REPORT ON THE STUDY OF PERFORMANCE-BASED REGULATION

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Executive Summary

This report by the Michigan Public Service Commission (PSC or Commission), on performance-based regulation (PBR) and its potential applicability in Michigan, was developed to comply with Section 6u of Public Act 341 of 2016 (PA 341). That statute implemented a comprehensive reform of energy policies in the state and directed the Commission to perform a study of PBR in other states and countries, including a well-established PBR approach used in the United Kingdom. The Commission was directed to engage stakeholders on this topic and evaluate four specific factors: (1) methods for estimating revenue needed, (2) methods to increase the time between rate cases, (3) options for establishing incentives and penalties, and (4) profit-sharing provisions that can spread efficiency gains among consumers and utility stockholders and can reduce the degree of downside risk associated with innovation.

The rates of investor-owned electric and natural gas utilities in Michigan are regulated by the Commission under cost-of-service regulation.[1] Under this traditional regulatory approach, utilities have been incentivized to build infrastructure to meet a multi-decade period of increasing energy demand. In more recent years, however, stagnant growth in energy demand has challenged the assumption that utility investment can be funded by anticipated future growth, causing rate cases to be filed more frequently. During a time of increased technology innovation, digitalization, and customer engagement affecting the energy industry, it is also difficult to encourage innovation and operating efficiency within the traditional regulatory model. PBR has been used in other jurisdictions to help adapt to these drivers of change, meet policy goals, extend time between rate cases, and remove disincentives inherent in traditional regulation for non-capital solutions such as energy waste reduction or customer-owned generation. As discussed in this report, PBR is complex and has both advantages and disadvantages. Accordingly, the direction from the Michigan Legislature and Governor for the Commission to undertake a comprehensive examination of PBR as a first step is timely.

The Commission examined PBR mechanisms in two jurisdictions: (1) the United Kingdom (revenues, incentives, inputs, and outputs for 8 years), and (2) New York (distribution rate freeze for 2 years). The Commission also created an inventory of four other PBR applications in (1) Alberta, Canada (distribution price cap for 5 years); (2) Australia (transmission revenue cap for 5 years); (3) Norway (transmission revenue cap for 5 years); and (4) Ontario, Canada (distribution price cap for 5 years). In addition to considering PBR mechanisms in other jurisdictions, the Commission also analyzed potential PBR approaches related to PA 341, including: (a) cost-of-service with targeted incentives, (b) performance incentive mechanisms for demand response, (c) shared-saving approaches, and (d)

[1] Cost-of-service regulation is also referred to as cost-plus-return regulation. In regulatory jargon, the term “cost-of-service” also refers to setting rates for individual classes of customer (e.g., residential, industrial) based on the utility’s cost to serve those groups of customers.

approaches to optimize overall capital expenditures and operating costs. The Commission analyzed these approaches in light of five specific objectives in PA 341: (1) customer satisfaction, (2) safety, (3) reliability, (4) environmental impact, and (5) social obligations. The MPSC relied on numerous secondary sources for its study of PBR.[2]

The Commission's review of PBR mechanisms in other jurisdictions indicates that similar approaches can be used to augment the existing regulatory model, provided they are tailored to specific requirements in Michigan. Sec. 6u did not create any new or revised authority addressing the Commission's ability to approve PBR but Sec. 6u (5) states that Sec. 6u does not limit the Commission's *existing* authority to authorize PBR. Notwithstanding, it is clear that *how* rates are set—whether through traditional regulatory methods or PBR—provides strong incentives that affect utility investments and behaviors. Integrating forms of PBR into the existing cost-of-service regulatory model could help utilities and regulators adapt to potentially profound changes affecting the energy industry in the coming years as discussed above. Consequently, the Commission intends to: (a) proceed through the use of pilot programs to evaluate the feasibility of different approaches, (b) integrate PBR with other energy planning and infrastructure programs, and (c) continue to keep stakeholders involved. More specifically, the Commission has a well-established program to accelerate the replacement of aging natural gas main pipelines that could be expanded to address other infrastructure challenges in conjunction with additional performance metrics. In addition, the Commission has a new electric distribution planning initiative to increase transparency and stakeholder engagement on grid modernization goals, metrics, and investment strategies that could provide a foundation for PBR. The Commission intends to evaluate the inclusion of PBR metrics in these programs and also review other programs that may prove fruitful for the use of PBR.

[2] One comprehensive source on PBR—a September 2017 report by the Regulatory Assistance Project (RAP) and the National Renewable Energy Laboratory is particularly timely and relevant given their research on the latest U.S. and global experience with respect to PBR and analysis of new regulatory trends involving the use of performance incentive mechanisms, or PIMs, to augment existing regulatory structures to achieve a diverse array of targeted policy outcomes. Due to its relevance, the RAP/NREL report on Next-Generation Performance-Based Regulation is referenced as Appendix F, the RAP report on Performance Based Regulation Options is referenced as Appendix G, and the report on Incentive Regulation of Distribution Utilities is referenced in Appendix H to this MPSC report.

Study Criteria

Act 341 of 2016, which amended Act 3 of 1939, charges the Commission to undertake a study of PBR, and to report on its findings with written recommendations (Sec. 6u). In conducting this study, the Commission was tasked with collaborating with representatives of each customer class, regulated utilities, and other interested parties.

