Incentive Mechanisms in Regulation of Electricity Distribution: Innovation and Evolving Business Models

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Table of contents

I. Introduction

Utilities, regulators and policy-makers around the world are revisiting the scope and role of utilities as players in the energy industry, driven in large part by advances in technologies and new societal goals. The current environment that electricity distribution businesses find themselves in is different from that when liberalization and industry restructuring took place. This is primarily due to the following factors:

- The development and availability of cost competitive energy options, beyond traditional large, centrally dispatched generating units. These include non-hydro renewables, as well as more distributed energy resources (DERs). As a result, increasing quantities of generation is connecting to the distribution network.
- Serious consideration is being given to the electrification of transport and space and water heating. Such "beneficial electrification" will almost certainly have a sizable impact on electric loads and infrastructure requirements.
- The deployment of digital communications, which is changing the way consumers can connect with suppliers and interact among each other. Advances in sensing, analytics and controls are changing the way customers and electricity distribution businesses can respond to peak events.
- Consumer behaviour and attitudes towards environment and climate issues, and growing interest in participating more actively in energy markets.
- The growing presence of non-utility innovators, including technology companies.

Around the world, regulators are recognizing that electricity distribution businesses[1] will need to make changes to how they plan and operate their networks in order to accommodate these trends. Traditional regulatory frameworks may not adequately support the new roles that distribution businesses need to play, nor allow them the ability to transform into a business that can meet the future needs of its customers.[2] In New Zealand similar issues have

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1 This report primarily addresses the "distribution function" and the regulation of the distribution business. The activities carried out by the distribution business varies across jurisdictions, and can include metering, billing, retailing and generation, in addition to distribution of electricity.

2 Carl Peterson & Agustin Ros, 'The future of the electric grid and its regulation: Some considerations", *The Electricity Journal, Vol. 31*, 2018, p. 18

been recently raised by the Expert Advisory Panel in its review of the electricity sector. The Panel pointed out that emerging technologies will have a major impact on distribution businesses, requiring new business models and new investments in technologies and infrastructure to enable the businesses to manage their networks more actively.[3] They also observed that the current "electricity regulatory framework was largely designed for yesterday's technologies and business models" and may act as a barrier to unlocking future consumer benefits.[4]

While the appropriate solutions for addressing the rapidly changing distribution business environment are not yet clear, a number of regulators are piloting or rolling out new incentive programs to start addressing the gaps in their current regulatory frameworks that they see as most important. Many see this as a first step towards creating a future utility that has a very different role from the electricity distribution businesses of today. For example the concept of the utility "platform" has gained widespread attention among industry participants and regulators as a potential future utility business model. In a general sense, a platform market differs from a traditional linear market in that it facilitates the direct connection between buyers and sellers. In a linear market, an intermediary would purchase upstream inputs and process, bundle or repackage them, before delivering the finished product to the end consumer. The intermediary adds value by producing a final product that is worth more than the sum of the parts, whereas platforms provide value by enabling, or intermediating, transactions between the end consumer and an independent seller.[5] Despite all of the attention given to the utility as a platform business model, the concept is still only loosely defined and is evolving differently in different jurisdictions, depending on their unique characteristics, history, policy goals and regulatory mechanisms. California and New York are notable early movers towards a platform business model.[6]

In New Zealand distribution businesses are subject to regulation under Part 4 of the Commerce Act. Among other goals, the act aims to ensure that suppliers of regulated goods or services:

a. "Have incentives to innovate and to invest, including in replacement, upgraded, and

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3 Expert Advisory Panel (New Zealand), "Electricity Price Review – First Report", pp. 61, 64

4 Expert Advisory Panel (New Zealand), "Electricity Price Review – First Report", p. 78

5 William Zarakas, 'Two-sided markets and the utility of the future: how services and transactions can shape the utility platform", *The Electricity Journal, Vol. 30*, 2017, p.43

6 Carl Peterson & Agustin Ros, 'The future of the electric grid and its regulation: Some considerations", *The Electricity Journal, Vol. 31*, 2018, p.19

new assets; and

b. Have incentives to improve efficiency and provide services at a quality that reflects consumer demands; and

c. Share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and

d. Are limited in their ability to extract excessive profits”.[7]

More specifically, section 54Q of the Commerce Act requires the Commerce Commission to promote incentives, and avoid imposing disincentives, for distribution businesses to invest in energy efficiency and demand side management, and to reduce energy losses.[8]

Most distribution businesses in New Zealand are regulated under what is known as “Default Price-quality Path regulation” (DPP regulation), which is intended to be a low-cost method of regulating distribution businesses.[9] The businesses also have the option to seek a customized price-quality path instead.[10] A default price-quality path consists of the maximum average price a distribution business can charge at the start of the regulatory period; an annual rate of increase across the regulatory period and minimum service quality standards.[11] The DPP is currently a price cap but will switch to a revenue cap for the next control period (starting April 2020). The DPP includes several additional features which adjust revenues according to business performance and thus provide a financial incentive:

1. **Performance incentive for reliability improvements.** Distribution businesses are rewarded (penalized) for increasing (reducing) reliability (frequency and duration of outages) relative to a target. The incentive is symmetric meaning that if firms underperform on reliability their revenue is reduced. There is a cap on the incentive of

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7 Ministry of Business, Industry and the Environment, “Commerce Act 1986, Part 4”, reprinted December 2017, p.55

8 Ministry of Business, Industry and the Environment, “Commerce Act 1986, Part 4”, reprinted December 2017, p.100

9 Commerce Commission, “Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020 – Main Policy Paper”, 28 November 2014, p.7

10 Commerce Commission, “Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020 – Main Policy Paper”, 28 November 2014, p.9

11 Commerce Commission, “Electricity lines default price-quality path”, last accessed 19 September 2018

1% of revenue.[12]

2. **Time-smoothed incentives for reducing operating and capital expenditures.** Incremental Rolling Incentive Schemes (IRIS) equalise the benefit of reducing costs across the regulatory period. Absent an IRIS mechanism, the benefit to the company of reducing cost is greater at the start of the control period than the end, but the IRIS mechanisms remove this distortion. However, the IRIS mechanisms do not equalise incentives between capex and opex.[13]

3. **Energy efficiency and demand side management scheme.** Distribution businesses can apply ex-post to recover any revenue foregone due to decreased sales volume from energy efficiency or demand side management programs.[14] These ex-post adjustments will no longer be necessary when the DPP switches to a revenue cap in the next control period. The scheme does not provide distribution businesses with additional revenue to cover costs incurred in running energy efficiency and demand side management programs, nor offer any incentives for successfully running these programs. Tariff based measures are also excluded from the scheme. [15]

In the next regulatory period distribution businesses may consider non-wires alternatives to traditional investment (procuring network support services from third parties) or trials to assess the performance of new technologies. The Electricity Networks Association (ENA) is concerned that there is currently no regulatory mechanism to facilitate this. The regulatory framework provides no incentive for distribution businesses to undertake research and development, or reward for successful innovation. This impacts the commercial incentives to pursue such options. Moreover, since many non-wire alternatives rely on substituting opex for capex, the regulatory framework needs to address possible biases that favour capex over

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[12] Commerce Commission, "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020 – Main Policy Paper", 28 November 2014, pp.34-36

[13] The distribution business retains 35% of the net present value of ongoing opex savings but only 15% of capex savings (Commerce Commission, "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020 – Main Policy Paper", 28 November 2014, pp.46-47).

[14] Commerce Commission, "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020 – Main Policy Paper", 28 November 2014, pp. 50-51.

[15] Commerce Commission, "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020 – Main Policy Paper", 28 November 2014, pp. 50-51.

opex.

The difficulty of relying on the current framework in New Zealand is illustrated by the case of distribution business Powerco, which recently applied for $18 million in capex funding for network evolution as part of its customized price-quality path (CPP) application. Powerco intended this funding to support the transition to a more flexible, dynamic network that could respond more quickly and efficiently to changing load patterns and could be tailored to customer requirements.[16] The Commerce Commission granted Powerco only $1.5 million in opex funding for network evolution. The Commerce Commission explained that its decision was not because they disagreed with the goal of network evolution, but because it was not clear whether Powerco had demonstrated sufficient consumer benefit to justify the funding.[17]

In this paper we describe regulatory tools that have been used to address the above topics, and reforms that are currently taking place, using a set of case studies. Our case studies are drawn from Great Britain, Australia, California, New York and Illinois and discuss incentive mechanisms for losses, connecting DERs, promoting non-wires alternatives, energy efficiency and innovation. In Great Britain and Australia the structure of the electricity industry is similar to New Zealand, and in particular there is separate ownership of distribution and retail. In California, New York and Illinois there is more integration; however, in all three of the case studies we examine, the utility is financially indifferent to the quantity of electricity distributed (or sold), as it would be with separate ownership of distribution and retail.

Table 1 shows which of the different issues were examined in which jurisdictions. There is some overlap, with multiple jurisdictions examining non-wires alternatives, innovation generally and platform innovation.

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16 Commerce Commission, "Powerco's customised price-quality path – Final decision", 28 March 2018, p.75

17 Commerce Commission, "Powerco's customised price-quality path – Final decision", 28 March 2018, pp.74-79

Table 1: Incentives studies by jurisdiction

Issue addressed	Great Britain	Australia	California	New York	Illinois
Losses	X				
Connecting DERs	X			X	
Innovation	X	X			
Non-wires alternatives		X	X	X	
Energy efficiency				X	X
Platform innovation				X	

The rest of the paper proceeds as follows: for each jurisdiction we describe the key features of the regulatory framework as they relate to incentives before examining specific regulatory reforms in that jurisdiction. Each reform is presented by identifying a perceived problem with the existing framework and the proposed solution. Outcomes are reported if available. After discussing each jurisdiction, we conclude this report by examining common themes across the different measures put in place. These themes may help identify gaps that need to be addressed in New Zealand.

II. Great Britain

Electricity distribution businesses in Great Britain are regulated on a revenue cap basis, with multi-year price control periods. The current "RIIO-ED1"[18] price control runs for eight years from 2015 to 2023; previously, the standard price control period was five years and the following "RIIO-2" will return to the five year control period.[19]

The revenue for each price control period is set to cover the regulator's forecast of the costs that the business will incur if it is operating efficiently. Within the price control period, revenues will be equal to the pre-authorized amounts, with limited adjustments if actual costs turn out to be different from those anticipated. As a result, there is a financial incentive for the businesses to reduce expenditure where possible (while still meeting performance requirements).

There are many important additional features over and above the basic revenue control formula outlined above which provide significant financial incentives of various kinds. In this paper we focus on the regulatory treatment of losses, distributed generation, and innovation.

A. Losses

1. Gap in the existing framework

Electricity distribution businesses can influence the quantity of electrical losses on their networks, since more heavily-loaded equipment tends to have higher losses, and higher-voltage equipment tends to result in lower losses than lower-voltage equipment for the same rate of energy distributed. The level of losses is important because the lost electricity has to be generated, with attendant financial costs as well as negative environmental externalities (eg, carbon emissions). Ofgem estimated that losses on the distribution system accounted for over 1% of total GB greenhouse gas emissions.[20] In Great Britain the financial costs associated with losses on the distribution network are borne in first instance by retailers, and thus ultimately recovered from customers. As part of the financial settlement process, there is a reconciliation

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18 RIIO: Revenue = Incentives + Innovation + Outputs; ED1: first RIIO control period for electricity distribution.

19 Ofgem, "RIIO-2 Framework Decision," 30 July 2018, p. 5.

20 Ofgem, "Electricity Distribution Price Control Review: Initial Consultation Document," 28 March 2008, ¶2.49.

between the quantity of electricity metered as leaving the transmission network and the quantity metered at various points in the distribution network (including final customers' premises). This settlement process results in the cost of lost units being assigned to retailers.

The actions of the distribution businesses can influence the level of losses, but neither the direct financial consequences of losses nor the associated environmental externalities are felt by the distribution businesses. As a result, distribution losses are possibly higher than is socially optimal.

2. Solution adopted

A loss incentive mechanism was first implemented in DPCR3 (the third Distribution Price Control Review), which ran from 2000 to 2005 and was renewed in DPCR4 from 2005 to 2010. The loss incentive mechanism in effect made the distribution businesses, as opposed to the customers, financially responsible for losses—with payments or penalties given to the businesses depending on whether annual losses were below or above a target level. This target level would be set by Ofgem each regulatory period,[21] and this meant that the distribution businesses were effectively being charged for marginal (incremental) losses at a price corresponding to the cost of the lost electricity.

In the initial consultation for DPCR5 (March 2008), after the operation of the losses incentive mechanism for eight years, Ofgem realized that there were significant measurement issues in determining losses, such that there could be large changes in measured losses from one year to the next, irrespective of the actions of the distribution business.[22] Metering approximations, estimated reads and billing issues were preventing the accurate measurement of changes in technical losses (and theft) which are the desired targets of the regulatory intervention.[23]

Although under Ofgem's loss incentive mechanism reported losses had declined from 6% to

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21 Ofgem, "Electricity Distribution Price Control Review: Final Proposals," November 2004, ¶4.77.

22 Ofgem, "Electricity Distribution Price Control Review: Initial Consultation Document," 28 March 2008, ¶2.51.

23 Losses are typically measured as the difference between metered electricity flowing onto the distribution network and metered consumption by end customers. The term "technical losses" is used to distinguish electricity lost as heat from wires and transformers and so on from other components of measured losses, including theft.

5% between 2000 and 2007, it was unclear to what extent these savings were caused by the actions of the distribution businesses. For example, changes to the way unmetered accounts were settled may have meant that loss measurements became more accurate over time. Measurement issues also concerned the distribution businesses, which were unhappy with the programme's inability to discern between outcomes stemming from their actions and the variations caused by commercial losses. Despite uncertainty over the programme's impact, the automatic incentive mechanism resulted in distribution businesses receiving about £100m per year in aggregate during this period, although one distribution business lost on average £8m per year during the first four years of DPCR4 (2005 onwards).[24,25,26]

The incentive mechanism was not included in the DPCR5 (2010 – 2015) regulatory period because Ofgem concluded that the mechanism could result in "unwarranted rewards and penalties of significant value."[27]

For RIIO-ED1 (2015 onwards), Ofgem introduced a new approach for reducing losses that consisted of obligations and discretionary rewards, rather than a mechanistic approach based purely on measured losses. Ofgem's new approach consisted of four key components: a licence obligation to keep the level of losses as low as reasonably practicable; a requirement to develop and maintain a strategy to reduce losses, with a cost-benefit analysis of proposed actions; a requirement to report on activities that reduce losses; and a "prize" fund for additional actions to reduce losses (money from the fund is given to any distribution businesses judged to be successful against detailed criteria published by Ofgem). These are described in more detail below:

– **Licence obligation**: as part of the distribution businesses' licence, an enforceable obligation is made requiring businesses to "design, build and operate their networks to ensure that losses are low as reasonably practicable."[28]

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24 Ofgem, "Electricity Distribution Price Control Review: Initial Consultation Document," 28 March 2008, ¶2.50–2.53.

25 Ofgem, "Document A: Decision not to activate the Losses Incentive Mechanism in the Fifth Distribution Price Control," 16 November 2012, p. 3.

