Improving the PBR Framework in Hawai‘i

ADDRESSING THE RISK OF “CAPEX BIAS”

PREPARED FOR

The Hawaiian Electric Companies

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Executive summary

In common with many utilities, the Hawaiian Electric Companies (Companies) are investing significant sums in modernizing their systems, integrating renewable generation and maintaining reliability. The regulatory framework in Hawaiʻi provides for a rate case every three years and annual revenue adjustments between rate cases, with this last feature being necessary to support the rate of investment that the Companies are undertaking. However, the Commission has expressed a concern that the traditional regulatory model could lead to over investment by the utility. This concern can be referred to as a risk of “capex bias”.

In this report we show that, across a wide range of jurisdictions, regulators have approved mechanisms that result in revenue adjustments between rate cases. The magnitude of necessary revenue adjustments will depend on the circumstances of the utility concerned, but there are many examples of revenue adjustments that exceed the rate of general inflation.

We have analyzed the operation of the Revenue Adjustment Mechanism (RAM) and the RAM Cap in Hawaiʻi and show that the Companies bear a portion of additional costs incurred between rate cases that were not included in test year costs. The financial burden on the Companies of such costs depends on whether the costs are capex or opex, when in the three-year regulatory period the costs are incurred, (for capex) whether the RAM Cap is binding, and (for opex) whether the expenditure is one-off or recurring. Because the sharing of costs depends on these factors, the strength of the direct financial incentive for the Companies to control costs will also vary across projects. Since RAM revenues adjust to reflect capital additions on an annual basis, the financial burden on the company of capex projects is lower than the financial burden of an equally-costly opex project, tending to increase the risk of a capex bias.

Regulators in several jurisdictions have implemented mechanisms to address the risk of a capex bias. These mechanisms include a total expenditure approach (totex), an efficiency carry-over mechanism (ECM), or targeted performance incentive mechanisms (PIMs) focused on implementing alternatives to traditional utility investment, such as relying on demand response. The regulatory framework in both New York and California includes such a mechanism supporting non-wires alternatives (NWA).

We suggest four possible improvements to the regulatory framework in Hawaiʻi to address the Commission’s concern. The RAM could be modified to correspond to anticipated changes in revenue requirements, but not adjusted to reflect actual additions. This would result in a more even financial burden for opex and capex projects. The period between rate cases could be extended. This would strengthen the incentive to control costs, including by reducing investment. An Efficiency Carryover Mechanism (ECM) could be implemented to maintain the strength of incentives towards the end of the regulatory period. Finally, an NWA PIM could be designed to encourage the Companies to adopt solutions that reduce or defer the need for traditional utility investment.

I. Introduction

A. Our assignment

The Public Utilities Commission of the State of Hawai'i has instituted a proceeding to investigate performance based ratemaking (PBR).[1] The Commission's order describes traditional cost-of-service ratemaking (COSR) and identifies a risk that COSR might encourage utilities to over-invest in infrastructure:[2]

> because earnings are tied to capital investments, COSR encourages electric utilities to increase these investments, thereby increasing the utility's associated return on investment… …The traditional regulatory model for electric utilities, in which the electric utility earns a return on its investments in the system based largely on the cumulative depreciated cost of the prudent infrastructure it has deployed, may exert an "infrastructure bias" to deploy capital-intensive solutions.[f/n citing Averch and Johnson] This occurs because the primary financial means through which the utility can grow its business and enhance earnings for shareholders is to invest in additional capital projects. Indeed, the electric utility, beyond expanding its rate base, has limited earnings opportunities within a traditional COSR framework. Generally, rates do not provide for earnings on utility operation and maintenance expenditures, or for the cost of purchased power. There are few financial incentives for the utility to employ cost-savings measures, to reduce electricity sales, to improve energy efficiency, to increase customer choice, to integrate customer-sited generation, or to establish new and innovative services, except to the extent that utility capital investment is required.[f/n omitted]

The Commission Staff has identified a desired outcome of "Grid Investment Efficiency" (under the goal of "Improve Utility Performance"). The second Staff Report describes the desired outcome as follows:[3]

> Given the already high cost of electricity for Hawaii customers, and the increasing availability of alternatives to traditional electric service, it is important that utilities pursue optimal solutions for identified grid needs irrespective of the nature of the investments (i.e., investment in utility-owned capital expenditures versus third-party provided service-based solutions).

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1 Order No. 35411 in PUC of Hawai'i Docket 2018-088, filed April 18, 2018.

2 *Ibid.*, pp. 10-12.

3 Hawaii Public Utilities Commission, "Assessing the Existing Regulatory Framework in Hawaii—Concept Paper to Support Docket Activities", September 18, 2018, Attachment B, p. 3.

The Hawaiian Electric Companies ("the Companies") have asked The Brattle Group to examine the current regulatory framework in Hawaiʻi and consider what adjustments to this framework might be warranted, given the Commission's and Staff's concerns quoted above, and other public policy objectives for regulatory reform in Hawaiʻi. The Companies asked that we illustrate our analysis with examples drawn from other jurisdictions where similar challenges have been addressed. In this report we discuss examples from other US jurisdictions, Australia, New Zealand and Great Britain.

B. Structure of this report

This report is structured as follows:

- In Section 2 we discuss how the traditional framework of utility regulation in North America does not function well in an environment where utilities need to make relatively rapid investment in order to maintain a safe and reliable system. We also provide some examples of how regulators have modified the traditional framework in circumstances where rapid investment is required.
- In Section 3 we explain the key features of the regulatory framework in Hawaiʻi as they relate to investment incentives.
- In Section 4 we examine the phenomenon of "capex bias" or a bias in favor of utility investments over the purchase of services from third parties. We discuss examples of how the regulatory framework has been modified in response, including "totex" and examples of specific mechanisms to encourage utilities to employ "non-wires alternatives" (NWA) to traditional utility investment.
- In Section 5 we describe an example from New Zealand of how utility capital expenditure plans are reflected in revenue adjustments between rate cases.
- In Section 6 we conclude by identifying possible adjustments to the regulatory framework in Hawaiʻi, taking into account the topics above.

II. Addressing the need for rapid capital expenditure

A. Trends in capital expenditure of US utilities

In a hypothetical notional "steady state" environment, utility investment would be driven only by the need to replace existing assets as they wear out. In this environment, utility rate base would change from one year to the next because of depreciation of existing assets and additions of new assets to replace retiring ones. Rate base would tend to increase over time because of inflation: the cost of a new asset to replace a retiring one is likely to be greater than the historical cost of the retiring asset. In practice there are many other factors influencing investment needs. For example, load growth and strengthened safety or environmental standards will increase investment needs, whereas technology change may reduce investment needs through productivity improvements. The rate at which a particular utility needs to invest is likely to fluctuate over time.

When the rate of utility investment is low, the traditional regulatory framework can work well, with relatively infrequent rate cases. However, when investment is rapid and rate base is growing, rate cases would need to be increasingly frequent in order for utility revenues to keep pace with increased revenue requirements.

Because some US utilities have their own generation and transmission assets, whereas others purchase power and/or transmission services, we have examined investment in distribution assets as a way to survey recent trends and highlight the challenges associated with rapid rates of investment.

Figure 1 shows that the rate of distribution investment across the US as a whole has been increasing over the last 20 years. Over this period, average additions to distribution plant has increased by a factor of approximately three, from about $70m per utility per year in 1998 to over $200m per utility per year in 2017 (these figures are averages across 119 utilities for which data is tabulated in SNL).[4]

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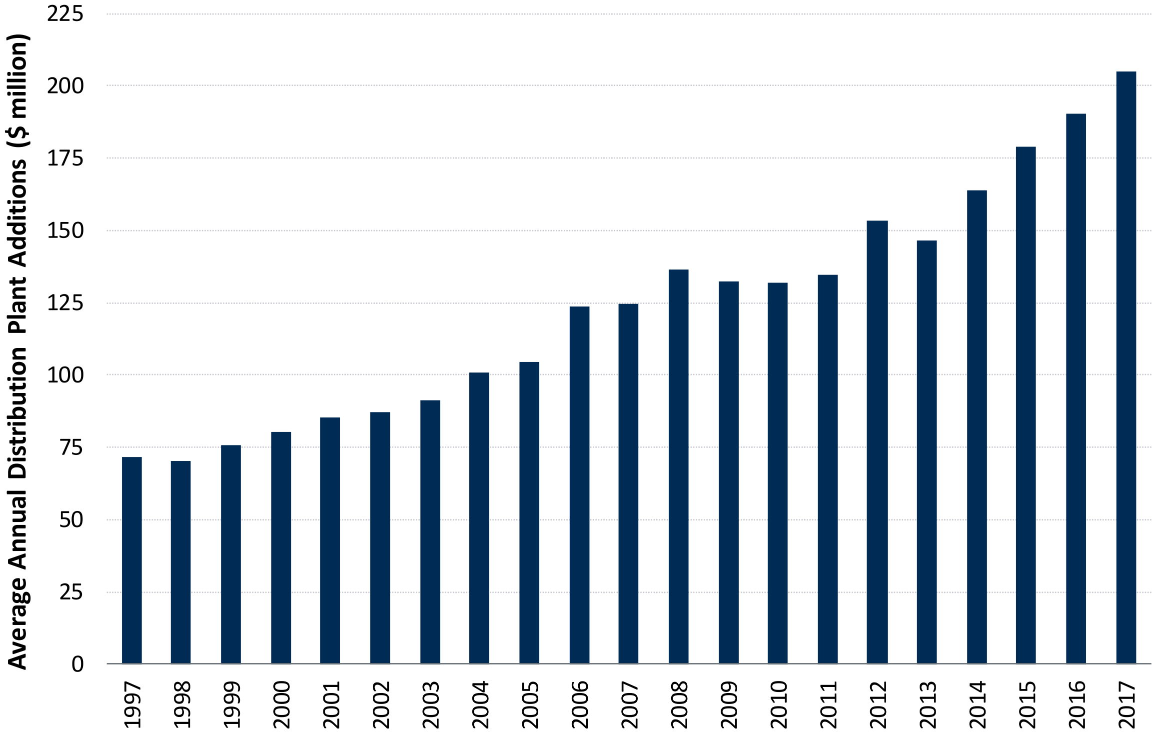
[4] The corresponding figures for the Companies are $83m in 1998 and $216m in 2017 (the 1998 figure does not include Maui Electric; the 2017 figure excluding Maui Electric is $182m).

Figure 1: Average Annual Distribution Plant Additions



Sources and notes: The Brattle Group analysis using FERC Form 1 data accessed from S&P Global Market Intelligence. Values represent the average distribution plant additions for all 119 utilities that had data available in every year.

For utilities with strong financial attributes, access to capital is not likely to limit the rate at which investments can be made. However, rapid investment tends to result in revenue requirement increases—in general, if capital additions in a year exceed depreciation in that year, the rate base will increase and hence the revenue requirement will tend to increase.[5] This will pose a challenge to the regulatory framework as frequent rate cases may be required to maintain just and reasonable rates.

Data on utility revenue requirements is not easily accessible in database format. However, evolution in net distribution plant[6] is a good indicator of the impact of distribution plant additions on the revenue requirement since it is a major contributor to the change in rate base (and hence the capital-related portion of the revenue requirement)[7] over time.

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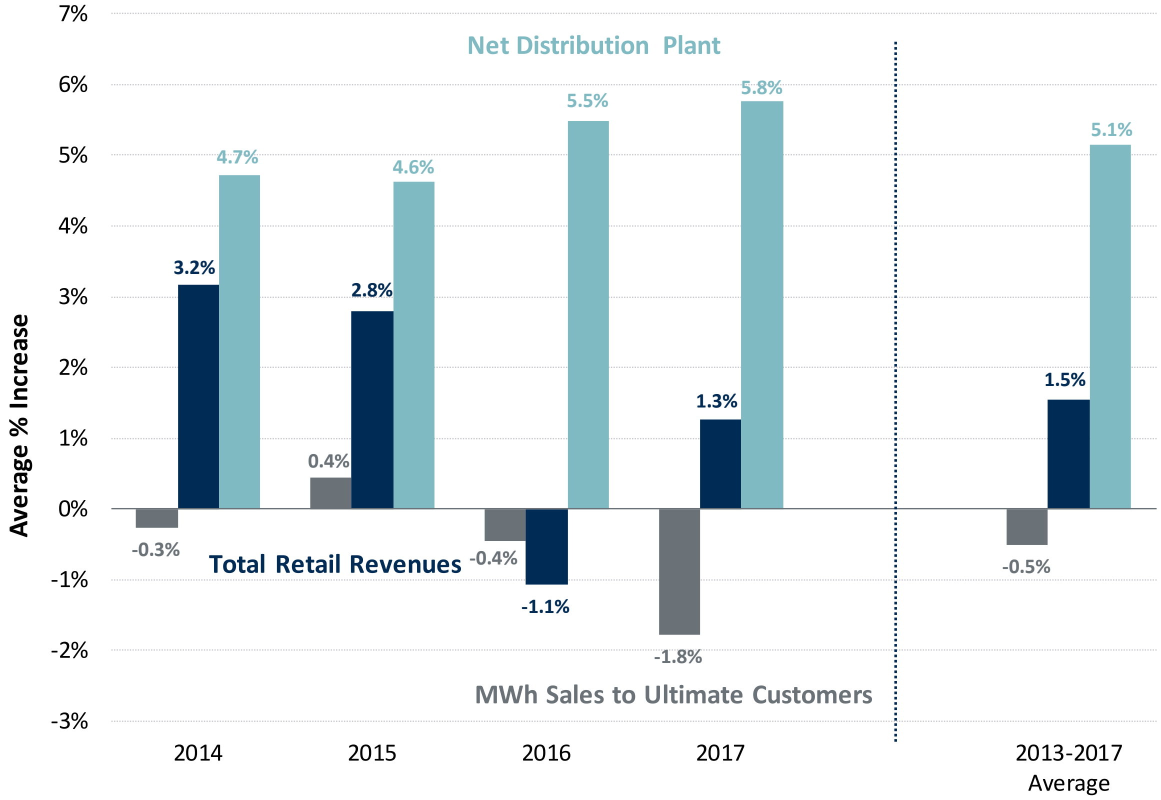
[5] By "revenue requirement" we mean the revenue which, in a particular year, would result in earning the authorized return on equity based on actual expenditures and actual rate base.

[6] Net distribution plant is gross plant in service, less accumulated depreciation, both of which are reported on FERC Form 1.

[7] The capital-related portion of the revenue requirement is return on rate base, depreciation, and income tax.