Sec. 6u (1) defines PBR, in part, as a regulatory system in which a utility's authorized rate of return would depend on the utility achieving targeted policy outcomes. Such outcomes could relate to cost control, customer service, reliability, safety, innovation, environmental performance, or other considerations. Regulatory mechanisms with targeted objectives are commonly referred to as performance incentive mechanisms, or PIMs.

Sec. 6u (2) directs the MPSC to examine PBR applications in other states and countries including, but not limited, the United Kingdom's RIIO (revenue = incentive, + innovation + outputs) model. RIIO is a broad-based PBR alternative to traditional cost-of-service regulation. Other jurisdictions have used PBR mechanisms such as PIMs to augment existing cost-of-service regulation.

Sec. 6u (3) directs the MPSC to evaluate four specific factors associated with PBR:

1. Methods for estimating revenue needed during a multi-year pricing period that uses forecasts of efficient total expenditures (i.e., TOTEX as used in the RIIO model);
2. Methods to increase the time between rate cases to provide the utility with opportunity to retain cost savings and to encourage investments that have extended payback periods;
3. Options (i.e., mechanisms) for establishing incentives and penalties that pertain to customer satisfaction, safety, reliability, environmental impact, and social obligations; and,
4. Profit sharing provisions that can spread efficiency gains among consumers and utility stockholders and reduce the degree of downside risk associated with innovation.

Comparison of Traditional Cost-of-Service Regulation and PBR

Economic Regulation of Public Utilities in Michigan

The origins of the MPSC as a regulatory body, and its jurisdiction over public utilities, stem from Act 3 of 1939 (Act 3). It is the Commission's core enabling legislation and outlines the scope of its legal authority to regulate public utilities.

Both Act 419 of 1919, and Act 9 of 1929, preceded Act 3. Act 419 created the Michigan

Public Utilities Commission, having jurisdiction over electric, manufactured gas and power. Act 9 expanded the MPUC's jurisdiction to include rate authority over amended natural gas purchase contracts, and the transmission and distribution of natural gas within Michigan. Act 3 replaced the Public Utilities Commission with the Public Service Commission, and consolidated the Commission's regulatory authority over public utilities. The Act granted the Commission broad ratemaking authority over investor-owned natural gas, steam, and electric utilities.[3]

There have been several major and minor amendments to Act 3 over the years to modify the structure of utility regulation in Michigan to respond to changes in the regulatory environment, and to modify the procedures and processes used to evaluate applications for rate increases.

Table 1: Economic Regulation of Public Utility

YEAR	PA #	TITLE
1919	419	Michigan Public Utilities Commission
1929	9	Natural Gas
1939	3	Michigan Public Service Commission
1982	304	Amended Act 3 of 1939
2000	141	Customer Choice and Electricity Reliability Act
2008	286	Amended Act 3 of 1939
2008	295	Clean and Renewable and Efficient Energy Act
2016	341	Amended Act 3 of 1939
2016	342	Amended Act 295 of 2008

The utility regulatory structure was developed over nearly a century with refinements over time to the core approach, known as "cost-plus-return" or cost-of-service regulation. Under this form of economic regulation, utility rates are set to allow the utility the opportunity to recover capital investments over time (including a return, or profit, on those investments) plus operations and maintenance expenses such as tree trimming, labor expenses, insurance, and taxes.

Under cost-of-service regulation, the following formula is used:
Revenue Requirement = Rate Base * r + D + O + T

Where:

Rate Base = Unrecovered Capital Investment
r = Cost of Capital; return "ON" capital
D = Depreciation; return "OF" capital
O = Operating and Maintenance Expenses
T = Taxes

[3] Changes to Michigan law in 2008 authorized cooperatives to become regulated, for purposes of setting rates, by their elected board of directors. All but one cooperative (Presque Isle Gas Cooperative) are now member regulated.

With the utility's profit tied to the level of capital investment, this approach provides a strong incentive for utilities to make capital investments in energy infrastructure. It has enabled utilities to build infrastructure to respond to a multi-decade expansion of energy demand and broad changes in the economy.

For decades, Michigan applied this rate-setting formula with historical data on the utility's revenue, sales, and costs, known as a historical test-year.[4] Act 286 of 2008 permitted regulated utilities to file rate case applications using projected costs and revenues for a future consecutive 12-month period (i.e., a *fully projected* test year, as opposed to the limited adjustments to actual costs and revenues made in a historical test year calculation).[5] While there are arguments made against the use of projected test years,[6] Michigan's experience with them does provide a foundation for PBR in that it better informs the Commission with respect to short-term utility capital planning and related goals (e.g., reliability improvement) to be met from the planned investments and such review can occur prior to the expenditure being made.

Under traditional regulation, prudence reviews often occur after the fact (although with projected test years, utilities may wait to make certain investments or incur expenses until they are approved by the Commission in a rate case given the potential uncertainty of cost recovery). Quality service is to be provided according to the performance requirements implicit in traditional utility regulation combined with prescriptive technical and customer service standards promulgated by the MPSC.

Traditional cost-of-service regulation incentivizes certain behaviors: regulated utilities recognize they can maximize revenue and profits by building more generation, distribution, and other infrastructure and by selling more electricity between rate cases.[7] This can work well for a system featuring large, centralized power plants that required large investments of capital resources with growing energy demand.

