of peak shaving resources at a price of P*



Further suppose that Q*, the market clearing quantity of peak shaving resources provided by "non-wires" solutions, is shy of the amount of peak load reduction that the planner would need to accommodate expected peak demand growth. In this case, the planner would accommodate the remaining necessary amount with conventional network upgrades at the marginal cost of network investment. This case is shown in Figure 8. The red shaded area in Figure 8 is the total cost of conventional network upgrades, whereas the area between the horizontal dashed green line and the horizontal axis is the total cost of "non-wires" or innovative solutions. The cost savings associated with partially relying upon "non-wires" solutions to meet network planning needs, relative to a scenario in which only conventional network upgrades were used to meet planning needs, is the area between the horizontal dashed green line and the horizontal red line (the marginal cost of network investment).

Figure 8. Efficient mix of "non-wires" solutions and conventional network investment



As discussed, the case study provided herein utilizes results from a modeling run in which increases in peak load and peak generation were spread evenly across an entirely distribution network. In practice, network planners would be more interested in applying this methodology in more granular areas of the distribution network (such as a neighborhood) that they expected might become constrained in future years. As previously mentioned, the methodology presented in this chapter could relatively easily be adapted for this purpose, and this will be an imminent research priority. Nonetheless, the illustrative case study in this section has demonstrated how the methodology might be used to aid planners in the assessment of the optimal mix of wires and non-wires solutions. Moreover it has illustrated that a more general methodology – in which increases in peak load and peak generation are evenly spread across an entire network – can also lead to value insights.

3 PROMOTING SPECIFIC OUTCOMES THAT ARE CONDUCIVE TO THE TRANSITION TO ACTIVELY MANAGED NETWORKS

In addition to network management solutions proposed in Chapter 3, which will contribute to ensuring short- to medium-term economic efficiency in networks with high penetrations of DERs, distribution utilities must also be incentivized to deliver specific outcomes that are not directly related to economic efficiency but nonetheless that drive incremental innovation and contribute to the transition to active management. These outcomes include traditional ones such as improving the quality of electrical service, reducing energy losses, ensuring workplace and public safety, and others. They may also include non-traditional outcomes that are more directly related to the transition to actively managed networks, such as deploying smart grid technologies, increasing DER hosting capacity, and decreasing the amount of time that distributed generators must wait before being connected to the network.

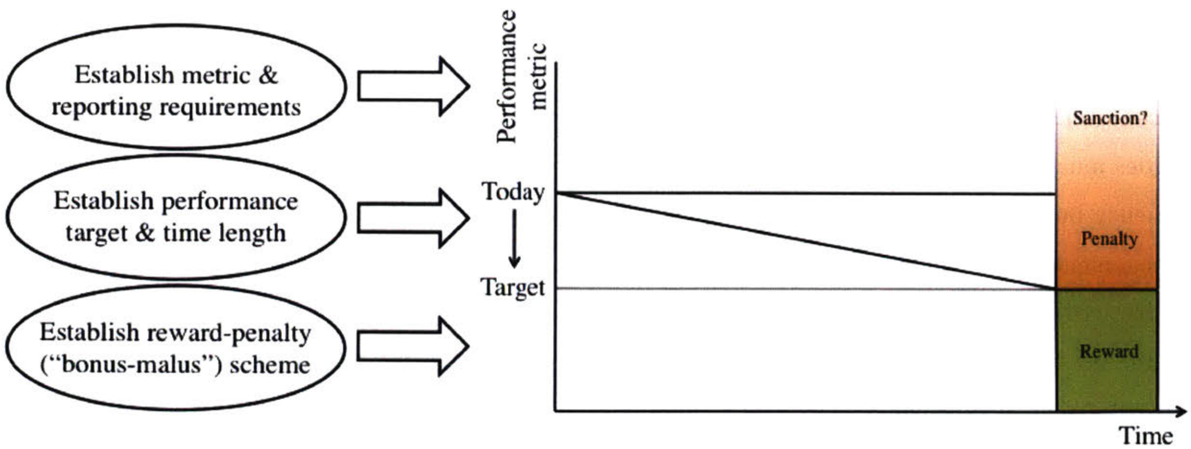
This Chapter is focused on best practices for the design of economic incentives, hereafter referred to as "outcome-based performance incentives", for achieving such outcomes. The Chapter focuses on four performance areas: commercial quality, continuity of electrical supply, voltage quality (which together comprise quality of service), and energy loss reduction, drawing from best practices in Europe and the U.S. Moreover the Chapter also discusses examples of two jurisdictions – the UK and New York – that have incorporated (or are planning to incorporate) outcome-based performance incentives into their regulatory frameworks as a critical part of the transition to actively managed networks. Before delving into specific performance areas, however, the Chapter first presents some general considerations for the design and implementation of outcome-based incentives, which will be useful for the discussion ahead.

3.1 General considerations for the design and implementation of outcome-based incentives

The basic regulatory design elements and stages of implementation of outcome-based performance incentives are illustrated in Figure 9.[7] The left part of the Figure enumerates the basic regulatory elements that may be used in the design of outcome-based incentives. These include:

1. A suitable performance metric and the establishment of reporting requirements that the network utility must adhere to;
2. A minimum performance target and the specification of a period of time during which the network utility must achieve the target;
3. A reward-penalty ("bonus-malus") scheme that rewards the utility for exceeding the performance target and penalizes the utility for failing to meet the target.

Figure 9. Stylized illustration of the implementation of an outcome-based performance incentive



The right part of Figure 9 illustrates the implementation of an outcome-based performance incentive that includes all three of the aforementioned elements. The distribution company is given a period of time over which it must improve its performance to the pre-established target or face a penalty associated with not meeting the performance target (or possibly a sanction if there is severe underperformance). If each of the elements of the outcome-based incentive is well designed, then the network utility will successfully meet or exceed the target at a cost that is no greater than the benefit received by the performance improvement. Considerations for establishing an efficient performance target are discussed in Box 3, while considerations for establishing an incentive formula for a reward-penalty scheme are discussed in Box 4.

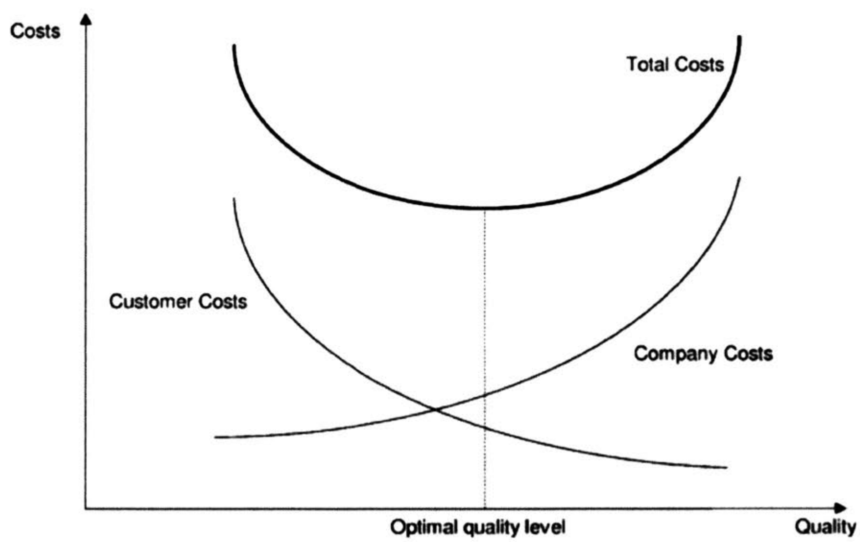
Note that while Figure 9 depicts the implementation of an incentive that includes all possible elements, in practice many outcome-based performance incentives are designed with only a subset of the elements described above. For instance in some cases a utility may not be subject to meeting a specific target but may simply be required to regularly report its performance level to the public. There is good evidence that the mere dissemination of information regarding a company's performance with respect to a metric provides an incentive for increased investments in performance improvements . Alternatively, the utility may be subject to a minimum performance target but may not be subject to a reward-penalty scheme, or may be subject to a reward-only or penalty-only scheme.

[7] This figure was adapted from (Aggarwal and Harvey, 2013).

Box 3: Establishing an economically optimal performance target

The inclusion of a performance target in an outcome-based incentive necessitates careful analysis regarding the value at which the target is set. From a social perspective (i.e. one that includes the interests of both customers and companies), the optimal level of performance is the level at which the marginal benefit of additional performance equals the marginal cost of supplying it. The benefit – or willingness-to-pay (WTP) – of an increment of performance improvement is usually difficult to quantify, so in practice WTP is often approximated by its inverse: the cost of – or willingness-to-avoid (WTA) – incurring an increment of performance deterioration. From this perspective, the optimal level of performance is that which minimizes the total cost function, i.e. the sum of the company's cost function and customers' cost function (Fumagalli et al., 2007; Gómez, 2013; Rivier and Gómez, 2000). This concept is conveyed in Figure 10.

Figure 10. The optimal level of performance is defined where the joint cost to the distribution utility and customers' is minimized.