26 Ofgem, "Electricity Distribution Price Control Review: Final Proposals," 7 December 2009, ¶2.12.

27 Ofgem, "Document A: Decision not to activate the Losses Incentive Mechanism in the Fifth Distribution Price Control," 16 November 2012, p. 3.

28 Ofgem, "Guide to the RIIO-ED1 Electricity Distribution Price Control," 18 January 2017, ¶7.9.

- **Losses strategy**: distribution business must make publicly available a document outlining the plans and actions taken to reduce losses, detailing the cost and benefits and how these practices can be used across the industry. For example, UK Power Networks has published a losses strategy report that outlines the steps it takes to help it achieve a notional reduction in losses valued at £46.9m during RIIO-ED1 (a cumulated savings of 1TWh priced at Ofgem's estimated cost of carbon).[29] One specific action it plans to undertake involves the utilisation of smart meter data to optimise network voltage and power flows, in addition to implementing direct load control.
- **Annual reporting**: Distribution businesses must report the annual and cumulative improvements achieved through loss reduction activities during the year and subsequent plans for the future. For example, Northern Powergrid reported a losses reduction of 800MWh in 2016-2017 through the installation of oversized electricity cables, with cumulative savings of 1.8GWh for the RIIO-ED1 period (2015 onwards).[30]
- **Losses discretionary reward**: For the entirety of RIIO-ED1, a discretionary reward of £32m was available, with the rewards spread out over three tranches. Each tranche has its own specific focus and evaluation criteria for the rewards.[31] Tranche 1 (2016/2017) focuses on the evaluation of processes that distribution businesses can undertake to reduce losses; Tranche 2 (2018/2019) assesses the processes and actions put in place and the outcomes it has achieved; and Tranche 3 (2020/2021) reviews the achievements made in reducing losses and the knowledge gained and how it can be used moving forward (such as RIIO-ED2). Of the £8m allocated to Tranche 1, Ofgem awarded only £3.8m, as not all criteria were met by all of the distribution businesses (some reasons being the lack of collaboration shown between the distribution businesses, and a lack of a clear smart meter plan). As one of the strongest submissions (it was awarded 68% of the maximum reward of £1.3m per distribution business) Scottish and Southern Energy had a Tranche 1 submission that included plans to establish a dedicated losses team, install transformers that outperform the EU Eco directive, and the use of smart meters to segment and characterise losses in more detail. [32,33]

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29 UK Power Networks, "Losses Strategy," September 2016.

30 Northern Powergrid, "Environment Report 2016-2017," 2017, p. 17.

31 Both the focus and criteria are subject to change by Ofgem to reflect the prevailing views and conditions of the industry.

B. Distributed generation

1. Gap in the existing framework

Connecting distributed generation (smaller generators which connect to the distribution network rather than the high-voltage transmission network) was not traditionally an important activity for distribution networks because there were relatively few such generators. Increasing interest in renewable generation, including because of financial support for renewables and technology change driving down cost, has made the connection of distributed generation to the distribution network increasingly important. Whereas traditionally the distribution network had very few connected generators and almost all customers were load, the number of generator customers, or customers with both load and generation on the same site, has risen significantly.

Increased interest from distributed generation in connecting to the distribution networks gave rise to two areas of concern: first, that the connections would require the distribution businesses to spend money (on reinforcing the network, over and above the cost of any sole-use connection assets paid for by the connecting generator), and that this money might not have been provided for in the revenue determination, so doing the work would leave the distribution businesses out of pocket; and second, that the distribution businesses might be unwilling to take necessary actions to help those seeking connections. Such unwillingness could be caused by adverse financial consequences for the distribution business, or because connecting significant numbers of distributed generators would be outside the ordinary course of operations.

2. Solution adopted

In June 2003, Ofgem began the Distributed Price Control Review 4 (DPCR4) for the regulatory period covering April 2005 through March 2010.[34] In light of significant financial support for renewable generation, a large increase in the amount of distributed generation connections was anticipated during the control period. Connecting distributed generation can result in significant capital expenditure for system reinforcement, but the quantity, timing

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Continued from previous page

33 Scottish and Southern Energy Power Distribution, "Scottish and Southern Energy Power Distribution Losses Discretionary Reward Tranche 1 Submission," January 2016.

34 Ofgem, "Distribution Price Control Review 4," 2018.

and cost of the system reinforcement that would be required was very uncertain. Ofgem introduced a "hybrid" mechanism designed to reduce the downside risk to the distribution business while incentivizing efficient connections.[35] Recognizing the uncertainty around connection volumes and associated reinforcement costs, the mechanism comprised of:[36]

– **Partial pass-through.** 80 per cent of use-of-system capex incurred to provide network access would be passed through to consumers. This addressed the total cost uncertainty surrounding connections (ie, uncertainty in the number of connections and the impact of each on costs).

– **Revenue driver.** Distribution businesses would also earn an incentive rate of £1.50 per installed kW of distributed generation capacity per year (for 15 years). The incentive rate was calculated such that distribution businesses would recover the additional 20 per cent of capex not already passed through if the per kW cost turned out as expected, plus they would also recover an additional rate of return of 1 per cent on this investment. This addressed the uncertainty associated with connection volume by passing on the volume risk to consumers, while preserving an incentive to control the cost per kW connected, and providing an incentive rate of return.

The hybrid mechanism was not applicable to sole-use asset costs that were recovered through connection charges.

As further protection against cost uncertainty, Ofgem introduced a cap and floor that would be applied to the rate of return on the distributor's overall portfolio of distributed generation connections at the end of the control period. The cap was two times the pre-tax WACC, and the floor was the allowed cost of debt. The framework also included an O&M allowance of £1/kW per year of total connected distributed generation, including both sole-use and shared assets.[37]

In December 2009, Ofgem published its final proposals for DPCR5 (the control period covering April 2010 through March 2015).[38] Observing that the actual connections of

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35 Ofgem, "Electricity Distribution Price Control Review: Initial consultation," July 2003, p. 51.

36 Ofgem, "Electricity Distribution Price Control Review: Final proposals," November 2004, pp. 42-44.

37 Ofgem, "Electricity Distribution Price Control Review: Final proposals," November 2004, pp. 43-45.

38 Ofgem, "Electricity Distribution Price Control Review: Final proposals – Incentives and

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distributed generation during DPCR4 were significantly lower than expected, there was disagreement among stakeholders as to whether the existing mechanism actually encouraged connections.[39] Ultimately however, Ofgem decided there were other reasons for the discrepancy.[40] Stakeholders also noted that distribution businesses were still being "unhelpful" to distributed generation customers.[41] In particular, it was difficult for generators to know where to connect because they did not have access to good information about the availability of network capacity. To address this, distribution businesses are now required to publish an annual Long Term Development Statement including the location of spare capacity in their network.[42]

Ofgem decided to retain the previous incentive framework in DPCR5.[43]

In November 2014 in the lead up to the RIIO-ED1 control period, Ofgem, with support from the majority of distribution businesses, decided to discontinue the revenue driver mechanism that had been used for DPCR4 and DPCR5. Ofgem viewed the previous mechanism as "primarily an uncertainty mechanism" that lacked sufficiently strong incentives to actually enable connections, noting that the revenue driver was "a maximum of 20 per cent efficiency incentive, but [there were] no incentives on opex." Some connection customers also noted that the previous mechanism was too complex for them to engage with distribution businesses. Starting with RIIO-ED1, Ofgem introduced broader mechanisms to incentivize

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Obligations," 7 December 2009, p. 17. Ofgem, "Distribution Price Control Review (DPCR) 5," 2018.

39 Ofgem, "Electricity Distribution Price Control Review: Initial consultation document," 28 March 2008, p. 18.

40 Reasons included an overly ambitious forecast and difficulty obtaining planning permission. Ofgem, "Electricity Distribution Price Control Review: Policy paper," 5 December 2008, p. 31.

41 Ofgem, "Electricity Distribution Price Control Review: Initial consultation document," 28 March 2008, p. 18.

42 Ofgem, "Guide to the RIIO-ED1 electricity distribution price control," 18 January 2017, p. 42.

43 In DPCR5 the incentive rate was adjusted down to £1/kW/year because the scope of the mechanism was narrowed to exclude certain "high cost" connection assets that had previously been included (Ofgem, "Electricity Distribution Price Control Review: Initial proposals - Incentives and Obligations," 3 August 2009, p. 20 and "Electricity Distribution Price Control Review: Final proposals – Incentives and Obligations," 7 December 2009, pp. 17-18)

efficient connections in an environment with an increasingly uncertain forecast of connection volumes.[44]

For RIIO-ED1, rather than having incentives specifically targeting distributed generation, Ofgem introduced incentives more broadly for customers' experience during connections (load and generation), as well as an overarching efficiency incentive and a set of reopeners to redress substantial differences between forecast and actual volumes/costs, including one that covers the costs due to connections.[45]

During the price control review, distribution businesses engage stakeholders to create a forecast of connection volumes and the associated reinforcement expenditure. Based on Ofgem's review of the forecast, the distribution business receives an ex-ante allowance to enable connections (and associated reinforcement) during the control period.[46] The load-related expenditure reopener addresses the volume risk of distributed generation connections,[47] by allowing distribution businesses to trigger a reopener if actual costs differ from their ex-ante allowance by more than 20 per cent, and if the differential is more than 1 per cent of their average annual base revenue. Reopeners may be triggered only during May 2017 and May 2020,[48] the reopener was not triggered during the 2017 window.

RIIO-ED1 also addressed the difficulty of some distribution businesses to identify the most efficient connection option for each prospective customer, given the volume of such requests. With support from stakeholders including distributed generators, Ofgem suggested that an "assessment and design" fee should be introduced to help reduce the volume of speculative

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44 Ofgem, "Strategy decision for the RIIO-ED1 electricity distribution price control: Outputs, incentives and innovation," 4 March 2013, pp. 26-29.

45 Ofgem, "Guide to the RIIO-ED1 electricity distribution price control," 18 January 2017.

46 Ofgem, "Strategy decision for the RIIO-ED1 electricity distribution price control: Outputs, incentives and innovation," 4 March 2013, pp. 28-29.

47 Ofgem, "Strategy decision for the RIIO-ED1 electricity distribution price control: Outputs, incentives and innovation," 4 March 2013, p. 29.

48 Ofgem may also trigger the reopener in the case of underspending. Ofgem has other reopener mechanisms, including an "Innovation roll-out mechanism" reopener pertaining to the "costs associated with the roll-out of proven low carbon or environmental innovations," which also had a reopener window in May 2017. Other reopener windows were in 2016, or will take place in 2019 or 2022. Ofgem, "Strategy decision for the RIIO-ED1 electricity distribution price control: Uncertainty mechanisms," 4 March 2013, pp. 5, 19-21, 24.

applications so that distribution businesses could provide better and more efficient service on applications that were more certain to proceed.[49]

C. Innovation

1. Gap in the existing framework

Ofgem found that after the privatisation of the distribution businesses in the 1990's, expenditure on research and development (R&D) started to diminish over time until it reached a near-zero equilibrium.[50,51] In Ofgem's view, the diminished incentive for R&D can be attributed to the socialisation of benefits (cost savings), since these would be transferred away from the innovating business to customers in the form of lower revenue allowances in future regulatory periods.[52] Ofgem's analysis on additional developmental expenditure (in contrast to "pure" research) found there was a net benefit in pursing those activities.[53]

2. Solution adopted

The Innovation Funding Incentive (IFI) and the Low Carbon Networks Fund (LCNF) were two incentive mechanisms implemented by Ofgem to catalyse research, development, and demonstration activities by the distribution businesses.

The Innovation Funding Incentive (IFI) was introduced in 2005 (DPCR4) and continued onto 2015 (DPCR5), allowing each distribution business to spend up to 0.5% of their allowed revenues on activities to conduct research and development.[54] The IFI funded up to 90% of the costs of these projects, with the distribution business responsible for the remaining balance. The IFI funding was provided at a use-it-or-lose-it basis, and funding would be received only after they had spent it (ie, this mechanism enabled the (partial) recovery of costs after they were incurred, in contrast to the up-front funding via the revenue cap for the

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49 Ofgem, "Strategy decision for the RIIO-ED1 electricity distribution price control: Outputs, incentives and innovation," 4 March 2013, p. 30.

50 Ofgem, "Electricity Distribution Price Control Review Final Proposals," November 2004, ¶5.39.

51 Ofgem, "The Innovation Funding Incentive and Registered Power Zones Annual Reports 2008-2009," 18 February 2010, p. 1.

52 Ofgem, "The Network Innovation Review: Our Consultation Proposals," 1 December 2016, ¶1.4.

53 Ofgem, "Electricity Distribution Price Control Review Final Proposals," November 2004, ¶5.39.

54 Ofgem, "Electricity Distribution Price Control Review Final Proposals," 7 December 2009, ¶2.38.

majority of required revenues). If any funding was unused in a given year, half of it could be carried forward to the next year (but not beyond the next year). To encourage early investment, the pass through rate of the IFI had a tapered design, starting with a pass through rate of 90% in 2005 which reduced to 70% in 2010, decreasing at 5% increments per year.[55]

The IFI focused on delivering value to end consumers through the technical development of distribution networks. Ofgem had indicated that the IFI's principal area of application is under the "development" phase within the innovation process ("research," "development," "demonstration," and "adoption.")[56] It was also not the intention of Ofgem to encourage expenditure for the formation of in-house R&D capabilities. Instead the incentive aimed to encourage the purchase of expert R&D services from third parties, with the allowable expenditure on internal resources capped at 15% of the total IFI funding in each year.[57] In 2015, UK Power Networks spent over £650k to develop link box blankets (the largest single project expenditure by the business) out of a total UKPN IFI expenditure of £4.5m (maximum IFI allowance was £7m).[58] The project developed a fire blanket that could be installed on link boxes that mitigated disruptive failures due to gas leaks and water ingress, which had been causing rising failure rates in recent years.[59]

The Low Carbon Networks Fund (LCNF) was introduced in 2010 (DPCR5) and allocated a total of £500m for the entire regulatory period to "stimulate culture change, innovation and trialling of the new technologies, commercial and operating arrangements the DNOs [distribution businesses] will need to deliver a low or zero carbon electricity sector."[60] A key participation requirement involved the sharing of information learnt from the projects undertaken by the distribution businesses, to maximise the benefits to the industry. This allowed all distribution businesses to share effective approaches for a "new low carbon economy". The sharing process were delivered through bi-annual project updates and a comprehensive "close-down" report that provided enough detail for stakeholders to fully

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55 Ofgem, "Electricity Distribution Price Control Review Final Proposals," November 2004, ¶¶5.40–5.42.

56 Ofgem, "Innovation and Registered Power Zones: A discussion paper," 16 July 2003, p. 5.

57 Ofgem, "Electricity Distribution Price Control Review Final Proposals," November 2004, ¶5.43.

58 UK Power Networks, "IFI Report April 2014 – March 2015," 23 July 2015.

59 UK Power Networks, "IFI Report April 2014 – March 2015," 23 July 2015.

60 Ofgem, "Electricity Distribution Price Control Review Final Proposals," 7 December 2009, p. 7.

understand the learning delivered.[61] Ofgem has stated that the learning as a result of the trials is being imbedded into the day-to-day businesses activities of the distribution businesses.

