Roadmap to Implementing
Michigan's New Energy Policy

Paths to the Future Report

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Section I. Introduction

The state's future energy policy is at the forefront of dialogue among Michigan's policy and business leaders, advocacy groups, and stakeholders. Concurrently, the business landscape for electric utilities is shifting due to factors like emerging technologies, changing economics of different fuel sources, state and federal policies, aging infrastructure, and regional wholesale electric market influences. Utilities struggle to adapt to this shifting business landscape, primarily because the current utility regulatory model is based on new plant construction and electricity sales (which are being eroded due to state and federal policies and new technology) and deficiencies in the existing electric delivery infrastructure (which limit integration of new technologies). To address these challenges and allow for successful implementation of the state's future energy policy, there will need to be enhanced coordination, thoughtful planning, and appropriate implementation of regulatory and utility ratemaking models.

In anticipation of changes to Michigan's energy policy, the Michigan Energy Office (MEO), with support from the U.S. Department of Energy (U.S. DOE), has undertaken a project to create a stakeholder- and research-driven roadmap for implementing new energy policies in a way that aligns utility business interests and customer behavior with public policy objectives. This project is directed by a multiagency steering committee, informed by a multisector stakeholder group, and supported with internal agency staff and external partners.

As the first step in this effort, the steering committee approved the *Roadmap for Implementing Michigan's Next Energy Policy Baseline Research Report,* which aimed to provide stakeholders with a common understanding of the state's current energy policies, how utilities perform on key indicators, and what factors drive industry change. Following the release of the *Baseline Report,* the next step in the roadmap process is to review alternative forms of regulation and rate design methods that could be implemented to better align utility behavior with public policy objectives. The MEO enlisted the support of the Regulatory Assistance Project (RAP)—a nonprofit team of experts focused on providing technical and policy assistance to policymakers and regulators[1]—to prepare this overview of alternative regulatory structures and rate design methodologies. RAP's work has been compiled into this report titled, *Roadmap for Implementing Michigan's Next Energy Policy Paths to the Future Report.* This report compiles five separate sections covering the following topics; codes of conduct for the future, performance based ratemaking, rate design, decoupling, and infrastructure planning analysis and review. In addition to the *Paths to the Future Report,* RAP will provide further technical assistance to the stakeholder group during the roadmap process.

[1] For more information about the Regulatory Assistance Project's approach, expertise and mission; visit www.raponline.org/about.

Section II. Codes of Conduct for the Future

Introduction

Historically, electric utilities have had a monopoly over the generation, transmission, and distribution of electricity to customers. In exchange for this exclusive franchise, state commissions regulated utilities in order to ensure that the rates charged were fair, just, and reasonable and that adequate service was being provided. With the advent of competition and emerging technologies, more customers from all classes are taking greater control over their energy service through energy efficiency, demand response, distributed generation and building and process controls. As a result, the utility industry is concerned about declining sales, the foundation of their revenues, and relationships with their longtime customers. Different rate designs are being explored and implemented in an attempt to balance the utilities' revenues with requirements to maintain grid reliability, maintain incentives for customers to engage in clean energy solutions and ensure that nonparticipants in distributed energy resources are not burdened with higher rates to cover utility revenue shortfalls.

While many models will emerge for power sector reform and the role of utilities, two have already taken center stage in the forum of public policy thinking. In one model, the electric distribution utility (EDU) serves as purveyor of competitive distributed energy services directed to the end-use customer with some attention to managing advantages the EDU has in the market. In another, the EDU becomes strictly a delivery company that controls and directs activities across its wires.[2] This section focuses on the former—that the EDU competes with private companies in the provision of competitive energy services to end-use customers with some controls over its actions, controls also called "codes of conduct."

If the EDUs compete with private entrepreneurs to win the hearts and minds of customers in the delivery of services, rules can protect competition so that it can flourish in a fair and transparent market, fully benefiting consumers. Many of the principles that applied to the nascent competitive generation market are also relevant as this next stage in power sector reform takes shape. To create a fair market in which the incumbent EDU does not have a competitive advantage, codes of conduct may be insufficient and states may consider requiring corporate separation.

Power Sector Reform

Power sector transformation is occurring by dint of the opportunities available to customers and the emergence of new technologies from businesses eager to serve that market. Some suggest that the trade-off for lost utility revenues is to allow utilities to supplement their revenues by engaging in competitive services. While on the surface this sounds like a reasonable solution, it is not that simple. There is no silver bullet to address the issue of utility-lost revenues in a manner that is fair to all stakeholders—the utility, the customers using distributed energy resources, and those customers who are not. Attention to corporate structure and codes of conduct matter greatly in order to get it right—such that utilities and private entities can compete toe-to-toe in a fair and robust market so that customers have multiple options from which to choose.

Some policymakers may want to allow utilities to compete, as a concession for enabling competitive services and to gain utility support. If utility participation in the competitive market is going to be part of the solution, there are two important points on which policymakers should reflect:

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[2] See for example the New York Public Service Commission proceeding, CASE 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, which examines the restructuring of the regulated electric distribution companies.

- In order to create a fair, functioning market devoid of cross-subsidies from captive customers, the implementation and enforcement of effective codes of conduct is of paramount importance, and some form of corporate separation may also be necessary.
- Allowing the utility to compete in the competitive market does not fully address reduced utility revenues due to customer choices/empowerment, unless the parent or holding company accepts reductions in revenue in exchange for opportunities in the competitive market. A parent or holding company is unlikely to accept this arrangement, as typically each business within a company must be successful on its own merit. Failing to address EDU revenue shortfalls is not sustainable in the long run, as the EDU needs sufficient funds to operate a reliable grid, including access to investment grade capital. Other mechanisms may be needed to address the utility revenue issue, such as new rate designs and more emphasis on the part of the EDU on cost-effective operations and efficiency.

This section will focus on what protections need to be in place to protect that market and the consumers if utilities are allowed to compete within it.

Why Codes of Conduct Matter

Capitalist theory states that competition will drive efficiency and lower prices to the benefit of all consumers. Where monopolies exist, regulation acts as a substitute for competition by keeping prices in check and ensuring adequate service and consumer protections. Once a market is open, it is important that there be fair competition in order to create a robust market with many participants. Here, the role of the regulator shifts emphasis from prices to ensuring that the market structure is fair so that the market can function properly and clear at reasonable prices. Without proper controls, EDUs can achieve a competitive advantage, squeeze out competitors, and control the market.[3] This will eliminate businesses and jobs and stifle innovation, as many would-be entrepreneurs may have otherwise developed new, cutting-edge technologies and services for customers. Having fewer competitors can translate into higher prices and less attention to quality of service, as dissatisfied customers will have fewer options. The worst outcome is for the EDU affiliate to be in a position to exercise market power, such that the public is left with a deregulated monopoly that can control prices and cut corners on service and quality.

Separation of the Distribution Company from the Competitive Utility

When creating or recognizing a new competitive arena in which a regulated utility is permitted to participate, separation between the regulated entity, the EDU and its competitive arm is critical. This can be accomplished in three ways: through divestiture, corporate separation, and functional separation. Each is discussed below:

- **Divestiture—**Disposition or sale of an asset by a company. A company may divest an asset which is not performing well, which is not vital to the company's core business, or which is worth more to a potential buyer or as a separate entity than as part of the company (Investor Words n.d. *Divesture*). Other reasons for divestiture can include a requirement for an EDU to spin off a competitive business enterprise in order to ensure that the competitive business has no competitive advantage by virtue of its association with the EDU. Divestiture removes all financial incentive for any kind of favoritism or sharing of costs or information.
- **Corporate separation—**Requires the EDU to separate its competitive enterprise from its regulated enterprise by creating a separate affiliated company. The EDU and the new affiliate both are part of the same parent or holding company.
- **Functional separation—**Maintains the competitive arm within the EDU as a separate division with its own accounting system, staff and services. It relies on the codes of conduct, including a "Chinese Wall"[4] to eliminate the flow of information between the two divisions.

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[3] Ways in which an EDU affiliate can obtain a competitive advantage will be discussed in more detail later in this paper.
[4] The term "Chinese Wall' refers to an information barrier separating different departments/divisions within a single firm (Investor Words n,d, *Chinese Wall*).