Figure 2 is based on FERC Form 1 data for a sample of 44 of the largest U.S. utilities by customer count,[8] and shows that across these utilities, net distribution plant in service has increased by about 5% per year on average over the past four years. Figure 2 also shows that, over the same period, total utility revenue has increased by only around 1.5% per year and MWh sales have decreased by 0.5%.[9]

Figure 2: Average Growth per Utility, Total Retail Electric Revenues, MWh Sales and Net Distribution Plant (2013-2017)



Sources and notes: The Brattle Group analysis using S&P Global Market Intelligence, FERC Form 1 data for net distribution plant, sales to ultimate customer, and total retail electric revenue. Average annual growth is calculated as a simple average across sampled utilities.

Sample was selected based on the top 50 largest utilities by customer count according to Form EIA-861, and restricted to utilities with at least 85% of their customers in a single state. BG&E, Duke Energy OH, Entergy Louisiana, Massachusetts Electric Co., PG&E, and Ohio Power were excluded from the sample due to missing or inconsistent data (where annual growth exceeded 25%). A total of 44 utilities were included in the sample.

If net plant is growing at 5% per year, distribution rate base will tend to grow at a similar rate, and thus so will the capital-related component of the revenue requirement. If distribution revenues are not growing at a similar rate and there are no offsetting reductions in expenses, a

8 The sample is the top 50 largest utilities by customer count with at least 85% of their customers in a single state, but BG&E, Duke Energy OH, Entergy Louisiana, Massachusetts Electric Co., PG&E, and Ohio Power were excluded due to missing or inconsistent data.

9 It would be better to compare change in distribution revenue with change in distribution net plant, but we were not able to access information on the breakdown of utility revenue by function.

rate case or other mechanism will be needed in order for the utility to increase its revenues to match the increase in revenue requirements. To illustrate the range of solutions adopted, we sorted the utilities for which data is shown in Figure 2 to find the ones with the highest rate of growth in net distribution plant. We find that some of these utilities have frequent rate cases; others have "formula rates", which automatically update revenue for changes in rate base without a rate case; others have multiyear rate plans with annual revenue adjustments approved prospectively in the rate case; and still others have capital trackers/riders to recover additional revenues outside of the regular rate case cycle. We summarize the key points in Table 1. These utilities either have very frequent rate cases or have some other mechanism to support the rapid rate of investment between rate cases.

Table 1: Utilities with Rapidly Growing Net Distribution Plant

Utility	State	Annual Growth in Net Dist Plant 2014	2015	2016	2017	Avg	Recovery of Distribution Investment
Hawaiian Electric Co	HI	13%	11%	10%	3%	9%	**RAM Mechanism within Multiyear rate plan.** Revenue adjusts annually for actual changes in rate base but overall revenue adjustment is capped at inflation. Rate case every three years. Full details in text.
Southern California Edison Co	CA	10%	11%	8%	7%	9%	**Multiyear Rate Plan.** SCE files a general rate case every three years. During the regulatory period, the test year budget is adjusted for inflation and other factors that may affect costs, such as additional capex projects.
Commonwealth Edison Co	IL	7%	10%	11%	8%	9%	**Formula Rate Plan.** Illinois' Energy Infrastructure Modernization Act (EIMA) allows utilities to file performance-based formula rates. Annual updates allow recovery of grid modernization investments without regulatory lag.
Florida Power & Light Co	FL	5%	8%	9%	13%	9%	**Multiyear Rate Plan.** During the most recent rate case (2016), the Commission approved a four-year rate settlement that will support approximately $3.5 billion of infrastructure investment a year in the period 2017-2020 (a multi-step $811 milllion electric rate increase).
Duke Energy Indiana, LLC	IN	4%	6%	7%	11%	7%	**Capital Tracker.** Transmission Distribution and Storage Improvement Charge (TDSIC) rider with annual true-up recovers costs for electric infrastructure expansion projects.
Consumers Energy Co	MI	6%	6%	7%	9%	7%	**Frequent Rate Cases.** Multiple rate cases filed in recent years: for test years ending in May 2016, August 2017, September 2018, and December 2019.
PPL Electric Utilities Corp	PA	6%	6%	7%	9%	7%	**Capital Tracker.** Distribution System Improvement Charge (DSIC) allows PPL to recover the fixed costs of eligible plant additions, in order to accelerate the replacement of aging infrastructure.
Duke Energy Florida, LLC	FL	3%	7%	8%	9%	7%	**Multiyear Rate Plan.** Most recent settlement (2017) approved a multi-year rate agreement through 2021, which reflects a plan to invest $1.2 billion in a modernized power grid. The settlement also includes a plan to invest $1 billion in solar power and the cancellation of the Levy County nuclear project - the net increase on customer rates is in line with inflation (1% to 3%).
Ameren Illinois Company	IL	4%	8%	6%	6%	6%	**Formula Rate Plan.** Illinois' Energy Infrastructure Modernization Act (EIMA) allows utilities to file performance-based formula rates (with annual updates allowing for recovery of grid modernization investments without regulatory lag).
DTE Electric Company	MI	8%	5%	6%	7%	6%	**Frequent Rate Cases.** Multiple rate cases filed in recent years: for test years ending in June 2016, July 2017, October 2018, and April 2020.
Public Service Co of Oklahoma	OK	6%	6%	6%	6%	6%	**[Proposed] Formula Rate Plan.** In September 2018, PSO submitted a Grid Modernization and Efficiency Plan with proposed annual updating of revenues to reflect changes in rate base (subject to an earnings test).
Entergy Arkansas Inc	AR	7%	4%	9%	5%	6%	**Formula Rate Plan.** A formula rate with annual forward test year filings adjusts for year to year fluctuations in service and system upgrade costs.
MidAmerican Energy Co	IA	7%	5%	5%	6%	6%	**Generation Revenue Offset.** MidAmerican Energy operated under a rate freeze in the state from 1995 to 2012, and was able to offset the increasing costs of supplying energy with revenues earned from selling excess generation output in the wholesale market.
Atlantic City Electric Co	NJ	7%	4%	5%	6%	6%	**Frequent Rate Cases and Capital Tracker.** Multiple rate cases filed in recent years: for test years ending in December 2015, July 2017, and December 2018. Most recent settlement (2017) also approved $79 million in grid modernization investments through the PowerAhead grid resiliency program.
San Diego Gas & Electric Co	CA	3%	7%	5%	8%	6%	**Multiyear Rate Plan.** SDG&E files a general rate case every three years. During the regulatory period, the test year budget is adjusted for inflation and other factors that may affect costs, such as additional capex projects.
Duke Energy Progress - (NC)	NC	1%	5%	8%	8%	6%	**Frequent Rate Cases.** Multiple rate cases filed in recent years: for test years ending in December 2015, December 2016, and October 2017. Following latest partial settlement (2018), increased customer rates by 4.7% (about $194 million additional revenues every year).

Sources and notes: The Brattle Group analysis using net distribution plant from S&P Global Market Intelligence, FERC Form 1 data. Utility mechanisms are from utility tariffs and state regulatory dockets. Table includes Hawaiian Electric Co, plus top fifteen utilities from sample in Figure 2 ranked by average annual growth in net distribution plant.

B. Revenue increases between rate cases

For many utilities, base revenues (or rates)[10] can only increase when there is a new rate case with a new test year, and revenues do not otherwise increase between test years. However, the regulatory framework in some jurisdictions gives rise to automatic increases in revenues between rate cases. The dollar amount of the increase, or sometimes a formulaic mechanism for calculating the increase, is determined in the rate case.

As part of the ratemaking framework in Hawai'i, the Revenue Adjustment Mechanism (the RAM) provides the Companies with annual revenue increases within the three-year regulatory period. However, the RAM Cap means that the increase cannot be more than inflation. These mechanisms are explained in section 0.[11] We are not aware of any examples of other US utilities with revenue increases that are tied to inflation in this way. Inflation-based revenue increases are the standard approach in some overseas jurisdictions, including Great Britain and Australia. In these jurisdictions, revenue increases are equal to inflation[12] plus or minus a fixed offset. The fixed offset is typically determined once every five years, and the offset is designed such that the real-terms revenue increase (or decrease) will correspond to the anticipated change in revenue requirements. When rapid capital investment is anticipated, the fixed offset will result in revenue increases above inflation. Note that, due to the traditional formulation of these revenue frameworks as "RPI minus X" (RPI = change in the retail price index), a negative X factor corresponds to revenues increasing in real terms.

Table 2 reports some examples of distribution utilities in Great Britain and Australia, and shows that there are situations in which large revenue increases above inflation have been authorized. For example, the DPCR5 price control in Great Britain provided the 14 distribution utilities with real terms increases of 5.8% each year for five years from 2010 to 2015.

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10 If there is full decoupling, the utility's revenue will not change until the next rate case; without decoupling, the rates will not change until the next rate case, so the revenues will change in line with billing determinants.

11 Order No. 32735 in PUC of Hawai'i Docket 2013-0141, filed March 31, 2015.

12 Note that in these jurisdictions, utility rate base is indexed to inflation (similar to "trended original cost" for FERC-regulated oil pipelines in the US).

Jurisdiction		Regulatory Period	Average Annual Real-Terms Revenue Increase (%)	Companies with Actual Revenue Growth in Real Terms
New South Wales (AER)	[1]	2009-2014	6.1	3 of 3
	[2]	2015-2019*	-0.2	1 of 3
Victoria (AER)	[3]	2011-2015	2.6	4 of 5
	[4]	2016-2020	1.8	5 of 5
Great Britain (Ofgem)	[5]	DPCR5 (2010-2015)	5.8	13 of 14

Sources: The Brattle Group. Calculations derived from decisions set by AER and Ofgem. For further details, see Workpaper 1, Table A.1.

Notes: The last column indicates the number of companies with actual revenue growth in real terms, eg, in the regulatory period 2009-2014 in NSW, three out of the three distribution businesses achieved real revenue growth.

*The 2015-2019 NSW Determinations have been appealed and remitted to the AER for reconsideration, current listed figures are preliminary.

Table 2 shows a wide range of real revenue changes of between zero and 6% over a five year period. This wide range reflects the fact that the anticipated change in revenue requirement is highly idiosyncratic and depends on the situation of specific utilities, which will change over time (for example, in line with system growth or the need for asset replacement).

In 2013, Ofgem modified the RPI – X framework (used prior to 2015, including DPCR4 and DPCR5) to place a greater emphasis on the use of output measures and revenue drivers. The current framework is known as "RIIO" (Revenue = Incentives + Innovation + Outputs). Under RIIO a greater proportion of total revenue is updated or adjusted during the price control period, therefore Ofgem did not report an explicit X factor for the regulatory period RIIO-ED1 (2015-2023).[13] Revenues for the distribution companies during RIIO-ED1 to date have been broadly flat or slightly declining.[14]

While US utilities do not typically have revenue increases linked to inflation, the regulatory framework in many US jurisdictions permits multiyear rate plans with revenue adjustments between rate cases. Later in this report we discuss two examples: Consolidated Edison in New York and Pacific Gas and Electric in California.[15] These utilities have three-year regulatory periods[16] with annual revenue adjustments that are determined at the outset (as part of the rate case decision). Expected changes in revenue requirements during the regulatory period, including due to expected investment and growth in rate base, are an input to this determination. Both PG&E and Consolidated Edison have recently had revenue increases for the distribution function slightly above forecast inflation, as shown in Table 3. The regulatory framework for PG&E and Consolidated Edison is similar in some respects to the RPI – X framework in Great Britain, though the revenue increases in Great Britain are specified in real terms whereas those in California and New York are usually specified in nominal terms.

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13 We use the term "regulatory period" to mean the period between general rate cases (five years for the utilities in Table 2).

14 Ofgem, "RIIO-ED1 Annual Report 2016-17," 19 December 2017, p. 13.

15 See section IV.B.

16 Similar to the current framework in Hawai'i, these utilities file rate cases every three years.

Table 3: Average real revenue increases for the distribution function for PG&E and Consolidated Edison

Company	Regulatory Period	Average Real Revenue Increase (%)
Pacific Gas and Electric (CPUC)	2017-2019	0.8
Consolidated Edison (NYPSC)	2017-2019	0.3

Sources: The Brattle Group. Revenue requirements from decisions set by CPUC and NYPSC.

Notes: Average real revenue increase is calculated as the simple average of the revenue requirement percent increases during the indicated regulatory period. For further details, see Workpaper 1, Table A.4.

In California, the three major utilities have had overall authorized revenues increasing faster than inflation for several years. Across both gas and electric utility functions (but excluding the costs of fuel and purchased power), for the period 2007 to 2018 authorized revenues have increased on average by 2.5% per year above the rate of GDPPI.[17]

C. Examples of capital trackers or riders

Many utilities in North America have adjustment mechanisms to increase rates between rate cases. Table 1 gave some examples. Capital trackers are increasingly widespread: for example, a recent survey shows that just over half of the major gas and electric utilities in the US have capital trackers for "generic infrastructure".[18]

In some jurisdictions, the use of these mechanisms has been encouraged by statewide legislation. For example, an amendment to the Pennsylvania Public Utility Code in 2012 authorized utilities to request a Distribution System Improvement Charge (DSIC), a surcharge to customer bills that recovers reasonable and prudently incurred costs for the repair, improvement, and replacement of its distribution system.[19] Under this amendment, PECO Energy received approval in 2015 to implement a DSIC mechanism recovering eligible costs from its Long-Term Infrastructure Improvement Plan, which forecast $324.3 million in

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17 This average excludes test years 2012 and 2016 for SDG&E and test years 2009, 2012, and 2015 for SCE, because previously authorized revenue requirements were not reported in a consistent fashion. It also excludes 2018 for SCE because the 2018 GRC has not yet been decided, and 2007 for SDG&E. The average of 2.5% per year is the simple average of the 29 annual real-terms increases for each utility in each year.

18 S&P Global Market Intelligence, "RRA Regulatory Focus: Adjustment Clauses", September 28, 2018. The survey includes 158 electric utilities, of which 65 have trackers for "generic infrastructure".

19 Act 11 of 2012 amending Title 66 of the PSC, February 14, 2012, accessed October 9, 2018, http://www.legis.state.pa.us/WU01/LI/LI/US/HTM/2012/0/0011..HTM.

additional spending between 2016 and 2020 for storm hardening and resiliency measures, underground cable replacement, substation retirements, and facility relocations.[20]

Texas Administrative Code similarly allows utilities to request a Distribution Cost Recovery Factor (DCRF), a rate adjustment mechanism for timely recovery of distribution infrastructure costs between rate cases.[21] CenterPoint Energy Houston Electric was approved a DCRF in 2015 allowing it to recover the change in net distribution rate base since its last rate case in 2009.[22] Since 2015, CenterPoint has filed annual updates to its DCRF to account for changes in its distribution invested capital.[23]

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20 Opinion and Order in Pennsylvania PUC Docket No. P-2015-2471423, filed October 22, 2015.

