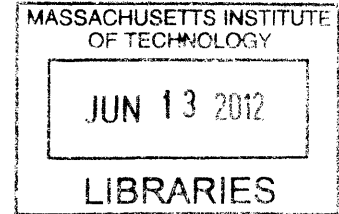


A Model-Based Approach To Regulating Electricity Distribution Under New Operating Conditions

by

Xiang Ling Yap

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Signature of Author:

Handwritten signature of Xiang Ling Yap.

.....
Engineering Systems Division
May 11, 2012

Certified by:

Handwritten signature of Ignacio J. Pérez-Arriaga.

.....
Ignacio J. Pérez-Arriaga
Visiting Professor, Engineering Systems Division
Thesis Supervisor

Certified by:

Handwritten signature of Richard L. Schmalensee.

.....
Richard L. Schmalensee
Professor of Economics and Management
Thesis Supervisor

Accepted by:

Handwritten signature of Joel P. Clark.

.....
Joel P. Clark
Professor of Materials Systems and Engineering Systems
Acting Director, Technology & Policy Program

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Xiang Ling Yap

Submitted to the Engineering Systems Division
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ABSTRACT

New technologies such as distributed generation and electric vehicles are connecting to the electricity distribution grid, a regulated natural monopoly. Existing regulatory schemes were not designed for these new technologies and may not provide distribution companies with adequate remuneration to integrate the new technologies.

To investigate how regulation should change in the presence of new technologies, current regulatory schemes and possible improvements to make them suitable for new technologies are reviewed. A Reference Network Model capable of calculating the costs of building a distribution network is utilized to compare the costs of accommodating different penetrations and locations of distributed generation. Results for residential generators with a 3 kW/unit power output show that as the penetration of generators among residential customers increases, costs initially decrease but then increase at higher penetration levels. A comparison of results for residential generators with results for distributed generator conurbations located far away from customers shows that residential and far away generators require similar investment costs when total distributed generation power output is lower than effective customer demand. However, when total distributed generation power output exceeds effective demand, residential generators necessitate higher investment costs than far away generators. At all levels of distributed generation power output, residential generators imply lower losses costs than far away generators.

A second Reference Network Model capable of calculating the costs of expanding an existing distribution network is utilized to compare the costs of expanding a network to accommodate new technologies under different technology management approaches. Results show that network investment costs are lower for an actively managed network than for a passively managed network, illustrating the potential benefits of active management.

Based on an analysis of the modeling results and the regulatory review, an ex ante schedule of charges for distributed generators that incorporates forecast levels of DG penetration is suggested to improve remuneration adequacy for the costs of integrating distributed generation. To promote active management of distribution networks, measures such as funding pots, outputs-focused

regulatory schemes, and regulating total expenditure rather than separating the regulation of capital and operating expenditure are selected as proposals.

Thesis Supervisor: Ignacio J. Pérez-Arriaga

Title: Visiting Professor, Engineering Systems Division

Thesis Supervisor: Richard L. Schmalensee

Title: Professor of Economics and Management

Biographical Note

Xiang Ling Yap grew up in Malaysia, Singapore, and Hong Kong. In 2004 she was awarded a scholarship to attend Lester B. Pearson College, a United World College in Canada. She graduated from Pearson College in 2006 with the International Baccalaureate diploma. She then moved to the US to attend Harvard University, where she completed a Bachelor's degree with a primary concentration in Engineering Sciences and a secondary concentration in Economics. While at Harvard, she was awarded a Herchel Smith Fellowship to conduct laboratory research at MIT's Research Laboratory of Electronics.

During university Xiang Ling interned at The Technology Partnership plc, where she wrote a report on electric grid modernization in the US and UK and developed a deep interest in "smart" electric grids. This report came to the attention of the co-directors of MIT's Future of the Electric Grid study and led to her conducting research for the study during the final year of her undergraduate studies.

After receiving her Bachelor's degree, Xiang Ling began a Master of Science degree in Technology and Policy at MIT and continued working for the Grid Study until the end of her first year at MIT. She was also awarded funding from the Instituto de Investigación Tecnológica (IIT) and the MIT-Spain Program, part of the MIT International Science and Technology Initiatives (MISTI) to research electric grid regulation at IIT in Spain. Her work on the Grid Study and in Spain motivated this study to explore issues in electric distribution grid regulation.

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Introduction

The ongoing introduction of new technologies such as distributed generation and electric vehicles makes new demands on electric grids. Many of these technologies are connected to the electric distribution grid, a regulated natural monopoly, so distribution grid companies and their regulators must ensure the appropriate investments in infrastructure and operations are made to accommodate the new technologies. But existing schemes for economic regulation of the distribution grid were not designed for the widespread integration of these new technologies. They may not provide distribution companies with sufficient remuneration to integrate the new technologies. This study addresses the question: how should distribution grid regulation change in the presence of new technologies?

To provide background on existing distribution regulation schemes, the study will begin by introducing the regulation of the natural monopolies in distribution grids. The need for and goals of distribution grid regulation will be introduced along with the common regulatory schemes in use today and their advantages and disadvantages. Regulatory issues especially pertinent to distribution grids such as the regulation of losses and quality of service will be discussed. Subsequently, the study will take a three-step approach to developing proposals for better regulation.

In the first step, the study will build on the introductory discussion of regulation to analyze several areas in which conventional regulatory schemes are inadequate to regulate the integration of new technologies. It will then review new methods that are emerging or have been proposed to regulate the distribution grid in the presence of new technologies.

In the second step, the study will employ two types of Reference Network Model (RNM) to determine the costs of integrating new technologies. The models will be used to calculate the distribution grid investment and losses costs necessary to accommodate various combinations of new technologies and different technology management approaches. The investment and losses cost trends will provide valuable insights as to how regulation of remuneration ought to change under different scenarios.

In the third step, the study will consider how, once costs have been determined, the payments needed to remunerate the companies should be allocated among different customer groups and the money recovered from them. The interaction between regulation of cost allocation and recovery and regulation of remuneration, or total allowed revenue, will be

discussed. Cost recovery methods in use for distributed generation will be reviewed and several additional methods will be suggested and detailed.

Finally, the review of regulatory methods for new technologies, the results from the modeling analyses and the discussion of remuneration and cost recovery issues will be combined to select, develop and support appropriate regulatory proposals.

Chapter 1: Regulating Electricity Distribution

1.1 Why Regulate Electricity Distribution?

Electricity distribution is a natural monopoly. Several features of the distribution business characterize it as a natural monopoly: it is capital intensive, owing to the high cost of investment in network lines and equipment that are normally expected to last many years. When a distribution company has built and is operating the wires network in an area, it benefits from the lower costs of expanding its existing network to serve additional customers whereas a distribution company seeking to enter that market as a new entrant would experience the higher costs of building its own network from scratch to serve the same customers. There is also a social cost to having more than one distribution company in an area since such a situation implies multiple parties constructing overhead and underground physical lines, causing public inconvenience and possibly disrupting everyday business in the area. Thus, a single company holds a natural monopoly on building and operating the electricity distribution network in the area it serves. As in all monopolies, the danger exists that the monopolist will raise prices above the socially efficient level since there is no competitive pressure to lower prices.

Regulation of the natural monopolies in electricity distribution can have many goals; three important ones that are particularly pertinent to this study are described here. The first could be described as economic sustainability: The regulator attempts to ensure that the distribution company is remunerated by a total revenue amount, via the prices charged for its electricity distribution service, that is sufficient to finance its operations, obtain a suitable rate of return, and survive as a business while providing an acceptable level of quality of service. A good regulatory scheme aims to provide adequate remuneration while simultaneously incentivizing the company to improve cost and operating efficiency. Regulation should also help insure the company is not overcharging customers to obtain an unreasonable level of profits. A second, closely related goal is service quality in itself: The regulator has to allow sufficient remuneration to maintain acceptable service quality, as described above. Regulators may employ additional targets, incentives, or penalties to ensure that the necessary investments are made to provide an acceptable level of quality of service. Because distribution grid quality of service and losses are particularly pertinent for electric distribution grids integrating new technologies, this goal is discussed separately from the first one and detailed later in this chapter. A third goal is equity: The regulator attempts to allocate the costs of the grid equitably among grid users

(customers) so that the costs of electricity distribution are recovered in a fair manner from them via the appropriate tariffs.

Regulators employ a variety of regulatory schemes to achieve the first goal, allowing an appropriate level of remuneration. Two of the most important schemes in electricity distribution regulation are cost of service regulation and incentive regulation. Cost of service regulation is now mostly used in the US and incentive regulation is mostly used in Europe, owing to a variety of historical factors. Both schemes are detailed later in this chapter but in brief, cost of service regulation attempts to remunerate companies for the prudent costs incurred in providing distribution service while incentive regulation caps the price or revenue companies may charge or recover, in such a way that companies are encouraged to improve cost efficiency.

Cost of service and incentive regulatory schemes do not come without drawbacks. One problem common to both schemes is information asymmetry between the regulator and the regulated firm. The regulator does not know what the most efficient costs of the regulated firm should be, so the regulatory process may allow a rate of return higher than what is socially efficient. Other drawbacks are inherent to the different designs of the schemes. Cost of service regulation can provide an incentive for companies to overinvest in capital so as to earn higher returns, whereas incentive regulation can provide an incentive for companies to cut costs below the socially efficient level necessary to provide acceptable service. This chapter will describe the development, application and drawbacks of both cost of service and incentive regulation, with examples drawn from the countries where they are used.

The second goal of regulation, ensuring an acceptable level of service, largely relates to regulating two technical aspects of electric distribution grid systems: losses and quality of service. It can be challenging to ensure the appropriate investments are made to reduce line losses in the process of electricity distribution and quality of service problems such as interruptions in electricity service. The distribution company has to be incentivized, for example through targets and rewards, to make the appropriate investments to mitigate these issues. When new technologies connect to the grid, they can have positive and negative effects on losses and quality of service. For example, the variable power output and demand of distributed generators and electric vehicles may affect quality of service negatively. But distributed generation may also help to reduce upstream losses in the electric grid. A more detailed discussion of these issues can be found later in this chapter and in Chapter 2.

Regulatory schemes can differ in their approach to achieving the third goal, equitable cost allocation and recovery. Regulators may allow the recovery of costs from different types of customers, such as residential or industrial customers, using tariffs that reflect the different costs to the distribution company of serving these customers. When new technologies connect to the grid, they may have positive or negative effects on distribution companies' costs, which makes it more difficult to allocate the costs appropriately among technology owners and network customers and recover the costs from them in a fair and consistent manner. Therefore, new technologies pose new problems in cost allocation and recovery which are discussed in Chapter 4.

1.2 Cost of Service Regulation

Regulators must decide how much remuneration a regulated company should be allowed to recover via its prices. Since distribution companies are natural monopolies it is generally not possible for a regulator to aim for an outcome representative of price equaling marginal cost (MC), the competitive outcome, as MC is lower than average cost and the company would not have sufficient revenue to cover its costs, as shown in Figure 1.

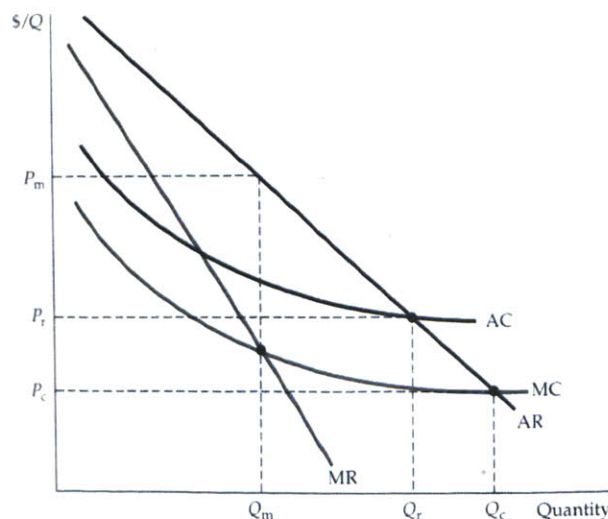


Figure 1. Regulation of natural monopoly diagram, showing firm theoretical average cost (AC) and marginal cost (MC) curves. The firm average revenue (AR) and marginal revenue (MR) curves are also shown. Regulation can move the quantity sold from the monopoly quantity Q_m to the regulated quantity Q_r but not Q_c , the quantity under perfect competition as this will not permit the company sufficient remuneration. *Source: Pindyck and Rubinfeld, Microeconomics (1992), p. 352.*

The regulator should attempt to set price as close to average cost as possible. In electricity distribution, the classic approach used to achieve this is termed cost of service regulation (also known as rate-of-return or cost-plus regulation) and it still applies in many states of the US today.

1.2.1 Cost of Service Regulation: Determining Allowed Revenue

To determine allowed revenue under cost of service regulation, the regulator may utilize the regulated company's accounting and cost information in combination with his own regulatory judgment. For example, the regulator may utilize information provided by the company concerning its assets and operating and maintenance costs in a past year, and its capital expenditure to provide service to its service territory. The regulator then allows the company a rate of return on its investments that covers the costs deemed prudent. The rate will also be adjusted to allow the company reasonable profits, using regulatory judgment and firm and industry information on profit levels. Crew and Kleindorfer give a general formula for the allowed revenue under cost of service regulation:

$$R = O + s(V-D)$$

where R is revenue requirements, O is operating expenses, including current depreciation, s is the allowed rate of return, V is the gross value of utility's property (rate base), and D is the accumulated depreciation (1986, 98). It is worth highlighting that the rate of return s is applied on the whole term V-D, or the rate base less depreciation, and that the rate base may include original and new assets as allowed by the regulator.

The regulator exercises judgment over the allowed rate of return s, what to include in the rate base V, and the depreciation value D to use. In the US, the rate of return set by the regulator is generally reviewed when the utility brings a rate case to the regulatory commission. This usually occurs when a rate increase is sought to cover an increase in expenditure by the distribution company. In the US, the state regulators of distribution companies (or distribution utilities) are often called Public Utility Commissions (PUCs), but regulator names and acronyms vary across US states.

Information asymmetry occurs in cost of service regulation when the regulator has to decide if the company's spending has really been prudent and if it should be allowed to recover those costs. It can be difficult to know if the most cost-effective investment was made in a given situation so that cost recovery should be permitted through the total allowed revenue.

1.2.2 Cost of Service Regulation Problems: Overinvestment

Cost of service regulation has been criticized for facilitating overinvestments, because the distribution company is guaranteed a rate of return on their capital and has no incentive to cut spending. As a result, the cost of service-regulated company will invest in capital even when doing so is not efficient, and operate at an inefficient level of production (Crew and Kleindorfer 1986, Averch and Johnson 1962). The overinvestment is formally known as the Averch-Johnson effect.¹

When the regulated firm maximizes profit under the cost of service regulatory constraint, it generally does not minimize its costs. The regulator sets an allowed rate of return on capital. When the firm's effective cost of capital is less than this allowed rate of return, the firm can increase its total returns by increasing capital investments. The optimal profit-maximizing solution is for it to substitute capital for labor by overinvesting in capital and increasing the level of production, as elaborated in Crew and Kleindorfer (1986).

1.2.3 Cost of Service Regulation Problems: Cost Allocation and Recovery

Once allowed remuneration for distribution network costs has been determined by the regulator according to cost of service principles, the network costs have to be allocated among network users and money recovered from them to remunerate the distribution company. Costs may be allocated by the function of the grid utilized (transmission, distribution etc.) or among different classes of customers (residential, industrial). An equitable solution would be to allocate costs to users of the grid in proportion to their responsibility for the costs, although doing this is difficult.

Cost recovery encompasses two main issues: ensuring the amount of money actually recovered is the same as the regulator's allowed remuneration, and deciding the format of the prices charged to collect the money from customers. The format of the prices charged can vary widely; one-time lump sum charges and network tariffs involving fixed and variable charges are a few examples of methods that can be used. The design of tariffs can be complex and is an area of academic research and regulatory innovation. In the US in particular, the recovery of fixed distribution network costs is primarily achieved by volumetric energy charges (Environmental Protection Agency 2007). This creates a cost recovery situation where fixed costs are recovered

¹ A full derivation and formulae may be found in Crew and Kleindorfer (1986, 121).

by a charge that varies with energy demand. Especially in the long run, this cost recovery method can distort companies' incentives to support some new technologies that reduce energy demand like distributed generation. A fuller discussion of problems with cost recovery methods can be found in Chapter 4.

1.2.4 Addressing Problems: Performance Based Regulation

Performance based regulation is an umbrella term that has been applied to a variety of reforms undertaken to improve cost of service regulation in the US. A 1997 review for the National Association of Regulatory Utility Commissioners (NARUC) defines this term very broadly to include penalty/reward regulatory schemes for quality of service as well as price or revenue caps (Synapse Energy Economics for National Association of Regulatory Utility Commissioners 1997).

The performance based regulation discussed in this study primarily relates to regulatory measures targeting improvements in the operational performance of the distribution network. An example of performance based regulation is targets for quality of service, with rewards for exceeding the targets and penalties for missing them. The application and extent of such performance based regulation varies widely across US states and even between distribution companies in the same state. Performance based regulation may also be expanded to include metrics that support the integration of new technologies.

Case study: The US and deregulation

Cost of service regulation remains widely used in US electric utilities, despite the drawbacks that have led to its phasing out in Europe. Many European (and other) countries moved from cost of service to incentive regulation following the unbundling of their electricity generation and retail sectors from the network activities, and that transition is discussed later in this chapter. Because the application of cost of service varies so widely among US states, several states' regulatory systems are summarized in Table 1. Significant points regarding each state are discussed in the following text.

Table 1. Distribution regulations in several US states

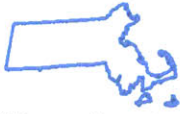




	 Massachusetts	 Florida	 Maine	 Texas	 California
<i>Cost of Service and/or Other</i>	<ul style="list-style-type: none"> • Cost of Service (CoS) with rate cases • Performance Based Rates (PBR) 	<ul style="list-style-type: none"> • CoS 	<ul style="list-style-type: none"> • CoS • Alternative Rate Plans (ARP) 	<ul style="list-style-type: none"> • CoS 	<ul style="list-style-type: none"> • CoS
<i>Rates and rate structure</i>	<ul style="list-style-type: none"> • CoS ratemaking • PBR adjusts rates for inflation, productivity 	<ul style="list-style-type: none"> • Rate design depends on forecast sales 	<ul style="list-style-type: none"> • Rates generally depend on kWh sold • Under ARP, rates are adjusted annually for inflation, productivity 	<ul style="list-style-type: none"> • CoS ratemaking 	<ul style="list-style-type: none"> • CoS ratemaking • Tiered rates; vary by utility and take seasonal demand into account
<i>Reviews of remuneration outside rate cases</i>	<ul style="list-style-type: none"> • Annual true-ups to review recovery of stranded costs through transition charge • Annual true-ups also include review of costs and rates (large capex is not mentioned) 	<ul style="list-style-type: none"> • Cost Recovery Clauses provide annual review for utility costs • Cost Recovery Clauses increasingly being used for capital expenditure 	<ul style="list-style-type: none"> • ARP allows for annual review of rates 	<ul style="list-style-type: none"> • True-ups for stranded costs • Distribution Cost Recovery Factor proceedings for capex 	<ul style="list-style-type: none"> • True-ups for revenue and cost discrepancies
<i>Quality of service</i>	<ul style="list-style-type: none"> • Quality standards apply; penalties and rewards 	<ul style="list-style-type: none"> • Quality standards apply; penalties only 	<ul style="list-style-type: none"> • Quality standards apply; penalties only 	<ul style="list-style-type: none"> • Quality standards apply; penalties only 	<ul style="list-style-type: none"> • Quality standards apply; penalties and rewards

Table 1. (continued)

	Massachusetts	Florida	Maine	Texas	California
<i>Energy efficiency and conservation</i>	<ul style="list-style-type: none"> Decoupled. Requires utilities to file decoupled rate plans, mostly by 2012. Efficiency performance incentives. 	<ul style="list-style-type: none"> Studying decoupling. 2008 report to legislature. 	<ul style="list-style-type: none"> Experimented with revenue cap in 1990s. No decoupling now. 	<ul style="list-style-type: none"> Efficiency performance incentives. 	<ul style="list-style-type: none"> Decoupled. Tiered rates. Efficiency performance incentives.

Sources: Commonwealth of Massachusetts Department of Public Utilities (2007), Executive Office of Housing and Economic Development and Executive Office of Energy and Environmental Affairs (2011), U.S. Energy Information Administration (2010), Florida Public Service Commission (2008), Maine Public Utilities Commission; Office of Energy Independence and Security (OEIS); Office of the Public Advocate (OPA) (2008), Maine Public Utilities Commission (2009, 2010), Window on State Government (2012), Public Utility Commission of Texas (2005, 2006, 2011), California Public Utilities Commission (2009, 2010, 2012), Edison Electric Institute (2005), Institute for Electric Efficiency (2010).

The unbundling process that occurred in Europe to open electricity retailing and generation to competition resembles the deregulation process in the US in some ways, but differs in some other important respects. The electric power sector in many US states underwent restructuring and liberalization (also called deregulation) in the 1990s.² As part of deregulation, electricity generation was separated from the transmission and distribution grid businesses to allow competition in generation. In some places like Texas, retail electricity supply was also separated to permit competition in retailing. However, in other places, retail and distribution continue to be integrated or ‘bundled’ together in the same business.

Deregulating parts of the electric power sector permitted the relevant electricity prices to be determined by the market. Where deregulation occurred, the distribution “wires” business, involving the installation and operation of the wires that transmit electricity, remained a regulated natural monopoly. In the discussion that follows for five US states, the status of

² An overview of the history of the US power sector is available in Holland and Neufeld (2009). The US Energy Information Administration’s latest data on electricity restructuring is available at: http://www.eia.gov/cneaf/electricity/page/restructuring/restructure_elect.html although as of April 2012, the most recent data was dated September 2010.

electric power sector deregulation is noted. Many formerly integrated US electric utilities were also allowed to recover stranded costs for their generation assets when these were separated from the distribution wires business during deregulation. Stranded cost recovery compensates the company by an amount meant to be equal to the company's loss of income due to deregulation. Because stranded costs principally relate to generation assets and not the distribution wires business, they are not discussed further here. Deregulation was halted in many areas following the California electricity crisis of the 1990s, when only partial deregulation combined with manipulation of the energy markets led to price spikes in the wholesale market and to some electricity companies declaring bankruptcy.

In Massachusetts, a deregulated state with retail choice as of 2010, pure cost of service regulation administered by the Department of Public Utilities coexists with a different method called Performance Based Rates (PBR). Under PBR, rates are determined by a cost of service procedure but then adjusted for productivity, inflation, etc. PBR thus resembles incentive regulatory schemes that adjust the price or revenue cap for inflation. Additional quality standards apply to the electricity and gas industries in Massachusetts. In addition, electric utilities recover their stranded costs via an annual "true-up" proceeding with the Department. (Commonwealth of Massachusetts Department of Public Utilities 2007).

In Florida, a regulated state with no retail choice as of 2010, cost of service regulation is applied to determine each utility's allowed revenue. In addition to the base rates utilities are allowed to charge to recover allowed revenue, "Cost Recovery Clauses" allow each utility to have additional expenses reviewed and recovered on an annual basis.³ A 2008 report by the Florida PSC found that 53-69% of utilities' costs are recovered via Cost Recovery Clauses. It was also found that capital expenses are increasingly being recovered through Cost Recovery Clauses instead of base rates, even though Cost Recovery Clauses were originally intended to allow recovery of more frequently fluctuating expenses (Florida Public Service Commission 2008).

³ "Cost Recovery Clauses" are used along with base rates in Florida to provide utilities with cost recovery for expenses. The base rates are determined during the rate case, while Cost Recovery Clauses (in theory) allow for an annual review of utility expenses to allow recovery of, "fuel costs, purchased power costs, costs associated with encouraging energy conservation, costs of complying with governmentally mandated environmental programs and standards, and costs of new nuclear power plants" (Florida Public Service Commission 2008, 3). However, as discussed in the text, they have been used to recover other types of costs as well. As such, their scope is greater than a stranded cost true-up proceeding.

In Maine, a deregulated state with retail choice as of 2010, distribution rates are regulated by the Public Utilities Commission. Two major electricity companies experimented with an Alternative Rate Plan (ARP) beginning in 2000. The ARP, under which rates charged are determined based on inflation and previous rates, represents a shift away from cost of service to incentive regulation of prices. The Central Maine Power Company requested a new ARP to begin in 2008, but the Bangor Hydro Electric Company did not propose that theirs be continued after expiration in 2007 (Maine Public Utilities Commission 2010, Maine Public Utilities Commission 2008).

In Texas, a deregulated state with retail choice as of 2010, distribution utilities continue to have their rates regulated under cost of service regulation. Both true-up proceedings and Distribution Cost Recovery Factor (DCRF) proceedings are allowed for under Texas law. A true-up proceeding allows utilities to recover stranded costs, whereas a DCRF proceeding allows utilities to file once per year to recover capital expenses on distribution systems outside of a normal ratemaking (Public Utility Commission of Texas 2005, 2011, 2006).

In California, where deregulation and retail competition were suspended as of 2010, distribution rates are regulated by the Public Utilities Commission under cost of service regulation (California Public Utilities Commission 2012). However, the PUC defines a baseline electricity allowance (kWh/day) and then defines several tiered rates for usage above the baseline for each distribution company (California Public Utilities Commission 2009). The higher rate tiers are applied to the corresponding amounts of electricity used above the baseline, which encourages energy saving by customers. For example, PG&E charges the Tier 1 price for usage up to the baseline, but then is permitted to charge the Tier 2 price for usage from 101%-130% of the baseline, and the Tier 3 price for usage from 131%-200% of the baseline (California Public Utilities Commission 2010).

1.2.5 Developing Incentive Regulation

As the worldwide electric industry developed, observers began to question the efficiency of vertically integrated monopoly distribution companies. It was thought that competition, which might lead to improved efficiency, could be introduced into some parts of the sector⁴. Beginning in the 1980s, some countries – notably the UK (1990) and Chile (1981) – began to explore

⁴ Newbery (1999) provides additional background on the introduction of competition to formerly vertically integrated sectors, including electricity.

electric power sector reform. The academic – and first President of the British Energy Regulatory Commission – Stephen Littlechild was responsible for key ideas that drove the regulatory reforms in electricity networks that began in the UK in 1990 (Vogelsang 2002).

The UK reforms permitted private companies to compete in the generation of electricity, and the retail of electricity to end customers. In some ways these reforms were the precursor to deregulation in the US. Through the 1990s, the UK reforms were adopted throughout other European Union member states. Littlechild, who became the UK electricity regulator, developed incentive regulation to regulate the network businesses that emerged from the reforms. Incentive regulation was initially used in telecommunications and then in the electric power sector following privatization. Incentive regulation operates by capping prices or revenues and providing incentives to companies to operate more efficiently, reduce costs or make other service improvements. In the UK after privatization, the initial goal of incentive regulation was to maximize the cost efficiency of the new distribution companies. The following discussion treats incentive regulation in detail, with particular focus on the experience in the UK. In the US, the similar process of deregulation was intended to transition electricity generation and retail sectors from monopoly to competition. However, in the wake of the California electricity crisis of 2001, some of these reforms were rolled back or placed on hold.

1.3 Incentive regulation

Incentive regulation is also an umbrella term referring to regulatory schemes that incentivize regulated firms to operate in socially efficient ways. Examples of incentive regulation include price cap regulatory schemes, revenue cap regulatory schemes, and yardstick regulatory schemes. Both price cap and revenue cap schemes are often known as “RPI-X” schemes, after the first price cap scheme introduced in the UK in 1990.

1.3.1 Price and Revenue Caps - RPI-X

RPI-X is the name given to the incentive regulation scheme developed in the UK by the academic Professor Stephen Littlechild (Helm 2003). Under RPI-X, each regulated company’s revenues or prices are capped for a regulatory period and indexed to a measure of economic inflation (in the UK, the Retail Prices Index, or RPI) to recognize the impact of inflation on real

revenues, less an adjustment factor X. Following Joskow (2006, 20) a basic RPI-X equation can be given as:

$$P_t = P_{t-1}(1+RPI-X)$$

If revenue and not price is capped, the equation is rewritten:

$$TAR_t = TAR_{t-1}(1+RPI-X)$$

The regulator chooses whether to cap revenues or prices. There is significant scope for different implementations of the caps. For example, the basket of prices being capped can vary: only the prices charged for specific metering activities could be capped, or the prices for all distribution services could be capped. It is notable that capping electricity prices gives the firm an incentive to increase the volume of electricity sold instead, to maximize revenues. Therefore the firm regulated under price cap does not have any incentive to reduce energy consumption for greater environmental sustainability. Revenue caps avoid this perverse incentive. The remainder of this discussion assumes that RPI-X regulation refers to a revenue cap.

Under RPI-X revenue cap regulation, the regulator determines the “total allowed revenue” (TAR) that the firm is allowed to earn to cover its costs and asset depreciation by establishing the firm’s costs and valuing the “regulated asset base” on which the company may earn a return. Costs may be benchmarked against comparable firms to reduce information asymmetry. The TAR is set for the next B years, where B is the length of the regulatory period, and is then indexed to the RPI-X term. The “RPI” factor ensures inflation is taken into account, and “minus adjustment factor X” equalizes the present value of revenues with the present value of costs over the regulatory period B. The X factor may also be determined through benchmarking against comparable companies. Supplementary measures may also be added to the regulatory scheme, for example to incentivize socially desirable investments on the part of the regulated firm such as investments to improve service quality or decrease distribution network losses.

During the regulatory period, the allowed revenues are allowed to increase (or decrease) as the RPI increases (or decreases), but adjusted by X so that the actual rate of change of revenues becomes RPI-X. X is generally a positive number so that, as long as the value of RPI does not change much and RPI remains positive and larger than X, the amount of allowed revenue decreases (until the end of that regulatory period). As long as companies’ costs are lower than the revenue cap as adjusted by the RPI-X term, the company makes a profit. This

demonstrates the chief advantage of the RPI-X regulatory scheme: it mitigates the incentive firms regulated under cost of service have to overspend on total investments by rewarding cost efficiency.

Figure 2 provides a graphical representation of how a company might behave under a revenue cap regulatory scheme with a 6-year regulatory period. At the beginning of the regulatory period, the regulator caps revenue at a given level and thereafter decreases the cap (as linked to RPI-X) to encourage the company to decrease its costs as well. The company will initially try to decrease costs as much as possible to capture the profit between the cap and its costs. But as the next regulatory period nears, the company has less incentive to decrease its costs because if its costs are “too” low, the regulator may decide to set the next cap even lower. If an efficiency improvement is made towards the end of the regulatory period that reduces costs, the company will only enjoy the cost reduction for a short time and may not even recover the costs of implementing the improvement. Hence companies may reduce their costs less towards the end of the regulatory period, as shown.

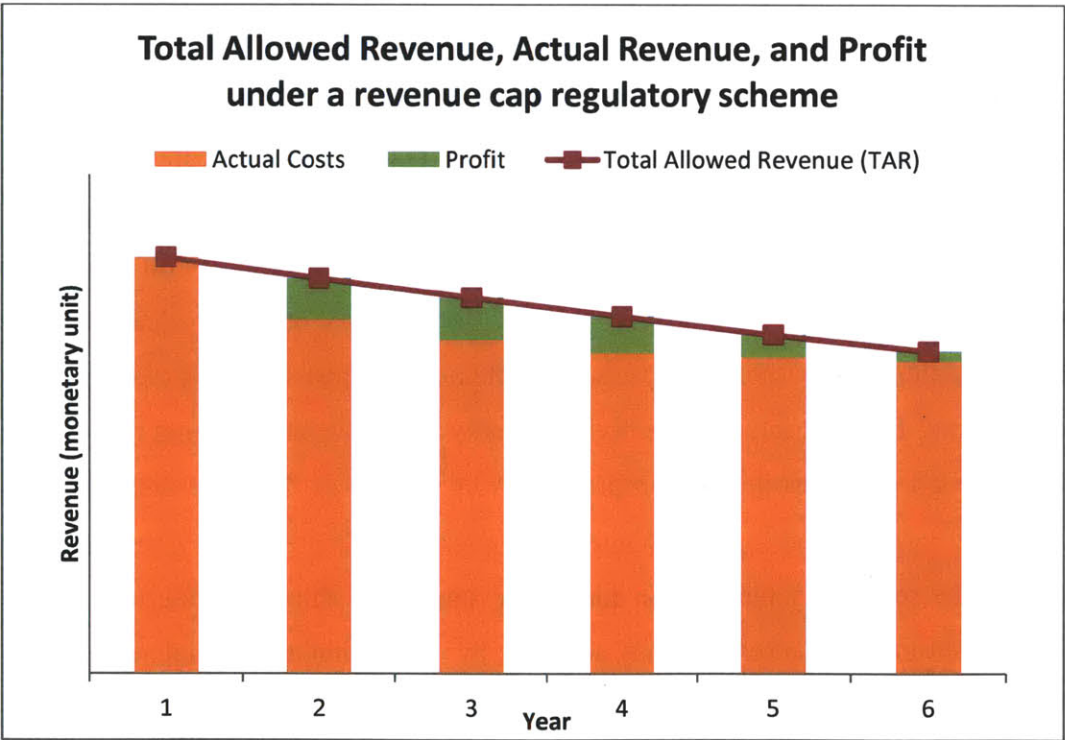


Figure 2. Demonstrating RPI-X

As noted in the UK, which was the first country to adopt this regulatory scheme, after some time companies may be unable to decrease costs further because they have reached an “efficiency frontier” where no further cost efficiency improvements can be made. Ofgem’s 2009 review, “Performance of the Energy Networks under RPI-X”, noted that under its then existing implementation of RPI-X, “Companies continue to have incentives to reduce costs, for example through the adoption of new business models, but the scope for further large-scale reductions may be limited” (2).