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[4] A historical test year is a *pro forma* calculation of revenue requirements using the requesting utility's books and records as a cost foundation (pro forma means based on historical costs, as adjusted for non-recurring events). Typically, historical costs were adjusted for "known and measurable" changes. A historical test-year did allow for the use of projected sales levels to ensure that the final rates for the various rate schedules fairly recovered a utility's approved revenue requirement.

[5] All rate case applications since the passage of Act 286 have used projected test years. In various rate case orders since 2008, the Commission has clarified its standards for utilities using projected test years, and in some instances relies on historical information for certain cost items.

[6] Use of projected costs in determining a utility's revenue deficiency can blunt the "regulatory lag" associated with the strict use of actual (historical) costs and revenues to set rates. Regulatory lag is the lapse of time between a petition for a rate increase and action by the regulatory body. Some entities and academics argue that such regulatory lag is a critical and positive feature of traditional cost-of service regulation, creating economic incentives for utilities to pursue cost efficiencies.

[7] In a rate case, to somewhat simplify, the rate is set by dividing the revenue requirement by expected sales to yield an allowed rate that utilities charge to customers on a volumetric basis of cents per kilowatt-hour. If the volume increases above the expected sales figure used in the rate case, that excess revenue is above the revenue requirement, and is traditionally retained by the utility. Decoupling and other revenue adjustment mechanisms can alter this outcome by adjusting rates if sales increase.

Drivers of Change

Several factors are leading to a re-examination of the traditional utility business model and regulatory approaches. These factors include, but are not limited to, technological change (e.g., electric vehicles, energy storage, renewable energy, Internet of Things, digitalization), stagnant growth in energy demand due largely to end-use efficiency improvements, and evolving customer preferences and engagement relating to energy sources and use. As utilities undertake significant capital investments to replace aging infrastructure, there is also an opportunity to integrate technological innovations and rethink approaches to energy production and delivery.

New capital investment to upgrade aging infrastructure such as gas pipelines, substations, poles, and generation equipment is the primary driver of rate cases in Michigan. The level of investment—on the order of $3 billion per year—is leading to regular rate cases before the Commission. The Commission had an unprecedented 11 rate cases in some stage of the process during 2017, and multiple cases are slated for decisions or to be filed in 2018.[8] The frequency of these cases (and the time and cost involved for the Commission, utilities, and stakeholders) has also led to questions about the traditional regulatory approach, and whether PBR could play a role in potential reforms.

As discussed further below, PBR is viewed as an option to help adapt to these drivers of change by specifying expectations of utility performance and outcomes for consumers, while staying agnostic to the exact means of delivery. PBR can also be designed to provide incentives and penalties to meet certain policy goals (e.g., service quality, reliability, power plant performance, innovation), extend time between rate cases, and remove disincentives inherent in traditional regulation for non-capital solutions such as energy waste reduction or customer-owned generation.

PBR vs. Traditional Cost-of-Service Regulation

In its most basic form, a transition to PBR entails capping utility rates or revenues (often with some provision for inflationary adjustments) and shifting to a series of pre-defined goals or metrics to ensure specific performance outputs and outcomes are met. Regulators began adopting various forms of PBR in the 1980's and 1990's.[9] Early forms of PBR focused almost exclusively on cost-control, and PBR has been used in the telecommunication and railroad industries as well. More recently, PBR has expanded beyond cost-control, and is now being utilized as a means to focus regulated utilities on jurisdictional goals ranging from energy efficiency and renewable integration, to grid modernization goals. Under traditional

[8] An increasing portion of utility rate increases are directly related to capital investment programs, reflecting a combination of low inflation (reducing the rate of increase in operating expenses or even reducing overall operating expenses) and major new infrastructure investment.

[9] 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

regulation, the levels of sales and capital expenditures primarily drive utility financial earnings, whereas PBR can be designed to optimize total utility expenditures regardless of whether they are operational or capital in nature.

In general, the goal of PBR is to embed explicit incentives and/or disincentives into the regulatory regime to directly encourage a utility to make investment and operating decisions that achieve certain policy or regulatory outcomes. More specifically, PBR has the ability to connect goals, targets, and measures to utility performance, executive compensation, and investor returns. PBR mechanisms determine utility revenue based on specific performance metrics and other non-investment factors. PBR can include multi-year rate plans (MRPs), performance incentive mechanisms (PIMs), alternative rate mechanisms, and rate or revenue caps, which are discussed in this report and in Appendix A. PIMs are metrics and formulas that determine the levels of financial rewards or penalties (i.e., adjustments to allowed revenues) for achievement of specified outputs and outcomes. A rate cap literally limits the rate a utility can charge its customers. A utility is allowed to keep some or all efficiency gains so long as rates do not increase. A revenue cap limits how much revenue a utility can recover so utility revenue cannot exceed a certain level.[10] In designing PBR metrics, regulators and policy makers can clearly articulate expectations for utility operations on particular targets and outcomes—such as reliability improvements, cost-effective energy efficiency or grid modernization—in advance of any utility decisions or expenditures.