The LCNF funded up to 90% of approved project expenditure, with the remainder being borne by the distribution businesses.

- A small proportion of the fund (Tier 1 of around £80m) was directly available to the distribution businesses as an allowance over the five year DPCR 5 period (2010-2015). Tier 1 was for small scale projects, and was provided on a use it or lose it basis.[62]
- A larger proportion of the fund (Tier 2 of around £320m) was used to set up an annual competition amongst the distribution businesses for larger 'flagship' projects. An expert panel determined the eligibility and the amount of funding granted for the proposed projects each year.
- The final £100m was allocated as three types of discretionary rewards: exceptional Tier 1 portfolios, well managed Tier 2 projects, and exceptional Tier 2 projects. These were called the First Tier Portfolio Reward (£15m), Second Tier Successful Delivery Reward (where the reward maximum is the distribution businesses' compulsory contribution of 10% of project expenditure), and the Second Tier Reward (£61m) respectively. The First Tier Portfolio Reward and Second Tier Reward were given to applications that were exceptional in meeting criteria concerned with the contribution to the development of the low carbon energy sector, benefits to future and existing customers, the value for money provided, and the value of the knowledge it brought to the industry.[63] In July 2017 £5.5m was awarded for the First Tier Portfolio Reward,[64] and in September 2018 £0.3m was given for the Second Tier Reward (of the total of £61m allocated, £30.5 was eligible for this round).[65] The Second Tier Successful Delivery Reward were made to completed projects that met expectations in reference to the performance in project delivery, i.e. was the project on time and did it meet standards, how was the budgeting and procurement performance, and how was the overall project managed.[66] In May 2018, £3.9m was given

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61 Ofgem, "Electricity Distribution Company Performance 2010 to 2015," 16 December 2015, ¶3.5.

62 Ofgem, "Low Carbon Networks Fund Governance Document v.6," 12 April 2013, ¶3.2.

63 Ofgem, "Electricity Distribution Price Control Review Final Proposals," 7 December 2009, ¶2.18.

64 Ofgem, "Decision on First Tier Portfolio Reward for the Low Carbon Networks Fund," 4 July 2017.

65 Ofgem, "Decision on Second Tier Reward for the Low Carbon Networks Fund," 14 September 2018.

66 Ofgem, "Decision on 2016 Low Carbon Networks Fund Successful Delivery Reward Applications,"

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for the Second Tier Successful Delivery Reward.[67]

An example of an innovation that was derived from Tier 1 funding is Electricity North West's Smart Fuse Project.[68] The Smart Fuse is a special low-voltage fuse device that carries two fuses. If the device is triggered and the first fuse fails, the remaining fuse is automatically connected while it sends an alert to nominated personnel. This allows quick restoration of power to customers, avoiding the call out to engineers to physically replace the fuse. The device was initially developed using IFI funding, but the deployment (the main goal of the Smart Fuse Project) was achieved through funding received through the LCNF. The Smart Fuse Project cost £390k overall[69], out of Electricity North West's entire portfolio of 6 projects which cost £4.3m.[70] 90% of the portfolio cost was recovered through Tier 1 funding. Electricity North West also received a First Tier Portfolio Reward of £1.75m[71], more than four times greater than the £430k out of pocket it contributed to the projects.

Tier 2 LCNF projects were eligible for a total of up to £64m per annum through yearly competitions. A total of £214m were funded in 23 projects during DPCR5 (2010 – 2015).[72] One of these projects includes the Scottish & Southern Electricity Networks' New Thames Valley Vision Project, a £30m project approved during November 2011. It was a five year project to better understand customer types and their usage, and how the use of demand response and power electronics can help distribution businesses manage their network.[73]

After the completion of DPCR5 and for the beginning of RIIO-ED1 in 2015, Tier 1 of the

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29 July 2016.

67 Ofgem, "Decision on 2018 Low Carbon Networks Fund and Network Innovation Competition Successful Delivery Reward Applications," 31 July 2018.

68 Electricity North West, "Low Carbon Network Fund Project ENWT1001 – The Smart Fuse," May 2014.

69 Electricity North West, "Low Carbon Network Fund Project ENWT1001 – The Smart Fuse," May 2014.

70 Electricity North West, "First Tier Portfolio Reward," 1 March 2017.

71 Ofgem, "Decision on First Tier Portfolio Rewards for the Low Carbon Networks Fund," 4 July 2017.

72 Ofgem, "Electricity Distribution Company Performance 2010 to 2015," 16 December 2015, ¶3.17.

73 Scottish & Southern Electricity Networks, "New Thames Valley Vision – SSET203," May 2017.

LCNF (small project funding) and the Innovation Funding Incentive (IFI, the incentive to spend 0.5% of revenue on R&D activities) were replaced by the Networks Innovation Allowance (NIA), and Tier 2 of the LCNF (competition based large project funding) was replaced by the Network Innovation Competition (NIC). And lastly, the discretionary reward component of the LCNF was removed.

The Networks Innovation Allowance (NIA) did not depart too greatly from the Innovation Funding Incentive (IFI), as each distribution business still received a percentage of base revenue allowed on a use-it-or-lose-it basis,[74] but the size of the fixed percentage is now based on the assessment of the submitted innovation strategies.[75] Under RIIO-ED1, two out of the six businesses received 0.7% and 0.6% of base revenue as their allowances, where the rest received 0.5% of base revenue.[76] The distribution businesses are able to pass through a maximum of 90% of NIA expenditure.[77]

The new Network Innovation Competition (NIC) shares the core principles with Tier 2 of the LCNF, which includes the encouragement of information sharing between industry participants to better the understanding of effective network strategies in the context of a low carbon economy. Similarly, a maximum of 90% applies to the level of project expenses recovered. A major change from the LCNF is that the competition is now available to all networks businesses (i.e. including transmission businesses, and gas), with a total annual funding pool of £90m per annum in 2015-2017 for the electricity NIC, and there is no discretionary reward element under the NIC.[78]

The newly-introduced Innovation Roll-out Mechanism (IRM) allows for distribution businesses to apply for licensing that enables funding for the roll-out of "proven low carbon or environmental innovations" through a revenue adjustment mechanism.[79] The Innovation

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74 Ofgem, "Strategy Decision for the RIIO-ED1 Electricity Distribution Price Control – Outputs, Incentives, and Innovation," 4 March 2013, p. 96.

75 Ofgem, "Guide to the RIIO-ED1 Electricity Distribution Price Control," 18 January 2017, ¶14.14.

76 Ofgem, "Guide to the RIIO-ED1 Electricity Distribution Price Control," 18 January 2017, ¶14.15.

77 Ofgem, "Strategy Decision for the RIIO-ED1 Electricity Distribution Price Control – Outputs, Incentives, and Innovation," 4 March 2013, ¶10.8.

78 Ofgem, "Strategy Decision for the RIIO-ED1 Electricity Distribution Price Control – Outputs, Incentives, and Innovation," 4 March 2013, ¶10.13.

79 Ofgem, "Strategy Decision for the RIIO-ED1 Electricity Distribution Price Control – Outputs,

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Roll-out Mechanism is subject to a cap of 1% of average RIIO-ED1 base revenue threshold. The distribution businesses make project proposals to Ofgem, which is then awarded or rejected for incentive funding. This funding mechanism explicitly prohibits requests that have already received funding from the price control or where an existing alternative funding scheme can be pursued to provide funding. The Innovation Roll-out Mechanism will only fund the shortfall between what is already recovered from the base allowance and the cost increases associated with the proposed projects.[80] The licensee is required to show that the funding provides additional benefits (carbon, environmental, or other), that it will not enable additional commercial benefits or fund any ordinary arrangements of the businesses, and that the technology is sufficiently ready.[81]

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Incentives, and Innovation," 4 March 2013, ¶10.8.

80 Ofgem, "Assessment of benefits from the rollout of proven innovations through the Innovation Roll-our Mechanism (IRM)," 28 April 2015, p. 3.

81 Ofgem, "Electricity Distribution Innovation Roll-out Mechanism Submission Guidance," 17 February 2016.

III. Australia

Electricity distribution businesses in the National Electricity Market (NEM) are regulated by the Australian Energy Regulator (AER) on a revenue cap basis.[82] The NEM comprises the states on the east coast of Australia – New South Wales (including the Australian Capital Territory), Victoria, South Australia, Queensland and Tasmania.[83] Since January 2008, electricity distribution businesses have been required to submit revenue requirement proposals on a five-year regulatory cycle to the AER.[84]

In 2012, the Australian Energy Market Commission (AEMC) revised the NER governing electricity network regulation to give the AER more discretion to reject inefficient network investment proposals and establish a national framework for distribution network planning.[85] The AER implemented these reforms through the Better Regulation program in 2013. The reforms included measures designed to make the distribution businesses neutral between capex and opex solutions, and to encourage consideration of non-wires options. These reforms included:

- **The Regulatory Investment Test for Distribution (RIT-D).** A cost-benefit analysis that networks are required to perform when they identify the need for an investment in the network, and the most expensive credible option to address that need costs $5 million or more. Networks must consult with stakeholders to consider all credible network and non-network options, and identify the option that maximizes the "economic benefit to all those who produce, consume, and transport electricity in the NEM". The AER provides

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82 Previously, some distribution businesses were regulated via a weighted average price cap. Starting in 2012, the AER began to consider moving to a revenue cap, and implemented the changes starting in 2015. AER, "Preliminary positions: Framework and approach paper, Ausgrid, Endeavour Energy and Essential Energy," June 2012, p. ix. AER, "Final decision: Ausgrid distribution determination 2015-16 to 2018-19, Overview," April 2015, p. 45.

83 AEMO, "National Electricity Market," 2018.

84 AER, "Issues paper: Potential development of demand management incentive schemes for Energex, Ergon Energy and ETSA Utilities for the 2010-15 regulatory control period," April 2008, p. 1

85 The AER defines efficient investments as those that allow networks to deliver the greatest possible benefit, in respect of price, quality, reliability, safety, and security, to consumers at the lowest long-term cost. AER, "Better Regulation: Explanatory statement, Expenditure forecast assessment guideline," November 2013, p. 17.

guidelines on how to quantify these benefits, such as changes in voluntary load curtailment, interruptions caused by outages, energy losses, and costs.[86]

- **The Capital Expenditure Sharing Scheme (CESS).** Similar to the capex IRIS in New Zealand, the CESS smooths out incentives for capex savings across regulatory periods. Under the CESS a distribution business will retain 30 per cent of the net present value of any underspend or overspend, while consumers will retain 70 per cent. This means that for a one dollar saving in capex a business gets 30 cents of the benefit while consumers get 70 cents.[87]
- **The Efficiency Benefit Sharing Scheme (EBSS).** Similar to the opex IRIS in New Zealand, the EBSS focuses equalizing incentives to reduce opex over the term of the price control (absent the EBSS, the incentive to control opex declines as the price reset at the start of the next control period gets closer. Unlike the opex IRIS, the EBSS also aims equalise incentives between opex and capex savings by allowing the same 30% retention rate for opex savings (in net present value) as for capex savings.[88]

At the same time as developing the EBSS and CESS, the AEMC reviewed incentives for demand management through the Power of Choice program, which ran from 2011 through 2012.[89] The recent history of demand management incentives, including the Power of Choice review, is described below.

More recently, the AER and AEMC have been considering and are actively piloting a number of projects that will help the NEM transition to a "distributed energy resources future", where up to 45% of all electricity is generated by customers in 2050.[90] The distributed energy resources future and a roadmap to get there are a joint creation of Energy Networks Australia (ENA) and the CSIRO. Current regulatory efforts include:

- A **trial of customer-centric regulation** in Victoria with distribution business AusNet

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86 The RIT-D replaces the Regulatory Test used previously. AER, "Better Regulation: Regulatory investment test for distribution fact sheet," 23 August 2013. AER, "Final: Regulatory investment test for distribution," 23 August 2013, p. 7.

87 AER, "Better Regulation: Expenditure incentives fact sheet," November 2013.

88 AER, "Better Regulation: Expenditure incentives fact sheet," November 2013.

89 AEMC, "Power of Choice – Stage 3 DSP Review," 2018.

90 Energy Networks Australia, "Electricity Network Transformation Roadmap: Final Report", April 2017, p.i

Services. The AusNet services "New Reg" trial commenced in March 2018, in partnership with the AER, ENA and Energy Consumers Australia (ECA), a consumer representative body. The New Reg approach establishes a "Consumer Forum" to represent the network's residential, small business, commercial and industrial customers. The Consumer Forum is not randomly chosen. The main idea of the New Reg process is that if the Consumer Forum and the distribution business can come to an agreement on the revenue proposal, then the AER will assess the regulatory proposal more favourably.[91 & 92]

- **Consideration of a "lighter-handed" totex approach.** The ENA's Roadmap suggests that a "lighter-handed" approach to regulation, such as a total expenditure framework ("totex"), may give distribution businesses more flexibility to deal with a dynamic and rapidly changing investment and operations environment.[93] Totex is lighter-handed in the sense that traditionally the regulator reviews separate forecasts of opex and capex for the upcoming regulatory period. Under a totex approach, the regulator would assess a forecast of total expenditure. The AEMC recently examined the possibility of implementing a totex approach, primarily as a tool to address perceived capex bias in investment incentives.[94,95] Following the review, the AEMC expressed qualifications about a totex approach, stating that it alone would not "resolve every issue and challenge faced by the electricity sector as it continues to transform" and

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91 AER, ENA & ECA, "New Reg: Towards Consumer-Centric Network Regulation", March 2018 and "New Reg Newsletter", June 2018

92 Customer settlements have also been trialled in the UK with Scottish Water and in the water sector in Australia with Yarra Valley Water in Victoria. Yarra Valley Water used a "citizens jury" of 35 randomly chosen customers to provide input into what Yarra Water's priorities should be at their next regulatory price review. The jury had access to internal and external experts to answer their questions and provided ten recommendations that were incorporate into Yarra Valley Water's 2017 price review. For more, see: Yarra Valley Water, "Price review and determination" and "Citizens Jury to help determine water services and pricing", last accessed 14 September 2018

93 Energy Networks Australia, "Electricity Network Transformation Roadmap: Final Report", April 2017, p.48

94 Frontier Economics, "Total Expenditure Frameworks," December 2017.

95 Australian Energy Market Commission, "2018 Economic Regulatory Framework Review – Information Sheet," 6 February 2018.

that a series of performance based incentives would also be needed.[96] The AEMC will examine the potential for such performance based incentives alongside totex, as part of the 2019 Economic Regulatory Framework Review.[97]

- **Rules on contestability of behind the meter services.** In December 2017 the AEMC published a rule change on contestability of behind-the-meter energy services. The rule change strengthened the ring-fencing rules already in place and prohibited distribution businesses from including in their regulatory asset base assets located behind a customer's meter.[98] However distribution businesses may still use operating expenditure to procure any necessary distribution services that are being provided by such assets from ring-fenced affiliates or third parties.[99] The AER may make exemptions to the behind the meter prohibition. However the AEMC required that if it does so, the AER would need to consider the likely impacts on competition for energy services. The rule change also gave the AER more flexibility in its ability to classify services as contestable moving forward, and required the AER to publish guidelines on how it intends to evaluate the classifications.[100] In September 2018, the AER published a behind the meter exemption guideline stating that exemptions may be made if the likely impacts will not have a negative effect on the development of competition in the market, or if the negative impacts are likely to be outweighed by other benefits.[101] Given that the guidelines were only published recently, there have not yet been any applications for exemptions. Prior to the introduction of the guideline, there were a number of ring-fencing waiver applications for temporary exemptions to allow the distribution businesses sufficient time to transition to the

96 Australian Energy Market Commission, "Economic Regulatory Framework Review: Promoting Efficient Investment in the Grid of the Future." 26 July 2018, p. 105.