1.3.2 RPI-X Regulation Problems: Inefficient Investment Behavior

In the absence of any supplementary measures, pure RPI-X incentive regulation may over-incentivize cost efficiency resulting in a lack of necessary investment in distribution networks. Since implementing RPI-X encourages companies to reduce their costs, it has to be utilized in conjunction with supplementary measures to ensure that investments are still made to keep quality of service and network losses at socially optimal levels. Some frequently used supplementary measures are targets for quality of service and losses, with penalties and rewards for missing or achieving above the targets. Companies regulated under RPI-X may also forego investment in R&D to reduce their costs. R&D funding pots and R&D mandates are examples of supplementary measures that may be utilized to address this. Finally, since regulated companies are assured of keeping savings from cost efficiencies only until the end of the price control period, RPI-X may encourage a focus on short-term cost efficiencies. Companies will prefer reducing operational expenditure for short-term savings to reducing capital expenditure for long-term savings. A rolling incentive has been used in the UK to mitigate this by allowing companies to keep their savings from capital expenditure reductions for a fixed number of years – so if the reduction occurs close to a price control review, they may roll over the years into the next price control period (Office of Gas and Electricity Markets (Ofgem) 2009).

Cost allocation and recovery under incentive regulation does not give rise to the same issues as under cost of service regulation. Since the revenue or price cannot exceed the cap set under incentive regulation, the company has a much more limited incentive to gain revenue by selling more electricity.

Case study: UK electricity distribution

The following case study describes some salient features of the UK experience with RPI-X regulation in electricity distribution, and outlines some measures applied in the UK to deal with the aforementioned problems of incentive regulation. Many countries that privatized their electricity sectors followed the UK's example and adopted a RPI-X method of regulation, adapting the basic RPI-X regulatory scheme as necessary for their country. For example, in Ireland the allowed revenue is indexed to the Harmonised Consumer Price Index (HCPI) instead of RPI, and in the Netherlands a Q-factor is added directly to the RPI-X equation to incentivize companies to improve their quality of supply (Commission for Energy Regulation (CER) 2010, Energiekamer 2010).

Electricity distribution in the UK was privatized following the Electricity Act 1989. The RPI-X regulatory scheme was applied to the resulting distribution industry, consisting of 12 Regional Electricity Companies (RECs) and 2 Scottish companies. In 2001 these 14 companies became the 14 Distribution Network Operators (DNOs) with licenses to distribute electricity in the UK, and provisions under the Utilities Act 2000 allowed for additional distribution licenses to be granted to independent DNOs (Office of Gas and Electricity Markets (Ofgem) 2009).

Since privatization, each distribution company has been regulated under RPI-X. The first price control was applied at privatization in 1990 and has since been revised every 5 years by the regulator, the Office of Gas and Electricity Markets (Ofgem). As described above, at each review the allowed revenue and efficiency factor is set by the regulator using information available on the companies and industry. RPI-X has so far performed well: in 2009 Ofgem noted that RPI-X had reduced the allowed revenues in electricity distribution by 60% since privatization, that evidence suggested a decrease in operating expenditure (i.e. an increase in operating efficiency) over the same period, and that additional regulatory incentives for quality of service had improved service (Office of Gas and Electricity Markets (Ofgem) 2009).

Over the years, the UK refined RPI-X to remedy fundamental challenges faced by the regulator, as well as address some of the scheme's inherent disadvantages. For example, incentive regulators still face the classic problem of information asymmetry: the regulator does not know the true capital costs of the regulated firm, so determining the socially optimal allowed revenue is challenging. Ofgem's Information Quality Incentive (IQI), introduced in the fourth distribution price control review in 2004, provides an incentive for firms to reveal their true costs

to the regulator (P. L. Joskow 2006, Pollitt and Bialek 2007, Office of Gas and Electricity Markets (Ofgem) 2004). Under this ““menu” of sliding scale mechanisms” (P. L. Joskow 2006, 25-26), an external consultant is employed to calculate the required capital expenditure for each firm to provide Ofgem with a reference calculation against which to compare the firm’s spending plan. Firms that select a revenue amount closer to the consultant’s assessment, and then underspend (thus beating the target) are allowed to keep more of their savings as profit. Firms that select a revenue amount higher than that estimated by the consultant and then underspend are allowed to keep less of their savings. This incentivizes companies that can beat the target to select a lower revenue amount to retain more savings as profit, thus keeping the efficiency incentive, while allowing companies nearer the efficiency frontier to have higher allowed revenues.

RPI-X’s focus on cost efficiency could lead companies to cut costs at the expense of service quality. To prevent this, quality of supply incentives were introduced to the regulatory scheme in 2002 in addition to the existing quality regulations such as Guaranteed Standards of Performance (GSOP) (Office of Gas and Electricity Markets (Ofgem) 2006, 2009). Ofgem’s 2009 review of RPI-X noted that industry performance on metrics such as the reported number and duration of customer interruptions had improved by 11% and 26% since the incentive was introduced (Office of Gas and Electricity Markets (Ofgem) 2009, 19).

RPI-X does not provide companies with incentives to make large capital expenditures, owing to its focus on reducing costs. In the UK this issue is particularly pertinent given the investments that will soon be needed to upgrade the electricity grid to integrate renewable electricity sources and meet national and EU carbon emissions targets (Department of Energy and Climate Change (DECC) 2011). In transmission, the UK regulator made an effort to address this issue through a very large capital expenditure allowance of £4.6 billion (a 100% increase over the past allowance) at the most recent transmission price control review (Office of Gas and Electricity Markets (Ofgem) 2006). More fundamental changes to the regulatory scheme for electricity and gas are being made as a result of 2009’s RPI-X@20 review and are discussed in Chapter 2 (Office of Gas and Electricity Markets (Ofgem) 2010).

Finally, RPI-X does not encourage investments in R&D, particularly in R&D with uncertain returns. This encourages conservatism in distribution companies and a lack of innovation. The UK regulator addressed this problem by adding an innovation funding incentive

(effective from 2005) and a Low Carbon Networks fund (effective from 2010) to the RPI-X regulation.

1.3.3 Benchmarking

Benchmarking is comparing a firm's performance on a metric (such as efficiency) against a reference value such as the performance of other firms on that metric. It can be one of a number of tools that regulators employ to mitigate the problem of information asymmetry when applying incentive regulation. It can also be the basic principle driving the regulatory scheme, as it is in yardstick regulation. In this section, benchmarking's use as a valuable input tool for incentive regulation will be discussed. Yardstick regulation is discussed in a later section.

Many different benchmarking methods exist. Benchmarking can be divided into frontier benchmarking (comparing a regulated firm to a 'best' firm: a firm on the 'efficiency frontier'), or average benchmarking (comparing a regulated firm to the average of all comparable firms (Jamasp and Pollitt 2001). Second, benchmarking methods may be econometric or have their roots in technical engineering models.

The following discussion draws upon Jamasp and Pollitt (2001). Frontier benchmarking methods include corrected ordinary least squares (COLS), data envelopment analysis (DEA) and stochastic frontier analysis (SFA). All three methods are detailed in Jamasp and Pollitt (2003). Jamasp and Pollitt (2001) conduct an international survey of benchmarking methods in use and Giannakis, Jamasp and Pollitt (2005) apply DEA to the UK electricity distribution utilities.

Average benchmarking methods include using ordinary least square (OLS) estimation for the cost function, using the average cost of a group of firms, and using total factor productivity (TFP) as the benchmark. Sliding scale mechanisms as applied in performance based regulation (PBR) in the US can also be seen as a form of average benchmarking, whereby the rate of return can vary within the dead band and the target return is determined by comparing the average performance of firms (Jamasp and Pollitt 2001).

Finally, reference network models as used in Spain, or Network Performance Assessment Models (NPAM) as used in Sweden, can be seen as another form of benchmarking that takes account of the technical engineering parameters of the electric grid (Jamasp and Soderberg 2010). A more detailed description of these models as used in regulation follows.

1.3.4 Reference Network Models (RNMs)

As their name implies, reference network models (RNMs) provide regulators with a “reference network” (like a benchmark) against which to compare regulated firms’ actual networks. A model is not a regulatory scheme; instead, it is a way for the regulator to estimate and compare network costs in order to apply a regulatory scheme. As Jamasb and Pollitt (2008, 1794) note in their study of Sweden’s use of such models, the models can thus be considered a form of “individual benchmarking” when a separate reference network is created for each firm.

The following is a brief description of the design and capabilities of RNMs. Several other papers (Jamasb and Pollitt 2008, Mateo Domingo, et al. 2010) go into greater technical detail on the models; the specific model later employed in this study is detailed in Chapter 3. The basic reference network model, called a “greenfield” model, designs an optimal distribution network from scratch using information on the electricity customers to be supplied by the network. The model works with a catalogue containing technical and financial parameters for grid elements, such as the capacity and cost of substations, transformers, low voltage (LV), medium voltage (MV), and high voltage (HV) power lines. Given the GPS coordinates and demand profiles of the customers and the location and capacities of the electricity supply points (transmission substations), the model designs the lowest-cost required LV, MV, and HV networks with the requisite substations, transformers, and other grid elements selected from the catalogue. Because the catalogue contains cost information for the lines and grid elements, the model is able to output the total investment cost of the “greenfield” network it has built as well as the locations and sizes of the grid elements.

A second type of RNM is an expansion planning model, also called a “brownfield” model. This model takes the existing network as its input and calculates the incremental network (network expansion) required to meet electricity demand owing to new customers or new technologies. The input data to the “brownfield” model can be a network input by the user, or can simply be a network output by the “greenfield” model. In addition, the expansion planning model used in this study can take as input 24-hour electricity generation or demand profiles. This permits the modeling of distributed generation units as additional generation points that supply electricity to the network, with their generation levels varying as appropriate through the day. For example, a home solar panel unit could be modeled by giving it a generation profile that generates power during the day but does not generate at night.

In Spain, the RNM is used to calculate the costs for each distribution company so that the regulator can establish the appropriate remuneration for each firm (Comisión Nacional de Energía (CNE) 2009). The regulatory scheme includes additional incentives for quality of supply and losses and the regulatory period is four years.

In Sweden, a related type of reference network model called a Network Performance Asset Model (NPAM) is also used to “benchmark” companies, currently on an annual ex post basis. At the end of the year, the regulator compares the cost output by the reference model with the revenues of the actual network and investigates firms that deviate excessively from the reference. From 2012, the Swedish regulator will move to an ex ante review with a regulatory period of four years, similar to Spain (Energy Markets Inspectorate 2009). The regulators hope the change will facilitate fairer charges to customers. Also, Jamasb and Pollitt (2008, 1798) note that the current ex post approach is likely to result in higher regulatory uncertainty than the ex ante approach.

Following Jamasb and Pollitt (2008) and Jamasb and Soderberg (2010)’s examination of the Swedish application of these models in regulation, the remainder of this section is a review of the literature on general advantages and disadvantages of the use of reference models in regulation when compared to other benchmarking methods and when compared to an RPI-X incentive regulation applied without extensive use of such models.

According to Jamasb and Pollitt, the advantages of the modeling approach include its contribution to regulatory stability and the ability of the model to incorporate quality of service in its technical framework. Because the model approach benchmarks the firm against a reference version of itself, it increases regulatory stability. Quality of service costs are included when the model designs the reference network, allowing the regulator to assign a monetary value to quality when calculating allowed revenue. However Jamasb and Pollitt also say that in Sweden some of these advantages may be offset by the regulatory framework in which the model is used. The reference network’s contribution to regulatory stability could be undermined by the ex post framework which revises revenues only at the end of the regulatory period. For firms with lower quality of service, the annual ex post review encourages a focus on short-term performance and discourages the large capital investments over longer time periods that might be needed to improve quality of service (Jamasb and Pollitt 2008).

Jamasb and Pollitt (2008) also discuss more general shortcomings of the modeling approach. The model cannot easily reflect the complex range of options available to actual firms or the chronological development of their networks. As a result, long-term efficiency improvements requiring large short-term capital investments are more difficult for firms to justify. Jamasb and Pollitt note that the ex ante RPI-X scheme together with appropriate incentives can be more effective at stimulating long-term efficiency improvements, since in the UK application of that scheme, only opex and not capex is benchmarked. The version of the model discussed in Jamasb and Pollitt also cannot reflect the actual development of the network over time⁵, so it is not as effective as benchmarking against actual firms.

Another disadvantage of the model is that its approach does not encourage innovation since it cannot automatically take technology improvements into account. Whether or not the model is up to date depends on the regulator's ability and readiness to incorporate the technology improvements into the model. In fact, the model may "penalise a firm that is in transition from an older specification to a more modern and advanced design" because of its backwards-looking approach (Jamasb and Pollitt 2008, 1798).

Despite the detailed technical network model that is constructed during the use of these models, Jamasb and Pollitt argue that the approach does not reduce information asymmetry and does not capture the relationships between firms in the sector. But Jamasb and Pollitt appear to be considering the model in isolation, as the sole regulatory method. If a reference network model were applied together with a sliding scale "menu" of contracts in the regulatory scheme the regulator might yet encourage companies to reveal more accurate information about their costs. (It is also unclear why it is significant to capture inter-firm relationships from a regulatory perspective, if each firm is regulated separately and holds a local monopoly.) Finally, Jamasb and Pollitt note that the complexity of the model may undermine regulatory transparency (Jamasb and Pollitt 2008).

Jamasb and Soderberg study the actual cost of distribution companies in Sweden vis-à-vis the implementation of the reference network model. They find that the cost of certain types of utilities have increased since the model's introduction and it has had little effect on the quality of

⁵ However, the Spanish expansion planning or "brownfield" RNM can take an existing network as input to reflect the actual status of the network at that point in time.

service. As a result they recommend benchmarking methods using actual firms rather than reference model firms (Jamash and Soderberg 2010).

1.3.5 Sliding Scales

Sliding scales are another approach to regulation. In one form, they present regulated firms with an automatic adjustment to prices given the actual rate of return – so prices are decreased when the firm’s rate of return rises above the target rate of return as established by the regulator (Joskow and Schmalensee 1986, Biewald, et al. 1997). In electricity, they were applied in this form in the US in the early 1900s.

Sliding scales have more recently been used within the broader framework of RPI-X incentive regulation. In the fourth UK distribution price control, a sliding scale incentive mechanism was utilized to present regulated distribution firms with a choice between lower capital expenditure offset by a higher return and a higher capital expenditure offset by a lower return (P. L. Joskow 2006, Office of Gas and Electricity Markets (Ofgem) 2004). Following Joskow (2006), in this system a “menu of sliding scales” is presented to firms. If they opt to target a higher capital expenditure than that estimated by the regulator to be efficient, they also select a sliding scale menu that allows them to keep less of the profits when they outperform (by reducing actual expenditure to below the target).

Finally, a similar “menu of sliding scales” has also been proposed as a regulatory scheme to meet the emerging challenge of distributed generation (Bauknecht and Brunekreeft 2008). Under this proposal the regulated firm chooses a point on the sliding scale between full cost pass-through of the costs of integrating DG, and a price cap on the prices charged to recover the costs of integrating DG. This allows firms with high connection costs to select full cost pass-through and connect DG knowing their costs will be remunerated, while firms with low connection costs may select a price cap but get to keep the difference between their low costs and their prices as profit.

In the US, some regulatory methods such as “shared savings” apply similar principles to sliding scales by adjusting returns based on the company’s actual spending relative to its original budget. Shared savings methods have been proposed to encourage reasonable spending by companies. In Illinois, the utility Commonwealth Edison (ComEd) proposed a ratemaking method that would approve projects ex ante but share savings with customers if the actual capital investment in a proposed project turned out to be more than 5% lower than the budgeted amount

(Commonwealth Edison Company 2010). However, this was rejected by the regulatory commission for several reasons including concerns that ComEd might inflate the budget above true costs while the commission, because of information asymmetry, would not know whether this had taken place (Illinois Commerce Commission 2011). In California, risk-sharing cost recovery methods have been approved for some new advanced metering infrastructure projects; these share some of the costs of cost overruns between ratepayers (utilities' customers) and utilities' shareholders (California Public Utilities Commission 2008, 2007, 2006).

1.3.6 Yardstick Regulation

Yardstick regulation was proposed by Shleifer (1985) as a more efficient alternative to cost of service regulation. This scheme, utilizing the basic principle behind benchmarking, compares a firm's performance to the average performance of similar firms that operate under similar conditions. Firms that outperform the average (by reducing costs) obtain higher profits, thus incentivizing efficiency. Jamasb and Pollitt (2000) note that yardstick competition allows firms that are geographically separated from one another to compete. Yardstick regulation, in conjunction with a price cap, is applied to electricity distribution in the Netherlands to determine the yardstick objective (Energiekamer 2010). It is also applied to electricity distribution in Chile (Jamasb and Pollitt 2001, Rudnick and Donoso 2000).

A deficiency of yardstick regulation is that it may incentivize firms to invest less so as to appear more productive relative to their costs. This underinvestment can decrease distribution quality of service. In the case of the Netherlands electricity distribution, this has been remedied by adding a quality factor to the price cap regulatory scheme (Energiekamer 2010).

Other problems identified with yardstick regulation include the difficulty of adjusting for differences between distribution firms, since no two distribution utilities can be exactly the same, and finding distribution firms whose accounts are similar enough to compare (since an analysis of the accounting costs is required to determine the allowed revenue) (Joskow and Schmalensee 1986, Jamasb and Pollitt 2000).

Finally, in Shleifer's original paper the need for the regulator "to be prepared to let the firms go bankrupt if they choose inefficient cost levels" under yardstick regulation is mentioned (1985, 323). However, it has been pointed out that electricity is a public service so it is unlikely that distribution companies will be allowed to go bankrupt (Ajodhia, Franken and van der Lippe n.d.).

1.4 Challenges and Issues in Power Systems Regulation

Two regulatory problems specific to electric power systems, regulating quality of service and losses, are described below. These problems occur in both cost of service and incentive regulatory schemes. Lastly a discussion of decoupling, a measure to mitigate distribution companies' disincentives to reducing the volume of energy consumption, is presented.

1.4.1 Quality of Service

Quality of service issues that arise from the technical characteristics of electricity include both reliability (supply is continuous and free of interruptions) and power quality (the waveform of the power is as close to a perfect sinusoid as possible, and free of damaging flickers and other problems). More generally, quality of service may also refer to commercial customer service issues such as time to respond to customer inquiries, but the following discussion focuses on quality issues specific to electricity.

The need to regulate quality of service within a cost of service regulatory environment was one of the factors behind the development of performance based regulation (PBR) in the US. When applied to quality of service, PBR imposes a financial penalty on the regulated distribution company for failing to meet quality of service standards, and/or gives the company a financial reward for exceeding the standard. The penalty or reward may be effected by changing the rate of return or through a more explicit penalty/reward incentive framework. Precise definitions of PBR applied to quality of service vary, and there are many gradations of PBR – some formats implement it with only penalties, and some formats include targets only without penalties or rewards.

Incentive regulation can deter investments needed to improve reliability and insure quality of service. In many countries where incentive regulation is applied, this is corrected by introducing quality of service targets into the regulation, with rewards and penalties for missing targets. For reliability, targets can be defined by utilizing indices (for example, number of interruptions) to measure reliability. An efficient level of reliability is then set as the target by the regulator. Distribution system reliability indices have been formally defined by the IEEE in Standard 1366; several important indices include the System Average Interruption Duration Index (SAIDI), and the Customer Average Interruption Duration Index (CAIDI) (IEEE Power Engineering Society 2004).

The amount of investment to encourage so that the efficient quality of service level is achieved can be difficult to determine. It may not be efficient, for example, to demand perfect power quality if this can only be achieved by extremely costly investments in voltage regulation equipment and other control systems. Customers may not even be willing to pay for such expenses. Figure 3 illustrates this tradeoff between cost and quality.

Reference Network Models (RNMs) may be used to determine the costs required to achieve a certain level of quality of service. The RNM takes different target numbers for service quality metrics (SAIDI, etc.) as input parameters, and outputs the cost of the network investments required to achieve those targets. The output data enables the construction of the investment costs function (ICF) in Figure 3 and the calculation of the slope of the tangent that intersects the optimum quality level. Thus, RNMs can assist regulators in determining the right service quality targets to set and the corresponding amount of revenue to allow the company so that it has sufficient funds to achieve those targets.

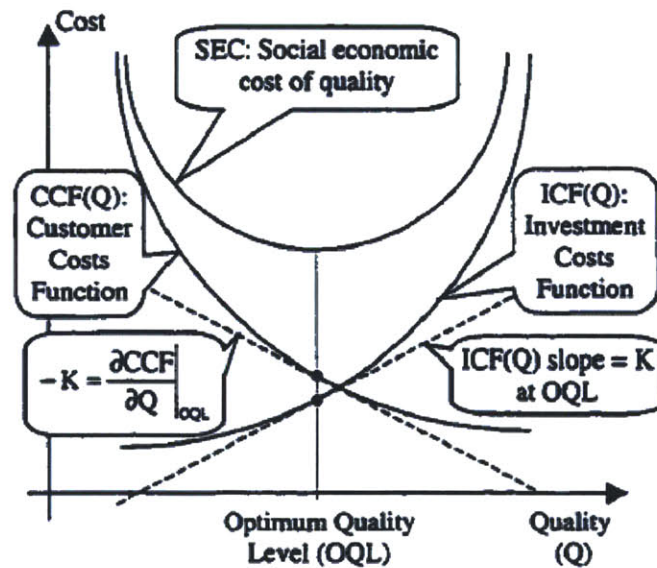


Figure 3. “Socio-economic cost of maintaining network quality levels”.
 Source: Rivier and Gómez (2000, 471).

1.4.2 Losses

When power is transmitted over distribution lines, some energy is lost in the distribution network owing to the resistance of the conductors and losses in other network equipment such as transformers. Under incentive regulation, a penalty and/or reward scheme may be applied to

reduce losses and encourage investment in losses reduction technologies. It can be more difficult to set targets for losses than for quality of service, since metrics to measure losses are relatively less standardized compared to the equivalent metrics (e.g. SAIDI) for quality of service. In the UK, where a penalty and reward scheme with targets is in use for distribution losses, the regulator observed the differences in measurements among companies and decided to require a common method for reporting losses in the 2010 price control (Office of Gas and Electricity Markets (Ofgem) 2009). On top of the basic reward/penalty scheme, a £16m funding pot was also made available to UK distribution companies to reduce losses in 2010 (Office of Gas and Electricity Markets (Ofgem) 2009).

New technologies such as distribution automation and distributed generation can add to as well as mitigate line losses. Chapter 2 discusses the impact of various new technologies on losses and the regulatory challenges they pose for losses regulation.

As with quality of service, there is a tradeoff between the cost and benefits of losses mitigation. RNMs can also be used to calculate the cost of losses under different network and technology scenarios. Hence RNMs may assist regulators with the calculation of appropriate losses targets and of allowed remuneration for companies to mitigate losses.

1.4.3 Decoupling

The principle of decoupling is that it removes inefficient linkages between revenues collected and the amount of electricity distributed by a distribution company, by making revenues largely independent of the volume of electricity distributed. Decoupling can help resolve issues posed by the timing of the introduction of new technologies or energy conservation measures to the network, and by artificial linkages between the calculation of remuneration and the cost recovery process.

If the revenues collected by a distribution company depend on the kWh of electricity used by its customers, as they often do in the US when volumetric remuneration principles are used, companies prefer to distribute more electricity so as to collect more revenue. But energy efficiency programs and energy conservation measures can reduce electricity demand. If such programs and technologies quickly penetrate the network, the kWh of electricity distributed can quickly decrease and reduce the revenues collected by the company. However, fixed network costs decrease less quickly than demand (if at all). If revenues fall too quickly, the distribution company may not recover a sufficient amount of money to continue operating the network.

Under cost of service regulation, it may also face a lengthy and expensive rate case proceeding to raise rates to recover the necessary revenues. Owing to this problem, distribution companies are disinclined to integrate technologies and programs such as energy conservation measures that could be socially beneficial.

Decoupling mitigates this problem by ensuring recovery of the total allowed revenue by making revenue collected independent of energy consumption; several decoupling mechanisms are described later. Decoupling has been applied to some US distribution companies to mitigate their disincentives to energy efficiency programs. That said, decoupling is not currently applied in all US states and even when it is applied, it can differ in implementation between states (MIT 2011, 192).

Another problem that can be mitigated by decoupling is the artificial linkage between allowed remuneration and cost recovery. Cost of service regulators in the US often utilize volumetric rates to recover money from customers to pay distribution companies for fixed distribution network costs. When a higher volume (amount) of electricity is distributed, companies may recover more than their efficient amount of revenue; when a lower amount of electricity is distributed, companies may not recover enough money (assuming rates do not change to account for the change in volume of electricity distributed; rates can generally only be changed through a rate case proceeding and they do not occur very often). So the linkage that volumetric rates create between electricity distributed, cost recovery and remuneration is not conducive to ensuring adequate remuneration for the distribution company. Decoupling removes unwanted linkages between remuneration and cost recovery and can help ensure adequate remuneration for the company.

Decoupling can be implemented in a variety of ways. The US Environmental Protection Agency's "Regulatory Incentives for Energy Efficiency" describes one method that "caps" the total revenue (determined during the rate case), and another method that "caps" the total revenue per customer. Under the first method, in the first year the revenue collected by the company above (or below) the cap is placed in a balancing account for the next year. The price charged per kWh in the next year is modified as needed to allow the company to recover the total allowed revenue less the amount it already has in the balancing account. Thus, the company is assured of recovering the total allowed revenue. But it is important to remember that the total allowed

revenue itself is fixed by the rate case and decoupling does not change its value (Environmental Protection Agency 2007).

Incentive regulation applied as a RPI-X revenue cap intrinsically achieves the goals of decoupling under ideal circumstances. Under price cap regulation, the company cannot change prices and would want to increase volume sold to increase revenues. But under RPI-X revenue cap regulation, the future network costs are projected for the regulatory period and the cap set to take account of those costs. If actual costs end up perfectly matching projected costs, the cap allows sufficient revenue and the company does not have an incentive to increase sales volume to cover its costs.

In the presence of new technologies, however, cost of service regulation with decoupling remains further away from ideal regulation than an ideal RPI-X revenue cap regulation because of the way allowed revenue is calculated. The allowed revenue continues to be determined through the rate case, and decoupling only targets recovery of the total allowed revenue without changing the sum allowed as the penetration of new technologies increases. To raise allowed revenue to integrate new technologies, the company has to keep bringing rate cases, which is time-consuming and costly and does not always ensure full cost recovery. Under an ideal implementation of RPI-X revenue cap regulation, the total allowed revenues are projected for several years into the future using a lengthy review process that takes into account forecasts of factors driving future network costs (such as demand growth, distributed generation penetration, etc.). The total sum allowed is also fully reviewed at pre-fixed regular intervals (at each price control review) without relying on a party's bringing a rate case. Finally, an idealized application of RPI-X can even permit the total allowed revenue to vary automatically if the actual values of distribution cost drivers differ from the forecasts as shown below:

$$TAR_t = TAR_{t-1} \cdot (1 + RPI-X) \cdot (1 + \sum_i \alpha_i \cdot \Delta DF_i)$$

where TAR is the total allowed revenue, RPI-X is the price index less the adjustment factor, α is the effect of a driving factor i on network costs and ΔDF is the change in the driving factor (cost driver) with respect to the forecast value utilized by the regulator. For example, the total allowed revenue in a given year t will increase as scaled by $(1 + \sum_i \alpha_i \cdot \Delta DF_i)$ if a driving factor, such as demand, grows slightly more than forecast so that ΔDF_i is small and positive; the increase in total allowed revenue will be proportional to the effect of a change in demand on network costs (indicated by the value of α).

1.5 The Future of Distribution Regulation

In sum, some important conventional objectives of the distribution grid regulatory system have been to ensure the distribution grid company is remunerated adequately, makes the necessary distribution grid investments to provide a reasonable level of quality of service, and that its costs are fairly allocated among and recovered from network users. Major regulatory changes in the early 1990s led to the development of incentive regulation that targeted improvements in distribution companies' cost efficiency. While challenged by classic problems such as information asymmetry between the regulator and regulated companies and the difficulty of regulating losses and quality of service, both these conventional regulatory schemes have generally functioned.

Recent years have seen a greater public, political, and regulatory awareness of electricity distribution networks' social, environmental, and economic impacts as well as the need to modernize the networks. This awareness has led to a push for specific social, environmental, and economic objectives to be met by distribution networks. In some cases, these objectives are different or wholly new compared to the objectives of conventional regulation. The use of appropriate regulatory tools can help meet such goals.

One objective is environmental sustainability. Distribution networks are increasingly capable of accommodating renewable generation from less polluting sources such as wind and solar generators, and they should do so as far as possible to improve environmental sustainability. Distribution networks should minimize wastage (for example, owing to line losses in distribution) so as to reduce the production of pollutants from electricity generation. Enabling the large-scale distribution grid connection of electric vehicles can indirectly reduce fuel consumption and air pollution.

Another objective is modernization for greater economic and operational efficiency. Improved power flow management systems can defer necessary investments in network capacity. Improved network control systems can minimize power outages and losses, improving reliability. Networks that are capable of incorporating demand response programs allow customers to modify their power demand on the fly and can also defer necessary capacity investments while saving customers money.

Many new technologies such as distributed generation, electric vehicles, and advanced metering infrastructure will connect to the distribution grid to meet these objectives. Integrating

these technologies will necessitate changes to the way the distribution grid is operated and maintained. Large capital investments in both distribution grids and the technologies themselves will be needed to ensure the technologies are installed and operated effectively to realize the economic and environmental benefits they promise. Distribution regulation schemes will need to evolve appropriately to support the required investments. New, more sophisticated incentives may be needed to remove disincentives to modernization and environmental sustainability that exist in current regulatory systems, and to ensure that new technologies are used optimally. These new technologies and the regulatory issues they raise are the subject of the following chapter.

Chapter 2: New Technologies and New Regulations

2.1 Regulating the Modernizing Grid

With the increasing penetration of technologies such as distributed generation and electric vehicles has come a sense that existing regulatory systems are not adequate to modernize the electric grid infrastructure to support these new technologies. The vast capital investment needed to upgrade the infrastructure is poorly matched to the incentive regulation systems in many countries, which encourage cost efficiency. The cost of service regulation used in many states of the US, on the other hand, can approve or deny grid modernization projects in each state, resulting in the lack of a coherent national grid modernization program – while still permitting cost inefficiencies in individual projects. The first part of this chapter discusses some of the new technologies coming into use and the inadequacies of existing regulatory systems in terms of supporting the introduction and optimal operation of these new technologies.

Much regulatory research has focused on Europe, where the European Union target for 20% of energy consumed to be sourced from renewable sources by 2020 provides a political stimulus for the uptake of renewable distributed generation (European Commission 2010). Academic researchers and economists have made suggestions for the enhancement of existing incentive regulatory schemes to meet the challenges posed by distributed generation in distribution networks (Frías, Gómez and Rivier 2008, Scheepers, et al. 2007, Bauknecht and Brunekreeft 2008). Recently, too, regulatory commissions such as the UK's Ofgem and the Netherlands' Energiekamer have conducted reviews to assess the adequacy of existing distribution network regulation and develop novel regulatory ideas to meet the challenges posed by new technologies generally (Office of Gas and Electricity Markets (Ofgem) 2010, Office of Energy and Transport Regulation - the Netherlands Competition Authority 2010). Hence, the second part of this chapter discusses some of the regulatory scheme reforms that have been proposed or are in use to meet the challenges of new technologies, and examines specific regulatory incentives targeting distributed generation and innovation.

2.2 Distribution Grid Challenges Posed by New Technologies

The electric grid in many countries is undergoing a process of modernization. The increasing uptake of renewable energy sources, the proliferation of new sources of electricity demand such as electric vehicles, and the changes in consumption behaviors enabled by

technologies like advanced metering infrastructure (AMI) all pose challenges to the existing electric grid system and the regulation under which it operates.

The distribution grid system is of particular importance because many of the changes brought about by grid modernization will have their initial impact felt by the distribution system. Already, as of March 9, 2012 the reported distribution system-related capital investments using the US' Smart Grid Investment Grants program total more than US\$3.5 billion. The breakdown of investments is displayed in Table 2.

Table 2. Estimated spending on distribution network modernization projects under US Smart Grid Investment Grant funding.

Category	Amount as of March 9, 2012 (US\$)
AMI Expenditures	2,356,484,978.00
Customer System Asset Expenditures	339,506,879.00
<i>Distribution Asset Expenditures:</i>	
Electric Distribution Automation Assets	878,807,644.00
Electric Distribution Distributed Energy Resource (DER) Assets	6,893,972.00
Total	3,581,693,473.00

Source: Compiled from information available at SmartGrid.gov: Program Asset Investments (U.S. Department of Energy n.d.)

As Table 2 shows, the new technologies and control systems necessitate large capital investments. But grid modernization will also necessitate investments in power system components such as wires and transformers for the distribution network itself, as well as investments in components like voltage regulators to better operate the distribution network. Deriving maximum benefit from grid modernization will often also require a rethinking of utilities' approach to network investment and a movement away from the 'fit and forget' philosophy of building a network by sizing it for maximum capacity.

As described in Chapter 1, distribution companies are regulated monopolies who are remunerated for capital investments by the regulator according to cost of service or incentive regulation principles. However, the existing regulatory schemes are ill prepared to serve the grid modernization process. Three main reasons exist for this: First, the existing schemes are not well suited to providing adequate remuneration for the large capital investments needed to modernize the grid since many of the new technologies being installed differ in important respects to

traditional distribution grid investments, affecting company investment decisions (in both the technologies and the distribution networks they are connected to) and regulatory approval processes. Second, the use of these new technologies can add to the costs of distribution grid operation in ways that existing regulatory schemes do not fully recognize and so do not adequately remunerate for. Third, some methods in use for the allocation and recovery of allowed costs – particularly costs related to new technologies – are inadequate and if continued, may eventually cause the system’s operational and economic efficiency to deteriorate.

The remainder of this section discusses the ways in which four new technologies pose particular challenges for distribution grid regulation: distributed generation (DG), electric vehicles (EV), advanced metering infrastructure (AMI), and distribution automation.