On the other hand, successful PBR requires the targets and incentives to be carefully designed so the incentives, whether negative or positive, do not unnecessarily burden ratepayers or generate unfair profits for the utility. Depending on the expenditure, it may be difficult for the regulator to foresee at the outset all possible unintended outcomes of the PBR metric. A conceptual review of a shift to a more performance based regulatory regime is shown below in Table 2. While the figure describes traditional cost-of-service regulation as "reactive," it is worth mentioning that projected test years can provide some visibility into near-term plans prior to certain expenditures being made. But even with projected test years, the model is still best characterized as reactive.

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[10] Migden-Ostrander, J., Littell, D., Shipley, J., Kadoch, C., and Sliger, J. (2018) Recommendations for Ohio's Power Forward Inquiry. Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/wp-content/uploads/2018/02/rap-recommendations-ohio-power-forward-inquiry-2018-february-final2.pdf

Table 2: Conceptual Contrast of Cost-of-Service Regulation with Performance-Based Regulation.[11]

Cost-of-Service Regulation	Comprehensive Performance-Based Regulation
Regulatory Involvement	
After-the-Fact	Before-the-Fact
Reactive	Proactive
Large regulatory input with imprudence	Large regulatory input up-front
Specificity of Regulatory Guidance	
Little regulatory guidance	Specific targets set
Less Innovation	Flexibility in methods to achieve outcomes

Well-designed PBR provides incentives and disincentives based on utility performance, and has the potential to benefit consumers and utilities alike. PBR provides goals and metrics that enable utilities to forecast efficient total expenditures. Some forms of PBR, such as multi-year rate plans, increase the time between rate cases, which provides utilities with more opportunity to retain cost savings without the threat of imminent rate adjustments. However, multi-year rate plans require detailed policy objectives at the outset. PBR encourages utilities to make investments that have extended payback periods, which can shift the focus from traditional capital plant investments to a longer horizon focused on designated performance outcomes. PBR can also be designed to provide incentives and disincentives that help the utility focus on and improve customer satisfaction, safety, reliability, and environmental performance.

PBR should not be viewed as a mechanism to avoid increases in utility rates, since the expected level of new capital investment, even with the deployment of new technologies, will be significant over the coming years. PBR is best defined as a unique regulatory tool that uses incentives to guide innovation and cost efficiencies, which may provide utility management flexibility to choose among operational options that can lead to improved performance and customer benefits.

The UK's RIIO (Revenues-Incentives-Inputs-Outputs) Mechanism

Pursuant to Sec. 6u of Act 341, the MPSC has evaluated the United Kingdom's (UK's) RIIO performance-based regulation model and its suitability for Michigan, in whole, or in part. The

[11] Hopkins, A. (2017). Utility Performance Regulation: Presentation to NASEO Western Regional Meeting. Cambridge, MA: Synapse Energy Economics. Retrieved from: http://www.naseo.org/Data/Sites/1/events/regional/west/2017/Hopkins--Utility-Performance-Regulation.pdf
NOTE: After-the-fact and reactive review is the case for historic test years, while projected test years include some before-the-fact and proactive review.

main goal of RIIO is the 'timely delivery of a sustainable energy sector at a lower cost to consumers than would be the case under the existing regimes.'[12] RIIO is a framework which retains strong cost control incentives while attempting to focus on long-term performance, outputs, and outcomes, with less focus on ex-post review of investment costs.[13] RIIO was intended to begin a transition away from the traditional approach of simply rewarding investment in networks under the prior regime to an outcome-based approach—a shift from inputs to outputs through revenue-based regulation overlaid with a system of financial rewards for achievement of specified goals (performance).[14] U.K. regulators changed their price and revenue control mechanism to remove any bias that may normally exist between capital expenditures and operational expenses that would tend to lead utilities to prefer capital expenditures. This approach, which has been referred to as TOTEX (i.e., total expenditures),[15] means there is an incentive to deliver outputs rather than simply build new infrastructure.[16] As discussed later in this report, the differences between the electricity industry structure in the UK and Michigan could make some of the UK approaches difficult to replicate. However, the Commission also examined this model to assess learnings for potential application in Michigan if elements of RIIO were used to augment the current cost-of-service based regulation structure. This review is attached as Appendix B of the Commission's study.

Key Incentive/PBR Mechanisms and Implementation in the U.S.

Michigan continues to employ traditional cost-of-service methods for regulating utilities, but has utilized incentive mechanisms, alternative methods, or performance metrics on a limited basis over the past 30 years. Although Michigan's utility regulatory past has not featured a formal PBR structure, Michigan has used variations of performance mechanisms designed to achieve improved energy efficiency, reliability, and quality and service. An ongoing issue for policy makers addressing PBR/incentive/penalty systems has been determining whether incentives should be applied to all phases of rates in a case or on a goal-specific basis. Regulators must then decide how to value those incentives and penalties associated with the chosen design based on specific goals and metrics. This report examines Michigan's past incentive mechanisms as well as implementation of PBR mechanisms in the United States and other countries.

Table 3 shows PBR for cost control in six jurisdictions. This review of incentive mechanisms can be found in Appendix C.

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

[13] 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.

