APPENDICES
TO THE
REPORT ON THE
STUDY OF
PERFORMANCE-BASED REGULATION

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MICHIGAN PUBLIC SERVICE COMMISSION
Department of Licensing and Regulatory Affairs
In compliance with Act 341 of 2016

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LICENSING AND REGULATORY AFFAIRS
CUSTOMER DRIVEN. BUSINESS MINDED.

Table of Contents

Appendix A: Stakeholders

Various parties who expressed interest and/or participated in the Commission's PBR study process are listed below:

5 Lakes Energy

Accenture

American Association of Retired Persons (AARP)

American Electric Power (AEP)

Association of Energy Engineers (AEE)

Brattle Group

Clark Hill

Constellation Energy

Consumers Energy

Detroit Thermal

DTE Energy

Ecology Center

Edison Energy, LLC

Enbridge, Inc.

Fiat Chrysler Automotive

FirstFuel

Indiana Michigan Power Company

Institute of Public Utilities (IPU), Michigan State University

Michigan Chemistry Council

Michigan Conservative Energy Forum

Michigan Department of Attorney General

Michigan Electric and Gas Association (MEGA)

Michigan Energy Innovation Business Council (MIEIBC)

Michigan Environmental Council

Michigan Gas Utilities

Natural Resources Defense Council (NRDC)

Oracle

PJM Interconnection

Public Sector Consultants

Pure Eco

Small Business Association of Michigan (SBAM)

Utility Boost

Utility Consumer Participation Board

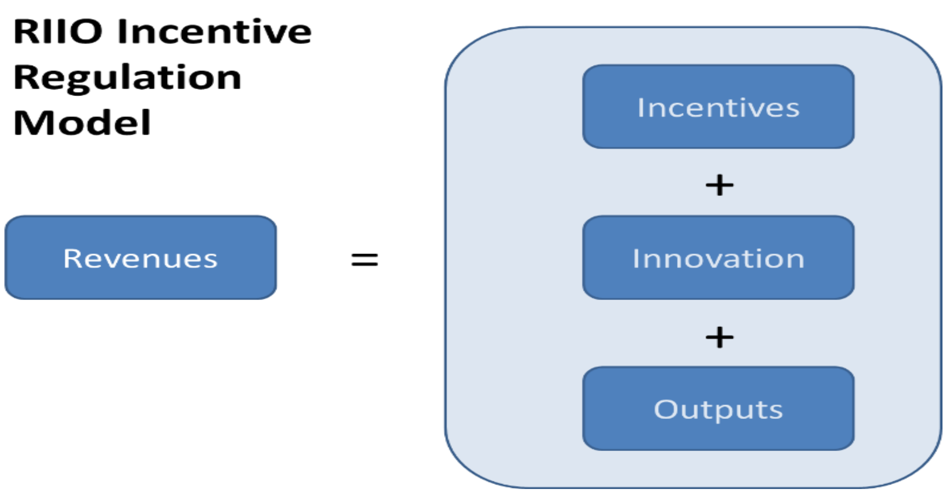
Varnum, LLP

WE Energies

Appendix B: UK's RIIO
(Revenue = Incentives + Innovation + Outputs)
The Core of RIIO

The acronym [**RIIO**] stands for Revenues = Incentives + Innovation + Outputs. In other words, regulators will set **R**evenue using **I**ncentives to deliver **I**nnovation and **O**utputs. RIIO is a broad-based incentive structure developed and administered by the UK's Office of Gas and Electricity Markets Authority (Ofgem). The new regulatory approach was formally approved in 2010 as an outcome of the RPI-X@20 initiative. According to Ofgem, "*The model is designed to promote smarter gas and electricity networks for a low carbon future.*" The new regulatory model was developed within the framework of existing statutory authority.

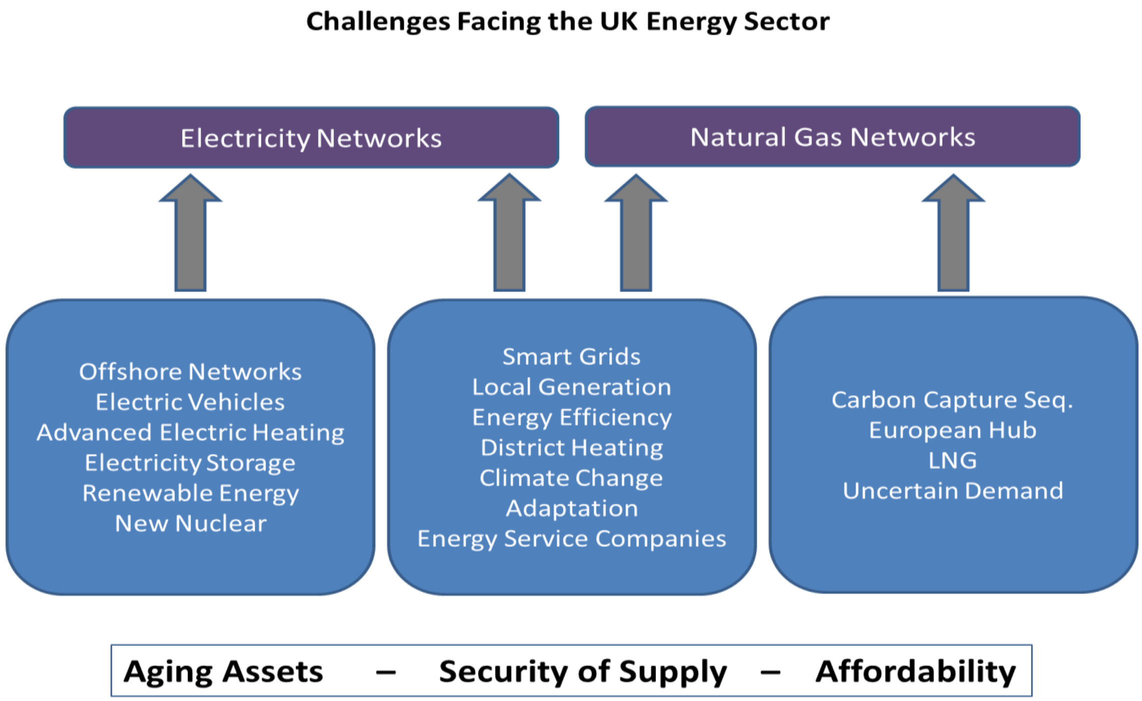
Figure 1. RIIO Incentive Regulation Model



In substantial part, RIIO reflects national energy and environmental policies articulated in legislation that set a national target to meet an 80% reduction in greenhouse gas emissions by 2050, and a decarbonized electric sector by 2030. It is clear that national policies supporting energy security, renewable energy, carbon reduction and social goals, will necessarily drive increased grid investment. Compounding the need for new investment, aging network infrastructure is requiring substantial new capital investment to maintain reliability and grid services.

The following graphic shows the interplay of challenges affecting the natural gas and electric industries in the UK.

Figure 2. Challenges Facing the UK Energy Sector



Substantial changes in policy goals, along with rapid advancement in enabling technologies in the energy industry, meant that the UK needed to refine the existing regulatory approach, which contained significant adversarial elements, into a more consensus driven approach, with strong stakeholder input. Doing so would allow the government to garner customer support for substantial network investments that would be needed to meet national environmental and renewable energy goals that would necessarily increase rates. The potential national investment to meet the nation's environmental and energy goals was estimated by Ofgem at approximately £200 billion, of which £32 billion would need to be invested by transmission and distribution network companies by 2020: a 75 % increase in existing rate-base.[1] The willingness to invest so substantially demonstrates that the UK sees transmission and distribution networks as vital to a sustainable future and drives the need to re-think the then existing regulatory framework.

In addition, knowing that the conversion of the existing electric grid into a platform for de-carbonization will require new technologies, rather than a simple one-for-one replacement of retiring assets, Ofgem set innovation as a primary goal for cost reduction in this new framework.

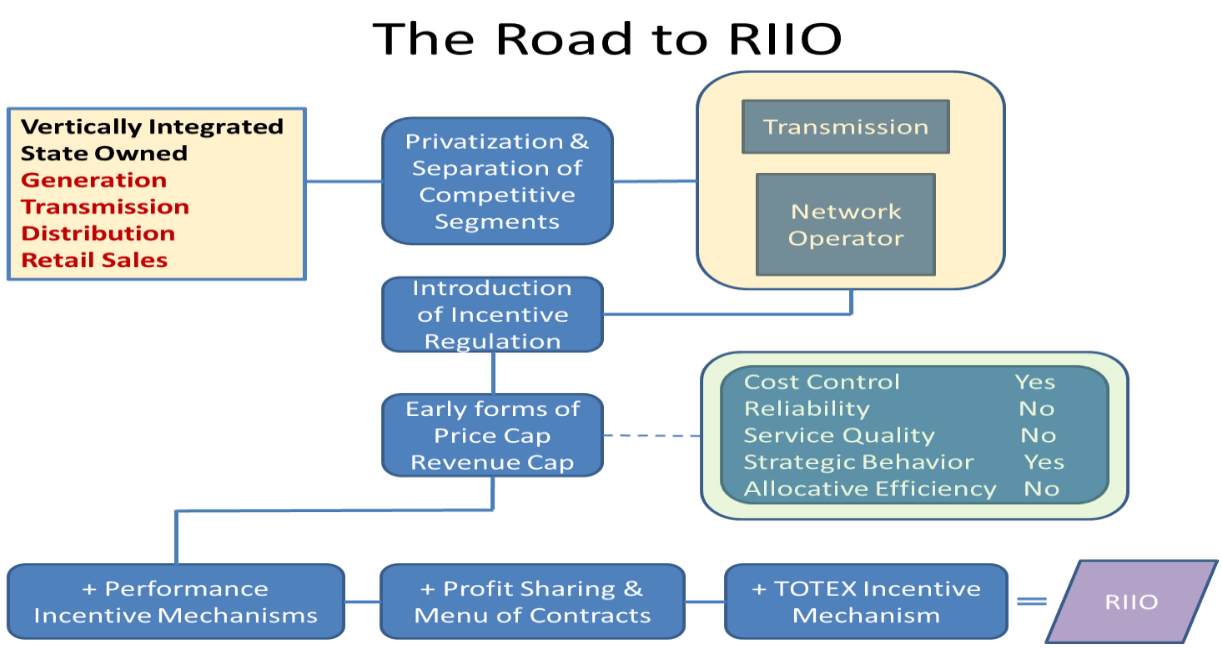
[1] Ofgem (2010). RIIO - a new way to regulate energy networks. Factsheet. Retrieved from: https://www.ofgem.gov.uk/ofgem-publications/64031/re-wiringbritainfs.pdf

The Road to RIIO

Contrary to appearance, the RIIO regulatory model is not completely distinct from the prior incentive regulation framework in the UK, called RPI-X, but is an extension of the former approach, particularly with regard to fundamental building blocks of performance-based regulation that were developed over the years. What is uniquely different about RIIO are its administrative innovations and a sharp focus on policy outcomes. Connected with such policy outcomes is an expanded set of targeted performance incentive mechanisms. Thus, RIIO itself is the result of a continuum of evolutionary steps that build upon decades of UK experience and learnings with incentive regulation.

The following chart encapsulates the multi-decade evolutionary path of RIIO that will be explored in more detail in this section.

Figure 3. The Road to RIIO



Industry Restructuring in the UK

In evaluating the RIIO framework, it is critical to understand that the RIIO regulatory model is applied to an energy industry that has been fully restructured. Formerly, in the 1980's both gas and electric networks took the form of a nationalized and vertically integrated model.

The UK's restructuring of its electric industries in 1990 (gas followed later) had the dual objective of *privatization* and *separation* of vertically integrated segments. Privately-owned competitive industry segments (generation and retail sales) were created, along with independent and privately-owned regulated segments (transmission and distribution). The former was unregulated, the latter being subject to economic regulation.

In particular, the restructured transmission and distribution firms, "wires-only" firms, were regulated using incentive-based regulation.

The early incentive-based regulation efforts that came out of restructuring were the beginnings of a continually evolving broad-based incentive-regulation paradigm. That paradigm was called RPI-X. It was implemented over a twenty-year period, ultimately culminating in RIIO which was first implemented for electric transmission and gas distribution networks in 2013 (electric distribution followed in 2015).

Importantly, the UK's energy industry model is founded on maximal unbundling that facilitates a market-based model of economic competition. This is an important distinction from Michigan's vertically integrated and broadly regulated model. In the UK, total unbundling simplifies the scope of the regulatory review process needed for the individual transmission and distribution firms which came out of restructuring. Such firms, being natural monopolies, continue to be regulated, however, since the functions of an individual transmission or distribution provider are limited in scope as compared to a vertically integrated utility, the economic regulation of an individual firm is simplified.

How Michigan's vertically-integrated utility structure would complicate a RIIO-type regulatory model

In contrast to the UK, Michigan investor-owned electric-utilities own and operate generation and distribution assets, along with providing the retail sales (supply) function for the majority of end-users (Michigan has a hybrid regulated/choice retail supply market, with a 10% cap on choice sales). This creates an inherently more complex cost-recovery and rate-setting process. For example, electric production related expenses (capacity and energy) can be nearly one-half of the cost of service for a Michigan electric utility, whereas in the UK, the power supply function is independently provided by unregulated firms in a fully competitive market.

Similarly, Michigan's regulatory process includes substantial effort toward a complex retail rate-setting process (cost-of-service studies and rate design). In contrast, a "wires-only" distribution company in the UK, for example, has a more limited set of rates only recovering distribution network costs.

From Price Caps to Performance-Based Regulation

The early years of incentive regulation in the UK were characterized by effective use of price and revenue caps to control strong inflation. Cost control was directly tied to use of a productivity offset to general inflation indices used to set prices/revenues. In fact, the term [RPI– X] reflects this two part approach to cost control (RPI stands for retail price index - a measure of general inflation, and X refers to a productivity offset index). Later on, statistical benchmarking of industry best practices was developed into an additional tool to estimate future *efficient* costs.

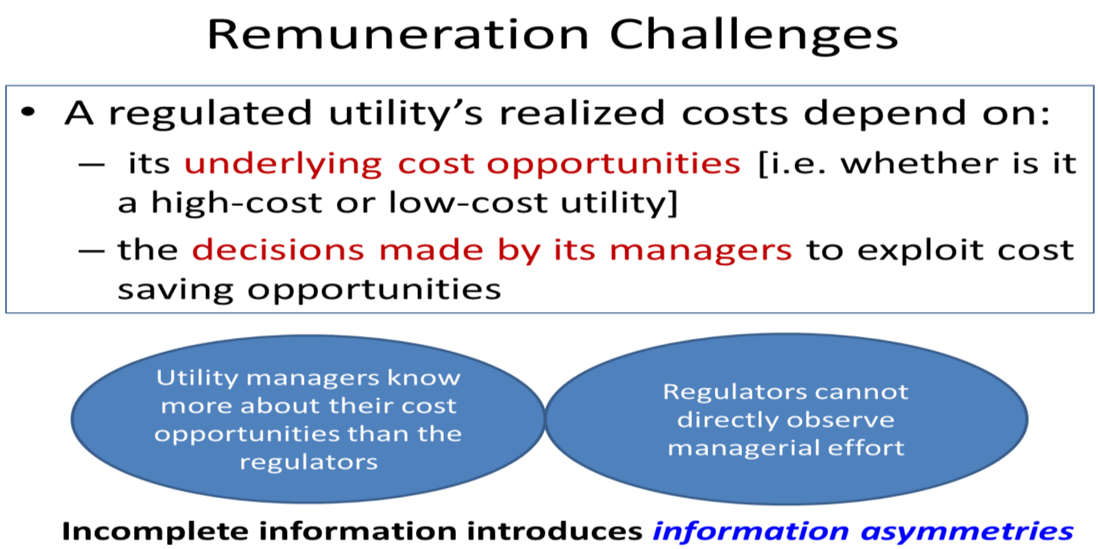
Several significant evolutionary improvements transformed the relatively simple regulatory approaches that were implemented in the early 1990's into a modern, broad-based incentive PBR model. This multi-decade evolution was strongly affected by a desire to mitigate unintended consequences related to high-power cost-control regulation that initially relied on simple price/revenue caps to achieve cost efficiencies.

As expected, Ofgem's focus on cost control put significant downward pressure on a regulated firm's unit costs, but over time resulted in regulated firms cutting back on customer service, reliability and service quality in order to sustain cost savings at high levels. In particular, it was observed that a price-control framework can induce capital deferral as a means to meet goals, and thus increase earnings. This unintended consequence was corrected by implementing a limited set of targeted (performance) incentive mechanisms that restore high levels of customer service, reliability and service quality.

Secondly, it was found that rate cap/revenue cap regulation, although having the power to unleash the highest levels of cost efficiency by regulated firms, failed to produce an outcome in which consumers realized a reasonable share of cost-control benefits (in terms of reduced bills). [Economists refer to the transfer of economic cost-efficiency savings to consumers as "*allocative efficiency*".] It was found by Ofgem that rate/revenue caps had poor allocative efficiency, as the bulk of cost savings induced by the use of RPI –X were kept by the regulated firms. In order to correct this situation, Ofgem designed a shared-savings mechanism that would balance economic efficiency with allocative efficiency. Ofgem reasoned that strong incentives toward cost control could be achieved even if regulated firms were required to refund to consumers a significant portion of the cost savings that were realized during the cost-control period, and this proved true.

Third, the issue of "*strategic behavior*" on the part of regulated firms was explicitly addressed by UK regulators during the RPI-X phase of incentive regulation. The term refers to a regulated firm's use of their inherent information advantage in the regulatory process, so as to attempt to increase the level of revenues approved. Strategic behavior is a product of the *information asymmetry* inherent to economic regulation, and it intensifies the challenges faced by regulators as they undertake the task of setting the level of revenues allowed to be collected by regulated firms.

Figure 4. Remuneration Challenges



The phenomenon of strategic behavior can be observed by comparing the level of revenues sought by regulated firms (over a long-term string of general rate applications) with the level of approved revenues set by a regulatory body. A consistent pattern of large differentials between requested and approved allowances can reasonably be interpreted as a manifestation of strategic behavior.

The UK regulator mitigated strategic behavior by offering a “menu” of possible levels of rate relief during a cost-control period, with a sliding scale of corrective profit-sharing incentives/penalties tied to the difference between the requested Opex underlying a regulated firm’s business plan, and the base Opex set by Ofgem. Thus, the depth of sharing of cost savings (i.e. refunds to customers) increased as the level of requested cost allowances diverge from the base allowance set by Ofgem. Choosing a particular aggregate cost allowance from among a “menu” of possibilities, results in a regulated firm revealing approximately where its true level of *efficient* costs lies, since the regulated firm maximizes its earnings by choosing a cost allowance close to the level it expects to achieve.

Because the Opex incentive mechanism under RPI-X strongly rewards cost control, the actual level of costs achieved by the firm (that is used to calculate cost savings in the annual reconciliations), should, in theory, correspond to the level of *efficient* costs that regulators have difficulty ascertaining, thus mitigating its information asymmetry.

The upshot is that the relatively simple price-cap model evolved over time into a more complex system of performance incentive mechanisms and profit-sharing mechanisms so as to address unintended consequences associated with incentive regulation. The system of coordinated regulatory mechanisms known as RPI-X became the foundation of the new RIIO model.

RIIO as a Broad-Based Incentive Regulation [PBR] Model

The RIIO regulatory model contains the essential attributes that are characteristic of a viable broad-based incentive-regulation system.

RIIO has the following attributes:

- Is an *ex ante* approach (Latin, "before the event") using projected revenues and cost inputs
- Projects *efficient* future costs (efficient refers to *productive efficiency*, where a regulated firm has minimized the inputs required to produce a given level of outputs, i.e. *x*-efficiency)
- Has a diverse set of targeted performance incentive mechanisms
- Puts investment and expenses on an equal footing, mitigating the incentive to invest where there are viable options to expense at a lower lifecycle cost
- Balances cost control (i.e. *x-efficiency*) with *allocative efficiency*, via sharing mechanisms
- Has a focus on specific policy outcomes and metric-based outputs

With respect to revenues, the RIIO model, like RPI-X, incorporates an *ex ante* regulatory review based on projections of costs, revenues, earnings and actions planned for a future consecutive multi-year period. RPI-X had a five-year price control period, whereas RIIO has an eight-year control period. The longer price-control period has three core objectives.

First, the extended price control period is intended to create financial incentives leading to *cost-efficient* expenditures associated with projects having a long useful life, since the firm keeps a share of cost savings over the first eight years of a project's life. However, according to the Guarini Center's (NYU/Law) January 2015 report to the New York Public Service Commission, the efficacy of extending the cost control period is contended by some experts, in that infrastructure projects typically have multi-decade depreciation lives allowing for a considerably longer period for earning a return on investment, and thus cost-control incentives are blunted. In fact, according to Ofgem's October 10, 2010 Final Decision adopting RIIO, a number of network companies expressed the view that the eight-year cost control period would increase their business risks, while at the same time would have only a “marginal impact on longer-term thinking”. Ofgem did acknowledge that it may reconsider the eight-year control period after logging some experience with the new system, possibly returning to the five-year control period formerly used in RPI-X.

In light of the difficulty of correctly forecasting future events over the lengthy price-control period, a mid-period review process was created that includes “uncertainty” mechanisms to make adjustments to the price controls where unanticipated events occurred.

Secondly, the eight-year cost-control period is intended to spread the considerable administrative costs of processing rate relief (24 to 30-month process) over the longer eight-year time horizon.

Third, the eight-year price control period is intended to improve strategic planning by both the regulatory body and regulated firms, thus facilitating a long-term approach to infrastructure development. The enhanced planning does appear to be a positive feature of the new regulatory model.

It should be noted that under RIIO, the UK backed away from the prior practice of fixing approved revenues for the entire price control period at the start of the control period. RPI-X was a relatively ‘static’ process. In contrast, RIIO is a dynamic process, with comprehensive annual adjustments to base revenues, which include annual inflation index adjustments. The type and scope of annual adjustments to cost recovery are significant. Ofgem refers to the suite of comprehensive adjustments as the “*Annual Iteration Process*”. As RIIO is an incentive regulation model with incentives and penalties, there is necessarily an element of *retroactive ratemaking* to the Annual Iteration Process.

The RIIO incentive model is essentially a compact between the network operator and network users. In exchange for approved revenues, the firm is obligated to deliver the outputs/deliverables explicitly defined in the price control order. In order to maintain regulatory certainty for the firms being regulated, Ofgem commits not to modify the identified deliverables over the course of the eight-year price control period.