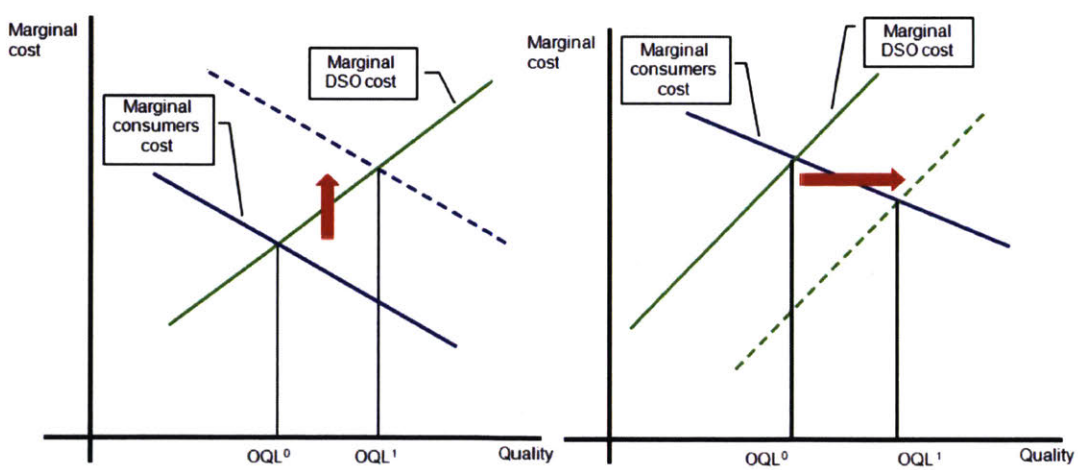
In practice, of course, determining these values is not straightforward. Determining customers' WTA is an inexact science that usually depends upon customer surveys and can vary widely within a given distribution network. Likewise, while it is possible to more accurately estimate the company cost of delivering various levels of performance, this too is usually at best a rough estimate due to the complexity of distribution networks.

(Box 3 continues on the next page)

Box 3 (continued)

Regulators should also bear in mind that optimal levels of quality will change, and therefore that performance target levels should evolve over time. Over time, the perception of the importance of a given performance goal for network users may vary. Likewise, the cost to the distribution utility of implementing a given performance goal may vary through time, as technology costs change and as economies of scale are realized. Consider the example of reducing the connection times for network users with solar PV. As more solar PV is installed in a network (or a certain area of a network), the economic incentive for a network user to install solar PV may decline (since the value of solar PV in a given network location decreases as a function of the total installed capacity of solar PV), and therefore the user's willingness-to-pay for a speedy connection time may also decline. Similarly, as distribution companies become more efficient at solar PV installations and realize economies of scale, the marginal cost of ensuring timely connections may decrease. The final position of the optimal level of quality will depend on the direction and magnitude of these changes. As Figure 11 depicts, the optimal level of quality will increase if network user willingness-to-pay increases, or if the marginal cost of performance delivery decreases. Conversely, the optimal level of quality will decrease if network user willingness-to-pay decreases, or if marginal cost of performance delivery increases.

Figure 11. The optimal level of performance evolves over time (Rivier and Gómez, 2000)



Box 4: Establishing output-based incentive formula in a reward-penalty scheme

The inclusion of a financial reward-penalty scheme in a performance incentive allows the regulated company some degree of discretion: given the performance target and the associated financial incentives, the company is expected to employ its superior knowledge of costs to deliver an efficient level of performance (Sappington, 2005). Financial reward-penalty schemes have delivered positive results where they have been applied (Fumagalli et al., 2007), however they are complex to design and therefore should be approached with appropriate deliberation and analytical rigor.

The incentive formula of a financial reward-penalty scheme can take numerous forms, including linear, quadratic, and step functions. To as much a degree as possible, the shape and the slope of the formula should reflect customers' willingness to pay (WTP) for increases in the performance level of a given outcome. Practical considerations, such as the ease of implementation, may also come into play in the choice of an incentive formula. Figure 12 presents examples of possible functional forms that reward-penalty schemes may take, as well as some of their potential benefits and drawbacks.

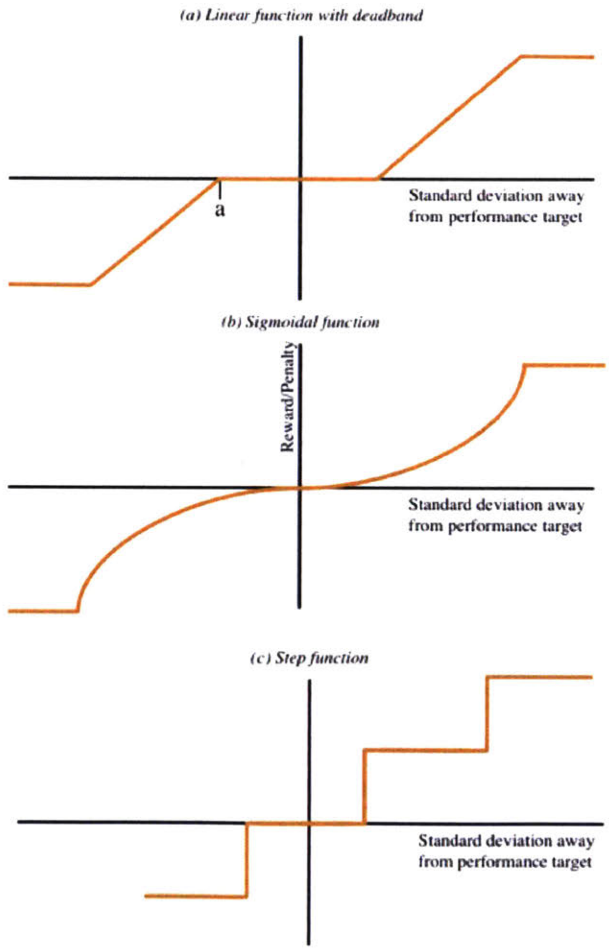
- A *linear function with a deadband* (Figure 12 (a)) is a popular functional form since it is simple to understand and to administer. Moreover, the deadband helps reduce the risk of the distributor achieving a reward/incurring a penalty due to a change in performance that occurs as a result of factors outside of the distributor's control. A potential drawback of a linear function with a deadband is that it might incentivize the distributor to perform at the negative-most performance level within the deadband (point *a*).
- A *sigmoidal function* (Figure 12 (b)) may be used as an alternative to a linear function with a deadband, since the slope of the sigmoidal function (i.e. the rate of change of the reward/penalty) is relatively low at small deviations from the performance target. Moreover, the parameters of the function can be tweaked so that the maximum reward and penalty occur at the same performance level as a similar linear function with a deadband. Moreover, the fact that the slope of the sigmoidal functions increases/decreases as the deviation from the target increases/decreases provides an additional incentive for strive for high performance levels, and avoid low performance levels. On the other hand, a sigmoidal function may be more difficult to administer than a linear function.

Box 4 continues on the next page.

Box 4 (continued)

- A *step function* (Figure 12 (c)) may be used if the objective is to provide a "sudden" reward/penalty if the distributor deviates from the performance target by a certain value. A step function may have as few as two steps, and as many as the regulator deems appropriate. While step functions are easy to administer, the fact that they are associated with "sudden" rewards/penalties can lead to contentious debate about whether the distributor did or did not deviate from the performance target by a certain amount. Moreover, this feature may incentivize the distributor to engage in unsound practices in order to receive a large reward or avoid a large penalty.

Figure 12. Examples of functional forms that reward-penalty schemes may take



3.2 Quality of service incentives

Service quality in the electricity distribution and retail sectors spans a large number of technical and non-technical aspects.[8] The aspects that are normally regulated can be grouped into three areas, one of which is non-technical and two of which are technical. First, commercial quality includes ensuring adequate performance on a number of service quality measures, such as the provision of a new electrical connection, meter reading, billing, and the handling of customer requests and complaints. Second, continuity of supply is related to interruptions of electrical supply, i.e. events during which the voltage at a customer connection drops to zero.[9] Finally, voltage quality is concerned with minimizing variations in deviations from desired levels of voltage characteristics. The design of regulation for each of these three services will be significantly affected by the emergence of DERs. Moreover, the transition to actively managed networks will mean that DERs may increasingly participate in the provision of some of these services. Each of these three performance dimensions, and best practices for their regulation, will be briefly discussed below.

Commercial quality regulation addresses the non-technical aspects of quality of service regulation and is concerned with maintaining minimum levels of quality for services that relate to the interaction between service providers (the distribution utility or retailer) and customers. Commercial quality regulation employs all three of the regulatory elements described in section 3.1: the establishment of performance metrics (and reporting requirements), the establishment of a minimum performance target, and (rarely) reward and penalty schemes. However it is recommended that when introducing a new commercial quality incentive, regulators do not adopt all three elements at once but rather introduce them incrementally, beginning with reporting requirements and moving (if necessary) to the establishment of a performance target and (again, if necessary) to the establishment of a reward-penalty scheme. Introducing regulatory elements in succession gives time to monitor and fine-tune each of the elements, which are often quite complex.

Table 2 provides a list of some of the most frequently regulated commercial quality services in the EU. These include services that are provided before the supply of electricity begins and those that are provided during an active contract. Services that are provided during an active contract can be further divided into those that are provided regularly and those that are provided occasionally. Services that are provided before supply begins include expedient connection times following requests for connection, expedient meter installation times, and expedient responses to requests for information about

[8] For a richer discussion of service quality regulation, see (Fumagalli et al., 2007).

[9] According to the European Norm EN 50160, a supply interruption is a condition in which the voltage at the supply terminals is below 1% of the declared voltage. The declared voltage is normally the nominal voltage of the system (i.e. the voltage by which the system is designated or identified), unless a different voltage is applied, by agreement between the supplier and the customer (CENELEC, 1999).

connection charges and charges for other connection-related works. The metric typically used to regulate these services is the waiting time for the provision of a service, following a service request.