DG is one new technology that may stress the distribution grid. Definitions of DG vary. It can refer to small-scale generation installations located at the homes of existing residential customers of the distribution grid (i.e. coincident with system load) (Pepermans, et al. 2005). But DG can also be located far away from customer residences, in the form of larger wind or solar farms. Regardless of location, the wide-scale installation of DG systems introduces a significant new energy resource into the electric grid. DG may also be defined by its level of connection to the electricity network; for example the EU Directive 2009/72/EC defines DG as generation installations connected to the distribution grid (rather than the higher-voltage transmission grid, where larger installations such as wind farms may be connected) (European Parliament and Council of the European Union 2009). Technologies used in residential DG installations may include micro-combined heat and power (CHP), rooftop solar panels (photovoltaic panels), and micro wind turbines. Micro-CHP, also known as cogeneration, refers to a variety of small-scale generating technologies that generate electricity and heat simultaneously.

DG implies both benefits and costs for the distribution network and issues for regulators. For example, DG may benefit distribution companies by providing electricity from a source closer to residential customers than conventional generators, thus reducing upstream losses in the network. But because distribution companies incur costs to connect each new DG unit to their networks and manage the power flowing from these new power generation sources, regulators must devise fair remuneration for the companies and recover the costs from customers and generators. When DG penetration is very high, the total power generated by DG may exceed the total system demand for power. Then the distribution company has to manage power flows from

different, perhaps widely dispersed sources. This will necessitate changes to operational processes and perhaps additional investments to manage power flows. Again, appropriate remuneration schemes must be devised or the company may not make the necessary changes or investments at all. Variable distributed generation resources such as wind and solar generators can pose technical challenges at the distribution level because it is difficult to predict when they will generate and feed energy into the grid. Irregular but significant power contributions by wind and solar installations can result in voltage or frequency irregularities in the distribution grid system that are challenging for companies to manage (Barker and de Mello 2000, Lo Schiavo, et al. 2011).

A second new technology that could also pose a challenge for the distribution system in the long run is electric vehicles. Large-scale penetration of electric vehicles effectively connects many more loads to local distribution networks, which may struggle to cope with the added capacity. A wide variety of vehicle charging times may also raise system balancing and quality of service issues. In addition, a variety of charging systems for electric vehicles are developing. The fastest of these (Level III charging) charges vehicles at relatively high currents in order to reduce their charging time. Multiple vehicles consuming such high currents could place added stress on the distribution grid. In the long run, it may become socially efficient to invest in systems to enable the resale of electricity from car batteries to the grid, or systems to use car batteries as an electricity storage buffer to mitigate variability caused by variable renewable energy technologies. An appropriate system of remuneration to allow investments in these new technologies will become necessary.

A third new technology is advanced metering infrastructure (AMI). The integration of AMI into the distribution grid poses a challenge to distribution system regulation because it enables potentially significant changes in electric power usage behavior. AMI enables the operation of customer demand response programs, which shift end-user electricity demand based on price signals or load signals from the utility in order to reduce strain on the network. Advanced meters are able to transmit these price signals and control signals from the utility to homes, causing appropriate shifting actions when the system is operating near peak capacity. On the one hand, these systems could reduce the need for investing in additional distribution network capacity. In this sense AMI represents a significant opportunity to reduce network investment costs while developing a more sustainable energy system. On the other hand,

distribution companies must invest not only in the meters but also the associated control systems and new operational processes that enable demand response programs to be effective. The current regulatory system may not be well prepared to accommodate and appropriately remunerate these non-traditional investments from utilities.

Finally, a fourth technology area is control systems to better manage power flows in the distribution grid. Technical advances in IT infrastructure and control systems are resulting in improved distribution automation systems that can improve visibility and control over power flows and power quality. One example of such a Distribution Management System was being installed in 2011 by Avista Corp. in Spokane, WA using funds from the US\$4.3 billion Smart Grid Investment Grant program introduced in the US in 2008 (U.S. Department of Energy 2011).

2.3 Regulatory Challenges Posed by New Technologies

Four aspects of current regulatory systems that may make them inadequate to support the installation and operation of new technologies are discussed here. These aspects are the regulation of lost revenue, capital investment (in the new technologies and in the distribution system itself), system performance, and innovation.

2.3.1 Regulating Lost Revenue

One problem posed by the current regulatory system, especially in the US is the widespread use of volumetric remuneration methods which allow distribution companies to recover costs by charging rates based on the volume of energy they distribute. In the long run, these methods can discourage companies from supporting low-carbon technologies or energy efficiency measures that would reduce the volume of energy distributed and raise the possibility of not recovering enough revenue for the companies. When coupled with a lack of regulatory incentives for connecting low-carbon technologies to the distribution grid, this issue can prevent those technologies from being integrated with the grid at all.

In the US, several methods, notably decoupling the volume of energy sold from remuneration, are in use to tackle this issue. Incentive regulatory schemes, often used in Europe, are designed so that allowed revenues do not depend on energy distributed but on the projected investment cases brought at the price control review.

2.3.2 Regulating Capital Investment in Networks to Accommodate New Technologies

The new technologies discussed above can significantly alter the network investment planning of distribution companies. Without new technologies, companies make regular investments to accommodate the natural power demand growth due to existing customers in the network. They also make investments to expand their network to serve new residential customers (for example, when a new residential development is built).

The introduction of new technologies changes the scenarios under which network investment planning occurs. Now, lines may have to be upgraded to accommodate additional power flows owing to the charging demands of electric vehicles. New network components may be required to accommodate the contributions that distributed generators make to the network from many dispersed locations, some far away from conventional generators. Other components may be required not for capacity but to ensure network reliability and continuity of supply given the variability and imperfect predictability of distributed generators' power contributions and electric vehicles' power demand. The same variability and imperfect predictability surrounding the numbers and locations of new technologies in the network can make it difficult to formulate appropriate network investment plans.

The Reference Network Models (RNMs) introduced in Chapter 1 can be utilized to estimate network investment costs under different scenarios for new technologies. In Chapter 3, two types of RNM are used to estimate network investment costs and losses costs under various technology penetration scenarios and technology management scenarios.

2.3.3 Regulating Capital Investment in New Technologies

The new technologies discussed above generally involve the introduction of new, digital control systems and digital devices to the power system. The challenges faced by regulators evaluating capital investments in projects to install and integrate these new technologies arise from several features of these technologies: their high risk of obsolescence and the shorter useful lives of digital technologies compared to conventional network investments, the difficulty of estimating benefits that are dependent on external factors such as evolutions in customer behavior or increased system reliability, the difficulty of quantifying certain types of benefits such as pollution mitigation, and the difficulty of determining cost and risk allocation given these uncertainties. These challenges could prevent companies from proposing (under cost of service

regulation) or undertaking capital investment (under incentive regulation) in grid modernization projects.

Both incentive and cost of service regulation cause risk aversion in relation to capital investments in new technologies. The current RPI-X incentive regulation scheme in the UK is found by Ofgem to encourage a focus on “tried and tested infrastructure solutions”, much as cost of service regulators are inclined to approve proven technologies or projects (Office of Gas and Electricity Markets (Ofgem) 2010, 8). Under incentive regulation, the focus on driving down costs can deter companies from undertaking large capital investments even when they are necessary to modernize the grid. In this case, the regulatory system itself is a problem, rather than the new technologies stressing the regulatory system. This risk aversion can be exacerbated if there is an ex post element to the regulatory scheme. For example, if companies’ costs are reviewed at the end of the regulatory period (as it was in Sweden before a recent change), companies do not know if they will be allowed cost recovery at the time they have to make investment decisions, which could make them reluctant to invest.

Experiences to date with grid modernization projects in the US suggests that cost of service regulation can result in at least two points of regulatory uncertainty that may make companies reluctant to file for new, high-capex projects in the first place. One is the inherent risk: the possibility that the regulator may deny any project proposed, as the Maryland Public Utilities Commission (PUC) initially denied Baltimore Gas and Electric Company (BGE)’s proposal for an AMI project (Public Service Commission of Maryland 2010). The other arises from the ex post nature of regulation: the regulator may deny full cost recovery after the project has been approved. The Colorado PUC reduced Xcel Energy’s cost recovery for its smart grid city demonstration project in Boulder, Colorado from \$44.5 million to \$27.9 million⁶ (Colorado Public Utilities Commission 2011).

The risk aversion of cost of service regulators is also a problem that may hinder achieving the full benefits from grid modernization. The Maryland PUC rejected BGE’s original AMI proposal and, among other things, required BGE to make Time-of-Use pricing non-mandatory before its proposal could be approved. Time-of-Use pricing is one means by which a form of customer demand response might have been achieved through the use of the AMI system. By

⁶ As of April 2012, the Colorado PUC is considering an application by Xcel to recover the remainder of its costs (Colorado Public Utilities Commission 2012).

mitigating the Time-of-Use pricing feature of BGE's proposal, the Maryland PUC may have reduced the potential benefits from the AMI systems being installed. In its approval, the PUC states that the AMI investments proposed are "a large, but classic, investment in BGE's distribution infrastructure" – and indeed, they are relatively "classic" without Time-of-Use pricing since without that, AMI systems are little more than basic meter upgrades. (Public Service Commission of Maryland 2010, 29). In this sense, the Maryland PUC's choice of regulatory instrument was appropriately classic but the full potential of the AMI investment may not be realized.

The technology risks of BGE's AMI project were also a consideration for the Maryland PUC. The originally proposed cost recovery methods were questioned in part because they "ask[ed] BGE's ratepayers to take significant financial and technological risks" (Public Service Commission of Maryland 2010, 1). In addition to the PUC's concerns regarding the proposals for cost recovery and time of use rates, the decision states that "BGE's ratepayers should not assume the entire risk of this significant investment in unproven and evolving technology" (35). BGE's AMI project was approved following a refiling that changed the cost recovery method from a surcharge to a conventional regulatory asset, removed Time-of-Use pricing, and included a customer education plan. The PUC regarded the change in cost recovery method to be critical in mitigating risks to customers, as the need for base rate cases would ensure scrutiny of the costs customers are asked to pay (Public Service Commission of Maryland 2010, 47).

Regulators, particularly in the US states, differ in their treatment of new distribution grid investments and this increases regulatory uncertainty. The Maryland PUC states that AMI investments are "a large, but classic, investment in BGE's distribution infrastructure" whose cost should be recovered through base rate cases rather than a surcharge or a tracker mechanism (Public Service Commission of Maryland 2010, 29). But the Texas PUC allowed cost recovery through a surcharge for CenterPoint Energy (Public Utility Commission of Texas 2008) and Oncor (Public Utility Commission of Texas 2008).

Non-traditional distribution grid investments to accommodate electric vehicles and integrate AMI can involve investing in a very diverse array of new technologies ranging from communications systems, LCD display hardware, to charging interfaces. But many of the new technologies still carry a large risk of technology obsolescence and regulators must manage the uncertainties associated with technology uptake, actual use, and useful life. A new technology

may become obsolete because a competing technology is officially declared the standard. Or it may become obsolete because it is superseded by a better version. The risks of obsolescence that these new technologies embody do not fit well with the conservative fundamentals of conventional regulation, which necessitate approving relatively safe investments that ratepayers are guaranteed to see benefits from. Furthermore, the fact that new technologies have inherently shorter asset lives compared to conventional power system technologies has ramifications for regulatory depreciation schedules and cost recovery mechanisms that were developed for conventional longer-lived technologies.

The difficulty of estimating benefits and costs related to capital investments in new grid technologies is another significant regulatory issue. Critical to a cost of service regulator's decision on whether to approve or deny a major capital investment project is the cost-benefit analysis of the proposed project. The lack of uniformity in regulatory and utility approaches across US states has so far resulted in a wide variety of cost and benefit estimates for advanced metering infrastructure programs alone. MIT's Future of the Electric Grid study examined 10 advanced metering projects in 6 states whose average cost per meter installed ranged from \$149 to \$484 (more than three times as much as the lowest estimate), and whose operational benefits per meter installed ranged from \$50 to \$232 (more than four times as much as the lowest estimate) (MIT 2011, 135-136). Not only may regulators applying cost of service principles find it difficult to evaluate whether or not to approve a project, because the technologies are so new and cost-benefit comparisons are so difficult to find, but they may also approve projects that cost too much. Or they may deny projects out of fiscal conservatism but consequently miss out on the multifaceted benefits such technologies can bring.

Complicating the issue is the fact that some benefits due to capital investments in grid modernization projects are inherently uncertain. Benefits may be uncertain because they are highly dependent on external factors difficult to forecast at the time of investment decision-making. For example, realizing the full benefits of an AMI project may depend on future scenarios involving receptive and active customer behaviors, availability and uptake of dynamic pricing programs, and supportive government policies. Other benefits are uncertain because they are difficult to quantify; such benefits may include environmental benefits and pollution mitigation.

Furthermore, the benefits due to high capital investment now may accrue over a much longer period than for conventional technologies, resulting in regulators having to take account of a much longer time period than before. Certain types of projects can take many years to show returns on investment. For example, the full benefits of AMI may not appear on balance sheets until the meters have been installed, customers educated about using them, and appropriate smart appliances and dynamic pricing schemes have been fully integrated. For both cost of service and incentive regulation, the length of the return on investment poses a problem. In cost of service regulation, the long time horizon needed before benefits are realized can deter regulators from approving funding for smart grid projects. In revenue and price cap incentive regulation, where the frequency of regulatory reviews depends on price control periods, shorter price control periods deter regulated companies from investing for long term benefits because they cannot be sure that they will recover all their investment costs over the short price control period. As noted by the UK's Ofgem, the short price control periods under RPI-X incentive regulation encourage companies only to focus on projects that quickly deliver cost savings or benefits in the short term (Office of Gas and Electricity Markets (Ofgem) 2010).

2.3.4 Regulating Performance

Regulatory challenges may arise from the technical effects of some new technologies on the operation and performance of the existing distribution system. For example, a large penetration of distributed generation from variable renewable energy sources may have a negative impact on the distribution network's quality of service, losses, or stability that can undermine the apparent benefits of the new technology. Therefore, regulatory remuneration schemes must take into account the costs distribution networks incur to maintain an acceptable level of performance with the penetration of new technologies, and remunerate companies accordingly. At the same time, regulatory schemes must acknowledge the positive contributions some technologies can make to system performance.

The Italian regulatory authority set up demonstration projects to investigate the effect of DG on medium voltage networks' protection relays and voltage regulation systems and noted that operational changes will be needed to smoothly integrate DG into the system (Lo Schiavo, et al. 2011). So grid modernization projects may necessitate additional network investments (for example, in stabilization or protection technologies) to maintain service quality and manage losses, increasing the cost to distribution companies. Such considerations make the cost-benefit

analysis of modernization projects more difficult. Regulatory measures such as penalty/reward schemes for quality of service may be needed to incentivize distribution companies to make the necessary investments in maintaining system performance alongside their investments in new technologies. Even at present not all US states have specific regulations targeting adequate reliability and the regulations of those that do can vary in design across states; for example, a 2011 report by the Galvin Electricity Initiative noted that 20 states have penalties for not providing adequate system reliability, and 5 have rewards for achieving above target reliability (Galvin Electricity Initiative 2011). The lack of more prevalent regulation could become a problem as new technologies with less predictable power flows, such as DG or electric vehicles connect to the grid and make ensuring reliability harder. It could also become necessary for regulators to change the total amount of revenue distribution companies are allowed to recover so that they are remunerated for any higher investments needed to maintain system performance levels.

On the other hand, some new technologies may help system performance. Distribution automation systems provide greater visibility of the distribution network and can improve responses to outages or service quality problems. Distributed generation located in the low voltage network may decrease the amount of power that has to be transmitted through the higher voltage network, and so reduce losses. But the cost efficiency incentive in incentive regulation can prevent investments in these new technologies despite their potential benefits. Deterring these investments will reduce the benefits seen by customers and distribution companies.

2.3.5 Innovation

Encouraging companies to undertake research and development and carry out innovative projects, when these projects may pose uncertain returns, is another regulatory challenge. Under cost of service regulation, where companies have to file for cost recovery for new projects, regulators and companies alike may be reluctant to pursue the lengthy rate case review process for innovative projects with uncertain returns, or even to approve the projects when the review is undertaken. Under incentive regulation, where an emphasis is placed on cost efficiency, companies may be unwilling to spend money on projects with such uncertain returns – especially when those could reduce their profits.

Encouraging innovative projects is a particularly important issue for grid modernization. The effective integration of many new technologies relies on distribution companies being

willing to consider innovative approaches to the installation, management, and use of these technologies as part of their systems. For example, the smooth integration of electric vehicle charging requirements into the distribution network may necessitate innovative power flow management strategies that have not previously been used. Regulation must provide companies with the security of remuneration and the appropriate risk incentives to undertake projects that experiment with innovative approaches to new technologies.

2.4 How can Regulation Incentivize the Uptake of New Technologies and Support their Operation?

With regard to new technologies, the issues identified above: regulating capital investment, regulating performance, cost recovery, and encouraging innovation may be addressed through the regulatory scheme and through specific or targeted regulatory incentives.

2.4.1 Regulatory Schemes

Two major regulatory schemes, cost of service and incentive regulation, were described in Chapter 1. As this chapter discusses, these schemes may be inadequate under a high take-up of new technologies that cause the electric grid to operate in different ways and that reduce electricity usage or change electricity usage patterns.

Regulators in some countries are considering, or have begun to undertake, wholesale changes to their regulatory schemes to address the coming challenges described above. The following discussion of some such changes draws upon the experiences of two countries whose power sectors are regulated under incentive regulation: the UK and Italy. This is followed by a discussion of the situation in the largely cost of service regulated US.

The UK

The regulatory shift underway in the UK is from an inputs-based to an outputs-based regulatory scheme. Under both schemes, revenues are capped with the RPI-X incentive mechanism. Inputs-based regulation intrinsically introduces a focus on regulating capital investment (the “input” to the regulatory scheme). Thus an inputs-based regulatory framework tends to focus on cost efficiency of distribution companies, with less attention paid to the performance metrics of the network (except where specific incentives with penalties or rewards are added, as they are for quality of service and losses). An outputs-based framework shifts the

focus to measuring network “outputs”, thus ensuring or at least encouraging a certain level of performance. As planned for the UK, such a framework would focus on setting targets for specific metrics (customer interruptions, carbon footprint) that the distribution companies would have to meet (Office of Gas and Electricity Markets (Ofgem) 2010). Like Ofgem, the Italian regulator is considering moving to an outputs-based framework (Lo Schiavo, et al. 2011).

In the UK, the shift to an outputs framework is prompted by a recognition of the need to move towards a low carbon economy by encouraging networks to invest for the long-term and be flexible in using a variety of new technologies, while ensuring the networks’ performance remain satisfactory (Office of Gas and Electricity Markets (Ofgem) 2010). In Italy, the shift is prompted by a sense that outputs-based regulation will be more efficient because the regulator does not have to select individual projects for approval, because such regulation can potentially prevent inefficient investments, and because it will fuel network innovation (Lo Schiavo, et al. 2011, 13).

The UK regulator, Ofgem’s new outputs-led framework is titled Revenue set to deliver strong Incentives, Innovation, and Outputs (RIIO). Under RIIO, electricity (and gas) transmission and distribution companies are set specific outputs to deliver in categories such as “reliability and availability” and “environmental impact” (Office of Gas and Electricity Markets (Ofgem) 2010). The underlying revenue cap is tied to RPI-X, but with a longer price control period.

The RIIO framework represents an attempt to address many of the problems discussed in this chapter. The longer-term 8-year price control allows companies to invest in technologies whose benefits may only be realized in the long term. The focus on outputs gives network companies some freedom to invest in the variety of technologies on offer as long as they deliver on the output metrics, which can help stimulate the take-up of innovative solutions. Furthermore, the outputs system permits the regulator to introduce broader targets for the network such as environmental targets (as part of the “environmental impact” output category), which is less easy to do under an inputs-focused regulatory framework.

Innovation is given additional attention under RIIO. An extra pot of money called the “innovation stimulus package” provides funding for innovative distribution grid projects. The stimulus is funded by customers via use of system charges (Office of Gas and Electricity Markets (Ofgem) 2010, 124). RIIO also adds to competition by allowing third party companies to participate in projects receiving innovation funding or to provide network services. The

regulator intends to create an “innovation licence” to enable such companies to receive the innovation funding. Such competition could itself stimulate greater innovation in the sector.

Access to capital is an important issue given the costly capital investments that will have to be made. Ofgem (2010)’s final decision on the RIIO scheme notes the importance of access to adequate financing for electricity companies to be able to make appropriate investments. The “financeability principles” of the RIIO proposals are meant to promote regulatory clarity and long-term thinking that will make the sector stable and attractive to investors (Office of Gas and Electricity Markets (Ofgem) 2010, 105). Similarly, the Netherlands’ Energiekamer conducted a review of its existing regulations in 2010 which also noted that “...financing substantial investments often requires additional equity capital. It is therefore imperative that shareholders not only focus on receiving dividends on the short term, but that they also take into account the network operators’ future capital demand” (5-6).

In addition to changing the regulatory scheme, the UK government has mandated that all electricity meters be upgraded to “smart” (advanced) meters as part of a national smart metering program. (However, it is worth noting that following 2006 changes to the UK regulations, metering is a competitive activity separate from distribution (Office of Gas and Electricity Markets (Ofgem) 2010).) Minimum technical specifications and a roll out schedule have been established by the government’s Department of Energy and Climate Change and the regulator. The data communications in the meter networks are to be managed centrally by a monopoly communications company regulated by Ofgem. This top-down approach to regulation is notable for its difference from the US’ smart metering projects, which are largely confined within each utility’s service territory with little nationwide coordination.

Italy

The Italian regulator is also examining ways to modify regulation to support DG and electric vehicles (EVs). While the overall regulatory scheme has not been changed yet, the regulator has supported demonstration projects to examine the capacity of the Italian distribution network to accommodate DG. Those projects, selected carefully to ensure that the more efficient ones were allowed to progress, were regulated under an inputs-based regulatory scheme with incentives and additional remuneration of capital investment. (However as noted above, the paper “Changing Regulation” indicates that the regulator would like to move to outputs-based regulation for the entire network (Lo Schiavo, et al. 2011, 8).) In the EV projects, the market for

charging infrastructure is open to other companies as well as distribution companies; customers recharging their vehicles may also select the retailer to buy the electricity from. The regulator sees public electric vehicle recharging as “almost outside the boundary of the regulated distribution business” (Lo Schiavo, et al. 2011, 11).

Innovation in electricity distribution has been tackled in Italy largely by the demonstration projects described above. The regulator has designed schemes that fund companies undertaking innovative projects, for example by allowing selected projects an extra 2% return on the weighted average cost of capital (WACC) for 12 years (Lo Schiavo, et al. 2011, 7).

In 2001 Italy began to install smart meters throughout the distribution network together with a Time-of-Use dynamic pricing scheme. At the time, the regulator set minimum meter technical requirements and the timing of deployment. However, because those meters use older technology that does not allow real-time control or real-time electricity usage reporting, the regulator is now dealing with the problem of technology obsolescence – meters available today are even more sophisticated. The regulator set a useful life for the original meters of 15 years, enabling them to be replaced and upgraded to keep them in line with technological developments. Indeed, a reconsideration of appropriate asset lives is likely to be necessary as part of regulatory changes to deal with new technologies.

The US

The approach of the US to implementing grid modernization contrasts notably with the approaches taken in Italy and the UK. The US approach relies on a bottom-up, industry-driven process aided by significant government funding. State regulators generally do not dictate the timing or features of smart grid rollouts, but they approve the projects and regulate cost recovery. So the focus is on inputs-based regulation through cost of service ratemaking. Although the performance based regulation (PBR) that has been introduced in some states encourages some focus on outputs, the present implementations of PBR are generally not directly motivated by grid modernization and focus more on target-setting related to network quality of service measures.

State regulators have largely regulated capital investments and projects involving new technologies under existing regulatory frameworks – generally cost of service regulation. As

some of the earlier examples in this chapter illustrate, state PUCs may differ in their approaches to cost recovery even when working under similar cost of service frameworks.

It is notable that California's PUC has required its regulated utilities to file smart grid deployment plans consisting of eight elements (a vision statement, deployment baseline, smart grid strategy, grid security and cyber security strategy, smart grid roadmap, cost estimates, benefits estimates, and metrics) (California Public Utilities Commission 2010, 29). With regard to communications standards, the PUC deferred a decision on adoption of specific standards in 2010 until the US' National Institute of Standards and Technology (NIST) had made sufficient progress on national standards (16). Instead the PUC's focus, as expected under cost of service regulation, is on the cost-benefit analysis of the project and cost recovery methods. There seems to be little scope for coordination between regulated firms; since each utility is required to have its own smart grid deployment plan, it would be possible for each utility to implement a different aspect of the smart grid (or use a different communications system or hardware technology) in its service territory even though all of them are regulated by the California PUC. This contrasts with the more coordinated top-down approach taken to smart metering projects in the UK and Italy.

The inclusion of progress metrics as a key element in the smart grid deployment plans represents an area of overlap with the principles of measurement and reporting that underlie outputs-led incentive regulation. Indeed, the need for and importance of metrics has been noted in other areas of grid modernization such as cybersecurity (Government Accountability Office 2011). California's PUC recently published a set of progress metrics to measure regulated utilities' progress towards smart grids, although it seems that specific targets are not binding (California Public Utilities Commission 2012, 2012) whereas they are likely to be under the UK's upcoming outputs-led regulatory scheme.

Most significant grid modernization projects in the US are currently financially supported by the US federal government's Smart Grid Investment Grants (99 projects) or Smart Grid Demonstration Projects initiatives (32 projects) (U.S. Department of Energy 2012). The government funds up to 50% of the cost of projects supported under the Investment Grant or Demonstration Project initiative. While the Demonstration Projects showcase the feasibility of new technologies relating to the smart grid or to energy storage, the Investment Grants fund modernization of the existing grid using feasible and relatively established new technologies in areas ranging from advanced metering and distribution automation to electricity transmission. In

a sense, the Investment Grants resemble the Low Carbon Networks fund used in UK electricity distribution. US metering projects in particular are often designed and proposed by private utilities, in contrast to the situation in the UK and Italy where the government regulates smart metering rollouts.

Comparing Approaches: Smart Grids and Smart Meters

Table 3 compares the regulatory and grid modernization approaches taken by these countries by focusing on their smart metering programs. But because US implementations of smart metering vary so widely between states and distribution companies, the example program used is the Smart Grid Deployment Plans mandated by the California regulator.

Table 3. Comparing smart metering and smart grids in Italy, the UK, and California

Area	California (smart grids)	Italy (smart meters)	UK (smart meters)
<i>Deployment schedule</i>	<ul style="list-style-type: none"> • Determined by companies 	<ul style="list-style-type: none"> • Defined in 2006 regulation; over 95% of LV customers to have installations by end 2012 	<ul style="list-style-type: none"> • Defined by government as 2019
<i>Meter functionalities/Technical Requirements</i>	<ul style="list-style-type: none"> • Determined by companies 	<ul style="list-style-type: none"> • Defined in 2006 regulation • Metering intervals regulated • Installation of in-home display required • Vital service mandated even without payment; reconnection within 1 day after payment • Incentive to record interruptions using smart meters 	<ul style="list-style-type: none"> • Functional Requirements defined by government e.g. two way communications • Requirement to offer in-home display • Other areas under consideration for regulation include interoperability requirement to suppliers' licences
<i>Time-of-Use, Critical Peak, other advanced pricing</i>	<ul style="list-style-type: none"> • No explicit regulatory requirement for ToU or other similar pricing 	<ul style="list-style-type: none"> • Regulated to introduce mandatory ToU pricing for all customers by end 2011 	<ul style="list-style-type: none"> • Meters must be technically capable of supporting time-of-use tariffs, but no explicit requirement to implement tariff

Table 3. (continued)

Area	California (smart grids)	Italy (smart meters)	UK (smart meters)
<i>Data communications approach</i>	<ul style="list-style-type: none"> For smart grid projects, determined by companies; Commission will await national interoperability standards before adoption decision 	<ul style="list-style-type: none"> Was established using Power Line Carrier communications over LV distribution network 	<ul style="list-style-type: none"> Managed by new data communications company regulated by Ofgem
<i>Multi-regional coordination</i>	<ul style="list-style-type: none"> Each company's service territory can have different technology 		<ul style="list-style-type: none"> New data communications company integrates all meter data
<i>Role of regulator/government</i>	<ul style="list-style-type: none"> Regulate cost recovery for meters and other investments 	<ul style="list-style-type: none"> Top-down; mandates smart metering 	<ul style="list-style-type: none"> Top-down; mandates smart metering Regulates the data communications company Sets meter technical specifications

Sources: Italy data from Lo Schiavo et al. (2011), Meeus et al. (2010). UK data from DECC and Ofgem (2011), DECC (2012). California data from California PUC (2010).

It is clear that the regulatory body and governments play a much more direct role in mandating and regulating deployments in Italy and the UK. However, the fact that private companies drive the modernization process in California may give projects there a greater impetus.

Conclusions from Comparative Analysis

The experiences of these countries, then, illustrate notable shifts in regulatory thinking about incentive regulation. Their approaches to grid modernization can be summarized in three trends. One is the focus on distribution network outputs for regulation of the distribution companies, which implies corollary foci on the development of appropriate metrics, performance measurements, and regulatory target setting. The second trend, which is applied selectively to nationwide rollouts of certain new technologies like advanced meters and less often to localized grid modernization projects, is increasingly detailed regulatory intervention including the dictation of minimum technical specifications for specific projects. The third is regulators' increasingly explicit focus on encouraging innovation, whether by providing grants to carry out

innovative projects or by allowing innovative projects to earn a higher return. This implies corollary foci on extending the length of the price/revenue control period to allow innovative projects more time to reach fruition (in incentive regulation), and shortening asset lives to encourage investments and (in some cases) recognize the shorter useful life of innovative new technologies. Figure 4 depicts these trends, highlighting countries that have given especial priority to each trend.



Figure 4. Trends in modern grid regulation. Countries that have prioritised a particular trend are highlighted in bold font.

Several of these trends appear to be somewhat contradictory. For example, the desire to encourage innovation by regulating outputs rather than inputs, leaving companies free to choose different approaches to achieving the outputs, is at odds with dictating detailed technical specifications (leaving companies less freedom) for projects such as AMI rollouts. This might be understood via the need to exert more control over special cases like AMI rollouts, which are one-off projects for the entire country (or service territory). But dictating specifications can increase the risk of missing innovative approaches or new technologies as they emerge.

Thus far, countries like the UK and Italy have prioritized the first trend – focusing on regulating outputs in a top-down approach. Many PUCs in the US have focused more on the second trend, driving innovative grid modernization via a bottom-up funding approach. But all three trends are seen to some extent in modern regulatory approaches. Whereas the US funds projects out of funding pots, the UK and Italy may employ other funding measures like the 2% additional return on capital for innovative projects (in Italy) or the additional revenue driver for innovative connection projects under the Registered Power Zones scheme (in the UK).

It remains to be seen whether the more regulator-driven regime in the UK and Italy, as opposed to the industry-driven process in the US, will affect the speed of AMI or smart grid program rollouts. The Italian smart metering rollout is expected to cover more than 95% of low voltage customers by the end of 2012 (Lo Schiavo, et al. 2011). The UK has recently set a target of 2019 for the AMI rollout to be complete nationwide (Department for Energy and Climate Change (DECC) 2012). The US is not dictating the timing of AMI rollouts at the national level, but the Federal Energy Regulatory Commission's 2011 update on smart metering reports AMI penetration of 8.7% (from a 2010 survey covering the year 2009) (Federal Energy Regulatory Commission 2011).

The preceding sections of this chapter describe several regulatory issues introduced by new technologies, including regulating capital investment, performance, and innovation. Outputs-based regulation can be seen as an attempt to address some of these issues. First, in terms of regulating capital investment in the networks and in the new technologies, outputs-based regulation under a RPI-X framework allows companies the freedom to make investment decisions as long as the output targets are met. Alternatively some aspects of outputs-based regulation such as metrics development and measurement may be adopted but regulatory remuneration continue to occur under cost of service regulation; some US states may eventually arrive at such a scenario. Then companies may propose any investment to the regulator, in theory having freedom of choice over the investments proposed, but they will still run the risk of having the proposal rejected and if risk averse, may choose not to make the proposal anyway. Second, in terms of regulating performance, outputs-based regulation is similar to setting performance targets. If coupled with the right rewards and penalties, it can be an effective method of ensuring a reasonable level of quality of service. Third, in terms of regulating innovation, outputs-based regulation – compared to inputs-based regulation – frees companies to implement innovative methods of managing new technologies so that the output targets are achieved.

The regulatory reforms adopted to date – especially the focus on outputs – are signs that regulators perceive the need for change to keep up with modern developments. It seems clear that outputs-based regulation is the way forward in terms of leaving the field open to innovation while achieving modern goals including environmental sustainability. In the US it could be useful to have a more coordinated approach to this aspect of regulatory reform across states; currently, some Public Utility Commissions such as California's are adopting a more proactive

approach than others. That said, the varied state of electric utility restructuring in different states and the mix of industry structures, from vertically integrated companies to retail competition, make it difficult to adopt a one-size-fits-all regulatory approach.

2.4.2 Regulatory Incentives

Technology or issue-specific incentives are distinct from the general regulatory schemes (such as incentive regulation schemes) that are evolving to encourage distribution grid modernization. Incentives may be added to conventional regulatory schemes, or may be deeply integrated into the design of a new or evolved regulatory scheme.

Incentives deserve particular attention because they can be especially useful for grid modernization projects. Often a new grid technology, such as an advanced or “smart” meter, has to be installed once so that it can be used for many years. Well-designed incentives can encourage these one-off, capital-intensive improvement projects. Furthermore, connecting new technologies, such as distributed generation, may affect distribution companies’ required network investments, distribution grid system operation, and system performance (voltage control, power quality, etc.) (Bayod-Rújula 2009, Pepermans, et al. 2005, Frías, Gómez and Rivier 2008). Therefore, targeted incentives often aim to modify the regulated asset base or allowed revenue by an amount that compensates the distribution company for the targeted technology’s effect on revenue. Well-designed incentives can thus encourage appropriate integration of the technology into regular distribution network operations.