How RIIO's Annual Iteration Process differs from a tracker

Although actual cost data is input into the Price Control Financial Model used in the Annual Iteration Process, the resulting adjustments to cost recovery differ fundamentally from a "tracker", as requested at times by Michigan's cost-of-service regulated utilities. A tracker, is a simple cost recovery mechanism whereby ongoing actual costs (say capital costs, in a capital cost recovery tracker) are regularly reconciled with recovered costs. With a tracker, recovery of new and additional costs, and re-calculation of rates, occurs in-between of the normal general rate application process. In contrast, pursuant to RIIO's Annual Iteration Process, regulated firms only recover a portion of actual costs that exceed allowed efficient costs and must refund a portion of cost-savings from allowed efficient costs. This Totex Incentive Mechanism, (as detailed below) is the foundation of cost control incentives inherent to RIIO. A tracker, in contrast, does not have a cost-control element. Thus, efficient costs (in economic terminology x-efficient) are not the standard for cost recovery in a tracker; it is purely an accelerated recovery mechanism.

Forecasted Efficient Costs under RIIO

The [R] in the term RIIO explicitly refers to a regulated firm's revenue allowance, where such revenues are heavily impacted by economic incentives. Necessarily, revenues are quantified by cost inputs, i.e. capital and operating costs needed to provide regulated services. The RIIO regulatory model relies heavily upon exogenous cost input data (i.e. external to the regulated firm) such as general inflation indices and statistical modeling. RIIO's fundamental dependence on exogenous cost data is intended to elicit a base revenue requirement that is not only *cost-efficient* but also reflects best-practices across the industry. The analytical process of establishing best practices is called "benchmarking". A major distinction between the former RPI-X and the new RIIO is that analytical benchmarking is now applied to both Opex and Capex whereas under RPI-X, benchmarking was restricted to Opex.

RIIO does make use of a regulated firm's actual/historical costs (as delineated in its books and records) along with its forecasted business plan in the evaluation process, but these are not the primary basis for quantifying cost allowances. One fascinating change in the new regulatory model is that under RIIO, the cost of debt will be backward looking, using historical indices of forward interest rates to adjust the cost of debt. The adjustment is made at the Annual Iteration Process.

RIIO Lessons for Michigan

Michigan's cost-of-service model, although technically an ex ante approach, (projected over a future 12-month period), does not directly project efficient future costs (x-efficient). Michigan obtains a measure of cost control through the Commission Staff's (and outside parties') evaluation of utility budgets for reasonableness. This evaluation involves, at times, the rejection of components that are prima facie imprudent, and an overall evaluation of whether or not an alternative approach to meeting an output goal would be more cost efficient. Although Michigan's approach is effective, is not strictly identical to broad-based incentive regulation practices that formally elicit future efficient costs, nor does it necessarily reflect a level of cost-efficiency that is commensurate with industry best practices. Such a regulatory practice would require the direct reference to exogenous economic factors including indices of price inputs and productive efficiency offsets, along with analytical models for benchmarking best practices.

Totex

The term "Totex" refers to *efficient* total expenditures. Totex integrates capital expenditures (Capex) and operating expenditures (Opex) into a single cost parameter. Customer contributions (e.g. for connections) are an offset to Totex.

Approximately 80 % of revenue requirements are set by Totex. The balance is generally related to return on rate base [regulated asset value] including debt and equity, taxes, depreciation, and revenues associated with incentive mechanisms.

According to Ofgem, Totex consists of <u>all the items of expenditure required for the regulated firm to carry on business</u> - with the exception of these particular items:

- Costs relating to de minimis activities;
- Costs relating to excluded services activities;
- Pension deficit repair payments, all unfunded early retirement deficiency costs;
- Pension Scheme Administration and PPF levy costs;
- The non-cash element of current service pension costs charged to the income statement in accordance with accounting standards;
- Costs associated with specific incentive schemes;

- Statutory or regulatory depreciation and amortization;
- Profit margins in payments to related parties (except where permitted);
- Costs relating to rebranding a company's assets or vehicles following a change of trading name or logo;
- Fines and penalties (including all tax penalties, fines and interest);
- Compensation payments made in relation to standards of performance;
- Bad debt costs and recoveries (which are subject to separate review);
- Costs relating to the network innovation allowance;
- Costs reported other than on a normal accruals basis;
- Costs in relation to pass-through items including:
    - business rates (except for business rates on non-operational buildings);
    - Ofgem license fees;
    - interest, other financing and corporation tax costs;
- Costs relating to Electricity Market Reform preparatory costs

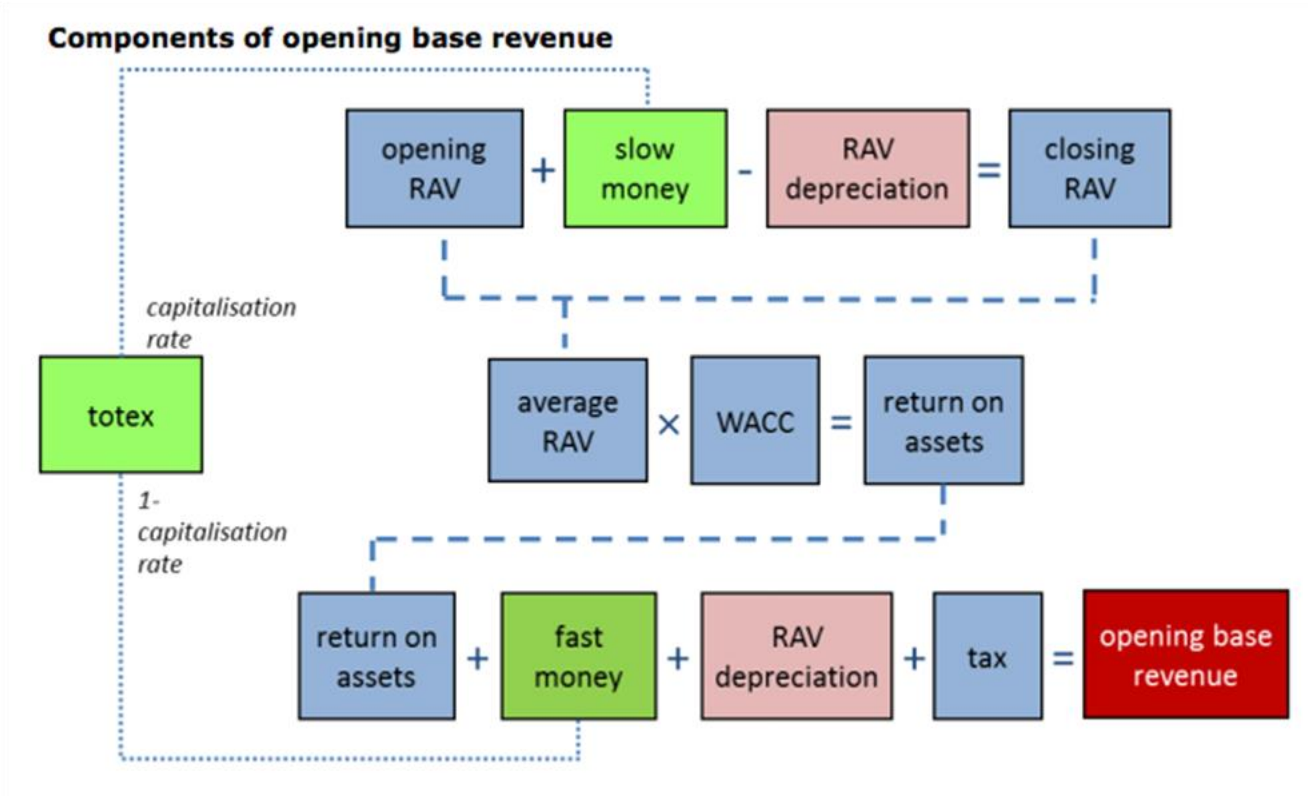
Ofgem condenses the individual components of Totex into seven categories, used in the price control financial model (PCFM) that is the basis for the Annual Iteration Process. It is clear that these categories have a relation to the output metrics established by the regulatory agency.

Table 1:

PCFM Variable Value	Totex sub-division
ALC	Actual load related Capex expenditure
ARC	Actual asset replacement Capex expenditure
AOC	Actual other Capex expenditure
ACO	Actual controllable Opex expenditure
ANC	Actual non-operational Capex
SOACO40	Actual controllable Opex expenditure (system operator)
SOANC44	Actual non-operational Capex expenditure (system operator)

Totex valuation does not directly establish allowed revenues. It must be divided into proxy capital and expense categories, called “slow money” and “fast money” respectively. Figure 5 illustrates how slow money and fast money are incorporated in the totex calculation. Such proxies are a means to divide an aggregate Totex valuation into an efficient projected Capex (slow money) and efficient projected Opex (fast money) that is specific to the regulated firm. Note that the aggregate Totex valuation is itself is a proxy, being derived from statistical analysis of data culled from all regulated firms under Ofgem’s jurisdiction.

Figure 5. Components of Opening Base revenue[2]



Slow money [new "investment"] is added to the firm's historical (embedded) rate-base in order to determine regulatory depreciation and the overall return (debt, return on equity, and related taxes) required to make the firm financeable.

Actual total expenditures may differ in several ways from projected Totex. A regulated firm may have multiple options to meet infrastructure replacement or enhancement goals: it may build-and-own hard assets, contract with a third party for services that constitute an operating expense, or it could implement customer programs that defer the need for new investment, which may include both operating and capital expense. The upshot is that financing an output goal can be through Capex or Opex or a combination of the two. Fortunately, via the formulistic valuation of "slow money" (through a percentage allocation of Totex) a regulated firm's return is independent of which approach is chosen. In this way, a cost-efficient operating expense that substitutes for a capital investment can earn an effective "rate of return".

[2] Ofgem (2017). Guide to the RIIO-ED1 electricity distribution price control. Retrieved from: https://www.ofgem.gov.uk/system/files/docs/2017/01/guide_to_riioed1.pdf

The idea behind the use of proxies (slow and fast money) that substitute for actual Capex and Opex is to mitigate the regulatory incentive to invest rather than expense, by creating a level playing field between the two. Thus, the Totex concept directly addresses the *moral hazard* issue inherent to rate-base regulation, where a regulated firm has an incentive to deploy capital projects even if they are cost-inefficient, because it earns a return on that option. [In economic theory, a *moral hazard* characterizes the economic forces affecting decisions made between two contracting parties, where a third party (consumers) bear the cost/risks associated with the contract.] Totex nullifies the moral hazard issue by creating a "win" for stockholders - if the firm chooses the most cost-efficient option. That win consists of a return on the proxy capital expenditure (slow money).

Totex also provides an additional "win" for stockholders by subjecting a regulated firm to an annual profit-sharing mechanism, called the *Totex Incentive Mechanism* (TIM) that annually passes a share of cost savings (the difference between projected and actual Totex) to customers, with the balance retained by the company. The TIM is implemented during the *Annual Iteration Process*. This sharing mechanism demonstrates that regulated firms do not need to keep 100% of cost-savings in order to induce efficient behavior. If one considers that Ofgem could require all cost savings to be passed on to ratepayers, then this mechanism can be considered a cost-control incentive from the perspective of the regulated firm.

RIIO's near immediate pass-through of a portion of actual cost efficiencies to customers markedly enhances *allocative efficiency* over early-generation incentive regulation models that only benefited customers at the end of a multi-year price control period. It is thus expands the "win" for consumers. Note that the prior approach to pass on cost efficiencies to customers was restricted to an end-of-period price control "ratchet". Such ratchet resets retail prices for the new price-control period, prospectively recognizing productive efficiency that occurred in the prior price-control period. A reset did not involve a refund of past cost savings.[3]

[3] Early price-cap version of RIIO, prior to profit-sharing mechanisms requiring partial refunding of cost savings. The later addition of profit-sharing mechanisms further increased allocative efficiency.

Totex Incentive Mechanism Example:

As a simplified example of how the Totex Incentive Mechanism works, suppose a distribution firm has the need to upgrade a constrained substation, due to expected load growth. The firm's business plan estimates a capital cost of expanding the substation at $12,000,000, but the efficient cost is $10,000,000 [via deployment of an advanced lithium-battery storage system], and such efficient cost is built into the projected Totex allowance. [Cost-efficient firms have used the energy-storage approach, thus the statistical benchmarking process for estimating a firm's future Totex reflects such industry best practices.]

Since the $10,000,000 investment in lithium battery storage is implicitly included in the valuation of the firm's Totex allowance, it is also reflected in the slow money portion of, and adds to the firms projected rate base. The firm will earn a return of and on the projected $10,000,000 through its annual depreciation expense and allowed return on rate-base (RAV) [Ofgem will not make retrospective adjustments to rate-base as long as the firm delivers its output targets; in this case, those related to addressing network expansion and system reliability].

However, the firm is savvy and instead of deploying an advanced battery-storage system, meets its output targets by deploying an innovative geo-targeted energy-efficiency and demand-response program, with a lifecycle cost of $5,000,000. The $5,000,000 cost savings [difference between projected Totex and actual Totex] is shared with consumers through the annual *Totex Incentive Mechanism* (TIM). The firm keeps a portion of the savings at a percentage rate called the Totex Incentive Strength Rate, say 40%. The refund to customers is at a sharing factor of (1-Totex Incentive Strength Rate) or 60%. The refund is accomplished annually by adjusting rates in the year following each Annual Iteration Process (2-year delay).

The reader should be apprised that the Totex Incentive Mechanism is a "two-way street", allowing the regulated firm to recover from ratepayers actual costs (if prudent) that exceed the base Totex allowance. However, it also caps the level of recovery of such over-expenditures. The firm bears the cost of over-expenditures at the same Incentive Strength Rate as used for keeping under-expenditures (e.g. 40%), and ratepayers cover the Totex over-expenditure at a sharing factor of [1 – the Totex Incentive Strength Rate], e.g. 60%.[4]

[4] Ofgem. (2013). ET1 Price Control Financial Handbook. Retrieved from: https://www.ofgem.gov.uk/ofgem-publications/53723/riio-et1-price-control-financial-handbook.pdf

Program improvements from learning

While creating a regulatory model and supervising its implementation are both critical, some commentators believe there is room to improve the RIIO price-control framework used in the UK. Programmatic improvements from learning are necessary for any regulatory shift, as experience is gained from assessing performance, outcomes, and outputs.

The most significant and key learning to date related to the Totex concept came out of an appeal of a price-control order setting charges for Bristol Water.[5] Water companies in the UK are regulated by the Water Services Regulation Authority (Ofwat), a non-ministerial department related to Ofgem. Ofwat's regulatory model is nearly identical to RIIO, using the Totex method of projecting cost allowances, and the "menu" regulation scheme that uses flexible sharing formulas that incentivize companies to submit accurate cost forecasts.

Bristol Water appealed to the UK's department of Competition and Markets Authority (CMA) that the Totex cost allowance approved by Ofwat was so low that the firm was essentially non-financeable. Ofwat agreed, ruling that the statistical benchmarking models used to calculate the Totex base allowance were defective on several fronts.

As to these defects, the models only controlled for differences in network scale and variations in regional labor rates. The models did not account for differences in topography, population density or network design. Secondly, the models assumed a common and synchronous investment cycle among utilities. This latter defect is especially egregious since capital enhancement projects, particularly those that rely on new technologies to enhance grid operations are not continuous expenditures, but "lumpy" and non-coincident between utilities.

In order to correct these deficiencies, the CMA split Totex into two categories: (1) capital maintenance plus Opex; and (2) capital enhancement.

Capital maintenance is Capex required to maintain the capability of existing assets. The sum of capital maintenance and Opex became the new base expenditure that replaces Totex [i.e. base Totex]. The CMA limited statistical benchmarking models to this newly defined base expenditure, as models for forecasting replacement and maintenance investments are relatively workable, as opposed to the difficulty in accurately forecasting infrastructure enhancement. In order to address the differences that were not accounted for, the CMA developed alternative econometric benchmarking models for the new base expenditure.

[5] For more information on the Bristol Water case study see: Competition Commission (2010). *Bristol Water Plc, Report Presented to Ofwat.* Retrieved from: https://assets.publishing.service.gov.uk/media/55194c70e5274a142b0003bc/558_final_report.pdf

On the other hand, with respect to capital enhancement (Capex that improves the existing capabilities of the network), the CMA reverted to the prior method of evaluation, *expert appraisal* of the regulated firm's business plan. [According to the CMA, enhancement is defined as a level of service delivered better than previously: examples include fewer supply interruptions for customers, fewer disruptions for the public in general, and less pollution.]

The CMA recognized that although benchmarking has advantages, "no benchmarking analysis or cost assessment method will be perfect, and there will always be limitations in any approach". Regarding those advantages, the CMA agreed (at least for the base Totex) that "Using benchmarking analysis as a starting point for cost assessment, rather than companies' business plans, reduces the risk that the cost assessment for a company is over-stated or takes insufficient account of the opportunities for cost savings. It also helps to mitigate risks relating to investment deferral that may otherwise arise under a price control framework that emphasizes outcomes."

Ofgem itself recognizes the importance of learning when administering such a complex regulatory model, noting that after it issues a price control order it will report on lessons learned and recommendations for future reviews [Handbook for Implementing the RIIO model].

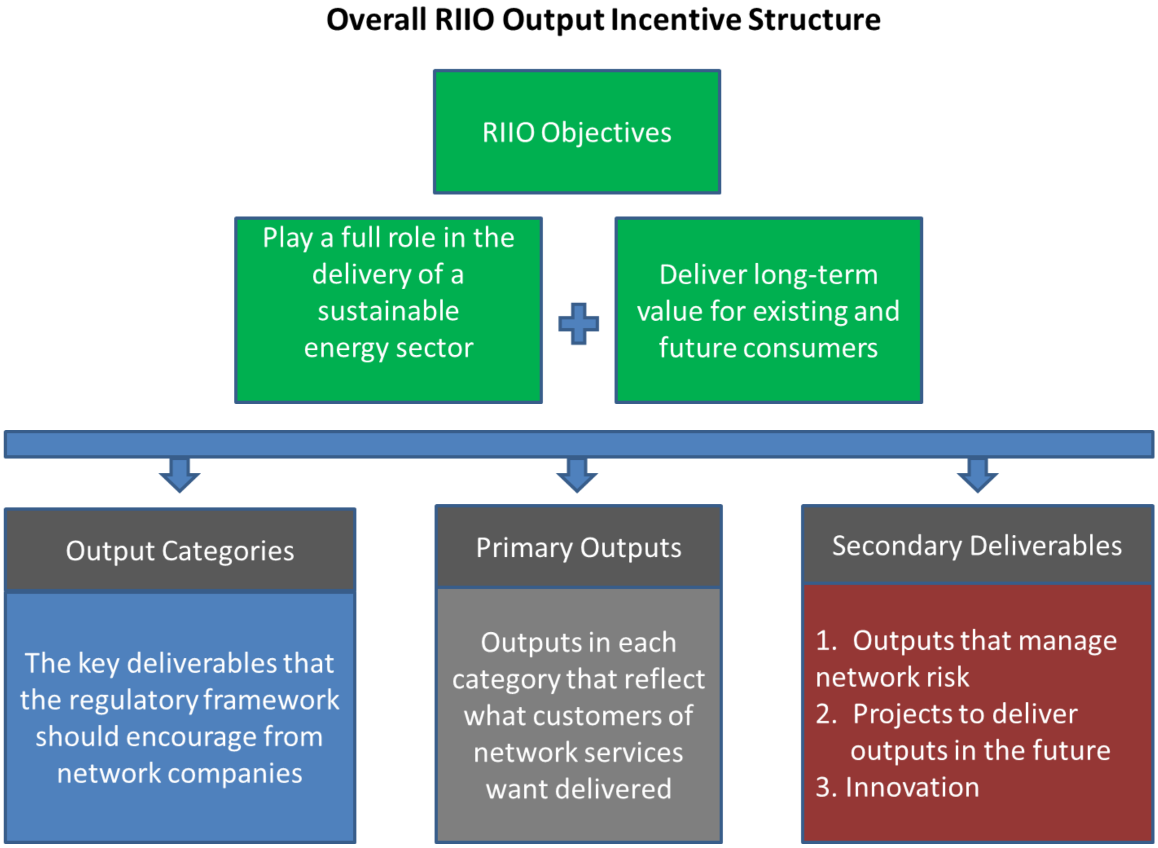
The Critical Importance of Targeted Output Incentives to RIIO

RIIO significantly expanded the diversity of targeted performance incentives. Under the former RPI-X incentive model, performance incentives were generally limited to SAIDI (system average interruption duration index), SAIFI (system average interruption frequency), quality of phone responses as established by customer surveys, and storm compensation payments to customers. In general, the RPI-X performance incentives went in both directions, i.e. included penalties. [Note, in the U.S. such targeted performance incentives are commonly referred to as Performance Incentive Mechanism's (PIM's)]

Targeted performance incentives (particularly relating to SAIDI and SAIFI scores) were found to be critical to the proper operation of RPI-X, and were thus carried over to RIIO, although expanded in number, scope and diversity.

The following chart delineates the overall output incentive structure:

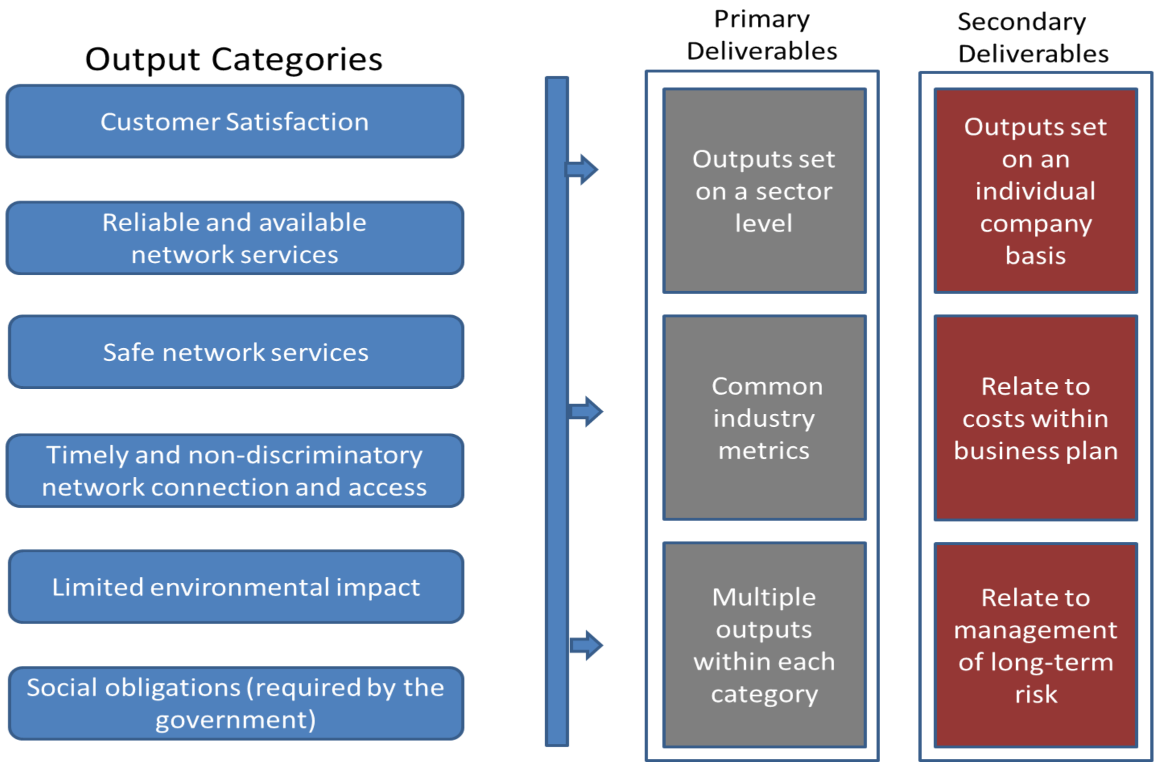
Figure 6. Overall RIIO Output Incentive Structure



Performance incentives under RIIO are intrinsically tied to the twin (core) objectives of "sustainability" and "value". These two overarching objectives are defined in terms of a set of output categories that express the key deliverables that the regulatory structure is incenting. Currently, six output categories have been adopted. Each category is broken down into primary and secondary outputs (deliverables) having specific performance metrics and associated rewards, penalties or both.