Most restructured utilities are corporately separated although some have divested or functionally separated (Curien April 2007). In some states like Ohio, the affiliate electric service provider (affiliate ESP) is allowed to compete in the EDU service territory, whereas in other states like Texas, the affiliate ESP can compete in any service territory except that of the EDU. Utility companies often object to full divestiture because it eliminates a potential revenue stream for the parent company. On the other hand, functional divestiture may not provide the appropriate level of separation between the EDU and the affiliate and makes the job of monitoring compliance that much more difficult. How do you monitor a conversation at the water fountain or in an elevator? To avoid this, regulators can direct physical and operational separation. The division or affiliate (in the case of corporate separation) would be located in a separate building from the EDU and have its own separate employees and operations.

Corporate separation has been viewed as a middle ground between divestiture and functional separation. It allows the utility, through a separate affiliate to engage in competitive enterprises, but it does so by separating the regulated from the deregulated functions. For corporate separation to succeed, there need to be strong and enforceable codes of conduct. Note that under corporate separation, the utility affiliate is not part of the business outcomes for competitive activities. This level of separation decreases the likelihood of communications and activities that would create an unfair advantage or preference.

Codes of Conduct

Specific Elements in a Code of Conduct

The codes of conduct set forth the rules by which all parties must abide in order to ensure the development of a robust competitive market for the public good. Examples are the codes of conduct in Texas (in effect) and Ohio (filed) by the Customer Coalition for Choice in Electricity.[5] One point to keep in mind is that a competitive affiliate is not subject to regulation by the commission in the same manner that the distribution company is. Therefore, the codes of conduct rely largely on setting the appropriate framework through the distribution company. The commission may regulate the competitive affiliate, but only to the extent that it regulates other nonaffiliates for the purpose of protecting the public. This regulation of nonaffiliates is typically restricted to terms and conditions of service with the exception that the commission should retain the authority to ensure there is no price collusion among energy service providers in violation of anti-trust laws. This goes to the commission's role as a market monitor under its broad statutory powers and duties. The key takeaway point is that the EDU and affiliated electric service provider (affiliate ESP)[6] are two separate companies and that should be reflected in all their actions.[7] Here are specific elements of codes of conduct, written prescriptively, using the word "should."

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[5] For Texas, see: https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.272/25.272.pdf. For Ohio, See, Before the Public Utilities Commission of Ohio, 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, Comments of Coalition for Choice in Electricity, Appendix C, October 13, 1999. The Code of Conduct contained in the Appendix, was developed largely by Enron Corp. as guidance for the creation of a competitive retail generation service market, but are applicable to power sector transformation models in which the distribution company and/or affiliate is competing against nonaffiliate energy service companies.

[6] For purposes of this paper, the term "affiliated electric service provider" is being used as if corporate separation were adopted. However, the same protections would apply for a "division" in the event of functional separation.

[7] The competitive affiliate may be regulated by the commission, but only to the extent that it regulates other nonaffiliates for the purpose of protecting the public. This regulation of nonaffiliates is typically restricted to terms and conditions of service to protect customers from unscrupulous actors. Examples might be rules on disclosures to customers, potential certification requirements as an energy service provider (depending on the services being offered), and notices on contract renewals that change the terms or price of the service offered, etc. Regulation of affiliates would not extend to establishing rates or prices. However, the one exception would be that the commission should retain the authority to ensure there is no price collusion among energy service providers in violation of anti-trust laws. (The Sherman Act prohibits any agreement among competitors to fix prices or engage in anti-competitive behavior, 26 Stat. 209, 15 U.S.C. §§ 1–7). This goes to the commission's role as a market monitor. That role can be interpreted to exist as a result of the Commission's broad statutory powers and duties, but including it in legislation would leave no doubt.

Nondiscrimination

The EDU should be prohibited from providing a competitive advantage to its affiliate ESP through any kind of preferential treatment that would extend to any service or price unless the same offer or advantage is contemporaneously provided to all unaffiliated electric service providers (unaffiliated ESPs). This would include the provision or procurement of any goods, services, facilities, information, or the establishment of standards. This kind of provision is fundamental to the creation of a fair market where every competitive electric service providers (competitive ESPs) is on the same footing. Equally important is the timing of any special pricing (such as a discount, rebate, or fee waiver), service or condition so that it is simultaneously offered to all.

Tie-ins are another area of concern, whereby the EDU might require as a condition of any service or special rate that it offers, that the customer must procure competitive energy services from its affiliate. An example might be if a utility conditioned the purchase of its customers' renewable energy credits (RECs) on a requirement that the PV rooftop installation must be purchased from its affiliate. Either the utility offers to buy the RECs from all of its customers, or none of them.

More subtle ways that discrimination can occur, but should not be tolerated, include:

- Processing requests of the affiliate ESP before the unaffiliated ESP, which results in faster and better service for the affiliate, impacting end-use customer satisfaction;
- Policing prohibitions against providing leads to the affiliate or directing customers who call for information to the affiliate;
- Sharing any kind of market analysis or other proprietary reports that are not made publicly available;
- Giving the appearance that the EDU speaks on behalf of the affiliate ESP and vice versa;
- Requesting customer permission to pass on customer information exclusively to the affiliate ESP.

These are some examples, but the principle is simple—all competitive ESPs should be treated the same at all times and at the same time.

Information Sharing and Disclosures

Customer information should be provided on a nondiscriminatory basis to both the affiliate ESP and unaffiliated ESP, but only with a customer's written consent. The manner of providing that information should be consistent, and is a separate consumer protection issue.[8] In the case of competitive ESPs needing customer usage history and past bills for example, a sample customer permission form prepared by the EDU and approved by the commission for all to use, may be a simple way to address the issue of informed customer consent. Rules should be clear that the EDU cannot share with the affiliate ESP any information it receives from an unaffiliated ESP. Moreover, if an EDU is to provide customers with a list of competitive ESPs that provide various services, that list should be approved by the commission and should be developed in such a way as to not provide any preference or emphasis on the services of the affiliate ESP. Nor should the EDU provide customers with any information or advice pertaining to the selection of a competitive ESP beyond the list of qualified service providers arranged in such a manner as to not provide unfair prominence to the AESP.

Corporate Identification and Logo

The affiliate ESP should not use or trade upon, promote, or advertise its business using the EDU's name or logo, as this would tend to be to its commercial advantage. The affiliate ESP should have its own separate identification, and its identity should also be kept separate. If such practice (same or similar name and logo) is permitted, then the affiliate ESP must be required to disclose expressly that the affiliate ESP is not the same company as the EDU, that the affiliate ESP is not regulated by the commission, and

[8] See for example, 52 PA Code § 54.8. Privacy of customer information, http://www.pacode.com/secure/data/052/chapter54/chap54toc.html

that the customer does not have to buy the affiliate ESP's services in order to remain a customer of the EDU. The affiliate ESP should also be prohibited to use the EDU to advertise its services or any kind of joint advertising between the two entities. This not only creates fairness in the market (a company with a utility logo or name has market recognition that gives it a competitive advantage), but also avoids customer confusion. Customers have the right to understand who the entity is with whom they are contracting. When the same or similar name and logo is used by the affiliate ESP, it can be difficult for the customer to understand that they are dealing with a separate company.

Recordkeeping

Recordkeeping is important to maintain confidence that the codes of conduct are being followed and that there is full corporate separation. EDUs should be required to maintain books in accordance with the applicable Uniform System of Accounts and the Generally Accepted Accounting Principles and the affiliate should be required to maintain its own separate books of accounts and records. The EDU should be required to document all tariffed and nontariffed transactions with the affiliate ESP, which includes (at a minimum) all discounts, waivers of tariffs or contract provisions, the name of the other party involved in the transaction, a description of the transaction, the terms and conditions of the transaction, and the time period involved. These records should be maintained for a minimum period of years as determined by the commission. They should also be available for review within a reasonable period to the party requesting to do so.

Sharing of Facilities, Equipment, and Costs

An EDU should not share any office space, office equipment, services, or systems with the affiliate ESP. The only exception would be determined by the manner of the separation between the EDU and the affiliate ESP and if corporate support functions are shared. (This will be discussed more in the Corporate Support section.) Divestiture is the only form of separation that truly separates the EDU from the competitive ESP arm, because it is sold to a nonaffiliated company. Integral to the separation of the two entities is the importance of maintaining separate computer systems such that the EDU and affiliate ESP do not have access to either's computers or information system, unless appropriate safeguard mechanisms are in place. However, separate systems are much easier to oversee to ensure market fairness, and the burden would be on the EDU to demonstrate that neither entity could access information from the other.