97 Australian Energy Market Commission, "Economic Regulatory Framework Review: Promoting Efficient Investment in the Grid of the Future." 26 July 2018, p. 105.

98 AEMC, "National Electricity Amendment (Contestability of energy services) Rule 2017", December 2017, p.iv

99 AEMC, "National Electricity Amendment (Contestability of energy services) Rule 2017", December 2017, pp.18, 20

100 AEMC, "National Electricity Amendment (Contestability of energy services) Rule 2017", December 2017, p.iii

101 AER, "Asset exemption guideline, Explanatory statement", September 2018, p. 15.

new ring-fencing rules.[102]

A. Non-wires alternatives and incentives for innovation

1. Gap in the existing framework

Regulators are increasingly concerned that technological progress and innovation should mean that in some circumstances traditional poles-and-wires capital expenditure could be more readily substitutable by alternatives such as contracting demand response. But regulators fear that a bias, perceived or otherwise, in favour of capital expenditure drives distribution businesses away from the most efficient business decisions.[103] The "capex bias" is due either to the financial incentives flowing from the regulatory framework, or other external factors such as investor perceptions. The bias could result in the misreporting of operating expenditure as capital expenditure, or in capital expenditure solutions where alternatives involving opex would be cheaper. The "capex bias" is related to the problem of "gold-plating" or the Averch–Johnson effect.[104]

The AER has stated that networks have historically been addressing constraints due to increasing demand through supply-side actions such as installing new network assets, without always giving due attention to "non-wires" solutions. Recognizing that technological improvements are "driving new, sophisticated forms of demand management and altering the information available for calculating the benefits of non-network solutions," the AER aims to incentivize more investigation into and implementation of non-network solutions. [105]

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102 See AER, "Ring-fencing waivers", last viewed 26 September.

103 In Great Britain, Ofgem has implemented a "totex" approach to abolish the distinction between capex and opex; similar reforms have been discussed elsewhere (eg, Australian Energy Market Commission, "Economic Regulatory Framework Review: Promoting Efficient Investment in the Grid of the Future." 26 July 2018; Spiegel-Feld, D., and Mandel, B., 2015, "Reforming Electricity Regulation in New York State: Lessons from the United Kingdom," January 2015).

104 Averch, H., and Johnson., L.L., 1962, "Behavior of the Firm Under Regulatory Constraint," American Economic Review, *52*(5), 1052 – 1069.

105 AER, "Final decision: Demand management incentive scheme and innovation allowance, Fact sheet," 14 December 2017. AER, "Explanatory statement: Demand management incentive scheme, Electricity distribution network service providers," December 2017, p. 27. AER, "Explanatory

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Focusing on network solutions over lower-cost non-network solutions would result in customer bills that are higher than they would otherwise be.

Under the RIT-D, distribution businesses are already required to consult stakeholders to identify the most efficient investment, including non-wires alternatives. However stakeholders had reported problems such as being consulted only a few days before the RIT-D deadline, giving them limited time to assess the options. The AER believes that providing an explicit financial incentive under the DMIS will incentivize distribution businesses to engage more proactively with stakeholders to procure attractive demand management projects.[106]

Furthermore, the AER acknowledges the lingering capex bias in the existing framework. Despite the introduction of CESS and EBSS, which were meant to balance incentives between capex and opex, industry experts and participants still perceive a bias that favours network options over non-network solutions. The DMIS is meant to rebalance incentives.[107]

Additionally, the AER recognized that regulated monopolies such as distribution businesses may underprovide innovative research and development activities, relative to a competitive market. This is because while the distribution business bears the full cost of innovation, they would receive only a share of the benefits, since they cannot use innovation to create a competitive advantage and win market share from competitors.

2. Solution adopted

In December 2017, the AER designed two schemes to address the gaps in the regulatory framework: the DMIS and DMIA (Demand Management Incentive Scheme and Demand Management Innovation Allowance). The former is a program to reduce the cost of undertaking efficient non-wires investments, and the latter is an innovation allowance to fund R&D. The DMIA is meant to incentivize R&D into innovative projects, while the DMIS

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statement: Demand management innovation allowance mechanism, Electricity distribution network service providers," December 2017, p. 9.

106 AER, "Explanatory statement: Demand management incentive scheme, Electricity distribution network service providers," December 2017, pp. 72-73.

107 AER, "Explanatory statement: Demand management incentive scheme, Electricity distribution network service providers," December 2017, pp. 16-18.

incentivizes the implementation of activities that have already been tested.[108] The DMIS and DMIA are based on an earlier Demand Management Incentive Scheme developed in 2008/9,[109] which aimed to facilitate (rather than incentivize) the investigation and implementation of demand management projects. We describe the original DMIS below, and later explain how it was revised in 2017.

The original DMIS gave electric distribution businesses a fixed annual allowance to be used for non-network demand management projects.[110] The allowance was added to the annual allowed revenue each year and any underspends or unapproved amounts would be transferred back to customers in the next 5-year regulatory period. Any overspends would be borne by the distribution business. Distribution businesses were required to submit annual reports on the cost and outcomes of their project to improve industry knowledge. For distribution businesses that were not under a revenue cap,[111] there was an additional true-up for any revenue lost due to sales reductions that could be directly attributed to the demand management program.[112]

In 2012, the AEMC concluded its Power of Choice review, which assessed the market conditions in the NEM and proposed recommendations to facilitate efficient demand-side participation.[113] With regards to the DMIS, the review found that it "had been applied in a

108 AER, "Explanatory statement: Demand management innovation allowance mechanism, Electricity distribution network service providers," December 2017, pp. 9-10.

109 The earlier DMIS mechanisms were rolled out separately across the states in the NEM, which at this stage didn't have a common regulatory framework. See, for example: AER, "Demand management incentive scheme: Energex, Ergon Energy and ETSA Utilities 2010-15," October 2008.

110 The AER approves projects on an ex-post basis. AER, "Demand management incentive scheme: Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011-15," April 2009, pp. 3-4.

111 The AER has the discretion to apply a revenue cap, price cap, or other form of control, based on the distribution business. Any distribution businesses under a price cap at the time have now been moved, or will be moved, to a revenue cap. AER, "Explanatory statement: Demand management incentive scheme, Electricity distribution network service providers," December 2017, p. 15. AER, "Draft Explanatory Statement: Rate of return guidelines," July 2018, p. 102.

112 See, for example: AER, "Demand management incentive scheme: Jemena, CitiPower, Powercor, SP Ausnet and United Energy 2011-15," April 2009, pp. 3-4.

113 AEMC, "Final report: Power of choice review – giving consumers options in the way they use electricity," 30 November 2012, p. i.

very limited manner and operate[d] as a pass through of costs incurred in undertaking approved [demand-side participation] activities plus an innovation allowance." The AEMC concluded that the current scheme didn't provide proper incentives, and recommended a rule change that included permitting networks to retain a share of the non-network related market benefits of their project. The risks and characteristics of demand-side projects specifically identified by the AEMC were: the time to investigate, scope, and implement a project; transaction costs; uncertainty about the project impact; and the burden of developing the project for a large number of residential consumers.[114]

Based on feedback on the Power of Choice report, the AEMC revised the NER in 2015 to allow the AER to develop a more effective non-wires incentive scheme. In doing so they separated out two different roles that the DMIS had been playing – encouraging established non-wires alternatives to be implemented, and encouraging experimentation into innovative non-wires alternatives. The new DMIS focused on the former, while the DMIA focused on the latter. By clarifying incentives to choose the least-cost option to manage demand, the AEMC believed the overall system costs would be reduced and result in lower prices for consumers.[115] The AER completed the development of these tools in December 2017.

Under the updated DMIS, distribution businesses receive an incentive payment for undertaking efficient demand management projects of up to 50% of the project's cost (the incentive payment is additional to recovering the costs of the project). To ensure that customers are made better off from any non-wires investment, the incentive amount cannot exceed the net benefit to the market. In addition there is an annual cap limiting total incentives received to 1% of the distribution business' allowed revenue for that year.[116]

To be eligible for the DMIS, a non-wires project must first be identified as the most efficient alternative under the RIT-D. The RIT-D is in turn undertaken whenever a distribution business identifies network constraints during their annual planning process, and the requisite network investment would exceed a predetermined threshold.[117]

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114 AEMC, "Final report: Power of choice review – giving consumers options in the way they use electricity," 30 November 2012, pp. 205-206.

115 AEMC, "New rules for a demand management incentive scheme," 20 August 2015.

116 The net benefit constraint will be determined by either the RIT-D (for large projects) or a simpler cost-benefit analysis (for smaller projects). AER, "Final decision: Demand management incentive scheme and innovation allowance, Fact sheet," 14 December 2017.

117 The RIT-D is required only if the most expensive option costs $5 million or more. AER,

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If a project is eligible for the DMIS, the distribution business can then assess the incentive amount it can accrue and commence investment in the demand management project. The business is then required to file a compliance report after each regulatory year to the AER, and will earn the annual incentive after a 2-year lag.[118]

The DMIA is similar to the funding that existed under the original 2008/9 DMIS, but there are a few differences.[119] First, the DMIA is designed to give around 30% more money than the original allowance. This complements increases in other sources of R&D funding for demand management projects, and addresses the downside risk of investing in such projects, which the previous allowance did not sufficiently mitigate. Consumer groups have voiced support for increased funding to promote innovative demand management.[120]

Other changes include clarifying the reporting requirements and tightening the criteria for eligible projects to focus only on innovation. Under the 2008/9 DMIS allowance mechanism, the AER found that some later projects were very similar to previous projects.[121] To discourage duplication, the new mechanism requires projects to be innovative, which is defined as having to meet at least one of the following criteria: (1) based on new or original

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"Explanatory statement: Demand management incentive scheme, Electricity distribution network service providers," December 2017, pp. 33-35, 61-62. AER, "Demand management incentive scheme: Electricity distribution network service providers," December 2017, pp. 8-10. AER, "Regulatory investment test for distribution application guidelines," 18 September 2017, p. 11.

118 AER, "Demand management incentive scheme: Electricity distribution network service providers," December 2017, pp. 10-14. AER, "Explanatory statement: Demand management incentive scheme, Electricity distribution network service providers," December 2017, p. 55.

119 AER, "Explanatory statement: Demand management innovation allowance mechanism, Electricity distribution network service providers," December 2017, p. 8.

120 The new mechanism includes a formula to calculate the amount of the allowance, while the original mechanism gave the AER discretion to set the amount. AER, "Demand management innovation allowance mechanism: Electricity distribution network service providers," December 2017, pp. 7-8, 19-20. AER, "Demand management incentive scheme: Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011-15," April 2009, p. 5.

121 AER, "Final decision: Demand management incentive scheme and innovation allowance, Fact sheet," 14 December 2017. AER, "Explanatory statement: Demand management innovation allowance mechanism, Electricity distribution network service providers," December 2017, p. 22.

concepts, (2) involving technology or a technique not previously implemented in the relevant market, or (3) focused on customers that have not previously been exposed to the technology.[122]

Following the development of the new DMIS and DMIA, in April 2018 the AEMC completed a rule change to allow distribution businesses to start the DMIS application process in their current regulatory period, rather than having to wait until their next cycle.[123]

No DMIS applications have been filed under the current framework as of the time of writing, although several distribution businesses have started the RIT-D process since the DMIS was published in December 2017.[124] Stakeholders did express some concerns with the DMIS though during the DMIS development process, including:[125]

- the burdensome compliance requirements;
- the need for a smoothing mechanism to remove disincentives for projects with significant up-front costs;
- the regulatory risk relating to the AER's right to change the cost multiplier (50% return) during the regulatory period;
- increasing or removing the annual incentive cap.

The new DMIA will take effect in the next regulatory period. As such, no applications have been filed under the new framework. However, under the 2008/9 DMIS, all distribution businesses applied for an R&D allowance and all expenditures were approved. Currently, every distribution business is working on at least one project. The projects vary widely in

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122 AER, "Demand management innovation allowance mechanism: Electricity distribution network service providers," December 2017, pp. 6-7.

123 The rule change did not apply to the DMIA. AEMC, "Rule determination: Implementation of Demand Management Incentive Scheme," 3 April 2018, pp. 6-7.

124 In December 2017, the AER also launched a large-scale review of the RIT-D and its counterpart test for transmission businesses, the RIT-T. Included in the review are ways to clarify the requirements and the need for additional guidance for replacement or refurbishment projects. The review is expected to conclude in November 2018. AER, "Review of the application guidelines for the regulatory investment tests for transmission and distribution," 27 July 2018.

125 AER, "Explanatory statement: Demand management incentive scheme, Electricity distribution network service providers," December 2017, pp. 70-71, 73, 75, 80.

their nature and scale, and include:

- tariff-based projects to encourage consumers to reduce or shift their usage during peak demand;
- residential battery energy storage;
- grid storage;
- design, construction, and operation of a microgrid.[126]

[126] Note that the approval criteria were less focused on innovation under the previous scheme, and more broadly targeting demand management projects. AER, "Decision: Approval of Demand Management Innovation Allowance (DMIA) expenditures by distributors in 2016-17 and 2017," July 2018, pp. 5-7, 14, 18-55.

IV. New York

In common with many US jurisdictions, the overall framework of utility regulation in New York is determined by a combination of state law and public service commission policy. However, each utility has its own independently-determined rate case, and decisions taken in one rate case about the implementation of the framework will generally only apply to that utility. The majority of New York's investor-owned distribution businesses[127] operate under "multi-year rate plans" (MRPs) that typically last three years.[128] The MRP determines allowed revenue (i.e., there is full decoupling of revenues from units distributed or sold), and there are annual pre-set revenue adjustments between rate cases. MRPs are typically the result of a negotiated settlement with stakeholders, including customer representatives. The regulator, the New York Public Services Commission (PSC), adjudicates the rate plan in instances where negotiated settlement fails.

New York MRPs typically have asymmetrical earnings sharing mechanisms (ESMs) that share only surplus earnings (i.e., if achieved return on equity (ROE) is above the authorized amount, some of the difference is returned to customers; but if achieved ROE is below the authorized amount, customers do not make up any of the difference).[129] In addition, most NY utilities also have Performance Incentive Mechanisms (PIMs) for customer service and reliability, which provide a financial penalty if the target level of performance is not achieved (there is no corresponding financial reward for exceeding the target level). In recent years, a claw-back mechanism has been added to MRPs to return the benefit of capex underspends to consumers.[130]

In 2014 the New York Public Services Commission launched the Renewing the Energy Vision (REV) program of regulatory reforms, which aims to reorient the industry and the

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127 The New York utilities have both distribution and retail functions. However, the regulatory framework is such that the utilities are financially indifferent to the quantity of electricity distributed (or sold).