[14] Id. By "revenue-based," we mean a method by which "target" or "allowed" revenue levels are determined by regulators and collected by means of adjustments to prices as sales vary (as they inevitably do) from expected levels. (This is what is known as decoupling in the United States.) The allowed revenues themselves may be periodically adjusted to deal with non-sales-related cost drivers, such as inflation, productivity improvements, and approved changes in investment. Such changes are often formulaic in nature and embedded in multi-year regulatory plans.

[15] The move to a total expenditure, or TOTEX, regime was first suggested by Ofgem in March 2008, when the energy regulator launched its RPI-X@20 review. From this comprehensive review of the previous regulatory regime, which had endured since privatization in 1989, emerged the RIIO model.

[16] 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.

Table 3: PBR for Cost-Control in Six Jurisdictions[17]

Jurisdiction	**Alberta, CA**	**Australia**	**New York, USA**[18]	**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)[19]	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

Cost-of-Service Regulation with Added Targeted Incentives

A broad approach to PBR in Michigan might look like revenue-cap or rate-cap regulation[20] to limit cost increases over time with specific PIMs to encourage a set of desired activities such as energy waste reduction, demand response and perhaps electric vehicle integration. Broad use of PIMs is a relatively new concept with little real-world experience among regulatory jurisdictions across the country. New York is an exception, being an example of a state leading PBR implementation in the U.S. There may be value to Michigan in considering incremental PBR additions built on the foundation of Michigan's existing cost-of-service regulation that has been refined over many years.

With specific PIMs, PBR can elevate the goals referenced in Act 341 related to customer satisfaction, safety, reliability, environmental impact, and social obligations. However, addressing all five goals at once is a tall order as each goal needs to be refined with incentive, performance criteria and metrics with a sense of the benefits, costs, and cost savings involved in moving forward with each. More narrowly, the MPSC may explore other specific objectives, such as the use of PIMs to integrate distributed energy resources or

[17] 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

[18] 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

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

[20] Multi-year rate plans often feature a rate cap or a revenue cap. A rate cap literally limits the rate a utility can charge its customers. A utility is allowed to keep some or all savings from efficiency gains so long as rates do not increase. A revenue cap limits how much revenue a utility can recover so utility revenue cannot exceed a certain level. The two concepts can be augmented with a formula, such as tying return on equity to a market index or a process, such as annual review of capital. An augmented approach may result in an adjustment of rates and revenues during the plan.

electrical vehicles in a cost-effective manner. Each effort would require stakeholder and public input and vetting so ratepayers understand what they are being asked to pay for and why it is valuable.

Targeted pilots could demonstrate results that could be achieved on a larger scale. In this manner, the MPSC could determine whether or not the PIM approach is able to meaningfully achieve the multi-faceted policy outcomes delineated in Sec. 6u of PA 341. Should pilots be undertaken, the MPSC recommends a regulatory process with a strong stakeholder focus, as is case with the UK's RIIO incentive regulation system.

With these general caveats, the Commission observes that the changing power sector -- including penetration of new disruptive technologies such as decentralized supply, growth of demand side resources, increasing intelligence and digitalization of networks -- will change what regulation looks like in the 21st century. PBR both to control costs and integrate these new technologies into Michigan's grid may prove a valuable concept in the future path for Michigan's utility regulation. Performance Incentive Mechanisms that may work for Michigan are further discussed below and in Appendix D.

PIM Options

Demand Response PIM

Michigan's 2016 energy laws require 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, certain utility companies are required to offer Commission-approved demand response programs. A PIM could be used as an 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.

Regulators can use generic or utility-specific economic and engineering studies to set targets. Energy efficiency and demand response potential studies that were undertaken pursuant to the energy laws can identify the level of cost-effective investments for utilities. These studies can help regulators identify and define specific resource investment targets and costs.[21]

Metrics associated with demand response depend in part on the specific goals to be achieved. Demand response can be used for multiple purposes such as peak load reduction, load reduction to avoid targeted infrastructure investment, displacing energy purchases during high price periods, customer engagement, operational load management including

21 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

emergency load reductions, and ancillary services to accommodate variations in net load. Metrics should reflect whether or not the underlying policy goal is being met; e.g., if peak demand has decreased over the prior year.[22]

Shared-Saving PIM for DR

By January 1, 2021, PA 341 requires the MPSC 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) 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 MPSC is to determine the net benefits.

b) 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.

c) 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.[23]

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, and avoided transmission and distribution plant costs. The potential for savings from demand response programs administered by the utilities is particularly strong if specific power plant, distribution and transmission investments 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 capital investments in infrastructure. Shared savings from avoided system investments can create a "profit" for the utility and a savings for customers. That said, the savings shared with customers must be fair so there is some form of joint savings from innovative cost-effective implementation.

With a shared net-benefit incentive structure, the utility shares with ratepayers in the benefits associated with, and identified from, its performance and the metric achieved. This can mean sharing in financial benefits between the utility and ratepayers. A shared net benefits approach needs to be carefully designed and implemented to clearly identify the shared

22 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

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

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.

Positive and Negative PIMs for Optimizing CAPEX and OPEX

If a good estimate of overall capital expenditures (CAPEX) and operational expenditures (OPEX) costs and timeframe can be set in advance through a formal proceeding, such as a general rate case, it is possible to use a carefully designed PIM mechanism to provide incentives and penalties for utility optimization of capital investment and operational expenses. Such a CAPEX/OPEX mechanism would provide incentives for cost savings and penalties for cost overruns.