Joint Purchases

An EDU should not be allowed to make joint purchases with the affiliate ESP that are associated with the marketing of the affiliate ESPs products and services. The EDU must ensure that all joint purchases are priced, reported, and conducted so as to clearly delineate the EDU's and AESP's portion of the costs. This would be included in the recordkeeping discussed above.

Corporate Support

Corporate support for the affiliate ESP can be created through a separate entity or provided by the parent company, which also houses the EDU. This support consists of overall corporate oversight, governance, support systems, and personnel. Any shared corporate support should be priced so as to not create subsidies, and it should be recorded and made available for review. The use of combined corporate support should exclude the opportunity to transfer confidential information, provide for preferential treatment, allow an unfair competitive advantage, or lead to customer confusion.

Employees

Generally, the EDU and the affiliate ESP should not jointly employ the same people. The only exception would be the case of shared directors and officers stemming from the corporate parent or holding company. In that case, rules and procedures would need to be in place to ensure that the codes of conduct are not circumvented. This presents difficulties, given that the same officers are responsible for the success of both the EDU and the affiliate ESP. Another mechanism that should be in place includes keeping records of any transfer of employees from one entity to the other. Once an employee is transferred, s/he should be required to stay with that entity for a minimum period of one year or longer. Temporary or intermittent assignments or rotations may appear to be a means of circumventing these rules. Transfers back and forth between the EDU and the affiliate ESP allow for too much information sharing and potential violations of the code of conduct. Employees should be required to sign a statement acknowledging that they understand this as well as the codes of conduct so that there can be no misunderstandings regarding permitted and prohibited actions.

Transfer of Goods and Services

In all proceedings, complaints, investigations, and filings, the utility should hold the burden of proof to demonstrate the fair market price. This is important because the utility has the obligation under the code of conduct not to subsidize the affiliate ESP. Therefore, it should be transparent in its dealings and readily able to demonstrate compliance. Transfers of goods and services from the EDU to the affiliate ESP should be set at the higher of fully allocated cost or fair market price. This will protect the captive customer from subsidizing the affiliate operation. On the other hand, any transfer from the affiliate to the EDU should be set at the lower of a fully allocated cost or market price. This will prevent the affiliate from selling any asset or service at an inflated price at the expense of those same captive customers. Furthermore, any assets, goods or services that are developed for sale on the open market by the EDU should be available to the affiliate ESP and unaffiliated ESP on an equal basis.

Regulatory Oversight

Regulatory oversight and the exercise of jurisdiction over codes of conduct are critical to the successful operation of competitive markets. There is a distinct difference between price regulation and the regulation of conduct. Many deregulated businesses have free reign in establishing prices based on what the market will bear, but their terms and conditions of service are still regulated. The airline industry is a good example of this.

Regulatory oversight should include compliance plans, compliance audits, complaint procedures and log, and penalties, each of which will be discussed below.

Compliance Plans

The EDU should be required to file a compliance plan setting forth its plan for implementing the code of conduct and keeping all aspects of its operation separate from the affiliate. Once an affiliate is created, the EDU should also file a plan for the unaffiliated ESP, detailing its plans to keep operations separate.

As part of the plan, there should be an educational component for all employees that includes training and a handbook, so that employees of both EDUs and affiliate ESP understand what conduct is and is not permissible. There should be training and education procedures in place for all new and existing employees.

Compliance Audits

The EDU should be subject to periodic compliance audits prepared by an independent auditor and filed with the Commission so that it is publicly available. Audits are useful in identifying practices and procedures that may lead to violations of the code of conduct. These audits can make recommendations to improve compliance plans and practices to ensure that the utility does not get in trouble for violations. So while the purpose of the audit is to make sure that the EDU and the affiliate ESP are complying, it also helps steer them away from troubled waters.

Complaint Procedure and Log

In order to allow an informal resolution of complaints regarding the code of conduct, the EDU should establish a process. The process should call for a speedy resolution within a defined number of days to record and investigate the complaint, and provide a written response to the complainant regarding the EDU's findings and what corrective action, if any, is being taken. If the matter is not resolved to the complainant's satisfaction, he/she would retain the right to file a complaint at the commission. If the commission finds that there is probable cause for the complaint, then the commission could set the matter for a hearing. The purpose here is to give parties an informal opportunity to resolve matters without burdening the commission with every complaint. That the complainant can reserve the right to file before the commission serves as an incentive for the EDU to take the complaint seriously and resolve the matter expeditiously and in good faith.

Penalties

While the goal is not to have to level penalties against an EDU, granting the commission the authority to do so, increases the likelihood that it will not be necessary. The purpose of penalties therefore is to act as a deterrent to anti-competitive practices and behavior. The commission should have flexibility with regard to penalties which can include: terminating a transaction; limiting the value of the transaction prospectively, or assessing a penalty that should reflect the actual or potential injury to ratepayers and competitors and the gravity and circumstances of the violation. Penalties assessed by the commission however, should not preclude an individual party's right to seek damages.

Ring-fencing and Credit Issues

Ring-fencing occurs when a regulated public utility business financially separates itself from a parent company that is engaged in nonregulated businesses. Ring-fencing "can best be understood as legally deconstructing a firm in order to more optimally reallocate and reduce risk. The deconstruction can occur in various ways: by separating risky assets from the firm, by preventing the firm itself from engaging in risky activities or investing in risky assets, or by protecting the firm from affiliate and bankruptcy risks" (Schwarcz 2014). In the utility context, the purpose of ring-fencing is primarily to protect the EDU and its customers from the risks associated with unregulated enterprises and to protect the delivery of essential utility services in the event of financial instability or bankruptcy of the unregulated affiliate. It insulates the credit risk of issuers of debt to the EDU. Another benefit is that ring-fencing can prevent information asymmetry (Schwarcz 2014 p. 97). This keeps the customer information that the EDU possesses separate from the unregulated, for-profit companies; this further strengthens the separation of the EDU from the affiliate ESP. This protects the confidentiality of customer information and helps bolster the codes of conduct.

Ring-fencing also benefits the parent company by providing more assurance to bondholders that their investments are safe. This also allows the parent company more flexibility to expand its unregulated businesses if it is not constrained by financial impacts to its regulated businesses that are providing essential services. Note that ring-fencing would need to be accomplished by the state, as there is no federal mandate requiring ring-fencing of public services (Schwarcz 2014).

The state can take several actions to protect customers from the risks associated with financial insecurity or debt from the nonaffiliated company. To the extent that these actions can be legislatively mandated, they will provide more certainty to the rating agencies, due to less likelihood of these mandates changing. In the absence of legislation, commissions can insist on corporate separation with separate books and accounts as discussed above. Further, the National Association of Regulatory Utility Commissioners Subcommittee on Accounting and Financing made the following additional recommendations as ring-fencing measures:

1. Commission authority to restrict and mandate the use and terms of sale of utility assets. This includes restriction against using utility assets as collateral for any nonutility business.

2. Commission authority to restrict dividend payments to a parent company in order to maintain financial viability of the utility. This may include, but is not limited to, maintenance of a minimum equity ratio balance.

3. Commission authority to authorize loans, loan guarantees, engagement in money pools and large supply contracts between the utility and affiliate companies.

4. Commission authority over the establishment of a holding company structure involving a regulated utility.

5. Expand commission authority over security applications to include the ability to restrict type and use of financing (Devlin n.d.).

All of these measures can protect the EDU's customers, but they are also important for the creation of a functioning competitive market. These restrictions will prevent the unaffiliated ESP from having a competitive advantage through garnering assistance in financing some of its operations through the EDU to the detriment of its captive customers. As policymakers and stakeholders consider various future roles for the EDU, attention needs to be paid to how a utility potentially engaged in competitive transactions will be structured and regulated. Just as with the creation of retail competition for generation, it is necessary to ensure that strong, enforceable rules are put in place that protect the competitive market. However, equally important is the protection of customers, both the captive customer of the EDU from paying cross-subsidies that benefit an affiliate and customers who are participating in the competitive market so that they have fair and reasonable prices for an array of goods and services to choose from.

Because corporate separation and ring-fencing mechanisms are designed to protect the captive customer, the customer engaged in the competitive market, the competitive market itself, and the unaffiliated competitors, it may be difficult for EDUs to participate in the market, although a separate affiliate could. While utilities should not be precluded from entering the market and offering energy services if there is divestiture or corporate separation, this will not help the EDU be more financially secure or garner increased revenues. This will, of course, help the parent or holding company (in the case of corporate separation), but it will not solve the EDU's concerns. And, if parent companies or holding companies insist that each affiliate stand on its own merit, they will look for other solutions to solve the decreasing EDU revenue issue in addition to having its unaffiliated ESP participate in the offering of competitive services. If functional separation is adopted, then the EDU could compete; however, strong codes of conduct and regulatory oversight would be necessary. The move from regulating utilities in a monopoly setting to regulating conduct in the competitive market becomes a new role for the commission.