21 Texas Administrative Code §25.243, October 13, 2011, accessed October 9, 2018, https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.243/25.243ei.aspx.

22 Order in Texas PUC Docket No. 44572, filed August 5, 2015.

23 Texas PUC Dockets No. 45757, 47032, 48226.

III. The current regulatory framework in Hawai'i

A. Overview of key features

The regulatory framework in Hawai'i includes general rate cases on a three-year cycle with a prospective test year, and automatic recovery of fuel costs through a separate mechanism.[24] In addition, key features which are relevant to a discussion of investment incentives are the Revenue Balancing Account (the RBA), the Revenue Adjustment Mechanism (RAM), the RAM Cap, and the Major Projects Interim Recovery (MPIR) mechanism.

The regular triennial cycle of rate cases means that, following review and approval through the rate case process, the Companies' reasonable costs to provide utility service are reflected in authorized revenues. Changes in costs between rate cases can give rise to a change in base revenues at the next rate case.

The RBA is a "decoupling mechanism". The Companies' rates automatically adjust as needed to collect authorized base revenues if billing determinants change over time.

The RAM adjusts revenues between rate cases as follows.[25]

- **The O&M RAM**: revenue increases[26] each year based on contractual bargaining unit labor rate changes (less an assumed productivity factor) and inflation of non-labor expenses. Importantly, the revenue increase between rate cases does not depend on how actual O&M expenditures change between rate cases.
- **The depreciation RAM**: revenue increases each year to cover changes in the depreciation expense. The depreciation RAM is updated in line with actual plant balances, so the depreciation RAM increase captures changes in actual depreciation expense between rate cases. In particular, if gross plant increases (due to rapid capital additions), the depreciation RAM provides additional revenue each year corresponding to the additional depreciation expense associated with the new additions.
- **The rate base RAM**: revenue increases each year to provide return on additional rate base corresponding to plant additions between test years.[27] The revenue increase corresponds to a return on the historical average amount of baseline plant

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24 We understand that the mechanism for recovering fuel costs has recently been modified so that it recovers less than 100% of the changes in fuel costs.

25 Final Decision and Order in PUC of Hawai'i Docket 2008-0274, filed August 31, 2010, pp. 47-76.

26 RAM revenues exclude recovery of fuel and purchased power expenses and costs that are subject to recovery through separate surcharge or rate tracking mechanisms.

27 The rate base RAM does not adjust for changes in all components of rate base: beginning of year net plant in service, accumulated deferred income taxes (ADIT) and contributions in aid of construction (CIAC) are updated to actuals, but the other components of the rate base are not adjusted.

additions in each year and projected major project additions, plus a return on actual rate base from the end of the prior year. Thus actual baseline plant additions do not give rise to additional return during the year in which they are added to rate base, but do give rise to additional return in subsequent years.

In addition, the RAM Cap[28] may limit the revenue adjustment: total RAM adjustments cannot result in a revenue increase greater than inflation times base (target) revenues. In the discussion below, we refer to situations when revenue increases are limited by the RAM Cap as situations when the RAM Cap is binding.

In addition to the mechanisms above, the MPIR can provide additional revenue for specific investments that have been approved by the Commission. MPIR revenues are not counted towards the RAM Cap.

Together, the mechanisms described above have the following features relevant for a discussion of investment incentives.

- A change in O&M expense from one year to the next between rate cases cannot result in a change in revenue until the next test year. Therefore, an increase in O&M expense from one year to the next will result in a reduction in utility profits, other things equal (and, correspondingly, a reduction in O&M expense will result in a profits increase). A "one-off" O&M expense (an expense that is incurred in one year but which does not recur in subsequent years) does not give rise to any additional revenue;[29] a "recurring" O&M expense which gives rise to a commitment to similar spending in future years (such as salary expense or a multi-year services contract) can give rise to additional revenue in the next test year, which will be one, two or three years away depending on when in the rate case cycle the new recurring expense starts. This is the case whether or not the RAM Cap is binding.
- When the RAM Cap is not binding, capital expenditure gives rise to additional revenue in the year following the year of the corresponding addition to rate base.[30] The first (part) year of return associated with the addition to rate base is not recovered. Return (and depreciation) in years following the addition to rate base are recovered in full. Under usual regulatory accounting conventions in Hawai'i, depreciation expense is in any case not collected until the start of the year following an addition to rate base.
- When the RAM Cap is binding, capital expenditure does not give rise to any additional revenue until the next test year, which will be one, two or three years away depending on when in the rate case cycle the corresponding addition to rate base is made.

28 Order No. 32735 in PUC of Hawai'i Docket 2013-0141, filed March 31, 2015, pp. 80-91.

29 We understand that some expenses that occur regularly but not every year (such as periodic maintenance) may be normalized for inclusion in test year expenses.

30 Major project additions can give rise to return in the year that the project goes into service on a forecast basis (provided that, at the time of the annual filing in March, the project is expected to go into service by the end of September).

– The MPIR can provide additional revenue for investments approved by the Commission. The guidelines for the MPIR state that a wide range of projects may be funded through the MPIR, but that this mechanism cannot be used for "routine replacements of existing equipment or systems with like kind assets, relocations of existing facilities, restorations of existing facilities, or other kinds of business-as-usual investments."[31] MPIR revenues are additional to the RAM (and RAM Cap).

B. Implications for financial incentives

The nature of the regulatory framework, and in particular how authorized revenues are derived, is an important influence on the behavior of utilities. It is of course not the only influence: utilities are required to provide a safe and reliable service; they are subject to many safety, environmental and other obligations; and they are directly influenced by investors, customers and other stakeholders. Any discussion of financial incentives provided by the regulatory framework is therefore not a complete picture of the factors which influence utility behavior. Nonetheless, when changes to the regulatory framework are contemplated, or where the utility has a choice between two actions that will give rise to different financial outcomes under the existing framework, it can be instructive to examine the financial incentives produced by the regulatory framework. In particular, we consider below the financial consequences for the utility of additional expenditure between rate cases, and specifically how those financial consequences differ according to whether the additional expenditure is an operating expense or a capital expenditure.

For the purposes of this discussion, we consider three possible options facing the utility: continue with previously planned expenditures (ie, the baseline); undertake an additional project involving capex; or undertake an additional project involving opex. We define the "financial burden" on the utility as the cost of the project, less additional revenues (if any) that will be collected as a result of having undertaken the project. Due to the way in which the regulatory framework operates in Hawai'i, the financial burden will vary according to whether the project is opex or capex (and according to parameters such as asset life and the period over which O&M commitments are made, as we explain below). Additional cost, additional revenues, and hence financial burden are all zero by definition under the baseline option where only previously planned expenditures are undertaken.

In the examples below we express the financial burden in percentage terms, representing the proportion of the project's cost that will be paid by the utility and not recovered from customers through future revenue increases. In these examples we take into account only the regular cycle of rate cases and the operation of the RAM (and the RAM Cap), and we do not consider the risk of disallowance.[32] Similarly, if a previously planned project is not undertaken (or a project is completed at reduced cost), the utility will benefit from the reduced cost but will also

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[31] Order No. 34514 in PUC of Hawai'i Docket 2013-0141, filed April 27, 2017, PDF p. 130, paragraph 3a.

[32] Other assumptions include: return on rate base of 7.5%; discount rate of 7.5%; 30 year asset life; all cash flows occur at the end of the year; and we do not take taxes into account.

collect lower revenues in the future. In percentage terms, the "financial benefit" to the utility will be the same as the financial burden we calculate below for an additional project or a cost over-run.

When the RAM cap is not binding (the RAM increase is below inflation), additional capex results in additional revenue from the year following the addition to rate base. Therefore the financial burden on the utility is relatively low: additional revenues are equal in net present value terms to the cost of the investment, except for the return on the expenditure in the year when the addition is made. For example, assuming a return on rate base of 7.5%, the financial burden on the utility is in the range 0%–7.5%, depending on when during the year the addition is made.[33]

For O&M, whether or not the RAM Cap is binding, additional unexpected O&M expenditure does not result in additional revenue until the next rate case. Supposing that the O&M is a recurring commitment (such as a salaried employee), the financial burden on the utility is in the range 7%–20%, depending on whether the expenditure starts at the end of the three-year regulatory period or at the beginning. These figures represent the net present value of the utility's share of the expenditure as a percentage of the total net present value of the overall project. If the O&M does not recur permanently but is (say) a five-year commitment, the financial burden is greater in percentage terms. The corresponding figures are shown in Table 4 below, together with an intermediate case of a 30-year commitment.

Table 4: Utility financial burden of opex projects

Expenditure starting in year	1	2	3
Permanently recurring opex	20%	13%	7%
Opex for 30 years	22%	15%	8%
Opex for 5 years	64%	44%	23%
Opex for 1 year	100%	100%	100%

Sources: The Brattle Group cash flows analysis. See further details in Workpaper 1, Table A.5 (switch allows users to vary expenditure start year).

Notes: Assuming an asset life of 30 years and a discount rate of 7.5%.

Table 4 also shows that a "one-off" O&M expenditure is fully borne by the utility—the financial burden is 100%.

33 We understand that conventional regulatory accounting in Hawai'i is such that depreciation starts at the beginning of the year following an addition to rate base, therefore the financial burden on the utility does not include any depreciation. If the expenditure is made at the beginning of the year, about 7.5% of return is "missing", whereas if the expenditure is made towards the end of the year, a smaller amount of return is missing. For the purposes of this analysis we do not take into account any differences of timing between capital expenditures and capital additions.

Table 4 and Table 5 indicate that for two projects that cost the same but where one is capex and one is opex, the financial burden on the utility is always greater for O&M unless the expenditure is right at the start of the third year of the regulatory period, when the burdens may be about equal for capex and permanently recurring opex. If the opex project has a defined lifespan, the shorter the commitment period, the greater is the financial burden on the utility (assuming that all the project options have equal total cost).

The picture is more nuanced if the RAM Cap is binding.[34] If the RAM Cap is binding, neither capex nor opex results in additional revenue until the next test year. The picture for opex is therefore unchanged from the discussion above, as is the picture for capex in the third year of the regulatory period. However, capex in years one and two results in greater financial burden for the utility. We estimate a financial burden of 10%-16% for capex in year two and 19%-25% in year one, as shown in Table 5.

Table 5: Utility financial burden of capex projects (when the RAM Cap is binding)

Expenditure starting in year	1	2	3
Capex at end of year	19%	10%	0%
Capex at start of year	25%	16%	7%

Sources: The Brattle Group cash flows analysis. See further details in Workpaper 1, Table A.5 (switch allows users to vary expenditure start year).

Notes: Assuming an asset life of 30 years and a discount rate of 7.5%.

Note that in Table 5 there is a small "step" in the size of the financial burden between a project towards the end of one year and the start of the next. This is due to an extra year's worth of depreciation which becomes the responsibility of the utility if the in-service date moves from the start of one year to the end of the prior year.

When the RAM Cap is binding, the financial burden of a capex project and an equally costly opex project is similar, if the opex represents a commitment that will last for a long time. This makes sense: for a capex project with a 30 year life and an opex project with a 30 year commitment (ie, expenses recurring annually for 30 years), the financial burden will be similar because in both cases the cost of the project is spread out over 30 years. The financial burden will not be exactly the same because we have assumed equal annual payments for opex, whereas straight line depreciation implies a "front end loading" to cost recovery for a capex project. However, if the opex commitment is for a shorter period than the lifetime of the capex project, the financial burden of the opex project is increasingly greater than that of the capex project. In the limit, a one-off opex project is entirely the responsibility of the utility (whereas a capex project of equal total cost will give rise to revenues over most of the asset's lifetime).

[34] The RAM Cap would be binding if the already-anticipated expenditures caused the RAM calculations to result in a revenue adjustment greater than inflation.

For all of the calculations above, the total cost of all the options is the same in net present value terms.

Based on the discussion above, we conclude that when the RAM Cap is not binding, the financial burden on the utility of an opex project is greater than of a corresponding capex project. When the RAM Cap is binding, the financial burden is similar if the opex project is a long-lasting commitment, but the burden of the opex project is greater if the opex commitment is shorter than the lifetime of the capex project.

In the discussion above, we have analyzed the current regulatory framework in Hawai‘i. In order to illustrate the relevance of the period of time between rate cases on financial burden and differences in the treatment of capex and opex projects, we have extended the calculations above to examine a hypothetical modification where the current framework is adjusted by extending the period between rate cases from three to five years. Table 6 shows the financial burden on the utility of opex projects where base revenues are not adjusted for actual opex for a period of five years. The financial burden of opex starting in year one of the longer regulatory period would be greater (increasing from 20% to 30% for permanently recurring opex).

Table 6: Utility financial burden of opex projects (5-year regulatory period)

Expenditure starting in year	1	2	3	4	5
Permanently recurring opex	30%	25%	20%	13%	7%
Opex for 30 years	34%	28%	22%	15%	8%
Opex for 5 years	100%	83%	64%	44%	23%
Opex for 1 year	100%	100%	100%	100%	100%

Sources: The Brattle Group cash flows analysis. See further details in Workpaper 1, Table A.6 (switch allows users to vary expenditure start year).

Similarly, Table 7 shows that capex projects at the start of a five-year regulatory period would give rise to a financial burden of 35%-40% when the RAM Cap is binding.

Table 7: Utility financial burden of capex projects (5-year regulatory period)

Expenditure starting in year	1	2	3	4	5
Capex at end of year	35%	28%	19%	10%	0%
Capex at start of year	40%	33%	25%	16%	7%

Sources: The Brattle Group cash flows analysis. See further details in Workpaper 1, Table A.6 (switch allows users to vary expenditure start year).

Notes: Assuming an asset life of 30 years and a discount rate of 7.5%.

Extending the regulatory period to five years increases the existing difference between opex and capex projects when the RAM Cap is not binding.

The discussion above explained how, under the existing regulatory framework in Hawai‘i, the Companies' spending influences future revenues, and hence cost recovery. We showed that a significant proportion of costs is borne by the Companies. The proportion of the costs borne by the Companies is increased by the following factors:

- the expenditure is towards the start of the regulatory period;
- the expenditure is opex rather than capex;
- opex is one-off rather than recurring; and
- the RAM Cap is binding (this has an impact on capex projects but not opex).

The analysis above was expressed in terms of the financial burden of additional opex and capex, and the proportion of the total cost borne by the Companies. The exact same analysis applies to *reductions* in expenditures: where expenditures are reduced, a proportion of the benefits accrues to the Companies. The proportion of the total savings benefitting the Companies is the same as the financial burdens calculated above.

Sharing the costs of additional expenditure and the benefits of reducing expenditure creates a direct financial incentive for the Companies to control costs. The magnitude of this incentive is indicated by the sharing ratios calculated above.