The six output categories and their associated deliverables are defined as follows:

Figure 7. RIIO Output Categories



Primary outputs (and associated metrics) are set on a sector basis. Primary outputs are related to how well the firm is serving network users in the present time.

Seconday deliverables are set on a company specific basis. Secondary deliverables relate to decisions made in the current price-control period that impact the achievement of primary outputs in future price-control periods.

The chief purpose of secondary deliverables is to prevent regulated firms from meeting primary output metrics at the expense on their ability to meet such metrics in the future. This stems from experience with the former RPI-X model, in which saw firms defer network investments so as to cut costs, and thus increase earnings in the current price-control period. In contrast, RIIO's secondary deliverables create a platform for firms to include costs to reduce future network risk in the current price control period. This negates an issue at the heart of high-powered cost-contol incentive ratemaking where the cost of addressing future network needs exceeds the benefits in the current price setting period, and is thus postponed by the regulated firm.

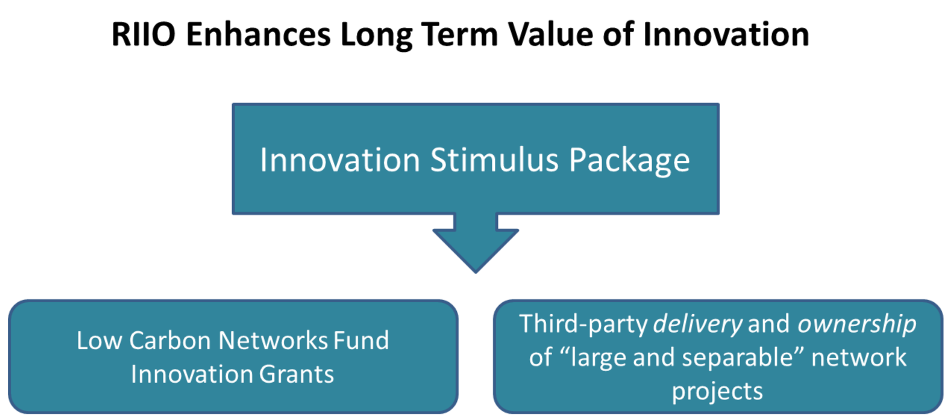
Secondary output deliverables (and associated metrics) are set on an individual company basis. It is the regulated company's responsibility to propose specific secondary deliverables, preferably in consultation with stakeholders. Clearly, a strategic planning function is associated with secondary outputs. That planning function requires companies to identify areas on the network where work may be required to maintain their such assets, and so reduce future risks to network operation, and future delivery of the primary outputs.

Although the diverse set output-goal based PIM's powerfully guides company decision-making, as an ultimate backstop, Ofgem can use the threat of its existing powers for enforcement action and potential license revocation for persistent non-delivery of outputs.

Innovation Incentives

Because infrastructure enhancement is so fundamental to meeting the UK's de-carbonization goals, an Innovation Stimulus Package was introduced and available to both third parties and network companies for innovative projects that accelerate a low-carbon and sustainable energy sector. The Innovation Stimulus Package is divided into two programs.

Figure 8. RIIO Enhances Long Term Value of Innovation



The first program provides innovation incentives is in the form of cash rewards disbursed after a time-limited competition. Rewards are sourced from the "Low Carbon Networks Fund" (LCNF).

Interestingly, the Low Carbon Network Fund has some similarities to Michigan's former Low Income and Energy Efficiency Fund (LIEEF). In both cases the funds are administered by the regulatory body, with disbursement made through a competitive request-for-proposal (RFP) process to both regulated firms and third-parties. Also, in both cases, the source of funding is through a surcharge on all network users. One distinction, is that the UK's LCNF only provides partial funding, similar to Department of Energy (DOE) grants in the US, whereas a Michigan LIEEF award could have provided near-total project funding, with only a small in-kind contribution, usually in the form of personal time donated to the project.

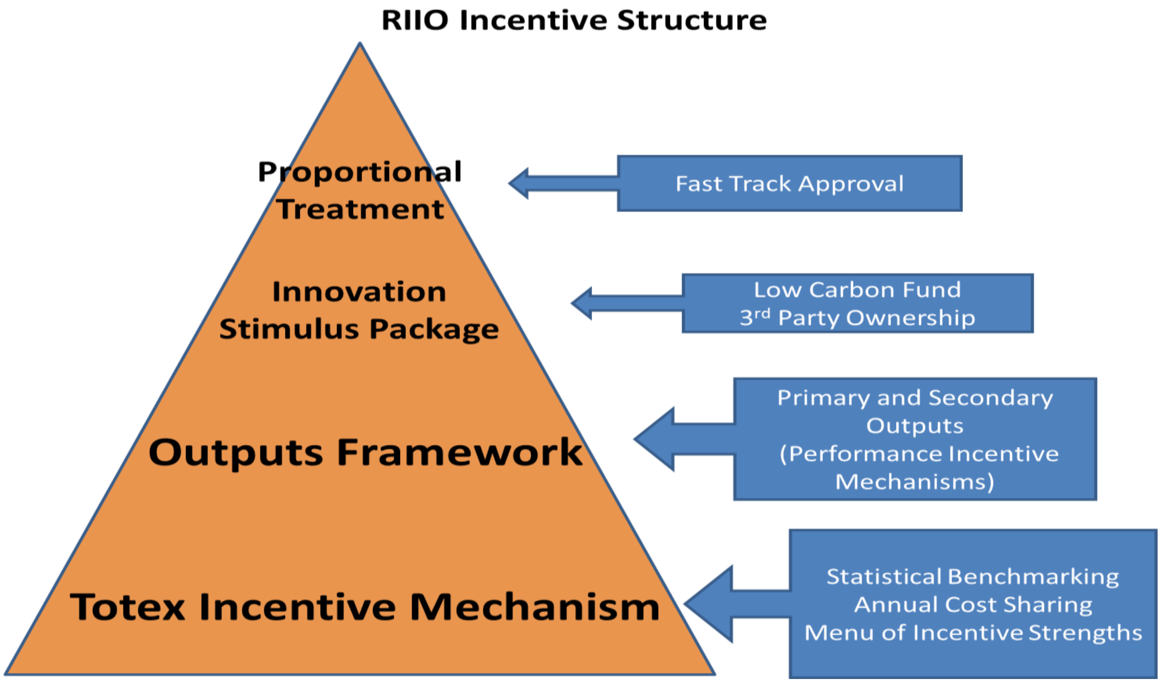
The second innovation program will drive increased long-term *value* of innovation. RIIO does this by allowing an option for greater involvement by third-parties in *delivery* and *ownership* of "large and separable" network projects. This option presumably provides a considerable measure of competition between regulated firms and privately held third-parties, with increased competition intended to drive down the cost of innovation. Such third-parties who receive approval to undertake a specific project would be licensed for provision of network services. Third parties also qualify for the LCNF funding program. The upshot is that expansion of the potential number of "network operators" appears to be consistent with the core focus of RIIO in ensuring value for consumers.

It should also be noted that regulated firms are encouraged to include innovation projects in their business case associated with their price control application. Because innovation carries with it considerable risk, such projects are considered as pilots. Since pilots are intended to demonstrate feasibility, regulated firms are not held at risk for cost recovery should the pilot demonstrate infeasibility. However, in order to minimize ratepayer risk, innovation pilots are subject to clearly defined PBR (*secondary output)* metrics.

Summary of RIIO as a broad-based incentive regulation model.

The diverse set of performance incentive mechanisms (PIM's) having an outputs framework work in conjunction with the symmetric cost-efficiency incentive mechanism for under and overspend of Totex expenditures (i.e. the Totex Incentive Mechanism), and statistical benchmarking of Totex expenditures. These foundational mechanisms, when combined with the Innovation Stimulus package and proportional treatment for fast-track approval, in aggregate constitute the *broad-based incentive regulation* scheme of RIIO.

Figure 9. RIIO Incentive Structure



Appendix C: Alternative Mechanisms used in Michigan and PBR examples from other jurisdictions

This Appendix provides examples of alternative mechanisms that have been used in Michigan. It then goes on to explore examples of PBR from multiple jurisdictions around the world, and provides more detail about PBR and PIMs in the US.

Examples of alternative mechanisms used in the past by the Michigan Public Service Commission includes O&M Indexing, System Availability Incentives, 90/10 Refunds, Electric Utility Multi-Year Rate Freezes and Energy Optimization Incentives.

O&M Indexing

The Michigan Public Service Commission utilized an indexing adjustment mechanism as far back as the late 1970's. In Cases #U-5331 (Consumers Energy) and #U-5502 (DTE), the Commission ordered the utilities to incorporate annual changes in a portion of their rates that included indexing for O & M expenses except fuel, production maintenance expense or purchase power, referred to as "Other O & M Expenses". It was a base rate plus Consumer Price Index (CPI) adjustment.

This treatment was developed to gain control of the growth of administrative and general expenses in the "Other O & M" category. Rate cases regularly included requests to cover increased costs for added personnel along with increased salary and fringes for existing staff. Under the traditional "cost-plus" system, the Commission could not effectively determine whether or not these costs were unreasonable. The utilities really had no incentive to keep these expenses down because they received no benefit for doing so. In contrast to the "cost-plus" regulated utilities, private sector entities had incentive to keep "Other O & M expenses" in check because they could not indefinitely pass on increased costs to their customers. The Commission recognized the limitations of the "cost-plus" regulation system and replaced it with the incentivized regulation that provided for a set "Other O & M" expense base allowance with an established process for adjusting the allowance in accordance with the CPI. If the utility allowed costs to increase at a faster rate than the CPI, then the utility was responsible for cost increase. If the utility kept costs lower than the CPI, earnings would be increased.

Critics of this process were concerned that this treatment did not protect the best interests of rate payers and intervenors. There were concerns that this treatment did not require that the utilities prove that O & M expenses actually increased. Some economists criticized the use of the CPI as a component in the calculation of the rate as an indicator because they believed the

CPI might be overstated based on the method used to compute it. This mechanism did seem to provide an easy process for managing "other O & M" expenses while rewarding efficient management and penalizing inefficient management. The O & M Indexing Mechanism was eliminated by the Commission in 1983.

System Availability Incentives

The Commission established a System Availability Incentive Provision for jurisdictional electric retail customers of DTE in May of 1977 (Order #U-5108) and Consumers Energy in July of 1978 (Order #U-5331). This provision served as an incentive for utilities to improve service and reliability to its customers by adhering to a service goal of system availability. The availability was determined on a calendar basis using the East Central Area Reliability (ECAR – a former regional reliability organization) model. Utilities were required to file testimony and supporting documentation showing the average system availability for the preceding calendar year. The MPSC staff performed an engineering review of the report for the period provided and made recommendations. Utility rates were then adjusted accordingly. If the annual average system availability was 0% to 70%, rate of return on common equity would be adjusted downward 0.25%. If the annual average system availability were from 70.1% to 80%, there would be no adjustment. For an annual average system availability of 80.1% to 85%, an adjustment of 0.25% was awarded. And finally, if the average system availability were between 85.1 and 100%, utilities would be awarded a .50% increase in its rate of return on common equity. This provision served the stakeholders in the process until it was abandoned in May of 1983.

The Customer Choice and Electric Reliability Act (PA 141 of 2000) required the Commission to adopt service quality and reliability standards for utility transmission and distribution systems. By Commission order (U-12270 – January 3, 2000) staff began working with utilities and stakeholders on standards. This culminated in an order in November 2003 approving administrative rules for service quality and reliability. The rules ultimately dictated that electric utilities shall operate as to permit quality service at acceptable levels of performance. Unacceptable performance was identified as any of the following:

- Using data from both normal and catastrophic conditions, the utility must restore service to 90% of its customers within 36 hours.
- Using only catastrophic data, the utility must restore service to 90% of its customers with 60 hours.
- Using only normal condition data the utility must restore service to 90% of its customers within eight hours.
- Using data from both normal and catastrophic conditions, the utility shall not experience

five or more same circuit repetitive interruptions in a 12 month period.

A utility may be eligible to request a financial incentive if it exceeds all the service quality and reliability standards. While the Commission may authorize an electric utility a financial incentive it has yet to do so. Penalties for not meeting standards have been assessed in the past. Utilities continue to update their reliability reports each year with the Commission.[6]

Electric Utility Multi-Year Rate Freezes

The Customer Choice and Reliability Act (PA 141 of 2000) required a rate freeze on the part of the utilities. The Commission was ordered to establish residential rates for each electric utility with more than 1,000,000 retail customers at a 5% reduction of rates in effect May 1, 2000. This freeze remained in effect until December 31, 2003 unless otherwise reduced. Further restrictions and freezes in rates were required subsequent to December 31, 2003. Electric Utilities during this time were able to request securitization from the Commission and recover stranded costs (utility charges that were to be recovered over time through regulated rates that would not otherwise be collected from customers that buy their generation services from an Alternative Electric Supplier), if any, as a result of the choice legislation. PA 141 required changes in the standard operating procedures of the utilities and created a focus on result oriented goals focused on efficiencies, effectiveness, reliability and quality of customer service.

Energy Optimization Incentive

Michigan's Energy Optimization programs have demonstrated the regulatory efficacy of performance incentive mechanisms. Michigan's PA 295 of 2008 [the "clean, renewable, and efficient energy act"] authorized the MPSC to approve energy efficiency programs (called energy optimization [EO] programs). All electric and gas utilities were required to submit EO plans on a biannual basis, with an annual reconciliation that included a determination of whether or not the utility met the EO savings standard. By, 2012 that standard increased to a level of 1% of an electric utility's retail sales and 0.75% of a gas utility's sales. Significantly, the statute provided for the Commission to approve an incentive mechanism for high performance. The relevant enabling section, [Sec. 75], states:

"An energy optimization plan of a provider whose rates are regulated by the commission may authorize a commensurate financial incentive for the provider for exceeding the energy optimization performance standard. Payment of any financial incentive authorized in the EO plan is subject to the approval of the commission. The total amount of a financial incentive shall not

[6] Michigan Public Service Commission's Financial Analysis and Audit Division. (2014, November) A Michigan Primer for Performance Based Ratemaking.

exceed the lesser of the following amounts: (a) 25% of the net cost reductions experienced by the provider's customers as a result of implementation of the energy optimization plan. (b) 15% percent of the provider's actual energy efficiency program expenditures for the year."

In orders issued on September 29, 2009 in Case No. U-15805 and Case No.U-15806, the Commission approved shared-savings mechanisms that provided for the maximum incentive allowed by Act 295 upon achieving 115% or greater of the minimum performance standard, with a benefit/cost score of 1.25 or better. The award was scaled for performance ranging between 100% and 115% of the statutory savings requirement (of 1% of retail savings for electric utilities or for gas utilities 0.75% of retail sales).

Subsequently, in Case No. U-16289, the Commission found that interest should not be included in the award. In all cases since 2009, an award based on 15% of program spend was less than an award based on 25% of the net benefits, so the 15% of spend became the *de facto* basis for award determination.

In the April 12, 2012 order in Case No. U-16671, the Commission determined that it was appropriate for the Energy Optimization collaborative to reevaluate the financial incentive metric so as to reflect broader measures of performance. The additional performance criteria could include factors such as:

- The extent to which EO Plan measures reduce on-peak demand;
- The availability and effectiveness of low-income programs as measured by a reduction in uncollectibles;
- Innovation of program design and implementation, and the extent to which they are focused on deep energy savings;
- Coordination of programs with other utilities or entities offering EO programs; and
- The extent to which the EO programs stimulate jobs or economic development.

In the December 20, 2012 order in Case No. U-17049, the Commission expanded the financial incentive mechanism to include specific multiple performance criteria. Multi-factor performance mechanisms were ultimately approved for Consumers Energy Gas, Consumers Energy Electric, DTE Gas, DTE Electric, Semco Energy, and Indiana & Michigan Electric. Although the multi-factor performance mechanisms had common elements for all utilities having an approved mechanism, individual utilities had some performance criteria that were specific to the utility. Examples of the key performance criteria that were added to the core metric (of exceeding the minimum energy savings standard) were: a 1.1 multiplier for long-life measures (i.e., measures with a life of ten years or more); market transformation multipliers of 1.5 to 2.0 for certain light emitting diode (LED) lighting, air-to-air heat pumps, and mini-split heat pumps; and a targeted MW peak demand savings that incented measures having a high coincident peak reduction.

EO program funding since 2009 amounted to $1.425 billion. EO Financial incentive awards authorized by the Commission since 2009 amount to $225 million. Thus, the gross program funding was $1.65 billion.

Figure 10. EO Financial Incentive Awards

EO Financial Incentive Awards							
Program Year	Consumers Energy Electric	Consumers Energy Gas	Energy - Electric	DTE Energy - Gas	Indiana Michigan Power Co.	Semco Energy Inc.	Annual Total
2009	$3,323,612	$2,361,693	$3,008,829	$913,374	n/a	n/a	$9,607,508
2010	$5,076,731	$3,407,064	$6,200,000	$2,400,000	n/a	n/a	$17,083,795
2011	$7,281,670	$7,312,307	$8,400,000	$3,400,000	n/a	n/a	$26,393,977
2012	$10,027,210	$7,282,721	$10,400,000	$4,300,000	n/a	n/a	$32,009,931
2013	$10,364,556	$7,166,544	$10,562,411	$3,848,020	n/a	n/a	$31,941,531
2014	$11,231,840	$6,090,390	$12,716,895	$3,617,094	$618,074	$780,795	$35,055,088
2015	$11,426,037	$6,277,944	$13,100,000	$3,600,000	$759,727	$933,725	$36,097,433
2016*	$11,582,390	$6,640,135	$13,300,000	$3,700,000	$609,580	$1,129,369	$36,961,474
Total	$70,314,046	$46,538,798	$77,688,135	$25,778,488	$1,987,381	$2,843,889	$225,150,737

* Anticipated

The Energy Optimization financial incentive mechanisms approved by the Commission demonstrate that performance incentive mechanisms are a useful regulatory tool to gain high performance in meeting given objectives, and in particular, to motivate utilities to pursue actions that are not normally in the short-term interests of the regulated firms. Although the EO performance incentive awards of $225 million are large, the net benefits to customers from Michigan's EO programs are much larger, being estimated at $5.53 billion.

Other States and Countries Considering/Adopting PBR Mechanisms of Various Forms

This section provides a brief overview of PBR examples that have been used in jursidctions in other states and countries. Figure 11 provides an overview of PBR for cost control in six jurisdictions.

Figure 11. PBR for Cost-Control in Six Jurisdictions[7]

Jurisdiction	**Alberta, CA**	**Australia**	**New York, USA[8]**	**Norway**	**Ontario, CA**	**UK**
Service	Distribution	Transmission (TranGrid)	Distribution (Consolidated Edison)	Transmission	Distribution	Transmission
Term	5 years	5 years	2 years	5 years	5 years	8 years
Form	Price Cap (I-X)	Revenue Cap (CPI-X)[9]	Rate Freeze	Revenue Cap (Yardstick)	Price Cap (I-X)	RIIO (Rev = Incentives + Innovation + Outputs)
Cost Benchmarking	No	Yes	No	Yes	Yes	Yes
Service Quality	Yes	Yes	Yes	Yes	Yes	Yes

PBR has also been used extensively in the United States. Numerous U.S. jurisdictions have used variations of PBR (incentive based mechanisms) to motivate adoption of energy efficiency goals and satisfaction of targets and metrics. At least 26 U.S. states have used incentives to encourage energy efficiency. These incentives range from a utility earning a percentage of program costs for achieving a savings target (8 states), to a share of achieved savings (13 states), to a share of net-present-value of avoided costs (4 states) to an altered rate of return for achieving savings targets (1 state).[10] California has utilized incentive based mechanisms since the early 80's. California has experienced many different iterations to their incentive based mechanisms while gaining valuable insight to the strengths and weaknesses of utilizing incentive based ratemaking. A California example is their gas utility mechanism that allows gas utilities to retain part of the proceeds from effectively managing gas supply costs.

[7] Elenchaus Research Associates, Inc. (2015). Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Québec Distribution and Transmission Divisions. Retrieved from: http://publicsde.regie-energie.qc.ca/projets/272/DocPrj/R-3897-2014-A-0003-Dec-Dec-2015_03_04.pdf

[8] The PBR mechanism referred to in this chart is an electric revenue adjustment mechanism, not NY REV. More information on the mechanism can be found at Elenchaus Research Associates, Inc. (2015). Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Québec Distribution and Transmission Divisions. Retrieved from: http://publicsde.regie-energie.qc.ca/projets/272/DocPrj/R-3897-2014-A-0003-Dec-Dec-2015_03_04.pdf

[9] Maximum allowed revenue is based on forecasts of the cost of service over the regulatory term.

[10] Next-Generation Performance Based Regulation – Emphasizing Utility Performance to Unleash Power Sector Innovation (September 2017). David Littell, Camille Kadoch, Phil Baker, Ranjit Bharvikar, Max Dupuy, Brenda Hayusauer, Carl Linvill, Janine Migden-Ostrander, Jan Rosenow, and Wang Xuan (Regulatory Assistance Project), Owen Zinaman and Jeffrey Logan (National Renewable Energy Laboratory). A Technical Report sponsored by an agency of the U.S. government. This report is attached in Appendix A.

Illinois approved a comprehensive incentive based mechanism structure directly associated with utility investments with their Energy Infrastructure Modernization Act (EIMA – October 2011). Illinois authorized an investment in the modernization (upgrade its electric system, smart grid infrastructure, distribution automation, and smart meter upgrades). The Illinois mechanism included formula rate increases but also penalties if certain goals such as reliability improvements were not realized.

In March 2017, Advanced Energy Economic Institute (AEE) prepared a report for Pennsylvania on PBR as a possible framework for regulation. Pennsylvania has not yet implemented PBR.