Especially in the event that the EDU does not compete, solutions that protect the EDU's ability to provide reliable grid service will also need to be developed. Some of this will occur through changes in rate design, and some of this will occur through efforts by the utility to optimize the efficiency of its operations.[9] Further, if policymakers are going to allow competition by affiliates, it is imperative that corporate separation and strict codes of conduct be implemented and enforced. To do otherwise would be to cripple the competitive market and its promise for new services and technologies for customers. These are all other facets that could be viewed comprehensively in defining the utility's role in power sector transformation.

Code of Conduct for Michigan Utilities

Michigan's code of conduct for electric utilities was established in 2001 following the passage of Public Act 141—the Customer Choice and Electric Reliability Act. PA 141 restructured Michigan's electricity market creating the opportunity for Alterative Electric Suppliers (AES) to sell power to retail customers. Recognizing that this legislation fundamentally changed the landscape for energy providers in the state,

[9] RAP will be releasing a paper in July 2015 that will focus on rate designs for the utility of the future.

the legislature directed the Michigan Public Service Commission (MPSC) to develop the state’s code of conduct which would include, “measures to prevent cross-subsidization, information sharing, and preferential treatment, between a utility's regulated and unregulated services, whether those services are provided by the utility or the utility's affiliated entities” (MCL 460.10(4)). The resulting code of conduct was adopted by the Commission on October 29, 2001 (MPSC October 29, 2001). Michigan’s code of conduct reflects many of the different elements described earlier in this section. A summary of Michigan’s code of conduct is available in Exhibit 1, see below.

EXHIBIT 1. Michigan’s Code of Conduct for Electric Utilities

Code of Conduct	Description
Applicability	Code of conduct applies to electric utilities and alternative electric suppliers (AES) who, together with their affiliates, provide both regulated and unregulated services in Michigan (MCL 460.562 and 460.10g).
Separation	Firms governed by the code of conduct shall have structural or functional separation designed to prevent cross-subsidization, information sharing, and preferential treatment between regulated and unregulated services.
Discrimination	Firms governed by the code of conduct shall not unduly discriminate in favor of or against any party including its affiliates.
Disclosure of Information	Information obtained by an electric utility or AES in the course of conducting regulated business in Michigan shall not be shared with its affiliates or other entities within its corporate structure unless the same information is provided to competitors operating in the state on the same terms and conditions contemporaneously.
Electric Utility – Alternative Electric Supplier Relationship	Except for instances covered by Section 10a(3) of 2000 PA 141 or other instances approved by the Commission, an electric utility shall not in any way interfere in the business operations of an alternative electric supplier.
Compliance Plans	Each electric utility or AES shall file a code of conduct compliance plan within 60 days of the order on rehearing on this code of conduct by the Commission.
Oversight, Enforcement, and Penalties	An electric utility or AES shall maintain documentation necessary to investigate compliance with the code of conduct, use a documented dispute resolution process to address complaints arising from application of the code of conduct, and file an annual report with the commission about complaints and complaint resolution.

To reference the complete code of conduct please visit the MPSC’s website at: http://www.dleg.state.mi.us/mpsc/electric/eleccodeofcon.htm.

SOURCE: MPSC. October 29, 2001. *In the matter of approval of a code of conduct for Consumers Energy Company and The Detroit Edison Company.* Available at: http://www.dleg.state.mi.us/mpsc/electric/download/elec_coc_order.pdf (accessed 7/20/15)

Section III. Performance Regulation

Introduction

Performance regulation is an option for regulators and utility executives interested in changing utility motivation. It differs from traditional regulation by including measurements of utility performance in measureable outputs, outputs of interest, and importance to public interest outcomes. Generally, there is some opportunity for the utility to be financially rewarded for a sufficient level of performance.

Experts may note that an element of performance regulation already exists in traditional regulation. If the utility fails severely enough, then statutes and regulatory practice have ways of punishing the utility. This management by negative exception, however, puts performance in the background.

It is important to understand of how the utility accumulates revenue and how that is distinct from how a utility earns net income; an understanding of the forms of penalties that are in the regulators' tool box and how they can be used; and an appreciation for the range of activities utilities do (outputs) that affect the public interest (outcomes). Utilities serve the public interest, and if this interest can be better served through improved performance, how can government motivate it?

Vocabulary

This section of the paper makes a point of using the terms "compliant," "exemplary" and "inferior" to be clear about distinct levels of performance. In execution, it is reasonable to use terms like "good" or "good enough" to mean compliance, "excellent" to mean exemplary, and "poor" or "bad" to mean inferior.

Another word that emerges in discussions about utility performance in innovation, in the context of questions like, "how can regulation promote innovation?" Other commonly used words:

- **Deadband**—A range of performance for which no reward or penalty applies.
- **Caps**—Used to bound upside and downside incentives; thus, a risk to consumers and utilities.
- **Attrition**—One of many adjustments that can influence the underlying revenue requirement during a performance plan, it addresses certain unforeseen changes in cost.
- **Outcomes**—Effects seen in society, such as lower cost, safe employees, reliable service, clean air and water.
- **Outputs**—Results of utility activities, such as energy-efficiency savings, line losses, generation availability, lost time accidents, various reliability metrics, average duration to answer customer calls, or interconnection requests.
- **Inputs**—Money spent (capital and operating), number of employees.

Traditional Utility Regulation

In order to appreciate performance regulation, it is important to consider the workings of traditional utility regulation and why it might fall short.

In traditional utility regulation, which has been in place for more than a century, the utility manages a monopoly delivery and customer care system, a portfolio of generators (where permitted) and the execution of other public interest responsibilities, such as delivering energy-efficiency programs and managing customer access for those struggling to pay for service. The reasonable costs for these services are calculated and spread over all the units sold and all customers in time-tested methods of allocation.[10]

The utility must routinely raise significant capital to invest throughout the system. It issues debt—and in the case of investor-owned utilities, it issues stock, which is more expensive. Stockholders own the utility's equity, while debtholders have first call on the value of assets in the event the utility is liquidated. The outcome of this capital flow, continuing renewal, and reliable operation of critical facilities is so important to society that regulation takes a special interest in assuring that the utility earns a sufficient return on equity and builds it into the cost of service. From this allowed return, the utility pays dividends to shareholders and reinvests in the company. Debt costs are known and added to the cost of service along with taxes.

Traditional utility regulation is said to operate in a "cost plus" environment (i.e., in its rates and charges, it recovers its costs and earns a regulated return on its capital account). Note that performance is not a factor in either utility revenue or utility profits. Further, some note that because of the broad range of utility activities and costs, it is infeasible for regulators to oversee it all, and too easy for utilities to be inattentive to cost and quality control.

Regulators have tried a range of ideas to adjust utility performance motivations.

- Rate caps—Because many customers are price-motivated, there is appeal to capping utility rates for a period of years. A utility may be attracted to a stable regulatory environment without a rate case in which it seeks ways to increase sales while lowering unit costs.[11]
- Revenue caps—The regulator may be interested in motivating the utility to control overall costs with a revenue cap. A revenue cap is a basic component of the revenue decoupling mechanism and can be allowed to change yearly for preapproved reasons or through annual attrition adjustments.
- Project-specific budgets—A capital project may be proposed at a certain budget amount, and the regulator can approve the project but only for a maximum budget. Budget excesses may be the responsibility of shareholders.
- Return on equity inducements—The regulator sets a specific ROE adjustment *ex ante* associated with a particular set of outcomes.
- Performance reporting—The regulator induces increased attention to performance by creating a public performance report card, relying on the attitude of management and staff to achieve above average and high marks.
- Performance rewards and penalties—The regulator offers financial rewards and penalties associated with a set of performance outputs.

Compliant Performance

Like an umpire in baseball, many view the utility as most successful if they don't see them at all. Stability is a virtue. If we do notice the utility, it is often because something bad has happened—a reliability problem, a service problem, a safety problem, an over-budget project, or a project perceived as unnecessary.

Utilities are constants in their communities and have the opportunity to distinguish themselves favorably in times of need, such as with storm restoration. Utilities can also stand out with customer education efforts and (typically at shareholder expense) philanthropy. But they are rarely able to demonstrate their capabilities in their fundamental tasks and overall mission.