IV. Perceived bias in favor of traditional utility investment

A. The "capex bias"

Technological progress and innovation are changing the nature of utility decision-making for infrastructure related-expenditures. Network service providers now have a growing range of options, some of which require investment and some permit investment to be avoided through the purchase of services. For example, advanced metering infrastructure may allow some substitution of communications infrastructure for manual meter reading. In other contexts, the substitution may go the other way: purchasing demand response services from customers (or from an aggregator) could substitute for investment in substation capacity. As a result, the nature of cost-efficient network operations may be changing, so regulators are increasingly interested in the factors that influence utility decision-making (especially in relation to options that no longer completely rely on traditional pole-and-wire capital expenditure). Regulators are particularly interested in the incentives resulting from the operation of the regulatory framework itself, in order to understand whether the regulatory framework itself should be modified to support uptake of new technologies.

Regulators in several jurisdictions have expressed concern with the optimal trade-off between capital expenditure ("capex") and operational expenditure ("opex"). This concern would arise particularly where there is a choice between investing in traditional assets (capex) versus contracting for a new demand response service (opex).

In almost all jurisdictions,[35] a dollar of capex and a dollar of opex do not result in the same pattern of cash flows and revenue recovery, even though in economic terms both result in an overall cost of one dollar. We illustrated these direct financial effects under the regulatory framework in Hawai'i in section 0 above. Furthermore, if a regulator were to set the authorized cost of capital higher than the actual cost of capital (the rate of return anticipated by investors when they provide funds), investment opportunities would have positive net present value for the utility[36], but this would not be true for opex opportunities.

In addition to these direct financial effects, regulators have other concerns about the risk of a capex bias, generally framed around four areas. First regulators have identified that utilities and investors seem to express a preference for stable rate base growth. In connection with a recent

35 Arguably an exception is the "totex" framework applied in Great Britain, where to first approximation the pattern of utility cash flows is the same for a dollar of opex and a dollar of capex. Even in Great Britain there may be some differences since utility income tax does differentiate between capex and opex and income tax is not a pass through.

36 If the regulator were to specify an authorized rate of return above the cost of capital, the future return and depreciation of a capital addition, discounted at the actual cost of capital, would have positive net present value. It would be as if the company were able to borrow money at (say) 5% and lend it on to customers at 6%: in such a situation, the company would benefit from lending as much as possible.

review of this topic in Australia, one of the regulatory authorities commissioned a survey of analyst opinion. The survey noted that capex biases were formed through favorable views of rate base growth (by analysts and investors), regardless of the difference between the regulated return and the actual cost of capital:[37] meaning pursuing rate base growth was a desirable outcome for investment analysts under all circumstances. Ofwat (the regulator of the water sector in England and Wales) also found that both management and investors exhibit preferences for rate base growth due to its use as a proxy for company growth.[38] This preference drives a self-reinforcing pathway: if managers believe that investors desire a growing rate base, they will design (internal) management incentives aligned with rate base growth. The AEMC, in agreement with Ofwat,[39] believes that an accepted perception of a capex bias is self-fulfilling, and "the perception is likely to have a large impact on [utility] preference for capex over opex."[40]

Second, regulators have noted that opex solutions are exposed to continuous scrutiny whereas a decision to employ a capex solution is scrutinized only once.[41] Once a project has been approved to enter rate base, it will not be re-examined, whereas the expense associated with a project can in principle be re-examined at every test year.

Third, regulators are concerned that opex solutions may give rise to more performance uncertainty from a utility perspective, as the utility may feel that it has less direct control over the underlying assets or processes when it is procuring services from third parties.[42] For example, the utility may be less willing to rely on a third-party demand response aggregator than on an expanded substation.

Fourth, regulators note that opex alternatives may be disadvantaged relative to capex options because risks from cost uncertainties in opex solutions are not compensated with a risk-based return. Existing frameworks typically do not explicitly provide for a margin to be earned on opex to compensate for the uncertainty/risk (of cost over-runs, or performance failures).[43]

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37 CEPA, "Expenditure incentives faced by network service providers, Final Report," 25 May 2018.

38 Ofwat, "Capex bias in the water and sewerage sectors in England and Wales – substance, perception or myth? A discussion paper," May 2011.

39 "A couple of the companies suggested that the perception that a bias exists is becoming 'self-fulfilling' in the sectors. Indeed, one company said that, 'to an extent, it doesn't matter how theoretically balanced the regime is, it matters how companies perceive it to be.'" See Ofwat, "Capex bias in the water and sewerage sectors in England and Wales – substance, perception or myth? A discussion paper," May 2011.

40 AEMC, "Economic regulatory framework review – promoting efficient investment in the grid of the future," 26 July 2018, p. 35.

41 AEMC, "Economic regulatory framework review – promoting efficient investment in the grid of the future," 26 July 2018, p. 32.

42 AEMC, "Economic regulatory framework review – promoting efficient investment in the grid of the future," 26 July 2018, p. 32.

43 Ofwat, "Capex bias in the water and sewerage sectors in England and Wales – substance, perception or myth? A discussion paper," May 2011.

Despite the above theoretical concerns, there is little empirical evidence for a bias in favor of capex.[44] The AEMC's 2018 Economic Regulatory Framework Review found inconclusive evidence for a capex bias in historical expenditure data for Australian network businesses. The AEMC examined indicators such as capex:opex ratios, actual expenditure versus regulatory allowance, and the consideration given to non-network solutions. The inconclusive findings were apparently caused by the difficulty in untangling the effects of changes in the operating environment and regulatory framework from other non-financial incentives that would result in a capex bias. However, the AEMC did observe a misalignment between capex and opex incentives,[45] and has implemented modifications to the regulatory framework to support alternatives to traditional utility investment (described below).

Similarly, while neither Ofgem nor Ofwat were able to put forward irrefutable evidence of a capex bias, both nonetheless recognized it as an important issue to address and have implemented totex as part of their regulatory framework.[46]

We describe regulatory responses to the risk of a capex bias in the sections below.

B. Regulatory responses

We describe below three modifications to the regulatory framework which can be used to address the risk of a capex bias: an efficiency carryover mechanism; a "totex" (total expenditure) framework; and tailored ratemaking treatment specifically for service-based projects which avoid or defer the need for traditional utility investments (non-wires alternatives or NWA). We describe efficiency carryover mechanisms in Australia and New Zealand; totex in Great Britain; and ratemaking treatment for NWA in New York, California, and Australia. The NWA arrangements in New York, California and Australia are a type of targeted Performance Incentive Mechanism (PIM).[47]

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44 This mirrors the well-known "Averch–Johnson effect", or "gold-plating", which is often discussed in theoretical terms but is not supported empirically. See, for example, "Regulation and Deregulation after 25 Years: Lessons Learned for Research in Industrial Organization," Review of Industrial Organization (2005), Volume 26, pp. 169-193 by Paul L. Joskow, p. 188.

45 AEMC, "Economic regulatory framework review – promoting efficient investment in the grid of the future," 26 July 2018.

46 CEPA, "Expenditure Incentives Faced by Network Service Providers," 25 May 2018.

47 Some of the information in this report is based on, and updated from, an earlier Brattle report on incentive regulation and innovation (Toby Brown, et al. (The Brattle Group), "Incentive Mechanisms in Regulation of Electricity Distribution: Innovation and Evolving Business Models," prepared for the Energy Networks Association of New Zealand, October 2018).

1. Efficiency carryover mechanism in Australia

As we explained above with reference to the regulatory framework in Hawai‘i, the strength of incentives to control costs is stronger at the start of the regulatory period than at the end, and is different for capex and opex projects. In general terms, an "efficiency carryover mechanism" (ECM) is designed to adjust the strength of the incentive and allow the incentive to be sustained until the end of the regulatory period. Without an ECM the desirable incentive properties of a multi-year regulatory period will be lost towards the end of the period as the cost-based reset approaches. That is, the savings from efficiency gains are limited to the years remaining in the regulatory period. An ECM can be designed to address this by "carrying over" the results from one regulatory period into the next, providing an additional incentive to control costs. Also, since the ECM adjusts the strength of the incentive, the ECM can be used to adjust the strength of incentives for opex projects relative to capex projects, and hence address the risk of capex bias.

Electricity distribution businesses on the east and south coast of Australia[48] are regulated by the Australian Energy Regulator (AER) on a revenue cap basis.[49] Since January 2008, electricity distribution businesses have been required to submit revenue requirement proposals to the AER on a five-year cycle.[50] The regulatory framework includes a type of ECM that is designed to do two things: first, it addresses the drop-off in the strength of the incentive to control costs that otherwise occurs as the end of the regulatory period approaches; and second, the ECM attempts to "equalize" financial incentives between opex and capex, so as to remove any direct cash-flow incentive biasing in favor of capex. The ECM is in two parts: the Efficiency Benefit Sharing Scheme (EBSS) for opex; and the Capital Expenditure Sharing Scheme (CESS) for capex. These schemes aim to provide a continuous financial incentive for utilities to pursue opex and capex improvements (at any point during the regulatory period) and share savings between the networks and customers. As we explained above, in a multi-year regulatory period additional capex and additional opex results in a financial burden on the utility (i.e., the utility recovers less than 100% of the cost), and the ratio of sharing between the utility and customers is different for opex and capex, and varies according to when the expenditure is made. The EBSS and CESS correct this so that the financial burden (sharing ratio) is 30%.[51] The ECM, by

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48 These utilities are in New South Wales, the Australian Capital Territory, Victoria, South Australia, Queensland, and Tasmania.

49 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.

50 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.

51 The sharing ratio depends on assumptions such as the commitment period for opex, asset life for capex, and discount rate. The assumptions behind the AER's calculation of a 30% sharing ratio are

allowing utilities to receive the benefit for a saving for a specified carryover period (regardless of when the saving was made), smooths out incentives for finding opex and capex savings throughout and across regulatory periods.

The sharing ratio of 30% means that the utility receives 30% of the net present value of any savings (and bears 30% of the net present value of cost over-runs), with the remaining 70% accruing to customers in the form of reduced revenues (increased revenues for an over-run). The larger is the sharing factor, the stronger is the financial incentive on the utility to control costs, but the smaller is the benefit for customers of successful cost control. The figure of 30% is approximately the sharing ratio for a reduction in permanently recurring opex in the first year of a five year regulatory period.

The opex efficiency carryover mechanism, EBSS, works as follows: [52]

- The regulatory regime derives the allowed revenue, and annual revenue adjustments, based on a forecast of opex for each year of the regulatory period which has been reviewed and approved by the regulator. If actual opex is different from the forecast, the difference is retained by the utility.
- The ECM operates by providing the utility with a carryover amount in each year that represents the sum of incremental opex gains (or losses) for the prior five years.
- The carryover amounts are additional to the authorized revenues, and the five year "look back" reaches across the rate reset at the start of the period, so that gains or losses in the prior regulatory period are carried forward.

Under this approach, any recurring savings (or losses) relative to the forecast opex allowance is shared approximately 30:70 between utilities and customers.[53]

We include the AER's worked example below (Table 8) of a hypothetical $5 million savings starting in year four of a five-year regulatory period.[54] The example assumes that the utility has an opex allowance of $100 million for each year of the first regulatory period, and that the utility is able to reduce its expenditure by $5 million each year (ie, a "recurring" reduction) starting in the penultimate regulatory year of the first regulatory period.

Under the EBSS ECM, the utility retains the $10 million savings ($5 million in years four and five), plus $5 million annually in carryover payments for an additional four years in the next regulatory period. In total, the efficiency saving of $5m benefits the utility in the year the saving is made, plus five years following.

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explained below. For the project parameters chosen by the AER, the sharing ratio for opex and capex projects is equal (and independent of timing) at 30%.

52 This is also called the revealed cost base-step-trend forecasting method. See AER, "Efficiency Benefit Sharing Scheme, Explanatory Statement", November 2013, pp. 5-6.

53 This is estimated by: (carryover period x savings) / (savings / discount rate) = 30% assuming carryover period of five years and a discount rate of 6%.

54 AER, "Efficiency Benefit Sharing Scheme, Explanatory Statement", November 2013, p. 26.

The total benefits of a $5 million saving in perpetuity is approximately $88.3 million (in NPV terms, as of the end of year four, assuming a discount rate of 6%). The benefit to the utility is $5 million per year for six years, or a total net present value of $26.1 million (sum of row [K] below). The utility's share of the savings is thus 30% of the total.

Table 8: Worked example of $5 million opex savings starting in year four

		Regulatory period 1					Regulatory period 2					NPV
Year		1	2	3	4	5	6	7	8	9	10	
Discount rate	[1] : 6%											
Discount factor (end of year)	[2] : 1 / (1 + [1]) ^ (t-4)	1.19	1.12	1.06	1.00	0.94	0.89	0.84	0.79	0.75	0.70	
Forecast opex	[3] : Assumed	100	100	100	100	100	95	95	95	95	95	
Actual opex	[4] : See notes	100	100	100	95	95	95	95	95	95	95	
Opex savings	[5] : Saving lasts forever	0	0	0	5	5	5	5	5	5	5	88.3
Opex savings retained by utility	[6] : Saving lasts forever	0	0	0	5	5	0	0	0	0	0	9.7
Efficiency carryover mechanism	[7] : See notes	0	0	0	0	0	5	5	5	5	0	16.3
Utility share of opex savings	[8] : See notes	0	0	0	5	5	5	5	5	5	0	26.1
Utility share of opex savings	[9] : NPV [8] / [5]											30%

Sources: Rules in Efficiency Benefit Sharing Scheme (2013); example from EBSS Explanatory Statement, p. 26.

Notes: Assumes the penultimate year in a regulatory period (RP) to be the base year. NPV calculated as of the end of year four.

[4]: Actual opex in the final year of a RP is estimated to be the forecast opex in that year minus the saving in the previous year.

[7]: Realized carryover is the sum of all incremental savings from the past five years.

[8]: [6] + [7].

The capex carryover mechanism, CESS, works similarly, as follows:[55]

- The regulatory regime derives the allowed revenue, and annual revenue adjustments, based on a forecast of capex for each year of the regulatory period which has been reviewed and approved by the regulator. If actual capex is different from the forecast, the consequential difference in revenue requirement terms is retained by the utility.
- The AER calculates the total savings (or overspend) for the current regulatory period in net present value (NPV) terms. A sharing ratio of 30 per cent is applied to calculate the utility's share.
- The benefit already achieved by the utility during the regulatory period is calculated, then subtracted from the utility's share of total savings (or overspend).[56] The benefit achieved during the regulatory period only corresponds to return on capital—there is no corresponding depreciation component because, at the start of

[55] AER, "Capital Expenditure Incentive Guideline for Electricity Network Service Providers, Explanatory Statement", November 2013, p. 21.