Services that are regularly provided during an active contract include billing, meter reading, and services offered by customer and call centers. The performance of these services is usually assessed with metrics that measure regularity and accuracy such as the number of incorrect bills, the frequency of meter readings, customer satisfaction with respect to the precision of information provided by call center staff, etc. Services that are occasionally provided include those that are provided at the customer's request. They include responding to a request to check for technical failures or disturbances (e.g., with the meter or the supplied voltage), responding to information requests, etc. Metrics used to regulate these services are typically the amount of time it takes for the service provider to respond to service requests.

Table 2. Commonly regulated commercial quality performance areas in the EU (Fumagalli et al., 2007)

Before supply	During contract validity	
	Regular	Occasional
Providing (supply and meter)	Accuracy of estimated bills	Responding to failures of a distributor's fuse
Estimating charges for connection*	Actual meter readings	Voltage complaints
Execution of connection-related works*	Service at customer centres	Meter problems
	Service at call centres	Appointement scheduling
		Responding to customer requests for information
		Responding to customer complaints
		Reconnection following lack of payment
		Notice of supply interruption

*Requested also during contract validity

Increasing penetrations of DERs will usher in a variety of new considerations for commercial quality regulation. Electricity customers are increasingly also becoming electricity service providers and therefore the ability to quickly and efficiently gain access to electricity services markets will become important for network users. Additional issues such as the availability of and ease of access to information about electricity services markets will also grow in importance. Network users will increasingly look to distribution utilities to provide platform services that enable network users' entry into electricity services markets. Commercial quality regulation will need to keep pace with these evolving needs and priorities, and if it is successful in doing so will contribute to innovation and to the transition to actively managed networks.

Continuity of supply regulation seeks to minimize interruptions of electrical supply, i.e. events during which the voltage at a customer connection drops to zero.[10] In practice, continuity of supply regulation uses all three of the elements described in section 3.1: the establishment of performance metrics (and reporting requirements), the establishment of a minimum performance target, and reward and penalty schemes. However, as with commercial quality regulation, we do not recommend the adoption of all three regulatory elements at the outset. Rather, we recommend the gradual implementation of each regulatory element in succession to allow ample time to fine-tune each of the elements. The introduction of sound continuity of supply regulation can take one to two years' work (or three to four if reliable data are unavailable) on the part of both the regulator and the distribution companies.

Continuity of supply regulation is primarily concerned with two performance categories: the number of outages experienced by customers in a given period of time, the duration of outages (which includes both the average duration of outages as well as the total duration of outages in a given period of time), and the intensity of outages (i.e. total amount of load that was curtailed). Moreover, continuity of supply regulation is concerned both with "long" unplanned interruption events and with "short" events. Unplanned interruptions are classified as "long" when they last more than three minutes, and as "short" when they last for up to three minutes (CENELEC, 1999).

With respect to long unplanned interruptions, three of the most frequently used system-level statistical indicators are: average number of interruptions per customer per year (also known as system average interruption frequency index, SAIFI); average interruption duration per customer per year (also known as system average interruption duration index, SAIDI); and energy-not-supplied. Regulation to minimize short interruptions (less than or equal to three minutes[11]) has been less common than regulation to minimize long interruptions. Nonetheless in recent years it has received more attention from customers (particularly industrial customers since they are the most sensitive to short interruptions) and regulators. As with long interruptions, when data is available for the number of customers affected by short interruptions, system-level indicators of performance can be calculated as the average number of short interruptions per customer per year (also known as the momentary average interruption frequency index, MAIFI).

After a target has been set, the regulator must determine the form of the function relating level of quality to financial reward or penalty. To as much a degree as possible, the functional form should reflect customers' willingness to pay (WTP) for increases in quality as reflected, for example, in

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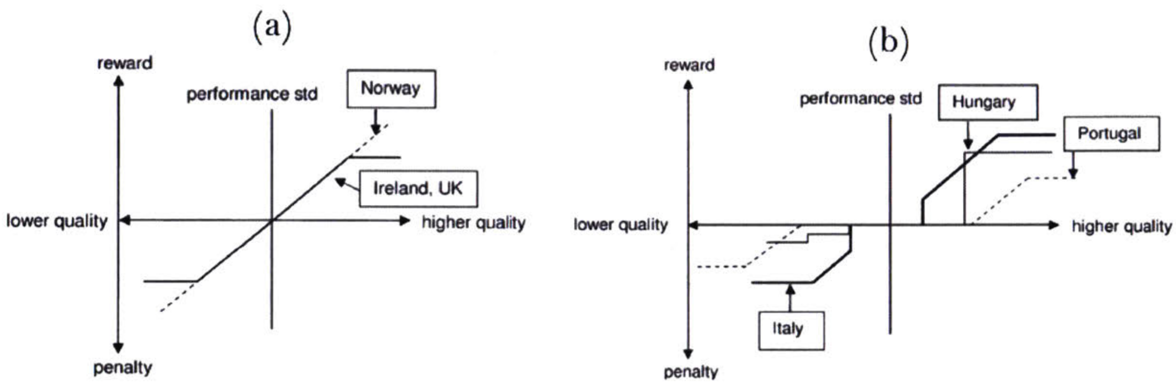
[10] For a richer discussion of continuity of supply regulation, see (Cossent, 2013).

[11] "Micro-cuts", losses of supply that last only a fraction of a section, are generally regulated under voltage quality standards and regulations, and not under continuity of supply regulation. Micro-cuts can be caused by a fault in a piece of equipment, changes in network configuration, and other reasons, and can be a serious problem for some industrial applications.

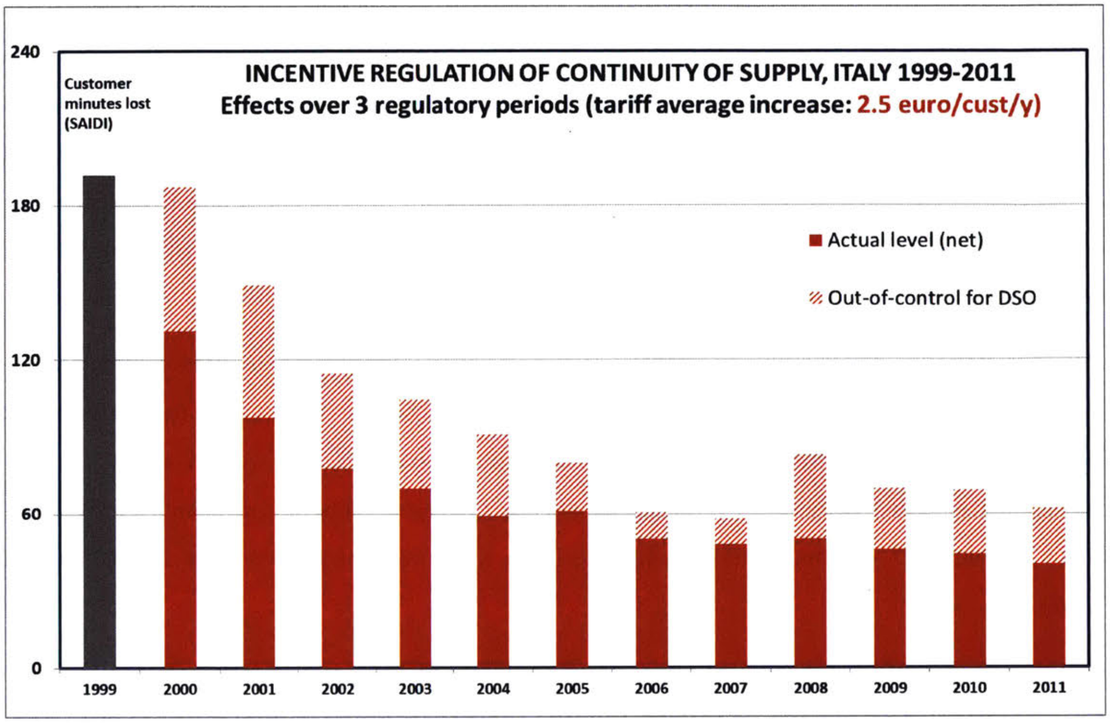
customer surveys. In practice, there is significant diversity in the incentive functions chosen by different countries that have implemented reward-penalty schemes for continuity of supply. Figure 13 shows the shape of the incentive functions for a variety of European countries. Figure 13 (a) shows examples of countries that use linear function (one with no cap and two with caps), while Figure 13 (b) shows examples of countries that utilize caps as well as dead-bands.

Figure 13. Shape of the incentive formula for continuity of supply regulation in different countries



Continuity of supply regulation has been widely adopted both in the US and in the EU and has proven extremely successful in many jurisdictions in significantly reducing outages (in both number and frequency). For example as shown in Figure 14, in Italy over a span of three regulatory periods (1999-2011), the number of customer minutes lost was reduced from more than 180 in 1999 to less than 60 in 2011 at an average cost to customers of 2.5 euros/customer/year. In Figure 14, a distinction is made between "actual" customer minutes lost and customer minutes lost as a result of events that are outside of the control of the distribution operator ("Out-of-control for DSO"). The Italian regulator considers outage events that are under the control of the distribution utility to be those that originate in the distribution network (LV or MV) and those that are not caused by a force majeure event (i.e. an event that stresses the distribution network beyond its designed resilience limits). Outage events that are beyond the control of the distribution utility include those that originate in the transmission system, those that trigger a system-wide response, and those that are caused by force majeure events.