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10 While time-tested, controversies remain regarding how this allocation should be accomplished, which are beyond the scope of this framing paper.

11 For background and current status of a rate cap with a 20-year history, see Order in Iowa Utilities Board Docket No. RPU 2013-0004, March 17, 2014, and New Regulatory Models by Sonia Aggarwal and Eddie Burgess.

What is compliance? It seems to represent a level of performance good enough that consumers are willing to pay for it. Yet translating compliance to numbers or quantifying the outputs of utility work can be imprecise. There are rarely public metrics that identify the key activities that utilities do that are assessed in the regulator's hearing room, though utilities are known to measure many of their activities.

Compliance can be defined as performance that raises no issues when it is examined by a rate case or other commission investigation. Service meets expectations and cannot be characterized by regulators as unnecessarily costly.

There are some states in which regulators ask for metrics. In these states, there is attention to reliability statistics for outage duration and frequency and trends over time. In some cases, utilities report service data for connections or responsiveness to customers' questions and problems. In some of these cases, a target performance level, compliance, is identified by regulators.

Perhaps the most prominent form of a target performance level is the energy-efficiency resources standard, since this is set by government, sometimes in statute. A renewable portfolio standard has similar significance.

Many activities of utilities not mentioned here or in attention to utility performance are important to service outcomes.

Inferior Performance

Since performance regulation does not exist in most states for most utility activities, how does a commission identify inferior service?

Generally, awareness of inferior service arises through an increased frequency of complaints. The most common complaints are about inferior service and reliability. Service complaints can arise from slow or no responsiveness in connections and disconnections, billing inaccuracies and line extensions. With increased interest in distributed generation, complaints may emerge from the generation interconnection process. Reliability complaints may focus on outage frequency, and outage duration, including storm preparedness and right of way maintenance. A utility that owns generation may call negative attention to itself if the forced outage rates for its fleet seem high, especially if purchasing replacement power from elsewhere is more expensive.

Energy-efficiency performance depends on actors outside the utility control—customers. For this reason, utilities can be especially concerned about being evaluated and potentially penalized for failing to reach targets.

Renewable portfolio standard performance failures are anticipated in most states by an alternative compliance payment—a fixed monetary amount that the utility pays per unit of deficiency compared with the standard. This money generally funds a state-managed fund associated with renewable energy deployment.

Most states have experience with penalizing inferior performance. State commissions may not have an explicitly established performance system, but they have the tools they need to regulate and command improved performance when it is deficient. These tools include:

- Cost disallowance if an undepreciated asset is found to be no longer "used and useful" or for money spent with inadequate results or based on imprudent management
- Reduction in the return on equity when the performance deficiency reflects badly on the company as a whole
- Fines, when there are identifiable violations, especially when there are many violations across a range of customers or events

In at least one state, management can be held personally responsible for poor performance.

Utilities are familiar with negative financial outcomes for poor performance; most are unfamiliar with positive opportunities to earn a return for exemplary performance.

Exemplary Performance

Do customers value exemplary service? In some instances of utility performance, better than compliant service may not be noticeable by most customers. In other cases, customers may value it, but it may be so expensive that customers would rather not pay more to get it. Many times, exemplary service would be appreciated, and the cost to achieve it is reasonable. With improving technology and opportunities to integrate it into utility activities, opportunities for exemplary service at reasonable cost may become more numerous. Traditional service regulation cost does not motivate the utility to investigate the potential for cost-effective achievement of exemplary service.[12]

Energy efficiency has attracted regulatory interest in many states to grant rewards for exceeding targets (Gilleo October 2014).

A less prominent focus for identifying exemplary performance is with generation-owning utilities and their ability to produce revenue from off-system sales. By allowing the utility to keep some revenue over a pre-set target, the utility motivation to manage its generation fleet within the larger wholesale market is changed.[13]

Looking forward, growing numbers of customers are considering generating their own electricity, or deploying energy management systems to customize service and take advantage of demand response programs. Utilities provide technical support to these new customer activities, and are generally not evaluated for their performance.

For a performance system to be valuable, it should associate utility outputs with public interest outcomes. Further, it will focus on priority public interest outcomes and reward those utility activities that produce outputs that serve to achieve those outcomes. For example, environmental outcomes (i.e., clean air, clean water, sound land use) are a priority, and are influenced by utility performance. A state may wish to exceed minimum standards and motivate its utilities with rewards if they achieve certain environmental performance standards. These standards could be designed as pounds of pollution per kWh delivered to customers, or, for a generation fleet owner, gallons of water consumed per kWh produced. Service is a simple example of a performance area. Customers expect a minimum level of service from their utility, so metrics that measure what customers want most in their interactions with their utility would be relevant. Cost of service is always important—a cost metric is relevant to a performance system, encouraging the utility to manage and control costs, with the prospect of public accolades and financial rewards accompanying sufficient success.

What to Measure—Particular Activities or a Scorecard?

When a state decides to reward exemplary performance, it may be because a specific issue is before them. In Iowa in the mid-1990s, MidAmerican Energy Company and its regulators decided to motivate off-system sales (Aggrawal March 2014). Chronic and lengthy power outages in Maryland have led to reliability standards for its utilities (COMAR 20.50.12.02*)*. Attention to service quality and reliability Vermont led to Service Quality and Reliability Plans for all utilities (PSB 2015). These plans include rebates to individual customers if minimum expectations are not met. In the Maryland and Vermont cases, there is no reward.

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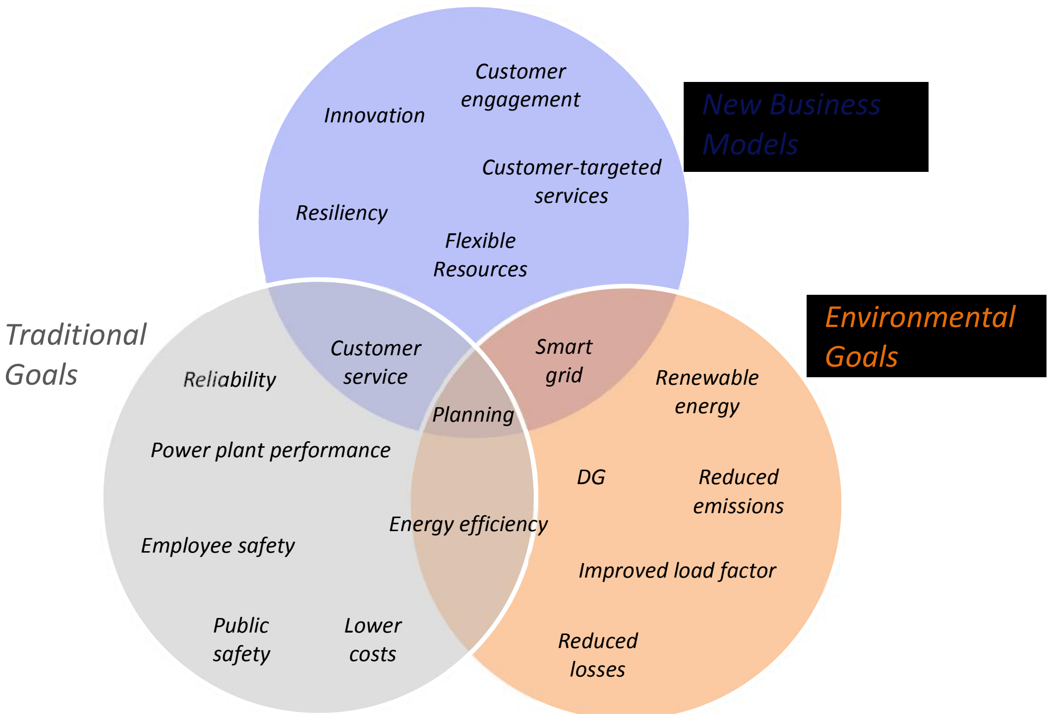
[12] Progress happens anyway because there remains pressure to control customer rates, so innovation that is reliable and saves money will be appealing. The personal standards of utility staff matter. Also, utilities do want to distinguish themselves among their peers.
[13] Iowa and Vermont are examples of states familiar with this practice.

A recent report prepared for the Western Interstate Energy Board includes a figure that presents a range of metrics for regulators and utilities to consider, see Exhibit 2. They range from traditional functions of utilities to ones addressing societal and innovation-driven progress (Whited March 9, 2015).