[56] AER, "Capital Expenditure Incentive Guideline for Electricity Network Service Providers, Explanatory Statement", November 2013, p. 8.

the next regulatory period, the opening rate base is calculated using only forecast depreciation (rather than actual depreciation) from the prior regulatory period.[57]

– The CESS payments are added to the authorized revenues.

The savings split is set at: 30% for the utility and 70% for customers. This approximately matches the reward a utility receives for reductions in opex (or penalty for increases in opex). The AER expects that this will encourage "more efficient substitution between capex and opex".[58]

We include the AER's worked example below of hypothetical capex underspends (Table 9).[59] The example assumes a capex allowance for each year of the regulatory period, and that the utility is able to reduce its capex below this amount in some years, and spends more than the allowance in other years. In total, these differences sum to $37.03 million (NPV as of the end of year five, assuming a discount rate of 6%).[60]

The capex savings, however, resulted in financing benefits accruing to the utility. This amounts to a total of $7.03 million (in NPV terms). In order to equalize capex and opex incentives, the utility's share of the capex savings should be 30% or $11.1 million. Since the utility has already benefitted from a financing saving of $7.03 million, the CESS ECM needs to provide the utility with additional revenue of $4.08 million in the following regulatory period.

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57 In effect, this means that the opening rate base takes into account differences between actual additions and forecast additions from the prior period, but it does not take into account differences between actual and forecast depreciation. Thus, if actual additions are higher than forecast during the period, at the end of the period rate base will be updated to reflect the undepreciated extra additions, meaning that future authorized revenues will reflect the return of the full (undepreciated) amount of the extra additions. If actual depreciation were used to update the rate base instead, the sharing ratio (before the operation of the CESS) would see the utility bear a greater proportion of overspends because future authorized revenues would include only return of the depreciated extra additions. However, in any event the CESS can be used to "correct" the sharing ratio.

58 This is from using forecast depreciation to roll forward the RAB. See AER, "Capital Expenditure Incentive Guideline for Electricity Network Service Providers, Explanatory Statement", November 2013, p. 9.

59 AER, "Capital Expenditure Incentive Guideline for Electricity Network Service Providers, Explanatory Statement", November 2013, pp. 60-61.

60 Capex is assumed to occur mid-year. The discount rate is based on a WACC of 6%.

Table 9: Worked example of capex savings

Year		1	2	3	4	5	
Discount rate	[1] : 6%						
Discount factor (mid-year)	[2] : 1 / (1 + [1]) ^ (t-5.5)	1.30	1.23	1.16	1.09	1.03	
Discount factor (end of year)	[3] : 1 / (1 + [1]) ^ (t-5)	1.26	1.19	1.12	1.06	1.00	
Forecast capex	[4] : Assumed	300	330	270	300	330	
Actual capex	[5] : Assumed	280	310	300	290	320	
Capex savings	[6] : [4] - [5]	20	20	-30	10	10	
Total financing benefit	[7] : Sum of [8] to [12]	0.59	1.79	1.51	0.90	1.50	
Year 1 benefit	[8] : See notes	0.59	1.20	1.20	1.20	1.20	
Year 2 benefit	[9] : See notes		0.59	1.20	1.20	1.20	
Year 3 benefit	[10] : See notes			-0.89	-1.80	-1.80	
Year 4 benefit	[11] : See notes				0.30	0.60	
Year 5 benefit	[12] : See notes					0.30	
NPV capex savings	[13] : [6] x [2]	26.00	24.52	-34.70	10.91	10.30	
NPV financing benefit	[14] : [7] x [3]	0.75	2.13	1.70	0.95	1.50	
Total NPV capex savings	[15] : Sum of [13]						37.03
Utility share of capex savings	[16] : Selected by the AER to match opex sharing ratio						30%
Total NPV financing benefit	[17] : Sum of [14]						7.03
CESS payment	[18] : [16] x [15] - [17]						4.08

Sources: Rules in Capital Expenditure Sharing Scheme (2013); example from CESS Explanatory Statement, pp. 60-61.

Notes: Assumes forecast depreciation. Capex is assumed to occur mid-year. Financing benefit is assumed to occur at the end of the year.

[8] - [12]: [6] of that year x [1], where the first year is based on a half-year discount rate equivalent.

The design of the EBSS and CESS ECM is such that the sharing factor is the same for capex and opex. However, it is important to note that the sharing factors calculated above depend on assumptions, including the asset life and the period over which opex commitments recur. In particular, the calculated sharing ratio for the EBSS applies to "permanent" opex—ie, opex that repeats forever. As we explained above in section III, the sharing ratio will be higher for opex with a shorter commitment period.

2. Efficiency carryover mechanism in New Zealand

In New Zealand, there is an ECM called the Incremental Rolling Incentive Schemes (IRIS), which operate similarly to the EBSS and CESS. Absent an IRIS mechanism, the benefit to the company of reducing cost would be greater at the start of the control period than at the end. The IRIS mechanisms, thus, aim to equalize the benefit of reducing costs throughout the regulatory period.[61]

[61] 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.

For opex, the IRIS is largely similar to the AER's EBSS. As with the EBSS, incremental efficiency gains (or losses) are carried over to the following five years. The New Zealand regulator assumes a discount rate of 7.19%, which corresponds to a sharing ratio of 35%.[62]

For capex, as with the CESS, the IRIS is designed to achieve a fixed sharing between the utility and customers. However, while AER's CESS is designed to provide the same sharing ratio for capex as for opex, in New Zealand the capex IRIS currently applies a sharing ratio of 15% As explained above, without the ECM the sharing ratio would depend on which year of the regulatory period the savings was made. The average split (average across savings made in year 1, year 2, year 3, year 4 and year 5) is about 15%, and the Commerce Commission decided to adopt this figure in the IRIS mechanism.[63] With the IRIS ECM, the utility keeps 15% of capex savings, whichever year of the regulatory period the saving is made in. In the most recent Commerce Commission decision (for Powerco, one of the larger distribution utilities in New Zealand), the same retention rate of 15% was retained.[64] In support of its decision, the regulator said that "a higher retention factor could have incentivised Powerco to under-deliver, or reward it for under-delivery of the investments required to stabilise network reliability and meet capacity needs on its network."[65]

While recognizing that having a different savings factor for opex and capex (35% vs 15%) may create biases for one kind of expenditure over another, the regulator considers that, given the uncertainty of capex forecasts, current arrangement represents an improvement relative to prior arrangements.[66,67]

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62 Commerce Commission, "Further amendments to input methodologies for electricity distributors subject to price-quality regulation", 25 November 2015, footnote 38.

63 Commerce Commission, "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020, Main Policy Paper", 28 November 2014, p. 47.

64 For Powerco's latest customized price-quality path determination.

65 Commerce Commission, "Powerco's customised price-quality path", 28 March 2018, p. 127.

66 "[O]ur likely starting position for future resets is that the retention factor for capital expenditure should generally be equal to the retention factor for operating expenditure, except where there are good reasons to prefer a different value… [I]n our view, incentives would be improved simply by avoiding large differences in the strength of the incentive to economise on operating relative to capital expenditure, which would occur if a symmetric IRIS is applied to one type of expenditure but not the other." See Commerce Commission, "Amendments to input methodologies for electricity distribution services and Transpower New Zealand", 27 November 2014, pp. 27-28.

67 "As discussed above, we have applied a 15% retention factor for capital expenditure for the forthcoming reset due to the significant uncertainty we have in capital expenditure forecasts. Clearly, this choice of retention factor does not equalise the incentive between capital expenditure and operating expenditure, but it does represent an improvement relative to the existing arrangements." See Commerce Commission, "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020, Main Policy Paper", 28 November 2014, p. 53.

3. Totex in Great Britain

Totex is a completely new approach to regulatory accounting. Under traditional regulatory accounting, most items of expenditure are classified either as capex or opex (there can be some exceptions, such as overheads which may be partly capitalized). Under totex there is no such thing as capex or opex: all expenditure is treated in the same way. For regulatory accounting purposes, a fixed proportion of all expenditure is capitalized, added to rate base, and depreciated. Similarly, when the regulator is assessing utility expenditures, it does not examine capex and opex separately, but rather looks at all expenditures together. If expenditure is disaggregated, this is done on the basis of the underlying activity or reason for spending the money, not on the basis of whether the expenditure is capex or opex. Because all expenditure is treated in the same way, the risk of a "capex bias" is reduced,[68] although totex does not address concerns about non-financial reasons that utilities might prefer capex, such as opex solutions being subject to repeated regulatory scrutiny or involving greater reliance on new technologies and third parties.[69]

Ofgem's application of a total expenditure framework (totex) was a direct move to address the bias towards traditional utility investment (capex). Under the traditional approach in Great Britain (prior to implementation of totex), the utilities would bear a proportion of the total cost for incremental expenditures. Specifically, distribution businesses faced anywhere from 29-40% of additional capex, compared to up to 100% of additional opex, depending on factors such as asset lives, assumed discount rate, and the length of the commitment for opex.[70] In other words, Ofgem considered that the sharing ratio or financial burden for capex could be much smaller than for opex.

Due to distorted incentives between capex and opex, Ofgem has recognized that utilities are benefited by making substitutions from opex to capex, in a reporting and accounting sense (where opex spends are classified as opex spends), and in actual business decision making (substituting suitable non-wires alternatives with traditional capex).[71]

From DPCR5 (2010-2015) onwards, a totex approach was adopted which combined opex and capex spending into a single totex figure. Since, under the totex approach, additions to rate base are no longer influenced by whether expenditures are categorized or reported as capex or opex. Thus, any inclination to pursue inefficient tradeoffs between capex and opex should be removed, or at least much reduced.

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68 Even under a totex framework the distinction between opex and capex may still matter from a direct financial perspective because of tax: the tax treatment of opex is more favorable than the tax treatment of capex, and this difference is not removed by the application of a totex framework.

69 See the second, third and fourth concerns described above in section IV.A.

70 Ofgem, "Workshops for Electricity Distribution Price Control Review, Networks Breakout Session – Briefing Notes," 2 February 2009.

71 Ofgem, "Electricity Distribution Price Control Review, Initial consultation document," 28 March 2008, pp. 60-61.

Thus, the key elements of a totex framework can be distilled down to two simple points:[72]

- Rather than approving spending as either opex or capex, expenditure is approved in aggregate with no distinction between the two.
- A proportion of total expenditure is capitalized into the rate base ("slow money"), with the rest received in the relevant regulatory period ("fast money").

As part of Ofgem's move to totex, in addition to the deliberation around the imbalance of incentives between opex and capex spending, part of the reason for totex was the amount of resources dedicated to reporting and monitoring "boundary issues", which occurred when expenses can be classified as either opex or capex (e.g. fault costs, asset replacement, site engineer costs).[73]

4. New York REV

Distribution utilities in New York are typically regulated under a framework similar to that applying to the Companies in Hawai'i. In particular, there is full decoupling, rate cases occur every three years, and revenues are adjusted in between rate cases. The most recent rate case for Consolidated Edison provided for revenue increases slightly above inflation, as shown in Table 3.[74]

In recent years, a claw-back mechanism has been added to return the benefits of capex underspends to consumers.[75]

In 2014 the New York Public Services Commission (PSC) launched Reforming the Energy Vision (REV), a program of regulatory reform with a particular focus on energy efficiency and integrating distributed energy resources (DERs).[76] 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"). Despite earlier reforms, the NY PSC observed that utilities "still [had] an incentive to maximize their capital expenditures, and little incentive to optimize system efficiency to reduce capital needs" and proposed that the PSC "consider ratemaking approaches that encourage the most efficient allocation between capital and

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72 Frontier Economics, "Why totex? – discussion paper", 24 July 2018.

73 Ofgem, "Workshops for Electricity Distribution Price Control Review, Networks Breakout Session – Briefing Notes," 2 February 2009.

74 Authorized delivery revenue increases were approximately 2.5% per year in each of 2017, 2018 and 2019. See State of New York Public Service Commission (NYPSC), "Order Approving Electric and Gas Rate Plans," Dockets 16-E-0060, 16-G-0061, and 16-E-0196, January 25, 2017, pp. 3, 19.

75 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.

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

operating expenses."[77] Under the New York multi-year regulatory period, the risk of capex bias is increased by the fact that capex underspends are "clawed back", so that utilities see no financial benefit from investing less than anticipated when their authorized revenues were set.[78] The framework in New York is thus similar to the framework in Hawai'i when the RAM Cap is not binding.[79] The NY PSC's REV program is giving rise to a range of initiatives which the utilities are bringing forward for PSC approval. The PSC has approved various mechanisms which modify the traditional multi-year regulatory period framework and which are designed to encourage the utilities to adopt non-wires alternatives, and therefore to address the risk of a capex bias.

Growth in system load typically requires significant capital investments. The REV mechanisms provide 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.[80] Non-wires alternatives (NWAs) involve utilities procuring DER services (such as demand response) as an alternative to investment in conventional utility assets.

A well-known NWA example is Consolidated Edison's Brooklyn-Queens Demand Management (BQDM) program. The PSC approved the project in 2014, when growth in the NYC boroughs of Brooklyn and Queens resulted in an anticipated 69 MW shortfall in feeder capacity by 2018. The expected cost of addressing the shortfall through traditional utility investment was estimated at $1.2 billion for new substations, feeders, and switching stations.[81] To encourage Consolidated Edison to pursue NWA (demand management, energy efficiency and distributed generation) rather than traditional capex, the Commission approved two incentives in relation to BQDM:[82]

- 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.[83] Consolidated Edison is permitted to earn its authorized

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77 State of New York Department of Public Service, "Case 14-M-0101- Reforming the Energy Vision: NYS Department of Public Service Staff Report and Proposal," 24 April 2014, pp. 50, 54.

78 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.

79 We explained above (section IV) that the framework in Hawai'i is more balanced as between opex and capex when the RAM Cap is binding because then additional capex results in additional revenue only at the start of the next regulatory period.

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

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

82 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.

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

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.[84,85]

The PSC also required satisfactory performance on the company's existing reliability PIMs. Consolidated Edison also proposed that it should be allowed an additional incentive based on sharing the net benefits of the project, but this proposal was rejected.[86]

The BQDM program (together with some traditional investment) was originally designed to defer the need for a substantial upgrade from 2017 to 2019. Subsequently, Consolidated Edison developed additional traditional infrastructure projects which further delayed the requirement for substantial upgrade to 2026.[87] As of the most recent program update, Consolidated Edison has spent $75m of the approved $200m BQDM budget, and has achieved 41 MW of peak reduction.[88]

In January 2018, the PSC approved Consolidated Edison's request to apply a new incentive structure to additional NWA projects, including the extension of the BQDM program after the original funding is exhausted.[89] For this and future NWA projects, Consolidated Edison will receive 30% of the net benefits as an incentive (in place of the 100 basis points ROE adder

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84 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.