The absence of such incentives can make companies reluctant to undertake the connection and installation work, not to mention the operational changes necessary to accommodate the new technologies. This is especially true for technologies where the upfront costs of connection and integration with the distribution grid are high.

Incentives for Distributed Generation

To date, incentives to encourage the integration of specific new technologies have largely focused on connecting, integrating, and optimizing the use of distributed generation. The following discussion concerns incentive approaches to tackle the issues of regulating capital expenditure (capex) and network performance in the presence of DG. The approaches that have been discussed for DG may serve as useful case studies for other new technologies.

The comprehensive report by the DG-GRID project of the European Commission enumerates 5 possible incentives for distributed generation, which were subsequently further studied in other papers and merit discussion here (Bauknecht and Brunekreeft 2008, Scheepers, et al. 2007, Frías, Gómez and Rivier 2008). These incentives assume an RPI-X incentive regulation scheme with a regulated asset base and a basic revenue cap formula:

$$TAR_t = TAR_{t-1}(1+RPI-X)$$

The incentives can be classified as extrinsic changes to the remuneration formula, or as intrinsic changes to the regulatory process to capture the effects of DG on the network. They range from direct modifications to the classic revenue cap formula, to changes to the benchmarking procedure.

1. Passing through costs of DG

$$TAR_t = TAR_{t-1}(1+RPI-X) + z\%I \quad \text{following de Joode, et al. (2009)}$$

This method, applied to revenue cap incentive regulation, simply passes through to customers a certain percentage of the costs of DG. The utility is guaranteed remuneration of z percent of the investment cost I of upgrading its network to integrate DG. This allows for direct remuneration of investment, similar to cost of service regulation. However, the value of z can be set to less than 100% to avoid the Averch-Johnson effect of overinvestment in capital when full cost recovery is guaranteed. This method relies on a certain degree of regulatory judgment as to how much of the cost to pass through to final customers.

2. Including a quality indicator in the regulated asset base (RAB) formula to capture DG's effects on network quality

$$TAR_t = TAR_{t-1}(1+RPI-X+Q) \quad \text{following de Joode, et al. (2009)}$$

This addresses the issue of regulating performance discussed above by focusing on DG's effects on the distribution network; for example, the reverse power flows from DG into the network can affect the frequency of the power system and the power quality (Pepermans, et al. 2005). This incentive adds a Q indicator to the equation for total allowed revenue to acknowledge that more DG connections can increase quality-related

costs, so distribution companies accommodating more DG should receive an appropriately incremented revenue. This method also relies on regulatory judgment to compute an appropriate value for Q. For revenue cap applications where a Q indicator is already included to incentivize quality of service, as in Italy, this method might necessitate modifying the indicator to factor in the effects of DG.

3. Including one or more revenue drivers in the revenue cap formula

$$\text{TAR}_t = \text{TAR}_{t-1}(1+\text{RPI-X}) + k_1k\text{W}^{\text{DG}} + k_2\text{MWh}^{\text{DG}} \quad \text{following de Joode, et al. (2009)}$$

This method allows the regulator to separately target DG connections and actual DG use (use of or integration of DG into the network). This could be viewed as a more sophisticated version of method 1, cost pass-through.

Although DG connections and DG use are the possible revenue drivers in this example, other metrics might conceivably be used. Here, the first revenue driver k_1 increases the DSO's revenue for each new DG connection made to the network. This can stimulate the DSO to invest in the network as necessary to increase DG uptake. However, the driver may also simulate investments in the network over and above the optimal level – giving rise to the Averch-Johnson overinvestment effect. A possible advantage of a revenue driver is that it encourages companies to decrease the cost of connection to a level below that of the revenue driver (Scheepers, et al. 2007, 46). The calculation of the revenue driver will then be especially important. That said, as Bauknecht and Brunekreeft (2008, 490) note, the DSO may also be incentivized to prevent any DG connecting where the connection costs are above the amount of the revenue driver.

The second revenue driver k_2 rewards the distribution company for each MWh of DG that is used to meet network demand. This encourages the distribution company to actively utilize the DG and may also provide it with revenue for operating costs and maintaining performance.

4. A combination of methods (1) and (3)

$$\text{TAR}_t = \text{TAR}_{t-1}(1+\text{RPI-X}) + z\%I + k_I\text{MWh}^{\text{DG}} \quad \text{following de Joode, et al. (2009)}$$

In this method a cost pass-through is combined with one (or potentially more) revenue drivers. This guarantees the DG some remuneration of cost while encouraging it to utilize the connected DG.

This method has been applied to UK electricity distribution since 2005, when it was adopted as part of the fourth distribution price control review and retained at the fifth price control review. Under the method in use in the UK during the present (fifth) price control, $z=0.8$ (80% of costs are passed through) and the revenue driver is £1.00/kW/yr for most of the regulated firms (it was £1.50/kW/yr for most regulated firms during the fourth price control). An additional allowance of £1/kW/yr is given for operation and maintenance costs. The overall returns on DG earned by the regulated firm have a cap and floor to decrease uncertainty (Office of Gas and Electricity Markets (Ofgem) 2004, 2009).

5. Changing the regulatory scheme: Changing the benchmarking process to allow for DG, or allowing companies more liberty to decide the spending allocation between OPEX and CAPEX

In addition to more direct incentives, some proposals center on taking DG into account at an earlier stage in the regulatory process. DG can be taken as an input factor during the benchmarking analyses that determine companies' relative efficiency. This would allow DG performance metrics to affect the computed productivity of each firm so that when firms are compared to each other, DG is intrinsic to the comparison and the calculation of X (Scheepers, et al. 2007, 45). Alternatively, the regulator can retain the original method of benchmarking companies' efficiency and adjust the results to allow for DG's impact (Scheepers, et al. 2007, 46).

Finally, in incentive regulation, the regulator can regulate overall spending (capital expenditure plus operational expenditure) leaving it up to the companies to decide the division of spending between capital expenditure and operational expenditure. This can allow companies to increase their operational expenditure to improve system performance, which may be necessary to fully integrate DG (Scheepers, et al. 2007, 46).

Bauknecht and Brunekreeft (2008, 482) also note that when capital and operational expenditure are regulated separately and the distribution company is benchmarked against others for operational expenditure efficiency, it may make higher capital investments to accommodate DG instead of accommodating it through operational investments in active management.

These methods are less specific to DG and might also incentivize investment in operational measures to integrate other technologies such as electric vehicles. Then again, it is unclear whether these less targeted methods would in fact improve DG integration.

Although most of the above schemes were developed with DG in mind, a number of them could also be appropriate for other emerging technologies. For example, a modified revenue driver (method 3) could be applied to encourage integration of electric vehicles or including distribution automation in the regulated asset base (method 1) could encourage DSOs to invest in distribution automation. A challenge for regulators is designing an integrated regulatory scheme that contains incentives appropriate to each technology.

It may be possible to introduce features to the regulatory scheme that present companies with a choice between the type of incentive. Bauknecht and Brunekreeft (2008) suggest the application of a sliding-scale mechanism that gives companies a choice between pure cost pass-through and full price cap. The choice encourages companies to reveal the true costs of connecting DG, because companies for which DG is expensive to connect will choose a greater cost pass-through whereas companies for which DG is cheap will choose a price cap.

A number of factors are likely to influence regulators' choice of incentive scheme. One is the relative uptake of each technology in the network. For example, to encourage distribution companies to integrate a new technology into their network it may be wise to stimulate connections by attaching a revenue driver to the number of connections. Conversely, for a distributed generation technology that already has many connections to the network, the revenue driver could be attached to the MWh of electricity it contributes to the network so that the distribution company is incentivized to ensure it maximizes the use of DG. Another factor is political: if there is special interest in encouraging a specific technology, the incentives for it can be made stronger. The mix of incentives can also depend on regulators' views of how DG (or

other technologies) should be used within the network. If it is desired to encourage network operators to use DG to offset capital investments in ancillary services such as frequency response, an incentive remunerating operators using DG for ancillary services would be appropriate.

Incentives for Innovation

Innovation merits a separate discussion because of the increasing attention incentives for innovation are receiving from regulators (Office of Gas and Electricity Markets (Ofgem) 2009). Stimulating appropriate capital expenditure and ensuring appropriate remuneration are especially important for innovation. Innovation can be tackled as a specific issue, for example by designing incentives to encourage expenditure on innovative projects. Alternatively, incentives may target innovation around specific new technologies. For example, the Registered Power Zones scheme in the UK funds innovative distributed generation solutions by adding an innovation incentive on top of the distributed generation incentive (Office of Gas and Electricity Markets (Ofgem) 2004, 46).

This section discusses and categorizes a number of approaches to incentivizing innovation. Some have been proposed and others are in use. Some are similar to the methods studied or proposed for distributed generation. It will be important to consider whether a similar approach can be used effectively to stimulate different aspects of grid modernization such as distributed generation take-up and innovative projects.

Regulatory approaches to innovation can be extrinsic or intrinsic to the regulatory scheme. Intrinsic approaches can include including innovation in the regulated asset base (similar to method 1 for DG, above), extending the length of the regulatory period in incentive regulation, or moving from frontier to average benchmarking during the analysis of regulated firms' cost or performance. While this last is suggested as an effective incentive for distributed generation by the EU's DG-GRID study, the study also mentions that "average benchmarking is more favourable to network innovation as it is easier for DSOs to capitalize on the efficiency gains due to their innovation investments" (Scheepers, et al. 2007, 45). Hence average benchmarking can also be a method of indirectly stimulating investment in innovative projects. Extrinsic approaches can include establishing a separate regulated cost base for innovation, and mandating a certain level of innovation spending. Finally, while innovation cost recovery can be addressed through use of system charges, establishing ex ante funding pots specifically for

innovative projects could direct the revenue from the charges towards funding innovation. In this way, the existence of the pot incentivizes innovation.

1. Passing through costs of innovative projects

The costs of innovative projects can be passed through to customers. The UK’s Innovation Funding Incentive (IFI) introduced during the fourth price control review for 2005-2010 mitigates the cost of R&D for innovative distribution grid projects by establishing a mechanism that allows the costs to be partially passed through to customers (Office of Gas and Electricity Markets (Ofgem) 2004). The 20-year review carried out in 2010 of the UK’s existing RPI-X regulatory scheme noted that this incentive appeared to have been very successful in stimulating R&D spending, as shown in Figure 5.

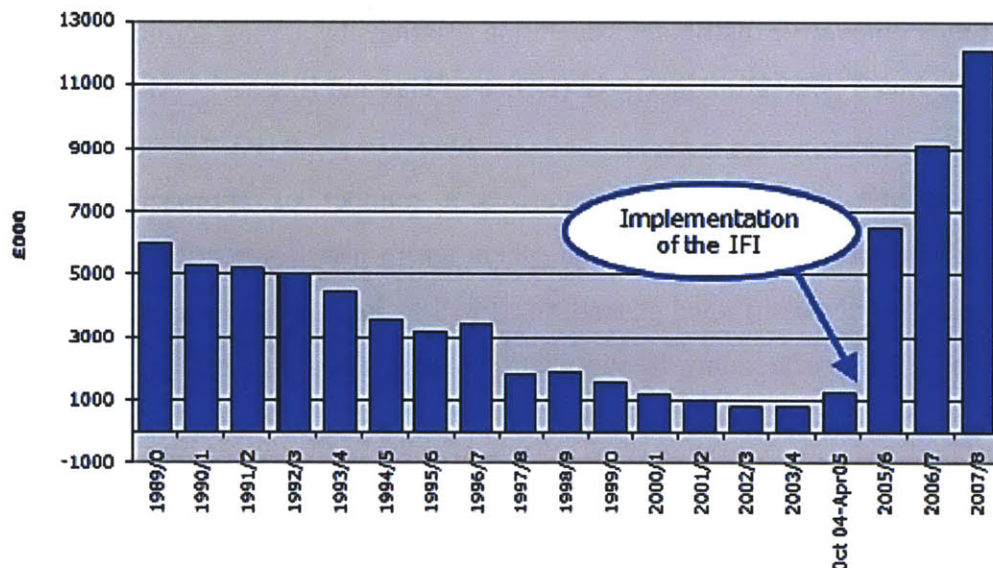


Figure 5. R&D Spending in UK distribution networks. *Source:* Office of Gas and Electricity Markets, “Regulating energy networks for the future: RPI-X@20 - Innovation in energy networks: Is more needed and how can this be stimulated?” (2009, 5).

2. Including an additional revenue driver for innovative projects

This is the method employed by Ofgem in the UK under its Registered Power Zones scheme. While this scheme in fact targets DG connections, the RPZ incentive gives an additional £3/kW/year on top of the DG incentive to DG projects employing innovative connection schemes, up to a cap of £0.5 million per distribution company (Office of Gas and Electricity Markets (Ofgem) 2004, 46).

3. Extending the length of the regulatory period

The 2007 DG-GRID study suggests that “a long-term framework, spanning several regulatory periods with clear and reliable objectives for DSOs” can help stimulate innovation (Scheepers, et al. 2007, 55). In its upcoming RIIO reform, Ofgem proposes extending the price control period from five to eight years, in part to encourage innovation (Office of Gas and Electricity Markets (Ofgem) 2010). However, Ofgem did not view this measure in itself as sufficient to encourage innovation and introduced a separate innovation stimulus as well.

4. Benchmarking

The 2007 DG-GRID study argues that an incentive regulation scheme incorporating average benchmarking will foster more innovation than frontier benchmarking, because average benchmarking enables an innovative company to benefit more from the greater productivity due to its innovations (Scheepers, et al. 2007). That said, the strength of this argument depends on the scope of the benchmarking implementation. For example, if losses are benchmarked it is true that a company might benefit from innovative solutions to reduce network losses. But a company with an innovative solution to connect expensive DG might not benefit from average benchmarking if DG connections are not benchmarked.

5. Innovation as a separate regulated cost base

To acknowledge the longer-term returns from R&D on innovation, the 2007 DG-GRID study suggests establishing a separate regulated asset base for innovation (Scheepers, et al. 2007). This enables a higher rate of return to be applied to innovative projects, although the design and regulation of such a scheme could be complex.

6. Mandating R&D

Citing Brazil as an example, the DG-GRID study suggests that mandating R&D spending may be another way of encouraging innovation (Scheepers, et al. 2007). In Brazil, a 2000 law mandates that 1% of utilities’ revenues is set aside for research; Jannuzzi finds that

utilities undertook progressively longer, more expensive research projects as their experience with R&D improved (Jannuzzi 2005, 1759-1760). Some of the money is allocated to specific purposes such as an R&D fund which allows for more risky and longer-term projects to be funded. It is similar to the funding pot approach except that its funds are determined as a percentage of utility sales revenues, so more R&D spending will occur when utilities earn higher revenue. This differs from the UK approach to funding pots, where the precise size of the pot has to date been established *ex ante*. The UK approach might offer more predictability but the Brazilian approach maximizes the potential of utilities' economic returns.

7. Funding pots

Funding pots that operate outside the main regulatory scheme are another means of stimulating innovation. For the UK's 5th distribution price control from 2010-2015, Ofgem introduced the £500m Low Carbon Networks fund directed at innovative projects (Office of Gas and Electricity Markets (Ofgem) 2009, 3). While Ofgem's earlier Innovation Funding Incentive funded innovative projects using cost pass-through, the design of the Low Carbon Networks fund introduces an element of competition for the funding which arguably stimulates more innovative projects. Currently, the Low Carbon Networks fund operates alongside the existing Innovation Funding Incentive that funds projects through cost pass-through. Ofgem suggests that the Incentive targets technical R&D, while the fund targets innovative low carbon projects (106). Sharing of experiences and lessons learnt from the pilot projects is a condition for receiving Low Carbon Networks funding (Office of Gas and Electricity Markets (Ofgem) 2009).

Ofgem's new RIIO regulatory scheme to be applied to distribution from 2015 will contain an innovation stimulus package (Network Innovation Competition) that will also fund innovative projects separately from the price control process; in distribution, it will be merged with the Low Carbon Networks fund (Office of Gas and Electricity Markets (Ofgem) n.d.). The package will be introduced "until the incentives inherent to the RIIO model are found to be encouraging required innovation themselves or there is a reduction in the level of innovation required" (Office of Gas and Electricity Markets (Ofgem) 2010,

129). Thus, the stimulus operates as a temporary support to the regulatory scheme. The package will be open to third party companies as well as the regulated networks (Office of Gas and Electricity Markets (Ofgem) 2010).

The amount of money available for the Low Carbon Networks fund was established ex ante as part of the price control decision. The innovation stimulus package is to be funded through customer use of system charges. From the RIIO proposals to date, it appears that the amount of money available for the innovation stimulus package will also be determined as part of the price control review process (Office of Gas and Electricity Markets (Ofgem) 2010, 124).

The experiences of the countries studied here reveal that different approaches to regulating innovation can modify the direction and length of innovation R&D spending. Funding pots are useful in stimulating spending, although depending on how they are funded and administered they may only stimulate projects of a certain length or scope. A mix of approaches, such as lengthening the price control period, mandating R&D spending or establishing funding pot contributions, might be needed to stimulate different areas such as spending on short versus long-term innovative projects or on technical R&D versus innovative projects. A regulatory design challenge is finding the balance appropriate to the electricity system in question. A regulatory implementation challenge is appropriate oversight to determine what projects are eligible for the different types of incentives.

The measures used to stimulate innovation might be similar to those used for DG – for example, revenue drivers can help adjust remuneration to account for the costs of both DG and innovative projects. Other measures do not overlap as much; for example, funding pots are more useful for innovative projects since distribution companies have to be incentivized to make the necessary capital investments upfront, while the concept of a per-kWh revenue driver is only relevant to DG and not generic innovative projects. Depending on the priorities of the system, a regulator may choose a mix of incentives.

2.4.3 Developing Appropriate Regulation

Knowledge of the effects of new technologies, such as distributed generation or more innovative network management approaches, on distribution network costs is useful to establish the allowed revenue and can also inform the design and selection of appropriate regulatory schemes and incentives. As described in Chapter 1, Reference Network Models or RNMs can determine the network costs of connecting and supporting new technologies. The following chapter describes and applies two types of RNMs to study distribution network costs under a variety of new technology scenarios.

Chapter 3: Modeling New Technologies in the Electric Distribution Grid

3.1 Modeling the Network Costs of New Technologies

This chapter models the network investments needed to accommodate new technologies using two types of Reference Network Model (RNM): the greenfield model and the brownfield model. The first half of this chapter describes the use of the greenfield model to analyze the cost of building a distribution network under different scenarios of DG penetration. Results are obtained for the investment costs needed to accommodate DG and the impact of DG on network losses costs. These results are useful as an approximation to some of the potential costs and benefits of DG in a network.

The second half of this chapter describes the analyses undertaken using the brownfield model. The brownfield model can analyze the cost of expanding an existing network to accommodate customers with demand response, distributed generation, and electric vehicles. In this study, the cost of expanding the network is analyzed when the technologies are passively managed, and when they are actively managed. These results are useful as an approximation of the relative costs and benefits of different network management methods for new technologies.

3.2 Modeling Distributed Generation in Distribution Networks

As briefly touched on in Chapter 2, DG can have a positive or negative overall economic effect on distribution companies. It may help the network reduce losses, but can also necessitate greater expenditure on power quality and ancillary services for voltage control. The following discussion of DG's costs and benefits draws upon Gómez ((forthcoming)).

Distributed generation may add to network costs in several ways. First, the presence of new distributed generators means an additional component to connect to the system, implying a connection cost. This connection cost will be higher the further away the distributed generators are from the network, since the length of lines required will be longer. Second, the presence of distributed generators may add to network losses costs especially when DG penetration is so high that DG supplies most of the energy demanded by the network, meaning that net power flows are in the opposite direction to power flows in the situation without DG. Third, distributed generation may add to system operation costs since there is a need to manage an additional power source within the network. Fourth, DG whose generation is variable and imperfectly predictable (such as small-scale solar or wind) may affect aspects of quality of service such as voltage quality and can necessitate additional investments in measurement and control systems to

maintain the same level of quality of service, or additional investments in ancillary services for spinning reserve capacity to fill the gaps in DG power production (Gómez (forthcoming)).

In other ways distributed generation may provide benefits to the network, decreasing network costs. Distributed generators located close to customers may help meet demand for generation located far away, reducing the cost of upstream losses in the distribution network. The contributions of DG to power generation may also decrease the need for future investment in the network. If the network has to meet targets relating to greenhouse gas emissions or environmental protection, renewable DG may help replace conventional, more polluting generators. DG could also be an enabler of islanded grid operation, in which a part of the grid is isolated from the rest of the network when its connection to the network is broken or disabled (for protection from faults in other parts of the grid, for example) so that it has to operate in islanded mode. DG within the “island” may serve as a backup generator supplying the island with electricity and ensuring continued operation. This can improve the network’s performance on quality of service metrics (Gómez (forthcoming)).

Knowledge of the network costs and benefits of integrating DG can thus assist regulators and companies in planning for the future. In the following sections, a greenfield reference network model is used to analyze the network costs of integrating DG into distribution networks.

3.2.1 Description of the Greenfield Model

The greenfield model is able to model the cost of building the optimal distribution network required to serve the customers and DG units that are set as input. As the network is built from scratch, the costs of the network may be interpreted as an approximation to long-run network costs. The following description of the greenfield model in use for this analysis draws upon the descriptions of the model and the modeling process in Mateo Domingo, et al. (2010) and Cossent, et al. (2010).

The “greenfield” reference network model takes as input the set of customers in a given network’s service area. In the following discussion, a *customer* is an entity or household that has entered into a contract with the distribution network for power delivery. In the data provided to the model, each customer is georeferenced by his geographical coordinates and *contracted power capacity*. The *contracted power capacity* is the maximum amount of power the customer may draw from the distribution network. More than one customer may have the same geographical coordinate when, for example, the customers are located in the same apartment building. In the

following discussion, each unique geographical coordinate is termed a *consumption point*. In general, a power line is built to each consumption point, and multiple customers connected to that consumption point may draw their power from that line. Customer data may be provided for high, medium, and low voltage customers separately.

A second type of input data is the set of distributed generation installations connected to the network. Each DG installation is georeferenced by its geographical (GPS) coordinates and the maximum power capacity each unit is contracted to contribute to the network.

Table 4. Greenfield model input data.

Data Type	Description of data
Customer	Geographical coordinates of customers, contracted capacity, connection voltage
Distributed Generation	Geographical coordinates of generating units, contracted capacity, connection voltage
Supply points	Geographical coordinates of transmission substations (power supply points to the distribution network)
Network equipment	Type of equipment (e.g. substations, lines), technical specifications (e.g. voltage level), economic specifications (e.g. investment cost, maintenance cost)
Technical constraints	Parameters such as customer simultaneity factors
Economic parameters	Parameters such as weighted average cost of capital (WACC)
Continuity of supply	Reliability indices relating to the required reliability of the network (for example, regulatory reliability requirements)

A third type of input data is data for transmission substations. These serve as power supply points for the distribution network. The model builds the distribution network given the coordinates and capacity of the transmission substations.

The model also takes a catalogue of network equipment data as input, to be used to build the output network. Network equipment data includes the technical specifications (voltage level, power, etc.) and the financial data (investment cost, maintenance cost, etc.) for each piece of equipment.

Finally, the model also takes as input a parameters file in which network-wide technical constraints, economic parameters, and continuity of supply indices can be set. Technical constraints include simultaneity factors for customers at low, medium, and high voltages. As it is highly unlikely that all customers simultaneously demand their full contracted power capacity from the network, the *simultaneity factor* for customers is an important technical parameter. Intuitively, this factor reflects the proportion of network demand that occurs simultaneously. It is possible to set different simultaneity factors for customers at low, medium and high voltage levels. An estimate of an LV customer's *effective power demand* is then given by the LV customer simultaneity factor multiplied by the customer's contracted capacity. Economic parameters include the weighted average cost of capital (WACC). Continuity of supply indices such as those defined by the IEEE (SAIDI, etc.) may be input to take account of regulatory requirements relating to network reliability.

The above data are necessary to run the greenfield model. In addition, it is possible to input additional supply point data such as the location of existing MV-LV substations instead of having the model create the optimal substations. However, such additional data is not necessary to run the greenfield model. Table 4 summarizes the greenfield model's data requirements.

Given the required input data, the model designs the network necessary to serve the customers and DG installations. First, the customers (loads) and distributed generators are modeled and classified by their number and load density as urban, suburban, concentrated rural, scattered rural, and industrial. Second, the model optimizes the network layout required to serve the input loads and distributed generators. Third, the model performs a power flow analysis for the layout and places the required power system equipment into the layout. The equipment and corresponding costs are taken from the network equipment data provided as input. Algorithms are used to size the network given the engineering constraints imputed by the locations and peak power flow needs of customers and distributed generation. The cost of the network is also minimized. Finally, the model adds any additional power system equipment required to ensure the network meets quality of supply requirements defined by the input continuity of supply indices. The final network is optimized from a technical and economic perspective.

The model produces two types of output files that fully describe the network required to serve the given set of customers and DG installations. First, it produces tables of cost and power flow data for the network required. The costs are broken down by network component (lines,

substations, and so on) and by type (capital investment, preventive maintenance, corrective maintenance, and losses). Second, the model produces a set of geographical information files in .SHX format. .SHX files may be opened in the software program ArcExplorer by ESRI (Esri, Inc. n.d.). When mapped in ArcExplorer, the set of files produces a visual representation of the geographical layout of the network required. Figure 6 summarizes the greenfield model's input and output processes. Several points relating to the brownfield model are also included in the figure; the brownfield model is described later in this chapter.

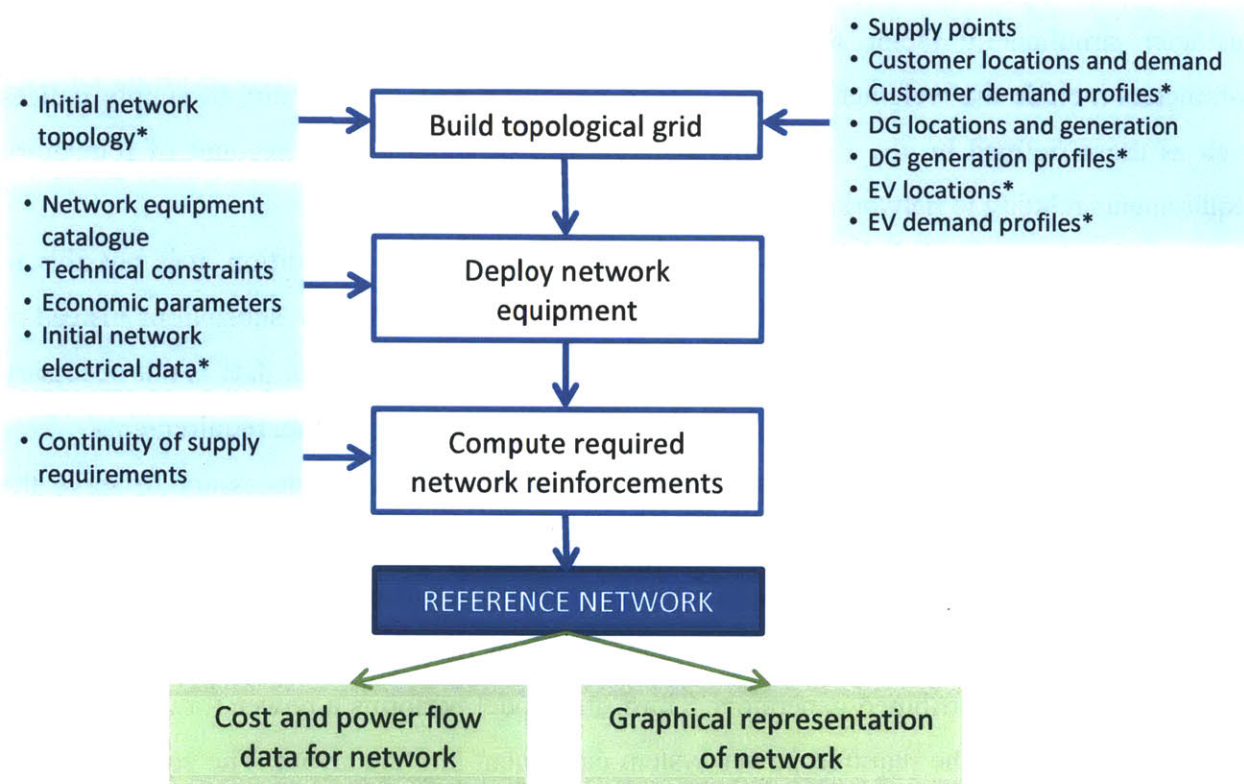


Figure 6. Flow diagram of model. An asterisk sign (*) denotes data input to the brownfield model only. Adapted from Cossent, et al. (2010).

It is important to note that the model does not include the exogenous capital costs of extrinsic control systems, software, and management systems that may be utilized by the utility to manage distributed generation power flows. The model calculates only costs intrinsic to the power network, such as higher-capacity wires or more substations needed to transmit the power flows. Exogenous capital costs can vary greatly depending on the size of the network, the number of customers, and the amount and quality of new technologies being installed. These

costs exist not only for distributed generation but also for other new technologies involving control systems and communications, such as advanced metering infrastructure. Table 2 shows that distribution system-related capital investments reported to date using funds from the US' Smart Grid Investment Grants total over US\$3.5 billion. A separate Electric Power Research Institute (EPRI) report estimates the costs of network modernization for the entire US grid (but does not separate out control systems that are specifically for DG); that report estimates the capital costs of installing distribution automation for the entire US distribution system to be between US\$124-177 billion (Electric Power Research Institute (EPRI) 2011, 6-17).

3.3 Modeling DG: Locations, Power Output, Penetration

It was desired to study the effect on network costs of DG located near to and far away from residential customers, at various DG per-unit power output levels and customer penetration levels. Throughout the following discussion, the *penetration level* of distributed generation refers to the percentage of customers who are modeled as having a DG installation. The following sections present the methodology and results for DG near to customers (residential DG), followed by the methodology and results for DG far away from customers.

3.4 DG Located Near to Customers

3.4.1 Methodology

A network of 66,848 customers was selected for analysis. Several customers in this network had the same geographical coordinates. This is the case when, for example, multiple customers are on record for the same apartment building location. Thus, despite there being 66,848 customers, there were a total of 14,492 unique geographical consumption points. Each of the 66,848 customers has a contracted power with the electric utility.

The model was run to compare the costs of building a network without distributed generation to the costs of building a network where 25, 50, 75, and 100% of customers had a residential distributed generation installation. To focus the results on the medium voltage (MV) and low voltage (LV) distribution networks, the transmission substations and HV-MV substations acting as supply points had their locations fixed in the same locations for all cases.

Two types of scenarios were used in this study. A “base” scenario consisting of 2 base cases with no or negligible DG power contributions to the network was developed for reference. The first base case B-1 represents the cost of building the network without any distributed generation installations. The network was built and network costs calculated for the 66,848 customers and levels of contracted power ranging from 3.3 kW to 10 kW. In the second base case B-2, the network was built for the same customers but 25% of customers were randomly selected to have a distributed generation installation that output negligible power. This base case therefore enables analysis of the connection costs of DG installations at the 25% penetration level.

Three “generation” scenarios were developed for the analysis of residential DG, each with a different power output per DG unit. Generation scenario 1 consisted of DG installations with a power output of 3 kW/unit. Generation scenario 2 consisted of DG installations with a power output of 0.5 kW/unit. Generation scenario 3 consisted of an equal mix of both types of DG installations: 50% of all units had a power output of 0.5 kW/unit and 50% had a power output of 3 kW/unit. For each of the generation scenarios, the model was run 4 times to obtain results for 4 cases representing 4 DG penetration levels: 25, 50, 75, and 100%; these 4 cases were named G1-25, G2-50, G3-75, and G4-100 respectively. At each DG penetration level, the corresponding percentage of customers was randomly selected to have a DG installation. The customers selected for the 25% penetration level case were the same as those modeled in base case B-2, to facilitate comparison of the results. In total, the model was run 14 times to obtain results for 2 base cases and 12 generation cases. Figure 7 summarizes the cases analyzed.

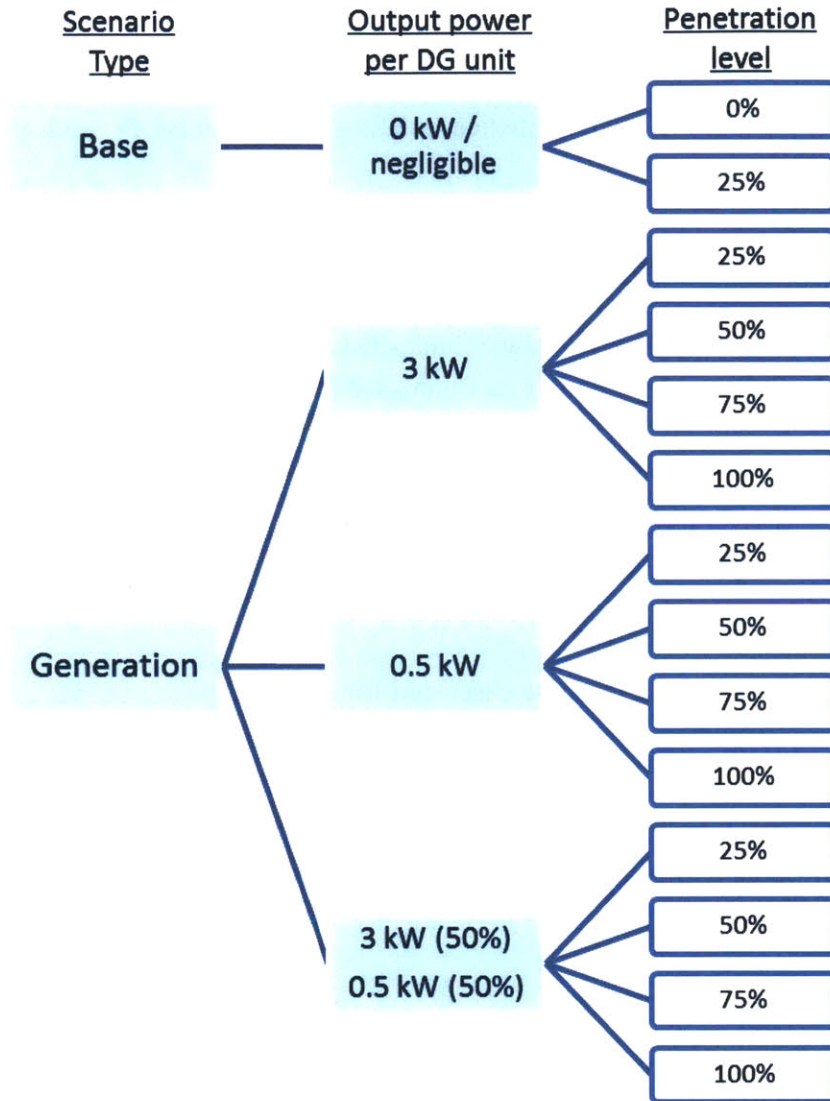


Figure 7. Modeling cases for residential DG

Throughout the generation scenarios studied, the power consumption and location of the 66,848 existing customers of the network were kept the same, with the only change being the addition of DG installations to the randomly selected customer locations. The coordinates of the DG installations were displaced by approximately 4.24 m from the customer coordinates to prevent the model from inaccurately consolidating the customers and installations. Because the greenfield model does not permit a time-differentiated power output, in order to run the model it was assumed that the DG installations produce a constant power output over time. In practice, this might be feasible for micro-CHP but is less likely for small-scale wind and solar. (The

brownfield version of the model, discussed later in this chapter, is able to model time-differentiated power output broken down by hour for 24 hours of a day.)