While such a CAPEX/OPEX PIM could stand alone, a PIM for capital expenditures could also be built into a cost-cap regime. 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 in business-as-usual operations. A focal point of 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 CAPEX budget and timeframe on which to calculate the capital expenditure adder (or rider) that savings would be measured from using OPEX judiciously. 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 three, five or eight 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 not be motivated to share these saving with ratepayers. If capital projects are managed to miss timeframes or run over budget, a penalty of disallowing some utility recovery of expense or profit might be imposed. So, if a set of 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 likely would oppose any disallowances for cost overruns.

The benefits to the utility of sharing in savings from optimizing capital and operation costs is that they may be able to achieve long-term capital investment certainty over a specified time frame such as three, five, or eight years. They also could share in benefits if the utility can use OPEX to operate more efficiently. With that certainty, utility management can focus on project management and implementation and assessing the least costly options to address known system deficiencies.

Output Goals: 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, adopt demand-side energy options, and the ability to see publicly reported performance data on their utility.

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 meeting customer needs and preferences. Focus on customer satisfaction can range from public reporting of customer satisfaction rankings, to metrics focused on utility customer empowerment, to public reporting scorecards.

Output Goals: 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. Metrics in this area are intended to provide indicators of incidents, injuries, and fatalities associated with the contact with the electric and gas system, and adequacy of response to emergency situations.[24] Metrics associated with natural gas operations safety compliance or reducing gas system losses could also be explored.

Output Goals: 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. For electric utilities, there are well established reliability metrics and benchmarking data addressing the frequency and duration of power outages such as:

24 id.

SAIDI – System Average Interruption Duration Index – The average number of service interruptions a customer served by the utility would expect to endure in a given year.

$$SAIFI = \frac{sum\ of\ all\ customer\ interruptions}{total\ number\ of\ customer\ served}$$

SAIFI – System Average Interruption Frequency Index – The average duration (minutes) of service interruptions a customer served by the utility would expect to endure in a given year.

$$SAIDI = \frac{sum\ of\ all\ customer\ interruption\ durations}{total\ number\ of\ customer\ served}$$

CAIDI – Customer Average Interruption Duration Index – The average time it takes the utility to restore service (minutes) after an outage has occurred on the system.

$$CAIDI = \frac{sum\ of\ all\ customer\ interruption\ durations}{total\ number\ of\ customer\ interruptions} = \frac{SAIDI}{SAIFI}$$

Governor Snyder has established goals for these reliability metrics to improve electric distribution reliability in the state.

Even with these and other established industry metrics, defining the precise incentive or penalties, and performance criteria can be difficult. It is important to ensure that customers receive reasonable value and return on reliability investments. There is a point of diminishing returns with respect to reliability investments. Low cost reliability improvements are certainly worth pursuing, whereas expensive reliability improvements should be weighed to consider whether consumers really desire to pay those costs to obtain the reliability benefits gained.

Output Goals: Environmental Impact

Michigan’s 2016 energy laws provided a framework to transition to cleaner sources of electricity. Michigan is also known as a technological and industrial innovator. The breadth of advanced energy technologies being developed and deployed makes tracking any one set of technologies a significant challenge. But this does not mean that regulators cannot set up accommodating utility structures to integrate advanced technologies into Michigan’s grid and resource planning and investments. Such alternatives could present new least-cost solutions that benefit not only individual customers, but all utility customers.

The challenge is to set up a flexible performance-based structure that encourages utilities, third-party providers, and customers to move toward environmentally beneficial and least-cost solutions whether those are traditional investments or more distributed options owned by the utility, third party, and/or the customer. With advanced technologies entering the market and quickly evolving in terms of cost and capabilities, it is almost impossible to determine cost-effectiveness in advance. But regulatory structures can create “facilitated 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 energy infrastructure upgrade costs.

Output Goals: Social Obligations

It is important for the regulator to be able to assess impact on low-income and vulnerable customers, and to correspondingly assess utility response to low-to-moderate income impacts. PBR and specific PIMs focused on these areas can help the regulator, the utility, and other stakeholders address and empower this segment of the population. 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.[25] 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.
2. Customer empowerment that enables vulnerable customers to pro-actively manage their consumption and make energy bills more affordable.

Multi-Year Rate Plans

The MPSC was also charged by law to evaluate methods to increase the time between rate cases with a view to encourage utility investments having extended payback periods and that promote cost efficiency. Multi-year rate plans, a first effort at PBR, were first used in in the 1980s for railroads, telecommunications, and other industries facing competition and changing demand, and were introduced for U.S. electric utilities in the 1990s. The purpose of these plans was to motivate efficient operations and thus low-cost service while maintaining reliability and customer service. Traditional cost-of-service regulation essentially assumes that sales growth is a predictor of cost growth. To address this, PBR is often explicit in allowing utilities to earn higher profits if they become more efficient by cutting cost and continuing to provide quality service.[26] The PBR construct to control costs is to set utility revenue over a number of years and then allow the utility to retain all or some portion of cost savings resulting from efficiency gains. The utility has a potential gain to increase earnings and also takes on the risk that it can operate more efficiently. Multi-year rate cases are nearly always negotiated in settlements with utilities, so any inherent risks in a negotiated

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25 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

26 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. 35.

settlement are ones that the utility believes are reasonable in comparison to the potential gain. The Commission has examined multi-year rate plans in other states as required. Please refer to Appendix E.