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

86 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. 9, 22.

87 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.

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

89 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. 6.

described above for the BQDM project).[90] 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).[91] The PSC explained that the advantages of an incentive calculated in this way are that the incentive is greater if customers have greater net benefits, and (unlike a return-based incentive) it avoids the perverse outcome of a larger incentive associated with higher-cost projects.[92] When a new NWA project is first approved, Consolidated Edison 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 Consolidated Edison (if NWA costs turn out below forecast) cannot exceed 50% of the net savings. Consolidated Edison 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 cost overruns on the NWA project is limited to the amount of the incentive.[93]

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 authorized rate.[94]

5. California IDER

The electricity distribution function in California is regulated under a framework similar to that in Hawai'i. There is full revenue decoupling, there are rate cases every three years, and revenue is adjusted between test years. 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.

As early as 2007, CPUC had considered integration of DERs within the investment plans of the utilities,[95] including via distribution-connected generation resources, energy efficiency, energy

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90 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.

91 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.

92 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. 9.

93 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.

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

95 CPUC, "Integrated Distributed Energy Resources," viewed 12 September 2018.

storage, electric vehicles, and demand response technologies. The CPUC labels these technologies Integrated Distributed Energy Resources (IDER).

Despite numerous CPUC decisions (and action from the state legislature), stakeholders have felt 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.[96] The CPUC recognized this financial disincentive using an "r minus k" approach to estimating the value to shareholders, where r is the return on equity and k is the cost of capital. The CPUC argued that the differential between the cost of equity capital and the authorized return on equity that generated shareholder value, and that this differential had consistently exceeded 2.5 – 3.5 percent in recent years. Thus, "utilities are creating investor value every time they make capital investments," but procuring DERs would displace such investments, thus resulting in the disincentive. In order to incentivize the procurement of DERs, the CPUC undertook the development of a framework such that shareholders could achieve returns from IDER at least as large as what they would otherwise earn from traditional investments.[97]

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 incentivized traditional capital intensive infrastructure investment.[98] And because DER solutions would displace capital investment, this sets up a "conflict with the company's [distribution businesses'] fundamental financial objectives".[99] 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.

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96 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.

97 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), pp. 3-7.

98 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.

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

In 2016, CPUC's Decision D16-12-036 laid out steps for the adoption of the Regulatory Incentive Mechanism Pilot.[100] The framework aimed to create a competitive solicitation process for DER projects.[101] 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"[102] 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.[103] 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),[104] 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 acquired by summer 2020.[105] 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

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

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

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

103 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.

104 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.

105 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.

viable or cost-effective solution.[106] 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 submitted another request for an alternate IDER project in May 2018 to solicit 2MW of distribution capacity at the Gonzales Substation by summer 2021. This request for procurement was approved by the CPUC in October 2018, and PG&E was ordered to complete the competitive solicitation process for the DER services by February 2019.[107]

- 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)[108] and ultimately did not receive bids that were cost-effective, meaning it will proceed with traditional investment.[109]
- Southern California Edison has not announced a winner for its IDER RFO, despite the final selection date having passed several months ago.[110] This suggests that there were also no conforming bids to displace the traditional wires investment.

6. Australia DMIS & DMIA

We explained above that the electricity distribution utilities in most of Australia are regulated on a revenue-cap basis with a five-year regulatory period. In addition to the ECM described above, the regulatory framework includes mechanisms to encourage the utilities to consider NWA.

The Demand Management Incentive Scheme (DMIS) was developed in 2008/9,[111] and was designed to facilitate (rather than directly incentivize) the investigation and implementation of demand management projects. The DMIS gave electric distribution businesses a fixed annual

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106 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.

107 CPUC, "Resolution E-4956: Approves, with modifications Pacific Gas and Electric Company (PG&E) 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," October 11, 2018.

108 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.

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

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

111 The DMIS mechanism was 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.

allowance to be used for non-network demand management projects.[112] 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, while 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,[113] there was an additional true-up for any revenue lost due to sales reductions that could be directly attributed to the demand management program.[114]

In 2012, the Australian Energy Market Commission (AEMC) revised the National Electricity Rules (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.[115] The reforms included measures designed to make the distribution businesses neutral between capex and opex solutions, and to encourage further consideration of NWA.

- **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".[116] The AER provides guidelines on how to quantify these benefits, such as changes in voluntary load curtailment, interruptions caused by outages, energy losses, and costs.[117] In December 2018, the AER completed a large-scale review of the RIT-D guidelines. Changes include (i) recommending consistent and early engagement with stakeholders before and throughout the RIT-D process; and (ii) encouraging flexibility when considering stakeholder suggestions made

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112 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.

113 The distribution utilities are currently regulated on a revenue-cap basis, but when the DMIS was implemented in 2008/9, some of the utilities were regulated on a price-cap basis. See AER, "Explanatory statement: Demand management incentive scheme, Electricity distribution network service providers," December 2017, p. 15. and AER, "Draft Explanatory Statement: Rate of return guidelines," July 2018, p. 102.

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

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

116 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.

117 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.

outside of written submissions, especially when multiple RIT processes are underway.[118]

- **The Capital Expenditure Sharing Scheme (CESS)** and **Efficiency Benefit Sharing Scheme (EBSS).** Section IV.B.1 discusses the CESS and EBSS in detail: these schemes amount to an efficiency carryover mechanisms (ECM) which aims to equalize the incentive to spend money on projects classified as opex or capex.
- **Reforms to the DMIS and implementing a new DMIA (Demand Management Innovation Allowance).** The AEMC found that the DMIS "had been applied in a very limited manner and operate[d] as a pass through of costs incurred in undertaking approved [demand-side participation] activities plus an innovation allowance.", and did not provide proper incentives. The AEMC proposed changes, described in detail below, included permitting networks to retain a share of the non-network related market benefits of their project.

The AEMC also more recently examined the possibility of implementing a totex approach, primarily as a tool to address perceived capex bias in investment incentives.[119,120] 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 that a series of performance based incentives would also be needed.[121] The AEMC will examine the potential for such performance based incentives alongside totex, as part of the 2019 Economic Regulatory Framework Review.[122]

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 through the revised DMIS and DMIA (Demand Management Incentive Scheme and Demand Management Innovation Allowance).[123]

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118 AER, "Final decision: Application guidelines for the regulatory investment tests," December 2018, pp. 19-21. Other changes in the 2018 RIT-D include guidance on how to account for policy changes, high-impact and low-probability system security events, and market-wide impacts using the Integrated System Plan, a strategic infrastructure development plan for the NEM. AER, "Fact sheet: Improving guidance to support cost benefit analysis in network investment," December 2018.

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

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

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

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

123 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

Since 2013, the RIT-D guidelines have required distribution businesses to consult stakeholders to identify the most efficient investments, including non-wires alternatives. However, the AER also 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.[124] Furthermore, the AER acknowledges the lingering capex bias in the existing framework. Despite the introduction of CESS and EBSS (discussed in Section IV.B.1), which were meant to balance incentives between capex and opex, industry experts and participants still perceive a bias that favors network options over non-network solutions. The DMIS is meant to rebalance incentives.[125]

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.

In December 2017, the AER designed two schemes to address these gaps in the regulatory framework: the DMIS and DMIA. These schemes are based on revisions to the earlier DMIS implemented in 2008/9, with the new DMIS being a program to reduce the cost of undertaking efficient non-wires investments, and the new DMIA an innovation allowance to fund R&D. The DMIA is meant to incentivize R&D into innovative projects, while the DMIS incentivizes the implementation of activities that have already been tested.[126]

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.[127] 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

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

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

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

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

127 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.

predetermined threshold.[128] 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 two-year lag. [129]

The DMIA is similar to the funding that existed under the original 2008/9 DMIS, but there are a few differences.[130] 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.[131]

In December 2018, the AER approved requests for early application of the DMIS from three distribution businesses: Energex and Ergon Energy (Queensland) and AusNet Services (Victoria),[132] allowing them to implement initiatives that will be eligible for incentives under the new DMIS without having to wait until their next regulatory period. Energex and Ergon Energy have already identified three initiatives for which they intend to apply for incentives under the DMIS:

- **Target Area Incentives**. The utilities will use load forecasting and end-use customer insights to identify areas where network investment can be deferred five years in advance, and provide sufficient time for end users and industry partners to participate.
- **Incentive Maps** will be published showing the location of target areas, the value of incentives available at each target area ($/kVA), and the timing of demand response needed to defer network investment.
- **Non-Network Alternative Projects.** In order to maximize the number of NWA solutions identified and implemented, the utilities will (i) engage regularly with

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

129 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.

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

131 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.

132 AER, "Approvals granted for early application of the new Demand Management Incentive Scheme (DMIS)," 11 December 2018.

their industry partners to ensure the development of competitive NWA as part of network planning processes and (ii) continue to manage existing contracts for NWA projects.[133]

[133] Energex and Ergon Energy, "Early application of the new Demand Management Incentive Scheme – supplementary information," 27 September 2018. Rather than wait until their next regulatory period, which begins 1 July 2020, they have been approved for an early DMIS starting on 15 December 2018. AER, "Determinations: Early applications of the Demand Management Incentive Scheme," 11 December 2018, p. 13.

V. Approach to capex forecasts in New Zealand

We explained above that the regulatory framework in several jurisdictions, including New Zealand, uses a multi-year forecast of utility expenditures as an input for determining the authorized revenue, and the approved annual revenue adjustments, for the upcoming regulatory period. Relying on a forecast of expenditures means that the regulator (and stakeholders) have to be comfortable that the forecast is well-founded. This challenge is faced in any jurisdiction that approves revenue adjustments between rate cases where the revenue adjustments do not simply reflect changes in actually-incurred costs (including, for example, New York and California), but it is not present where capital trackers are used, because those mechanisms permit revenue recovery corresponding to actual costs rather than a forecast of costs. Similarly, the framework in Hawai'i does not currently use a forecast of capex to set revenue adjustments (rather, the rate base and depreciation RAM is based on actual additions to rate base). Adjusting revenues based on actual additions gives rise to problems including a risk of bias in favor of capex, and relatively weak incentives to control costs on capex projects, as we explained in section III.B. In this section we therefore examine an example of how stakeholders and regulators can become comfortable that a capex forecast is a suitable basis on which to approve revenue adjustments during the regulatory period.

There are many jurisdictions in which regulators have to assess forecasts, and a range of approaches is taken.[134] We use the approach of the New Zealand regulator as an example—we think that this approach is interesting in that the regulator explicitly recognizes the need to take a "low cost" approach, given the relatively small size of the utilities (there are 29 distribution utilities serving a total population of about 3 million).[135] To achieve a relatively fast decision and keep the costs of the process low, the regulator mandates various steps and checks throughout the process. The objective is to ensure that, by the time the final application is submitted, as much of the information it contains as possible, including the capex forecasts, has been reviewed by an independent entity.

The application must include information about the following.

- **Verification**: An independent entity examines the policies and strategies of the utility and assesses the appropriateness of the applicant's forecasts. Verification includes an assessment of whether the utility has provided complete information in the proposal, properly consulted with stakeholders, and has the capacity to deliver the projects included in the cost forecasts. The verifier will review the assumptions underpinning the cost forecasts and will carry out a detailed check on a sample of projects or programs.

134 For some examples, see Bagci, Pinar, Toby Brown, Paul Carpenter, and Philip Hanser, "Framework for assessing capex and opex forecasts as part of a 'building blocks' approach to revenue/price determinations", The Brattle Group, June 2012.

135 About half of the utilities are investor-owned and regulated by the Commerce Commission; the other half are customer-owned and are not directly regulated.

- **Audit**: An independent entity examines the financial and other quantitative information in the utility's proposal to check for accuracy. This is distinct from the verification step since auditors, unlike the verifier, are not qualified to form an opinion on the quality of the applicant's policies, strategies, and procedures.
- **Certification**: Directors of the utility personally certify that the information provided to the regulator is truthful, accurate, valid, and otherwise reliable.

The New Zealand approach puts an emphasis on assessing the *processes* that utilities use to develop their cost forecasts. This allows the regulator to focus on a subset of projects and programs for detailed review, rather than preparing its own comprehensive "bottom up" forecast as a cross-check of the utility's proposal.

Following two recent rate cases in which this approach was used, the regulator reviewed and consulted stakeholders on its overall approach to the rate case process. The regulator seems to think that verification was a valuable part of the process: "Overall we consider the verification process for Powerco [one of the distribution utilities] to be successful. Powerco was provided with confidence that a large proportion of its proposal was justified in the opinion of the verifier, and once satisfied with the Verifier's conclusions, we were able apply a more targeted approach in our assessment."[136] Few stakeholders commented directly on the verification process. One association of industrial customers expressed the concern that using a verifier might reduce the ability of customers directly to influence the utility and the regulator.[137] One major industrial customer saw value in the use of an independent verifier to test the utilities' proposals.[138]

Further details about New Zealand's application requirements and an example of a recent decision can be found in the Appendix.

136 Commerce Commission, "Open letter seeking feedback on Powerco and Wellington Electricity CPP processes", 3 July 2018, pg. 11.

137 Major Electricity Users' Group, "Feedback on recent customised price-quality path processes", 31 July 2018, pg. 7.

138 Fonterra, "Re: Feedback on recent Customised Prices and Quality Path Process", 31 July 2018, p. 2.

VI. Conclusions

The Commission has expressed concerns about the risk of "over-investment" in traditional infrastructure, and the second Staff Report discusses the balance between utility investment and procuring services from third parties. These ideas have been discussed by regulators in many jurisdictions under the label "capex bias".

The existing regulatory framework in Hawaiʻi permits revenues to increase between rate cases, reflecting an understanding that rapid investment is required and that the three-year cycle of rate cases does not provide sufficient revenue between test years to support this investment. Many jurisdictions in North America and elsewhere have modified the traditional regulatory framework to address the need for rapid investment and hence revenue increases between rate cases. However, the framework in Hawaiʻi is unusual in that revenue increases are capped at inflation. We are not aware of any other examples where this is the case and, in contrast, we would expect that the rate of revenue increase required to support needed investment would sometimes be below inflation and would sometimes be above, depending on the situation of the individual utility. We have documented several examples of regulators in the US and elsewhere that have permitted above-inflation revenue increases. These revenue increases are based on the business plans and corresponding financial forecasts put forward by the utility and tested in a rate case. In comparison, it is unlikely that the inflation-based RAM Cap in Hawaiʻi will align with the actual investment needs of the Companies, since the investment needs are unrelated to the rate of inflation.