Figure 14. Average interruption duration per customer per year (SAIDI) in Italy from 1999 to 2011



Increasing penetrations of DERs and ICT-enabled smart grid technologies will provide new opportunities and challenges for continuity of supply regulation that, if acted upon, will contribute to innovation and to the transition to actively managed networks. For example, the presence of DERs may contribute to system reliability through islanded operation (Cossent, 2013; McDermott and Dugan, 2003) and therefore well-designed output-based performance incentives for distribution utilities – combined with regulations that equalize incentives for OPEX and CAPEX – could lead to the establishment of markets for distribution-level reliability services in which DERs play an active role.

Moreover, regulators will have to carefully consider how to update continuity of supply regulation in light of increasing injections into distribution networks. For an increasing number of network users, the cost of interrupted service is not only the cost of lost energy consumption, but also the cost of foregone revenues from distributed generation production (Cossent, 2013). Relatedly, increasing penetrations of electric vehicles may significantly increase customers' WTP for continuity of supply since mobility will become increasingly linked to electricity supply. Finally, continued deployments of ICT-enabled smart grid technologies and systems will very likely reduce the costs associated with providing continuity of supply. All of these changes mean that regulators that have established outcome-based performance incentives for continuity of supply will have to regularly re-evaluate the target levels, incentive structures, and the reward-penalty amounts associated with these incentives.

Finally, **voltage quality** regulation is concerned with a subset of a wide range of factors that describe deviations of voltage from its ideal waveform. Such deviations can lead to damage or to the malfunctioning of customers' electrical equipment. To date, the economic regulation of voltage quality has been relatively rare. Voltage has typically been regulated with the use of technical standards. Nonetheless, in theory the economic regulation of voltage quality lends itself to all three of the regulatory elements discussed at the beginning of this section: the establishment of performance metrics (and reporting requirements), the establishment of a minimum performance target, and reward and penalty schemes. Interest in voltage quality regulation has increased in recent years due to a proliferation of electronic devices that are extremely sensitive to voltage quality.

The types of data required for voltage quality regulation are more technical and more difficult to obtain then the other two types of service quality regulation. Voltage that is supplied to customers has a number of characters – including frequency, magnitude, waveform, and symmetry of three-phase voltage – each of which experiences variations during the normal operation of an electrical system (CENELEC, 1999). Deviations of these characteristics from their nominal values are called voltage disturbances.

Due to these complexities and the large costs associated with voltage measurement at every connection point in a network, the regulation of voltage quality has typically been achieved via technical standards and bilateral arrangements between affected customers and distribution utilities. The use of outcome-based performance incentives for the regulation of voltage quality has been relatively rare. The few cases that we are aware of where outcome-based performance standards have been applied are in Latin America. In Argentina, for example, economic regulation for power quality indicators was introduced in the 1990s following the privatization of distribution companies in the Greater Buenos Aires area. Other Latin American countries also introduced similar schemes following the privatization of public-owned national utilities. Moreover, several jurisdictions have implemented outcome-based performance standards that rely on "non-technical" metrics of voltage quality to enforce voltage quality regulation. These include, for example, customer waiting time before receiving a response following a voltage-related request.

As with continuity of supply regulation, the proliferation of ICT-enabled smart grid technologies is likely to reduce the costs of providing voltage quality services. Moreover, DERs may become capable of providing voltage quality services, in which case the distribution utility could contract with or provide a market for these services. Regulators should be cognizant of these facts and should update regulation accordingly.

3.3 Minimization of energy losses

Electrical losses are defined as "the difference between the amount of electricity entering the transmission system and the aggregated consumption registered at end-user meter points" (ERGEG, 2008) and are comprised of technical or physical losses (i.e. those that occur as a result of heat and noise as electricity passes through network components) and non-technical or commercial losses (i.e. electricity consumption that is not metered such as consumption at distribution substations, energy theft, non-metered consumption, and metering errors). This section only considers technical or physical losses, which are the most common type of losses in most if not all developed countries.

Technical electricity losses in distribution networks increase costs for customers and increase CO_2 emissions (and emissions of other pollutants from power plants). In a vertically integrated setting (in which the utility is the owner/operator of power plants, transmission, and distribution networks), the utility has an incentive to reduce technical losses to a level at which the cost of further loss reduction is equal to the marginal benefit of that reduction (where benefit is defined as the upstream savings associated with increased power plant efficiency). However, since they do not bear the cost of technical losses, unbundled electricity distribution companies do not have an incentive to reduce them, and therefore additional regulation is required in these jurisdictions.

Technical losses can be improved via specific operational and planning strategies (Arritt et al., 2009), and therefore regulations that target such strategies may be desirable. However, many of the approaches to reduce losses through targeted operational and planning strategies present tradeoffs with other regulatory objectives and incentives, and therefore it may be more appropriate to regulate losses via outcome-based performance incentives (Cossent, 2013). Similarly to other forms of outcome-based performance regulation, the targeted level of losses is that at which the marginal benefit to society of energy loss reduction is equal (in magnitude) to the marginal cost to the utility of energy loss reduction. Nonetheless, the use of performance incentives for the regulation of technical losses is distinct from other forms of quality regulation (such as quality of service regulation) in that network users are not directly affected by the occurrence of technical energy losses (except for the increase in overall system costs). In practice, the regulation of technical energy loss reduction has proven to be challenging and some of these challenges are likely to be exacerbated by increasing penetrations of DERs (Cossent, 2013). On the other hand, DERs also may present important opportunities for the provision of energy loss reduction.

Increasing penetrations of DERs poses significant challenges for the regulation of technical loss reduction. Increasing DER penetrations can significantly change power flow patterns and therefore have can have a particularly large effect on variable technical losses.[12] As such, losses that arise as a result of DERs may perversely penalize the distribution utility for losses that the utility did not cause (Cossent, 2013). There have been proposals for ways to compensate network utilities for costs that are incurred by utility but caused by DG, including losses (de Joode et al., 2009). However in addition to this type of compensation, it will also be important to incorporate the effect of DERs on technical losses into the methodologies used to determine the reference value of losses. Richer descriptions of how this might be accomplished, and how it has been done in practice, can be found in (Cossent et al., 2009) and (Cossent, 2013).

Increasing penetrations of DERs also pose challenges for the determination of a metric that would be used in an outcome-based performance incentive for technical loss reduction. There are two obvious metrics that could be used for the measuring, reporting, and regulation of losses: an absolute value expressed in units of energy; or a percentage expressing losses as a proportion of total energy injected into the distribution network or total energy consumed. In order to make the metric comparable across services areas, it is preferable to use the latter metric. However, the presence of DERs makes the use of this metric potentially problematic. For example, consider a scenario in which losses references values are determined as a percentage of energy consumed (i.e. using the latter metric), and in which there is a high level of distributed generation (DG) in the system that has the effect of reducing net consumption and total variable losses in the system. In this case, due to the presence of fixed (transformer) losses that are unaffected by DG, the distribution utility would be penalized if DG loss reductions were higher (in percentage terms) than the reference loss value (Shaw et al., 2010). Moreover, the higher the proportion of fixed losses in the network, the more likely that it would be for this to occur. One solution to this potential problem would be to meter electricity consumption and generation separately. Another possible solution would be to use the first of the two metrics introduced above, i.e. an absolute value expressed in units of energy.

On the other hand, DG and DERs may also present opportunities for energy loss reduction. For instance, DG may contribute to energy loss reduction if it is sited close to consumption points. Moreover, demand response technologies may contribute to energy loss reductions, although the significance of this contribution may depend on the price elasticity of electricity demand of customers that are participating in the demand response program (e.g. see Shaw et al., 2009 and Venkatesan et al., 2012). The use of ICT-enabled smart grid technologies such as the ones presented in Appendix A may also contribute to technical loss reductions, since these technologies will assist network utilities in real-time network monitoring and automation, and in the dispatch of DER resources that contribute to loss

[12] Variable technical losses are those that occur in electrical wires and are distinct from fixed losses that occur in transformer cores. Variable technical losses can range between 66% and 75% of total distribution losses (KEMA, 2009; Ofgem, 2003).

reduction. However, it is likely that a significant share of the loss reductions that are enabled by smart grid technologies could be achieved as a byproduct of technology deployment that occurs via quality of supply regulation (Cossent, 2013). With respect to electric vehicles (EVs), there is ample evidence to suggest that high penetrations of EVs are very likely to contribute to increased losses (Clement-Nyns et al., 2010; Fernández et al., 2011; Peças Lopes et al., 2011, 2009a, 2009b).

Due to the challenges associated with regulating energy loss reductions, and the fact that these challenges will only be exacerbated with increasing penetrations of DERs, regulators must tread extremely carefully with respect to the design of performance-based incentives. Incorporating the effect of DERs on technical losses into the methodologies used to determine the reference value of losses will prove critical in the design of any incentive mechanism aimed at reducing losses.