128 William Zarakas, et al. (The Brattle Group), "Performance Based Regulation Plans: Goals, Incentives and Alignment," prepared for DTE Energy, December 6, 2017. Appendix A-1.

129 William Zarakas, et al. (The Brattle Group), "Performance Based Regulation Plans: Goals, Incentives and Alignment," prepared for DTE Energy, December 6, 2017. Appendix B-3, p. 2.

130 New York PSC, "Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision," 19 May 2016, p. 99.

ratemaking paradigm toward a consumer-centred, market-mediated approach, with a particular focus on energy efficiency and integrating distributed energy resources (DERs).[131] The policy background and context for this initiative includes concerns over high and increasing distribution tariffs, and tariff increases are linked to increasing investment requirements (aging plant, need for storm response/resilience spending), and inefficient capital deployment under the traditional regulatory framework (i.e., a "capex bias"). New York also has ambitious emissions reduction targets, which imply greater reliance on distributed energy resources such as PV and storage.

The overall objectives of REV include:[132]

1. Customer focus: improve affordability by better utilising existing assets through demand management and by implementing alternatives to capital upgrades. Empower customers through the provision of better information over their electricity usage and support customer utilisation of distributed energy resources (DERs).
2. Environment: cut greenhouse gas emissions 80% by 2050 (from 1990 levels) by supporting energy efficiency, DERs, demand management, clean energy innovation and cleaner transportation. Use demand management, storage, and energy efficiency to help integrate renewables.
3. Service quality: build a more resilient grid that can withstand severe weather events and continue to operate (at least partially) during storm outages by using DERs.

The NY PSC's REV program is giving rise to a range of initiatives which the utilities are bringing forward for PSC approval. It is up to the individual utilities to file their own proposals and implement REV principles in their rate cases.[133]

We focus on Consolidated Edison's (Con Ed) implementation of REV, since Con Ed was the first utility to have its rate case litigated after REV policies around ratemaking and MRP design were decided upon. In the following sections, we describe modifications to the traditional MRP framework that are designed to encourage Con Ed to adopt non-wires alternatives and to evolve its business model towards that of a platform between customers

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131 State of New York Department of Public Service Commission, "Case 14-M-0101- Reforming the Energy Vision: NYS Department of Public Service Staff Report and Proposal," 24 April 2014, p. 2.

132 New York State, "Reforming the Energy Vision: Building a clean , more resilient, and affordable energy system for all new yorkers" and "REV Objectives: Lets' take a closer look at how REV defines success," last accessed 19 September 2018.

133 William Zarakas, et al. (The Brattle Group), "Performance Based Regulation Plans: Goals, Incentives and Alignment," prepared for DTE Energy, December 6, 2017, pp. xxx-xxxi.

and electric service providers.

A. Non-wires alternatives

1. Gap in the existing framework

Many regulators have suggested that the traditional regulatory framework provides utilities with an incentive to grow their rate base, for example where there is a "wedge" between the cost of capital and the authorized return on capital.[134] Under the New York MRPs, any such incentive is strengthened by the fact that capex underspends are "clawed back", so utilities see no financial benefit from investing less than anticipated when their authorized revenues were set.[135] An example of this concern about capex bias is in relation to managing load growth through demand-side measures rather than expanding the system.

2. Solution adopted

As the growth in system load typically requires significant capital investments, REV seeks to realign incentives by providing an opportunity for the utility to earn a financial reward from adopting solutions involving DERs to meet load growth at lower costs than conventional solutions. The difference between the cost of conventional and DER-based solutions provides a shared savings opportunity for customers and utilities.[136] Traditional investments will decline compared to a "no-REV" case because DERs are substituted for some conventional utility investment.

Non-wires alternatives (NWAs) are the best-known example of this type of earnings opportunity. With NWAs, utilities can show the efficiency of procuring DER services (such as demand response) to meet system needs by comparing DER costs to the cost of conventional infrastructure.

A key NWA example is Con Ed's Brooklyn-Queens Demand Management (BQDM) program. The PSC approved the project in 2014, as growth in the NYC boroughs of Brooklyn and Queens meant feeders serving two substations were on pace for a 69 MW shortfall by 2018. Rather than spending $1.2 billion for new substations, feeders, and switching stations, the

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134 See discussion above under the Australia case study.

135 New York PSC, "Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision," 19 May 2016, p. 99.

136 New York State, "Track Two: REV Financial Mechanisms," last accessed 19 September 2018.

utility turned to a range of demand-side options (demand management, energy efficiency and distributed generation), as well as utility-sited resources.[137]

To overcome the disincentive for Con Ed to pursue NWA projects rather than traditional capex, the Commission approved two incentives (also contingent on satisfactory performance on the company's existing reliability PIMs) in relation to BQDM:[138]

- All costs incurred for delivering the NWA solutions will be treated as an investment, to be recovered from customers over a 10 year period. These costs can include both "utility side" and "customer side" costs, and both capex and opex. The costs are capped at $200m.[139] Con Ed is permitted to earn its authorized overall rate of return (as approved in its most recent rate case) on all BQDM costs up to the $200m cap.
- The utility can earn up to an additional 100 basis points (incremental to its authorized rate of return on equity) on the BQDM costs. The 100 basis points consists of 45 basis points to be earned if a target amount of alternative capacity is procured; 25 basis points for achieving "diversity" in DER providers (i.e., contracting with multiple smaller providers rather than a few larger ones); and 30 basis points for achieving BQDM costs below the cost of the traditional alternative.[140,141]

Con Ed had proposed that, in addition to the above incentives, it would also receive 50% of the savings achieved by the project. However, this proposal was rejected by the PSC (although the PSC did require Con Ed to demonstrate that there were savings in order to receive the 30 basis points incremental return described above).[142]

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137 R Walton, "Pushed by REV, ConEd tests new utility business models in New York," 3 April 2017.

138 New York PSC, "Case 14-E-0302 - Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program: Order Establishing Brooklyn/Queens Demand Management Program," 11 December 2014, Appendix B, p. 1.

139 Consolidated Edison, "BQDM Quarterly Expenditures & Program Report, Q2-2018," 1 September 2018, p. 3.

140 New York PSC, "Case 14-E-0302 - Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program: Order Establishing Brooklyn/Queens Demand Management Program," 11 December 2014, pp. 19-22.

141 New York PSC, "Joint Proposal: Cases 16-E-0060, 16-G-0061, 15-E-0050, and 16-E-0196," 19 September 2016, p. 29.

142 New York PSC, "Case 14-E-0302 - Petition of Consolidated Edison Company of New York, Inc. for

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The BQDM program (together with some traditional investment) was originally designed to defer the need for a substantial upgrade from 2017 to 2019. Subsequently, Con Ed developed additional traditional infrastructure projects which further delayed the requirement for substantial upgrade to 2026. The PSC approved a request to extend the BQDM program (without providing additional incentive funding through that program).[143] As of the most recent program update, Con Ed has spent $75m of the approved $200m BQDM budget, and has achieved 41 MW of peak reduction.[144]

For future NWA projects, Con Ed will receive 30% of the net benefits as an incentive (this replaces the 100 basis points ROE adder described above for the BQDM project).[145] The net benefits are to be calculated according to a defined methodology, but the objective is to capture the full "social" cost–benefit (for example, with a value placed on changes in emissions).[146] When a new NWA project is first approved, Con Ed will be authorized to collect an initial incentive equal to 30% of the projected net savings; as the NWA project is implemented, any cost overruns or savings will be shared with customers 50:50, except that the total incentive to Con Ed (if NWA costs turn out below forecast) cannot exceed 50% of the net savings. Con Ed can recover the prudent costs of NWA projects even if the savings from deferring the traditional investment are less than anticipated (for example, if the traditional investment is not deferred for as long as originally anticipated), and its exposure to

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Approval of Brooklyn Queens Demand Management Program: Order Establishing Brooklyn/Queens Demand Management Program," 11 December 2014, pp. 8, 22.

143 New York PSC, "Case 14-E-0302 - Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn/Queens Demand Management Program: Order Granting Modification and Clarification," 18 January 2018, p. 2.

144 Consolidated Edison, "BQDM Quarterly Expenditures & Program Report, Q2-2018," 1 September 2018, pp. 2-5.

145 New York PSC, "Case 15-E-0229 - Petition of Consolidated Edison Company of New York, Inc. for Implementation of Projects and Programs That Support Reforming the Energy Vision: Order Approving Shareholder Incentives," 24 January 2017, p. 2.

146 Consolidated Edison, "Benefit Cost Analysis Handbook," Revised 19 August 2016; New York PSC, "Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision: Order Establishing the Benefit Cost Analysis Framework," 21 January 2016.

cost overruns on the NWA project is limited to the amount of the incentive.[147]

As with the BQDM project, other NWA project costs will be treated as investment and recovered over a ten year period, including a return at the usual authorised rate.[148]

B. Platform innovation

1. Gap in the existing framework

The initial phase of the REV proceeding sought to envision and define the appropriate role of distribution utilities in the future. The conclusion was that they should move towards a Distributed System Platform (DSP) provider role, under which they will accommodate customer-sited DERs and energy service companies, and may offer new services that use smart grid technologies. As utilities increasingly take on the DSP role, the expectation is that "platform service revenues" (PSRs) will become increasingly important as traditional revenues decline. PSRs are utility earnings tied to selling products and services that facilitate the operation of DSP markets, with pricing and revenue sharing to be approved by the PSC. While the specifics of a DSP market structure have yet to emerge, the DSP functions of a utility are expected to revolve around integrating DERs into the electricity delivery system:[149]

– Integrated system planning: analysis and planning for system needs integrating DER;
– Reliable grid operations: safe and reliable service with integration of DER;
– Market operations: pricing and market settlement for DER.

Many of the REV demonstration projects are testing grounds for the utility in a DSP provider role. For example, Central Hudson Gas & Electric initiated a pilot project to test its

147 New York PSC, "Case 15-E-0229 - Petition of Consolidated Edison Company of New York, Inc. for Implementation of Projects and Programs That Support Reforming the Energy Vision: Order Approving Shareholder Incentives," 24 January 2017, pp. 10-13.

148 New York PSC, "Joint Proposal: Cases 16-E-0060, 16-G-0061, 15-E-0050, and 16-E-0196," 19 September 2016, p. 29.

149 New York State, "Track One: Defining the REV Ecosystem," last accessed 19 September 2018; New York PSC, "Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision: Order Adopting Regulatory Policy Framework and Implementation Plan," 26 February 2015, p. 32.

communication system with certain intelligent devices in portions of its service territory.[150]

Under the current regulatory framework, however, utilities have no positive financial incentive to develop into the DSP role, and might perceive a financial dis-incentive from the prospect of losing revenue from providing traditional utility service.

2. Solution adopted

While PSRs are expected to become significant in the long term, the PSC has in the short term recommended that Earnings Adjustment Mechanisms (EAMs) be implemented to encourage utilities to develop the DSP role. The PSC has said that EAMs are "best thought of as a bridge….[the Commission expects] that through the opportunity to earn from platform revenues that produce sustained value to end-use customers and utility shareholders, the need to establish specific EAMs to accompany the same consumer benefit will diminish."[151] In the near to medium term before platform services become significant, EAMs are expected to provide a significant incentive to utilities and encourage them to adapt their behaviour and business operations to better meet customer needs.

EAMs are incremental performance incentives that utilities can earn in return for achieving REV objectives.[152] The PSC has requested that utilities propose incentives that are not calculated as a rate of return on rate base (to avoid encouraging utilities to grow their rate base).[153] The PSC also indicated that the EAMs should not require a comparison with estimated counterfactuals to avoid controversy, and that the EAMs should be structured on a multiyear basis in order to allow sufficient time to develop sought after outcomes.[154] EAMs provide a financial reward if progress is achieved, but there is no financial penalty for failing

150 New York PSC, "Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision: Memorandum and Resolution of Demonstration Projects," 12 December 2014, p. 2.

151 New York Public Service Commission, "Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision: Order Adopting a Ratemaking and Utility Revenue Model Policy Framework," 19 May 2016, p. 60.

152 New York State, "Track Two: REV Financial Mechanisms," last accessed 19 September 2018.

153 MN Lowry, et al. (Pacific Economics Group Research LLC), "State Performance –Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," July 2017, p. 6.17.

154 William Zarakas, et al. (The Brattle Group), "Performance Based Regulation Plans: Goals, Incentives and Alignment," prepared for DTE Energy, December 6, 2017, p. xxxi.

to demonstrate progress. Each utility is to make separate proposals to the PSC for the scope, metrics and targets, and the level of incentive associated with each EAM.

The EAMs proposed by Con Ed in its 2017 rate case are shown in Table 2 below, which summarizes the target levels and associated incentive revenues for each EAM in the first year of the three-year rate plan. There are two separate types of metric for evaluating Con Ed's performance in achieving these objectives: outcome-based and program achievement-based.

Table 2: Con Ed EAMs (Rate Year 1)

Types	EAMs	Min	Target	Max
Outcome- based	Residential energy intensity (kWh sales/residential customer)	4.676	4.587	4.409
		$0.11M	$0.39M	$0.95M
	Commercial energy intensity (kWh sales/private employment)	7.164	6.931	6.465
		$0.20M	$0.72M	$1.76M
	Customer load factor	To be determined		
	Distributed energy resources (DER) utilization (MWh)	150,000	244,500	360,000
		$0.06M	$1.11M	$2.72M
Program-achievement-based	Peak reduction	28.3	43.5	58.7
		$0.29M	$1.15M	$3.46M
	Energy efficiency (net GWh)	158	178	198
		$0.58M	$4.03M	$9.22M

Outcome-based EAMs evaluate Con Ed's performance solely on a measured outcome. For example, Con Ed has an outcome-based EAM to encourage utilization of DERs, which rewards Con Ed based on the MWh generated by DERs in a given year. This reward will be paid for increased DER generation without analysing the extent to which that increase should be attributed to actions taken by Con Ed. In contrast, program-achievement EAMs pay a reward only if the program itself is judged to have met or exceeded its targets.

Table 2 above shows the incentives available in year 1 of the three-year rate plan. The incentives increase in years 2 and 3, such that the maximum incentive available under the three outcome-based EAMs across the three years is $52.7m,[155] and the maximum available under the two program-achievement EAMs across the three years is $49.8m.[156]

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155 New York PSC, "Joint Proposal: Case 16-E-0060, Case 16-G-0061 and Case 16-E-0196," 25 January 2017, p. 74.

156 *Ibid.*, p. 72.

In 2017 Con Ed received the maximum possible reward for the two program-based EAMs, and performance was below the minimum threshold on the DER utilization and residential energy intensity EAMs (performance for the commercial energy intensity could not be measured because employment data was not available for 2017).[157]

In addition to the EAMs shown above, Con Ed is also working on an emissions reduction EAM and an EAM to encourage connection of DERs.[158]

157 New York Public Service Commission, "Case 16-E-0060: Order Approving Electric and Gas Rate Plans," 25 January 2017 and "Con Edison 2017 Energy Efficiency Earnings Adjustment Mechanism Achievement Report," 30 March 2018.