In 2017 Massachusetts, Minnesota and Rhode Island had open dockets, orders and public comment notices addressing incentive structures and rate design approaches for grid modernization, savings, and multi-year rate plans. In terms of exploring incentive mechanisms, New York's, Reforming the Energy Vision (REV) program is the most active state sponsored program in the country (see New York section below).

Many other states have examined incentive based mechanisms as a regulatory tool and are in various stages of review, discovery and planning. Additional information addressing other states incentive mechanism activities can be found in the references provided in this section.[11] [12] [13] [14]

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[11] Performance Base Regulation – Theory and Applications to California (May 2016). Dan Aas, UC Berkely – Goldman School of Public Policy and Energy & Resources Group.

[12] Utility Performance Incentive Mechanisms – Handbook for Regulators (March 2015). Melissa Whited, Tim Woolf and Alice Napoleon. Synapse Energy Economics, Inc. Prepared for the Western Interstate Energy Board.

[13] Performance Based Regulation for Pennsylvania – An Opportunity for Pennsylvania to Driver Innovation in the Utility Sector (March 2017). Advanced Energy Economy Institute (AEE).

[14] PBR State Chart (October 2017). Benjamin Stafford. Advanced Energy Economy Institute (AEE).

Table 2: Performance Based Rate (PBR) State Chart – AEE (illustrative but not complete list)

Policies	Program Area – types of performance foci	Principle(s) – guiding performance	Incentive(s) – general characterization
UK Office of Gas and Electricity Markets - RIIO[15]	Broad- gas transmission, electricity transmission, gas distribution and electricity distribution	Put stakeholders at the heart of their decision-making process Invest efficiently to ensure continued safe and reliable services Innovate to reduce network costs for current and future consumers Play a full role in delivering a low carbon economy and wider environmental objectives.[16]	Each index has a range of incentive options (e.g. min/max)[17]
Massachusetts Department of Public Utilities	Energy Efficiency Performance Incentive(s)	(1) be designed to encourage Program Administrators to pursue all available cost-effective energy efficiency; (2) be designed to encourage energy efficiency programs that will best achieve the Commonwealth's energy goals; (3) be based on clearly defined goals and activities that can be sufficiently monitored, quantified, and verified after the fact; (4) be available only for activities in which the Program Administrator plays a distinct and clear role in bringing about the desired outcome; (5) be as consistent as possible across all electric and gas Program Administrators; and (6) avoid any perverse incentives.[18]	Design-level performance is defined as 100 percent of a Program Administrator's projected benefits and net benefits (Statewide Plan, Exh. 1, at 241-242). Exemplary performance is defined as 125 percent of design-level performance, while threshold performance requires the achievement of 75 percent of design-level performance, by component (Statewide Plan, Exh. 1, at 241).
New York Public Service Commission Reforming the Energy Vision[19] – Track 2	Broad regulatory reform, emphasis on distribution-level networks to be utilized as platforms	1) reform the utility business model and 2) align ratemaking practices with an evolving set of regulatory and policy objectives	
Ontario Energy Board: Renewed Regulatory Framework for Electricity Distributors[20]	Broad regulatory reforms related to rate setting, planning, and measuring performance	Outcomes targeted for distribution companies include customer focus, operational effectiveness, public policy responsiveness, and financial performance	

[15] https://www.ofgem.gov.uk/network-regulation-riio-model
[16] https://www.ofgem.gov.uk/network-regulation-riio-model
[17] https://www.ofgem.gov.uk/ofgem-publications/86688/decisiononriio-ed1customerserviceandconnectionincentives.pdf
[18] http://www.mass.gov/eea/docs/dpu/electric/2016-2018-3-yr-plan-order.pdf
[19] https://www.ny.gov/programs/reforming-energy-vision-rev
[20] http://www.ontarioenergyboard.ca/html/performance/report_builder_select.cfm?showdist=Algoma%20Power%20Inc.

New York – “Reforming the Energy Vision” (REV)[21]

The following explores the NY REV example further, as it is the most comprehensive US example of PBR. Following Hurricane Sandy in October of 2012, a consensus evolved in New York to address aging infrastructure, improve environmental outputs and increase the reliability, affordability and distribution capabilities of its electric system. New York’s effort aims to construct a regulatory system that rewards distribution utilities for high levels of customer satisfaction, facilitates power sector transformation to cleaner and more distributed resources, and increasingly focuses on outcomes rather than inputs (similar to the United Kingdom’s RIIO approach). This comprehensive effort, still in its infancy in terms of implementation, is referred to as “Reforming the Energy Vision,” or NY REV, and is led by the New York Public Service Commission (Commission).

To incubate power sector transformation, NY REV is using a form of PBR that provides for several outcome-based incentives to be implemented, called Earnings Adjustment Mechanisms (EAMs).[22] The purpose of EAMs is to “encourage achievement of new policy objectives and counter the implicit negative incentives that the current ratemaking model provides against REV objectives.” EAMs are intended to play a bridge role until other forms of market-based revenues are available at scale to become a meaningful contributor to distribution utilities’ revenue requirements. The Commission believes the need for EAMs will diminish over time, as utilities’ opportunities to earn from platform service revenues increase.[23] However, the Commission does not intend to place a time limit of the intended bridge-role on any particular EAM, and expects that some EAMs will supplement the contributions of platform service revenues for the foreseeable future. Figure 12 illustrates this bridge for utility revenues as envisioned. The

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[21] The section on best practices for performance-based regulation draws from D. Littell, C. Kadoch, P. Baker, R. Bharvirkar, M. Dupuy, B. Hausauer, C. Linvill, J. Logan, J. Migden-Ostrander, J. Rosenow, and W. Xuan, O. Zinaman, Next-Generation Performance-Based Regulation, Emphasizing Utility Performance to Unleash Power Sector Innovation, 21st Century Power Partnership, Sept. 12, 2017, attached as Appendix F.

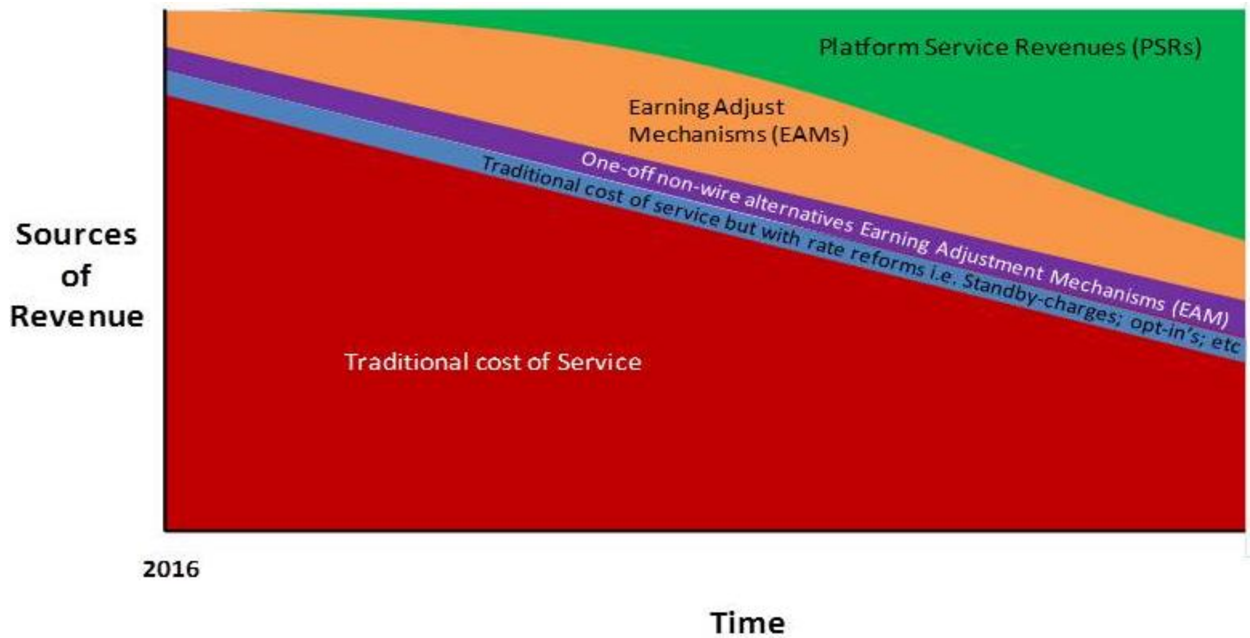
[22] State of New York Public Service Commission. (2016, May 19). Case No. 14-M-0101. *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework*.

[23] Platform Service Revenues (PSRs) are new forms of revenues utilities will earn from displacing traditional infrastructure projects with non-wires alternatives. They include: (*1*) services that the NY-PSC will require the utility to provide as part of market development; (*2*) voluntary value-added services that are provided through the distribution system provider (DSP) function that have an operational nexus with core utility offerings; and (*3*) competitive new services that can be readily performed by third parties, including non-regulated utility affiliates, and should not be offered by regulated utilities.

In the Order, the NY-PSC noted that its staff had provided examples of PSRs that could generate revenue for utilities, including: (*1*) customer origination via online portal; (*2*) data analysis; (*3*) transaction and/or platform access fees; and (*4*) engineering services for microgrids. This list is not intended to be exhaustive, as the NY-PSC believes PSRs will evolve over time as the DER market matures. Additionally the Order provides standards for evaluating and approving PSRs. Finally, the NY-PSC noted that a portion of the revenue related to PSRs should be allocated to utility earnings to provide an incentive to optimize the use of the DSP.

specific portfolio of EAMs offered to utilities by the regulator may also change over time to reflect advancing technologies with new and different capacities, such as energy storage installed at a distribution substation or at consumer premises, which would offer complementary but different capacity to grid operators and consumers. Because of the unique situation of each distribution utility, the financial details of the EAMs are developed in rate proceedings.

Figure 12. Sources of Utility Revenue Within NY REV[24]



Like RIIO, the NY REV process focuses on outcomes, because the Commission believes that this focus will be the "most effective approach to address the mismatch between traditional revenue methods and modern electric system needs."[25] This "outcome orientation" also has the potential to better align utility activity and performance with public policy and societal objectives of the regulators and jurisdiction authorities.

[24] Mitchell, C. (2016). U.S. Regulatory Reform: NY Utility Transformation. U.S. Regulatory Reform Series. Retrieved from http://projects.exeter.ac.uk/igov/us-regulatory-reform-ny-utility-transformation/

[25] The early New York experience with one utility is that in order to ensure the EAMs are outcome-oriented, there should be a strong stakeholder group and process to help define the metric outputs (the individual measurable activities undertaken by the utility, such as "X number of calls answered in less than 20 seconds"). If a stakeholder group does not exist, the utility may be more likely to propose metrics based on program targets rather than outcomes. This tendency may change over time as experience with New York's EAMs grows and also as a function of strong utility leadership.

Appendix D: Performance Incentive Mechanism Options

PIMs have been used successfully for many decades in the US and other jurisdictions. Multiple jurisdictions have developed experience using various types of PIMs to incentivize utilities to achieve specified energy efficiency performance criteria. Further, experience with multi-state utilities in the U.S. demonstrates that PIMs can help to improve utility energy efficiency program performance markedly. Experience has shown that utilities with operations in multiple states substantially improved efficiency in states offering incentives.[26]

Michigan has identified a particular interest in controlling utilities costs, yet ensuring adequate system investments occur. Cost control is often pursued through a multi-year rate plan with a cost- or revenue cap. Multi-year rate plans can be layered on traditional cost-cap regulation. Typically, a multi-year rate plan approves a set rate, with the utility sharing in the savings it achieves through operational efficiencies over the time period.

Combining multi-year cost-cap regulation with efficiency PIM incentives that allow utilities to earn revenue even with lower sales can incentivize other utility behavior such as pursuing energy efficiency measures. These proven mechanisms illustrate the potential of PBR (multi-year rate plans) and PIMs (additional efficiency incentives) to be effectively layered onto existing regulatory structures and yield excellent results both to control costs and incentivize efficiency program implementation.

A critical design consideration in the structure of PBR or PIMs is the appropriate level of impact. Policy makers and regulators need to assess the level of impact they want the PBR or PIM to have. If applied incrementally, PBR or PIM can provide a low-risk test of whether utility performance can be improved with incremental modifications to existing regulatory structures. If the initial impact is not consistent with the jurisdiction’s goals, the PBR or PIM can be flexibly adjusted to assess whether the desired outcomes are achieved or not. Success in implementation may be able to be measured at low incremental levels and can be assessed in evaluating the performance target.

The countervailing consideration for policy-makers and regulators is that PBR incentives are unlikely to make a major impact if they remain a thin icing on a cake of existing utility revenues, earnings, and the executive promotion system. If the primary measures of revenue remain as invested capital (in private utilities), sales, size of utility, and revenue, then PBRs will have little impact on outcomes. In other words, it may not work to have all but a minor fraction of revenue

[26] EE incentives were found to motivate utilities to improve EE performance targets. Nowak, S., Baatz, B., Gilleo, A., Kushler, M., Molina, M., and York, D. (2015) Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency. ACEEE. Retrieved from: http://aceee.org/research-report/u1504.

determined by invested capital – such minor PBR may or may not work depending on the overall incentives facing the company.

A moderate alternative between a full-scale PBR such as RIIO or NY REV and minor PBR incentives might be to have a significant fraction of revenue come from service and performance rewards. For privately-owned utilities, the cost of debt service and operational expenses determine a floor to maintain utility solvency for utility operations. The cost of debt service is a minimum floor for utility revenue whether privately or publicly owned. For investor-owned utilities, a negative incentive scheme could set incentives between the cost of debt return level and the allowed return on equity, whereas a positive incentive scheme could set incentives above the allowed return on equity to recognize superior utility performance as a competitive market would reward superior business performance.

To understand how PIMs can be most effectively layered on top of traditional cost-of-service regulation, it is important to understand the incentives that are inherent in traditional regulation. Utility management, whether private or publicly-owned and managed utilities often are motivated toward large investments that increase rate base (the "Averch-Johnson effect" [27]). Traditional cost-of-service regulation sets a rate of return on rate base[28] and so the utility is incentivized to increase revenue (and earnings for shareholders if privately owned) by investing in its own plant. Early forms of PBR designed to counter the Averch-Johnson effect by allowing utilities to keep savings from efficient operations. This early form of PBR, multi-year rate plan mechanisms, set electric rates and adjusted them for inflation and productivity. Utilities that operate with fewer costs than what was approved in the last rate case (adjusted for inflation and productivity) can keep some or all of the savings. In this way, multi-year rate plans reward cost control. This means that between rate-setting proceedings, prices increase as function of inflation, and are reduced by expected productivity gains, but not as a function of capital investment.

With a performance-based compensation mechanism, efficiency, or distributed energy resources decrease utility earnings. Not only do DER investments potentially reduce the need for utility investments, DERs also reduce utility sales volume which reduces utility revenue in the short-run. The utility desire to build rate base and increase the volume of sales (the "throughput incentive") give utilities two strong structural incentives to resist DERs, even in scenarios where

[27] The "Averch-Johnson" effect is identified by economists as the tendency of regulated companies to engage in excess capital investments to increase their profits.

[28] For publicly owned systems with no private shareholders, there is still revenue and earnings pressure. Universally, lenders (bondholders) demand certain coverage ratios to justify investment grade interest rates and enable reasonable retail rates which drive revenue concerns. Other hidden incentives for growth include federal and global aid programs where loan administrators pursue volume of loans and grants placed. A related concern is setting administrator salaries keyed to the size of the electric system.

they are the lowest cost resource option available. These factors can become barriers to deploying DER solutions.

A PBR structure can incentivize utility cost control and utility revenue growth: The multi-year rate plan, an early form of PBR, is also a proven form of PBR to control costs. As always with PBR, it must be carefully designed to achieve cost control objectives and not to encourage undesirable outcomes. Shared saving or percentage of program revenue approaches are common for energy efficiency programs to provide utilities with a share of the savings from successfully implementing conservation and efficiency programs. Shared savings or revenue sharing is usually predicated on successful program implementation, sometimes with thresholds to achieve a utility-incentive. These are classic "performance based" incentive programs. Michigan's Energy Waste Reduction program follows this general model of increased levels of utility compensation with better utility performance on energy waste reduction.

In the context of advanced grid technologies, a cost cap may provide an approach to incentivize utilities to market to new EV customers and increase sales. Utilities under a multi-year rate plan may be able to retain or share in revenue growth from revenue of EV-based rates between rate cases.

Multi-year rate plans can encourage competition – in this case competition of electric utilities with transportation fuel providers. Multi-year rate plans are often adopted to allow utilities more flexibility in marketing when faced with competition and to allow superior utility performance to earn superior returns over a multiple year period. Utilities should have management time freed up to respond to competitive pressure by providing superior service and lower costs. On the other hand, utilities should not be allowed to use its monopoly status to block competition through interconnection or other processes. Multi-year plans could encourage anti-competitive behavior as well, if not addressed through other mechanisms.

Multi-year rate plans could provide an incentive for utilities to market attractive rates, perhaps EV specific rates or perhaps time-of-use rates -- to ratepayers for home EV charging because utilities would enjoy increased revenue from additional sales. Use of electricity for efficient air-source heat pump application also is a growth market in many states for electricity sales. In this manner, growing consumer usage through home EV charging and as a heating "fuel" is entirely consistent with the multi-year rate case model developed in the U.S. In states with multi-year rate plans and where utilities have marketing flexibility, the multi-year rate plan approach has potential to become a powerful driver of EV charging usage and interest among utilities and utility customers.

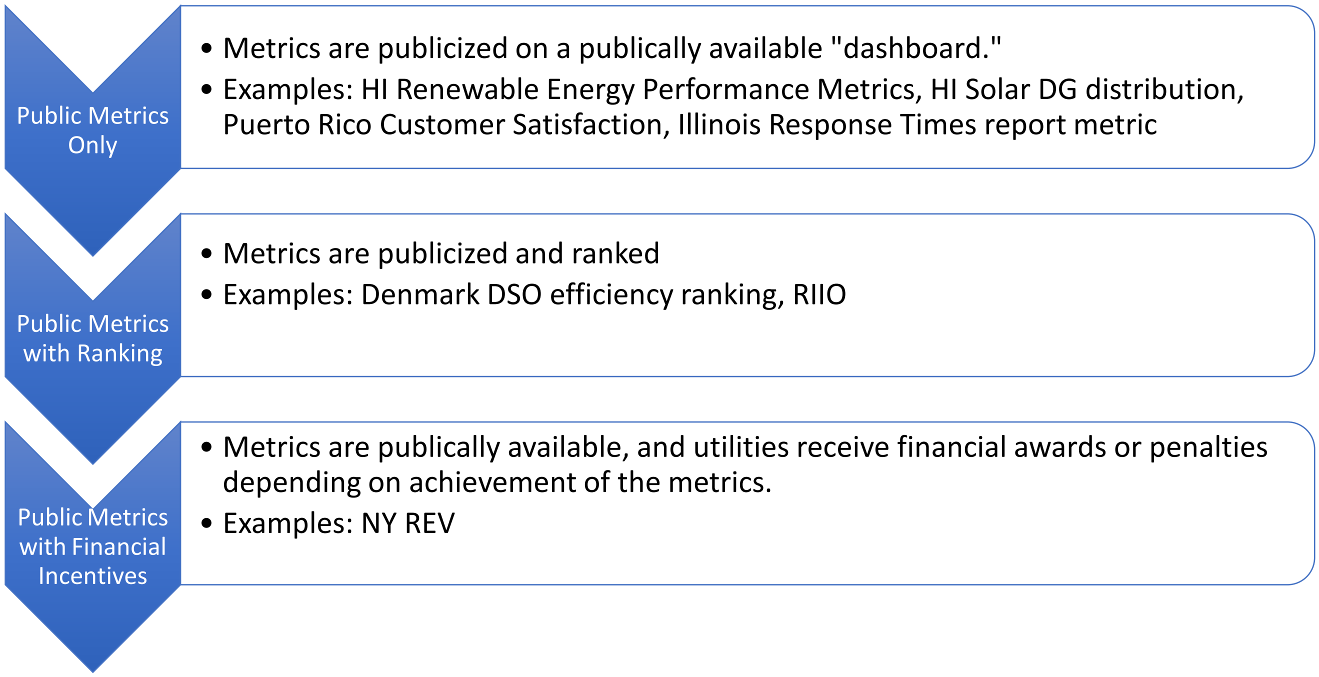
Public reporting obligations as a transition to fully developed PIM's with incentive associated metrics

Public reporting obligations, such as tracking specific performance criteria and metrics that are important to a jurisdiction, are a way to build experience with performance metrics prior to attaching rewards or penalties. The benefit of a public report-only metric is that regulators and utilities can implement performance metrics without attaching financial awards to gain experience and training as the performance metrics are fine-tuned. Regulators, utilities and stakeholders can examine what's important and ask how we are doing without focusing on obtaining rewards or penalties – at least initially. Then, after a while regulators and utilities can ask, "if we were doing better, what is that worth?"[29]

Reporting obligations for performance criteria and metrics themselves can be a light form of PBR: a reporting requirement and metric without a positive or negative financial incentive connected with the reporting obligation. The establishment of a reporting obligation communicates the importance of that performance criteria and metric. The requirement that utilities track, analyze and report specific information can both encourage different utility behavior, be precedent to establishing incentives, and provide transparency which may allow other stakeholders to address utility performance through various regulatory, public or policy avenues. Figure 13 illustrates the continuum of metrics for PBR, ranging from reporting metrics made publicly available, to public reporting of metrics with financial awards or penalties based upon performance.

[29] The U.S. State of Vermont used this approach and now has utility-specific service quality plans for all utilities. Vermont Public Service Board. (2016, December 9). Service Quality Plan. Retrieved from: http://psb.vermont.gov/document-category/service-quality-plan?page=1

Figure 13. Metrics Continuum



A few options Michigan could consider for a public tracking metric include progress on green pricing programs and on-bill financing.

Green Pricing:

Under Public Act 342, electric utilities must offer customers the option to participate in a voluntary green pricing program. Under this law, customers can specify the amount of electricity provided to the customer that will be generated from renewable energy. Utilities are to submit their programs to the Commission for review in the fall of 2017, for review of 1) whether different customer preferences or objectives are met, 2) how program costs are calculated, 3) how much of fees go to marketing and administration, and 4) whether the program is based on cost-of-service principles. The programs are to be reviewed every two years, with the next review scheduled for October 2019.

A public tracking metric or metrics, based on survey results of customers enrolled in the green pricing programs, could help the Commission and utilities identify whether customer objectives and preferences are being met, and make apparent clarifications or improvements.

On-Bill Financing:

Under the new energy law, rate-regulated utilities may offer residential customers the option to finance home energy improvement projects, and the ability to pay off the costs of those projects on their utility bill. The Commission is to work with utilities and other interested parties to create a framework for “on-bill financing” programs. A public tracking metric could be developed as part of this framework to enable the Commission and utilities to track the number of improvement projects that use on-bill financing, customer savings, and feedback from customers on various the utility offerings and implementation of this option.