3.4 New frontiers for outcome-based performance regulation

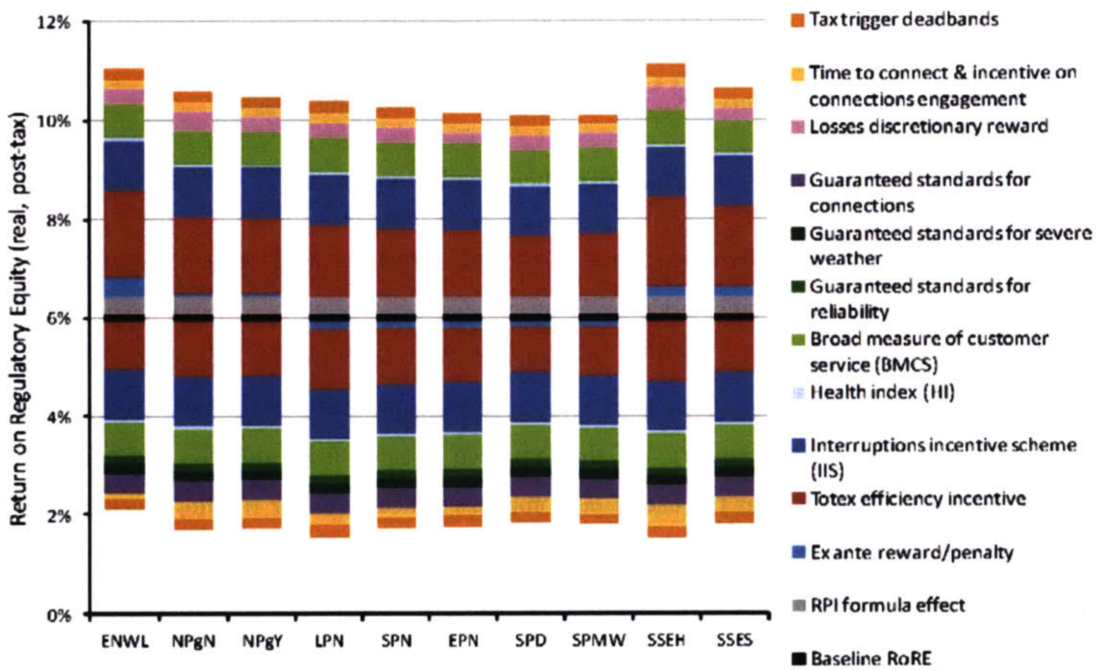
The preceding paragraphs have discussed some of the best practices with respect to outcome-based regulation in four critical performance areas: commercial quality, continuity of supply, voltage quality (which together comprise quality of service), and energy loss reduction. In each of these areas, the implementation of outcome-based performance incentives has helped steer network utilities in directions that are beneficial for network customers and that have led to safer, more reliable, and more efficient networks. It is also very likely that the use of outcome-based incentives for the improvement of these services has contributed to the creation of new knowledge, technologies, and processes that will play an important role in the transition to actively managed electricity networks.

These facts have led some regulatory authorities to move toward regulatory frameworks in which outcome-based performance incentives play a major role. Perhaps the best example is in the U.K., where in 2011 the U.K. regulator (Ofgem) launched a new regulatory framework titled "Revenue = Incentives + Innovation + Outputs" (RIIO) in which outcome-based performance incentives play a central role in the determination of network utility profits.

Figure 15 shows the relative strength of incentives associated with the core remuneration framework, and with additional outcome-based performance incentives, for distribution utilities in the UK under RIIO. The vertical axis in Figure 15 is the rate of return on regulated equity (ROR) and the horizontal axis labels in Figure 15 are different distribution companies in the UK. As Figure 15 shows, the allowed ROR of network utilities is linked to core efficiency incentives (the "RPI formula effect", "Ex ante reward/penalty", and the "Totex efficiency incentive") as well as to a variety of important outcomes: improving network reliability ("Interruptions incentive scheme", "Guaranteed standards for reliability", "Guaranteed standards for severe weather"), improving worker safety ("Health index"), improving customer service ("Broad measure of customer service"), improving connection times and network user engagement ("Guaranteed standards for connections", "Time to connect & incentive on connections engagement"), and reducing electricity losses ("Losses discretionary reward").

Figure 15 shows that the success or failure in meeting minimum targets for certain outcomes can lead to an increase or decrease (respectively) of two to three percentage points in the network utility's allowed rate of return on TOTEX, comparable to the possible gains and losses associated with efficiency incentives that are part of the core remuneration framework (Ofgem, 2014).

Figure 15. Range of possible return-on-investment for distribution utilities in the UK (Ofgem, 2014)



The UK is not the only jurisdiction that envisions outcome-based performance incentives playing an important role in the transition to actively managed electricity networks. In 2014 New York launched "Reforming the Energy Vision" (REV), an ambitious policy and regulatory initiative aimed at decarbonizing the state's energy sector. A major goal of the REV initiative is the transformation of the electric power system from a passively managed system to an actively managed system in which DERs participate in the operation and planning of networks. As such, efforts are underway to completely rethink the regulation of distribution utilities so as to align their revenue streams with the goals of active system management.

One of the mechanisms by which the New York regulatory authority seeks to align the incentives of network utilities with the goals of the REV initiative is by developing a set of outcome-based performance incentives (which it has termed "earnings adjustment mechanisms" or EAMs) (NYDPS, 2016). In particular, regulatory staff have proposed outcome-based incentives that would apply to five performance areas that are seen as critical to achieving the objectives of the REV initiative: peak load reduction, energy efficiency, customer engagement (i.e. the education of, engagement with, and provision of data to customers), affordability (i.e. the promotion of low-income customer participation in DERs and a reduction in the number of terminations and arrearages), and interconnection (i.e. improvements in the speed and affordability of distributed generation units). The regulatory mechanisms that would incentivize performance improvements in these areas are explicitly temporary and would be updated and reassessed regularly (NYDPS, 2016).

4 PROMOTING LONG-TERM INNOVATION

Finally, increased uncertainty about the evolution of network needs, cost drivers, and opportunities will intensify the need for long-term *innovation*, including expanded investment in demonstration projects, as well as the technological learning that emerges from those projects and dissemination of that knowledge between network utilities.[13] Uncertainty about how networks will evolve implies that the technological solutions that will lead to the greatest levels of productive efficiency in the medium- to long-term (i.e. lengths of period that are typically longer than the regulatory period) are also uncertain. The technologies and systems that will be most efficient for facilitating active network management in distribution networks with high penetrations of DERs are simply not known with precision today. Therefore there is a need for greater investment in demonstration projects.

One of the most straightforward regulatory approaches for achieving increased levels of innovation is to offer explicit financial incentives, outside of the core remuneration framework, for network utilities to spearhead demonstration projects. The most common way to do this is via so-called "input-based" financial incentives, whereby demonstration projects are capitalized and included in the regulated asset base (in a cost of service regulatory context). It is also possible to incentivize demonstration projects via output-based financial incentives such as those discussed in Chapter 3. However this is not recommended, since the precise outcomes of such projects are inherently uncertain. Nonetheless, as was discussed in Chapter 3, outcome-based performance incentives will inevitably incentivize some additional near-term innovation. This Chapter presents case studies of three jurisdictions that have had success in promoting innovation in electricity networks via input-based regulatory mechanisms. The case studies illuminate best practices from Europe and the United States and serve as guidance to regulatory authorities considering the adoption of incentives for innovation.

4.1.1 United Kingdom

[13] In other words, activities focused on supporting potential solutions that may not be commercially ready within one regulatory period, or that are extremely uncertain with respect to performance or returns, and therefore that need to be demonstrated and learned about in practical utility context. The objective is for utilities to transform into consistent adopters and integrators of novel solutions.

The United Kingdom is one of the earliest jurisdictions to explicitly embed significant incentives for innovation into its regulatory framework. By 2004, two new mechanisms creating dedicated funds for research, development, and demonstration (RD&D) projects had been established (Bauknecht, 2011; Lockwood, 2016; Müller, 2012). One was the Innovation Funding Incentive (IFI), covering 'all aspects of distribution system asset management' (Ofgem, 2004), which was capped at 0.5% of allowed revenue and available on a use-it-or-lose-it basis. Ofgem (the U.K. regulator) allowed 90% of the costs of IFI projects to be recovered in the first year of the price control, but this tapered off through the period to 70% in the fifth year, in order to incentivize early uptake. IFI projects tended to be focused on R&D rather than on pilot or demonstration projects. The second mechanism was Registered Power Zones (RPZs) – a scheme aimed at demonstrating innovative solutions for the connection of new distributed generation on sections of network. Distribution utilities were allowed additional revenue for each kW of DG connected, capped at a total of £500,000 per company per year. These mechanisms were small relative to the size of total spend by network utilities, but they created a new niche of activity that subsequently led to a much larger scheme.

Once launched, the IFI quickly produced a response. Spending by network utilities under the IFI increased from around £2 million in 2003/04 to around £12 million in 2008 (Jamasb and Pollitt, 2008). By contrast, RPZs were less successful, with only a small number of projects materializing during the price control period (Bolton and Foxon, 2011; Woodman and Baker, 2008).