A summary of descriptive statistics relating to the network and its customers are presented in Table 5.

Table 5. Descriptive statistics of network

Unique Customers	66,848
Maximum Power Contracted (kW)	10
Minimum Power Contracted (kW)	3.3
Total Power Contracted (MW)	420
Unique Consumption Points	14,492
Customer simultaneity factor	0.3

3.4.2 Results

Results are presented for the base cases and for each DG power output level.

Base Cases

The results for the base cases are shown in Table 6 and a graphical representation of the base network built for case B-1 is provided for reference in Figure 8.

Table 6. Results for the base cases

Base Case B-1						
	Replacement cost of fixed assets (Investment cost) (euros)	Preventive maintenance cost (annual) (euros)	Corrective maintenance cost (annual) (euros)	Losses costs (euros)	Total (NPV) (euros)	Percentage contribution to total cost (%)
LV network	11,654,587	2,057	30,904	254,967	14,429,161	39.83
MV-LV substations	3,993,400	259,660	10,303	117,138	10,411,577	28.74
MV network	6,947,404	81,492	73,215	62,469	10,586,919	29.22
HV network	447,977	10,181	4,717	6,351	801,235	2.21
Total	23,043,368	353,390	119,139	440,926	36,228,893	100
Base Case B-2						
	Replacement cost of fixed assets (Investment cost) (euros)	Preventive maintenance cost (annual) (euros)	Corrective maintenance cost (annual) (euros)	Losses costs (euros)	Total (NPV) (euros)	Percentage contribution to total cost (%)
LV network	13,831,590	2,410	36,201	283,275	16,954,384	42.2
MV-LV substations	4,074,800	263,720	10,466	117,043	10,577,444	26.33
MV network	7,890,241	96,981	73,359	64,558	11,862,585	29.52
HV network	430,853	9,792	4,537	7,736	784,074	1.95
Total	26,227,483	372,903	124,563	472,612	40,178,488	100

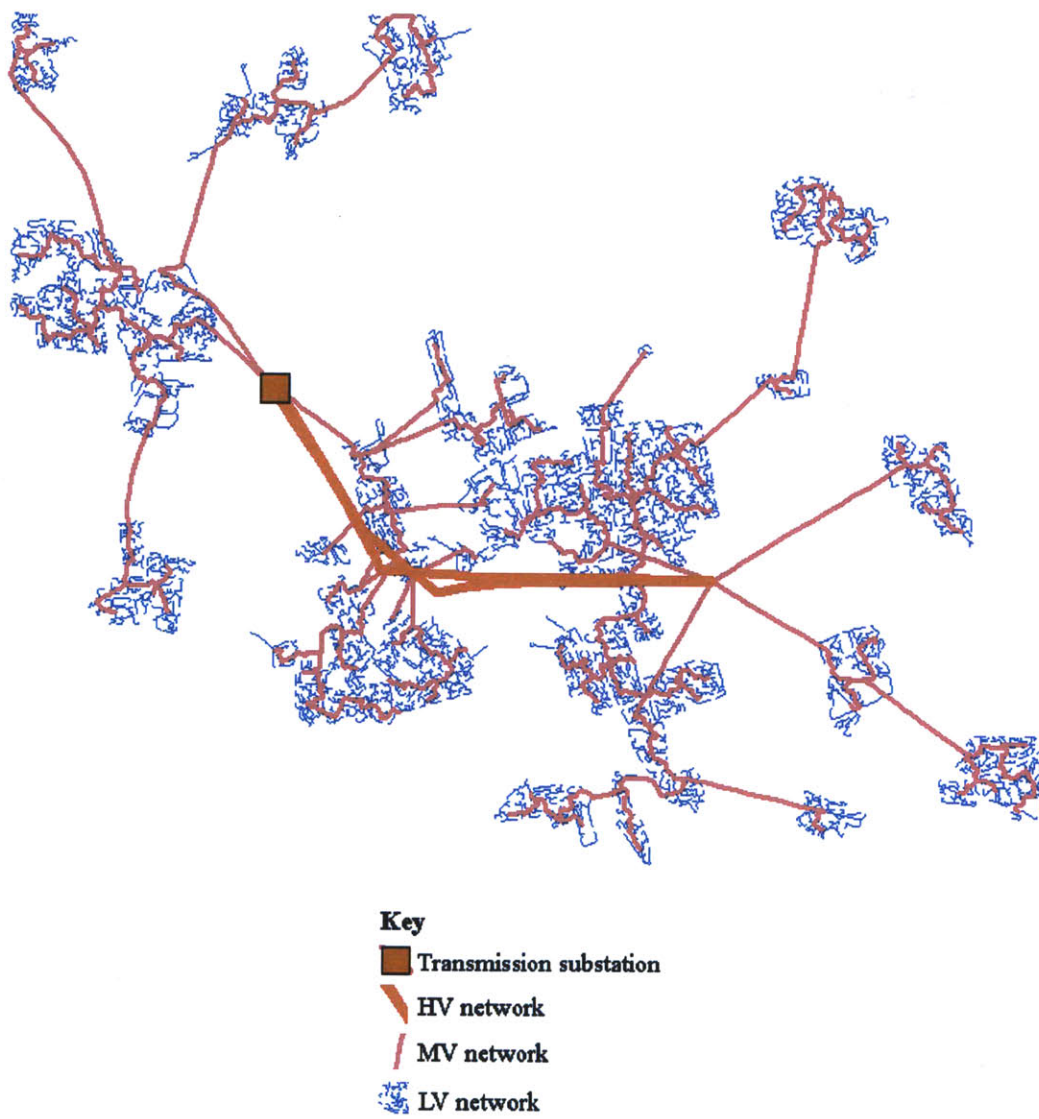


Figure 8. Graphical representation of the network for base case B-1

Generation Cases

For each of the 3 DG power output levels studied, results are presented for 4 DG penetration levels (25, 50, 75, and 100%). The results from the 2 base cases are included for comparison.⁷

Table 7. Results for base and generating cases at each penetration level studied. “Total Network Costs” are the sum of investment, maintenance, and losses costs output by the model.

Total Network Costs (NPV) (euros)						
Generation Scenario 1 - 3 kW/unit						
Case	B-1	B-2	G1-25	G2-50	G3-75	G4-100
DG Installed Power (MVA)	0	0	50.09	100.72	150.92	200.54
LV network	14,429,161	16,954,384	16,268,081	15,279,359	15,235,803	17,806,871
MV-LV substations	10,411,577	10,577,444	7,731,557	6,015,315	9,476,494	8,739,085
MV network	10,586,919	11,862,585	10,314,742	8,565,718	16,266,901	14,041,802
HV network	801,235	784,074	738,308	722,304	720,133	720,133
GRAND TOTAL	36,228,893	40,178,488	35,052,688	30,582,696	41,699,331	41,307,891
Generation Scenario 2 - 0.5 kW/unit						
DG Installed Power (MVA)	0	0	8.35	16.79	25.15	33.42
LV network	14,429,161	16,954,384	16,968,438	17,656,200	17,742,066	18,331,447
MV-LV substations	10,411,577	10,577,444	10,166,844	9,908,161	9,583,955	8,979,349
MV network	10,586,919	11,862,585	12,227,058	11,816,896	12,547,549	12,259,824
HV network	801,235	784,074	768,799	764,476	751,190	753,927
GRAND TOTAL	36,228,893	40,178,488	40,131,138	40,145,734	40,624,761	40,324,547
Generation Scenario 3 – 0.5 and 3 kW/unit						
DG Installed Power (MVA)	0	0	29.25	58.97	88.26	117.16
LV network	14,429,161	16,954,384	16,693,151	16,880,013	16,364,337	14,553,149
MV-LV substations	10,411,577	10,577,444	9,000,735	7,481,772	6,295,653	9,804,855
MV network	10,586,919	11,862,585	11,149,670	9,814,224	9,140,520	12,059,399
HV network	801,235	784,074	749,400	735,085	724,250	720,552
GRAND TOTAL	36,228,893	40,178,488	37,592,957	34,911,094	32,524,761	37,137,956

⁷ The model takes input for DG per-unit power output in kW. The results tables output by the model compute the total DG power output and present it in MVA. As DG is connected using direct current, the volt-ampere (VA) unit is equivalent to the watts (W) unit for power. In general, this study will place units in the same position they are in the model.

The results for each scenario are presented graphically in Figures 9-11 to facilitate a comparison of costs with respect to DG penetration level. The cost results are plotted alongside the effective customer power demand in the network, which is the contracted power multiplied by the simultaneity factor. The DG installed power is also plotted, as is the net power (the contracted power minus the DG installed power). Figure 12 shows graphical representations of the networks displayed in ArcExplorer for the 2 base cases and the 4 generating cases analyzed for generation scenario 1 with a DG power output of 3 kW.

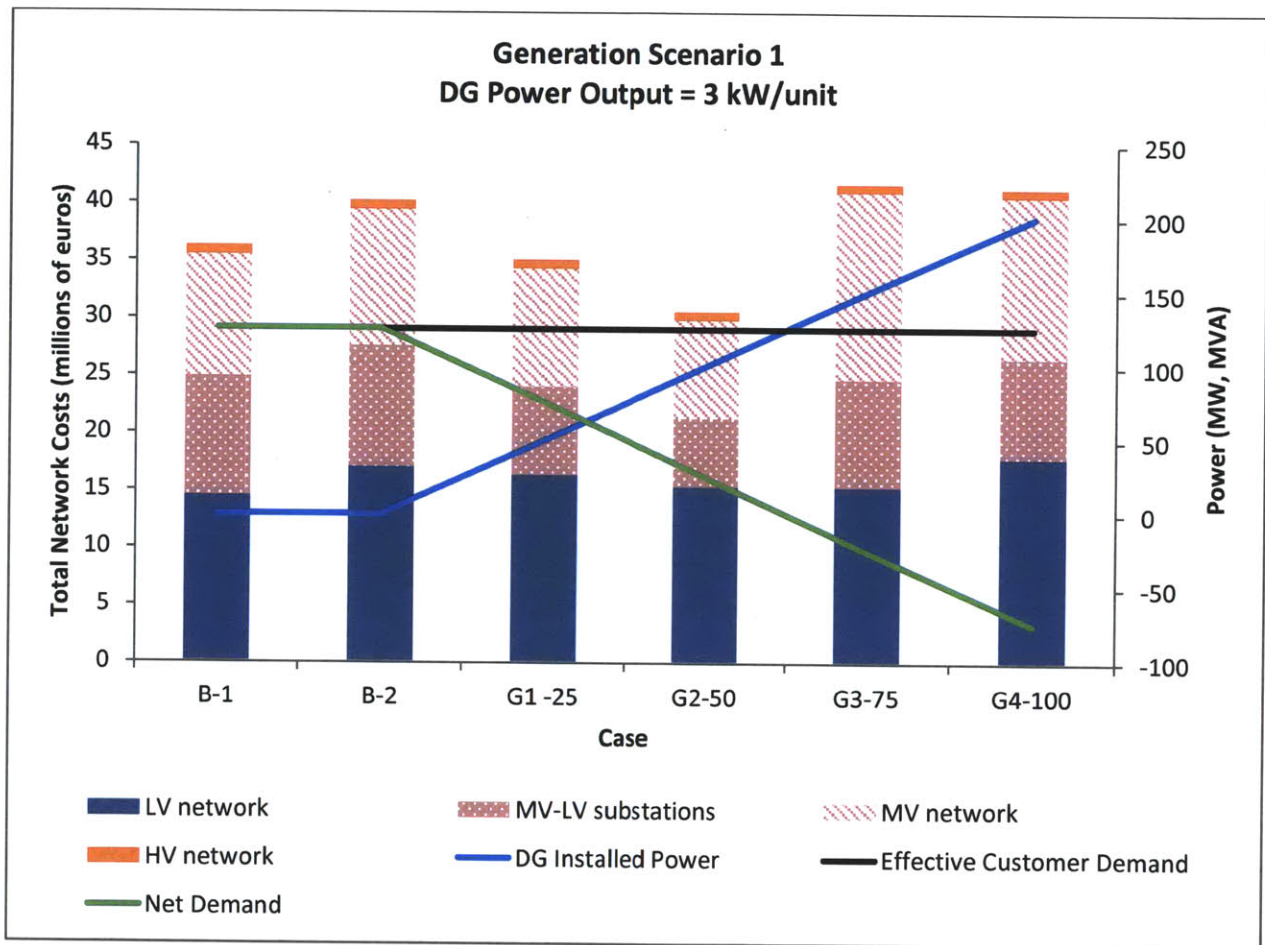


Figure 9. Results for generation scenario 1 with a DG power output of 0.5 kW/unit

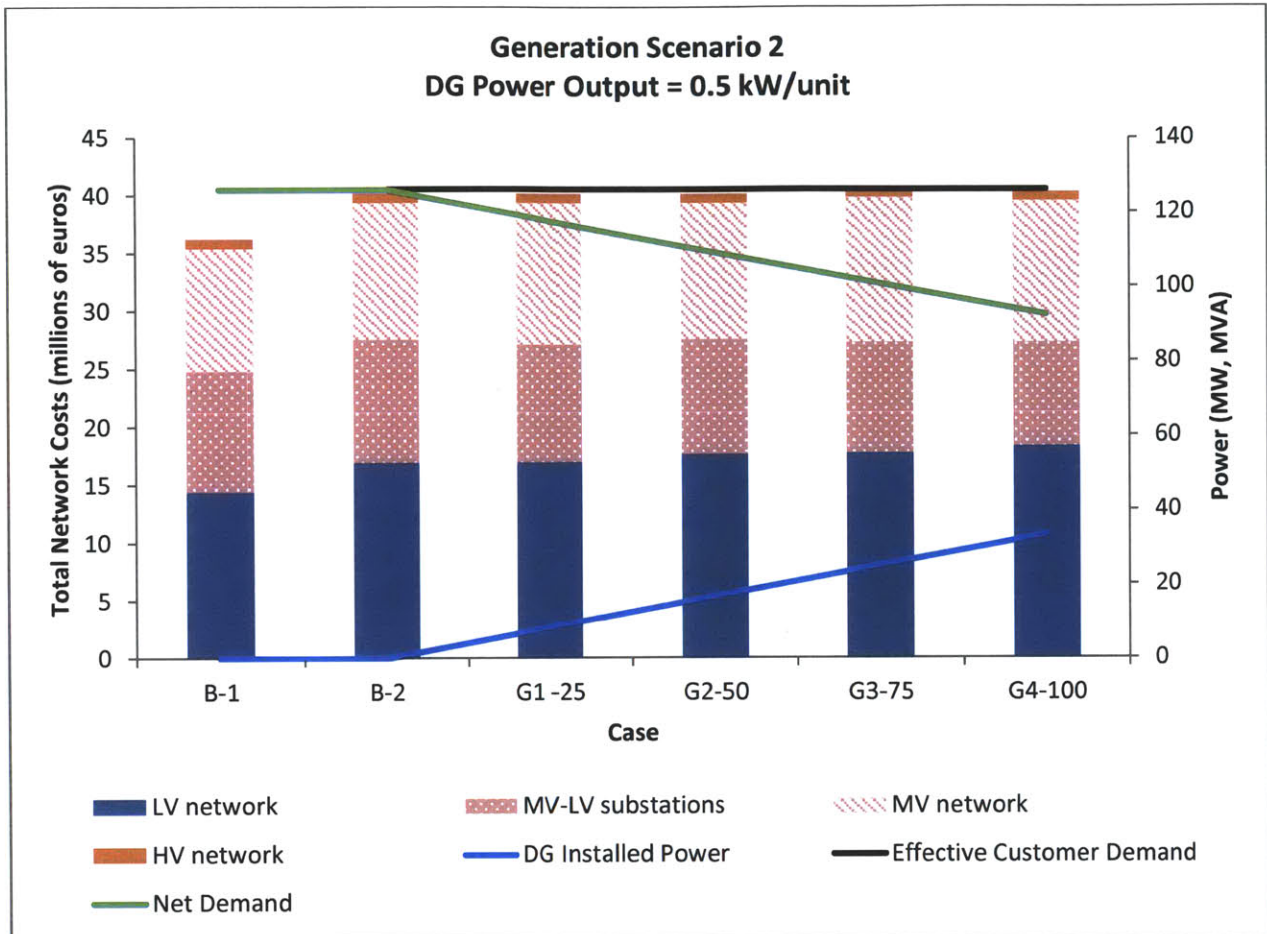


Figure 10. Results for generation scenario 2 with a DG power output of 3 kW/unit

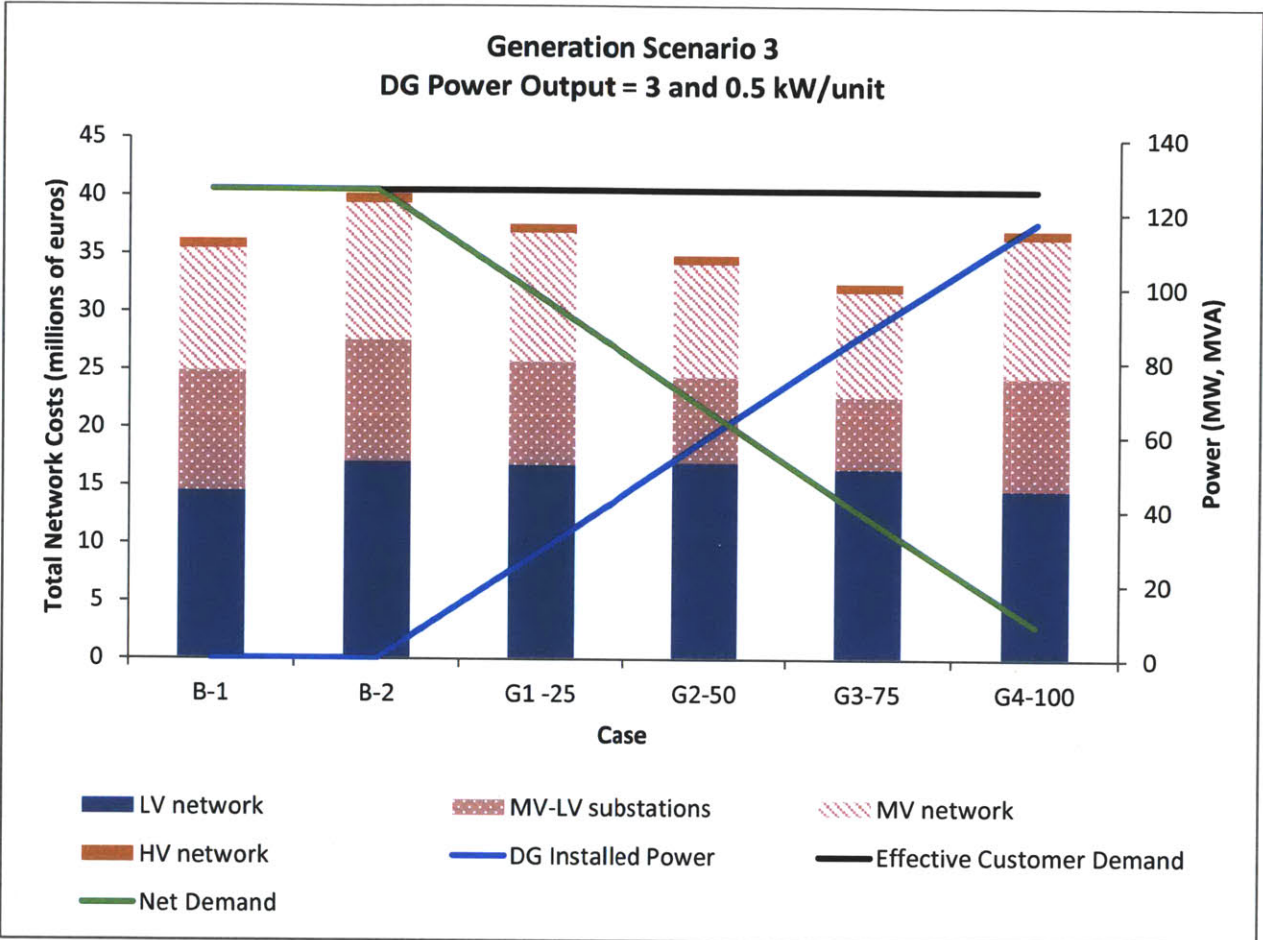
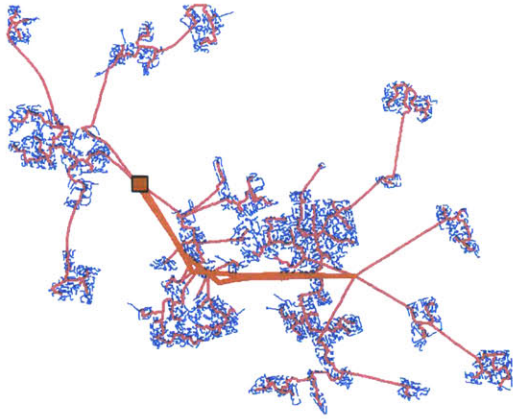
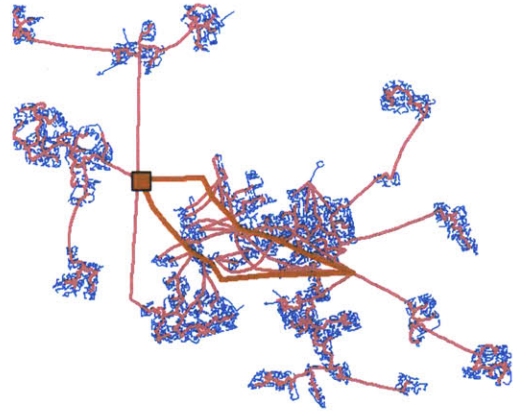


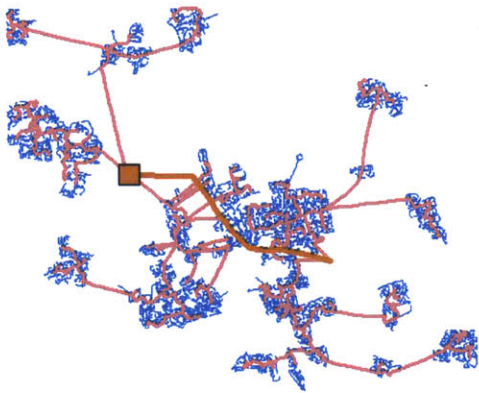
Figure 11. Results for generation scenario 3 with 50% of units having a DG power output of 0.5 kW/unit and 50% having a DG power output of 3 kW/unit



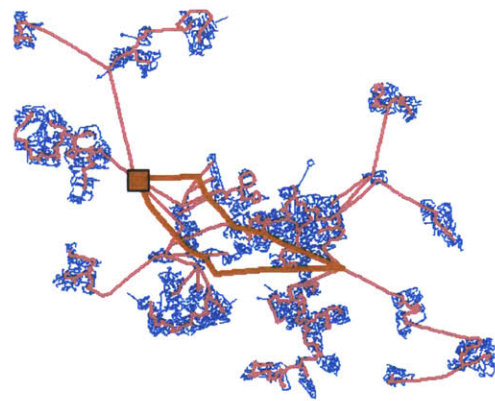
B-1



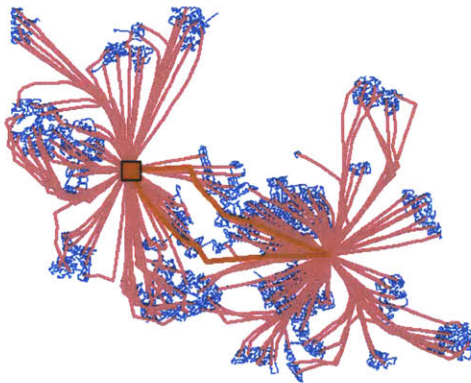
B-2



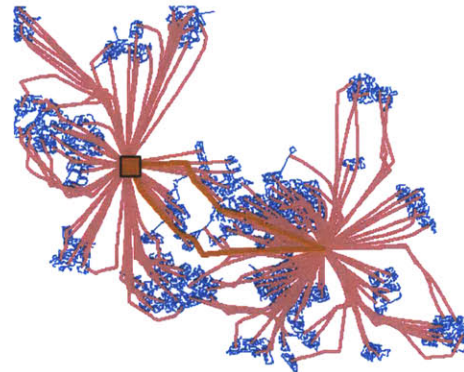
G1-25



G2-50



G3-75



G4-100





- Key**
-  Transmission substation
 -  HV network
 -  MV network
 -  LV network

Figure 12. Network diagrams showing the LV, MV, and HV networks built by the model and the input transmission substations for the 2 base cases and the 4 generating cases studied for generation scenario 1.

3.4.3 Discussion

Total network costs decrease and then increase across generating cases within both generation scenarios 1 and 3, as shown in Figures 9 and 11. The U-shape pattern of costs is consistent across both these cases. However, for generation case 2 where DG power output is very low at 0.5 kW, total network costs do not change noticeably with DG penetration level.

For *generation scenario 1* ($DG\ power\ output = 3\ kW/unit$), the increase in total cost from base case B-1 (no DG) to base case B-2 (25% penetration of DG with negligible generation) shown in Table 7 may be interpreted as the connection cost of that DG. Subsequently, from case B-2 to case G1-25% the total cost decreases as DG power generation increases. This may be because the DG reduces the need for long and medium-distance transportation of power from conventional generation facilities, thus reducing the MV network costs and the total costs. In other words, the cost decrease may be interpreted as the benefit from DG contributions to the network. From case G1-25 to G2-50, total network costs continue to decrease.

Subsequently, network costs increase when moving from case G2-50 to G3-75. In Figure 9 the plot of net power demand (demand corrected for the customer simultaneity factor, less the power generated by DG) shows that from 50% to 75% DG penetration, the net power demanded turns negative (from 25.3 MVA to -24.9 MVA). Therefore, when moving from 50% to 75% DG penetration, DG power production begins to exceed the power demand in the network and DG becomes the main source of power for the network. Significant DG power generation implies power flows in the reverse direction to the base cases, since power flows from residential DG to customers instead of from transmission substations to customers. These directional changes in network power flows may account for the total cost increase when moving from 50% to 75% penetration.

Finally, a total cost decrease from case G3-75 to G4-100 penetration is observed. The detailed cost breakdown in Table 7 shows that from 75% to 100% penetration, the cost of LV networks increases considerably but the cost of MV networks and MV-LV substations decrease. The changes in costs may reflect the consequences of a high penetration of DG connected at residential customer locations: most power is being generated and consumed within the low

voltage network, so LV network costs increase. Since the DG connected at LV is sufficient to meet the network power demand, less power flows from higher voltages through the medium voltage network and MV network costs decrease. The cost decrease at MV slightly outweighs the cost increase at LV, resulting in the decrease in total costs when moving from 75% to 100% penetration. Figure 12 illustrates how the networks built for cases G3-75 and G4-100, where DG production exceeds network demand differ from the networks built in other cases where DG production is less than network demand.

For *generation scenario 2* (*DG power output = 0.5 kW/unit*), the changes in costs as penetration level varies are not large, as illustrated in Figure 10, which may reflect the low level of power output by DG. These results suggest that few network reinforcements will be necessary to accommodate even high penetrations of residential DG, if each individual DG unit's power output is very low. Such a situation might arise for very small-scale installations, for example of solar PV panels.

For *generation scenario 3* (*DG power output = 0.5 and 3 kW/unit*), cost trends follow the same U-shape pattern as for generation scenario 1. Total costs decrease as penetration increases from 0% to 75%, then increase from 75% to 100%. It can be seen in Figure 11 that the costs begin increasing again when the total DG production increases from 88 to 117 MVA (from 75% to 100% penetration), or, equivalently, when net demand in the network decreases from 38 MW to 9 MW. These results suggest that network costs can begin increasing even before DG production begins to exceed network demand.

In both generation scenarios 1 and 3, changes in total costs appear to be driven by cost trends at the MV level, although the LV network plays a role particularly at higher DG penetration levels. Finally, it is important to note that the level of residential DG installed power at which costs begin to increase after initially decreasing, depends on the system demand. A cost driver is net system demand, which is the demand taking into account simultaneity factors and DG power contributions.

3.5 DG Located Far Away from Customers

3.5.1 Methodology

Following an examination of the results for DG located near to customers, it was desired to study DG more closely by modeling DG with a similar total power output, but with generating units located far away from customers. Such conurbations of DG may represent large wind or solar farms. Each DG conurbation was modeled as a single generating point with a power output representing the combined power output of all the individual generating units (e.g. turbines, solar PV panels) within the farm.

For the earlier case with DG located near to customers, the cost results for generation scenario 1 display the most interesting U-shape trend when DG power output is between 50-200 MVA. Therefore, it was decided to study DG located far away from customers at 4 power output levels between 50-200 MVA: 50, 100, 150, and 200 MVA. To ensure the results were reasonably comparable with the previous cases for DG located near to customers, the transmission substations and HV-MV substations acting as supply points to the distribution network had their locations fixed in the same locations as in the previous cases.

Costs relating to far away DG were examined by modeling the change in costs as new generating points (for example, new wind farms) are added to the network. New generating points were added so as to change the total DG power output level to obtain results for total DG power output of 50-200 MVA.

The model was run 6 times to obtain results for 2 base cases, BF-50 and BF-200, and 4 generating cases, F-50, F-100, F-150 and F-200. The generating points in base case BF-50 corresponded to those present in the generating case F-50, and those in base case BF-200 corresponded to generating case F-200, but in both base cases the generating points were assigned a negligible power output. In the corresponding generating case F-50, the total power output of all the DG generating points was 50 MVA and in the corresponding generating case F-200, the total power output was 200 MVA.

The 4 generating cases represented the 4 total DG power output levels studied: 50, 100, 150, and 200 MVA. These cases were denoted F-50, F-100, F-150, and F-200 respectively. The base and generating cases are detailed in Table 8.

Table 8. Modeling cases for DG located far away from customers

DG Far Away from Customers						
Case Code	BF-50	BF-200	F-50	F-100	F-150	F-200
Number of generating points	10	40	10	20	30	40
Power output per DG generating point (MVA)	5	5	5	5	5	5
Total DG output (MVA)	0	0	50	100	150	200

3.5.2 Results

Table 9 presents the detailed cost results for the 2 base cases and 4 generating cases. The remaining tables and figures in this section present additional analyses of the results.

Table 9. Results for DG located far away from customers.

Case	Total Costs (euros)					
	BF-50	BF-200	F-50	F-100	F-150	F-200
Number of generating points	10	40	10	20	30	40
DG power output/generating point (MVA)	5	5	5	5	5	5
Total DG output (MVA)	0	0	50	100	150	200
Investment Costs (euros)						
LV network	11,722,562	11,760,198	11,821,200	11,829,378	11,804,366	11,776,546
MV-LV substations	3,993,400	3,993,400	3,993,400	3,993,400	3,993,400	3,993,400
MV network	6,870,478	7,048,157	6,979,208	7,367,879	7,551,140	8,678,164
HV network	447,977	447,977	447,977	447,977	447,977	447,977
TOTAL	23,034,417	23,249,732	23,241,785	23,638,634	23,796,883	24,896,087
Losses Costs (euros)						
LV network	254,967	254,967	254,967	254,967	254,967	254,967
MV-LV substations	117,138	117,138	117,138	117,138	117,138	117,138
MV network	64,913	64,618	113,577	88,208	96,410	83,719
HV network	6,182	6,351	6,605	4,505	5,916	6,523
TOTAL	443,201	443,075	492,288	464,818	474,432	462,347
Total Network Costs (investment+maintenance+losses) (NPV) (euros)						
LV network	14,497,137	14,534,772	14,595,775	14,603,953	14,578,940	14,551,121
MV-LV substations	10,411,577	10,411,577	10,411,577	10,411,577	10,411,577	10,411,577
MV network	10,492,302	11,326,320	11,731,369	11,771,021	12,284,497	14,009,518
HV network	799,840	801,235	803,337	785,960	797,636	802,657
GRAND TOTAL	36,200,856	37,073,905	37,542,058	37,572,511	38,072,651	39,774,873
Percentage increase on previous case (%)				0.08%	1.33%	4.47%

Note: Maintenance costs are not shown for brevity, but are included in the model's calculation of total costs.