PIM structure

When designing a PIM, as with any PBR mechanism, the following are considered best practices.[30]

Clear Goal Setting – if the goal is not clearly set, the metrics, incentives and outputs will likewise not be clear, and can lead to an unsuccessful mechanism;

The important initial steps in creating a PBR mechanism are to identify, articulate and prioritize goals, then to understand how well or poorly conventional regulation meets those goals in a business-as-usual scenario. This goal setting can be legislative, ideally at a high-level, to be further refined in detail needed for effective PBR through commission processes.

An honest assessment is needed and is not trivial since it is a self-assessment by the regulator of its process or an independent governmental/legislative or third-party assessment of the current regulatory structure in meeting the cost and public policy goals of the State. If reallocation of risk is being considered as between ratepayers and utilities, then the stakeholders must understand who bears the risk now, how a shift in risk will affect investment and operational decisions, reductions in net risk through providing more certainty, and whether there are cost-management implications to shifting risk.[31]

For example, if new natural gas combined-cycle generation and/or pipelines to supply natural gas are proposed based on the expectation of low nature gas prices, who pays for higher gas supply costs and electricity costs if the projections of low nature gas price are incorrect? Usually utility proposals implicitly shift the risk of inaccurate price predictions to ratepayers – is there a way to share the risk so utilities and ratepayers share the risk of price projections being accurate? The outcome of this process could be that guiding principles that support a diversified generations portfolio or could support DER adoption. The goals may also focus on cost-cutting or risk shifting. This topic is further covered in section i below.

[30] The section on best practices for performance-based regulation draws from D. Littell, C. Kadoch, P. Baker, R. Bharvirkar, M. Dupuy, B. Hausauer, C. Linvill, J. Logan, J. Migden-Ostrander, J. Rosenow, and W. Xuan, O. Zinaman, Next-Generation Performance-Based Regulation, Emphasizing Utility Performance to Unleash Power Sector Innovation, 21st Century Power Partnership, Sept. 12, 2017, attached as Appendix F.

[31] Regulatory Assistance Project. (2000). Performance-Based Regulation for Distribution Utilities. Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/wp-content/uploads/2016/05/rap-performancebasedregulationfordistributionutilities-2000-12.pdf, p. 19.

Identification of Clear and Measurable Metrics – metrics should be able to be clearly identified, with measurable and objective data;

A metric is a quantitative measure that is useful in assessing utility progress toward a goal or target. A metric is best if it is objective and under the utility's control.[32] While directional incentives provide measurable performance criteria to evaluate whether the guiding incentives are being met, metrics are the medium through which measurable performance criteria are applied. Utility performance metrics can be thought of as a set of specific, quantifiable outputs of work that represent aspects of utility service that are critical to successful outcomes. Each metric should have measurable performance criteria against which results can be measured. Individual accomplishments related to each metric are scored relative to a reward scale to determine an incentive level. Metrics can then be used individually or in combination to create a basis for an incentive reward.

Metrics work well if they are able to use a standard definition or, lacking that, are precisely defined. The availability of relevant data to evaluate how close the utility is to achieving its goals is critical to determining the effectiveness of the directional or operational incentive. The availability of information applicable to the goals and metrics is necessary for purposes of awarding incentives or assessing penalties. Some basic considerations in setting metrics are:

- Reliable data is a prerequisite to measuring utility performance. Data should be evident on its face and not subject to multiple interpretations. Ideally, data is available or can be made available so that results measured by metrics are more objective than subjective.
- If data are not available, consider how and who will develop it and who will verify the data under the metrics adopted.
- Avoid the need for precision where precision adds little value, particularly compared to the cost of obtaining such precision.

Establish Transparency at Each Step -- transparency at each step of the process, including the development of goals, metrics and incentives often improves the quality of the final goals;

Transparency is essential at each step of the process of establishing a PBR, including the development of goals, metrics and incentives, and often improves the quality of the final goals. Stakeholders, utilities and the public may have more refined targets and experience than regulators. And transparency can lead to utility, stakeholder, customer and public buy-in,

[32] Widespread use of performance systems in institutions and settings as disparate as employment and foreign aid programs show that the entity subject to the performance evaluation should have control over the factors influencing their performance.

enhancing the credibility of targets and reducing the risk of (oftentimes very public) disagreements when rewards or penalties are applied.

Transparency is important because:

Broad stakeholder involvement is critical: Transparency is important for the stakeholder process in two ways: 1) for ensuring that broad stakeholder groups are involved and 2) by including broad viewpoints and incorporating them into the process, consensus is more likely.

Stakeholder involvement can lead to consensus -- By having the stakeholders work together to develop the list of goals, incentives, performance measures and metrics for utility performance improvement and consider how the utility will be rewarded and/or penalized as a result, the stakeholders may set the stage for consensus-building. Working together builds the relationship and opens dialogue among the parties, even when there are substantive disagreements. To the extent that consensus is reached, it reduces the risk of denial of requests for cost recovery.

Reveals the value of the PBR construct: A transparent process with broad participation provides a mechanism for regulators, stakeholders and the utility to understand the value proposition offered by a PBR construct. Utility participation in stakeholder processes also affords utilities a sharper understanding of what is important to other stakeholders, and how achieving the goals of PBR constructs could increase their bottom line.

Make Value to the Public Clear -- The public values understanding what utility services they are paying for. A guiding goal with directional and operational incentives and performance criteria is a transparent commitment from the utility to its customers and the public with an opportunity for reward. PBR can offer a clear “value for money” transaction to the utility, customers and the public. Value comes from exceptional or beyond compliance utility performance, creating tangible value for specific customers or the public. A clear set of goals, performance criteria and metrics that the public and stakeholders can understand benefits them. This can be useful in a transition to a new regulatory model based on performance rather than rates.

Align Benefits and Rewards -- Aligning customer receipt of benefits through timely payment of rewards and incentives (or imposition of penalties, if negative impacts occur) is advisable to the extent practical and feasible. When rewards and penalties are applied closely in time with utility performance, the relationship of incentive to performance is easier to assess. A close linkage can reduce the probability that regulators over- or under-reward utilities for performance in the eyes of customers. For instance, if consumers have a season of poor service quality, application of reduced utility revenue or penalties is more easily understood and assessed by customers, the public and the utility itself if done close to that season and with direct reference to seasonal service quality.

Learn from Experience -- Learning from experience and modifying PBRs to address operational observations is a good management practice. Because some outcomes are driven by influences partially outside of utility control, utilities may be reluctant to accept a pure outcome target or metric. One method to address this is to consider a rolling multi-year average rather than a pure annual target or annual metric. Over time the range of utility performance becomes evident as well as trends in a rolling average.

Compared to What? -- The simple question that looks for improvement in regulatory mechanisms along a continuous improvement pathway; PBR discussions can get mired in efforts to reach the perfect set of incentives (in a very imperfect world). It is easy to focus on areas that are not especially important and lose recognition of how a proposal compares to the existing utility system.[33] This question is helpful in program design and examination of program improvements. It is a simple question that looks for improvement in regulatory mechanisms along a continuous improvement pathway.

Simple Designs are Good -- To minimize the risk of gaming, the best bulwark is to design a clear and well-defined metric. If the metric, as well as the corresponding data required to evaluate it, are difficult to measure, manipulation can be more difficult to detect. This is especially the case if data are collected and analyzed by the utility, because it is potentially expensive or difficult to conduct regulatory or third-party verification of the data accuracy and analysis. Data collection and analysis that is difficult to audit or review should be avoided. Further, third-party experts can be used to collect, analyze and verify data where practical.

So while simple incentive designs are good and clarity for the public is important, that does not mean designing proper goals, incentives, performance criteria and metrics is simple. Indeed, having smart and well-financed regulatory staff is critical for sophisticated PBR design and implementation. The best PBR designs are simple and clear but require substantial expertise, effort, and regulatory competence to achieve and implement successfully.

Evaluation and Verification -- Evaluation and verification of the outputs achieved is essential to ensure ratepayers and the public are receiving the value anticipated in a PBR reward scheme. EM&V is easier when metrics are clear and data is available and independently verifiable.

[33] Regulatory Assistance Project. (2000). Performance-Based Regulation for Distribution Utilities. Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/wp-content/uploads/2016/05/rap-performancebasedregulationfordistributionutilities-2000-12.pdf, p. 4.

Innovation and market transformation through PIM's

The following are innovative examples of PBR mechanisms that may be adopted as specific PIMs in Michigan.

Demand Response

New energy legislation in Michigan requires the Commission to promote voluntary load management programs such as demand response programs, time-of-use and peak pricing, and air conditioner remote shut off. Additionally, it requires certain utility companies to offer Commission-approved demand response programs. A PIM could be the primary implementation mechanism for some or most of these requirements and provide guidance to utilities on achieving successful demand response program participation to meet PSC-set performance criteria.

The demand side of the power sector has historically been unresponsive to supply-side conditions.[34] New technology is now enabling customers from all segments to behave more responsively to the real-time price of energy, and enabling them to receive payments for shifting their demand when grid conditions require it. This is occurring through both regulated utility programs and via private third-parties; in both scenarios, an entity is responsible for aggregating groups of customers, calling upon them to reduce demand when needed, and facilitating a payment for services. Demand response programs are growing in number and sophistication, with some aggregation schemes allowing participation in wholesale power markets. There are still many technical and regulatory barriers to entry, with unresolved issues in many markets concerning, *inter alia:* access to customer and market data, the role of 3rd party aggregators, and reliability of and fair compensation for demand response resources. As increasing amounts of low-cost variable renewable energy drive the need for greater system flexibility, the aggregation of demand response may prove to be a valuable resource for many power systems.[35] [36]

Regulators can use utility-specific economic and engineering studies to set targets. Energy efficiency and demand response potential studies can identify the amount of investments that would be cost-effective for the utility to make. These studies can help regulators identify and

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[34] A notable exception to this statement is the example of large industrial customers (e.g., aluminum smelters) who enter into interruptible load demand response contracts with utilities, oftentimes for contingency events.

[35] In competitive markets, the energy service company (ESCO) business model is predicated on monetizing a portion of the value associated with saving consumers money on their electricity bills. ESCO revenues are generated by sharing the savings achieved and thus driven by reductions in savings from retail prices. Whether that model can now extend into energy supply and potentially wholesale markets is an open question.

[36] D. Littell, C. Kadoch, P. Baker, R. Bharvirkar, M. Dupuy, B. Hausauer, C. Linvill, J. Logan, J. Migden-Ostrander, J. Rosenow, and W. Xuan, O. Zinaman, Next-Generation Performance-Based Regulation, Emphasizing Utility Performance to Unleash Power Sector Innovation, 21st Century Power Partnership, Sept. 12, 2017, attached as Appendix F.

define specific resource investment targets and costs.[37]

Metrics associated with demand response depend in part on the specific goals to be achieved. Demand response can be used for peak load reduction, load reduction to avoid targeted infrastructure investment, customer engagement, ancillary services to accommodate variations in net load, etc. Metrics for this area typically include: percent of customers per year, number of customers enrolled, MWh of DR provided over past year, potential and actual peak demand savings. However, if a policy goal is to improve the system load factor by reducing peak demand, it is not meaningful to simply report the number of customers enrolled in a demand response program, as this provides no information regarding whether these customers actually reduce demand, and by how much, during peak periods. To be useful, a metric should reflect whether or not the underlying policy goal is being met; e.g., whether peak demand has decreased over the prior year.[38]

Codes of Conduct

20th century rules of separation between regulated and unrelated utility businesses are even more critical as new opportunities competition from third-parties and for unregulated utility businesses are now present through advanced technologies. Code of conduct are traditionally used as a way to regulate a monopoly utility's ability to favor its own affiliates. The Michigan Legislature recently mandated that the PSC review code of conduct revisions in Section 10ee of Senate Bill 437 (H-4). In particular, the code of conduct is to prevent cross-subsidization, preferential treatment, and information sharing between a utility's regulated services and unregulated programs and services. PBR is a potential mechanism to create a self-implementing PBR mechanism.

Codes of conduct govern how utilities (and their affiliates) interact with companies that compete with them. Historically monopolies did not have competition. In the late 20th and now 21st century, competitive opportunities can emerge through restructuring of the electric industry[39] and later advanced technologies offered through energy services companies[40]. Even in restructured

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[37] Whited, M., Woolf, T., and Napoleon, A. (2015). Utility Performance Mechanisms: A Handbook for Regulators. Synapse Energy Economics. Retrieved from: http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p.37.

[38] Whited, M., Woolf, T., and Napoleon, A. (2015). Utility Performance Mechanisms: A Handbook for Regulators. Synapse Energy Economics. Retrieved from: http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf

[39] Seventeen states and the District of Columbia have adopted electric retail choice. US Energy Information Administration. (2012). Electricity Retail Choice 2010. Retrieved from: http://www.eia.gov/todayinenergy/detail.cfm?id=6250

[40] See for example, the NY Reforming the Energy Vision proceedings, NY DPU CASE 14-M-0101, Feb.26,2015, among others; DC PSC, Formal Case No.1130, In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability; California PUC, Distribution Resource Plan, http://www.cpuc.ca.gov/PUC/energy/drp/

markets, utilities maintain monopoly positions over certain services and will often have superior economic resources and access to customer and market information and system knowledge that competing companies cannot match unless it is shared by the utilities. If a utility can use its economic and information advantages, there is the risk it can drive out competitors and operate as a deregulated monopoly, exercising market power. While the rules to prevent anti-competitive behavior can be detailed and in certain respect quite distinct among jurisdictions, there are basic principles that govern the establishment of rules:

- Discrimination in providing access to essential services should be prohibited.
- There should be no sharing of competitive information among companies affiliated with the utility.
- Cross-subsidization by the utility to benefit a competitive enterprise, such as an affiliate, should be prohibited and carefully monitored.[41]

By way of recent historical example, many U.S. states enacted codes of conduct as part of their restructuring procedures.[42] Examples of codes of conduct include the New York Public Service Commission's Order as part of the Reforming the Energy Vision proceedings,[43] PEPCO Holdings,[44] and Dominion Resources Inc. as between its affiliates in North Carolina and Virginia.[45] Texas also has a comprehensive code of conduct addressing the affiliate relationship.[46] All of these codes of conduct are fairly similar in substance and put into practice the three basic principles described above. These concepts can be applied to multiple aspects of a utility business in which a regulated utility or its affiliate enters the market to offer a competitive service. Table 2 describes various common aspects of utility codes of conduct for interacting with their own affiliate companies, as well as competitors.

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[41] See Migden-Ostrander, J. (2015, November). Power Sector Reform: Codes of Conduct for the Future. Electricity Journal, 28(6), p.4. Retrieved from: https://www.researchgate.net/publication/285216738_Power_Sector_Reform_Codes_of_Conduct_for_the_Future

[42] An example of a code of conduct filed in Ohio by the Customer Coalition for Choice in Electricity (1999, October 13). In the Matter of the Promulgation of Rules for Electric Transition Plans and of a Consumer Education Plan Pursuant to Chapter 4928 Ohio Revised Code. Case No. 99-1141-EL-ORD. Appendix C. Retrieved from: http://dis.puc.state.oh.us/TiffToPDf/J_YLZ8DECRL5YXDH.pdf

[43] State of New York Public Service Commission. (2016, September 15). Order Setting Standards for Codes of Conduct. Case Nos. 15-M-0501 and 14-M-0101. Retrieved from: https://www.energymarketers.com/Documents/utility_code_of_conduct_DER_order.pdf

[44] Pepco Holdings. (undated). Codes of Conduct. Retrieved from: http://www.pepcoholdings.com/codes-of-conduct-/

[45] Dominion. (undated). Code of Conduct Governing the Relationships between Dominion North Carolina Power, its Affiliates and the Nonpublic Utiltiy Operations of Virgina Electric and Power Company. Retrieved from: file:///Users/camille/Downloads/codes-of-conduct.pdf

[46] Texas PUC (undated). §25.272. Code of Conduct for Electric Utilities and Their Affiliates. Retrieved from: https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.272/25.272.pdf

Table 3. Utility Code of Conduct Areas

Type	Description
Nondiscrimination	Utility provision of the same services and information to all competitors including its own affiliates, without preferential treatment for its affiliate. Utility provision of the same information sharing and disclosure to all competitors including prohibition on sharing information with affiliates that is not shared with competitors
Corporate Identification and Logo	Use of a different name and logo from the parent to eliminate customer confusion and avoid a name-recognition competitive advantage.
Goods and Services	Transfer of goods and services to, sharing of facilities with, an affiliate only at market price to the regulated utility for any goods or services received to avoid a subsidy from ratepayers and prevent it from gaining a competitive advantage. Sharing equipment and costs sharing does not occur between the utility and distribution company except for perhaps corporate services.
Joint Purchases	The utility should not be allowed to make joint purchases with their affiliate that are associated with the marketing of the affiliate's products and services.
Corporate Support[47]	Shared corporate support must be priced to prevent subsidies, be recorded and made available for review.
Employees	The utility and their affiliate(s) do not jointly employ the same people, with the only exception being shared directors and officers from the corporate parent or holding company.

[47] Corporate support means overall corporate oversight, governance, support systems, and personnel Any shared corporate support between the utility and the competitive entity should be priced to prevent subsidies and should be recorded and made available for review. The use of combined corporate support should exclude the opportunity to transfer confidential information, provide preferential treatment or an unfair competitive advantage, or lead to customer confusion.

For codes of conduct to be effective there needs to be regulatory oversight including requirements for compliance plans and audits to ensure that the codes of conduct are being adhered to. The utility is usually required to maintain a compliance procedure and log in which it records all informal complaints and their disposition. The regulator usually has the ability to levy penalties for noncompliance.[48]

Incentivizing compliance with codes of conduct through PBR may offer regulatory benefits. A PBR mechanism and public metrics could foster a transparent and open environment that supporting competition and new market entrants allowing energy services markets to flourish. Such as PBR regime would like involve tracking utility complaints, and makes public how the utility is responding to, for example, interconnection requests or sharing data with third party DER providers and facilitating customer consents when necessary. The PBR metrics could track the number of complaints of violations made to the utility. Complaints most often go directly to the utility; thus, a requirement to keep a log to document the complaints is necessary. Since competitive companies are dependent on good will and utility relationships, they may be reluctant to file complaints. For that reason, the utility log of complaints can be a useful tool. The logs will indicate the resolution of issues as well as indicate any patterns of recurring problems. Unresolved matters or serious complaints would be addressed at the regulator level. The information obtained by the regulator can be used to form the basis of metrics regarding utility interaction with competitive DER providers.

It is unusual for violations of codes of conduct to be adjudicated by regulatory officials. Such investigations are not common and a PBR scheme can incentivize compliance (or disincentivize noncompliance) much more efficiently than a regulatory adjudication. Any regulatory adjudication to effectuate a policy goal is weakened when there is a probability is will not occur due to lack of regulatory resources. Further, the expected nature of compliance and violations as deviations from acceptable norms may form the basis for creating a negative incentive or penalty.

While Michigan Considers Innovation and Market Transformation, Predictability and Incrementalism Matter: Experience with multi-year rate plans also suggests that regulatory *predictably* is important to encouraging utility and market investment, particularly over the long-term. Predictability allows utilities to project the impact of a change in utility investment or operational results on the utility revenues. Unpredictable incentives do not send efficient

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[48] See: See Migden-Ostrander, J. (2015, November). Power Sector Reform: Codes of Conduct for the Future. Electricity Journal, 28(6), p.4. Retrieved from:
https://www.researchgate.net/publication/285216738_Power_Sector_Reform_Codes_of_Conduct_for_the_Future

investment and management signals. For this reason, regulators are well advised to adjust targets and incentives gradually where a PBR system is working to encourage utility and market confidence in the investment environment.

Profit-sharing under targeted incentive mechanisms - reducing the degree of downside risk associated with innovation.

With a shared net-benefit incentive structure, the utility shares with ratepayers in the benefits associated with, and identified from, the metric achieved. This can mean sharing in financial benefits between the utility and ratepayers. In the context of EE programs, a “shared savings” approach is commonly employed to recognize and share EE savings between ratepayers and the utility.

A shared net benefits approach needs to be carefully designed and implemented to clearly identify the shared benefits, ensure the utility appropriately controls costs, and that the mechanism cannot be gamed. Implementation of shared savings schemes can be difficult because the focus on evaluation, measurement and verification (EM&V), the concept of shared net-benefit’s inherent imprecision, and translation to dollars can negatively impact a utility-regulatory-ratepayer relationship. This approach relies upon accurate benefit calculations through evaluation and measurement, and a clear EM&V plan based on objective metrics.

Shared net benefit mechanisms can blunt the incentive for utilities to control costs, which is otherwise a prime motivation for implementing PBR constructs. Worse yet a poorly designed shared benefit mechanism can give a utility motivation to invest in expensive programs that enhance utility revenue. To ensure that cost control incentives are maintained in a PBR scheme with a shared net benefit construct, the mechanism can be designed to apply to benefits outside a band where earnings are not affected. Identifying a band of savings where net benefits are likely to occur under business-as-usual scenarios is the first set to identifying savings where no incentive should apply. Then, a dead band approach adopts a range around a performance level that results in no incentive until the range is exceeded.[49]

Shared net benefit regimes also need to be carefully designed to avoid the possibility of gaming. For example, in the context of a shared savings mechanism for cost of natural gas, a large U.S.

[49] For example, no sharing of savings from EE may be appropriate within a band of, for example, EE savings of zero to 0.02, which are expected to be produced through market forces such as enhanced appliance efficiency standards. So designed, a sharing mechanism with a “deadband” operates as a reward for only exemplary performance for marked increases (or decreases) in performance. For more information on shared net benefit mechanisms and deadbands, see Regulatory Assistance Project. (2000). Performance-Based Regulation for Distribution Utilities. Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/wp-content/uploads/2016/05/rap-performancebasedregulationfordistributionutilities-2000-12.pdf, p. 4.

utility was ordered to refund $72 million to ratepayers when it manipulated its gas storage to release gas it had purchased previously at a lower cost. In this case, the gas in storage had a year-vintage, so the utility chose to release gas from very-low priced year to artificially produce a "cost savings" under a shared savings PBR.[50] In this case, the ability of the utility to control purchase and sale times with no relevant performance guideline left the system open to manipulation.