PBR over multiple years should be based on projections of costs, revenues, inflation and productivity in the future. PBR focused on cost control often takes the form of a multi-year rate plan, with various mechanisms: productivity indexes, attrition relief mechanisms, earning sharing mechanisms and PIMs. Without those mechanisms being in place, and without earnings sharing mechanisms, multi-year rate plans could fail to achieve cost-control incentives and fail to encourage increased utility productivity.[27]

The MPSC could test whether PIMs can be used to extend the period between general rate cases. In doing so, it would be necessary to utilize a diverse set of target performance mechanisms allowing for both positive incentives (rewards for good performance) and negative incentives (for unacceptable performance). At a minimum, such PIMs would address known potential issues arising out of multi-year rate setting periods, such as reduced customer service and service quality that are well established as issues in many other jurisdictions using multi-year rate plans.

Prudent PBR design in the U.K. and other U.S. States has recognized the need for a symmetric mix of incentives, both positive and negative, to ensure utilities continuously perform in a manner warranting annual rate increases absent the direct regulatory review that occurs in single year rate cases prior to a rate increases being granted. The mixture of incentives that can enhance well-established and time tested traditional regulation is different for the priorities of each jurisdiction.

Public Reporting Mechanisms

Public reporting obligations, such as tracking specific performance criteria and metrics that are important for Michigan’s regulatory goals, 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. The establishment of a reporting obligation communicates the importance of that performance criteria and metric to the utility, stakeholders, and the public.

The requirement that utilities track, analyze, and report specific information can encourage different utility behavior, assist in establishing incentives attached to some or all of the metrics, and provide transparency which may allow other stakeholders to interact in more predictable ways with the utility that are important for supporting third-party energy service

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[27] Lowry, M., Woolf, T., and Schwartz, L. (2016). Performance-Based Regulation in a High Distributed Energy Resources Future. Berkley, CA: Lawrence Berkley National Lab. Retrieved from: https://emp.lbl.gov/sites/all/files/lbnl-1004130.pdf

businesses and customer investments in on-site generation, demand response, or energy waste reduction. Some of the above-mentioned PIMs could first be instituted as public reporting only measures. Additional options Michigan might 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 submitted proposed green pricing programs, which are under Commission review based on criteria such as:

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.

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 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 working with utilities and other interested parties to create a framework for such "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.

Potential Applicability of Broad-Based PBR in Michigan

RIIO as Applied in the UK Would Not be Appropriate for Michigan under Existing Market Structure

The RIIO incentive structure now in place in the UK is an evolution from the regulatory framework that was in place before it, called RPI-X. RPI-X was itself an incentive-based regulatory scheme, focused primarily on price and revenue caps. RIIO is a regulatory evolution building on experience and lessons learned from many years of utilizing incentive regulation in the UK's utility sector. UK regulators made improvements over the course of many years to result in the broad-based incentive PBR model now in place. The multi-year regulatory review prior to finalization of RIIO as well as its incremental implementation were critical to building stakeholder support for the reforms.[28] The prior projections of efficient future costs were an essential element of RIIO and would require a modeling and economic projection ability beyond that currently in use in setting rates in any U.S. jurisdiction. If Michigan were to move toward a similarly ambitious performance incentive regime it would likely require a similar regulatory review and stakeholder engagement over a multi-year timeframe.

Though the comprehensive RIIO process in full form is likely unrealistic for Michigan to pursue, there are some lessons learned from RIIO that could be applicable here. First, the UK regulators' initial focus on cost control resulted in regulated firms cutting back on customer service, reliability, and service quality to achieve maximum cost savings. Regulators corrected this by implementing incentive mechanisms that focused on customer service and service quality. Second, UK regulators learned that cost cap regulation was not producing the kinds of consumer savings they desired and implemented shared-savings mechanisms to balance utility and customer benefit. These types of incentive design features are ones that Michigan could consider in a PBR scheme, even if not as broad-based a regulator apparatus as RIIO.

In undertaking RIIO, UK regulators recognized the need for substantial new capital investment in the utility system to replace aging infrastructure and maintain reliability and grid services. They also recognized that the investment in the existing grid could not consist simply of a one-for-one replacement of retiring assets if decarbonization goals were going to be met. Thus, the regulators set innovation as one of the primary goals for incentives in RIIO. Several innovation rewards were created including competitive awards for innovative proposals to improve environmental performance of distribution networks and an annual competition to fund up to 90% of costs for large-scale projects that demonstrate environmental benefits. There are a variety of approaches that Michigan could take from RIIO in this area, including PIMs (incremental increase in return on base revenue) or monetary rewards for innovative projects or for replacing aging infrastructure with new, decentralized technologies. Michigan's traditional leadership in the automobile industry may also lend itself to innovation in integration platforms for utility- or aggregator- models for EV charging linked to modern distribution system investments.