Table 10. Comparing investment costs for base and generating cases

	Investment Costs (euros)			
	BF-50	F-50	BF-200	F-200
LV network	11,722,562	11,821,200	11,760,198	11,776,546
MV-LV substations	3,993,400	3,993,400	3,993,400	3,993,400
MV network	6,870,478	6,979,208	7,048,157	8,678,164
HV network	447,977	447,977	447,977	447,977
TOTAL	23,034,417	23,241,785	23,249,732	24,896,087
Percentage increase on corresponding base case (%)		0.90%		7.08%

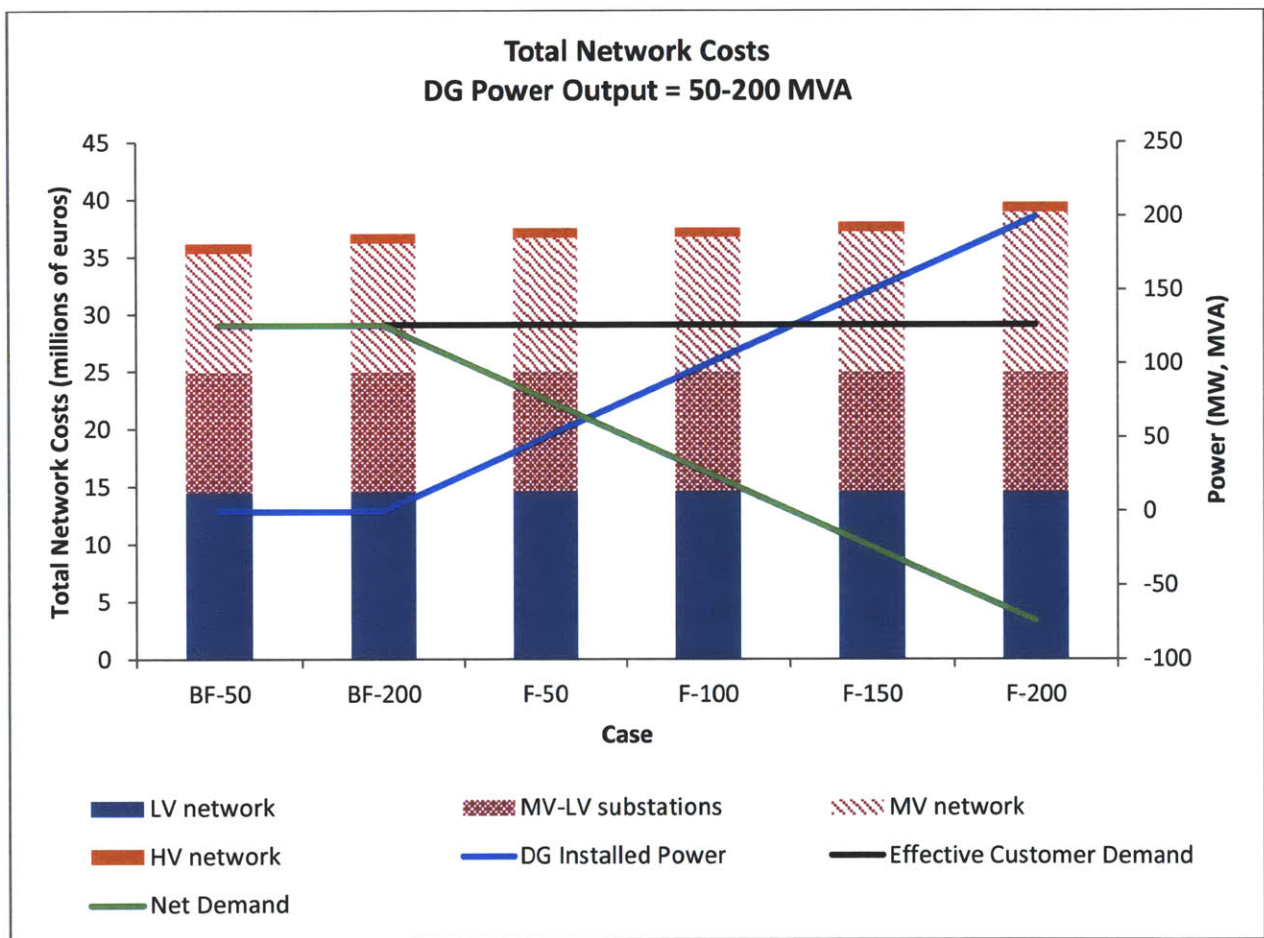


Figure 13. Total network costs for the base and generating cases

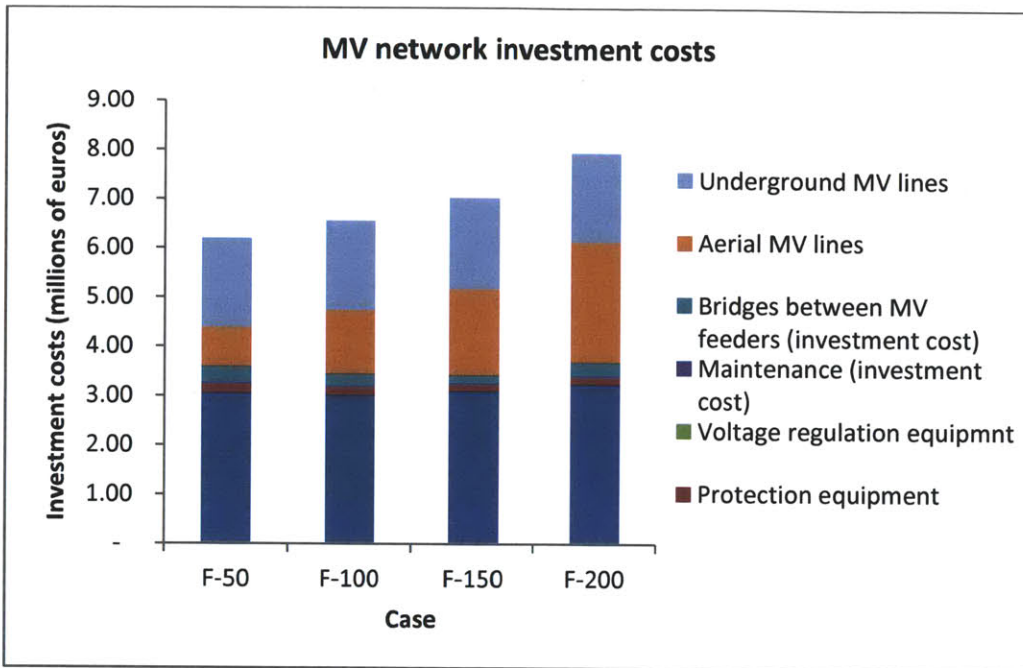


Figure 14. MV network costs broken down by MV network component

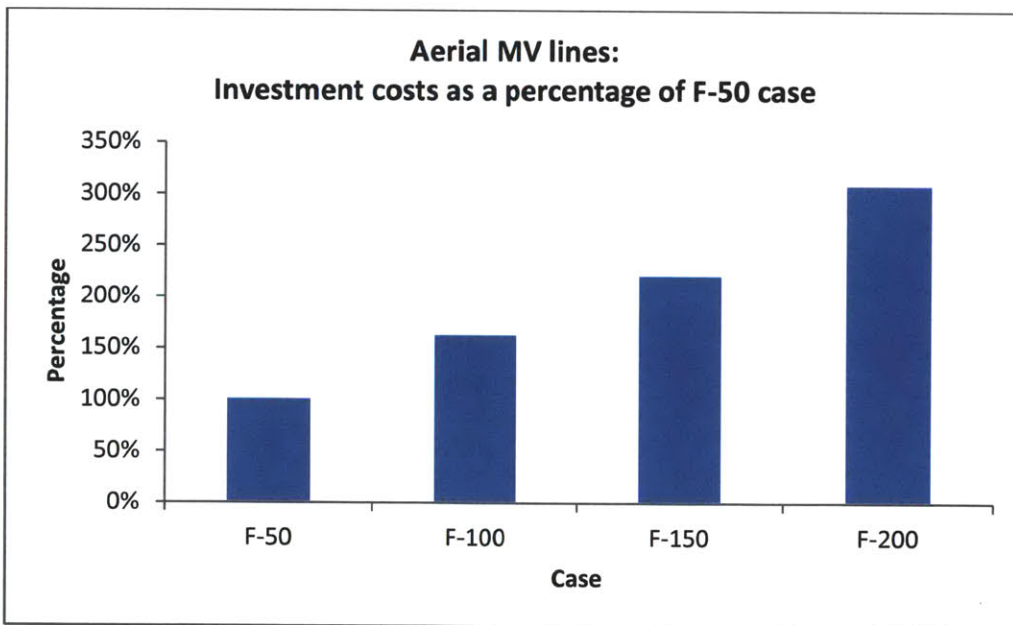


Figure 15. Percentage increase in investment cost for aerial MV lines in generating cases F-100 through F-200, relative to the F-50 case

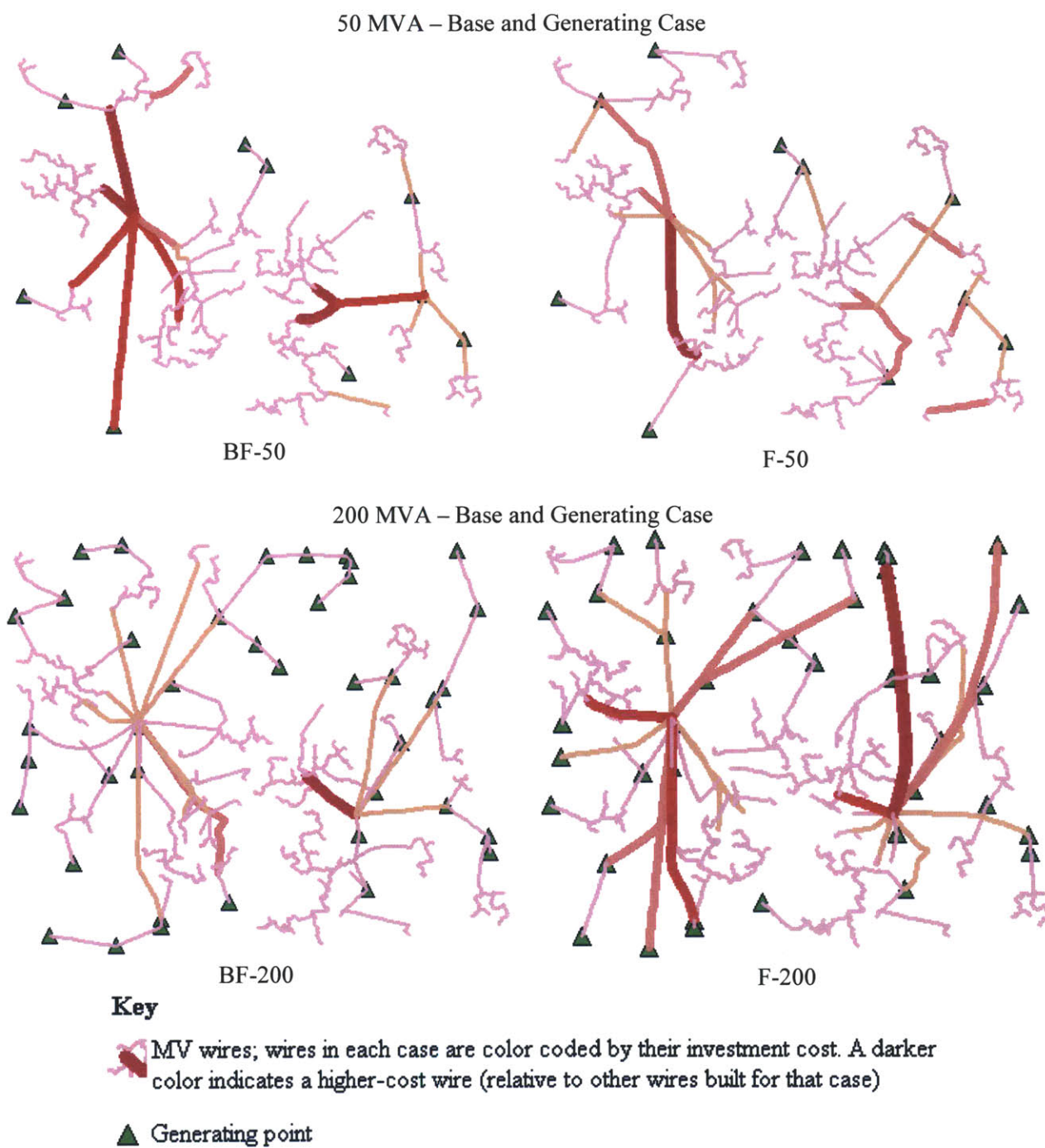


Figure 16. Graphical representations of the networks built for the 50 MVA and 200 MVA generating cases alongside their respective base cases, illustrating the difference caused by generation

associated with the MV network, since the wind farms are connected to the MV network. The more detailed MV network component cost analysis of Figure 14 shows that most MV network costs are driven by the costs of aerial MV lines. This is reasonable as the new aerial lines are required to connect the new generating points that are added to the network when moving from case F-50 to case F-200.

For aerial MV lines, the cost differences between the 4 generating cases are notable as shown in Figure 15. The clear trend is for these costs to increase as generating points are added to the network. Aerial MV lines required in case F-100 have a cost that is 150% of the cost in case F-50, whereas aerial MV lines required in case F-200 have a total cost that is 300% of the cost in case F-50.

Table 9 compares the total network costs for the base cases and generating cases.⁸ The difference in total network costs between the base case BF-200 with 40 non-generating DG points and the base case B-1 without any DG (which could be considered an approximation to the connection cost) is 0.845 million euros to whereas the cost difference between the F-200 generating case and BF-200 base case (which could be considered an approximation of the network costs of DG generation) is 2.70 million euros (to 3 s.f.). That is, for this case the connection cost of building wires to new locations is relatively small but the cost to accommodate the DG units' generating capacity can be significant. A consideration of the technical specifications of the lines built by the model suggests the increase in cost can be traced in part to the need for more expensive lines with a higher capacity for the generating case, and in part to the different optimal configurations output by the model for generating and base cases. That said, relative to the corresponding base cases, the investment costs of accommodating far away DG are not very large. As Table 10 shows, the differences in investment cost between the generating case F-50 and the base case BF-50, and between the generating case F-200 and the base case BF-200 are 0.90% and 7.08% respectively.

As Figure 16 shows, increasing the generating output for each generating point (while keeping the generating points at the same location) can change the optimal network

⁸ The difference between the BF-50 case and the earlier B-1 case is about -0.028 million euros. The cost difference is negative because although a greater length of MV lines are required in the B-50 case (113.12 km) than the B-1 case without any DG (105.39 km), the model builds a greater number of cheaper aerial lines in the B-50 case. As the wind farms in BF-50 are far away from customers, these aerial lines are long and can sometimes also replace previously needed, more expensive underground lines. Ultimately, this decreases the total cost for BF-50 relative to B-1.

configuration. This suggests long-term cost implications for distribution networks if, for example, a wind farm decides to upgrade its turbines so that its overall power generation level increases significantly. Hence it is clearly important whether distribution companies include the projected contributions of DG (in terms of both locations and capacity) in their expansion planning processes, or whether they utilize a “fit and forget” approach to network planning. (Passive network management, closely related to the “fit and forget” approach, is analyzed with the brownfield model in the second half of this chapter.)

Figure 17 illustrates the different network configurations when new wind farms are added to the MV network. As shown, the optimal configurations and costs of MV lines can change considerably when new wind farms are added in new locations far away from customers. In practice, distribution companies may not always be able to achieve the optimal network configuration owing to the placement of existing lines. However, as Table 9 illustrates, the impact on overall network costs is small as total DG power output increases. The incremental increase in cost when moving from the F-50 through the F-100, F-150, and F-200 cases ranges from 30,500 to 1.70 million euros (to 3 s.f.), or 0.08% to 4.47%. These results suggest that significant additional remuneration may not be needed to add a substantial number of non-local distributed generation units. This has implications for the design and implementation of connection and use of system charges for DG, which are described in Chapter 4.

In general for these cases with DG located far away from customers, both the overall network cost analysis (Figure 13) and the detailed MV network cost analysis (Figure 14) do not show the same U-shaped trend that is found for residential DG. Instead, costs steadily increase as the amount of network power supplied by distributed generation increases. Even when net system demand turns negative, the upwards cost trend does not change. The size of the cost increase as generating points are added to the network is also relatively small. In terms of the overall network cost, the difference between scenario F-200 (with 40 generating points) and F-50 (with 10 generating points) is less than 5%. Although the relative changes in costs for aerial MV lines are significant when considered in isolation, these costs do not constitute a significant part of the total network cost. At most (case F-200), the aerial MV lines make up 6.14% of the total network costs. Therefore, the changes in costs for the aerial MV lines do not translate into a significant difference in total network costs.

3.6 Comparison of Results for DG Located Near to and Far Away from Customers

The selection of DG installed power levels for the study of DG located far away from customers permits comparison of the results with those for residential DG with a 3 kW/unit output power. These two types of DG location are denoted here as far-DG and near-DG respectively. In particular, the penetration levels 25, 50, 75, and 100% of near-DG can broadly correspond to the total DG installed power of 50, 100, 150, and 200 MVA studied for far-DG. Figures 18-20 show the total network costs, investment costs, and losses costs plotted against total DG installed power for both types of DG location. On all figures, the effective customer demand (the total customer demand multiplied by the simultaneity factor) is marked as a reference point.

In making comparisons between these two types of DG locations, it is important to note that the near-DG units were connected to the low voltage distribution network whereas the far-DG units were connected to the medium voltage distribution network. In terms of voltage, thus, the comparison is not a direct one. However, the results for investment costs and losses can illuminate whether it is more beneficial to connect DG at dispersed locations using the LV network or in wind farm-like conurbations using the MV network.

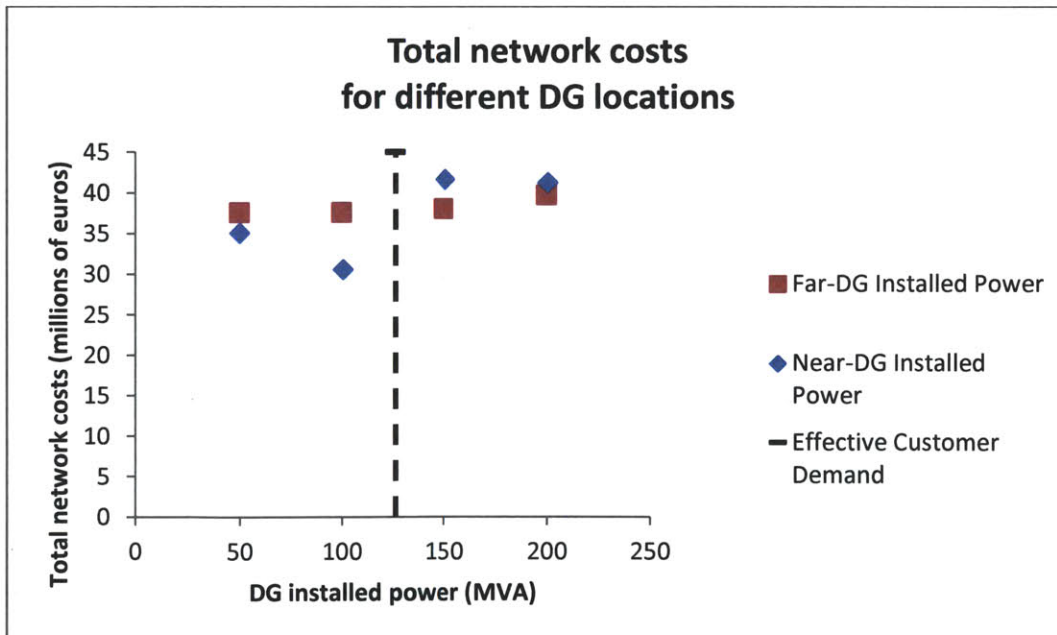


Figure 18. Comparison of total network costs for different DG locations

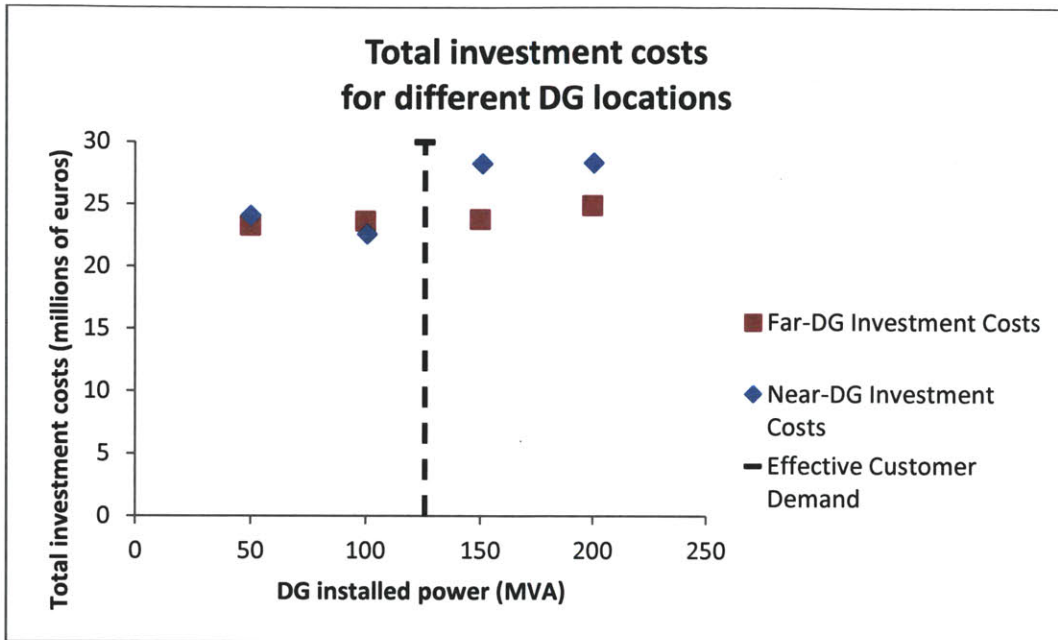


Figure 19. Comparison of investment costs for different DG locations

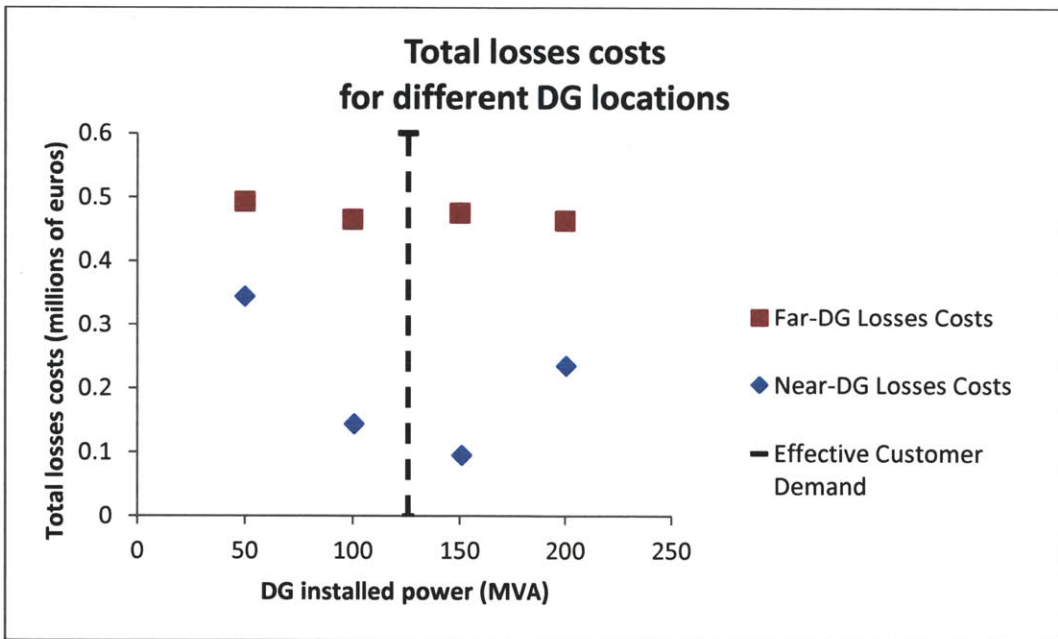


Figure 20. Comparison of losses costs for different DG locations

As shown in Figures 18-20, total network costs differ by a small amount depending on DG location. The investment cost differences between the near-DG and far-DG results are larger at higher levels of DG installed power. Required investments (in the LV and MV networks, and

MV-LV substations) for near-DG cases decrease as DG penetration increases until DG installed power approaches total system demand, after which the required investments increase. Far-DG investment costs generally relate only to the MV network and for the cases where DG contributes 150 MVA and above of power, the investments required for far-DG are lower than those required for near-DG. A reason for this may be that as the far-DG units are both fewer in number and less dispersed through the network than the near-DG units, less extensive MV reinforcements are needed to accommodate them when they supply a majority of network demand compared to the extensive reinforcements required in the LV network for near-DG units supplying a similar amount of power.

Although far-DG can be cheaper than near-DG at higher levels of DG installed power, it is worth noting the effects of near-DG on the costs of losses. At every level of DG installed power studied, losses costs are lower for near-DG than far-DG. As near-DG units are located at residential customer sites, the power generated may be transmitted only over a short distance before it is consumed; this reduces the power flows upstream and so the overall cost of line losses decreases. These results illustrate the potential benefits of residential DG installations relative to far away DG installations. That said, the results for near-DG also show that losses costs increase at very high penetration levels whereas the far-DG results do not display such a marked change. In terms of losses costs, it may yet be beneficial to avoid very high penetration of near-DG.

3.7 Modeling Passive and Active Management of Distribution Networks

Knowledge of the effects of integrating several new technologies into an existing network can help regulators and companies that are modernizing existing electric grids. Additionally, knowledge of the cost implications of passive and active management of such new technologies can be useful in determining the costs and benefits of different management systems.

Passive management refers to a situation where new technologies are installed and draw or contribute power to the network, but these power flows are not managed by the distribution companies operating the network. In countries where restructuring or privatization of the electric power sector has occurred to separate generation from the distribution network business, or where independent distributed generators play a significant role in the industry, this issue is more important as the distribution company has less direct control over generation. Passive management requires a network to be sized for maximum capacity in a “fit and forget” approach, since the network must have sufficient capacity to handle a ‘worst-case’ scenario of many new technologies connecting at once.

Active management refers to a situation where the new technologies are installed and their power flows managed by the distribution company to optimize the network’s performance and investment costs. For example, distributed generation could be managed so it is dispatched to supply the network at times of high demand and is stored at times of low demand. Power flow management could also be directed by more sophisticated real-time capacity monitoring systems, electricity price signals from the open market, and other metrics. Real-time system protection and voltage control of the fluctuations that may be caused by new technologies like DG can also be implemented as part of active network management. Another aspect of active network management is reconfiguration of the medium voltage network, for example by selectively utilizing feeders and rerouting power flows so that the network is operated in a meshed rather than a radial configuration. This may help the network respond to unusual power demand or outage situations. The installation of new sensors, communications, and control systems is generally required to achieve active network management.

Active network management has been discussed in literature, particularly with respect to Europe where distributed generation uptake is reaching a level that enables active management to be seriously considered (Djapic, et al. 2007). Among the perceived benefits of active network management are a reduction in network capacity requirements (compared to the requirements

with passive network management) and a corresponding deferment of capital investment requirements. Figure 21 illustrates this benefit.

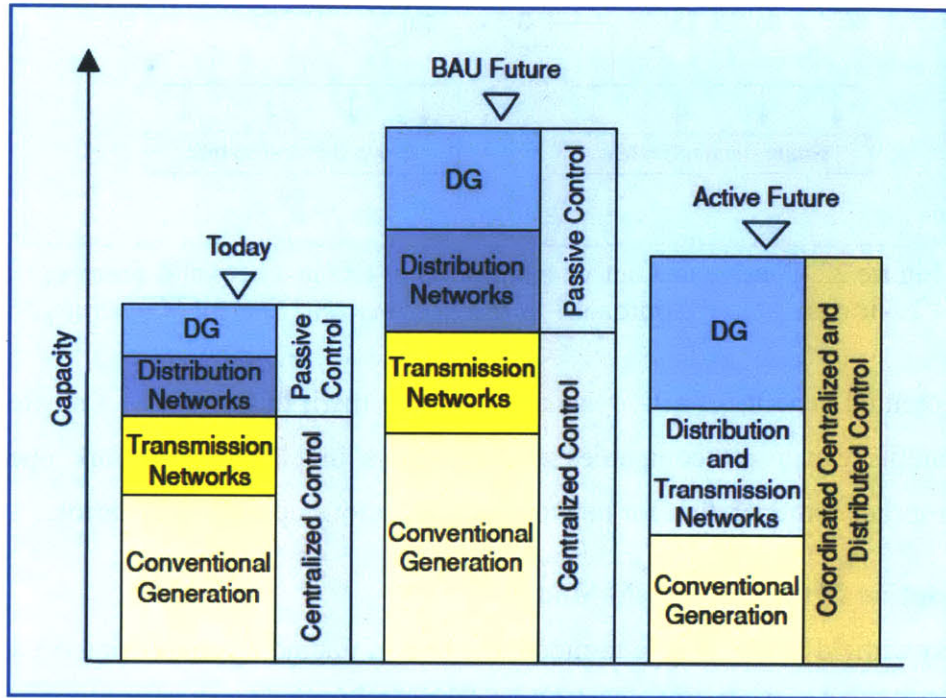


Figure 21. Comparing the passive (BAU) and active management of networks.
 Source: Djapic, et al., “Taking an Active Approach” in *IEEE Power and Energy Magazine* (2007, 70).

Most discussions of active management center on DG, because in an actively managed network DG connections would be facilitated by the ability under active management to dispatch DG when necessary, use DG for ancillary services in addition to power generation, and otherwise optimize the use of DG (Peças Lopes, et al. 2007, Djapic, et al. 2007). “Active” integration of DG could allow DG to be used to meet network requirements relating to performance, reliability, and security of supply among others. Such use of DG could provide wider economic benefits to the distribution companies by deferring or substituting for investment in additional power system components. As an example, Figure 22 illustrates the difference in required power system components when a 30 MW DG unit is incorporated into network planning to help meet security of supply requirements. When DG is used, as on the right side of the figure, it replaces otherwise necessary investment in a third circuit T3.

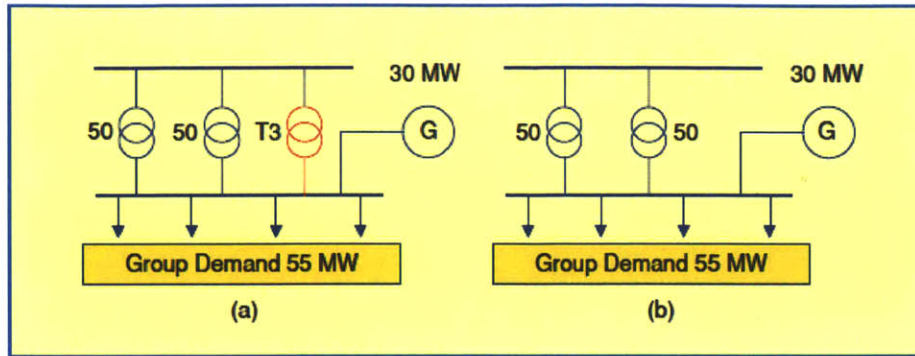


Figure 22. Passive and active integration of DG in a network. *Source: Djapic, et al., “Taking an Active Approach” in IEEE Power and Energy Magazine (2007, 75).*

The potential benefits of active management thus merit further study. Knowledge of such costs and benefits can assist companies and regulators in planning network operations and ensuring appropriate remuneration for networks under various operation scenarios.

3.7.1 Description of the Brownfield Model

The brownfield model is able to model the cost of upgrading an existing network to meet the demands of new technologies. It is furthermore able to model the difference between managing these new technologies passively and actively.

Like the greenfield reference network model, the brownfield reference network model outputs the cost of building a network given various input considerations relating to the number of customers, the locations and generation capacity of distributed generation, and so on. Although the greenfield model is able to construct a network from scratch given data on the power demand of customers in the area, the brownfield model requires an existing electricity network and set of customers as input data. The brownfield model then constructs the network extensions and upgrades necessary to accommodate new customers or new technologies, and calculates the cost of these extensions and upgrades. The existing electricity network data input to the brownfield model may be from files describing a network output by a run of the greenfield model, or from files created manually in the required format describing an existing network.

The brownfield model takes as input time-differentiated power demand (or generation) profiles for customer consumption points, distributed generation, and electric vehicles as illustrated in Figure 6. Each consumption point and each distributed generator may have a 24-hour demand (or generation) profile attached to it to simulate the power it demands (or generates) for each hour, over 24 hours. The brownfield model then sizes the network given the

24-hour power demand/consumption profiles for the customers, DG, and EVs connected to the network. Therefore active network management can be modeled by, for example, shaving a consumption point's demand during the peak hours of the 24-hour power demand profile. Passive network management can be modeled by not making any exogenous changes to the shape of the demand profiles – equivalent to the utility not managing connected demand.

3.7.2 Description of the Base Network for the Brownfield Model

The brownfield model works from an existing network to build the additional network needed to connect new customers, DG and electric vehicles. To create the existing network, the greenfield model described in the first half of this chapter was run. The greenfield model produced output files describing the characteristics of the existing network. These files were input to the brownfield model to provide it with the required existing network.

An initial network of 66,848 customers was selected to serve as the base network for the brownfield model and the files describing the base network were created by running the greenfield model. Given default input parameters the greenfield model designs an idealized base network with sufficient spare capacity to minimize the cost of losses over the network planning horizon, assuming that network components are installed today with a useful life of 40 years. However, this ideal does not represent most distribution networks in use today. Most networks today would not have such significant spare capacity in their components since most network equipment has been installed for at least several years and their spare capacity has been partially used by the natural electricity demand growth of the population. Therefore, it was decided to reduce the spare capacity of the base network by reducing the parameter for cost of losses in the greenfield model. This ensures the model sizes less spare capacity into the network for losses. The result is a network of components with a higher capacity utilization that is likely to be a more realistic representation of distribution networks in use today. The passive and active management cases were run on this more realistic network. For comparison, several cases were also run with the idealized base network with a higher spare capacity and a selection of these results are presented later in the chapter. Descriptive statistics and a graphical representation of the more realistic base network are provided in Table 11 and Figure 23 respectively.