Where, as in Hawaiʻi (when the RAM Cap is not binding), revenues are adjusted between rate cases to take into account capital additions, only a relatively small share of the cost of such capital additions is borne by the Companies, because revenues adjust before the end of the regulatory period so that customers bear a large share of the cost of these capital additions. In contrast, a larger share of changes in operating expenditures is borne by the Companies because revenues do not adjust to reflect changes in opex until the next rate case.[139] Furthermore, the share of the cost of operating expenditure increases borne by the Companies can depend on whether the expenditure is in year 1, 2 or 3 of the regulatory period. We showed above that additional capex results in a financial burden or sharing ratio for the Companies of 7% or less, whereas additional opex results in a burden of between 7% and 100%, depending on whether the opex is one-off or recurring, and when in the regulatory period the opex starts.[140]

When the RAM Cap is binding, revenue is not adjusted between rate cases to reflect changes in rate base.[141] As a result, the share of capex projects borne by the Companies is greater than when the RAM Cap is not binding, at up to about 25%. Thus, when the RAM Cap is binding,

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139 Although the RAM has an O&M component, the RAM increase is not influenced by actual utility expenditures. Thus, if actual O&M increases from one year to the next within a regulatory period, 100% of the increase is borne by the Companies, until the next rate case.

140 The shorter the commitment, the larger the financial burden; and the earlier in the regulatory period, the larger the financial burden. See section III.B.

141 Additional revenue can be collected for projects approved via the MPIR process.

the financial burden of capex and recurring opex (eg, hiring a new employee) is similar. The financial burden of capex projects remains lower than the financial burden of shorter-term opex commitments.

The Companies bear a share of the cost of additional spending between rate cases, and they similarly receive a share of the benefit of reduced spending between rate cases. As a result, the Companies have a direct financial incentive to control costs.[142] The sharing ratios described above are different for capex and opex, and (for capex) depend on whether the RAM Cap is binding or not. The strength of the incentive for opex could be increased by lengthening the period between rate cases. For capex, the strength of the incentive could be increased by removing the dependence of the rate base RAM and depreciation RAM on actual rate base. The O&M RAM does not depend on actual O&M expenditure between test years, and if the same were true of the rate base and depreciation RAM, the strength of the incentive to control capex between test years would be increased.

In addition to the differences explained above between sharing ratios (and hence strength of incentive to control costs) for capex and opex, it is also the case that the sharing ratio and the strength of the incentive is greater at the start of the regulatory period and smaller towards the end. In some jurisdictions, a specially-calibrated efficiency carryover mechanism (ECM) has been implemented to equalize incentives over time. In both Australia and New Zealand the ECM provides an additional reward for reduced costs (or a penalty for increased costs) on a rolling basis. The result of the ECM is that the strength of the incentive to control costs on a particular project or category of spending is not dependent on when the project is undertaken during the regulatory period.

An ECM can also be calibrated to help reduce the risk of a capex bias. In Australia the ECM is designed to provide the same strength incentive for a capex project as for permanently recurring opex. However, the financial consequences of opex and capex spending, and hence the strength of the incentive to control costs, will only be equal for a precise set of parameters (such as project life time). For projects with different parameters, the incentives will not be exactly the same even with an ECM similar to that in Australia.

We are not aware of empirical evidence to suggest that the risk of a capex bias is resulting in inappropriate investment decisions, either in Hawai‘i or elsewhere. However, regulators in several jurisdictions are concerned that utilities may not be giving sufficient attention to the possibility of using services provided by third parties as an alternative to traditional utility investment (“non-wires alternatives” or NWA). If this is happening, a capex bias could be part of the cause, but other factors could also be important such as aversion to the risks associated with new technologies or new ways of operating. Regulators have designed new incentive

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142 The direct financial impact is one source of incentive to control costs which influences utility behavior. Incentives are also provided by other elements of the regulatory framework, such as the Commission’s ability to disallow imprudent expenditure. Utilities are subject to many safety, environmental and other obligations, and they are directly influenced by investors, customers and other stakeholders.

mechanisms to encourage utilities to implement NWA (we describe the approach in New York, California and Australia).

Great Britain is the only jurisdiction we know of to have implemented a "totex" approach for energy utilities. The totex approach eliminates the separate treatment of capex and opex in regulatory accounts, and therefore significantly reduces the direct financial component of capex bias.[143] However, totex does not address other factors which may be important in encouraging utilities to adopt NWA.

Based on the discussion above and the experience from various jurisdictions presented in this report, we offer four suggestions for improving the regulatory framework in Hawai'i. First, necessary revenue adjustments between test years could be derived from forward-looking assessments of the revenue that will be required over the regulatory period, and determined as part of the rate case process. This assessment could examine multi-year projections of capex and opex (sometimes referred to as "multiple forward test years"). The existing method of adjusting revenues between rate cases to reflect actual capital expenditures results in a preferential treatment of capex compared to opex, because the O&M RAM is not updated to reflect actual changes in opex, whereas the rate base and depreciation RAM is. Annual updating of revenue to reflect changes in rate base significantly reduces the strength of incentives to control capex, and could increase the risk of a bias in favor of capex over opex solutions. Revenue adjustments based on actual expenditures could be limited to expenditure categories that are particularly uncertain in magnitude or timing (for example, because they depend on third party actions). While this suggestion would reduce the risk of a bias in favor of capex solutions, we would not expect it to be sufficient, by itself, to encourage adoption of NWA such as relying on demand response to defer system upgrades.

Second, the strength of incentives to control costs could be increased by extending the period between rate cases. For example, if the period were extended from three years to five years, the sharing ratio would increase from about 20% to about 30%, and the strength of the incentive to control costs would increase correspondingly. A five-year period is in use in many jurisdictions including Australia, New Zealand and Great Britain.[144] However, if the regulatory period were extended, it would be important to take steps to ensure that the Companies have a reasonable opportunity to earn a fair rate of return over the period. This would require revenue adjustments to support needed investment over the period, as set out in our first suggested improvement above.

Third, if the Commission is concerned that incentives to control costs are weaker towards the end of the regulatory period, an ECM can be designed to maintain the strength of incentives independent of the timing of expenditures relative to the end of the period.

143 Totex does not change the way in which utilities in Great Britain pay income tax. The tax system creates an advantage for opex over capex since opex is fully deductible.

144 The regulatory period in Great Britain was five years between 1990 and 2015; the current period is eight years with mid-period review; and Ofgem intends to return to a five year period at the end of the current period.

Fourth, if the Commission and stakeholders are concerned about the balance between utility investment and procuring services from third parties, a PIM specifically targeting such NWA could be designed. We think that an NWA PIM is more likely to be successful at encouraging such activity than a broad-based adjustment to how capex and opex is remunerated (such as our first suggestion above, or a totex approach). Broad-based adjustments to the remuneration of capex and opex can reduce the direct financial incentive to prefer capex over opex, but do not address other factors such as a preference for standard solutions over untested approaches.

Appendix. Approach to capex forecasts in New Zealand

A. Price-quality paths framework

The rate-setting process in New Zealand is governed by the price-quality path framework, as set out in "Input Methodologies".[145] A price-quality path specifies the maximum average price a utility can charge for a given level of service quality it must meet. There are two types of price-quality paths relevant to distribution utilities. All utilities start on the default price-quality path (DPP), which is a generic approach that does not necessarily reflect the specific circumstances of an individual utility. A departure from a DPP may be warranted if the default path does not suit the specific circumstances of a utility, in which case the utility can elect to propose a customized price-quality path (CPP). As of October 2018, three utilities have applied for and received CPPs, compared to fourteen that have remained on a DPP.[146] In this subsection we explain the regulator's low-cost revenue determination approach, in section B we provide further details about the application process, and in section C we describe a specific example (the recent CPP application by Powerco).

Consistent with the pursuit of a relatively low cost approach for price setting,[147] a utility's application includes three types of check:[148] (i) the self-verification of information by the utility (certification), (ii) independent audits of information (audit), and (iii) independent opinions on information by a subject matter expert (independent verification). The regulator designed this approach to achieve several outcomes:[149]

- Promote certainty for applicants as to how their expenditure will be assessed.
- Give an opportunity for the applicant to rectify concerns raised before the final proposal.
- Allow the Commerce Commission to be able to rely on information contained in the proposal.
- Allow the Commerce Commission to focus on the most important aspects of the proposal.
- Reduce the time needed for the Commerce Commission to make an assessment.

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145 IMs are the rules, requirements, and processes for regulation of the price and quality of goods or services in markets with monopoly characteristics.

146 Commerce Commission, "2015-20 default price-quality path," 10 October 2018.

147 Commerce Commission, "Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper," December 2010, p. 188.

148 Commerce Commission, "Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper," December 2010, p. 239.

149 Commerce Commission, "Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper," December 2010, pp. 234, 239.

The CPP's more tailored approach focuses on the specific costs and circumstances of the businesses, and it follows that the information provided to support the analysis must be examined for its adequacy. In addition to the usual information on historical and forecasted financials provided as part of the DPP process, a CPP must include an external audit report and certification from the directors confirming the information provided in the proposal is accurate and reliable, and an independent expert's opinion on whether the analyses and the methodology in the proposal are reasonable and verifiable.[150]

As such, the Commission recognizes that a CPP will likely be more costly than a DPP determination due to (i) the preparation, verification, and consultation on the individualized information needing to justify the proposal, (ii) the Commission's evaluation of the proposal, and (iii) the Commission's determination of the CPP. Nevertheless, the CPP process is relatively quick and low cost (approximately 15 months from planning to decision,[151] and about NZD$2m).[152] This cost includes spending on external advisers by the utility, and the regulator's costs for assessing the application, but does not include the utility's "internal" costs.

B. DPP application requirements

1. Verification

The independent verifier's work involves the examination of an applicant's proposal prior to submitting it to the Commerce Commission. Steps of verification include:[153]

- assessment of the applicant's internal policies, and to what extent they have been implemented,
- assessment of the completeness of information provided,
- assessment of opex and capex forecasts, whether they meet the expenditure objective and how likely the business will be able to deliver the forecasts,
- assessment of the applicant's consumer consultation, and
- creating a list of key issues for the Commerce Commission's consideration.

It is expected that the verifier will use a range of engineering, management and economic tools, such as trending or time-series analysis, expenditure category benchmarking, high level governance and process review, project and program sampling, process or functional modelling, unit rate benchmarking, and internal benchmarking of forecast costs against historic costs,

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150 Commerce Commission, "How do businesses apply for a CPP?" 2 October 2018.

151 Commerce Commission, "Powerco's Customised Price-Quality Path – Final Decision," 28 March 2018, p. 13.

152 Commerce Commission, "Powerco's Customised Price-Quality Path – Final Decision," 28 March 2018, p. 126.

153 See the Appendix for the terms of reference.

critiques (or independent development) of demand forecasts, labor and other unit cost forecasts.[154]

The Commerce Commission explained that: "the intent behind the verifier role is to 'frontload' as much of the work as possible in preparing and reviewing the CPP."[155] This allows the regulator to focus on only the most important issues, which is essential since the regulator must be able to evaluate four or more proposals in any one year, each within 150 working days.[156]

A verifier's opinion is sought to judge the reasonableness of assumptions or practices for the development of information (e.g. the approach in making an opex forecast), and the generation of conclusions about the information (e.g. whether it is efficient or prudent).[157] The verifier forms an opinion on the same issues that the regulator would consider integral to its evaluation, including the analysis of all cost forecasts and underlying assumptions.

The regulator must be satisfied that the verifier is sufficiently independent and qualified to assess the proposal. The verifier may not act as an auditor or advisor to the applicant in relation to any other aspect of the CPP proposal.[158] The verifier must submit a draft report to allow the applicant to address concerns and revise its proposal before the final proposal is submitted.[159] Upon the submission of the verification report, the verifier must make itself available for questioning by the regulator, and the verifier is explicitly required to owe a duty of care to the Commission. These steps ensure the independence of the verifier.[160]

2. Audit

The purpose of the audit is to ensure the materials (financial and quantitative information) submitted by the applicant and examined by the regulator for the purpose of CPP determinations are reliable. The audit role is separate the verifier's role since auditors, unlike the verifier, are not qualified to form an opinion on the quality of the applicant's policies, strategies, and procedures. The purpose of the audit is to ensure a fair representation of historical financial information. In the case of forecast information, the audit provides

154 See Commerce Commission, "Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper," December 2010, pp. 644-655.

155 Commerce Commission, "Input Methodologies Review Draft Decisions, Topic Paper 2: CPP Requirements," 16 June 2016, p. 68.

156 Commerce Commission, "Input Methodologies Review Draft Decisions, Topic Paper 2: CPP Requirements," 16 June 2016, p. 69.

157 Commerce Commission, "Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper," December 2010, p. 241.

158 Commerce Commission, "Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper," December 2010, p. 643.

159 Commerce Commission, "Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper," December 2010, p. 643.

160 Commerce Commission, "Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper," December 2010, p. 643.

assurance that forecasts were prepared according to the stated assumptions. The auditor is not responsible for the reasonableness or appropriateness of assumptions.[161]

3. Certification

Certification involves the directors of the applicant utility personally certifying that the information provided to the regulator is truthful, accurate, valid and otherwise reliable. The regulator considers this to be a relatively low-cost means of supporting the production of accurate and reliable information.[162]

C. Case study: Powerco

In this subsection we describe the operation of the New Zealand framework with reference to a recent application by Powerco (owner and operator of the second largest electricity distribution network in New Zealand). In June 2017 Powerco submitted a CPP proposal for the period April 2018 to March 2023. Powerco's proposal included:[163]

- an independent verification report by Farrier Swier Consulting;
- an audit report by Deloitte; and
- a certification letter from the directors of Powerco.

This was the first time Powerco had pursued the option of proposing a CPP.

Powerco made a CPP application due to the need for significant uplift in network investment to prevent asset deterioration and to anticipate future needs of the network. Funding available under the DPP would not support the level of investment needed.

1. Timetable and cost

The proposal was submitted by Powerco on 12 June 2017, with the regulator's final decision made on 29 March 2018, for the period starting 1 April 2018.

The work of the verification consultant began approximately six months prior to submission, on 16 December 2016 with a tripartite workshop with Powerco and the regulator. Between then and the summary of the initial findings on 10 March 2017, the verifier analyzed data in a data room, made site visits for interviews, and made several information requests. Following the initial findings, a draft verification report was provided to Powerco on 6 April 2017, which

161 Commerce Commission, "Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper," December 2010, p. 240.

162 Commerce Commission, "Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper," December 2010, p. 240.

163 Commerce Commission, "Powerco's 2018-2023 CPP", October 9 2018.

led to further meetings and information exchanges before the final verification report on 7 June 2017.