As discussed earlier, the differences between the electricity industry structure in the UK and Michigan could make some of the UK approaches difficult to replicate. The "unbundled" nature of the electric industry in the UK with generation separate from transmission and distribution contributes to the difficulty regulators there face in achieving environmental goals. This structure means that UK regulators oversee network distribution companies but have little authority over the sources of electricity supply, or how end-use consumers behave. As a result, much of RIIO's environmental incentives are focused on encouraging network

[28] Guarini Center's (NYU/Law) January 2015 report to the New York Public Service Commission.

companies to take measures that reduce environmental impacts, but does not hold network companies accountable for a low-carbon transition. This is one potential shortcoming that need not exist in vertically integrated states like Michigan where utilities have more direct control over the generation fleet and therefore the environmental attributes associated with electricity supply.

Pros and Cons of Different Approaches and Conditions for Successful Implementation

Stand-alone PIMs are not prohibited under Michigan's current regulatory framework. They are available ratemaking tools as long as rates remain just and reasonable. Some PIMs, such as cost trackers, are already a part of the regulatory framework. Trackers, an accounting of specific costs for recovery in the next rate case or on top of approved rates, have been used in a limited manner in Michigan in recent years. Trackers can be used to track and reconcile specific types of expenses or investments. Trackers can reduce regulatory lag and provide certainty on an approved investment strategy that could increase cost efficiencies through material procurement and better workforce planning. The use of trackers, such as uncollectible expense equalization mechanisms, have been tested at the Court of Appeals and validated as an appropriate ratemaking tool under Michigan's regulatory framework. In re Application of Consumers Energy Co., 279 Mich. App. 180 (2008). Trackers are currently in place for utilities' natural gas main pipeline replacement programs to accelerate the replacement of at risk pipe made of vintage materials.
Another example of a PIM available under the current statutory scheme is a revenue decoupling mechanism (RDM). RDMs are available for gas utilities; for electric utilities the statute limits RDMs for companies with fewer than one million customers. Power supply cost recovery (PSCR) and gas cost recovery (GCR) mechanisms (where fuel and purchased power costs which are estimated in a plan and trued-up through a separate reconciliation under the law) are similar to a PIM and permissible under the current regulatory framework.

Summary and Recommendations

This report examines PBR systems that have been implemented across the United States and in other countries. The majority of states have maintained, at least in large part, the traditional cost-of-service ratemaking structure. This structure, which dates from the late 1800s, has evolved over time to meet emerging issues, such as changing economic conditions, the growth of wholesale energy markets, aging infrastructure, and evolving consumer needs. This evolution continues today, with the introduction of advanced technologies in the utility industry, the potential for expanding renewable and distributed generating resources, and enhanced focus on reliability and grid resilience. States that have implemented some form of PBR have also retained cost-of-service regulation as a foundation.

The Commission's review of PBR mechanisms indicates that they can be used to augment the existing cost-of-service approach provided that they are tailored to the specific requirements associated with utility regulation in Michigan. The Commission is mindful that Michigan courts have repeatedly held that the "PSC's power to fix and regulate rates does not carry with it, explicitly or implicitly, the power to make managerial decisions." Detroit Edison v Michigan Public Service Commission 221 Mich App 370, 386 (1997). Consequently, any PBR program must distinguish between the Commission's regulatory authority to set rates and the utility's managerial decision-making powers. Notwithstanding, it is clear that how rates are set – whether through traditional regulatory methods or PBR – provides strong incentives that affect utility investments and behavior. Integrating forms of PBR into the existing cost-of-service regulatory model could help utilities and regulators adapt to potentially profound changes affecting the energy industry. A variety of approaches are available.

Multi-year rate plans, for example, build on the foundation of cost-of-service regulation by providing incentives for cost-control to the utility. PBR also has the potential to enhance customer satisfaction through public reporting metrics on various measures of customer satisfaction. PIM's for demand response, shared-saving approaches, and approaches to optimize overall capital expenditures and operating costs could complement Michigan's existing regulatory model if carefully designed and implemented to ensure ratepayers receive the benefits of enhanced utility performance. PBR can also be used to encourage "non-wires" alternatives, which may in certain applications be more cost-effective than traditional utility capital investments in transmission or distribution upgrades such as a new substation. In any event, well-designed PBR should include both positive incentives (rewards for good performance) and negative incentives (for unacceptable performance such as reduced customer service and service quality) in order to improve utility performance.

The Commission will continue to explore whether diverse PBR approaches facilitate the evolution of regulated utilities in Michigan toward a more reliable, resilient grid, while increasing value to customers. This will likely require shifting the traditional focus of infrastructure maintenance from a like-for-like replacement of grid assets toward the development of lower life-cycle cost, advanced technologies and practices. Regulated utilities, under this approach, would have (in addition to their traditional role as retail energy supplier) a stronger role of providing network services to a diverse group of users. Such an approach will be explored in the context of current initiatives in long-term distribution planning, energy waste reduction programs, distributed generation tariffs, interconnection standards and processes, PURPA proceedings, and the integrated resource planning approach recently put in place under Act 341. Such transformative changes would not be made to the entire regulatory paradigm overnight; the Commission is more inclined to test the efficacy of PBR through specific natural gas and electric utility pilot programs or other targeted opportunities. This study has demonstrated that incorporation of a public process with stakeholders and utilities is important to the success of new and innovative programs. This is particularly the case as advanced technologies offer grid and customer values simultaneously, and the Commission intends to keep all stakeholders engaged as it moves forward.