Table 11. Descriptive statistics of base network

Customers	
Unique Customers	66,848
Unique Consumption Points	14,492
Total Power Contracted (MW)	420
Peak Power Consumption (MW)	126
Lines	
LV lines (aerial) (km)	156.53
LV lines (subterranean) (km)	215.69
MV lines (aerial) (km)	38.96
MV lines (subterranean) (km)	66.17
HV lines (aerial) (km)	13.13
HV lines (subterranean) (km)	0

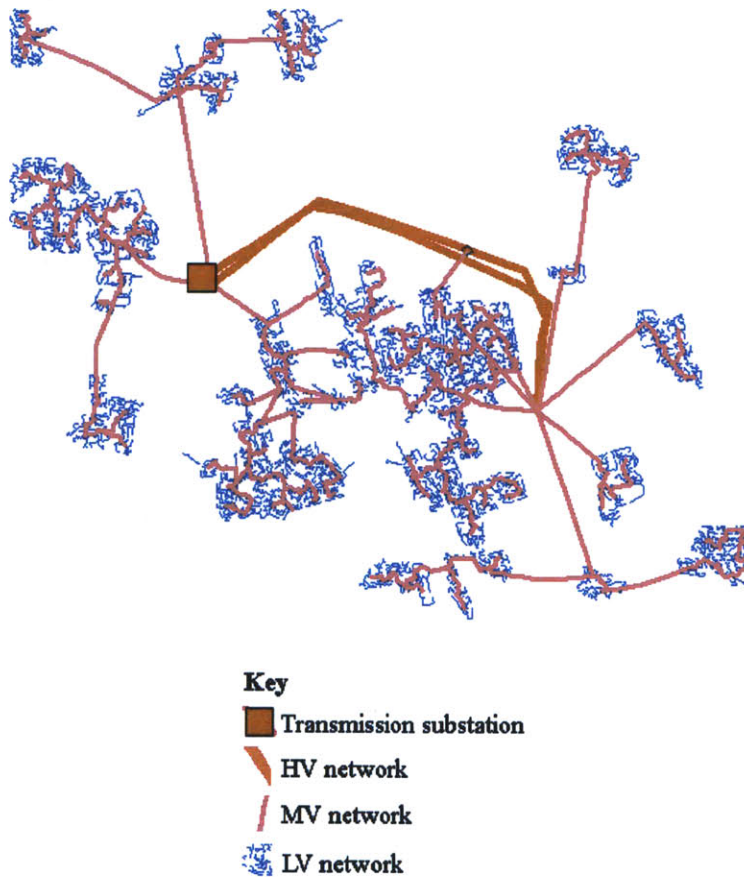


Figure 23. Graphical representation of base network used to study network management

3.7.3 Methodology to study Costs under Passive and Active Management

To model the difference in network costs between passive and active network management of new technologies, 5 modeling cases were created of which 1 was passive management (denoted P-1) and 4 were varying degrees of active management (denoted A-1, A-1a, A-2 and A-2a). Table 12 presents summary statistics relating to the new technologies modeled; more detailed descriptions of the technologies are in the following sections. Table 13 presents a summary of the modelling cases, which are also further detailed in the following sections of this chapter.

Table 12. Descriptive statistics of new technologies modeled

New Technology	Penetration Level	Total Number of Units
Advanced Metering Infrastructure (AMI) (Demand Response (DR) Programs)	100% (50-100%)	66,848
Distributed Generation (DG)	33%	22,434
Electric Vehicles (EVs)	20%	13,463

Table 13. Modeling cases for passive and active management

	Case P-1	Case A-1	Case A-1a	Case A-2	Case A-2a
AMI	No demand response (DR)	50% of consumption points have DR with 10% peak shaving	50% of consumption points have DR with 10% peak shaving	100% of consumption points have DR with 10% peak shaving	100% of consumption points have DR with 10% peak shaving
DG	No management	50% of DG is managed	50% of DG is managed	100% of DG is managed	100% of DG is managed
EVs	No management; EVs charge uncoordinated	50% of connected EVs have managed charging	50% of connected EVs have managed charging; Level III charging spread over 2 hours under active management	100% of connected EVs have managed charging	100% of connected EVs have managed charging; Level III charging spread over 2 hours under active management

Passive Management (Case P-1)

In Case P-1, the brownfield model was run assuming that all (100%) of customers had advanced metering, a randomly chosen 33% (one-third) had distributed generation installations, and a randomly chosen 20% (one-fifth) had adopted electric vehicles as a mode of transportation. These technologies were passively managed as described next.

Customers: To model passive management for customers, it was assumed that each aggregated customer consumption point had a demand profile corresponding in shape to a normalized power system demand curve. (Owing to the design of the model, it was necessary to assign profiles to each consumption point rather than to each customer.) To create this curve, a system demand curve was taken from information made available by the Independent System Operator of New England (ISO-NE) and normalized to obtain a shape that was applied to all customers. The curve used is shown in Figure 24.

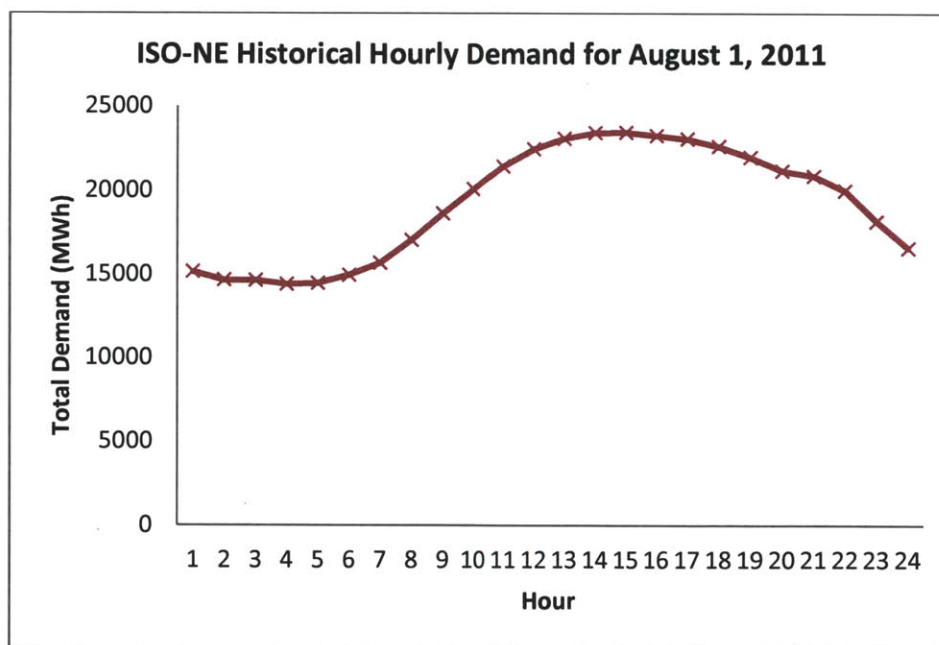


Figure 24. System hourly demand curve. *Source:* ISO-NE (2012).

Distributed generation: 33% of customer locations were assumed to have a distributed generation installation. The distributed generators were defined as solar or CHP generators as

shown in Table 14. The solar and CHP⁹ generation types were selected both to facilitate modeling and as two of the most likely residential generation technologies connected to the low voltage network in Germany, the country of the network used for this analysis (KEMA 2011). To create the 24-hour power generation profiles for distributed generators, a reasonable power generated per hour was assumed for each type of distributed generation studied. It was assumed that solar generators could only generate power for 5 consecutive hours between 11am-6pm. It was assumed that CHP units could generate power constantly over the 24-hour period, although such units are likely to generate less power during the summer when their heating component is unused. Table 14 summarizes the distributed generation data input to the model.

Table 14. DG types and penetration levels

Type	Percentage of total DG units	Number	Power generation (kW/hour)	Hours of generation
Solar	70%	15691	3	5
CHP (incl. biomass, biogas)	30%	6743	4	24
Total	100%	22434		

Electric vehicles: 20% of customer locations were assumed to have an electric vehicle charging point. To model passive management of electric vehicles, it was assumed that customers charge their vehicles at any convenient time. Data from the US National Household Travel Survey (NHTS) was used to identify likely charging periods (U.S. Department of Transportation 2009). Customer charging profiles also depend on the type of charger in use: Level I chargers draw low voltage and take longer to charge, whereas Level III chargers charge more quickly at high voltage. The precise charging powers corresponding to each level vary. Several sources' definitions are presented below.

⁹ The report finds that solar and biomass installations are two of the most frequently connected installations at low voltage. It notes the biomass installations are "biomass in cogeneration plants"; cogeneration is also known as CHP. The CHP is used for the modeling.

Table 15. Electric vehicle charging power at different charging levels

Charging Level	EU (MERGE)	Society of Automotive Engineers (J17772) standard
Level I	3 kW	Up to 1.92 kW
Level II	10-20 kW	Up to 19.2 kW
Level III	> 40 kW	Not yet defined

Sources: Bending, et al. (2010) and MIT (2011).

Customer electric vehicle charging profiles were categorized into one of Level I, II, and III. 75% of customers were assumed to have a level I charger, 20% a level II charger, and 5% a level III charger. It was assumed that vehicles began charging in the evening. For Level I charging, the start time was 7pm; it was felt unreasonable to change this hour because Level I charging takes 12 hours to complete and vehicles are likely to be needed for travel (and unavailable for charging) before 7pm and after 7am. For Level II and III charging, the start time was a randomly selected hour between 10pm-3am. These hours were selected because according to 2009 data from the NHTS, the period between 10pm-6am contains the fewest number of trip starts so is the most likely period when vehicles are available to be charged. To acknowledge the minimum time required to fully charge a vehicle, the cutoff time for starting a charge was set to 3am rather than 6am. Table 16 summarizes the electric vehicle data input to the model.

Table 16. EV penetration levels and charging levels

Charging Level	Percentage of total EV units	Number	Power demand (kW/hour)	Hours to full charge
Level I	75%	9462	3	12
Level II	20%	3330	15	3
Level III	5%	671	40 (20 in cases A-1a, A-2a)	1 (2 in cases A-1a, A-2a)
Total	100%	13463		

Active Management (Cases A-1, A-1a, A-2 and A-2a)

The capacity of the model to evaluate hourly demand (or generation) profiles was utilized to model two different degrees of active network management. In case A-1, 50% of the connected new technologies were actively managed and in case A-2, 100% of the connected new technologies were actively managed. Two additional cases denoted case A-1a and case A-2a

were run later where the active management of Level III EV charging was modified, as explained below.

Customers: To model active management for customers, it was decided to use peak shaving to simulate demand response (DR) of customers to the total system power demand. First, the power demand curves used for the passive management case were analyzed. The peak hour and valley hour were identified, and the 2 hours on either side of the peak and valley hour were also selected. This resulted in a 5-hour peak demand period, and a 5-hour valley demand period. To generate the active demand curves, 10% of the demand from the peak periods was shaved and added to the valley demand periods. The resulting active demand profiles were assigned to the customers who previously had the corresponding passive demand profiles. 50% of customers had active management in cases A-1 and A-1a, and 100% of customers had active management in cases A-2 and A-2a.

Distributed generation: To model active management for solar units, it was assumed that the utility had some control over the generator and could shift generation output to a 5-hour period between 12pm-9pm, through a combination of storage and management. For CHP units, the power profiles were modified to output at their maximum level during 12pm-9pm and a corresponding amount less during all other hours. The total power generated by each unit over the 24-hour period remained the same. 50% of all distributed generation units had active management in cases A-1 and A-1a and 100% of units had active management in cases A-2 and A-2a.

Electric vehicles: To model active management for electric vehicles, it was assumed that the utility could stagger Level II and III charging start times over 11pm-5am for Level II and 12am-5am for Level III. The vehicle charging profiles were modified by time-shifting them to the appropriate time period and randomizing their start times so that fewer vehicles began charging simultaneously. The total power demanded by each vehicle over the 24-hour period remained the same. 50% of all electric vehicles had their charging actively managed in case A-1 and 100% of vehicles had their charging actively managed in case A-2.

Following an examination of preliminary results, it was decided to investigate the management of Level III charging further to check the effect of the high 40 kW power demand of Level III charging on the results. Instead of merely time-shifting Level III charging to valley demand hours, the Level III charging was time-shifted, the power consumption per hour of Level

III chargers was halved to 20 kW and charging took place over 2 hours instead of 1 hour. This change was applied to the electric vehicles with Level III charging in case A-1 (50% penetration of electric vehicles) and the resulting case was denoted A-1a. Similarly, the change was applied to the electric vehicles with Level III charging in case A-2 (100% penetration of electric vehicles) and the resulting case was denoted A-2a.

3.7.4 Results

Results are presented for the active and passive management cases studied.

Table 17. Comparison of investment costs required under passive and active network management cases A-1 and A-2

Component	Network Investment Costs for P-1, A-1 and A-2 (euros)				Savings vs. P-1 (%)	
	Initial Network	P-1	A-1	A-2	A-1	A-2
LV wires	10,108,054	4,289,635	2,969,005	3,266,111	31	24
MV-LV substations	4,014,400	1,986,600	1,227,800	1,440,600	38	27
MV wires	7,235,973	1,424,508	650,785	650,785	54	54
HV-MV substations	8,120,000	2,800,000	2,800,000	2,800,000	0	0
HV wires	577,645	0	0	0	0	0
Total	30,056,072	10,500,743	7,647,590	8,157,496	27.17%	22.32%

Note: The “Initial Network” column provides the investment costs of the initial network, as a reference.

Table 18. Comparison of investment costs required under passive and active network management cases A-1a and A-2a

Component	Network Investment Costs for P-1, A-1a and A-2a (euros)			
	Initial Network	P-1	A-1a	A-2a
LV wires	10,108,054	4,289,635	2,813,113	2,845,865
MV-LV substations	4,014,400	1,986,600	1,227,800	1,401,600
MV wires	7,235,973	1,424,508	650,785	708,983
HV-MV substations	8,120,000	2,800,000	2,800,000	2,800,000
HV wires	577,645	0	0	0
Total	30,056,072	10,500,743	7,491,698	7,756,448

Note: The “Initial Network” column provides the investment costs of the initial network, as a reference.

Table 19. Comparison of new lines required

Line	Additional Lines Required		
	P-1	A-1	A-2
LV lines (aerial) (km)	81.07	60.68	64.82
LV lines (subterranean) (km)	73.9	45.99	52.8
MV lines (aerial) (km)	15.02	9.39	9.39
MV lines (subterranean) (km)	9.72	3.92	3.92

Table 20. Comparison of number of new substations/transformers required

Additional Substations/Transformers Required					
Vnom1 (kV)	Vnom2 (kV)	Nominal Power (kVA)	P-1	A-1	A-2
66	20	38000	2	2	2
20	0.4	810	150	93	108
20	0.4	290	3	2	3
20	0.4	110	1	0	1

Note: Vnom refers to the nominal voltage of the substation or transformer.

Table 21. Comparison of total investment costs for all cases

Total Investment Costs						
Case	P-1		A-1		A-2	
Total Investment Costs	10,500,743	100.00%	7,647,590	72.83%	8,157,496	77.68%
<i>(Percentage of Case P-1)</i>						
Case	A-1a		A-2a			
Total Investment Costs			7,491,698	71.34%	7,756,448	73.87%
<i>(Percentage of Case P-1)</i>						

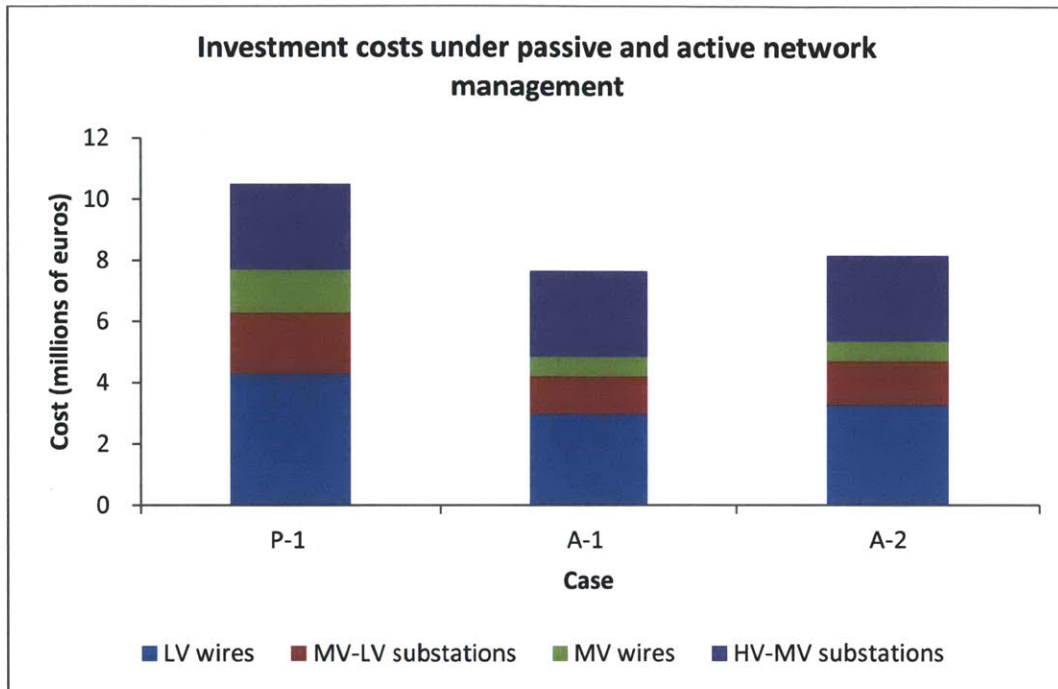
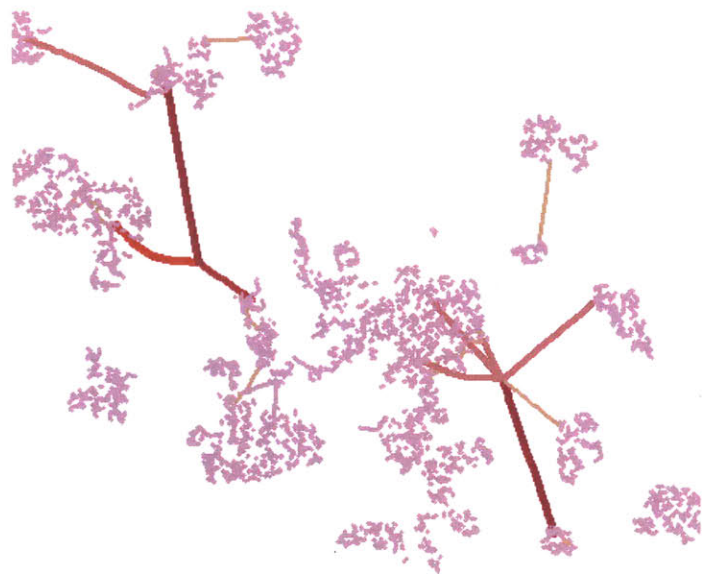
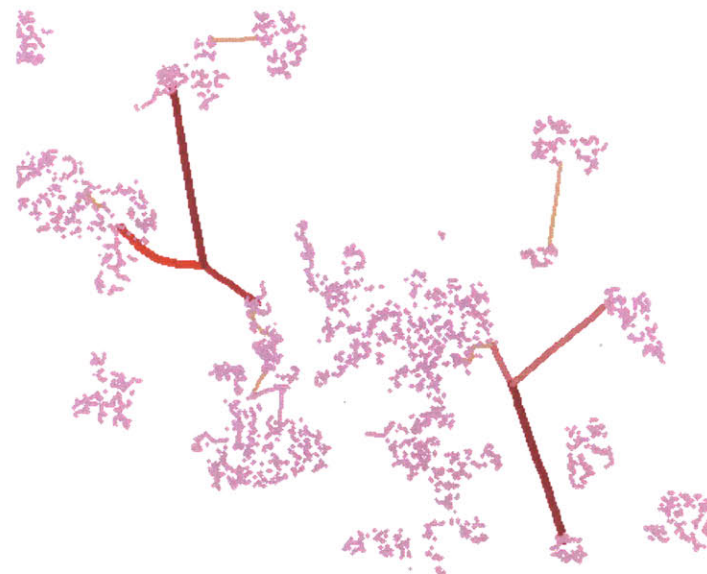


Figure 25. Investment costs under passive and active network management, broken down by network component



P-1



A-2

Figure 26. The incremental wires network required (in addition to the base network) for cases P-1 and A-2. *Note:* Wires in each case are color coded by their investment cost. A darker color indicates a higher-cost wire (relative to other wires built for that case).

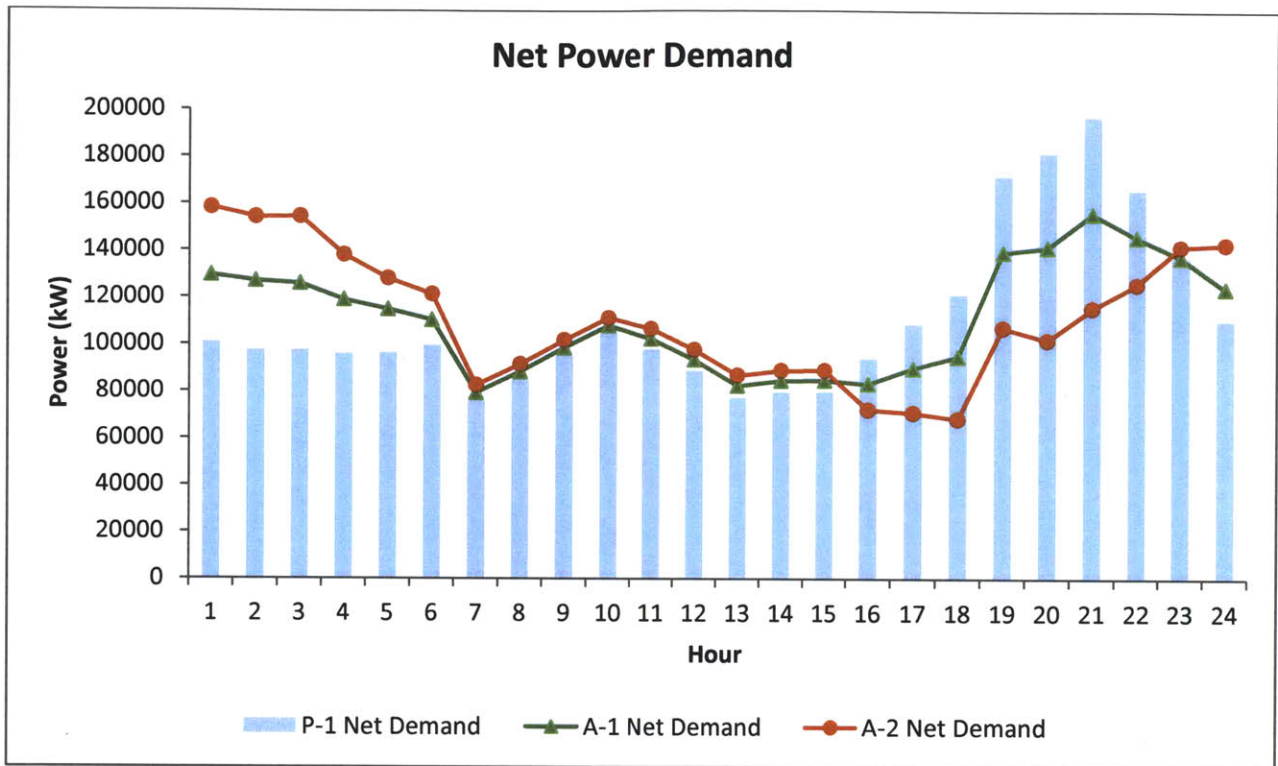


Figure 27. Net power demand of customers and electric vehicles less power contributions from distributed generation, for cases P-1, A-1 and A-2.

3.7.5 Discussion

It can be seen that the benefits of active management are fairly significant. In the low voltage network (LV wires and MV-LV substations), active management cases A-1 and A-2 translate into savings of between 24-38% compared to the passive management case: that is, component costs are 24-38% less than under passive management as shown in Table 17. For the medium voltage network, the savings are the same, 54% for both actively managed cases. It is likely that the similarity occurs because as the voltage level of network components increases, the investments required are increasingly lumpy so the differences between the two forms of management are less clear. For example, as shown in Table 20, 2 incremental 66 kV-20 kV (HV-MV) substations are required for the network built in all cases analyzed so there is no HV-MV substation cost difference between passive and active cases. However, there is a difference in the number of 20 kV-0.4 kV (MV-LV) substations required which translates to a difference in MV-LV substation costs under active management compared to passive management.

Table 17 and Figure 25 show how case A-1 with only 50% of the customers and new technologies actively managed, results in a lower overall network investment cost than case A-2 with 100% of customers and new technologies actively managed. This network investment cost is largely determined by the peak power demand in the network when the net power demands in all 24 hours are analyzed by the model. Figure 27 superimposes the power demands in all 24 hours for cases A-1 and A-2 on the power demands for case P-1. In case A-1, the peak occurs in hour 21 (9pm) and is driven by Level II and III electric vehicle charging since under this 50% actively managed case, only 50% of electric vehicles have charging times shifted. In case A-2, 100% of vehicles had their charging times shifted to nighttime and because of the high power demands of electric vehicle chargers, the peak occurs in hour 1 (1am).

Active management was investigated further with particular attention paid to Level III electric vehicle charging because of the extremely high 40 kW power demand per hour under Level III charging. In cases A-1a and A-2a, the Level III chargers' power demand was reduced to 20 kW per hour and the total time allowed for charging was doubled to 2 hours. Table 18 shows the detailed results for cases A-1a and A-2a while Table 21 compares the costs to those under cases P-1, A-1, and A-2. Although case A-1a continues to produce a lower network investment cost than case A-2a, the percentage difference in investment cost between case A-1a and case A-2a is small, 3.53%. The corresponding difference between case A-1 and case A-2 is 6.67%. This result illustrates the importance of active management design and implementation processes. If active management is implemented by only time-shifting the demand, without spreading it over a greater number of hours, the different technologies and customer power demands may interact in such a way that the net peak power demand is still fairly high in a fully actively managed network. If enough customers are indifferent to the total time taken to charge their vehicles at night, even fast chargers that have a very high power demand could be actively managed in sophisticated ways so as to reduce their peak power demand and reduce the power demands on the network. It may be that Level III chargers' power demand can be reduced to even lower than 20 kW per hour and those vehicles' charging times spread throughout the night, which would change the effect of EV chargers on net power demand even more. Finally, on the one hand the results suggest that many of the benefits of active management may be captured by a network that has 50% active management. On the other hand, a 100% actively managed network may see additional benefits that a 50% actively managed network does not. For example,

a network with loads and generation fully manageable by the distribution company may be quicker to respond to emergencies or sudden changes in network conditions.

The benefits of actively managed case A-2 relative to passively managed case P-1 are largest in the MV wires network. For example, as Table 19 shows, under case A-2 the required length of underground MV lines was less than half of the requirement under case P-1. The graphical representation of the P-1 and A-2 networks in Figure 26 also shows that under active management (A-2), several lines that were required under passive management (P-1) are no longer built. The visual density of the lines is higher in P-1 compared to A-2, reflecting the fact that more lines are required in P-1 than in A-2.

In general, the results demonstrate the benefits of active management compared to passive management in terms of required network investment costs. The differences in the two active management cases studied also illustrate the importance of design and implementation of active management programs.

3.7.6 Methodology to study Losses under Passive and Active Management

Losses were also compared for a passive management case and an active management case. In order to make the networks comparable for the purpose of studying losses, a different methodology was applied to the analysis of losses.

In step 1, the base network was created using the greenfield model as described in section 3.7.2. In step 2, the brownfield model was run to obtain results for the passively managed network. Losses are affected by transformer taps since the model normally varies the taps to change the output power of the transformers. To make losses in different cases comparable, the taps should be fixed in both cases so that they do not affect losses. Hence in step 3, the brownfield model was run again on the results of step 2, with passively managed power flows and transformer taps fixed. The results of step 3 provide an indication of losses costs.

To study losses in an actively managed network, it was necessary to prevent the model from planning a different network to meet the requirements of the active case. The networks planned above to study investment costs for the passive case P-1 and the active case A-2 are materially different in terms of their configurations, components, and equipment. While this is an expected result owing to the different demands of active and passive management, it was felt that distribution line losses in two essentially different networks should not be compared directly.

Hence, to study losses under active management, the passively managed network was obtained from step 2 as described above. In step 3 the brownfield model was run again on this network but with actively managed power flows and transformer taps fixed. That is, the underlying network was that created for passive management but the power flows were those of an actively managed network.

3.7.7 Results

Results were obtained using the methods described above for losses and are tabulated in Table 22. As the unit cost of losses is a discretionary parameter in this model, for this close examination of losses it is considered more useful to present the kWh of losses calculated by the model for the first year of the network. Owing to the need to keep the underlying network configuration consistent and transformer taps fixed in both cases in order to compare losses, the networks are not precisely the same as the P-1 and A-2 networks planned by the model during the study of investment costs, so they are not labeled as P-1 and A-2. However, in terms of network management approaches, the passive case for which losses were studied broadly corresponds to the fully passively managed case P-1 and the active case broadly corresponds to the fully actively managed case A-2.

Table 22. Losses under passive and active management

Component	Passive management (kWh)	Active management (kWh)	kWh of losses in active case as percentage of passive case (%)
LV wires	1,527,984	1,005,344	65.80
MV-LV substations	271,113	217,459	80.21
MV wires	345,859	219,806	63.55
HV-MV substations	136,452	113,777	83.38
HV wires	65,573	41,354	63.07

3.7.8 Discussion

The benefits of active management can also be seen in the cost of losses. By reducing the peak utilization of network components, active management generally mitigates losses. The cost of losses is lower under active than under passive management for all network components studied.

The benefit is clearest in the wires network at all voltage levels, with active management implying a cost of losses that is between 63-66% of the cost under passive management. The

benefits of active management in substations are not as large, as costs are 80-83% of those under passive management. For the network studied, the reason for this could be that the substations in the base network already have a very high level of capacity utilization. Thus, when the brownfield model plans network expansion for demand growth and new technology integration, the need for the substations to operate even closer to capacity to meet the new requirements reduces scope for cost reduction through reducing losses.

3.7.9 Comment on Base Network Capacity and Incremental Investment Required

As described in Section 3.7.2, the cases for passive management and 100% active management were also run using an idealized base network created by the greenfield model. The results are presented in Table 23. The incremental investment required for passive and active management is significantly higher for substation components than for the LV or MV feeders. The smaller required investment in feeders is because the idealized base network already has significant spare capacity designed into its LV and MV feeders. The greenfield model designs this spare capacity into the base network because of the high cost of losses set as an input parameter, implying the need for a network with sufficient spare capacity to mitigate losses. When the brownfield model is run using a base network with such high spare capacity, it results in a smaller required investment in feeders since the base network's feeders have sufficient spare capacity to accommodate the increment in demand.

Table 23. Results for passive and active management when the brownfield model is run on an idealized base network

Component	P-1 (ideal base network)		A-2 (ideal base network)	
	Incremental Investment costs (euros)	Incremental investment costs as percentage of base network costs (%)	Incremental Investment costs (euros)	Incremental investment costs as percentage of base network costs (%)
LV wires	1,372,240	12.69	659,070	6.08
MV-LV substations	2,220,600	55.61	1,707,800	42.77
MV wires	275,362	3.93	88,395	1.26
HV-MV substations	2,800,000	34.48	2,800,000	34.48

Although the initial network used in this case is viewed as an idealized base network that is less approximate to reality, the benefits of active management versus passive management are

still apparent in the results. Active management results in a lower required investment cost in LV wires, MV-LV substations, MV wires, and HV-MV substations as it reduces the peak power demand in the network.

3.7.10 Conclusions from Modeling Analyses

The results of the greenfield and brownfield models show the necessary network investment costs for various new technology penetration scenarios and new technology management scenarios. For distributed generation, investment costs depend on the location and per-unit power output of the distributed generators. Costs display a trend of decreasing and then increasing as penetration increases for DG located near to customers with a power output of 3 kW/unit. However, costs do not change so markedly as DG penetration increases when the DG is located near to customers and has a very low per-unit power output. Nor do they change so markedly as DG power output increases when the DG is located far away from customers.

The brownfield model clearly demonstrates the benefits of active network management of new technologies, and additionally shows the importance of design and implementation of active network management programs. Active management generally implies a decrease in LV and MV distribution network investment costs relative to passive management. Depending how active management is implemented, active management of 50% of the new technologies may not give very different results to active management of 100% of new technologies especially if the peak power flows are not very different.

In the presence of new technologies like those studied here, regulatory schemes to remunerate distribution companies for their costs need to be designed appropriately to take into account the changes in costs under different scenarios as illustrated by the modeling results. Otherwise distribution companies may be over- or under-compensated, and will not make the investments needed to accommodate new technologies in an efficient way. Once companies' allowed revenue (amount of remuneration) has been determined, the costs need to be allocated to and recovered from network users. The following chapter considers the linked issues of remuneration, cost allocation and cost recovery in the presence of new technologies.

Chapter 4: Remuneration, Cost Allocation and Recovery

4.1 Existing Methods of Cost Allocation and Recovery

After the appropriate changes to a distribution company's allowed revenue have been established (for example with the aid of modeling analyses) to compensate for capital investments related to accommodating new technologies, the allowed revenue has to be raised from network users through appropriate tariffs. To achieve this, regulators need to *allocate* the costs between network users, and devise a consistent mechanism (tariff) for charging each group of users so as to *recover* the costs.

In the US under cost of service regulation, a particularly diverse set of judgments has been made with regard to cost recovery. Utilities install many of these new technologies through one-time projects developed for their installation, which are proposed to the relevant regulatory commission for approval. The proposals approved so far have employed a diverse set of cost recovery mechanisms. The mechanism selected for cost recovery is important because if well designed, it can permit an appropriate level of risk sharing and may reduce the risk of cost overruns.