Powerco was able to recover the costs of the verification and audit components of its proposal, after regulator review.[164] Powerco listed the total CPP audit fees as $375k, and the total CPP verifier fees as $369k.[165]

2. Independent verification report

The independent verification report was produced by Farrier Swier Consulting with input from WSP Australia. The verifier's main task was to test whether the proposed capex and opex for the CPP satisfied the expenditure objective (that capital expenditure and operating expenditure reflect the efficient costs that a prudent [utility] would require to- (a) meet or manage the expected demand for electricity distribution services, at appropriate service standards, during the CPP regulatory period and over the longer term; and (b) comply with applicable regulatory obligations associated with those services).[166] The verification process also considered Powerco's relevant policies, key assumptions informing the proposal, the extent to which Powerco will be able to deliver the CPP work program (deliverability), and the extent and effectiveness of Powerco's consultation with its customers. The verification report was structured and drafted to assist the regulator's considerations by directly addressing the matters required by the IM, highlighting matters that the consultants have identified as worthwhile for the consideration and investigation by the regulator.[167]

Farrier Swier's approach to the verification was to assess Powerco's inputs (policies and planning standards; service measures, levels, and quality standards; and demand forecasts), expenditure (opex and capex forecast; capital contribution forecast; and contingent projects), to come to an overall conclusion (opinion; expenditure objective satisfaction, expenditure deliverability, consumer consultation effectiveness; CPP proposal completeness; and key issues and information requirements), this is laid out in a chart from the verification report (see Figure 3).

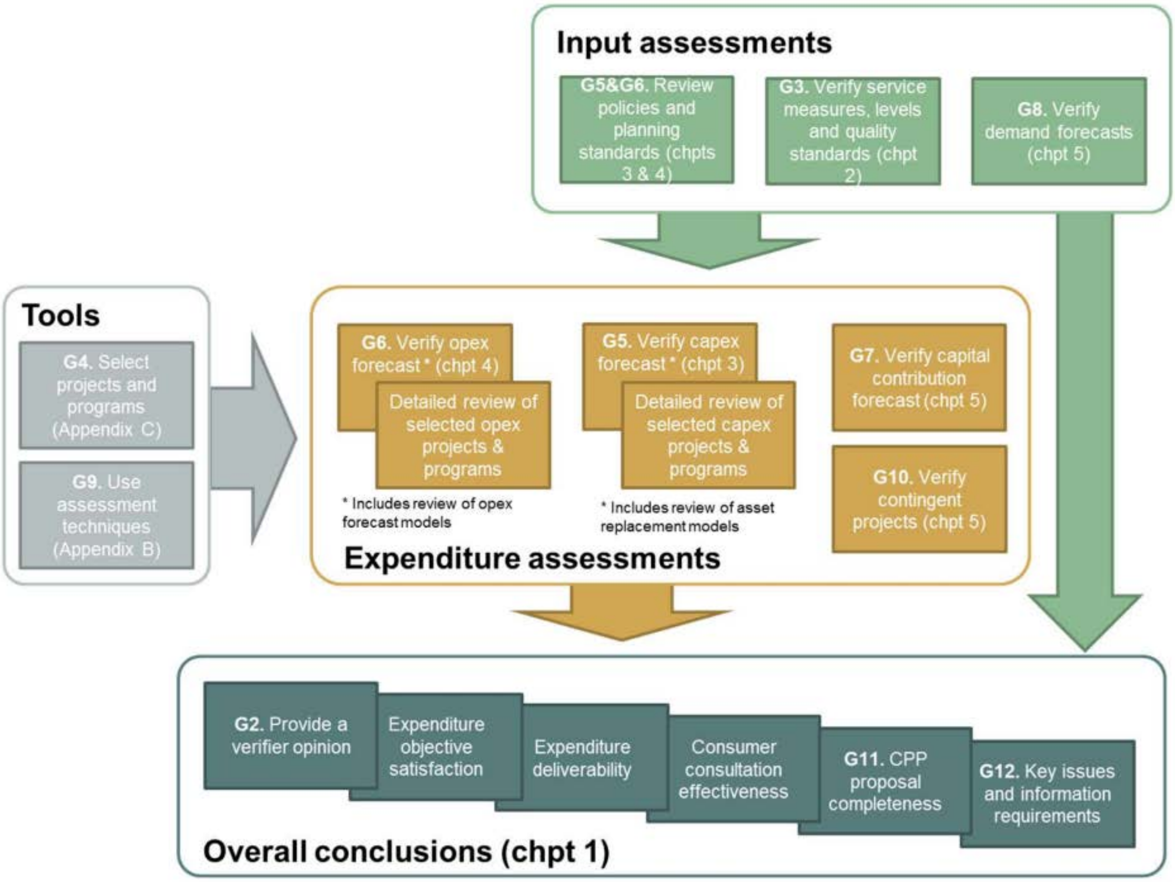
[164] Powerco, "Customised Price-Quality Path (CPP) Financial and Modelling Information", 12 June 2017, p. 51.

[165] Powerco, "Customised Price-Quality Path (CPP) Financial and Modelling Information", 12 June 2017, p. 57.

[166] See Farrier Swier Consulting, "Powerco's Customised Price Path Application – Final verification report for Powerco," 7 June 2017, p. 9.

[167] Farrier Swier Consulting, "Powerco's Customised Price Path Application – Final verification report for Powerco," 7 June 2017, p. 6.

Figure 3: Farrier Swier's overall approach to verification[168]

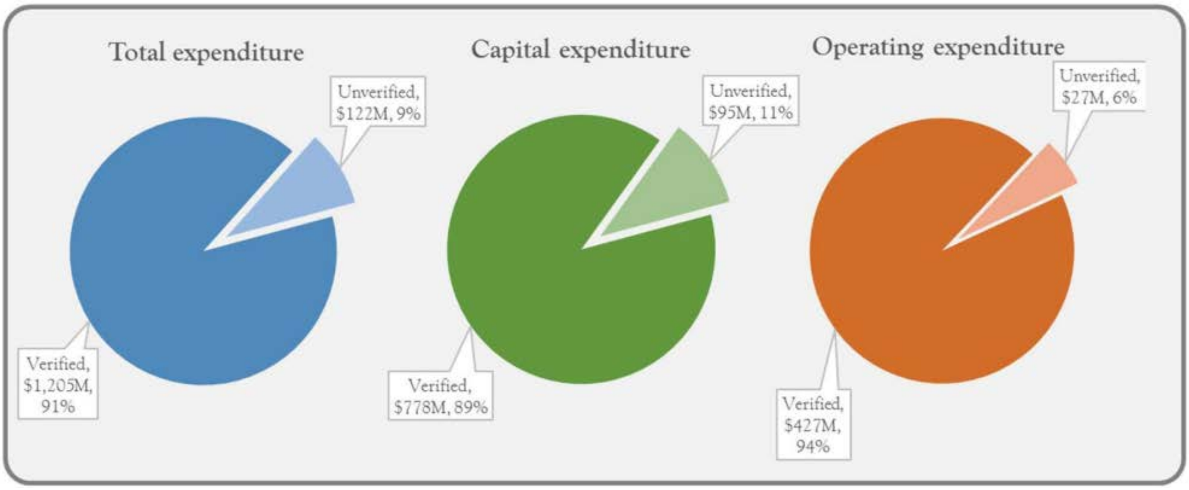


Farrier Swier nominated a sample of 15 projects and programs for detailed review, assessing those using tools such as benchmarking, trend analysis, desktop reviews, interviews, and model critiques. The verification process was done over a five-month period, which was in parallel to Powerco's continuous development of its CPP application. The verification process included a workshop with Powerco and the Commission, site visits, access to a data room with plans, policies, spreadsheets, and expert reports. Questions and information requests made to Powerco resulted in over 350 responses. Powerco had actively considered feedback provided by the consultants throughout the process. As a result, Powerco made changes to models to reduce modelling uncertainty and correct errors, updated and expanded documentation, reconsidered strategies (e.g. vegetation management), and moderated the forecasts to reflect forecast efficiencies and interdependencies between components of the expenditure forecasts.

The verifier's overall findings are illustrated in the chart in Figure 4. The amounts that were not verified against the expenditure objective made up 9% of total expenditure ($122m out of $1,327m). These unverified expenditures were left to be assessed by the regulator.

[168] Farrier Swier Consulting, "Powerco's Customised Price Path Application – Final verification report for Powerco," 7 June 2017, p. 11.

Figure 4: Farrier Swier Consulting overall findings[169]



The majority of project expenses were verified as prudent and satisfactory and meeting the expenditure objective. These met industry best practices, and involved assumptions and modelling that were deemed as reasonable and appropriate.[170]

Analyses of projects are highly individualized depending on the specifics of the case. In the broadest sense, steps include the assessment of forecast methods, the examination of expenditure trends, the checking of assumptions made to justify expenditure, and general comments on the approaches that the applicant made in reference to standard industry practice.

Farrier Swier was unable to verify some expenditure against the expenditure objective due to problems it found with some capex and opex expenditure and the nature and quality of some policies. For example, according to Farrier Swier, Powerco did not properly assess the risks with overhead conductor failures, specifically the probability of failure and likelihood of damage and injury. The existing evaluation method involved scoring based on visual inspection techniques, which are limited and not as robust as other inspection techniques.[171] This meant the expenditures could not be proven to be prudent.

Key issues identified by Farrier Swier are shown in Figure 5.

169 Farrier Swier Consulting, "Powerco's Customised Price Path Application – Final verification report for Powerco", 7 June 2017, p. 13.

170 Farrier Swier Consulting, "Powerco's Customised Price Path Application – Final verification report for Powerco", 7 June 2017, pp. 132-208.

171 Farrier Swier Consulting, "Powerco's Customised Price Path Application – Final verification report for Powerco", 7 June 2017, p. 46.

Figure 5: Subset of issues identified by Farrier Swier for the Commission[172]

Forecast component	Why should the Commission investigate it?	Suggested additional information or line of inquiry
Overhead conductors renewals capex	Powerco has not proven that the risk associated with the current level of faults is unacceptable and needs to be reduced.	Undertake suitable investigation/analysis to assess the risks posed by distribution conductors failing, and hence the number of faults that can be expected on the network of a prudent EDB.
Overhead structures renewals capex	Powerco has not proven that the current fault rate is unacceptable and needs to be reduced. Additionally, Powerco's overhead structures survivor curves include 'green defects' which may overstate levels of expenditure required.	Construct new survivor curves excluding green defects. Revise the overhead structures forecast to reflect any changes to the overhead conductor renewals capex.
Zone substation renewal capex	With the information provided, we have identified five transformer replacements that could be deferred beyond of the CPP period, although Powerco has not yet had the opportunity to respond to this finding.	Confirm with Powerco that its proposed replacement of transformers is prudent in light of our findings.

3. Audit

The audit was conducted by Deloitte on the historical information and forecast information included in the CPP Proposal. No issues were found in the actual/forecast financial information as it was prepared in accordance with the input methodologies, and the quantitative historical/forecast information were properly compiled on the basis of relevant underlying source information and reasonable disclosed assumptions.

The Auditor report was attached as part of the application.[173]

4. Certification

The application was certified by two directors of Powerco to be in line with the relevant requirements, including the proper representation of qualitative and quantitative information, that the assumptions made are reasonable, and that the verifier and auditor were engaged in a proper manner.

The certification letter was attached as part of the application.[174]

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172 Farrier Swier Consulting, "Powerco's Customised Price Path Application – Final verification report for Powerco", 7 June 2017, p. 19.

173 Powerco, "Customised Price-Quality Path (CPP) Application", 12 June 2017, p. 72.

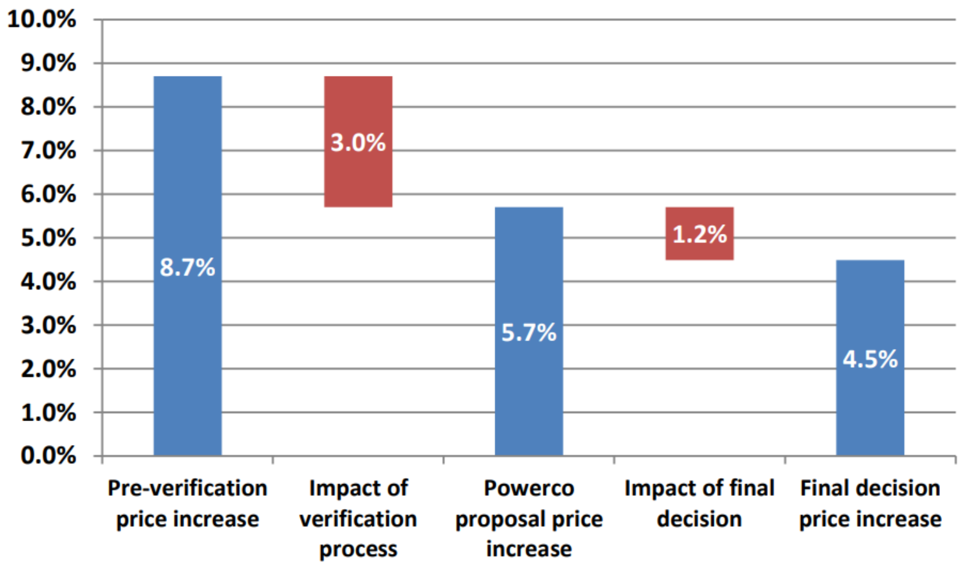
174 Powerco, "Customised Price-Quality Path (CPP) Application", 12 June 2017, p. 76.

5. Final Submission and Decision

Powerco's proposal was compliant with the rules and processes for CPP applications and was accepted by the Commission on 28 March 2018. Of the original $1,327m that was sought after, 9% was determined to be unverified by the consultant, and after an industry consultation process, the Commission determined that 4% of the total proposal amount remained to be disallowed, resulting with an allowance of $1,273m for the CPP period of 1 April 2018 to 31 March 2023.

The final decision reduced the proposed first year price increase from 5.7% to 4.5% (see Figure 6). It was determined that the increase in revenue requirements would be implemented through an initial price increase, with subsequent annual increases in line with inflation thereafter.

Figure 6: Impact of verification and final decision on Powerco revenues[175]



Of the $873m in capex that was proposed by Powerco, the Commission approved $825m. The approved capex expenditures included programs for asset renewals, network growth and security, other network capex, and non-network capex.[176] The Commission stated that major elements of Powerco's proposal was largely satisfactory in meeting its evaluation criteria, specifically regarding safety and reliability, and capacity and supply security.[177]

175 Commerce Commission, "Powerco's Customised Price-Quality Path – Final Decision," 28 March 2018, p. 24.

176 Commerce Commission, "Powerco's Customised Price-Quality Path – Final Decision," 28 March 2018, p. 21.

177 Commerce Commission, "Powerco's Customised Price-Quality Path – Final Decision," 28 March 2018, p. 7.

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