EXHIBIT 2. Dimensions of Utility Performance That May Warrant Tracking or Incentives



SOURCE: Melissa Whited, Tim Woolf, and Alice Napoleon. March 9, 2015. *Utility Performance Incentives Mechanisms: A Handbook for Regulators*. Available at: http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf. (accessed 4/15/15)

In the United Kingdom, regulators have adopted a performance-based system, known as Revenue = Incentives + Innovation + Outputs, or RIIO (OFGEM March 2013). This system applies to all utilities, transmission and distribution, and reflects enterprise-wide performance in “bread and butter” and societal areas.

A recent publication from RAP builds on performance regulation work prepared for European Union regulators and includes some specific guides on constructing performance metrics and reward systems (Lazar May 2014). Publications on performance management cite the importance of a supervising authority identifying a broad range of utility outputs for which good metrics and standards for compliant performance exist. This is the approach taken by the UK regulator, OFGEM.

Generally, performance regulation plans focus on utility activity outputs. Sometimes, however, an important utility project may present an exception where the regulator may want to oversee the activity itself. Activities in this category could include smart meter deployment, a meter data management system installation, or a power generation construction project.

Many states have decided to measure and sometimes reward a small number of utility activities. Recent discussions in some states are moving toward covering all outcomes of utility service, and a range of utility outputs that would potentially be influenced to some extent by all utility employees.

Rewards

A commission could determine that simply measuring and reporting publicly on key metrics, via a utility performance report card, will motivate exemplary performance. However, since exemplary performance may require investment and commitment from management, regulators also consider implementing system of financial rewards and penalties. A commission has many choices to consider in creating this system:

How much of a reward to offer? Conventional wisdom is that a performance reward must be enough to catch the attention of utility management, but does not need to be more than that. A performance reward that produces value for the system and for consumers can be justified as “value for money.” If a reward and its justification should be able to pass the test of public scrutiny from the press (“the front page test”), that is a sign that the reward package is sustainable.

What constitutes performance for rewards? In some instances, a shared savings approach works well, with the utility and the customer sharing in some ratio the benefits of the enhanced performance. In other instances, measuring these savings can be expensive or imprecise, so it may be useful to reward hitting a specific target of exemplary performance. There could be a deadband around the level of compliant performance, where no reward would accrue as performance ebbed and flowed around that level.

Should rewards be continuous or based on levels? Regulators may decide that every unit of added value based on its performance in a given metric should produce a reward to the utility. Shared savings energy-efficiency reward plans are an example. An issue for shared savings is the need to calculate overall savings. This can be complicated. Regulators can also decide that achieving a certain level of performance presents one reward, and that a significant added quantum of performance is needed to produce a higher level of reward—as with letter grades in school. The regulator may be influenced by the precision of utility data to track performance. If precise data is expensive, the levels of performance may be sufficient to motivate utility behavior.

Should rewards be provided up to a limit or cap? If there is continuing value in further improved performance, then, in theory, a performance reward system should have no upper bound. In the political setting in which utility regulation occurs, that approach is not always possible. In recognition of the front page test, rewards are often capped in some manner. A hard cap, often based on a certain amount in excess of the normal allowed return on equity is set. A more nuanced approach changes the sharing ratio as performance improves and attendant benefits accumulate. For example, during an initial range of exemplary performance, the utility may share benefits with the consumer 50-50. In an even higher range of exceptional performance, the sharing can change to 90-10, customer to utility. Under this approach, the utility reward keeps rising, but at a slower rate less likely to hit unacceptable heights.

Symmetry refers to a performance system offering both rewards and penalties for exemplary and inferior performance. Some argue that symmetry should be a routine part of any metric. Others suggest that each metric has its own purpose and its own implications for exemplary and inferior performance. For example, a regulator may determine that improved reliability may provide benefits worth paying for, while inferior reliability would require steep penalties (inferior performance in critical areas like reliability may produce penalties today).

Implementing Performance Regulation

The topic of performance regulation is getting renewed attention. Electric service is now subject to a wave of technology-driven innovation offering improved and new services to customers. Regulators in some states are asking whether changes to the practices under their supervision are vital to motivating utility companies to organize themselves differently in order to seek out and embrace innovation that will improve public interest outcomes like cost control, risk management, environmental quality, and customer choice.

Clear definitions are important. Regulators creating categories of performance that may be reported and rewarded should consider carefully the category definitions. They are best if they are clear and unambiguous to all. Consistency throughout the jurisdiction is important to maintain clarity.[14] In the UK, utilities are sufficiently similar that performance standards can act as benchmarks among them. In some states that may apply, but utilities within some U.S. states have quite different service areas in terms of customer density and systems. Regulators should exercise care in using performance regulation metrics as benchmarks. Controversy in measuring energy-efficiency savings in California for programs delivered in 2006–2008 led to utilities being unable to anticipate the decision of the regulator on performance rewards and represents an example to avoid (CA PUC December 18, 2008).

Technology is making it easier to more accurately and objectively measure utility activities. Sensors in the delivery systems are able to determine the state of the system at fine intervals and accuracy. Smart meters are able to assess the nature of service for individual customers with robustness and provide customers with new measures of control of their equipment including interaction with the grid. In order to use the information for performance purposes, the utility will need a data management capability that will collect data in suitable ways, and systems that will translate data into actionable information.

A common characteristic of performance regulation is that it is implemented for a significant duration. This stability enables utility management to change systems and culture to manage new metrics. There is no rule, but the duration can be roughly equivalent to the horizon of confidence in key assumptions. Most plans, which may also include revenue decoupling and adjustments built into the plan, have lasted three to five years between reassessments. RIIO plans are intended to last eight years, with assessments midway, falling into the three- to five-year window.

The role of the utility itself is being revisited. Can the utility be the agent of delivering innovation to customers, or will it operate the delivery system and enable innovators to reach customers directly? In either case, performance metrics can contribute to assuring that the evolving role of the utility is carried off successfully.

As the role of the utility and the regulator are reconsidered along with utility compensation, financial analysts for utility debt and equity will need to be heard from to get their guidance on cost of capital implications for these changes.

Last Word on Regulatory Efficiency

A performance system should be manageable for the regulator. Factors that promote the regulator’s ability to supervise a performance system:

- Experience with the metrics—If the regulator is familiar with the output activity and utility performance, it can set a reward system with confidence.
- Transparent metrics—Utility reporting can be clear and are voluntarily reported in a consistent manner that is subject to little or no judgment.
- Periodic reports—If the regulator stays in touch with utility performance system over time, there is less likelihood of misunderstandings when it is time for final reports and reward calculations.
- Openness to change—A form of regulation relying more on measuring effectiveness against public interest outcomes and utility activity outputs will need to spend less time focusing on inputs – how the

[14] Reliability measures present a good illustration of how consistency can be harder than it appears. In some states all events are counted, but not in others. Some states choose to exclude momentary events, or events of unusually long duration from extraordinary causes.

utility is doing its many jobs. Also, this approach is designed to promote innovation, so regulators can expect to see new methods to address updated expectations.

The commission faces a choice as to whether it will take improved performance as an indication that a standard needs to be raised, or if it should stick with the standard and allow a well-performing utility to earn rewards for consistently exemplary performance. A common complaint among utilities that have had performance systems is that their exemplary performance becomes the new normal, and regulators lack the appreciation for the effort to achieve this level. For some metrics, the performance standard is based on technology and systems in place. If they are understood and do not change, there is little rationale to raise standards—even as a utility is getting top marks. In other cases, technology and improved methods are raising the standard of performance, and the metrics over time should recognize these changes.

Performance Regulation in Michigan

Traditional utility regulation—as described earlier in this section—is still the dominant model for Michigan's electric utilities. However the state has implemented elements of performance regulation in recent years with the introduction of its renewable energy standard (RES) and Energy Optimization (EO) program. Adopted as a part Michigan's energy policy overhaul in 2008, the RES and EO program—established by Public Act 295—created compliance incentives for utilities.

For the state's EO program, PA 295 gave the Commission the ability to approve financial incentives for rate-regulated utilities when they exceed energy savings targets for a given year (MCL 460.10 (75)). According to the Commission's *2014 Report on the Implementation of PA 295 Utility Energy Optimization Programs* these incentives, "address some of the barriers EO programs have been facing in terms of lost revenue from declining sales" (MPSC November 2014). As outlined by PA 295, the financial incentive cannot exceed 15 percent of the providers' actual annual EO program spending or 25 percent of the customers net cost reductions as a result of the energy optimization plan, whichever is less (MCL 460.10 (75)). Through 2013, only Consumers Energy and DTE Energy have received performance incentives, but Indiana Michigan Power Company and SEMCO Energy Gas Company have received approval for the 2014-2015 program year (MPSC November 2014). For a summary of the performance incentives earned by utilities see Exhibit 3.