158 See Case 16-E-0060, Staff Letter dated 28 June 2018; Case 16-E-0060 etc, 2017 Outcome-based EAM Collaborative Report, 23 August 2017; Case 16-E-0060, Con Edison Outcome-based EAM Collaborative: Emissions Metric Report, 30 April 2018.

V. California

Utilities in California are regulated by the California Public Utilities Commission (CPUC). Most customers pay for a “bundled” service, including electricity procurement, distribution and retail, but the distribution activity has its own revenue requirement. The electricity distribution function is regulated on a revenue cap basis (ie, there is full “revenue decoupling”, such that the distribution revenue ultimately collected from customers is equal to the revenue authorised by the CPUC, independent of changes in units distributed or sold). The utilities typically use a three year price control period. The revenue requirement in the first year of the period (called the “test year”) is set on the basis of a detailed forecast of costs in that year. For the second and third years of the period, the revenue requirement is typically adjusted for anticipated changes in costs. These anticipated changes in costs are usually determined using broad trends rather than a detailed line-by-line forecast of costs as is used for the test year.

A. Non-wires alternative (IDER)

1. Gap in the existing framework

As early as 2007, CPUC had considered the further integration of DERs into offerings by distribution businesses.[159] These offerings include distribution-connected distributed generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies, all of which are supported through schemes shown in Table 3. Demand side energy solutions and technologies, or as CPUC calls it, Integrated Distributed Energy Resources, can provide similar or perhaps more attractive attributes in comparison with traditional distribution investment as the proliferation of DERs continues.

Despite numerous CPUC decisions (and action from the state legislature), stakeholders feel that the full potential benefits of DERs are not being realized, for example because utilities are reluctant to rely on DERs in place of traditional network solutions, and that they may face a financial disincentive in adopting them over traditional network solutions.[160]

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159 CPUC, “Integrated Distributed Energy Resources,” viewed 12 September 2018.

160 CPUC, “Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Distributed Energy Resources” (Rulemaking 14-10-003, filed 2 October 2014), p. 3.

Table 3: Distributed Energy Resources (DER) Sourcing Mechanisms

Sourcing Mechanism	Description	Applicable Customer Segment(s)
Tariffs		
Net Energy Metering Tariff	Customers receive a full retail rate bill credit for energy they generate and export to the grid.	All sectors
Feed-in-Tariff	Customer and utility enter into a long term contract to purchase wholesale power generation from clean energy resource.	Varies
Rates		
Time of Use rate	Customers charged rate based on time of day that electricity is used.	Mandatory for all non-residential + Net Energy Metering Customers, opt-in for residential
Critical Peak Pricing rate	Default rate for all commercial and industrial customers. Customers pay peak pricing on event days and lower pricing on other days.	Default for all non-residential
Electrical Vehicle rate	Customer rates exclusively for EV charging on a separate meter. All are TOU.	Residential and non-residential
Incentive Programs		
Investor Owned Utility Demand Response programs [AC Cycling, ToU, Agricultural and Pumping Interruptible, Capacity Bidding Program, Demand Bidding Program]	Customers agree to lower demand during called events. Incentives may be offered to offset upfront costs or as reduced rates or both. Capacity payments + penalties for non-performance in certain programs.	All sectors
Utility DR programs [Permanent Load Shift]	Load modifying DR program to incentivize mature Thermal Energy Storage technologies.	Mostly non-residential
California Solar Initiative	Incentives to customers installing eligible solar.	Non-residential (waitlist)
Self-Generation Incentive Program	Incentives to customers installing eligible DERs.	Residential (mostly Advanced Energy Storage) and non-residential (all technologies)
Investor Owned Utility EE programs (mass market)	Deemed upstream incentives to manufacturers for lighting, etc.	All sectors
Utility EE Programs	Deemed midstream incentives (to distributors) and downstream incentives (to customer) for HVAC, lighting, appliances, etc. Custom incentives for more complex projects.	All sectors
Third-Party Implemented Investor Owned Utility EE Programs	IOU EE portfolio implemented by third-parties, procured through competitive solicitations.	Mostly non-residential
Third Party Administered EE Programs	Pilots administered by third-parties.	Specialize in hard-to-reach segments (Multi-Family, small commercial and industrial)
Energy Savings Assistance	Free installation of approved weatherization and EE measures for qualifying low-income customers.	Low-income residential
Competitively Procured (RFOs)		
Preferred Resources Pilot + All-Source RFO	CPUC-directed RFO process to meet need specified in long term procurement plan.	Non-residential
Resource-specific competitive procurement [Advanced Energy Storage RFOS, Demand Response Auction Mechanism pilot]	Third-party or aggregator bids for specific DERs, as directed by CPUC decision or on IOUs' own motion. Resources bid into wholesale markets. DRAM provides capacity payment; third-party Demand Response Providers bids energy or Ancillary into CAISO market.	Residential and non-residential
Wholesale Market Products and Services		
Proxy Demand Response	Market platform for economically-triggered load to participate in day-ahead and real-time energy and Ancillary Service markets.	All sectors
Reliability Demand Response Resource	Market platform to provide CAISO visibility to reliability-triggered DR as administered through CAISO markets.	Mostly non-residential
Non-Generator Resource / Distributed Energy Resource Provider	Market platform for DERs to participate in day-ahead and real-time energy and Ancillary Services markets through the Non-Generator Resource model.	All sectors

Adapted from CPUC, "California's Distributed Energy Resources Action Plan: Aligning Vision and Action," 3 May 2017.

2. Solution adopted

The Californian Governor's approval of Assembly Bill 327 (2013), Senate Bill 350 (2015), and

Senate Bill 32 (2016) kick-started reforms to distribution planning and investment, increased obligations to grow DER incentives, and established commitments for California to massively reduce greenhouse gas emissions through an increase of renewables, energy efficiency schemes, and electrification.

Consequently, several concurrent programs currently exist, such as the DER Action Plan, Distribution Resources Plan (DRP), and the Integrated Resource Plan (IRP). The DER Action Plan focuses more on the strategic future of Californian DERs; the Distribution Resources Plan is an initiate to fast track DERs into the business plans of the distribution businesses; and the Integrated Resources Plan is more concerned with the overall target with greenhouse gas reduction goals and renewables penetration.

The CPUC's rulemaking R.14-10-003 proposed an incentive mechanism for the deployment of DERs specifically to address the possibility that utilities may face a financial disincentive for facilitating DERs over traditional utility investment. The underlying logic expressed by the CPUC rulemaking is that if utilities view investment in wires and other fixed assets as creating value for their shareholders, then utilities will resist DER deployments to the extent that DERs crowd out traditional investment and thereby destroy shareholder value. The rulemaking points to an apparent wedge between the historically observed actual return on equity invested in utilities and the cost of equity capital. This wedge (named "the value engine") was purported to have incentivised traditional capital intensive infrastructure investment.[161] And because DER solutions would displace capital investment, this sets up a "conflict with the company's [distribution businesses'] fundamental financial objectives"[162]. Thus the rulemaking proposes a similarly sized offsetting incentive arrangement to balance the purported disincentive: the same "wedge" should be provided to the utility as an adder over and above expenditure incurred in deploying DERs.

In 2016, CPUC's Decision D16-12-036 laid out steps for the adoption of the Regulatory Incentive Mechanism Pilot.[163] The framework aimed to create a competitive solicitation

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161 The gap between a distribution businesses' return on equity and its cost of equity was said to be between 2.5% and 3.5% in recent years. See CPUC, "Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Distributed Energy Resources," 2 October 2014.

162 CPUC, "Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Distributed Energy Resources," 2 October 2014.

163 Listed, these include: (i) formation of the advisory group, (ii) identification of projects, (iii) advice

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process for DER projects.[164] The pilot was deemed to have received general support due to it being a first step in examining alternative payment structures for distribution businesses, while managing to strike "a reasonable balance"[165] between the need to implement the pilot on an expedited schedule and ensuring adequate oversight of ratepayer costs. Under the pilot, distribution businesses were required to identify at least one project where DER deployment would displace or defer capital expenditure, but were also encouraged to select up to three additional projects.

To date, no IDER projects have successfully commenced for the three regulated Californian distribution businesses:

– Pacific Gas & Electric (PG&E) originally identified Rincon Substation as a viable project, after rigorous screening to find a suitable candidate.[166] Although PG&E initially considered four use cases where DERs could substitute for distribution investment: distribution capacity, voltage support, reliability (back-tie), and resiliency (microgrid),[167] the proposed project would only supply one—distribution capacity. The existing Rincon Substation had a capacity of 16MW, with plans for it to be upgraded to 30MW, though this could be deferred if 2MW to 4MW of additional distribution capacity could be

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letter process, (iv) solicitation approval process, (v) solicitation process, (vi) contract approval process, and (vii) pilot evaluation process. See, CPUC, "Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot," 15 December, 2016.

164 CPUC, "Decision Modifying Decision 16-12-036," 21 June, 2018.

165 CPUC, "Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot," 15 December, 2016, p. 42.

166 This included two sets of screens, and an evaluation to determine if the DERs were incremental and likely to be cost effective. See more at: PG&E, "Advice 5096-E, Request for approval of distributed energy resource (DER) procurement for the IDER Utility Regulatory Incentive Mechanism Pilot (Incentive Pilot)," June 16, 2017.

167 Reliability services (such as back-tie) provide fast reconnection and/or excess reserves to reduce demand, and resiliency services (such as microgrids) provide power to stranded end-use customers. See California Energy Storage Alliance, "Comments of the California Energy Storage Alliance on the Amended Scoping Memo of Assigned Commissioner and Joint Ruling with Administrate Law Judge," 29 March 2018, p. 5.

acquired by summer 2020.[168] The area has a diverse customer mix with a mix of residential, small and medium businesses, and large commercial and industrial customers, implying demand response could potentially be procured from a diverse group of customers. However, after the proposal was filed, conditions changed and PG&E found that DER was no longer a viable or cost-effective solution.[169] Unusually hot conditions, wildfire damage, and two new connection requests from large customers, pushed the timing of the capacity need forward, resulting in a timeframe that was not tenable for the deployment of DERs under IDER. Moreover, it was found that reconductoring could meet the capacity needs at a third of the previously preferred alternative to DERs of expanding the Rincon Substation. PG&E has submitted another request for an IDER project in May 2018 to solicit 2MW of distribution capacity by summer 2021.S

- San Diego Gas & Electric (SDG&E) received three bidders for its solicitation to provide distribution capacity on two circuits in Carlsbad California (which if successfully provided, would defer the need for a new circuit to 2026)[170] and ultimately did not receive bids that were cost-effective, meaning it will proceed with traditional investment.[171]
- Southern California Edison has not announced a winner for its IDER RFO, despite the final selection date having passed several months ago.[172] This suggests that there were also no conforming bids to displace the traditional wires investment.

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168 PG&E, "Advice 5096-E, Request for approval of distributed energy resource (DER) procurement for the IDER Utility Regulatory Incentive Mechanism Pilot (Incentive Pilot)," 16 June 2017.

169 PG&E, "Advice 5096-E-A, Supplemental: Request for Approval of Distributed Energy Resource (DER) Procurement for the IDER Utility Regulatory Incentive Mechanism Pilot (Incentive Pilot) Pursuant to Resolution E-4889 and D.16-12-036," 1 May 2018.

170 SDG&E, "San Diego Gas & Electric Company's Request to Procure a Distributed Energy Resource Solution as Required in Ordering Paragraph 14 of Decision (D.) 16-12-036," 21 June 2017.

171 CESA, "CESA's Response to SDG&E Advice Letter on IDER Pilot RFO Results," 23 July 2018.

172 SCE, "SCE IDER RFO Schedule," viewed 13 September 2018.

VI. Illinois

Commonwealth Edison ("ComEd") is an investor-owned electricity distribution utility which provides delivery services to 3.8 million customers in northern Illinois, or about 70% of the state.[173] While ComEd also acts as a retailer and offers a "bundled" service (delivery and energy) to retail customers in its service territory, the regulatory framework is such that it is financially indifferent to the quantity of electricity distributed (or sold).[174]

ComEd's distribution rates are regulated by the Illinois Commerce Commission and are set by a "performance based formula rate" plan.[175] The formula rate process was established in Illinois under the Energy Infrastructure Modernization Act[176] ("EIMA") in 2011, and the rate formula was scheduled to be in effect until 2019. The Future Energy Jobs Act ("FEJA") recently extended the formula rate ruling through 2022.[177]

Prior to 2016, the formula rates were calculated such that there would be an adjustment if the achieved ROE was outside 50 basis points above or below the allowed ROE (if actual earnings fell outside of this range, the difference would be incorporated into revenues for the next year).[178] The FEJA ruling in 2016 modified the ROE collar from 50 basis points above or

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173 Verified Petition of Commonwealth Edison Company, for the Approval of the Energy Efficiency and Demand Response Plan and Update to the Energy Efficiency Formula Rate Cost Inputs Pursuant to Section 8-103B of the Public Utilities Act, ICC docket, June 30, 2017, p. 1. Available at https://azstg.comed.com/SiteCollectionDocuments/MyAccount/MyBillUsage/ProposedRevisions/Rider_EEPA_Petition.pdf and http://www.exeloncorp.com/companies/comed

174 See Schedule Of Rates For Electric Service for Commonwealth Edison Company, table of content. Available at https://www.comed.com/SiteCollectionDocuments/MyAccount/MyBillUsage/CurrentRates/Ratebook.pdf.

175 Verified Petition to Initiate Annual Formula Rate Update and Revenue Requirement Reconciliation Under Section 16-108.5 Of The Public Utilities Act, Docket 17-0196, in front of ICC, April, 17 2017, page 2.

176 Illinois Senate Bill 1652, "Energy Infrastructure Modernization Act," passed October 31, 2011.

177 Illinois Senate Bill 2814, "Future Energy Jobs Act," passed December 7, 2016.

178 Infrastructure investment and modernization; regulatory reform." Illinois Compiled Statues, Sec. 16108.5 (c) (5). Available at: http://www.ilga.gov/legislation/ilcs/fulltext.asp?DocName=

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below allowed ROE to 0 basis points,[179] so that all costs are effectively passed through,[180] subject to ComEd meeting metrics related to reliability, outage duration and frequency, safety, customer service, efficiency and productivity, and budget control. If the performance goals are not achieved, there is an associated penalty which decreases the earned ROE by up to 38 basis points. [181] Because formula rates essentially allow ComEd to adjust its rates each year to be in line with its costs and add recent investments to the rate base, higher levels of investments will likely result in higher distribution bills to customers, provided performance objectives are met. However, the formula rate plan sets a limit for this dynamic through a cap of 2.5% imposed on average annual increases in residential customer distribution bills.