By January 1, 2021, Senate bill 437 requires the PSC to authorize a shared savings mechanism for an electric utility to the extent the utility has not otherwise capitalized the costs of the EWR, conservation, demand reduction, and other waste reduction measures as follows:

- A savings of 1 percent to 1.25 percent of the utility's total annual weather-adjusted retail sales in megawatt hours in the previous calendar year equals a shared savings incentive of 15 percent of the net benefits validated as a result of the programs implemented by the electric utility related to EWR, conservation, demand reduction, and other waste reduction, but not to exceed 20 percent of the utility's expenditures associated with implementing EWR programs for the calendar year in which the shared savings mechanism was authorized. The bill details how the PSC is to determine the net benefits.
- At least 1.25 percent to 1.5 percent savings equals a shared savings incentive of 17.5 percent of the net benefits, with a cap of at 22.5 percent of expenditures.
- Greater than 1.5 percent savings equals a shared savings incentive of 20 percent of the net benefits, with a cap of 25 percent of expenditures.[51]

A similar shared net benefits scheme could be developed for demand response programs that save the utility and customers expenditures on peak energy supply costs including the costs of fuel, peaking capacity, avoided transmission and distribution plant costs. The potential for savings from demand response programs administered by the utilities is particularly strong if specific plant, distribution and transmission investments that can be avoided through demand-response. A shared savings mechanism ideally would provide sufficient benefit to the utility that the utility prefers demand response solutions where feasible to traditional investments in plant. The savings shared with customers must be fair so there is some form of joint savings from innovative cost-effective implementation.

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[50] Whited, M., Woolf, T., and Napoleon, A. (2015). Utility Performance Mechanisms: A Handbook for Regulators. Synapse Energy Economics. Retrieved from: http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 94.

[51] Michigan Public Service Commission. (2017). Energy Law Updates. Retrieved from: http://www.michigan.gov/mpsc/0,4639,7-159-80741---,00.html

The relationship of these statutory provisions to environmental standards under PBR is addressed below in subsection 4, Environmental Impact.

Additional shared benefit provisions could be adopted under the PSC's rate making authority within specific parameters set forth by the Michigan Legislature as explored in the following sections.

Positive and Negative PIM's

To those not steeped in the utility regulation, it might come as a surprise that anticipated capital expenditures are not required to be made by the utility even if put forth in a future test year construct to calculate a revenue requirement and rate. The utility's expenditures of funds on ordinary OPEX and CAPEX is subject to prudence review after the fact but the utility decides how to spend revenue and – lacking a very specific Commission order – can alter spending even if rates are approved based on particular capital investments, projects or programs. This can manifest in changes in CAPEX and OPEX spending as well as construction delays, increased project costs, changes in plans for specific expenditures while ratepayers are nonetheless paying the Commission set revenue requirement and utility rates. In short, under ordinary principles of utility regulation, the regulators control the revenue requirement and rates, but the utility management controls spending after the rates are set.

If regulators want to guarantee a specific set of capital investments, projects, or programs are implemented on a specific timeframe or budget, more than a revenue requirement and rates are required. The Commission may set forth a very specific set of spending within specified timeframes, which a utility may resist because utility management views its job as running the business, including wise control of expenditures and project management. What is really at stake is allocation of the risk that the prospective budget and time frames prove inaccurate: Commission specification of budgets and timeframes would effectively force the risks of project implementation, project management, construction risks, financing risk, development risk, and cost management onto the utility from the ratepayers who would bear this risk if ordinary revenue requirements and rates are set using future test years. To the extent that larger capital investments spanning multiple years are envisioned, the risk of inaccurate projections of need, cost and implementation become larger.

The traditional way to manage these risks is through intensive annual Commission review of capital investments using a future test year and after-the-fact prudence review. Both mechanisms place regulators in the very difficult position of understanding business expenditures and management details prospectively (for the future test year) and retrospectively (for prudence review) from a position of information asymmetry. The utility will always understand its own financial and project decisions in far greater detail than a regulator. And, it should be noted that prudence reviews seldom result in disallowances, particularly for out-of-the-ordinary capital expenditures. And the level of knowledge and judgment necessary to pass between utility officials and regulators for capital investments in generation, distribution, and subtransmission plant places a tremendous burden on regulators to ask for requisite information and detail and to review it. It also places a burden on the utility management if these expenditures are reviewed regularly and actively.

If a good estimate of overall CAPEX and OPEX costs and timeframe can be determined in advance, it is possible to use a carefully designed PIM mechanism to provide incentives and penalties for the utility capital investment and operational expenses. This section suggests such a mechanism which provides incentives for cost savings and penalties for cost overruns.

A PIM for capital expenditures could be built into a cost-cap regime, or it could stand alone as a separate mechanism. Either way, the “new” capital expenditures would need to be added into the revenue requirement cap and translated to a rate cap adder for additional capital expenditures beyond those involved business-as-usual operations. An advisable focal point in such a system is to ensure that business-as-usual capital expenditures are counted only once in either the revenue requirement or the capital expenditure adder to avoid double recovery of these costs. Beyond that, the critical element that would require substantial effort up front is to establish a reasonable capital expenditures (CAPEX) budget and timeframe on which to calculate the capital expenditure adder (or rider). This would involve a substantial initial effort by the regulators and utility to determine a reasonable capital expenditure plan over some time frame such as 3, 5 or 8 years based on a proposed and adjudicated capital investment plan.

From a capital expenditure plan and timeframe, a series of incentives could be designed to reward the utility for implementation under budget or ahead of schedule, and penalize the utility with disallowances of some percentage of costs for delays or over-budget projects. As an example, if a utility completes a set of distribution upgrades on time with savings of 10 percent from the project budget, the utility could be allowed to keep half of those savings and half could be “returned” to ratepayers. While the symmetry of such a proposal may appear elegant, the current system results in utilities often keeping 100 percent of any saving from a future test year, so the utilities may have mixed views on sharing these saving with ratepayers.

If capital projects are managed to miss timeframes or to run over budget, a penalty of disallowing some utility expense might be imposed. So, if a set distribution upgrades is completed 10 percent over budget, the utility may only be allowed to recover half from ratepayers, and utility shareholders would be expected to absorb half of the cost overruns. Again, while the symmetry of this may appear elegant, it is worth noting that the risk of cost overruns is typically placed on ratepayers under traditional regulation (unless a prudence review finds utility imprudence). For this reason, utilities may have mixed views on sharing in cost overrun risks.

The benefits to the utility of sharing in savings and cost overruns is that they may be able to achieve long-term capital investment certainty over a specified time frame such as 3, 5, or 8 years. With that certainty, utility management can focus on project management and implementation and assessing the least costly options to address known system deficiencies.

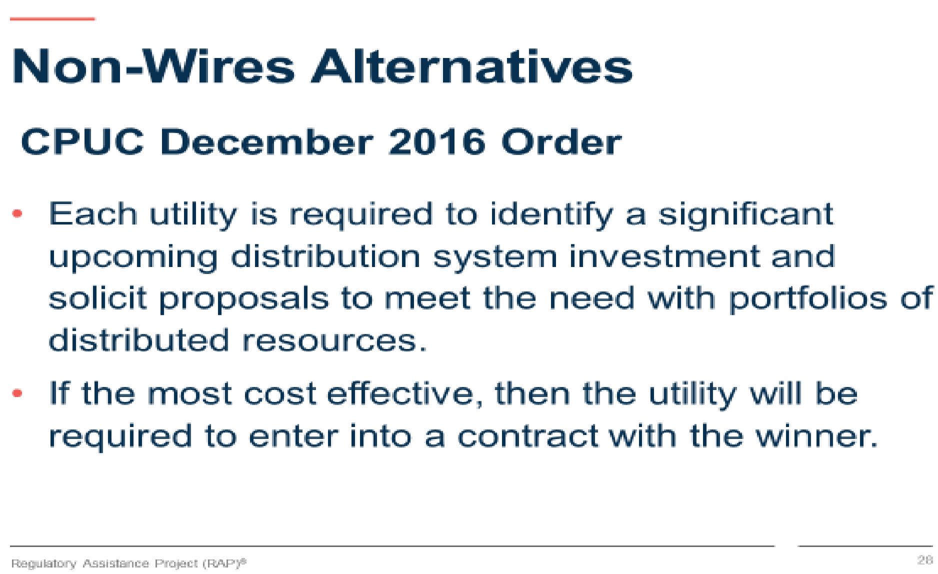
As noted above, a CAPEX adder could be structured within a cost-cap regime or as a separate rate rider. As part of a cost-cap regime, the overall effort might begin to resemble a multi-year cost-control PBR system. Again, establishing such a regime would entail substantial effort initially to determine a reasonable baseline for a multi-year cost cap and then a reasonable budget and timeframe for capital expenditures deemed necessary beyond business-as-usual CAPEX and OPEX. System needs assessments would be followed by assessments of least-cost solutions and then cost basis for proposed solutions sets for generation, distribution and subtransmission systems where some system needs can be addressed through a variety of different solutions.

The advent of advanced grid technologies makes each aspect of this needs and solutions inquiry more difficult, but also presents opportunities for cost savings not previously available. The task is more difficult because predicting future generation capacity necessary for resource adequacy and distribution plant CAPEX is influenced by the magnitude and type of consumer investments and interconnections for distributed resources including distributed generation. These resources can either complement and support the existing grid or place additional burdens on the grid if poorly integrated. A well-designed PBR system would provide the utility and customers with incentives to coordinate their efforts to maximize the mutual benefits of customer-side investments for the grid and to minimize the costs both to the grid and to the customers of customer-side and grid investments.

The trajectory of customer-side and grid-side technologies with capabilities and cost are difficult to predict precisely because they are new and costs are changing in dynamic markets. It is nonetheless possible to develop a cost-saving structure that rewards utilities for implementing innovative alternative to the utility’s capital budgets and timeframes. Such alternative may involve non-wire alternatives owned by the utility and/or customers when specific grid issues can be addressed more cost-effectively through deployment of non-traditional advanced technologies. Such a process might involve competitive procurements to address specific distribution system issues with any achieved savings shared between the utility and the ratepayers.

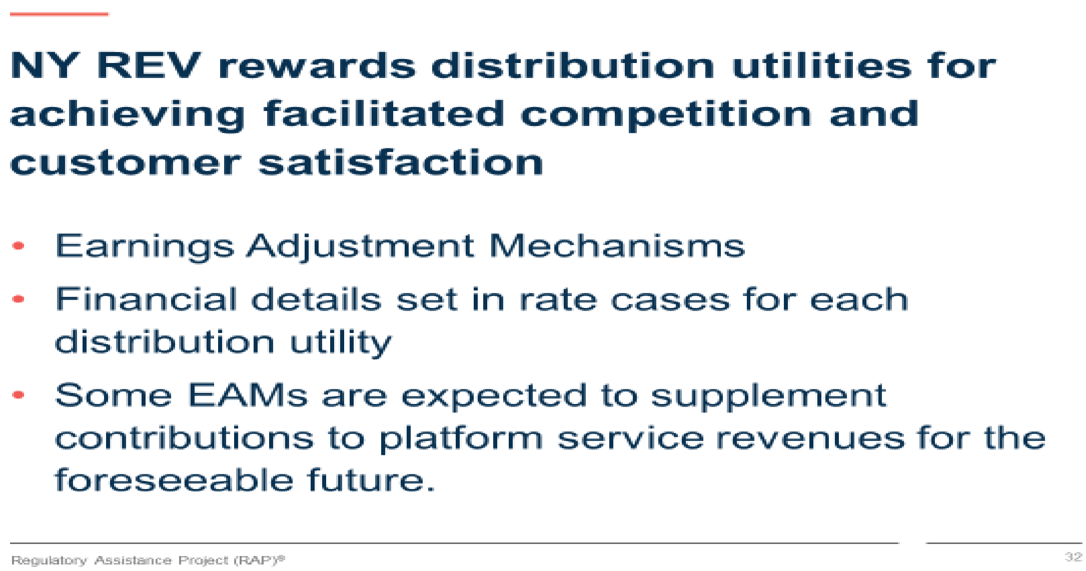
Competitive Procurement Examples from Other States

Other states demonstrate one advantage of building competitive procurements into a PBR system is that PBR can be used to harness the ability of market players to present unanticipated solutions. California has attempted to do this is a December 2016 CAPUC order where each utility is required to identify a significant upcoming distribution system investment need and to solicit proposals to meet the need with portfolios of distributed resources. For distribution system upgrades, the utility is required to specify the reliability services that are needed to address the need, and to issue a request for proposals to procure the needs. The submitted proposals are to be evaluated based on a technology-neutral least cost, best fit basis. If the most cost effective, best value proposal is superior to the distribution wires investment solution, then the utility will be required to enter into a contract with the winner. A pro forma contract will be developed over time to make the non-wires contracting process more routine. The utility is entitled to recover all costs of administering the non-wires solicitation and, as compensation for an effective solicitation, the utility will be entitled to earn 4% on the annual contract cost of the contracted non-wires alternative.[52] The PBR incentive in California is 4% of annual DER contract costs.



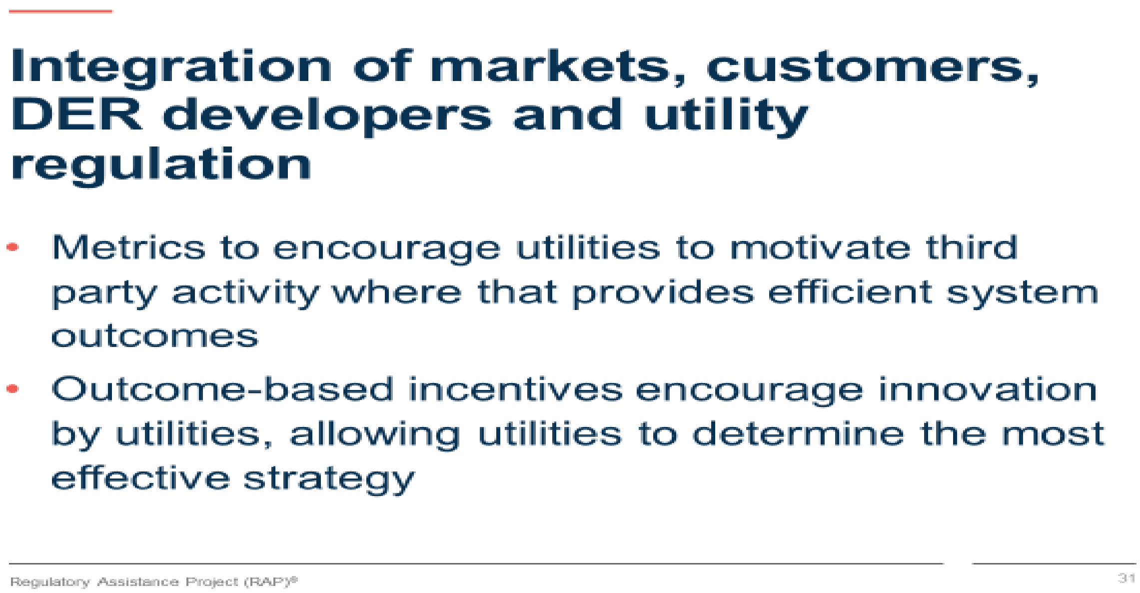
[52] CPUC. (2016). Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot. Rulemaking 14-10-003. Page 8.

New York is also attempting to facilitate third-party distributed resource development through a more complicated system of Earning Adjustment Mechanisms as part of the New York Reforming the Energy Vision (REV) initiative. These incentive mechanisms are set for each utility separately in each rate case to provide specific incentives for DER integration based on the financial and characteristics of each utility.[53]



The NY system is a full PBR system with multiple purposes. NY aimed to motivate utilities, DER providers and customers to work together with metrics that reward utilities for achieving efficient and least-cost DER/utility outcomes. The general criteria for each performance incentive and metric is set in the form of an Earnings Adjustment Mechanism in a generic Commission REV Order and the specific metrics and incentives and then set in each electric utility's rate case. The breath and ambition of NY REV suggestions that perhaps a more focused PBR effort on cost savings incentives and integrating modern distributed resources into Michigan's grid with a focus on overall least- cost planning, rate design, incentives and implement may be the right fit for Michigan's ratepayers and utilities rather than an expansive NY-style or UK-style full PBR system.

[53] See, e.g., RAP, D. Littell, C. Kadoch, J. Rosenow, Performance-Based Regulation: the Power of Outcomes (Part 2), http://www.raponline.org/event/performance-based-regulation-power-outcomes-part-2/?sf_action=get_data&sf_data=results&_sf_s=PBR.



Output goals

PBR allows regulators to focus on whether desired outcomes and how to achieve those goals. Less time can be spent evaluating specific costs involved in cost-based cost-of-service regulation, so-called input regulation but that base level of analysis cannot be ignored either. Thus, outputs are emphasized by regulators and stakeholders in evaluating utility outcomes.

There are a number of goals that can be accomplished through a PBR mechanism, including:

1. Customer Satisfaction

PBR can focus on improving customer satisfaction and can also promote customer empowerment. Customer empowerment is defined here as the ability of customers to provide feedback on utility service, demand-side energy options, and the ability to see publicly reported performance data on their utility.

Customer satisfaction metrics can include:[54]

- Number of formal and informal customer complaints, including response time to resolve complaints and a short description of the complaint and how it was resolved;
- Response time to service requests and outages;
- Residential customer satisfaction, based upon a survey of residential customers conducted by an independent entity with expertise in conducting customer surveys;
- Business customer satisfaction, based upon a survey of business customers conducted by an independent entity with expertise in conducting customer surveys.

Case studies from around the world indicate that paying attention to customer satisfaction is an important indicator of utility performance. And done well, these metrics can help transform the utility business model by focusing utility attention on integrating customers. Focus on customer satisfaction can range from public reporting of customer satisfaction rankings, to metrics focused on utility customer empowerment, to scorecards.

Publication of customer satisfaction rankings – RIIIO, Denmark

Regulators in the UK and Denmark have published rankings of consumer satisfaction. Surveys in the UK determine how satisfied customers are with the utility service, understandable bills, ease of contacting the utility, and whether the utility values the customer. Under the U.K.'s RIIO, customer satisfaction has increased significantly. This increase in satisfaction appears to some extent to be related to the published rankings of utility performance. Customers are able to see the satisfaction rankings, and based on these rankings or their own personal experience, are able to switch network suppliers.[55] Figure 14 shows RIIO's comparative customer satisfaction ranking.

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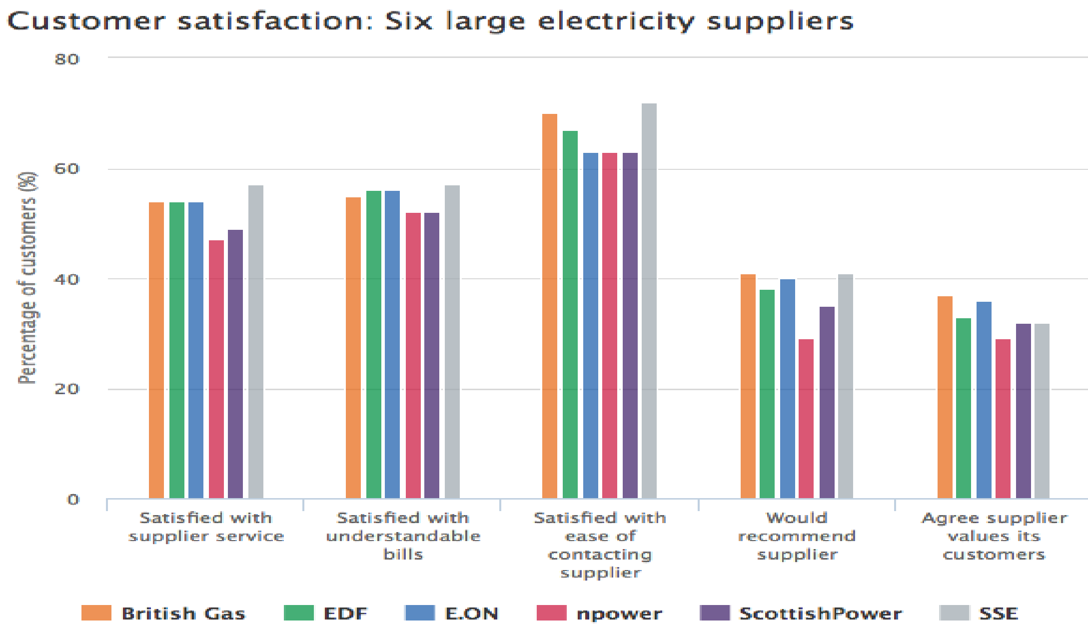
[54] Puerto Rico Energy Commission. (2015). Regulation on Integrated Resource Plan for the Puerto Rico Electric Power Authority. Order 8594, Article V. Other topics include reliability, system costs and environmental goals.

[55] Unlike in the US, customers of energy supply companies in the United Kingdom are able to switch network suppliers if dissatisfied. Thus publication of rankings of utility companies on various aspects of customer service has greater impact, as customers can "vote with their feet." The Guardian. (2017). Energy bills: are UK customers finally starting to switch supplier? Retrieved from: https://www.theguardian.com/money/2017/feb/27/energy-bills-more-uk-customers-are-moving-supplier-figures-show

Figure 14. Customer satisfaction in the UK[56]



Likewise, Denmark annually reviews its utilities' performance with its benchmarking scheme. The outcome of the benchmarking processes, are reported in an annual report to share the efficiency findings with the Danish public. The distribution system operators are required to strive to become as the best 10% of the DSO community. Customers in Denmark are not able to switch their distribution system operator as they are in the UK, but the benchmarking scheme does to some extent compensate for this by giving customers some comfort that their DSO is required to strive efficient. The Danish annual report is a less pronounced effort than RIIO's but directionally similar in that it endeavors to provide utility performance data on compliance with regulatory benchmarking.[57]

Customer empowerment enabled by customer satisfaction metrics.

Another form of customer empowerment is to expand on past customer satisfaction metrics to show expanded measures of customer satisfaction. The Puerto Rico Energy Commission focused its recent PBR decision on customer empowerment through a series of metrics related to customer choice to make customer-sited energy management decisions. The Commission promulgated the following metrics related to customer empowerment:

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[56] Ofgem. (2016). Customer Satisfaction: Six large electricity suppliers. Retrieved from: https://www.ofgem.gov.uk/chart/customer-satisfaction-six-large-electricity-suppliers

[57] The DERA annual report reports efficiency data for the DSO community as a whole and is therefore "directionally similar" to Ofgem's RIIO annual report, however the latter and its associated documents provide far more detailed information for each individual DSO. One reason why DERA may report on a DSO community basis is the number of DSOs involved.