EXHIBIT 3. Utility Performance Incentives Awarded or Anticipated through 2013

Program Year	Consumers Energy(Electric)	Consumers Energy (Gas)	DTE Energy (Electric)	DTE Energy (Gas)	Totals
2009	$3,323,612	$2,361,693	$3,008,829	$913,373	$9,607,507
2010	$5,076,731	$3,407,064	$6,200,000	$2,400,000	$17,083,795
2011	$7,281,670	$7,312,307	$8,400,000	$3,400,000	$26,393,977
2012	$10,027,210	$7,282,721	$10,500,000	$4,300,000	$32,109,931
2013*	$10,364,556	$7,166,544	$11,237,246	$3,848,020	$32,616,366
Totals	**$36,073,779**	**$27,530,329**	**$39,346,075**	**$14,861,393**	**$117,811,576**

SOURCE: MPSC. November 26, 2014. *2014 Report on the Implementation of the P.A. 295 Utility Energy Optimization Programs.* Available at: http://michigan.gov/documents/mpsc/2014_eo_report_475141_7.pdf (accessed 1/21/15)

Section IV. Rate Design

The rates that monopoly utilities charge for electric services need to serve two fundamental roles. First, rates need to be designed to recover the utility's costs of providing that service, including an appropriate return of and on capital. Second, rates need to send price signals to customers to guide their consumption and investment choices in an economically efficient way, in order to minimize the societal costs of providing these essential services.

With these two needs in mind, regulators can design electricity rates in a multitude of ways. For decades, these decisions have been guided by a fairly consistent set of principles. Putting those principles into action, similar rate design structures have been developed in most jurisdictions. Changes in the electric power sector, particularly regarding the proliferation of distributed energy resources, suggest limitations of traditional rate designs. Innovation in rate design is now widely discussed and some changes have been implemented. Regulators may need to consider updated principles for rate design for the utility of the future.

Recovering the Utility's Costs of Service

Utility rates are designed to give the utility a reasonable opportunity to recover its revenue requirement through the sale of electricity services. The foundation of this process is the cost of service study. A cost of service study will typically follow a three step process. First, the utility's costs are identified and categorized by function.[15] Relevant functions typically include generation costs, transmission costs, distribution and customer relations costs, and common costs. Next, the costs within each function are classified as to whether they are customer related (meaning the costs vary based on the number of customers); demand-related (i.e., the costs vary based on the peak needs of the system); or energy related (i.e., the costs vary based on the volume of energy sold). Finally, the costs are allocated to different classes of customers based on each class's contribution to those costs. Rates can then be designed for each customer class that will yield revenues to cover the allocated costs, based on the expected quantities of goods and services sold to customers.

Sending Price Signals to Customers

Utility rates should also be designed to send economically appropriate price signals to customers. Rates are virtually always designed in such a way that customers are assessed a variable charge based on how much (and when) they use electricity. It is common for regulators to set those variable charges based on long-run marginal costs of service. The rationale for this is that all of the utility's long-run costs of service are variable, even if its short-run costs consist of a bigger mix of fixed costs and variable costs. With time, every utility asset will be retired. Whether an asset is replaced, when it is replaced, and what it is replaced with will all depend on how customers use energy. If customers make consumption decisions today that are not based (to the degree possible) on long-run marginal costs, then long-run total costs of service could end up much greater than necessary to provide essential public services.

Traditional Principles for Public Utility Rate Design

Recognizing the fundamental need to recover the utility's costs of service and send price signals to customers, regulators nevertheless have a multitude of options for designing electricity rates.

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[15] Most jurisdictions identify actual costs from an "historical test year." Some jurisdictions project costs for a "future test year." There are tradeoffs between these two methods. Projected costs for a future year are obviously going to be more speculative and less accurate than past actual costs, but using a future test year may allow for a more realistic assessment if there is reason to expect future costs to differ substantially from historical costs (Lazar 2011).

More than 50 years ago, James Bonbright published a treatise on the theory of economic regulation, *Principles of Public Utility Rates* (Bonbright 1961). His principles are the best known and most widely cited framework for approaching the question of electric utility rate design. They can be summarized as follows, and should address the following considerations and objectives (Weston 2000):

Practical Considerations

- Tariffs should be practical: simple, certain, understandable, acceptable to the public, feasible to apply, payable conveniently, and to the extent possible, free from controversy as to their interpretation.

Revenue-related Objectives

- Tariffs should keep the utility viable, effectively yielding the total revenue requirement and resulting in relatively predictable and stable cash flow and revenues from year to year.
- Rates should be relatively stable and predictable, such that customers only infrequently experience unexpected, adverse changes.

Cost-Related Objectives

- Tariffs should fairly apportion the utility's cost of service among customers and should not discriminate against any customer or group of customers.
- Tariffs should be set so as to promote economically efficient consumption (static efficiency).
- Rates should reflect the present and future private and social costs and benefits of providing service (i.e., all internalities and externalities).
- Rates should promote innovation in supply and demand (dynamic efficiency).

There have always been inherent tensions and tradeoffs between Bonbright's principles. For example, stability of rates for customers may be at odds with stable cash flow and revenues for the utility if sales or costs change while rates are in effect. And keeping tariffs simple and relatively stable may conflict with promoting economic efficiency through price signals in situations where dramatic changes in costs are precipitated by short-term events. These inherent tensions require regulators to exercise informed judgment. While there is no single right answer when it comes to rate design, there are practiced ways to reconcile any tensions that reflect the priorities of the place and the moment.

Traditional Rate Designs

Applying Bonbright's principles, regulators across the country have reached fairly similar conclusions about the preferred structure of utility rates. They opted for rate designs that mostly reflect the classification of costs as customer related, demand related, or energy related. In an era when electric meters had limited capabilities and transactions between utilities and their customers flowed in one direction only (with the utility as a seller and the customer as a buyer of energy services), these traditional rate designs were sufficient to meet the two fundamental needs of recovering the utility's costs of service and sending price signals to customers.

Rate Designs for Residential Customers

The default rates for residential customers (and in many cases, for small commercial customers) typically consist of a monthly customer charge (or basic charge), plus an energy charge in cents per kilowatt-hour (kWh). To keep rates as simple as possible for these customers and to minimize total costs, demand-related charges are not used, and demand-related costs are recovered through the energy charge. The energy charge may be a flat rate (the same for all usage), an inverted or inclining block rate (with higher rates for usage over a base level), or a declining block rate (with lower rates for usage over a base level). In many jurisdictions, extremely simple versions of time of use (TOU) rates are used such that higher rates are charged during the months of the year when energy demand is highest. More complicated rate designs may be available to residential customers as an option.

Rate Designs for Large Commercial and Industrial Customers

Rates for large commercial and industrial customers are usually more complex than residential rates. This reflects the view of regulators that, for these customers, other rate design objectives are as important as (or more important than) simplicity. Larger customers are generally able to manage energy consumption and can use more sophisticated rates to avoid costs for themselves and the system. Commercial and industrial (C&I) rates normally include a fixed customer charge and a per kWh energy charge, as is the case for residential customers, but also a demand charge based on the customer's highest (noncoincident) demand during a specified time period. Because the demand charge recovers some of the costs associated with power supply, transmission, and distribution facilities, the energy charge per kWh assessed to these customers is typically lower than that for residential customers. More sophisticated meters are often required for C&I customers, and the largest customers are often assigned to TOU rates that vary based on time of day or based on real-time wholesale energy prices.

Rate Designs for Customers with Distributed Generation

The Public Utility Regulatory Policy Act of 1978 (PURPA) created new opportunities for entities other than utilities to generate and sell electricity. Under PURPA, utilities must offer to purchase electric energy from "qualifying small power production facilities" and "qualifying cogeneration facilities" at avoided cost rates that are just and reasonable to the utility's customers and in the public interest, and nondiscriminatory toward qualifying facilities. Rules promulgated by the Federal Energy Regulatory Commission (FERC) further require each utility to offer standard rates for purchases from all qualifying facilities with a design capacity of 100 kilowatts (kW) or less. Standard rates are optional for larger qualifying facilities.