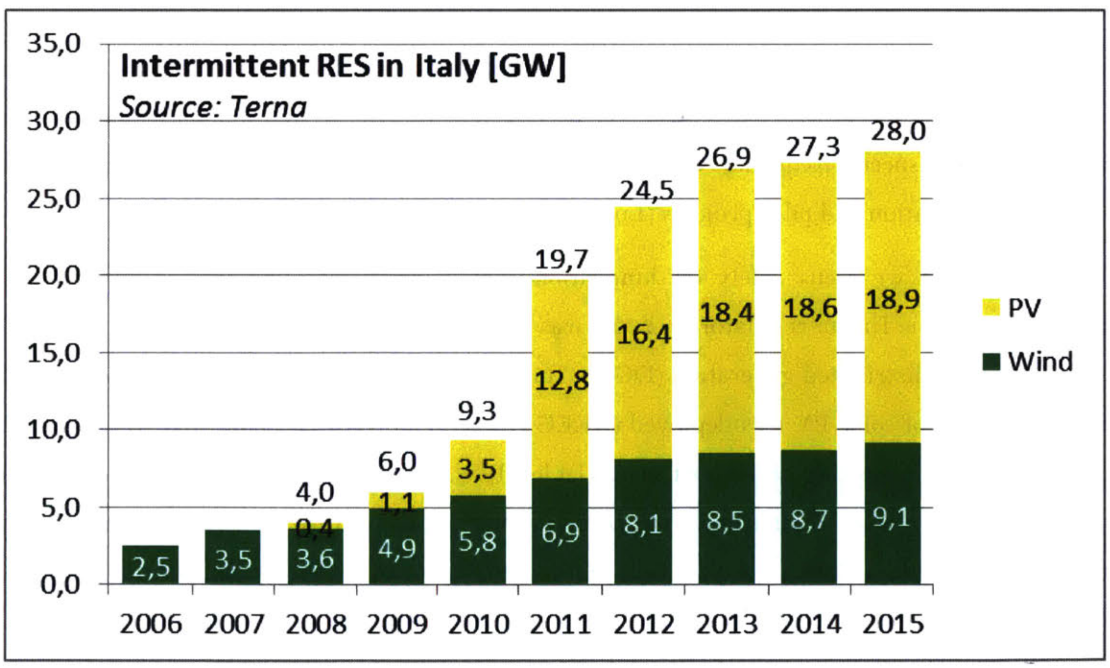
In 2010, a new mechanism for RD&D projects was introduced in the fifth distribution price control review, the Low Carbon Network Fund (LCNF). This was a competitive mechanism that allowed distribution companies to bid for up to £500 million over 5 years (Ofgem, 2010), equivalent to 2.3% of allowed revenue, an order of magnitude larger than the IFI and a very substantial increase on levels of innovation spending a decade earlier. There were two "tiers" of funding, one allowing distribution companies to recover most of the costs of smaller projects in allowed revenue, and another for larger projects in the form of a competitive fund of £64 million a year. Tier 2 funding requires companies to cooperate with ICT firms, suppliers, generators and consumers in projects in order to encourage cross-sector collaboration and innovative partnerships. Essentially the same structure for RD&D funding is continuing into the first RIIO price control period (2015–2023).

The LCNF has led to a step change in levels of RD&D activity by UK utilities as well as much larger scale demonstration projects. Moreover, the Fund requires the sharing of knowledge gained from trials between utilities and other market participants and has led to a website and an annual conference, which is now a major event attracting several hundred participants. In this manner, the Fund is accelerating important learning, knowledge sharing, and networking processes that can speed up the spread of best practices and successful innovations. There is some evidence that it has also a significant effect on distribution company thinking and culture, albeit to varying degrees between companies. It has required distribution companies to work together with suppliers, ICT firms, renewable generators and consumers on concrete demonstration projects. It has engaged network company board level interest in the smart grid agenda, and made distribution companies aware of potential new commercial relationships and opportunities (for example, in demand response). However, whether the LCNF will actually lead to major changes in network investment and operation remains to be seen.

4.1.2 Italy

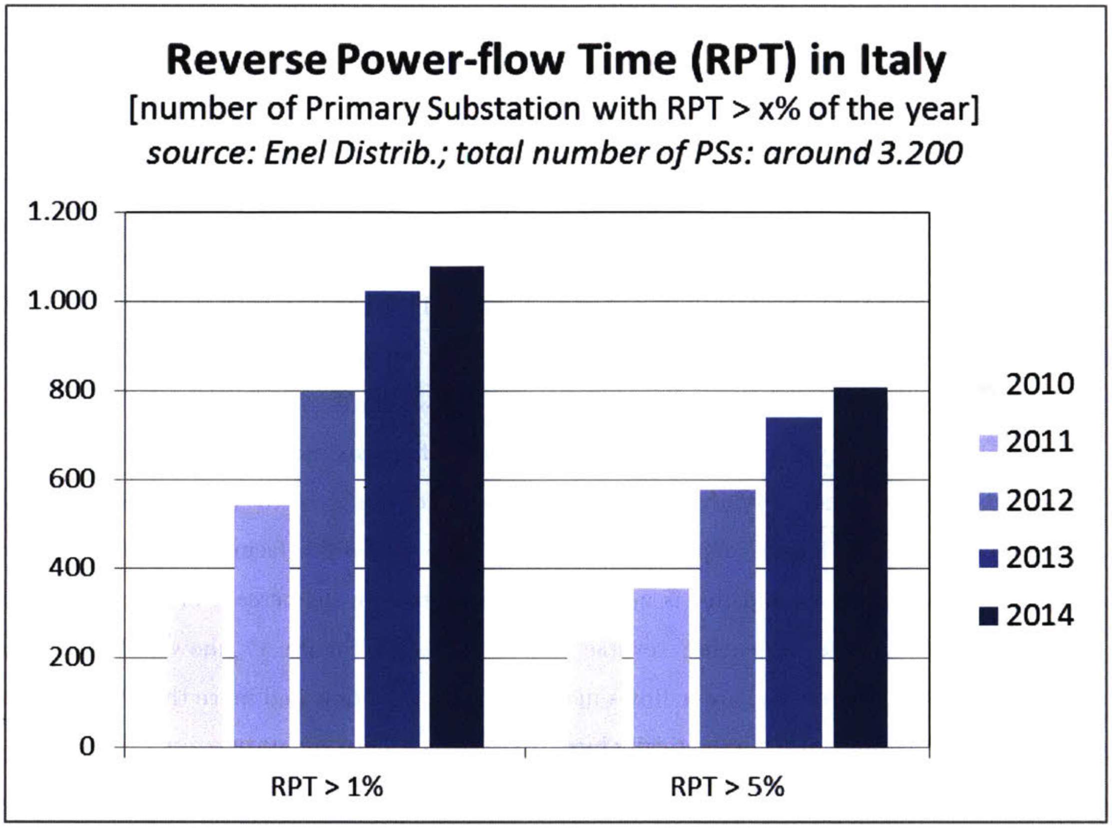
Italy has also been particularly active in the promotion of long-term innovation in distribution networks. The rate and scale at which distributed generation (DG) has increased in Italy is astounding (Figure 16). In 2006 the installed capacity of DG was 2.5 GW, comprised entirely of wind turbines. By 2015 the installed capacity of DG had ballooned to 28 GW, two thirds of which was distributed solar PV. The Italian electricity system, with a maximum demand of approximately 53 GW and a minimum demand of approximately 20 GW, has so far accommodated this growth via traditional network investments, i.e. a “fit and forget” approach. Nonetheless the challenges facing distribution network utilities in Italy have increased and this is no better reflected than in the percent of time that primary (HV/MV) substations are experiencing reverse power flows. As Figure 17 shows, the number of primary substations facing reverse power flows more than 1% of the time and more than 5% of the time in the Enel distribution network[14] dramatically increased between 2010 and 2014.

Figure 16. Installed capacity of intermittent renewable energy sources in Italy, 2006-2015 (Lo Schiavo, 2016)



[14] Enel is the largest distribution utility in Italy, serving 86% of total Italian electricity demand in 2011.

Figure 17. Number of primary substations in Italy that experiencing reverse power flows for more than 1% and more than 5% of the year



As a result of these challenges the Italian regulator has implemented a number of new regulations, including output-based regulatory incentives (as described in Chapter 3) new standards and codes (e.g. network codes that specify frequency variation tolerance requirements for DG units), and input-based incentives for innovation and pilot projects (Lo Schiavo et al., 2013).

For this discussion we focus solely on innovation-related incentives. The first innovation-related initiative taken by the Italian regulator, in 2009, was to commission a research study to investigate the hosting capacity of distributed generation (DG) in Italian medium voltage distribution networks, where the majority (75%) of solar PV was deployed (AEEG, 2009). The research found that MV networks in Italy have a very large hosting capacity at the nodal level – 85% of buses in the sample were individually able to host at least 3 MW of distributed generation – but that there were certain problems that would limit the system-wide DG hosting capacity (Delfanti et al., 2010). Another outcome of the research was the identification of an indicator of network "activeness" called "Reverse Power-flow Time" (RPT), the percentage of time in a year during which power flows from medium to high voltage.

The results of this research motivated the Italian regulatory authority to solicit competitive offers for innovative demonstration projects whose primary objective would be to reduce RPT and thereby improve the DG hosting capacity of distribution networks (AEEG, 2010). A committee of experts conducted a selection process on behalf of the regulatory authority, and the selected demonstration projects were capitalized and benefited from an additional 2% weighted average cost of capital (WACC) on top of the standard rate of return, for a period of 12 years.[15] The committee assessed the different proposals using a variety of parameters including qualitative indicators and technical scores, the cost of the project, and an indicator known as P_{smart}. P_{smart} is defined as the increase in DG production that can be connected to the grid, without undermining safe operating conditions (voltage, current, frequency), as a result of the pilot project.

Eight pilot projects were deployed under this regulatory framework and as a result several functionalities pertaining to active network management have been tested. In particular, the pilot projects have shed light on functionalities pertaining to DSO-TSO interactions, smart voltage control, active power modulation, anti-islanding functionalities, fast MV fault isolation, and functionalities related to electricity storage. The Italian regulator is currently focused on using the learning generated from the pilot projects to develop outcome-based incentives that are related to the transition to active system management. A detailed analysis of various active management functionalities was undertaken in 2015, and it was proposed that two functionalities – TSO-DSO data exchange and smart voltage control in MV networks – should be considered for outcome-based regulation (AEEG, 2015a, 2015b).