Table 3: Puerto Rico Metrics for Customer Empowerment

Energy efficiency	number and percent of customers served by programs, annual and lifetime energy savings, levelized program costs per lifetime energy saved
Demand response	number and percent of customers served by programs, annual and lifetime demand savings, levelized program costs per MW saved
Distributed generation	number of installations per year and cumulative, capacity (MW) of installations per year and cumulative
Energy storage	number of installations per year and cumulative, capacity (MW) of installations per year and cumulative
Electric vehicles	number of installations per year and cumulative, capacity (MW) of installations per year and cumulative
Information availability	number of customers able to access hourly usage
Time-varying rates	number of customers on time-varying rates.[58]

Scorecards-- a hallmark of 21st century power regulation

Scorecards, with clear metrics and mandated formats approved by regulatory authorities, and designed with broad utility and stakeholder input, may become a hallmark of 21st century power sector regulation. Taking a page from RIIO success with increased customer satisfaction, the NY-PSC will require utility scorecards for simplified reporting to ratepayers and the public under the NY-REV. Development of these scorecards is underway with performance criteria and metrics likely to be settled by 2018 in NY. The NY-PSC ordered the parties of the REV proceeding to undertake a collaborative effort to specify metrics that should be maintained as scorecards to measure desired outcomes, although scorecards would not have any direct impact on regulated earnings. Scorecard categories include metrics for customer satisfaction and

[58] Puerto Rico Energy Commission. (2015). Regulation on Integrated Resource Plan for the Puerto Rico Electric Power Authority. Order 8594, Article V. Other topics include reliability, system costs and environmental goals.

customer enhancement (includes affordability). The following scorecard categories are to be used initially, and are still in the process of being defined and developed; other categories may be explored in the future:

- System utilization and efficiency
- DER penetration
- Time-of-use rate efficacy
- Market development
- Market-based revenues
- Carbon reduction
- Conversion of fossil-fueled end uses
- Customer satisfaction
- Customer enhancement (includes affordability)
- Affordability
- Resilience

2. Safety

PIMs for safety generally focus on employee and public safety goals. These are usually to require a high and improving level of both employee and public safety.

Employee safety performance metrics commonly include the following:

- Total case rate,
- Days away, restricted, and transfer case rate, and,
- Days away from work case rate.

These are all an indicator of employee injuries, fatalities, and productivity losses due to work-related incidents.[59]

[59] Whited, M., Woolf, T., and Napoleon, A. (2015). Utility Performance Mechanisms: A Handbook for Regulators. Synapse Energy Economics. Retrieved from: http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf

Common public safety performance metrics include:

- Incidents, injuries, and fatalities (electric)
- Emergency response time (electric)
- Incidents, injuries, and fatalities (gas)
- Emergency response time (gas)
- Leak repair performance (gas)

These metrics are intended to provide indicators of incidents, injuries, and fatalities associated with the contact with the electric and gas system, and speed of response to emergency situations.[60]

As with all PBR, it is important to understand the type of incentive that is created, and to safeguard for unintended consequences. For example, when the California Public Utilities Commission (CPUC) required reporting of employee injury data for rewarding workplace safety, it found that supervisors encouraged non-reporting, self-treatment, or treatment by personal physicians and other measures in order to avoid the creation of internal utility reports of injuries. Further, the reporting of injury data by group and incentives provided on a group basis within the utility led to employee desires to see their group or unit safety rankings maintained, and thus created a disincentive to report injuries.[61] This PBR system intended focus on worker safety improvements was found instead to produce an employee incentive to avoid reporting and a management incentive to falsify data reporting. The lesson from this experience is that careful consideration of internal data management and reporting within the utility may be necessary, particularly when there is a reward and penalty aspect of an incentive that affects individual and group employee compensation. The nature of the safety incentives and group-based incentives in some units created an unintended effect that compromised the purpose of the performance goal itself.[62]

[60] id.

[61] Whited, M., Woolf, T., and Napoleon, A. (2015). Utility Performance Mechanisms: A Handbook for Regulators. Synapse Energy Economics. Retrieved from: http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 31, 63-69.

[62] Another booby trap is that a focus toward a particular metric may take utility employee attention away from other tasks that do not have a reward or any reported metric, and instead focus their time on tasks that do influence achievement of performance targets, such as the customer experience or societal benefit. Regulators can address this with a broader array of metrics that are reported without reward (a scorecard) such that all utility performance is subject to public disclosure and a likely future correction.

3. Reliability

Setting reliability goals, performance criteria, or metrics is universally recognized as desirable since it effectuates one of the central public utility service goals: safe and reliable service at just and reasonable prices. That said, establishing the precise performance criteria and metrics can be difficult. Reliability is good but too much reliability is expensive and may be more than ratepayers want to pay. It is important not to fall into the "no-amount-of-reliability-is-enough" trap because reliability investments are limitless. The amount of reliability that regulators should require and how to measure it are perennial utility questions: how much reliability should be required, or another way to ask the question is how much reliability do customers want to pay for their electricity service? The Canadian Province of Alberta recognized this quandary squarely in its decision rejecting a reward-based PIM for exceeding expected reliability standards:

> *". . . in a competitive market, a company may increase its service quality and charge a higher price, but risks losing customers. For monopoly utility companies, there is no risk of losing customers. Customers have no choice but to pay the higher price of service quality levels that they may not want or cannot afford."* [63]

Norwegian regulators approached the reliability quandary by asking utility customers how much they value reliability using customer surveys to construct a willingness-to-pay curve for different levels of system reliability. The Norwegians then use a PBR scheme to have their utilities internalize the reliability valuation by customers. Norway uses revenue cap regulation to control utility costs. It allows utilities to retain cost savings from operating below approved costs. Because revenue cap regulation can create an incentive to cut costs in ways the impact system reliability, this system adjusts utility revenues each year based on the costs of outages to customers. Thus, if outages increase, utility revenue is reduced - or if outages are reduced below a baseline level, the utility receives higher revenues the next year.[64]

Under this system, a Norwegian utility seeking to maximize profits will increase expenditures to the point where the marginal cost of increased reliability equals the customers' willingness to pay (as shown in the customer surveys). The Norwegian reliability PBR is designed to achieve the optimal level of reliability. The optimal reliability level is where marginal utility costs equal

[63] Whited, M., Woolf, T., and Napoleon, A. (2015). Utility Performance Mechanisms: A Handbook for Regulators. Synapse Energy Economics. Retrieved from: http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 41.

[64] Whited, M., Woolf, T., and Napoleon, A. (2015). Utility Performance Mechanisms: A Handbook for Regulators. Synapse Energy Economics. Retrieved from: http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 35.

marginal customer benefits determined in the customer surveys. Use of the survey instrument to determine the optimal level of reliability and then motiving the utility with positive and negative incentives is a particularly innovative approach to implementing reliability goals.

An incentive mechanism in Illinois provides a US example that was applied through a rate tariff. As part of a grid modernization initiative in the U.S. State of Illinois, the Illinois Commerce Commission (ICC) adopted a PBR formula rate tariff.[65] These tariffs were approved under Illinois's Energy Infrastructure Modernization Act which authorized $3.2 billion in grid hardening and smart meter investments. The guiding principle of the act and tariff is to achieve increased grid reliability and operational efficiency by offering the utilities increased certainly around capital investments ranging from distribution reclosers, substation improvements, pole reinforcements, undergrounding targeted lines, and vegetation management.[66]

This Illinois tariff approved formula rates for participating utilities providing greater utility confidence that grid modernization expenses would be found prudent with a set rate of return to be adjusted based on known factors annually. In exchange for this formula rate treatment, participating utilities are required to file multi-year metrics with the ICC to improve performance over a 10-year period, including reliability performance.

After installing grid automation and more intelligent sensors and the range of approved grid hardening and smart grid investments described above, the utilities reported improvements in outage frequency and duration.[67] But the utilities have failed to meet the 75% improvement performance criteria set by the ICC and been penalized with a 5-basis point reduction in authorized ROE as a result. This reduction of ROE resulted in an approximate $2 million reduction in Commonwealth Edison's roughly $2.5 billion annual revenue requirement.[68] This is a negative incentive scheme which imposes a relatively low penalty reduction in an approved formula rate when reliability criteria is not met.

[65] Illinois Compiled Statutes. Infrastructure investment and modernization; regulatory reform.220 ILCS 5/16-108.5. 2017.
[66] McCabe, A; Ghoshal, O, & Peters B. (2016, May). A Formula for Grid Modernization? Public Utilities Fortnightly. Retrieved from: https://www.fortnightly.com/fortnightly/2016/05/formula-grid-modernization
[67] Both utilities, Ameren and Commonwealth Edison report reliability improvements. See Ameren Illinois (2015, June 1). Modernization Action Plan. Retrieved from: https://www.icc.illinois.gov/downloads/public/edocket/406271.pdf; Commonwealth Edison (2015, April). Multi-Year Performance Metrics. Retrieved from: https://www.icc.illinois.gov/downloads/public/edocket/402546.pdf
[68] McCabe, A; Ghoshal, O, & Peters B. (2016, May). A Formula for Grid Modernization? Public Utilities Fortnightly. Retrieved from: https://www.fortnightly.com/fortnightly/2016/05/formula-grid-modernization

4. Environmental Impact

The RIIO context is partially explained by a strong commitment across the full spectrum in the U.K. to mitigating climate change. That commitment carried through to supportive efforts to establish performance criteria for UK network companies. The context is different in Michigan though it is still fair to say there is general support for a transition to a modern and cleaner electrical sector across a broad spectrum of energy sector stakeholders.

Perhaps more significant is Michigan's reputation as a technological and industrial innovator. The breadth of advanced energy technologies being developed and deployed makes tracking any one sets of technologies a significant challenge for analysis or regulators. But this does not mean that regulators cannot set up accommodating utilities structures to integrate advanced technologies into Michigan's grid planning and distribution investments. In fact, this is imperative where new technologies present the opportunity to allow Michigan ratepayers to improve the quality of their own or distribution service overall and present potential least-cost solutions.

The challenge is to set up a flexible performance based structure that encourages utilities, third-party providers and ratepayers to move toward environmentally beneficial and least-cost solution across the grid, third-party and customer benefit and cost spaces. With advance technologies, it is almost impossible to determine cost-effectiveness in advance. But regulatory structures can create "facilitate competition" space where utilities are rewarded for acquiring competitively bid services that reduce overall system costs. Most advanced customer-site resources (excepting distributed fossil generators) will have an environmentally beneficial effect so it is possible to focus on achieving the least-cost set of distributed solutions and comparing those to a set of grid upgrade costs.

The California PUC recently promulgated a structure to do this. With its December 2016 Order[69], the CA PUC requires that each utility identify significant upcoming distribution system investment needs and solicit proposals to meet the need with portfolios of distributed resources. Each utility is required to specify the reliability services to address the need, and to issue a request for proposals to procure the needs. The submitted proposals are to be evaluated based on a technology-neutral least cost, best fit basis. If the most cost effective, best value proposal is superior to the distribution wires investment solution, then the utility will be required to enter into a contract with the winning proposer. A pro forma contract will be developed over time to make the non-wires contracting process routine. The utility is entitled to recover all costs of administering the non-wires solicitation and, as compensation for an effective solicitation, the

[69] CPUC. (2016). Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot. Rulemaking 14-10-003. Page 8

utility will be entitled to earn 4% on the annual contract cost of the contracted non-wires alternative.[70]

The NY PSC is also implementing a more complex attempt to achieve the same result. NY REV is implementing outcome-based incentives encourage innovation by utilities, allowing utilities to determine the most effective strategy to achieve policy objectives, including cooperation with third parties and development of new business concepts that would not be considered under narrow, program-based incentives. New York's effort aims to construct a regulatory system that rewards distribution utilities for implemented facilitated competition using DERs and for customer satisfaction. NY REV is using a form of PBR that provides outcome-based incentives called "Earnings Adjustment Mechanisms." Because of the unique situation of each distribution utility, the financial details of the EAMs are developed in rate proceedings. [71]

Both the California and the New York initiatives recognize that the power sector is changing rapidly. Regulation can seek outcomes that simulate competitive market behavior where possible. For some purposes, advanced distributed technologies enable competition for provision of safe, reliable and low-cost service. The question becomes how to simulate competitive markets when monopoly barriers can impede competition so measures to support the competitive markets, or set up structures for regulated competition, may be necessary.[72]

NY and CA use a PBR model of full cost recovery combined with an ROE adder in NY's case or a contract recovery percentage in CA's case to provide the utility with an incentive to support and implement a facilitated competition with its own traditional services.[73]

For broader environmental impact, PIM relating to emissions, greenhouse gases, amount so renewable energy (on the system and distributed) and water usage can be developed for reporting or even incentives.[74] The performance criteria can be fashioned to meet the specific objectives that Michigan policy makers deem appropriate. Potentially, the PSC could fashion a PBR regime to assess whether meeting Michigan's renewable energy and waste reductions goals through various rate based or distributed resources is most cost effective and to provide incentives to pursue the most-cost effective set of implementation solutions through a regulated competition model.

[70] D. Littell, C. Kadoch, J. Rosenow, Performance-Based Regulation: The Power of Outcomes (Part 2), webinar, Oct. 5, 2017, http://www.raponline.org/event/performance-based-regulation-power-outcomes-part-2/?sf_action=get_data&sf_data=results&_sf_s=PBR
[71] Id.
[72] Id.
[73] Id.
[74] See, e.g., NREL/RAP Report at Section 7.1.1 and 7.1.2.

5. Social Obligations

A main goal of the RIIO mechanism was to ensure operation of a retail market that works for all consumers, including those in vulnerable circumstances. The regulator also believes that domestic energy suppliers have a responsibility to help support vulnerable customers.[75] As a result, the regulator created the "social obligations" metrics to measure specific outputs on customer payment methods, levels of debt and debt repayments, disconnection rates, prepayment meters, and non-financial support for consumers in vulnerable situations. This information enables the regulator to understand how suppliers are meeting the needs of consumers in vulnerable situations. The data also enables the regulator to check that suppliers comply with the rules, challenge poor performance, and to inform policy.[76]

In the US context, social obligations are often included in a focus on low-income and vulnerable customers. The primary question with PBR schemes that is often raised by low-income and other consumer advocates, is how to craft incentives that force meaningful utility action in exchange for reasonable, but not excessive, revenues.[77] There are two components to metrics in this area: 1) protection of low-income customers and attention to payment method options, disconnection rates, prepayment meters, etc., and 2) customer empowerment which enables vulnerable customers to pro-actively alleviate their consumption and interact with the grid.

Low-income metrics

It is a good regulatory practice to create metrics which are clear, identifiable and under the utility control, as articulated earlier in Section X, but also metrics that are useful in showing utility progress to the goal of low-income customer participation and protection. A few useful metrics in this area may be:

1.) Number of Disconnections, Length of Disconnections and Number of Reconnections

Tracking the number of disconnections and reconnections on a monthly basis can provide important information on affordability and ability to pay. While many states require the tracking of the number of disconnections, few states include analysis of how many of the disconnected customers get reconnected and the length of time that they stay disconnected. For example, some low-income customers allow themselves to be disconnected from gas through the warm

[75] Ofgem. (2017). Vulnerable Customers. Retrieved from: https://www.ofgem.gov.uk/system/files/docs/2017/10/consumer_vulnerability_report_web_003.pdf

[76] Ofgem (2017). Consumer Vulnerability Strategy: Social obligations reporting. Retrieved from: https://www.ofgem.gov.uk/about-us/how-we-work/working-consumers/protecting-and-empowering-consumers-vulnerable-situations/consumer-vulnerability-strategy/consumer-vulnerability-strategy-social-obligations-reporting-sor

[77] Thompson, A. (2016). Protecting Low-Income Ratepayers as the Electricity System Evolves. Energy Bar Association. Retrieved from: http://eba-net.org/sites/default/files/18-265-305-Thompson%20-%20FINAL_0.pdf

months if they have electric appliances. In this way, they avoid the customer charge and save money – especially if the customer charge is relatively high. On the other hand, a long disconnection period could also reflect the inability of the customer to obtain the requisite funds. If many customers fall into this category, that might signal a need to re-examine the company's reconnection policies. Tracking this data can also help determine how many customers are disconnected once or multiple times in a year and for how long they remain disconnected. Identifying these customers can help the utility target the customers most in need with programs to help them stay connected. The total number of customers without service will give the Commission a truer picture of how many customers are foregoing utility service. The arrearage numbers will provide the Commission with information on how many customers that maintain service are nevertheless finding it a struggle to do so.

Sample data that the utility could be required to file at the Commission preferably on a monthly basis (but could be quarterly) include:

- Number of customers 30 days in arrears
- Number of customers 60 days in arrears
- Number of customers disconnected that month[78]
- Total number of customers without service that month (number of previously disconnected customers who have not been reconnected + number of customers disconnected in the reporting month)
- Number of customers reconnected
- Length of time the customer is disconnected, reported as an average for those reconnected that month
- Number of customers the Company did outreach to prior to disconnection to help them get on an extended payment plan
- Number of customers referred to social service agencies or nonprofit organizations that provide bill assistance.

[78] In SB 598, legislation that was proposed but not passed in California, utilities would have been required to conduct an assessment of the impact of any proposed rate increase on the number of disconnections for nonpayment. The Affordability Headcount discussed above could be used as a tool in this assessment. If NGRID does such an assessment and finds that the impact on affordability increases, the Commission could require NGRID to develop solutions and metrics that address solutions to this problem.

Metrics on extended payment plans which measure the effectiveness of programs to keep customers connected should be integrated with this data. We would recommend that the reporting requirements for extended payment plans also be included with the metrics discussed in this section.

Utilities have significant control over payment plans, credit and collection procedures, and collection and delivery of payment assistance. In these ways, termination for nonpayment is partly within the control of the utility. The utility that works with its most disadvantaged customers to keep them connected to the grid is more likely to reduce its terminations for nonpayment. Termination for nonpayment is the way most low-income customers become disconnected from the grid.[79]

2) Availability of Extended Payment Plans (EPP) and Their Effectiveness

A very useful tool to help customers avert a disconnection is the availability of extended payment plans. Payments for eligible low-income customers can be as low as $10 per month for the arrearage. These plans should be widely advertised to customers through bill inserts, text messaging when customers are 30 days and more in arrearages, and through free and paid media. Early intervention too, can help mitigate large arrearages from piling up.

Another option to consider is whether the utility has programs in place to encourage payment of the arrearage, while easing the financial burden. For example, if a customer has a $100 arrearage that will be paid off in 10 installments of $10, for every payment the customer makes, the utility matches by forgiving one month of debt. In a perfect scenario, the customer pays $50 of the debt instead of $100.

Options for metrics on which the utility could be required to report on a periodic basis include:

- Number of customers the Company did outreach to prior to disconnection to help
- Number of customers on an extended payment plan
- Number and/or percentage of customers adhering to the extended payment plans
  Number of customers defaulting on an extended payment plan
- Number of customers successfully completing an extended payment plan

This data will enable the Commission and stakeholders to determine how successful the Company is in reaching out to customers and how realistic the EPPs are in terms of allowing the customer the opportunity to catch up and pay the outstanding arrearage.

[79] Biewald, B., Woolf, T., Chernick, P., Geller, S., and Oppenheim, J. (1997). Performance-Based Regulation in a Restructured Electric Industry. Synapse Energy Economics. Retrieved from: http://www.synapse-energy.com/sites/default/files/SynapseReport.1997-11.NARUC_.PBR-in-a-Restructured-Electricity-Industry..97-U02.pdf

3) Availability of Bill Payment Assistance Programs and Rate Discount programs

Discount programs

Discount programs increase the number of low-income homes connected to the grid by increasing the affordability of electricity. A utility has considerable control over the participation rate in such programs by whether or not it engages in such outreach activities as promoting the rate in the community, quoting the rate when customers apply for service, and developing innovative initiatives to reach the target audience. Utilities can coordinate with public assistance agencies to reach low-income customers, and can provide default sign-up for discount programs, such as sending a letter offering the discount unless the recipient takes action to decline.[80] For example, average enrollment in Massachusetts electricity low-income discount programs is a third of low-income customers while Eastern Edison, which automatically enrolls customers on the basis of a computer match, achieves almost half.[81]

Another option could be a “good payment discount,” in which a low-income customer that pays on time for a period of months, receives a percentage discount on a period of subsequent months.

Metrics for this area include:

- Description of the program;
- Description of outreach efforts to the eligible customers;
- Number of customers enrolled; and,
- Number of customers enrolled who were nevertheless disconnected for nonpayment.

[80] Id.

[81] Id. National Consumer Law Center computations based on 1995 data from the Massachusetts Department of Public Utilities and 1990 Census data. Low-income is defined for this purpose as household income at or below 175 percent of the Federal Poverty Line. At 150 percent, the respective percentages are 41 percent and 60 percent.

Bill Payment Assistance Programs:

Bill payment assistance programs which can take a number of forms. Some program ideas include:

- Customer bill check-off similar to the Pennsylvania Dollar Energy Program[82] or Palmetto Electric Coop's Energy Round-up program[83] in which customers can make a donation into a low-income energy assistance fund;
- Compiling a list of potential sources of assistance including government agencies and non- profit organizations and connecting customers to those funds; and
- Creating a shareholder fund to make charitable contributions to customers in need.

Customer empowerment

Many jurisdictions now recognize energy efficiency as a new tool for helping low-income populations—a way to offer social equity. Efficiency strategies and other distributed resource strategies empower customers—both low-income and other customers—by providing access to affordable capital for projects that lower their energy costs. These strategies also provide long-term system and societal benefits rather than price distortions.

A "customer equity" or "customer empowerment" indicator would provide valuable feedback on utility progress on these issues. This should assess the energy burden of customers, particularly customers in the bottom economic quartile.[84] Deep efficiency, access to renewables, and participation in demand response would all be high priorities. An indicator such as household energy burden could be the basis for new incentive structures. Incentive designs would need to reward strategic assistance in access to capital for these customers.