A. Energy Efficiency

1. Gap in the existing framework

In 2007, the Illinois Power Agency Act created an Energy Efficiency Portfolio Standard that required utilities to gradually increase annual incremental energy efficiency savings to reach

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022000050K16-108.5

179 FEJA allows Illinois utilities with a performance-based formula rate, such as ComEd, to "to reduce the 50 basis point values to zero that would otherwise apply under paragraph (5) of subsection (c) of Section 16-108.5." See Illinois Senate Bill 2814, "Future Energy Jobs Act," passed December 7, 2016, Section 9-107 (Revenue balancing adjustments), p. 250.

180 See Infrastructure investment and modernization; regulatory reform." Illinois Compiled Statues, Sec. 16108.5(d)(1). Available at: http://www.ilga.gov/legislation/ilcs/fulltext.asp?DocName=022000050K16108.5 and Illinois Commerce Commission (ICC) Order, "Annual Formula Rate Update and Revenue Requirement Reconciliation under Section 16-108.5 of the Public Utilities Act," Docket 16-0259, December 6, 2016, p. 3.

181 Infrastructure investment and modernization; regulatory reform." Illinois Compiled Statues, Sec. 16108.5 (f-5). Available at: http://www.ilga.gov/legislation/ilcs/fulltext.asp?DocName=022000050K16-108.5. For example, ComEd did not meet its 2015 performance targets and was penalized for the 2017 revenue requirement in the 2016 formula rate update (Illinois Commerce Commission (ICC) Order, "Annual Formula Rate Update and Revenue Requirement Reconciliation under Section 16-108.5 of the Public Utilities Act," Docket 16-0259, December 6, 2016, p. 41).

an equivalent of 2 percent of sales by 2016.[182] The same year, Senate Bill 1592 was passed into law requiring Illinois utilities subject to the Act, such as ComEd, to submit plans to "implement energy efficiency and demand response programs to meet aggressive energy reduction goals."[183]

In 2016, the Illinois Department of Commerce and Economic Opportunity conducted an evaluation of the Energy Efficiency Portfolio Standard and found that the state was failing to achieve its goals set by the 2007 standards by about 65% because of critical flaws in the standards' design.[184] In particular, a cost cap[185] in the state's Public Utilities Act limited the amount of energy efficiency spending (even if measures were cost-effective) and thus savings that utilities could achieve.

2. Solution adopted

As part of the FEJA law passed in December 2016, the state of Illinois has further emphasized its priority to promote energy efficiency, and has addressed the issues identified by the Illinois Department of Commerce and Economic Opportunity. Section 1(a)(2) of FEJA introduces the bill by stating that "the State's existing energy efficiency standard should be updated to ensure that customers continue to realize increased value, to incorporate and optimize measures enabled by the smart grid, including voltage optimization measures, and to provide incentives for electric utilities to achieve the energy savings goals." The legislature

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182 See Illinois Department of Commerce and Economic Opportunity, State of Illinois: Goals Status Report for Energy Efficiency and Renewable Energy, March 2016, p. 25. Available at https://www.eenews.net/assets/2016/03/28/document_ew_03.pdf.

183 Final Order for docket 07-0540 https://www.icc.illinois.gov/docket/files.aspx?no=07-0540&docId=119840 page 2.

184 See Illinois Department of Commerce and Economic Opportunity, State of Illinois: Goals Status Report for Energy Efficiency and Renewable Energy, March 2016, p. 68. Available at https://www.eenews.net/assets/2016/03/28/document_ew_03.pdf. See also analysis in National Resources Defense Council, "Engine of Growth: Energy Efficiency Investments and the Future Energy Jobs Act will Spark Illinois's Clean Energy Economy," July 2017.

185 Under the cost cap, utilities are entitled to "collect fees from consumers to pay for the costs of the energy efficiency programs up to the allowed 2.015% over the base year rate impact," see Illinois Department of Commerce and Economic Opportunity, State of Illinois: Goals Status Report for Energy Efficiency and Renewable Energy, March 2016, p. 25. Available at https://www.eenews.net/assets/2016/03/28/document_ew_03.pdf

had several goals in implementing FEJA, among which are "stimulat[ing] job creating with new investments in energy efficiency, renewables and energy innovation" while preserving customers' bills from increasing too much, and "enhanc[ing] Illinois' position as a leader in the clean energy economy, attracting new investment and new companies."[186]

FEJA also sets new energy savings goals for utilities. For example, ComEd is required to achieve 21.5% of annual sales of cumulative persisting energy savings[187] by 2030.[188] Three measures in FEJA contribute to promoting energy efficiency:

- **Introducing an explicit performance incentive mechanism** through the Energy Efficiency Pricing and Performance Rider, which capitalizes energy efficiency spending and allows a return based on the authorized ROE applicable for other (more generic) capital expenditures increased/reduced by 8 basis points to a max of 200 basis points (2%) for each 1% above/below the annual demand reduction target.[189] This mechanism provides an explicit incentive to ComEd to invest in effective energy efficiency when compared to supply-side resources, creating an opportunity for the utility to earn an additional return on spending in energy efficiency and thus "sharing" with customers the net benefits that result from implementation of energy efficiency programs.
- **Reducing the ROE collar from 50 basis points above or below allowed ROE to 0 basis points**,[190] as noted above, effectively tightening the true-up mechanism and decoupling

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186 See FEJA website. Available at http://www.futureenergyjobsact.com/about, accessed September 15, 2018.

187 FEJA defines cumulative persisting annual savings as "the total electric energy savings in a given year from measures installed in that year or in previous years, but no earlier than January 1, 2012, that are still operational and providing savings in that year because the measures have not yet reached the end of their useful lives." See Illinois Senate Bill 2814, "Future Energy Jobs Act," passed December 7, 2016, Section Sec. 8-103B (b), p. 183.

188 See Illinois Senate Bill 2814, "Future Energy Jobs Act," passed December 7, 2016, Section Sec. 8-103B (b-5), p. 185.

189 See Illinois Senate Bill 2814, "Future Energy Jobs Act," passed December 7, 2016, Section Sec. 8-103B (b), p.193

190 FEJA allows Illinois utilities with a performance-based formula rate, such as ComEd, "to reduce the 50 basis point values to zero that would otherwise apply under paragraph (5) of subsection (c) of Section 16-108.5." See Illinois Senate Bill 2814, "Future Energy Jobs Act," passed December 7, 2016, Section 9-107 (Revenue balancing adjustments), p. 250.

the utility's revenues from its electricity sales. Indeed, energy efficiency programs create a risk for utilities like ComEd that they will not fully recover all of their costs of serving customers. This is because although many of ComEd's costs are fixed, only a portion of these costs are recovered through a fixed charge, the rest are recovered through volumetric energy charges. Therefore, programs that reduce sales, such as energy efficiency, will reduce revenues by a greater amount than they reduce costs, and this creates a disincentive for utilities to pursue effective energy efficiency programs. Allowing ComEd to true-up its revenues to the level of its actual costs (based on its actual sales) prevents from this disincentive.

- **Establishing a minimum annual spending in energy efficiency programs for low-income residential customers** – ComEd is required to spend at least $25 million.[191]

The explicit energy efficiency performance incentive included in FEJA provides an attractive alternative for utilities to invest in new substations, distribution and transmission lines or centralized generation. Thus, it said to shift utilities' business model toward being a "service provider" by "treat[ing] a service like energy efficiency as an asset".[192]

VII. Observations

A. Themes from the case studies

The case studies we describe in this report are examples of regulators identifying a gap in the existing regulatory framework and designing an additional regulatory mechanism to fill this gap. In some cases, the mechanism is intended to be a step towards a new business model. In order to discuss design principles for these regulatory mechanisms and identify what sort of mechanism might be appropriate for various different circumstances (different "gaps" in the existing framework), we have created a classification scheme for these regulatory

191 See Illinois Senate Bill 2814, "Future Energy Jobs Act," passed December 7, 2016, Section Sec. 8-103B (c), p. 192.

192 See Utility Dive, "Chicago's REV: How ComEd is reinventing itself as a smart energy platform," published on March 31, 2016. Accessible at https://www.utilitydive.com/news/chicagos-rev-how-comed-is-reinventing-itself-as-a-smart-energy-platform/416623/. See also analysis by CLEAResult, "Creating Customer and Investor Value through Energy Efficiency," July 11, 2017, accessible at https://www.clearesult.com/insights/whitepapers/creating-customer-and-investor-value-through-energyefficiency/.

mechanisms.

The standard regulatory framework is that the distribution business collects a pre-determined amount of revenue, from which it covers the costs of running the business. The default is that a change in costs will not result in a corresponding change in revenue: ie, the business has a financial incentive to control its costs. This standard framework contains gaps because the amount of revenue that the business collects is not contingent on performance. Thus, if the regulator wishes the business to adjust its performance in a way that gives rise to additional cost, the standard regulatory framework creates a disincentive for the business to help achieve the regulator's goal. If the regulator were to provide additional revenue to cover the costs of meeting a particular goal, the standard framework would allow the business to benefit from that revenue irrespective of whether progress is made towards the goal. As a result, in many contexts regulators have identified additional mechanisms to fill gaps in the existing framework. We classify these additional incentive mechanisms as shown below.

Cost pass through: a particular activity is identified, and spending on that activity is tracked and passed through (ie, revenue automatically increases during the control period to cover the costs for this specific activity), perhaps subject to a cap on the total passed through. This type of mechanism has the feature that, unlike the baseline regulatory framework, if money is not spent on the specific defined activity, no revenue is collected, or any assigned revenue that has already been collected is refunded. Some of Ofgem's innovation funding mechanisms have been of this type.

Cost plus: to motivate the distribution businesses to undertake the identified activity they are given an additional incentive payment over and above the cost pass through for doing so. The magnitude of the incentive is not dependent on what the activity achieves; rather the incentive is an adder on top of the costs associated with the activity. The California IDER mechanism is of this type.

Cost plus performance incentive: similar to cost plus, but the incentive adder depends on the performance of the distribution business in executing the activity. The incentive is usually calculated as a share of the overall net benefit achieved. The New York non-wires alternative (NWA) mechanism is of this type (with the net benefits capped at zero – ie, the business will recover its costs for the non-wires alternative, plus, if there is a positive net benefit, an additional amount equal to a share of that net benefit). In this example, the net benefit is the estimated value of the traditional utility investment avoided by means of the NWA project, less the actual cost of the NWA project. Unlike the cost-plus pass through, a performance incentive mechanism would result in no incentive payment if the project was unsuccessful.

Revenue incentive: a certain quantifiable and measurable output is defined, together with a target output quantity and a unit incentive rate. For every unit of output above the target, the business collects additional revenue equal to the incentive rate (and, similarly, for every unit of output below the target, revenue is reduced by the incentive rate). The New York EAMs for energy efficiency and peak demand reduction are of this type. With a revenue incentive, the magnitude of the incentive revenue depends only on the measured output (unlike the cost pass through or the cost-plus pass through, where the incentive revenue depends on the cost that the business incurs). There is no guarantee that costs spent on the particular activity (which in any case may not be identified) will be covered by the incentive revenue. Another example of a revenue incentive is the commonly-used service quality incentive mechanism targeting the frequency and duration of distribution network interruptions.[193]

Discretionary reward: for a discretionary reward scheme, the regulator reviews the implementation and performance of a particular project against a broad set of pre-defined criteria. Any projects which are judged to be particularly successful will result in a financial reward (ie, the business is permitted to collect additional revenue). Ofgem has implemented discretionary reward schemes in relation to losses and innovation. Unlike a revenue incentive mechanism, a discretionary reward mechanism has no direct link between a specific quantified output and revenue (for example MW of new connections) and can be used in a situation where "success" cannot be narrowly defined or easily quantified. Unlike a cost plus incentive mechanism, a discretionary reward does not guarantee that costs will be covered by additional revenue, and there is no pre-specified link between the size of the reward and a particular way of quantifying net benefits.

Regulatory obligation: the final type of mechanism we identify is an obligation placed on the business to perform a certain activity. There is no reward associated with success, though failure to meet the obligation may attract regulatory enforcement action. For example, Ofgem's current approach on losses includes the obligation to keep losses as low as reasonably practicable, and to report on actions planned and results achieved (in addition, there is also a discretionary reward for successful outcomes). In New Zealand, distribution businesses do not require a license to operate, so regulatory obligations would need to be imposed through some other mechanism.

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193 We have not included a service quality incentive mechanism in our case studies, but such schemes are employed in Great Britain, Australia, New Zealand, New York, and other jurisdictions (the mechanisms in US jurisdictions tend to be "penalty only" but are otherwise similar).

Table 4: Incentive mechanisms by jurisdiction

	Cost pass through	Cost plus	Cost plus performance incentive	Revenue incentive	Discretionary rewards	Regulatory obligation
Losses				*Great Britain (loss incentive mechanism)*	Great Britain (RIIO-ED1)	Great Britain (RIIO-ED1)
Connecting DERs	*Great Britain (hybrid mechanism)* Great Britain (RIIO-ED1)			*Great Britain (hybrid mechanism)*		
Innovation	Australia (Demand management innnovation allowance)					
	Great Britain (Innovation programs*)				*Great Britain (Low Carbon Networks Fund)*	
Non-wires alternatives		California (Regulatory Incentive Mechanism Pilot)	Australia (Demand management incentive scheme)			Australia (Regulatory Investment Test for Distribution)
		New York (Brooklyn Queens Demand Management)	New York (Future projects for ConEd)			
Energy efficiency			Illinois (Energy Efficiency Pricing and Performance Rider)	New York (Earnings Adjustment Mechanisms)		
Platform innovation						

Notes: Mechanisms in *red italics* are no longer active
* Innovation Roll-out Mechanism , Networks Innovation Allowance and Networks Innovation Competition

In Table 4 we classify the incentive mechanisms from our case studies into the different types described above. Note that there are currently no funding mechanisms for platform innovation in the jurisdictions reviewed.

The classification and the description of different types of incentive mechanisms shown in Table 4, result from our synthesis of the case study materials. In general, regulators do not provide explanations for their choice of incentive mechanism in a way that explicitly maps onto this classification. Nonetheless, we have thought about the circumstances which gave rise to the particular incentive mechanisms chosen in each of the case studies, in order to provide some guidance as to how regulators select a starting-point for new incentive mechanisms when new gaps in the regulatory framework are identified. For this purpose we think the following are relevant questions.

- Can the desired performance or output be objectively quantified, and necessary metrics specified before the desired activity is undertaken? If yes, a revenue incentive is possible. For example, in Great Britain a revenue incentive was found not to be a suitable mechanism for loss reduction since losses were more difficult to measure than first envisaged. Additionally, if either costs or benefits associated with a unit of desired output are highly uncertain, then a revenue incentive may not be feasible because it will then be difficult to relate the strength of the incentive to the cost of achieving the output or the value of doing so.
- Are the anticipated net benefits of the activity reasonably clear to the regulator or external stakeholders before the activity is undertaken, or do the net benefits only become clear afterwards, for example because they depend on project execution rather than project design? If the benefits are clear up front, a cost plus approach may be appropriate, but if the benefits depend on execution then an incentive that depends on assessed performance (or a discretionary reward) would be better.
- Will the desired activity give rise to at least some benefits for the distribution business (eg, likely, but non-quantifiable reductions in future costs)? If not, pure cost-pass through without an incentive may not provide a sufficient incentive to overcome inertia or risks associated with the desired activity.
- Can the necessary activities (and associated costs) be clearly identified and separated from other "business as usual" activities? If they can, a cost-based mechanism (cost pass-through, cost plus or cost plus performance incentive) is possible, but if they cannot, such approaches risk double-counting. For example, cost-based schemes would be difficult to use in the context of managing service quality, because it would be difficult to distinguish activities designed to improve service quality from activities associated with running the network generally. Revenue incentive schemes are often used to address service quality.