4.1.3 New York

In the United States, New York State has been at the vanguard of developing regulation for the promotion of long-term innovation. Under the REV proceeding, electricity distribution companies are envisioned to become "Distribution System Platform (DSP)" providers in which the majority of their revenues will be generated from the provision of market or platform services rather than from expenditures on capital equipment and from sales volumes (NYDPS, 2016). The intent is to change the regulated utility business such that distribution utilities facilitate DER participation in electricity markets and such that network utilities are agnostic between traditional network upgrades and DER-based "non-wires" solutions.

As part of this transition, distribution network utilities in New York are required to submit "Distribution System Implementation Plans" (DSIPs), documents intended to demonstrate (to the regulatory commission) how the network utilities intend to move toward actively managed networks, while ensuring that traditional utility objectives (e.g. reliability, safety, etc.) continue to be met. Each utility's DSIP will document the utility's plans over a five-year period, with a formal DSIP filing every

[15] To participate in the selection process, demonstration projects had to meet three main requirements: 1) distribution networks in which the projects were deployed had to show an RPT of at least 1% annually; 2) projects had to focus on development and deployment (i.e. not basic research); and 3) projects had to meet standard protocols for any communication applications involving network users.

two years. As one of the components of a DSIP, each utility is required to explain how it "expects to maximize option value of the distribution system for customers through better planning, system operations and management and vastly scaled integration of DER – without making unnecessary investments" (NYDPS, 2015b). Relatedly, distribution utilities are charged with including information about relevant current and near-term RD&D pilot projects. Utilities are encouraged to include pilot projects in their DSIPs because it is recognized (by the regulatory authority) that data collected from REV demonstration projects will "assist the process of integrating DER resources into system planning, development, and operations on a system and state-wide scale" (NYDPS, 2015b).

As a result, all of the major distribution utilities in New York have submitted proposals for pilot projects and there are currently (at the time of writing) more than 10 such projects underway.[16] Examples of projects include: "CenHub Marketplace", whereby a distribution utility is partnering with a technology company to build an online portal for energy products and services to provide customers with personalized recommendations and to offer an enhanced data analytics package for customers who want greater insight into their energy use; "Clean Virtual Power Plant", whereby a utility is partnering with DER providers that bundle solar with storage, which when aggregated serves as a "virtual power plant" to provide grid services on clear days; "Flexible Interconnect Capacity Solution", whereby a utility is partnering with a technology company to offer a new, less costly, and faster way for customers and third parties to connect large DG projects to the grid by providing an "infrastructure as a service" alternative to traditional interconnection; and others.

4.1.4 Summary

The case studies described above shed light on some of the novel ways in which regulatory authorities in jurisdictions in Europe and the United States have created input-based incentives and competitive rewards for the promotion of long-term innovation in electricity distribution networks. By enabling distribution utilities to invest in RD&D projects, these regulations are helping to generate new technological knowledge pertaining to the integration of DERs into network operation and management. Much of the knowledge that emerges from these pilot projects will contribute to the deployment of new technologies, systems, and processes that are critical to the transition to active system management, thereby leading to much greater efficiencies in the medium- to long-term. We therefore strongly encourage regulatory authorities to establish appropriate incentives for greater utility investment in RD&D projects.

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[16] A full list of demonstration projects can be found at the NY REV demonstration project web portal: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/B2D9D834B0D307C685257F3F006FF1D9?OpenDocument.

5 CONCLUSION

This research has presented a set of state-of-the-art tools to enable electricity distribution network regulators and planners to engage in a host of activities that will contribute to the development and adoption of new technologies, the dissemination of new technical knowledge between utilities and technology providers, and ultimately to the transition to a more efficient electricity sector in which distributed energy resources actively participate in the provision of electricity services.

The challenges associated with enabling this transition are numerous. To date, the majority of distribution utilities are not impartial to the deployment of OPEX and CAPEX solutions for avoiding future network constraints. In most regulatory jurisdictions utilities earn a rate of return on CAPEX and not on OPEX, thereby skewing these utilities' incentives for achieving the economically efficient mix of these two forms of expenditures. This, in turn, may distort the efficient mix of conventional and innovative solutions that are deployed, since the proliferation of DERs and ICT-enabled smart grid technologies have given rise to a variety of new, potentially cost-saving, solutions that are associated with varying or uncertain proportions of CAPEX and OPEX. Moreover, even if incentives did enable utilities to invest in an economically efficient mix of conventional and unconventional resources, there is a dearth of quantitative modeling methodologies that would enable utilities to soundly assess what this economically optimal mix is. Increasing penetrations of DERs will exacerbate these challenges, and therefore the challenges should be addressed soon in order to avoid large economic inefficiencies.

Moreover, in addition to the challenges associated with ensuring short- to medium-term economic efficiency in distribution networks that are home to increasing penetrations of DERs, there is also a need to ensure that network utilities maintain adequate levels of performance in areas that are not directly related to economic efficiency. Network utilities must continue to deliver adequate levels of critical quality of service outcomes including commercial quality, continuity of supply, and voltage quality. The delivery of quality of service outcomes will become more complex with the emergence of DERs, since the willingness-to-pay (WTP) for service quality may increase for DER users that are no longer only customers but are also now suppliers of valuable electricity services. Moreover the cost of delivering service quality may decline as increased levels of functionality of ICT-enabled smart grid technologies are realized. In addition to the delivery of quality of service outcomes, the delivery of technical loss reduction will also continue to be an important outcome for network utilities throughout the transition to actively managed networks. This outcome, too, however, will be significantly complicated by the emergence of DERs. Finally, there may be outcomes that are specific to the transition to actively managed networks – such as the provision of market data to DER users, expediency in the provision of market access to DER users, and others – that network utilities may need to deliver in the coming years.

Finally, the transition to actively managed networks will critically depend upon the promotion of long-term innovation – that is, investment in demonstration projects, as well as the technological learning that emerges from those projects and dissemination of knowledge and best practices between network utilities, technology providers, technology users, and other market participants. The technological solutions that will lead to the most economically efficient outcomes in distribution networks in the long-term (i.e. that will lead to "dynamic efficiency") are simply not known today, and therefore there is a need for network utilities and technology providers to engage in demonstration projects that are inherently risky but that, over time, will lead to efficient solutions.

This thesis has provided some of the tools that regulators and planners will need to address these numerous critical challenges. In Chapter 2.1, examples are presented of two regulatory jurisdictions – the United Kingdom and New York – that have implemented (in the case of the UK) or are moving toward the implementation of (in the case of New York) regulatory approaches that help equalize incentives for operational and capital expenditures. These include the UK regulator's "fast-money"-"slow-money" TOTEX-based approach, and the New York regulator's revision of a "clawback" mechanism that will help enable utilities to pursue cost-effective operational expenditures and DER alternatives to planned capital projects.

Chapter 2.2 presents a quantitative methodology that can be employed by network planners to assist in determining a least-cost mix of conventional and unconventional network resources to avoid anticipated network constraints. The methodology itself makes use of two powerful software tools: an engineering-based reference network model (RNM) that can be used to determine the costs associated with different levels, combinations, and distributions of peak load and peak generation, using only conventional network upgrades; and Matpower, an electricity network simulation tool whose optimal power flow (OPF) functions can be used to determine the levels of load curtailment and/or generation curtailment that would be necessary to accommodate different levels, combinations, and distributions of peak load and peak generation.

Chapter 3 presents an overview of regulatory best practices and important considerations for the design of performance incentives for the delivery of specific outcomes. The Chapter begins by providing a set of general considerations for the design of such incentives, including the generic steps required for their design and implementation, considerations regarding the target level at which the performance incentives are set, and information about the variety of functional forms that a reward-penalty scheme might adopt. The Chapter proceeds to investigate best practices, intricacies, and impending challenges and opportunities associated with the design of outcome-based performance incentives – including quality of service outcomes and technical loss reduction – in distribution networks that are home to increasing penetrations of DERs.

Finally, Chapter 4 presents case studies of three jurisdictions – the UK, Italy, and New York – that have been particularly active with respect to the implementation of incentives for long-term innovation into their regulatory frameworks. In each of the cases, regulatory authorities have enabled network utilities to spearhead demonstration projects by allowing utilities to include the costs of demonstration projects in their regulated asset bases. In the cases of the UK and Italy, project funds are competitively awarded, and in the case of Italy awardees have earned an additional rate of return on the demonstration projects. These case studies provide important insights into the design of regulation for the promotion of long-term innovation, and should serve as a guideline for regulators that are currently considering these types of incentives.

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APPENDIX A. SMART GRID TECHNOLOGIES AND THEIR FUNCTIONS

There is a great variety of novel network technologies that are commercial today but that have been not much deployed in modern electricity networks (for example, see US Department of Energy, 2014).[17] Many of the major technologies and technology categories are shown in Figure 18. Figure 18 shows four groupings of technologies: distributed energy resources, technologies capable of generating

[17] Nonetheless, the rate of deployment of novel network technologies has been rapidly growing and is expected to increase over the next decade (Elberg and Lockhart, 2014; Institute for Electric Innovation, 2014).

reactive power ("VAR management technologies"), sensor technologies ("sensors on the distribution grid"), and "other technologies and systems."

First, DER itself is a category of novel network technologies. As previously mentioned, while DER can pose challenges and costs for network operators, they may also help provide electricity and network services. Often, the provision of services by DER depends upon the deployment of other novel (non-DER) network technologies, such as AMI, SCADA, and others. DER include demand response and energy management systems, distributed storage, electric vehicles (and associated infrastructure), gas-fired distributed generation, solar PV, and wind power plants.