Several studies of smart grid project cost recovery methods to date have compiled a variety of cost recovery approaches. Some common approaches are summarized in Table 24.

Table 24. Some cost recovery methods

Mechanism	Description
Rate Base	The most basic form of cost recovery allows utilities to recover their costs by adding the cost to the rate base, which is the basis for how customer charges are determined. Rate base cost recovery can be partial (only part of the project costs are recovered through modifications to the rate base) or deferred (cost recovery approved, but exact formulations deferred – for example till the next base rate case).
Tariff rider	A rider formula (that calculates an amount in \$/kWh) is added to the base electricity tariff to recover costs specific to that project and can be trued-up regularly to account for over or under-recovery.
Costs plus avoided cost (DR)	The utility can be compensated for a demand response program by the program cost plus an amount related to the amount it saves from not investing in additional generation capacity. The additional amount serves as an incentive.
Surcharge with/without Tracker Mechanism	A fixed surcharge amount in \$ can be added monthly or annually to bills to cover the project costs. A tracker tracks the project-related costs and allows the surcharge to be reset on a periodic basis to adjust for ongoing changes in costs. The surcharge is similar to a tariff rider, but a surcharge is a preset dollar amount while a rider may be implemented as a formula.

Table 24. (continued)

External funding	Regulators can require that part or all of the capital costs of a project be funded by specific funding pots set aside for grid modernization. Examples of such pots include the Smart Grid Investment Grants in the US and the Low Carbon Networks fund in the UK.
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Sources: Based on information in KEMA (2011), Edison Electric Institute (2005), MIT (2011), and EnerNOC (2009).

In cost of service regulation, regulatory opinions over the type of cost recovery to approve differ across states. One of the principal reasons BGE's advanced metering project was rejected by the Maryland PUC was its proposed cost recovery mechanism – a surcharge. The PUC objected to this because of its implications for risk allocation: “BGE’s Proposal... also is a request to establish a customer surcharge for advance recovery of the costs of the Proposal, thereby shifting all financial risk to BGE customers” (Public Service Commission of Maryland 2010, 3). But in Texas, surcharges have been approved for CenterPoint Energy and Oncor Electric Delivery’s advanced metering projects (Edison Electric Institute 2009). Whereas the Maryland PUC considers BGE’s advanced metering project “classic utility infrastructure investment that should be recovered through distribution rates”, the Texas PUC finds Oncor’s AMS Surcharge Model “a reasonable method”, approves it and then affirms “If the Commission conducts a general base rate proceeding related to Oncor’s base rates during the AMS deployment period (2008 - 2012), then Oncor will not seek to include the costs of the AMS in base rates” although the decision also allows for future base rate cost recovery for meters installed in addition to those in the AMS project (Public Utility Commission of Texas 2008, 5, 7, Public Service Commission of Maryland 2010, 4).

Another cost allocation issue for regulators is that when benefits are difficult to quantify and allocate, it is more difficult to decide who should pay for the project. For example, projects may produce public benefits such as pollution mitigation and climate change mitigation that are not only difficult to quantify but also accrue to customers outside the project utility’s service territory. But the project itself has to be cost and paid for by a group of investors and ratepayers that does not include all those who benefit from it.

The benefits of many new technologies are also inherently uncertain. It may be desirable to allocate the costs to the customers likely to benefit from the new technologies. But the benefits of certain types of investments such as AMI investments may depend on uncertain external

factors such as customer behaviors, dynamic pricing problems, and government policies, making it hard to decide how, at the outset, to allocate costs fairly.

4.2 Remuneration, Cost Allocation and Recovery for Distributed Generation

The following discussion pertains to residential, small-scale distributed generation often installed at residential customer locations. The case of distributed generation is particularly interesting owing to the remuneration, cost allocation and cost recovery methods that have been implemented for it to date. As one of the more mature technologies studied here, DG can provide valuable lessons on appropriate regulatory principles in the presence of new technologies. As determining allowed revenue (remuneration) for integrating DG is closely linked to problems in cost allocation and recovery, all three issues are discussed below.

In the US, a number of states have implemented net metering for small-scale distributed generation facilities with power outputs below certain levels. This may distort incentives for distribution companies because as described in Chapter 1, a common means of recovering distribution network costs in the US is volumetric energy charges. Distribution companies charge customers based on the amount of energy they consume. Under net metering, the volumetric charge then depends on the net amount of energy consumed. Hence net metering combined with volumetric remuneration make distribution companies unfavorably disposed towards technologies or measures (such as distributed generation or energy efficiency programs) that reduce the amount of energy distributed by them to be consumed by customers. For energy efficiency, a wide range of regulatory modifications such as decoupling, lost revenue adjustment, or energy efficiency program-specific cost recovery (among other methods) have been used to mitigate this disincentive (EnerNOC 2009, Environmental Protection Agency 2007, MIT 2011). Nevertheless, this disincentive on the part of distribution companies towards energy usage reduction applies to many other measures besides energy efficiency and will only grow more acute with the introduction of technologies like DG that can reduce energy consumption.

A second, related issue that complicates cost allocation and recovery is that residential distribution grid customers in the US, unlike some other countries, generally do not have a “contracted power capacity” (kW) with their distribution companies since revenue collected is determined by total amount (kWh) of energy consumed. Not knowing the capacity (kW) of

energy that customers are utilizing makes it difficult to know how this capacity, and so network costs, would be affected by distributed generation. In turn, this makes it more difficult to allocate costs for distributed generation among the network customers.

Thirdly, determining allowed revenue and cost allocation for small-scale DG have become more problematic with the introduction of net metering as a system of remuneration for DG. In areas such as the US state of Massachusetts, net metering allows customers with qualifying DG installations to pay only for the net electricity they consume (Commonwealth of Massachusetts 2008). As the public FAQ relating to net metering in Massachusetts explicitly states, “If net consumption is positive, customer pays electricity bill. If net consumption is negative, customer receives credit on electricity bill” (Commonwealth of Massachusetts 2012). However, under this system, customers with DG installations contribute less to the cost of the distribution network than customers without DG installations. In fact, since every kWh generated is offset against the electricity bill, every kWh generated avoids paying electricity distribution charges. Yet customers with DG installations still utilize the distribution network since the generators are connected to the network, are part of the entire network circuit, and cannot be viewed in isolation. Whenever a DG unit is generating, the connected DG unit charges electrons in the distribution network it is connected to and transfers energy through the network. The power generated by DG therefore makes use of the distribution network, and should incur appropriate network costs.

DG installations may even add to distribution network costs when the DG units utilize wind or solar energy that do not generate electricity consistently, necessitating operational changes or investments in equipment or control systems to manage the ensuing current and/or voltage fluctuations. Customers wishing to sell excess electricity generated by their DG installations back to the grid may also add to network management costs. Furthermore in the presence of DG, the existing grid network provides a useful source of reliable backup power for cases when DG is not available to generate power. It can also provide cheaper power when the power generated by DG is too expensive. Such features are benefits which the distribution company should be compensated for.

Net metering thus raises the possibility of inadequate remuneration. If net metering combined with volumetric remuneration is in use, in the long run as more customers install DG units or increase the power output of their DG units, the amount of money recovered from

customers will decrease. But for the reasons described above and as the modeling results of Chapter 3 show, DG-related costs do not always decrease as DG penetration level increases. In fact the modeling results suggest costs can take an upward trend at higher customer penetration levels. This is to say nothing of the costs of maintaining the aforementioned services that the network provides to DG-owning customers, such as backup power, reliability, and an acceptable level of network quality of service. Also for these reasons decoupling revenues from energy consumption, which has been used to ensure revenue recovery in the presence of energy efficiency programs, is not likely to be a sufficient regulatory solution for DG. Decoupling may work to mitigate disincentives to energy efficiency programs that simply reduce demand for electricity without necessarily adding to distribution companies' costs. But unlike energy efficiency programs, DG technologies inject power into the network and imply network capacity and management requirements – and so, costs – for the distribution company.

Net metering can also cause inequity issues in cost allocation. In the long run, faced with the additional costs of integrating DG, the distribution company may attempt to recover its additional costs from other customers who do not have net metered DG installations and who cannot offset generation against consumption. By allowing customers with qualifying distributed generation installations to receive a credit for their generation, net metering causes customers without such installations to subsidize the cost of the distribution network for customers with installations (MIT 2011, 182-183).

Net metering may have been introduced to indirectly encourage distributed generation by decreasing customers' energy costs, measured on a per-kWh basis. However, owing to net metering's drawbacks, it is not an effective subsidy. The inequity of the cross-subsidies among customers with and without DG caused by net metering is not economically efficient and in the long run net metering can prevent adequate cost recovery for distribution networks. If it is desired to subsidize DG to encourage more DG connections to the network, an explicit subsidy such as feed-in tariffs is arguably preferable to the implicit subsidy of net metering.

4.2.1 Approaches to Remuneration and Cost Recovery

Several methods have been proposed to recover DG-specific costs, such as connection and use of system charges. Connection charges are paid by the generator to the network for connecting to the system. They are a one-time payment made at first connection. They can be shallow (the distribution company is paid for the direct cost of connection), deep (the company is

paid for the cost of connection and network reinforcements), or shallowish (a mixture of the two methods) (Cossent, Gómez and Frías 2009, Frías, Gómez and Rivier 2008). Bauknecht and Brunekreeft note that deep charging can be unfair to different DG, since the cost of connection and network reinforcements and the transaction costs of negotiation between DG and the distribution company differs for each DG, while shallow charging “does not internalize the external costs and benefits” (2008, 494). A mix of deep and shallow charging may also be used to reflect different connection costs of different types of generators, as in the Netherlands and the UK (where deep charges are permitted when the cost of integrating DG exceeds £200/kW) (Cossent, Frías and Gómez 2008, Office of Gas and Electricity Markets (Ofgem) 2009). Use of system charges are paid periodically by network users, and in current practice in Europe they may or may not be paid by DG (Cossent, Gómez and Frías 2009). Use of system charges for DG can be made dependent on the DG’s voltage level, location, or other metrics. This could allow a regulator to allocate higher costs to distributed generators that are more expensive to integrate into the system, making for more efficient cost allocation. These means of cost allocation and recovery may make distribution companies neutral regarding connecting DG to their networks, or even incentivize them to do so.

The EU’s 2007 DG-GRID study by Scheepers, et al. (2007) suggests shallow connection charges to reduce the cost of DG connections and encourage DG to connect to the network. To cover ongoing integration and operation costs of DG, Scheepers, et al. (2007) and Frías, Gómez and Rivier (2008) suggest use of system charges differentiated by time-of-use. Scheepers, et al. (2007) suggest that use of system charges also be made dependent on location, since the cost of DG integration depends on the location of the DG within the network. Finally, Frías, Gómez, and Rivier (2008) suggest use of system charges also be dependent on the voltage level of the DG connection.

Other methods of cost recovery include revenue driver incentives outside the revenue control, or even setting the revenue or price cap to account for the cost of DG connections so DG-related costs may be recovered from generators or network users. An example of an incentive is the revenue driver in the UK that automatically remunerates the distribution company per kW of DG connected, as described in Chapter 2. The cost of the incentive is recovered from network users but using a cost-reflective methodology to recover an appropriate

proportion from demand and from generation (Office of Gas and Electricity Markets (Ofgem) 2009).

In some states in the US, the regulatory framework permits standby rates to be levied on certain distributed generation facilities, generally large ones with a power output above a certain level. Standby rates establish tariffs that charge DG owners for the costs of providing them with backup power when their DG does not generate enough power to fully serve them. Depending on their design, these rates may partially address the problem of cost recovery for DG-related costs. However, as the name implies, standby rates are intended to remunerate the grid for providing “standby” or backup service to generators. They may not provide sufficient remuneration for the network capacity expansion, power management systems, or other features that may be needed to accommodate DG. For example if the rates are designed to take effect only when the DG does not generate, they remunerate for network backup service costs but not for capacity additions that may be needed to accommodate the total power output by many DG units, and not for the network management costs implied when the DG-generated power injected to the grid has to be managed to balance the network and avoid deteriorations in service quality.

It is also important to note that first, according to a review by Environmental Protection Agency standby rates mostly apply to generators defined to have larger capacities than the smaller residential units considered in this study (Environmental Protection Agency 2009) but smaller units will become more important as the penetration of residential DG increases. Second, DG eligible for net metering may be exempted from standby rates as in North Carolina and as in the Southern California Edison service territory, meaning such standby rates cannot help to resolve cost recovery problems with net metering (U.S. Department of Energy 2012, Southern California Edison 2009). Third, the use and design of standby rates vary greatly across states and between companies in the same state so there is not a consistent method in use. Standby rates may also be provided on a case-by-case basis via negotiations between the generator and distribution company, which implies transaction costs of negotiation. Such an implementation of standby rates would not be very effective for residential distributed generators, since there would likely be many more units of small residential generators than there are large generators and it would be inefficient to negotiate each small generator’s contract separately.

In the US, recent proposals to remedy net metering cross-subsidization and inadequate remuneration for networks accommodating residential DG have seen regulators take opposite

views. In California, SDG&E proposed a network use charge to charge customers based on their use of the network (Earl and Barnes 2011). Such a use-based charge would have collected payments from DG owners for their use of the network during DG generation. The proposal was rejected in part because the lawfulness of differentiating between customers with and without DG was questioned (California Public Utilities Commission 2012). On the other hand in Virginia, the commission approved a “standby charge” for DG between 10 kW and 20 kW, acknowledging that “customer-generators who engage in net metering still make use of the transmission and distribution grid” and that the benefits from their DG alone were insufficient to remunerate the distribution company (State Corporation Commission, Commonwealth of Virginia 2011, 3). Strictly speaking, the Virginia “standby charge” does not appear to resemble standby rates that are levied only when the DG has an outage and requires power from the network. The “standby charge” approved provides for a fixed sum per month and does not mention making the levy conditional on a DG outage (State Corporation Commission, Commonwealth of Virginia 2011). However, a news report noted that the power output eligibility criteria for the standby charge was set so high that only one customer was found to be liable for it in 2011, suggesting that remuneration for smaller-scale residential DG has yet to be addressed fully (Lillian 2011).

4.2.2 Proposals to Remunerate for and Recover Network Costs in the Presence of DG

In the US, shifting away from volumetric remuneration would remove a disincentive to the connection and use of DG. The decoupling process that has been used in several states to remove disincentives to energy efficiency is a step towards this end, although current implementations do not acknowledge the added costs implied by DG units generating power. One form of decoupling that removes the disincentive to connect DG could be to impose lump sum capacity charges based on historical energy use patterns. While the initial charge amount could be based on a historical analysis of energy used, the charging structure thenceforth should be made completely independent of changes in future energy usage to avoid the present disincentives arising again. Such a method should also include a small volumetric charge component so that network users retain some incentive to conserve energy.

To ensure that customers with distributed generators pay a fair share of the network costs they are responsible for, net metering should be reformed. One method of doing this could involve the installation of two meters, one measuring all energy consumed and the other

measuring all energy generated. The principles of net metering could be applied by charging an energy charge based on net consumption (the difference between the two meter readings). However, then, an additional capacity charge should be imposed. As mentioned above, a key problem with volumetric charges is that they can allow DG to avoid paying network costs. Capacity charges resolve this issue. This charge could be based on the maximum power generated or consumed, as measured by the meters. Network expansion costs (investments in larger feeders, transformers, etc.) are largely driven by the peak power transmitted in the network, so a capacity charge linked to the maximum power generated or consumed is an elegant solution.

Another method of reforming DG cost recovery could take advantage of the sophisticated hourly metering features of advanced metering infrastructure. Two tariffs could be designed, one for generation and one for consumption. Both would incorporate the need to pay for network costs. The advanced meter would record whether net generation or consumption occurred in a given hour. The appropriate tariff would then be applied to that hour. This system would result in a measurement of net demand and a second measurement of net generation as shown in Figure 28. The tariff for demand might incorporate both capacity and quantity demanded charges to recover costs (that is, be a two-part tariff). Similarly, the tariff for generation might incorporate both capacity and quantity generated charges. If the peak value of net generation was very small relative to the peak value of net demand (as it is in the example of Figure 28), the capacity charge would be determined by the maximum capacity required to meet demand and be paid through the demand tariff. Then the capacity charge for generation would be zero. In a sense, this is an economically elegant solution as the capacity charge is tied to the type of network usage (demand or generation) which drives the need for network capacity.

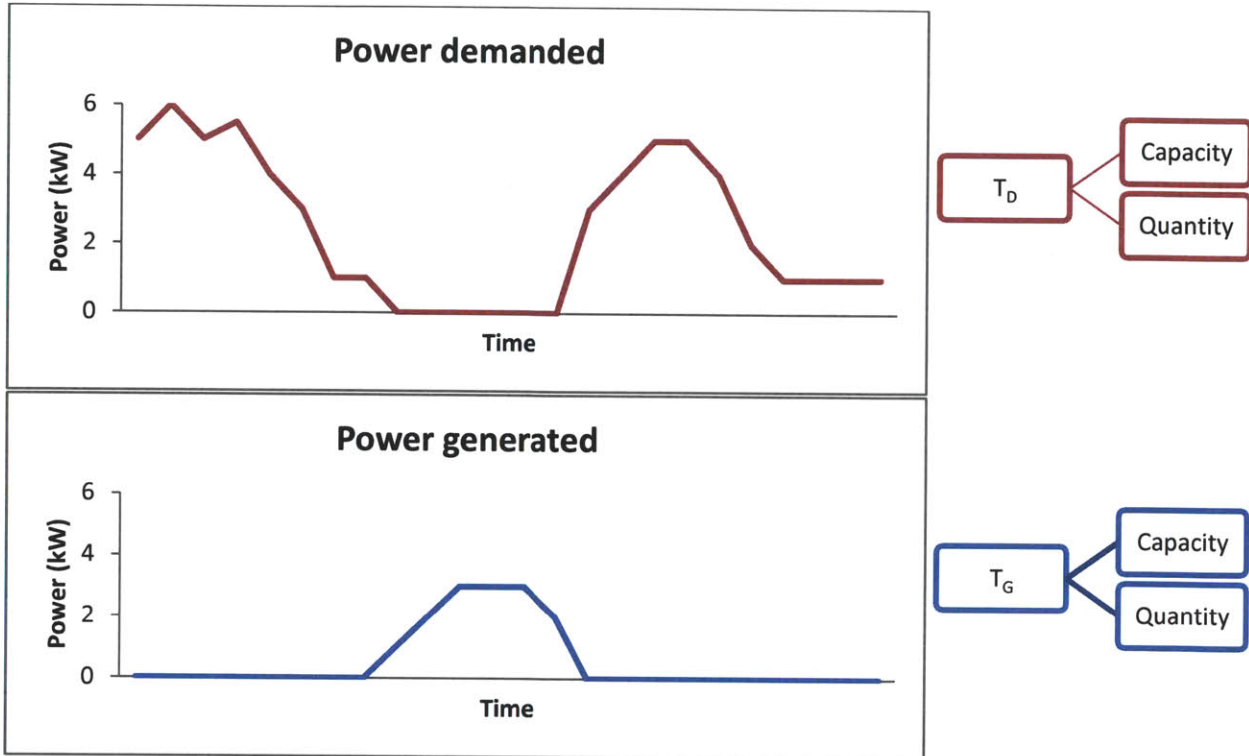


Figure 28. Theoretical generation and consumption and the application of two tariffs

In the context of transmission cost allocation, it has been proposed that the costs of new lines be divided into two components (Pérez-Arriaga and Olmos 2009, 15). The first cost component would be “allocated to the network users (both generators and loads) according to their responsibility in the construction of the line”, and the remaining component of cost would be allocated to the final beneficiaries of lines, generally the customers (15-16). In distribution, when the penetration level of distributed generation is high enough, it may be valuable to consider similar methods of cost allocation.

More advanced methods of cost recovery via connection and use of system charges may also be considered. For example, different connection charges may be levied on DG generators depending on their time of connection to the network to pay for the costs the distribution company incurs because of those generators (such as new lines that have to be built as a result of the new DG connections). Existing users of the network, who do not precipitate the building of those new lines, should contribute relatively less towards their cost. A similar principle is advanced in Pérez-Arriaga and Olmos (2009), for transmission.

Ex ante DG charges are another possible method of cost recovery. As the modeling results of Chapter 3 show, network costs caused by some types of residential DG connections are expected to decrease at first, but then increase as DG penetration increases. If DG connections are forecast to increase in future to a level that increases network costs, DG generators now connecting to the network could be required to pay charges determined ex ante that take into account the expected future costs. The fee schedule could be pre-set to increase each year as the amount of DG in the network is forecast to grow. By confronting DG with ex ante charges dependent on forecast DG connections in the area, this method also allows a locational signal to be sent. DG is incentivized to install in areas with less DG, where the forecast level of connections grows at a slower rate and the ex ante charges are less.

Finally, Locational Marginal Pricing (LMP) has been used in transmission to provide short-term price signals to network users depending on the congestion and demand in the network at that point in time. A similar concept applied to distribution would pay DG more when a network has a high power demand, as DG (particularly when located near to customers) would help meet that demand. Since this pricing concept depends on the state of the network at that point in time, no additional pricing signals are required. However, it requires a sophisticated network system capable of calculating the price at different nodes on the distribution system. The modernization of the distribution system may increase network visibility and control to a point where such a system is feasible.

4.3 Remuneration, Cost Allocation and Recovery for Other New Technologies

Other new technologies such as electric vehicles and advanced metering infrastructure also necessitate appropriate cost allocation and recovery. Although the problems of each new technology differ, some of the ideas advanced with respect to DG may be of use. For example, electric vehicles may someday contribute electricity to the network via Vehicle-to-Grid systems and it will be necessary to avoid the net metering problems seen when remunerating for distributed generation that contributes electricity to the network. More likely in the near future is that electric vehicles require investments in network capacity owing to the high power demands of Level II and III charging. As seen in the results for active and passive management scenarios in Chapter 3, the capacity demands of Level III chargers can have a large effect on network costs.

To ensure the distribution company is adequately remunerated for these costs, a capacity charge similar to that proposed for DG can help recover the costs from electric vehicle owners.

In the following concluding chapter, the regulatory proposals considered in Chapter 2, the results from the modeling analyses in Chapter 3, and the cost allocation and recovery issues discussed in Chapter 4 are synthesized to select and develop appropriate regulatory proposals for regulating distribution companies' allowed revenue in the presence of new technologies.

Chapter 5: Regulatory Proposals

5.1 Regulation for the Future

Two key questions for future distribution grid regulation are: what should the regulatory scheme itself look like, and how should any additional regulatory incentives be utilized to stimulate the adoption and optimal integration of new technologies?

New technologies such as distributed generation (DG), distribution automation and electric vehicles among others are increasingly connecting to distribution networks. The introduction of these technologies is given impetus by new objectives such as improving environmental sustainability by utilizing distributed renewable generation, and modernizing the grid by utilizing technologies that enable better management and control of the grid. As described in Chapter 2, many new technologies create challenges for distribution regulation in terms of regulating the necessary capital investment, accommodating lost revenue recovery (in some cases), regulating network performance and regulating innovation.

To meet these challenges incentive regulatory schemes are moving towards an outputs-based framework, with associated incentives targeting the introduction of new technologies or the implementation of innovative projects. An outputs-based framework to a degree permits companies to decide how to deploy and use new technologies provided a set of output targets (for example, relating to network reliability) are met, which opens up innovative potential in network design and use. As the regulatory scheme is the framework within which specific incentives such as distributed generation incentives operate, it is important to consider the interactions between the scheme and incentives in the design of regulation.

In places in the US, cost of service regulatory schemes have adopted some of the features of outputs-based incentive regulation via the introduction of targets for losses and quality of service. The California PUC's interest in the development of metrics for assessing grid modernization points to potential measures that might be used to regulate network outputs.

The new regulatory schemes are not powerful enough, by themselves, to facilitate the optimal penetration and operation of new technologies without specific incentives. Countries which have introduced or considered new outputs-based regulatory schemes have often accompanied them with regulatory incentives intended to stimulate adoption and, increasingly, the optimal use of the new technologies. Such incentives may provide added support for distributed generation connections or investment in innovative network projects.

In the design of incentives for specific technologies, it is vital to consider the goal of the incentive. If the goal is simply to increase the number of DG units that the distribution company connects to its network, a simple and elegant revenue driver that provides some revenue for each connection may work. If the goal is to encourage the distribution company to utilize and manage the electricity generated by DG to meet demand for power and ancillary services in an efficient and environmentally sustainable manner (an implementation of active network management), then a revenue driver that rewards the company for the amount of electricity supplied to end users by DG might be more appropriate.

Incentives should be appropriate to the technology they target and its level of sophistication. If DG installations do not yet contribute much power to the grid, having just one revenue driver to stimulate connections might be sufficient while having both a connection revenue driver and a revenue driver for power contributed to the network by DG installations might be overreaching. It will also be important to avoid designing inappropriate incentives that over-remunerate distribution companies for a particular service. For example according to the modeling results of chapter 3, when DG penetration is low to begin with, network costs can decrease as DG penetration increases. At those penetration levels it may not make sense to remunerate the distribution company for each new DG connection, when additional DG connections in fact reduce some network costs.

A problem with creating incentives for specific technologies is the level of regulatory specificity such design entails. A very new technology may not be incentivized if innovation incentives are not also in place. As regulatory schemes become more complex, it is important to consider not only the design of specific incentives, but also the effect of simultaneous operation of multiple incentives in the regulatory scheme. Where possible, it might be efficient to design an incentive suitable for several new technologies to minimize the added regulatory burden. The time horizon of incentives is also important, and depends on the original objective of the incentive. If an incentive was developed to stimulate connections of DG, it would be efficient to remove the incentive when DG penetration has reached the desired level. Under the price control system of incentive regulation, the operation of incentives can be regularly reviewed. This is more difficult under cost of service regulation.

While it can be attractive to add specific modernization incentives to a regulatory scheme, doing so can not necessarily substitute for ensuring appropriate remuneration via the

underlying regulatory scheme. Merely adding incentives – for example for quality of service and losses - to cost of service regulation in the US may be insufficient to meet all the challenges posed by new technologies. For example, it would be ineffective to set a target for quality of service while not allowing the company sufficient remuneration to invest in a new power management system needed to maintain quality of service in the presence of DG.

5.2 Modeling Results and Regulation

As the applications of the Reference Network Models in this study demonstrate, new technologies can have disparate impacts on network costs. Costs vary with penetration level and location of distributed generation, and also depend on the presence or absence of active management and the details of its implementation.

5.2.1 Modeling Distributed Generation and Regulatory Proposals

An awareness of how costs can change in the presence of new technologies is vital to continued effective regulation of the distribution network. For distributed generation, the modeling results show that with a 3 kW/unit power output, DG located near to customers could decrease long-run network costs as DG penetration level increases until DG power contributions approach net system demand (Figure 9). This result suggests it could be efficient to support DG until that point through subsidies or a reduction in use of system charges. After DG begins to supply a majority of demand, DG necessitates network investments and increases long-run network costs. In that case, it would be necessary for DG to pay to remunerate the distribution company so that they can make the necessary network investments.

For situations like the 3 kW/unit DG power output case modeled in Chapter 3, where increasing DG penetration can change the trend of network investment costs from downwards to upwards, ensuring adequate remuneration via appropriate cost recovery methods poses particular problems. It may not be effective to fix a single connection charge for DG and keep it the same for many years when increasing levels of DG in the network change costs so markedly. Similarly, a direct revenue driver that increases the distribution company's revenue when more DG is connected or more energy distributed originates from DG may not be efficient if DG actually decreases the company's network costs up to a point. In such cases regulatory approaches that take DG penetration forecasts into account may be especially appropriate. As

suggested in Chapter 4, DG charges could be imposed ex ante incorporating forecasts for future DG penetration. Upon connecting to the network DG would agree to a schedule of payments (or subsidies) for the next x years, where the schedule takes into account forecast DG penetration over x years. Having all DG agree to an ex ante payment schedule implies that after the point in time at which DG is forecast to pay network costs, the costs can be socialized among all DG. This could mitigate the potential inequity of ex post charging which might give rise to a situation where DG connecting after a certain level of DG penetration has been achieved pays costs whereas DG connecting before that period receives subsidies.

Additionally, the comparison of costs for near and far-DG show that losses costs can be less for near-DG than far-DG, but these costs follow a U-shape pattern for near-DG (Figure 20). Since losses costs decrease when the power contribution of near-DG is increasing from a low level, the ex ante schedule of charges might recognize this by including a lower charge for new near-DG when existing near-DG is not yet contributing much power to the network. This lower charge can also send a locational signal to DG to locate near residential customers and ensure a benefit to the network in terms of the reduction in losses costs. But since losses costs start increasing when the power contributions from near-DG are high, the charges in the ex ante schedule may be adjusted accordingly to ensure appropriate remuneration when such situations are forecast.

If DG in an area is expected to be far away from customers rather than near to them, costs are shown by the model to increase by a relatively small amount with DG penetration. Then, it may be effective to remunerate for the additional costs via simple connection and use of system charges. As the model suggests that the initial connection cost is small relative to the costs of upgrading the network as the capacity of connected DG increases (for example, through generator upgrades), the use of system charges may need be set progressively higher to recover network costs in tandem with DG capacity upgrades.

A possible problem is that DG could decrease the amount of energy sold by conventional generation. Where generation and retail businesses are separated from the distribution network businesses (as in many countries that have adopted incentive regulation), this is generally not an issue. But it may be a problem for vertically integrated businesses in the US that generate and sell electricity alongside operating the distribution network. Such businesses might lose revenue from electricity sales where these are displaced by DG.

5.2.2 Modeling Network Management and Regulatory Proposals

The modeling results also demonstrate the benefits of active management in terms of avoided network investment, while illustrating the importance of careful design and implementation of active management programs. Actively managing connected technologies and power flows decreases the required network investment costs relative to passive management. The precise implementation of active management – whether it is time-shifting flexible power demands to hours of low demand or spreading the power demand over a greater number of hours – can also affect the benefits of active management seen. Time-shifting demand but not spreading it over several hours, so that the peak demand does not change much in absolute value, can lessen the benefit of active management in terms of network investment costs. As the benefits of active management appear to be highly scenario-dependent, the results suggest that companies must be encouraged to invest in active management yet be given freedom to design their own implementations of active management (to optimize it for their networks). Hence the detailed regulatory intervention in use for some advanced metering projects and reviewed in Chapter 1 might be less appropriate for active management.

One regulatory measure that could directly encourage active management approaches while avoiding excessive regulation of implementation details is funding pots. An example of such a funding pot might be the UK's Low Carbon Networks funding program for innovative projects leading to a low-carbon energy future, where most of the projects selected for funding appear to be developing various implementations of active management (Office of Gas and Electricity Markets (Ofgem) 2011). A recent review of the Low Carbon Networks program found it to be “a significant success to date” (Office of Gas and Electricity Markets (Ofgem) 2011). Some of the projects funded by the US' Smart Grid Investment Grants funding pot also target the development and implementation of active management of new technologies, but others appear to be limited to funding installation of the new technologies without corresponding changes in network management or operations (U.S. Department of Energy 2012).

Another regulatory measure that can encourage active management involves moving to an outputs-based regulatory scheme and then setting appropriate output targets that stimulate active management adoption. Some penalties or rewards for missing the targets may add to the strength of such regulatory stimulus. For example, environmental targets such as reducing the network's carbon footprint can encourage distribution companies not just to install AMI but also

to implement demand response programs that use AMI to reduce customers' energy use and the need to distribute energy through the network. As long as the output targets are met, this measure allows companies the independence to utilize implementation approaches suitable for the situations they face.

Long-term investment in active management approaches generally could also be stimulated by allowing companies more liberty to choose between operational expenditure (opex) and capital expenditure (capex). After the initial capital outlay on necessary equipment, many active management expenses relate to the daily operations of the network and may be classified as operational expenditure rather than capital expenditure. For example, the daily operations of a demand response program including interacting with customers, sending them appropriate price signals, and managing the power flows caused by changes in their energy consumption, can all involve operational expenditure. As applied in incentive regulation, this measure (suggested by the European DG-GRID project on distributed generation) implies regulating the total sum of capex and opex instead of regulating them separately (Scheepers, et al. 2007). This allows the company to choose the proportion of expenditure that is capital expenditure and the proportion that is operational. On the other hand, when capex and opex are regulated separately, the company's opex is benchmarked but capex is not. Since passive network management involves installing wires and equipment of a large enough capacity to meet the 'worst case' network power flow scenario, it can involve a larger capex outlay than active management. So a scheme where capex is not benchmarked can make investing in passive management more attractive than investing in active management (Scheepers, et al. 2007). Regulating the total sum of capex and opex may therefore promote the choice of active over passive management.

5.3 Conclusions and Further Research

The cost of integrating technologies like DG and management approaches like active management into distribution networks is highly scenario-dependent, but models like the Reference Network Model used in this study can readily analyze technology penetration scenarios to provide an estimate of network costs for regulators. The continued development of these models to improve computations of the network costs of new technologies would be a valuable area of research.

The remuneration of distribution companies for these costs can be improved through outputs-based regulatory schemes and appropriate incentives. For the new technologies modeled here, specific proposals are advanced such as ex ante charging schedules for certain types of residentially located DG. For the active management approaches studied, reforms to regulatory schemes are found to be useful in stimulating the appropriate investments: allowing companies to divide their spending between capital and operational expenditure and allocating money to funding pots for active management projects.

Further research in some areas will assist the development of better regulation. The RNM is a distribution network-focused model that provides cost results for capital investments in the networks, but not in the exogenous capital costs of new hardware or software systems also needed to accommodate new technologies in the networks. More research is needed on the cost trends of such systems and how they should affect regulatory remuneration; the data collected by the US Smart Grid Investment Grants on smart grid project investments made to date may be a useful starting point.

In conclusion, the modernizing electric distribution grid implies challenges for distribution companies and regulators alike. Regulatory schemes and tools must modernize as well to ensure distribution companies are remunerated appropriately for integrating modern technologies into their networks. The application of effective regulation combined with active engagement by distribution companies in improving electric distribution grids can provide significant societal benefits.

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