The Puerto Rico Energy Commission provides an example of customer empowerment metrics, as it focused in its recent PBR decision on customer empowerment through a series of metrics related to customer choice to make customer-sited energy management decisions. The Commission promulgated the following metrics related to customer empowerment:

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[82] Dollar Energy Fund. (2017). 2017-2018 Pennsylvania Hardship Program Guidelines. Retrieved from: https://www.dollarenergy.org/need-help/pennsylvania/hardship-program/

[83] Palmetto Electric Cooperative, Inc.. Operation Round Up. Retrieved from: https://www.palmetto.coop/operation-round-up/

[84] Teller-Elsberg, Jonathan, Benjamin Sovacool, Taylor Smith, and Emily Laine. "Energy Costs and Burdens in Vermont: Burdensome for Whom?" Report to the Vermont Low-Income Trust for Electricity, Inc. (South Royalton, Vt.: Institute for Energy and the Environment at Vermont Law School, 2014). http://wwwassets.vermontlaw.edu/Assets/iee/VLS%20IEE%20Energy%20Burden%20Report.pdf

Table 4: Puerto Rico Metrics for Customer Empowerment

Table 4. Puerto Rico Metrics for Customer Empowerment

Metric	Description
Energy efficiency	Number and percent of customers served by programs, annual and lifetime energy savings, levelized program costs per lifetime energy saved
Demand response	Number and percent of customers served by programs, annual and lifetime demand savings, levelized program costs per MW saved
Distributed generation	Number of installations per year and cumulative, capacity (MW) of installations per year and cumulative
Energy storage	Number of installations per year and cumulative, capacity (MW) of installations per year and cumulative
Electric vehicles	Number of installations per year and cumulative, capacity (MW) of installations per year and cumulative
Information availability	Number of customers able to access hourly usage
Time-varying rates	Number of customers on time-varying rates.[149]

An example of these metrics for low-income customers includes the following:

- Participation in low-income energy efficiency programs. By increasing the affordability of electricity, efficiency programs increase the number of low-income homes connected to the grid. A utility has considerable control over the participation rate in such programs, as well as the effectiveness of such programs, by how well it funds the program and whether or not it engages in such outreach activities as promoting the program when customers apply for service and developing innovative initiatives such as program delivery via community-based organizations.[85]

- Low-income energy efficiency savings. If there is a DSM incentive mechanism already in place, this measure could be a bonus incentive. This metric measures how effective the utility's efforts are in accomplishing low-income energy efficiency. It requires a monitoring and evaluation function in the program.[86]

[85] Biewald, B., Woolf, T., Chernick, P., Geller, S., and Oppenheim, J. (1997). Performance-Based Regulation in a Restructured Electric Industry. Synapse Energy Economics. Retrieved from: http://www.synapse-energy.com/sites/default/files/SynapseReport.1997-11.NARUC_.PBR-in-a-Restructured-Electricity-Industry..97-U02.pdf

[86] Biewald, B., Woolf, T., Chernick, P., Geller, S., and Oppenheim, J. (1997). Performance-Based Regulation in a Restructured Electric Industry. Synapse Energy Economics. Retrieved from: http://www.synapse-energy.com/sites/default/files/SynapseReport.1997-11.NARUC_.PBR-in-a-Restructured-Electricity-Industry..97-U02.pdf

Appendix E: Multi-year Rate Plans

Multi-year rate plans were used first for electricity in California, New York, and the New England states, and have since become common in Australia, the U.K., Germany, the Netherlands, Canada, and New Zealand.[87] This appendix contains short case-studies of multi-year rate plans in a select number of U.S. states. In Canada, multi-year rate plans are becoming mandatory for electric and natural gas distributors in the four most populous provinces.[88] Some statistical studies of vertically integrated electric utilities indeed suggest, and those that operate for long periods without rate cases indicate that multi-year rate plans can exhibit superior cost management[89] – one of the primary goals of adopting multi-year rate plans in these jurisdictions.

The goals of PBRs in the form of multi-year rate plans are in many respects remain the same today as when multi-year rate plans were adopted over the last 25 years: reasonably priced and reliable service to customers. But today's technologies allow for more consumer control over their energy future and clean energy decisions where desired by customers. Thus, the pathways and the potential outcomes are different than in the 20th century when centralized generator stations and large infrastructure dominated the utility landscape.

The multiple benefits of Multi-Year Rate Plans

Multi-year rate plans provide clarity and focus for regulators and utilities alike. Utility executives like to say that multi-year rate plans enable them to focus on service and priorities rather than the rate case. Rate cases can demand the attention of the best people in the company, so fewer rate cases allow those best people to focus on other things. Improved performance can become a new profit center for a utility at a time when traditional opportunities for earnings growth are diminishing. Less frequent rate cases can help utility managers focus on their basic business of providing customer responsive services cost-effectively.

From the regulatory perspective, which frequently aligns with the consumer perspective, multi-year rate plans:

- Can reduce the frequency of rate cases, freeing up commission resources for other needs
- Can improve the culture of utility management
- Can improve utility performance and lower utility costs
- Can strengthen incentives for utilities to improve performance in a wide range of initiatives, and
- The benefits ideally are shared between utilities and their customers

[87] There is strong evidence that electrical distribution company productivity is improved by operating under a multi-year rate plan. Mark N. Lowry, Performance-Based Regulation: Can "The Other PBR" Make Sense for Wisconsin? Wisconsin Retreat on Utility Business Models of the Future, March 29, 2016, slide 23 (compare productivity of Central Maine Power to the Northeastern U.S. and Mid-Atlantic Regions productivity 1993-2011); M. Lowry, T. Woolf, L. Schwartz, Performance-Based Regulation in a High Distributed Energy Resources Future, Future Electric Utility Regulation, Lawrence Berkeley National Lab, Rept. No. 3, Jan. 2016..

[88] M. Lowry, T. Woolf, L. Schwartz. (2016). Performance-Based Regulation in a High Distributed Energy Resources Future. Lawrence Berkeley National Lab, Rept. No. 3. Retrieved from: https://emp.lbl.gov/publications/performance-based-regulation-high, p. 30

[89] M. Lowry, T. Woolf, L. Schwartz. (2016). Performance-Based Regulation in a High Distributed Energy Resources Future. Lawrence Berkeley National Lab, Rept. No. 3. Retrieved from: https://emp.lbl.gov/publications/performance-based-regulation-high, p. 31

Cost Cap PBR Creates the Need for Reliability and Customer Service Penalties: With cost-cutting incentives under PBR multi-year rate plans came the possibility that utilities would save money not by operating more efficiently but by reducing quality of service. This concern revealed the need to address service quality through PBR design too. PBRs for service quality identify service goals, set targets for acceptable service levels, and measure outages (number or and duration of), meter reading disputes, time to answer consumer phone line, number of customer complaints, time to provide a new service connection, and similar measures. These can be based on specific operational data sets from each Michigan utility. Each measure would be translated into a reward or penalty or both to modify revenue. It should be noted that some customer service targets are likely to assist low or moderate-income ratepayers who may be more likely access consumer phone lines, have service disconnected, and file complaints.

PBR Can Rationalize Utility Incentives and Make Them Accessible: While it is true that all regulation provides financial incentives that motivate utility performance, these incentives are often only understood by experts involved in utility management or regulation. PBR arrangements make regulatory goals and incentives explicit for the utility, regulator, ratepayers and public and other stakeholders. The incentives of traditional utility regulation are often not understood by the public and many stakeholders.

While many regulators and utility management professionals do understand the incentives built into traditional utility regulation, it is difficult to resolve the conflicting incentives that are inherent in much existing regulation. Examples include the conflict between the cost-recovery guaranteed for capital expenditure (the incentive to build more) and energy efficiency cost recovery structures (the incentive to save more energy). Performance based regulation is an explicit effort to rationalize sometimes conflicting regulatory incentives to make them consistent and to avoid conflicting regulatory signals.

Allocation of Profits, Costs and Risk Matters: In most utility structures, revenue growth is a predominant goal. Multi-year rate plans may slow revenue growth compared to regular cost-of-service regulation. For this reason, utilities may oppose PBRs unless the PBR relieves the utility of costs or risks it otherwise would bear. Conversely, if the PBR produces faster than expected revenue growth, consumer advocates and groups may oppose it.[90] That tension may be productive if decisions on PBR are made in a transparent manner.

Because some outcomes are driven by influences partially outside of utility control, utilities may be reluctant to accept a pure outcome target or metric. One method to address this is to

[90] Regulatory Assistance Project, 2000, p. 36.

consider a rolling multi-year average rather than a pure annual target or annual metric. Over time the range of utility performance becomes evident as well as trends in a rolling average. As an example, the UK regulator Ofgem, under the RIIO framework, has implemented a rolling average target for reliability purposes. Specifically, an unplanned outage target is set based on either the minimum of a utility's 2014/15 outage target or utility's own four year moving average.[91] This is an example of an approach that regulators might employ to implement targets or metrics where utility performance may be subject to appreciable uncertainty.

Any PBR scheme must account for factors that are significant in scale and outside of the utility's control that might affect metric achievement. For multi-year rate plans, an adjustment called a 'Z Factor' is commonly used to identify specific factors defined by metrics outside the utilities control. Advanced PBR target and metric setting can step beyond merely identifying risk within and outside the utility's control to consider who currently bears the risk of non-achievement, who pays for achieving or not achieving the goals, who can most efficiently address the risk (utility, consumers, third-parties) and how the risk will affect the utility's, customer's and third-parties' decisions.[92] Risk can translate to long term costs that are not currently defined; the allocation of risk determines who pays those indefinite long-term costs.

Table 5: Benefits and concerns associated with MRPs noted in the Order

Benefits	Concerns
Reduced regulatory lag	Inaccuracy in forecasting costs and revenues grows with time
Reduced financing costs	Mismatch of relevant costs to relevant revenues if there is a desire to approve specific costs
Reduced need for rate cases and other riders	Challenges associated with evaluation and administration of plans
More predictable utility bills	
Reduced rate shock	

[91] Ofgem (2012). Quality of Service Presentation. Reliability and Safety Working Group. Retrieved from: https://www.ofgem.gov.uk/sites/default/files/docs/2012/07/rswg_17_may_slides_qos_0.pdf
[92] Regulatory Assistance Project, 2000, p. 38.

MRP Conclusions

MRPs can materially improve utility cost performance and therefore provide a promising strategy for addressing some of the regulatory challenges facing Michigan's utility industry. MRP can improve the efficiency of regulation under the right set of circumstances. The additional scrutiny associated with MRPs means utilities will have to improve their budgeting and project management practices in order to be compliant and successfully earn the allowable rate of return. The need to develop complementary operational incentives to maintain and improve reliability through the most effective mix of operational and capital investment decisions.

Michigan Statutory Provisions Relating to Multi-Year Rate Plans

Currently, rate cases are based on a 12-month test period and can be filed every 10 months. Sec. 6a 1-2 of PA3 of 1939 [as amended by Act 286 of 2008 and Act 341 of 2016] addresses the filing of general rate cases by regulated utilities. It states in part:

Sec. 6a 1 "A gas utility, electric utility, or steam utility shall not increase its rate and charges…without first receiving commission approval as provided in this section. … The commission shall require notice to be given to all interested parties within the service area to be affected, and all interested parties shall have a reasonable opportunity for a full and complete hearing. A utility may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges.

The general rate case contemplates the utility projecting rates to a future 12-month period. Absent from the Legislation is the requirement of what year the 12-month period is targeted toward. It is conceivable that a utility could project forward to a 12-month period that is more than 18 months into the future, such as three years. That would allow for a plan that could be useful for multiple years. The Commission could approve incremental spends. This would need to be done very carefully to prevent a utility from failing to hit targeted goals in-between review periods. Still without a change in statute, a utility could come back within 10-months for another rate case, unless it were to forgo that right by settlement. A test period of 12 months does not mean that the rate plan must be for 12 months. A rate plan continues until the rates are changed, and the subsequent years are based on mathematical formulae rather than multi-year test periods.

Settlement is probably the best mechanism to address a multi-year rate plan in Michigan under the current legislation. It could still be challenged legally, as there is no legal precedent.[93] A utility could settle a case in whole or in part, by stipulating to a stay-out provision and a multi-year plan. There is favorable parallel precedent at the federal law where stay-out provisions are currently used routinely at FERC.

[93] http://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=11AL-947E Public Service Company of Colorado 2011 rate case, Decision C12-0494, filed May 9, 2012. The Colorado Public Service Commission first approved a multi-year settlement in 2012, which has resulted in refunds to ratepayers based on an earnings sharing mechanism. Colorado's legal provisions appear to be substantially similar to Michigan's. Title 40 gives the Colorado Public Utility Commission its authority. http://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=11AL-947E

Multi-Year Rate Plans – Rate Making Formula and Case Studies

The basic formula for revenue growth in multiyear rate plans:
Revenue growth=growth ARM+ Y+ Z
Growth ARM= between rate cases, an attrition relief mechanism (ARM) permits rates to grow in the face of cost pressures. Defined as annual rate escalations. ARMs are usually capped either in terms of rates or total revenues. Typical ARM designs include:

- Stairsteps- predetermined increases in rates or revenues based on cost growth forecasts
- Indexing- variable increases tied to an index like the CPI inflation rate
- Hybrids- indexing for O&M and stairsteps for CAPEX
- Cost Trackers

Earning sharing mechanisms to distribute excess earnings between utility and customers (when allowed ROE is exceeded.

Y= the Y factor indicates the rate adjustment for costs, such as fuel and purchased power.
Z= the Z factor indicates the rate adjustment for miscellaneous factors such as government mandates or severe storms.

States that use Multiyear Rate Plans[94]

MRPs have been used in U.S rate regulation since the 1980s. The Federal Energy Regulation Commission (FERC) uses MRPs to regulate oil pipelines. The table below shows some states in the US that use MRPs.

Table 6: States with Multi-year Rate Plans

Electric	Gas	Electric and Gas
Colorado	Indiana	California
North Dakota		New York
Minnesota		Washington
Iowa		New Hampshire
Louisiana		Maine
Florida		
Georgia		
Virginia		
Ohio		

[94] References for this section include Lowry, M., Makos, M., Deason, J. and Schwartz, L. (2017, July). State Performance-Based Regulation Using Mutiyear Rate Plans for US Electric Utilities; and Madden, S. (2014, February). Innovative ratemaking – Multiyear Rate Plans.

Traditional Cost of Service regulation v/s Multiyear rate plans

Under Cost of Service regulation (COSR) base rates that address costs of capital, labor and materials are reset in rate cases. Rate cases usually occur at irregular intervals and are typically initiated by utilities. Rate case frequency also depends on inflation and the need to replace aging infrastructure. The regulatory cost of COSR is high (for utilities, public utility commissions and stakeholders) when rate cases are frequent or unusually difficult. Rate cases can also be difficult when utilities are large and involve complex issues. MRPs cannot replace rate cases, but can reduce their frequency, which can increase the efficiency of regulation. The ARMs can provide timely, predictable rate escalation that permits an extension between rate cases. Streamlining ratemaking processes can free up resources in the regulatory community to more effectively address other important issues. MRPs have the potential to reduce regulatory lag.

Case Studies- California

The California Public Utility Commission (CPUC) has extensive experience with PBR. Six investor-owned electric utilities are regulated, along with natural gas, telecommunications, water, railroad, rail transit and passenger transportation companies. This gives the CPUC strong incentives to contain regulatory costs. MRPs were also facilitated by the CPUC's routine use of forward test years. The broad outline for Pacific Gas and Electric (PG&E), which started in 1981 is as follows:

- O&M expenses were escalated only for inflation.
- Capex per customer was fixed in constant dollar at a five-year average of recent net plant additions, then escalated for inflation.
- Other components of capital costs, like depreciation and return on rate base, were forecasted using cost of service methods. Other examples were capex budgets have occasionally been fixed in real dollars for several years, then escalated for construction cost inflation.

Cost trackers have provided supplemental revenue for advanced metering infrastructure and some reliability related capex.

In 2013, the CPUC adopted the Energy Savings Performance Incentive a type of DSM PIMs. Under this mechanism, performance awards for many programs were based on energy savings delivered. The Energy Savings Performance Incentive rewarded both codes and standards support programs and non-resource programs using a management fee based on utility dollars spent.

Long-term Outcomes: Over the 1986-2014 period during which MRPs have been extensively used in California, the productivity growth of California utilities averaged a 0.14 percent annual *decline*, whereas the productivity growth of sample US utilities averaged 0.43 percent annual *growth.* These unflattering results may reflect special California operating challenges and may also reflect ineffective plan design.

Case Studies- New York

New York also has a long history with MRPs for energy utilities. Plans typically have terms for 3 years. There are PIMs for customer service as well as reliability. Reducing regulatory cost has been cited in the Commission's support of MRPs. In a 2008 rate case decision for Consolidated Edison, the Commission discussed the drawbacks of annual rate cases. The issues noted:

The annual rate case proceedings includes many of the same, or similar, issues and major cost drivers as did the Company's last one-year electric rate case. These raise a significant concern that the public benefit might not be optimized if annual rate cases ultimately boil down to consideration of the same, or similar issues on which parties just replicate arguments that the Commission has already reviewed and either accepted or rejected.

Some key takeaways from 2010 Consolidated Edison order:

- ConEd requested $854.4million and was awarded $420.4million. Year 2 rate increase was 6% on total bill basis ($420.4m) and Year 3 was 6% on total bill basis ($420.4m).
- ROE threshold percent shared with customers, 11.15%→50% and 12.149%→75%.
- ConEd required to reduce O&M by a set amount annually.
- Net plant targets established for 3 categories, if actual net plant in service is less than targets, ConEd must defer carrying costs for the benefit of customers. If actual net plant exceeds targets, ConEd must absorb costs during term of plan. Any overages must be justified.
- Plan includes 2% annual productivity adjustment to revenue requirement
- ConEd encouraged to consider the rate impacts on customers in their capital budgeting and planning.
- Commission finds that three-year plan is beneficial by providing utility with clarity of revenue expectations for next three years.

- Order includes a reliability performance mechanism that penalizes revenue allowance if performance on certain metrics is not achieved.
- Annual earnings report is to be filed with the Commission 60 days after rate year is complete, which includes detailed computations for ROE for the year to be submitted to the secretary. Calculations determines profit-sharing levels as specified in plan.
- Annual capital expenditure report to be filed with secretary by February 28, which provides list of new projects, cancelled projects, and explanations for variances in actual versus budget.
- Review meeting with Commission Staff on or before December 15 prior to year 2 and Year 3 to review capital spending plans.

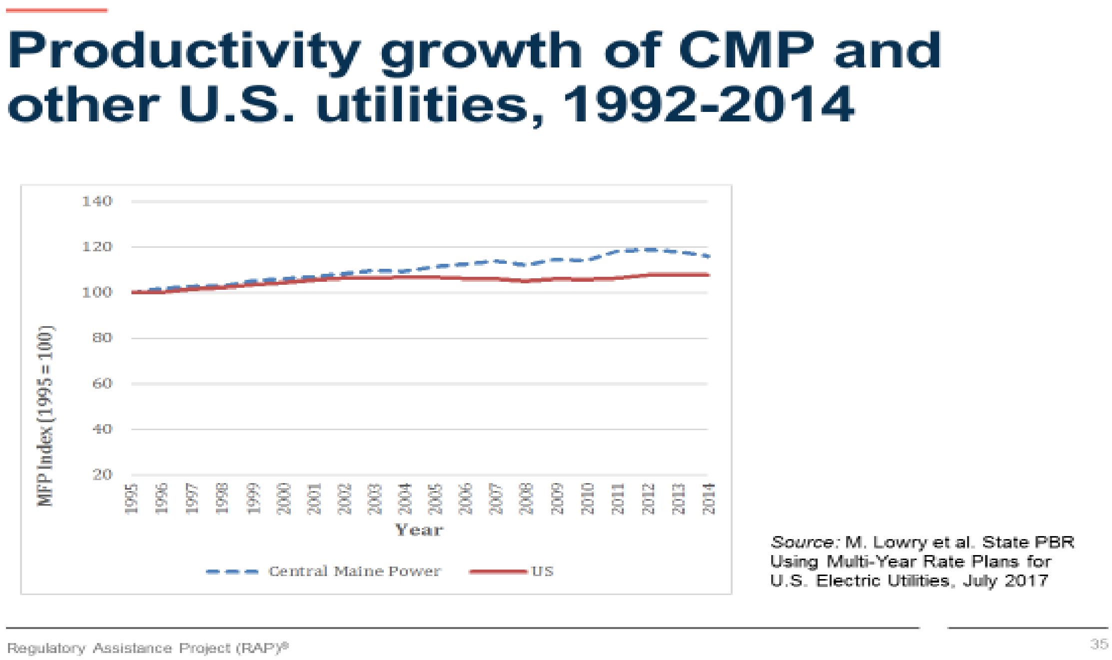
Long–term Outcomes: From 1980-1993, before MRPs became commonplace, the productivity growth of New York power distributors averaged 0.98 percent annually. This was 51 basis points above the average for sampled power distributers nationwide. From 1994-2014 during which MRPs have been prevalent, the productivity trend of New York utilities averaged 0.54 percent annually, whereas the average for utilities nationally was 0.45 percent. CAPEX productivity was more rapid in New York but O&M productivity was slower. Evidence that MRPs have improved cost performance is not strong. This is not surprising since New York's approach to MRP design is conservative, with short rate case cycles.

Case Studies- Maine

In Maine, it's largest investor-owned utility, Central Maine Power (CMP), operated under multi-year rate plans for more than two decades. CMP was allowed to retain all savings. CMP's plans also included a productivity factor that exceeds inflation. The effect of requiring greater growth in productivity than the rate of inflation is to require more efficient operations through the productivity factor. Even with this productivity factor larger than the increasing inflation/cost factor, CMP operated and reported profitability during these years.

Further, independent analysis by Mark Lowry of productivity growth indicates that CMP exhibited superior productivity growth during this time. Figure 15 below shows this superior productivity growth in comparison to the average U.S. utility productivity. Maine's experience is positive and typical of utilities in the Northeastern U.S.

Figure 15. Productivity growth of CMP and other U.S. Utilities, 1992-2014



Long–term Outcomes: Maine's experience with over two-decades of a multi-year rate cap regime exhibited superior utility productivity. However, the same utility, CMP filed a rate plan in 2014 seeking a negative productivity factor (cost-increase formula) claiming that cost dynamics in the utility industry made increased productivity gains difficult to achieve. The same utility also requested substantial pre-approval of capital investments in the system. The Maine PUC declined to approve a multi-year rate cap with a negative productivity factor putting CMP's rate plan back on a traditional COS basis.

<u>Case Studies- Minnesota</u>

Minnesota legislature authorized the Commission to approve MRPs in 2011. The final order was issued on June 17, 2013. Some of key outcome of MPUC deliberations on the various parameters of MRPs are:

- Three-year maximum term, which will begin on effective date of new rates.
- MRPs are filed within context of general rate case.
- Utilities will not be permitted to file a new rate case until MRPs has expired.
- Plans will specify fixed rates for each year of the plan. MRPs that propose formula rates will not be approved. Fixed multiyear rates allow prices to adjust over time but are based on fact-driven rate-making process and substantial evidence. Formulaic rates automatically pass through utility costs to customers and reduce incentive to manage costs.

- The established ROE will be used to determine rates for all years of MRPs.
- Allow some riders on case-by case basis.
- Imprudent rate increases will be subject to refund and utilities must waive any claim that such a decision would constitute retroactive rate making.

Appendix F– Regulatory Assistance Project / National Renewable Energy Laboratory 2017 report on Performance Based Ratemaking

Littell, D., Kadoch, C., Baker, P., Bharvirkar, R., Dupuy, M., Hausauer, B., Linvill, C., Migden-Ostrander, J., Rosenow, J., Wang, X., Zinaman, O., and Logan, J. (2017). Next-Generation Performance-Based Regulation. Golden, Colorado: National Renewable Energy Laboratory.

Retrieved from: https://www.nrel.gov/docs/fy17osti/68512.pdf

Appendix G – Regulatory Assistance Project Performance Based Regulation Options 2017 report to the Michigan Public Service Commission

Littell, D., and Shipley, J. (2017). Performance-Based Regulation Options: White Paper for the Michigan Public Service Commission. Montpelier, VT: The Regulatory Assistance Project.

Retrieved from:
http://www.michigan.gov/documents/mpsc/RAP_PBR_options_for_MI_PSC_7_14_17_579246_7.pdf

Appendix H – Economic regulation of public utilities – fundamental concepts relevant to economic incentives and regulatory efficacy (including the UK's RPI –X mechanism: a second-generation performance incentive framework)

http://www.michigan.gov/documents/mpsc/Appendix_H_609239_7.pdf