Second, volt-ampere reactive[18] (VAR) management technologies are technologies that can provide reactive power to electricity networks, help maintain a high power factor, and help reduce electrical losses. Traditional VAR management technologies have been in use for over 30 years, but newer technologies are superior and can help reduce distribution line losses by 2-5% through tight control of voltage and current fluctuations (NEMA, 2012). Third, "Sensors on the distribution grid" refers to emerging technologies that offer real-time grid monitoring and measurement solutions for distribution operators. These include smart meters, which generate real-time electricity consumption data, power quality (PQ) meters, and phasor measurement units (PMU). PQ meters and PMU meters both provide real-time power quality data (i.e. data related to voltage waveform).

Finally, technologies that are listed in the "other technologies and systems" category are diverse and do not easily fit into the other categories. A brief description of each of the technologies in this category is provided here:

- An active power filter is a device that is used to improve power quality.[19]
- AMI is not a single technology but rather refers to an integrated system of smart meters, communications networks, and data management systems that enable two-way communication between network operators and customers.
- A line voltage regulator is a voltage regulator that is installed along a distribution feeder that automatically maintains voltage within a given range.
- New protection systems refer to systems of technologies that are employed to protect network users from faults (abnormal electric current) by isolating the faulted parts of the network from the rest of the network. Although traditional protection systems have existed for decades,

[18] Volt-Ampere reactive (VAR) is a unit used to measure reactive power in alternating current systems.

[19] For more information about active power filters see, for example, El-Mamlouk, Mostafa, & El-Sharkawy, 2011 and Kumar, Varaprasad, & Siva Sarma, 2014.

advanced protection systems are emerging that are superior to traditional systems and that integrate DER into the protection system (e.g. see Fazio, Russo, & Valeri, 2015).

- A point of common coupling (PCC) regulator is a device that regulates voltage at the interface between an inverter and an inverter-connected device (such as a solar PV panel) (e.g. see Perera, Ciufo, & Perera, 2013).
- Remote switching systems are switchgear systems (electrical disconnect switches, fuses, and circuit breakers) that are operated remotely and automatically in order to help with fault isolation, service restoration, and system optimization.
- Ripple control systems refer to frequency-sensitive relays that trigger circuit breakers. These systems are typically used by network operators to control load.
- SCADA in LV/MV refers to centralized systems that monitor and control low- and medium-voltage distribution networks. SCADA systems are typically composed of several subsystems including remote terminal units, programmable logic controllers,[20] a telemetry system,[21] a data acquisition server,[22] a human-machine interface,[23] and others.
- A transformer with quadrature control (also known as a phase angle regulator, phase shifter, or quad boosters) is a specialized type of transformer that is used to control the flow of real power on three-phase electricity networks. This technology helps network operators relieve loads on congested circuits by re-routing power.[24]
- A virtual power plant (VPP) is a system that aggregates distributed energy resources to provide reliable power and other electricity services.
- A voltage regulated distribution transformer is a transformer that contains an on-load tap changer that is capable of dynamically adjusting voltage.

[20] Remote terminal units (RTUs) and programmable logic controllers (PLCs) are used to convert sensor signals to digital data. PLCs have more sophisticated embedded control capabilities than RTUs.

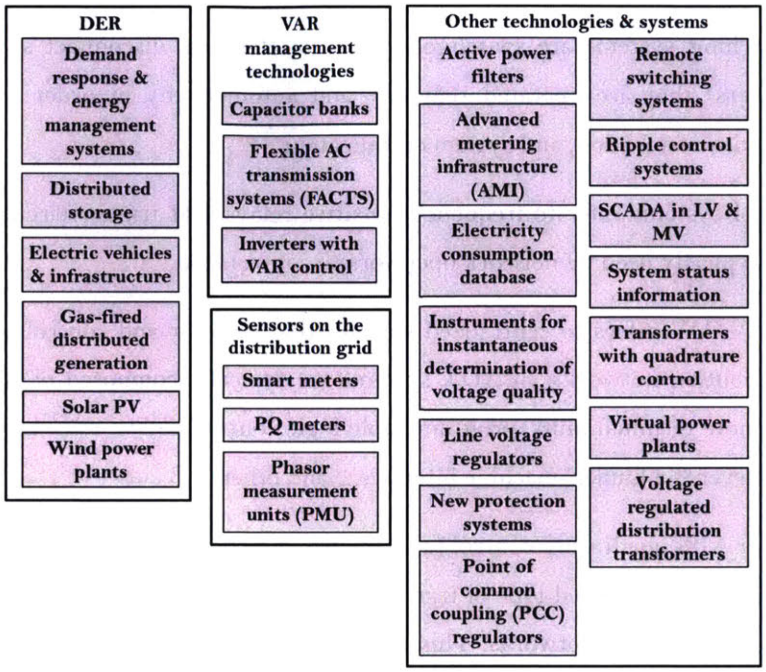
[21] A telemetry system is typically used to connect PLCs and RTUs with control centers, data warehouses, and the enterprise.

[22] A data acquisition server is a software service that uses industrial protocols to connect software services, via telemetry, with field devices such as RTUs and PLCs.

[23] A human–machine interface (HMI) is the apparatus or device that presents processed data to a human operator.

[24] For more information on transformers with quadrature control, see (UK Power Networks, 2014).

Figure 18. Emerging electricity network technologies and systems (Basse et al., 2015)



Each of the technologies and systems described above and shown in Figure 18 contributes to one or more specific *network functions.* A network function is an operation that contributes to the provision of electricity services but that is not itself an electricity service. Figure 19 lists the network functions that are most relevant to the provision of services by distribution network operators. These functions fall into five categories: operational management, grid efficiency and network deferral, DER management, and fault and protection:

- *Operational management* refers to network functions that contribute to day-to-day reliable operation of distribution networks. The specific functions within the category include fault localization via sensors, imminent failure prediction, outage verification, power flow management to minimize losses, self-healing,[25] real-time voltage phase symmetry monitoring, and others.

[25] Self-healing a general term that refers to the use of sensors, automated controls, and advanced software that utilizes real-time distribution data to detect and isolate faults and to reconfigure the distribution network to minimize the number of customers impacted. For more on this topic see Amin & Wollenberg, 2005 and Farhangi, 2010.

- *Grid efficiency and network deferral* functions improve the efficiency of the network, increase DER capacity, and defer the need for conventional network upgrades. The functions in this category include more efficient grid planning, real time line monitoring, reduction of grid losses via localized provision of reactive power, the inclusion of controllable loads when determining "n-1" reliability requirements,[26] and others. Many of the functions in this category fall under the subcategory "smart voltage control." Functions within this subcategory include: maximizing the useful voltage range in the medium voltage part of the network by exclusively deploying voltage-regulated distribution transformers (VRDT) in medium voltage; dynamic voltage control using VRDT with an "on-load" tap changer;[27] voltage control via local autonomous feed-in control,[28] and others.

- *DER management* functions increase DER capacity and enable DER to play an active role in the provision of electricity services. Within this category there are three subcategories: demand side integration, control of the load curve shape, and control of DER voltage set points.
  - The only function related to demand side integration is demand response (changes in power consumption that occur as a result of price or control signals).
  - Functions related to the control of the load curve shape include load shifting and peak clipping (also known as peak shaving).
  - Functions related to the control of DER voltage set points include feed-in management with communication between the network operator and DER; local autonomous power control of the DER user; and power feed-in limitation.

- *Integration of load into operations* refers to the utilization of load elements (electricity consumers and DER) to contribute to system operations and to provide electricity services. Functions within this category include conservation voltage reduction (CVR),[29] maximization of self-consumption, reduction of consumption via smart meters, and "valley filling" (shifting load to periods of the day where load is the lowest). This category also includes functions related to the

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[26] It is common practice for electricity network planners to employ the "n-1" or "n-2" reliability criterion, which means that the system must operate with one or maximum two elements out of service (Prada, 1999). Traditionally the "elements" have been central generating stations and network capacity (transmission lines), however it is now possible to also employ load resources to meet the reliability criterion.

[27] For more on this topic see Esslinger & Witzmann, 2012 and Gao & Redfern, 2011.

[28] Autonomous feed-in control refers to the automatic control of DER injections into distribution networks.

[29] CVR is a means of reducing energy and peak demand without any intervention on the part of consumers. CVR is implemented by setting the voltage on a distribution circuit at the lower end of a tolerance band. When voltage is lowered in this way, certain end use loads draw less power. CVR has been shown to lead to significant energy savings (on the order of 0.5-4%) in distribution circuits. See, for example, Moghe, Tholomier, Divan, Schatz, & Lewis, 2016 and Schneider, Fuller, Tuffner, & Singh, 2010.

provision of ancillary services from DER: frequency stabilization using DG and appliances, and real and reactive power provision from DER.

- *Fault and protection* refers to functions that reduce the probability of faults and mitigate the impacts of faults when they do occur. Functions within this category include automatic protection adjustment,[30] fault detection of de-energized lines, real-time fault diagnosis, and real-time fault identification.

- Finally, *meter-to-cash* refers to the use of new technologies to improve the customer billing process. The specific functions within this category include using AMI for better billing control, the provision of detailed responses to customer billing queries, the detection of excessive power consumption, and remote meter reading.

[30] This refers to the automatic changing of settings of protection equipment and devices in response to real-time information about the current status of the network.

Figure 19. Functions performed by emerging network technologies (Basse et al., 2015)