Table 5 shows the factors needed to implement each incentive mechanism. In each case a checkmark indicates that the mechanism cannot be used if that element is not present. So for example, it would difficult to use a cost pass through if the costs of implementing an activity are not separately identifiable from other distribution business operations, or if the distribution business sees no benefit from implementing the activity.

Table 5: Necessary features to implement an incentive mechanism

Necessary features		Cost pass through	Cost- plus	Cost plus performance incentive	Revenue incentive	Discretionary rewards
Benefits	Program benefits have to be objectively measurable			✓	✓	
	Benefits need to be known upfront before implementation			✓	✓	
	The distribution business must independently obtain benefit from implementing the program	✓				
Costs	Program costs need to be separately identifiable from business as usual	✓	✓	✓		

✓ Indicates that the feature must be present for the the regulatory mechanism to be implemented.

We have not included regulatory obligations in Table 5 because we think that an obligation makes most sense when it is supported by other mechanisms. For example, an obligation to identify and implement opportunities to reduce losses makes sense where it is supported by a) the traditional framework for recovering costs in relation to "standard" network design and operation , and b) a reward or other incentive scheme in relation to more innovative ways of reducing losses.

The discretionary reward mechanism is particularly useful in situations where the benefits of an activity are hard to assess before the activity has been undertaken.

B. Implications for the DPP framework

In the next control period in New Zealand, the DPP framework will contain the basic "revenue allowance" common to most frameworks for regulating distribution businesses, and it will contain a revenue driver for service quality (with up to +/- 1% of revenue dependent on measured frequency and duration of service interruptions in the current control period—the amounts may be reset for the next control period).[194] There are no other financial

[194] This basic framework also applies to the CPP option, with the main difference being that the CPP revenue allowance depends more strongly on the anticipated specific needs of the individual

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incentive mechanisms which would be relevant to business performance in relation to goals such as end use energy efficiency, losses, implementation of demand-side management or other non-wires alternatives, innovation generally, platform innovation, or the connection of DERs.[195] Businesses may be able to apply for a revenue allowance within a CPP application to cover costs associated with these activities, but as the experience of Powerco and the case studies in this report show, the basic revenue cap framework is not well-suited to the funding of innovation because the funding depends neither on actual expenditures nor on realised benefits.

We note that the framework in New Zealand does not include measures to "equalise incentives" as between capex and opex, in contrast to the frameworks in Great Britain and Australia. Furthermore, in Great Britain there are additional incentives to support innovation, and in Australia there are additional incentives to support innovation and (separately) to support NWA. This suggests not only that there is a risk of a "capex bias" in the New Zealand framework, but also that a measure to equalise incentives may not be not be sufficient to encourage NWA or other forms of innovation. The framework in New Zealand makes provision for distribution businesses to recover the costs of DER connection assets,[196] but it does not account for disincentives that may arise, such as network reinforcement costs associated with DER connections. New Zealand's unique low-cost DPP framework may also mean that some of the regulatory structures underlying new regulatory mechanisms in other jurisdictions are not present in New Zealand. For example, Australia's NWA mechanism is a cost plus performance incentive that relies on the pre-existing RIT-D cost–benefit analysis to identify NWA cost savings relative to traditional network investments.

The case studies we have described illustrate that many jurisdictions have identified gaps in the basic regulatory framework and have implemented a variety of incentive mechanisms to fill these gaps.

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business, rather than anticipated sector-wide trends under the DPP.

195 The existing framework includes the possibility for the businesses to apply ex post to recover "lost revenue" associated with demand-side management or energy efficiency; however, the next control period will be a revenue cap rather than a price cap, so the businesses will no longer be exposed to the risk of losing revenue and this mechanism will no longer be relevant.

196 Electricity Authority, "Electricity Industry Participation Code, 2010". Schedule 6.4, 31 August, 2018, p.50

Losses: To reduce losses in Great Britain, Ofgem imposed a licensing obligation requiring distribution businesses to minimize losses. This includes mandatory reporting on loss reduction strategy and outcomes. There is also a series of discretionary awards for loss reductions focused on various steps in planning, implementing and realizing loss reductions. Great Britain originally had a revenue incentive which rewarded distribution businesses for exceeding a target for reducing losses (and penalized failure to achieve the target). However difficulties in accurate measurement of losses prevented this mechanism from working as intended.

Connecting DERs: In order to ensure that distribution businesses in Great Britain were motivated to connect DERs to the grid in situations where this would require network reinforcement, Ofgem introduced a "hybrid" mechanism with a partial cost pass through and a partial revenue incentive. This was designed to reduce the downside risk to the distribution business while incentivizing efficient connections. Later, when the uncertainty surrounding new connections had decreased and connecting DERs was considered normal business operations, Ofgem switched to a pass through of excessive reinforcement costs.

Innovation: In Australia, the AER recognized that economic regulation of distribution businesses may cause them to underprovide innovative research and development (R&D) activities. Distribution businesses have thus been provided with a cost pass through allowance for R&D activities related to non-wires alternatives. Similarly in Great Britain, Ofgem has implemented a set of cost pass through mechanisms focused variously on the technical development of the distribution networks; transitioning business culture and technology to a low carbon future; and implementing low carbon innovations.

Non-wires alternatives: In Australia, California and New York, regulators were concerned distribution businesses suffer from a capex bias and have not given sufficient attention to potentially less expensive "non-wires" alternatives. In New York, ConEd's iconic Brooklyn Queens Demand Management project was funded with a cost plus incentive. Newer projects will be eligible for a cost plus performance incentive mechanism. In Australia there is also a cost plus performance incentive mechanism. Although distribution businesses were already under an obligation to identify the most efficient investment (including non-wires alternatives), this was considered insufficient to motivate businesses to identify and pursue cheaper non-wires alternatives. In California, a pilot study requires distribution businesses to identify potential projects with viable non-wires alternatives. If implemented these projects will receive cost plus funding, although to date no projects have commenced.

Energy efficiency: In order to better meet state mandated energy efficiency targets, a cost plus performance incentive was introduced in Illinois that allowed distribution businesses to capitalize energy efficiency expenditure and earn a return on the balance. The return is centred on the ROE, but will be higher/lower dependent on program performance. In New York, Con Ed receives a revenue incentive for energy efficiency and demand management. This is seen as a first step in the transition to a distribution platform model.

Platform innovation: In New York the end goal of the REV proceedings is to move towards a Distributed System Platform (DSP) provider role, under which distribution businesses will accommodate customer-sited DERs and energy service companies, and may offer new services that use smart grid technologies. "Platform service revenues" (PSRs) tied to selling products and services that facilitate the operation of DSP markets will compensate distribution businesses for these services, replacing traditional revenue sources. Revenue incentives such as the energy efficiency measures described above are seen as a stepping stone in the transition to PSRs. In Australia, much of the drive for platform innovation has come from the industry, led by the ENA. The AEMC and AER have responded to varying degrees – instituting non-wires solutions; addressing capex bias; considering totex; piloting new regulatory approaches and protecting competition behind the meter. However, there has not yet been a systematic re-examination of the future distribution network business model.

In this paper we have not assessed the specific situation of distribution businesses in New Zealand, but we note the concerns of the Expert Advisory Panel over the need for new business models and new technologies to enable more active network management.[197] In line with experience elsewhere, the existing framework would require additional incentive mechanisms to encourage these new behaviours.

Electric vehicle (EV) uptake provides an illustration of how the existing framework could fail to support desired change. The transition to electric transportation provides an opportunity to reduce New Zealand's dependence on fossil fuels and lower customer bills by better using the existing electricity infrastructure.[198] In addition to having lower emissions than petroleum fuelled cars, EVs can help integrate intermittent renewable generation through intermittent charging and reverse vehicle to grid flows.[199] However, as with other types of DER, if EV adoption and use is not properly integrated into the existing network, EV charging could significantly increase future system costs.[200] Without changes to the status quo, EV charging

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197 Expert Advisory Panel (New Zealand), "Electricity Price Review – First Report", pp.61, 64

198 Expert Advisory Panel (New Zealand), "Electricity Price Review – First Report", pp.6, 24

199 The Brattle Group, "New Sources of Utility Growth – Electrification Challenges and Opportunities", November 2017, pp.6-7

200 Expert Advisory Panel (New Zealand), "Electricity Price Review – First Report", p.55

can result in dramatic increases in local peak load, triggering costly upgrades.[201]

The impact of EV uptake on the network, and hence the need for network reinforcement, may depend on how the network is operated. For example, the way in which network services are priced could influence whether or not EVs are charged during the network's system peak; and "smart" charging could act as a form of demand response thereby avoiding some of the network reinforcement that would otherwise be required (ie, NWA and/or platform innovation). The Expert Advisory Panel concluded that, in order to minimize the costs of the transition to EVs and other DERs and ensure that all of the benefits are realized, distribution networks will need to make "big investments and reinvent business practices".[202]

The extent and pace of EV uptake is likely to be very uncertain,[203] as are the impacts of EVs on the network. Direct current fast chargers (DCFCs) can charge most EVs in 30 minutes or less, and have 350 kW or higher demand at a single charging port (DCFC charging stations may include multiple ports).[204] EVs thus have the potential for significant impact on distribution network usage and local reinforcement needs.

Significant EV uptake could reveal gaps in the existing regulatory framework: on the one hand, the existing framework may not be well-suited to encourage necessary network reinforcement; on the other hand, it may not sufficiently encourage a "smart" approach to EV charging.

EV adoption will likely be spread unequally across distribution businesses. The amount and cost of required reinforcement may be very uncertain, and activities beyond business-as-usual network planning and operation may be required. In this rapidly changing, uncertain environment, the DPP/CPP framework is not likely to encourage the optimal response to EV uptake on the part of the distribution businesses. We discuss below how the different types of incentive mechanisms might perform in addressing gaps in relation to EVs.

Incentives for network reinforcement to support EV charging

Cost pass through, cost plus and cost plus performance incentive: Cost-based incentives require that the costs specifically associated with network reinforcement associated with

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201 Jurgen Weiss, et al, "The electrification accelerator: Understanding the implications of autonomous vehicles for electric utilities", *The Electricity Journal, Vol.30(10),* December 2017

202 Expert Advisory Panel (New Zealand), "Electricity Price Review – First Report", p.6

203 Expert Advisory Panel (New Zealand), "Electricity Price Review – First Report", p.24

204 Jurgen Weiss, et al, "The electrification accelerator: Understanding the implications of autonomous vehicles for electric utilities", *The Electricity Journal, Vol.30(10),* December 2017

EV charging can be identified and tracked separate from other costs. If this is possible, cost-based incentives have the merit of allowing the distribution businesses to collect the revenue required to pay for the EV-associated network reinforcement costs. Unlike relying on the existing framework, a cost-based incentive addresses the uncertainty in the quantity (and cost) of EV-associated reinforcement that is needed. If the distribution businesses will see a benefit from undertaking this reinforcement, then no further incentive is needed. For example, the benefit could come in the form of brand-building and stakeholder engagement. If policy makers believe that these benefits are not sufficient to encourage the distribution businesses to conduct EV-associated network reinforcement (even with cost pass through), then an additional incentive could be offered over and above cost pass through. This might be needed if, for example, the cost pass through mechanism is not able to capture all of the additional costs associated with the EV-associated reinforcement. In a cost-plus incentive mechanism, the financial incentive payment is proportional to the costs of the reinforcement work. This might be appropriate if the wider benefits to customers of a dollar of reinforcement work do not vary greatly from one reinforcement project to another. Alternatively, a performance incentive would measure the benefits of the reinforcement work and provide a financial incentive in proportion to the measured benefits. For example, the performance incentive could be proportional to the MW of charging capacity connected (rather than proportional to the cost of the reinforcement work). Since the distribution business will receive a share of the benefit generated, they have an incentive to maximize this figure. If there are a number of possible ways to reinforce the network, the distribution businesses will try to implement the portfolio of measures with the highest returns and implement them effectively.

Revenue incentive: If metrics for a desired outcome can be identified and objectively measured, then a revenue incentive could be implemented. Relative to a cost plus incentive mechanism, the benefit of a revenue driver is that it encourages the distribution business to undertake the cheaper projects first. However, if the reinforcement cost for a typical charging project is uncertain, a revenue driver may not work as well as a cost plus incentive: the revenue incentive rate may turn out to be much higher than needed to support the work delivered, or much too small to deliver any projects.

Discretionary reward: If it is not clear ahead of time what types of beneficial actions need to be taken and what the likely results would be, then a discretionary reward scheme could be designed. If EV-associated reinforcement is mainly traditional reinforcement work, albeit triggered by a new demand source, this approach is unlikely to be needed. Uncertainty may discourage participation.

Incentives for "smart charging"

By "smart charging" we mean charging services provided in a way that optimises use of the network. For example, this could be by encouraging charging only at off-peak times, thereby avoiding network reinforcement. Alternatively, smart charging could include a "platform" to enable EVs to provide services to the network and other market participants.

Cost pass through, cost plus and cost plus performance incentive: cost-based incentives might be suitable if the costs of a smart charging platform can be clearly identified. However, presumably the benefits of a smart charging platform would be strongly dependent on the design, implementation and operation of the platform. Up front, it may be difficult to estimate what kinds of benefit might be most important, much less quantify them. An incentive component would seem desirable, though we anticipate that it might be difficult to specify the desired benefits in a way that they could be measured for use in a financial incentive. Some benefits could perhaps be measured: for example, the ratio of charging kWh to incremental system peak kW. However, the true benefits are likely to be multi-dimensional, and any cost plus incentive mechanism might over-encourage one or a subset of the possible desirable outputs. It is possible that the distribution businesses may see the future benefits to its businesses of designing an effective smart charging platform as a predecessor to a more general network platform.

Revenue driver: designing a revenue driver may similarly be difficult because the nature of the benefits may not be clear before the smart charging platform is built. Furthermore, the magnitude of the benefits and the costs may both be highly uncertain.

Discretionary reward: a discretionary reward scheme does not guarantee any contribution towards costs, but provides the possibility of a financial reward for the most successful projects. The advantage of such an approach is that it can be low cost (only successful projects are paid for) and "success" does not have to be precisely defined up front. However, the disadvantage is that uncertainty may limit participation. A staged or hybrid approach could also be considered: for example, a cost pass through for project design work; partial cost pass through for project implementation; and a discretionary reward for success.

The choice of appropriate regulatory mechanisms to address gaps in the basic regulatory framework needs to align with regulatory and policy goals in New Zealand and the situation of the distribution businesses. Addressing gaps by implementing new regulatory mechanisms will need to work with New Zealand's DPP framework. This paper provides a "typology" of alternative regulatory mechanisms to assist with this choice.

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