In recognition of limitations in PURPA and improving economics of and public interest in solar power, many jurisdictions developed net energy metering (or simply net metering) tariffs as a simple way to meet the purchase obligation in FERC's rules or to promote the deployment of DG systems. Net metering tariffs have the advantage of relying on traditional and familiar rate designs, with the distinction being that the customer is billed based on its *net* energy usage in each billing period, (i.e., consumption minus generation). Today, many small distributed generation (DG) facilities and nearly all nonutility photovoltaic (PV) installations operate under a net metering tariff (SEPA June 2013).[16] In many cases, customers with PV systems on net metering tariffs have annual electricity bills that are at or near zero.

Variations on Traditional Rate Designs where Retail Competition Has Been Introduced

In some jurisdictions, including Michigan, energy services for some customers are provided by competitive retail electric service companies selected by those customers. Most competitive retail electric service companies offer traditional rate designs based on a combination of fixed charges, variable demand charges, and variable energy charges. However, some companies offer rate structures that are not based on traditional models.[17]

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[16] The Solar Electric Power Association estimated that as of the end of 2012, 99 percent of installed PV systems in the United States were on NEM tariffs.

[17] For example, in Texas, several retailers offer rate packages that include free electricity on nights or weekends, with more traditional rate structures at other times of the week. Note that where retail competition exists, distribution utilities retain a monopoly over energy delivery services, and operate under regulated rates for those services that are generally structured in the same manner as described for vertically-integrated utilities. The customer receives a single bill that combines charges based on the regulated rates of the distribution utility and charges based on whatever prices they agreed to pay their competitive retail electric service company.

Changes in the Power Sector Necessitate and Facilitate Changes in Rate Design

As noted earlier, many factors now drive unprecedented change in the electric power sector. These changes have implications for the existing utility business model and for rate design. In particular, the growing proliferation of distributed energy resources (DERs)—including DG, energy efficiency (EE), and demand response (DR)—is calling into question decades-long assumptions about the inevitability of load growth. Traditional rate designs, which rely on volumetric energy sales to recover not just variable energy costs but also fixed infrastructure costs, may not be sustainable in the face of these trends. In addition, as the number of customers on net metering tariffs steadily increases, a debate remains about whether or not those customers are over-compensated or under-compensated under that tariff design. If a *sufficiently large* portion of customers on typical net metering tariffs were to net their annual energy consumption to close to zero, and the utility takes no action to shed costs for services now being provided by customers themselves, it could put upward pressure on rates that would be mostly paid by customers without DG systems.

At the same time, advanced metering infrastructure (AMI, including "smart" meters) gives utilities the ability to measure customer usage on an interval basis and presents new opportunities to send time-varying price signals to more customers and provide customers with more tariff options under which to take electric service.

Innovative Rate Design Options for the Utility of the Future

Without making radical changes to traditional rate designs, rates can be modified to address many of the changes in the power sector described above. In particular, the deployment of modern metering technologies to more and more customers creates new opportunities. In addition, completely new rate designs are being proposed and introduced in some jurisdictions, especially for customers with DG systems. Some of the options that Michigan may wish to consider are described briefly below. Variations on traditional rate designs are offered first, followed by more innovative rate design options.

Time-varying Rates

There are time-varying elements of cost. But prior to the deployment of AMI, the vast majority of customers had simple electromechanical meters that had to be read manually. Due to the high cost of manual meter reading, meters were typically read no more than monthly. This constrained the types of rates that an electricity provider could offer. Fixed volumetric energy rates (perhaps with inclining or declining blocks) were essentially the only option available for all but the largest C&I customers, because the time of the customer's energy use could not be identified and associated with a time-varying cost of service.

Smart meters can record and digitally communicate electricity consumption data on frequent intervals (e.g., 15 minutes or hourly), without requiring any manual meter reading. This technology opens the door to new rate designs in which rates can vary by time of day and can more closely reflect time-varying costs of service. The new types of rates that are enabled by smart meters can be referred to collectively as "time-varying rates" (Faruqui July 2012). These rate designs normally retain the traditional elements of a fixed customer charge, volumetric energy charges, and for C&I customers a demand charge. But AMI makes it possible to charge higher energy prices during high cost hours, when wholesale energy costs are highest, and lower prices during low cost hours.[18] This approach allocates energy costs based on how customer behavior causes those costs and establishes price signals that encourage customers to shift consumption away from peak hours. This will ultimately reduce system costs for all customers by reducing the need to invest in expensive new facilities justified primarily to serve the peak. A reduction in

[18] An assumption that high cost hours are coincident with peak hours would have significant counter-examples so this paper does not refer to peak and off-peak hours.

demand during high-priced hours can reduce wholesale market energy prices in those hours, to the benefit of all customers.

There are many forms of time-varying rates that have been offered to large C&I customers and even (usually on an optional basis) to smaller customers, including TOU prices that vary not just seasonally but by the days of the week or hours of the day; rates that apply extremely high prices during "critical peak" periods; rates that offer rebates to customers who reduce consumption during critical peaks (called peak time rebates); and rates based on real-time wholesale energy prices. All of these options can be designed to better ensure that utilities collect their costs of service and customers see a price signal to encourage economically efficient consumption of energy. Many customers can respond to these price signals in a way that decreases their electricity bill. Experience, indicates that mandatory time of use rates can be successful, particularly if customers have the means through technology (primarily automation) to respond to price changes. These experiences have recently been demonstrated in a subset of American Reinvestment and Recovery Act (ARRA)-funded smart grid implementation grants.

Customers do save money through TOU pricing programs (U.S. DOE April 2013). However, there are arguments against mandatory time-varying rates. The primary disadvantage with these rates is that they are more complex than traditional rate designs, and thus harder for many customers to understand and accept. Also, some customers cannot shift their electricity demand in response to price signals, and their bills may increase relative to traditional static rate designs. Although time-varying rates may better reflect actual costs of service, these customers may not welcome the change.

A consideration that often comes up regarding time-varying rates is whether to make them the default rate, but also to allow customers to "opt out," or to offer them as an option to existing rates, known as "opt in." Research on this point suggests that a high percentage of customers stick with the assigned rate (George August 6, 2014 and Faruqui July 1, 2013). One way to enable customers to make an informed choice on this matter is to provide a shadow bill. A shadow bill reports what the customer would have paid in an alternative rate design. The accumulation of information over a series of bills can give the customer some basis to make a choice.

High Monthly Customer Charges

In many utilities, rates have historically been made up of a small fixed monthly charge, which recovers the cost of billing, collection, and payment processing; they also contain a per-kWh charge that varies per customer based on consumption. This rate design allows for fixed recovery of some costs, but for most customers the largest part of the customer bill is the per-kWh charge. This sends an important signal to consumers, in that a consumer pays for what they consume, and if they avoid consumption of energy, they do not pay for it. This is consistent with the "cost causer pays" principle (Boiteux August 1949).

In an era of declining sales and flattening demand, the idea of increasing the fixed charges has gained momentum in some states to increase the utility revenue not dependent on sales (RAP June 2011).[19] In increasing the fixed charge, the variable part of the customers' bill shrinks as the costs traditionally recovered through volumetric charges are instead recovered in fixed charges. Therefore, the signal sent to the consumer is much different. Instead of "you pay for what you consume, and don't pay for what you don't consume", it changes to a bill largely made up of fixed charges, and a decreasing amount that is controllable by the consumer in per-kWh charges.

This proposal to raise customer charges has implications that should be considered carefully. From the utility perspective, it provides revenue stability. However, it also has serious implications on the following:

- Small-use customers, such as apartment dwellers, low-income households, and second homes will receive higher electric bills. There is a correlation between low-income households and low-use

[19] Note that revenue decoupling is an alternative solution to this concern. Revenue decoupling is addressed in a later section of this paper.

households, this changes public policy which typically protects low-income households and rewards low-usage (Colton April 2002).

- Urban residents who use natural gas for space and water heat will receive higher electric bills.
- Large-use customers, including large single-family homes in suburban and rural areas without access to natural gas most often will receive lower electric bills, depending on the existing utility rate design.
- The lower per-kWh prices that result when a significant portion of costs are recovered in a fixed monthly customer charge will stimulate consumption. It will reduce the economic incentive for careful customer energy management practices and investment in energy-efficiency measures by increasing payback periods (Lazar November 2014). By stimulating consumption with volumetric rates below long-run marginal cost, the utility system will require more facilities to serve this incremental customer demand, facilities that will cost more to all customers than energy efficiency discouraged by low prices.

Regulators should consider requests for increasing customer charges in relation to public policy goals and the effect such a change would have on all stakeholders.

Demand Charges for Small Customers

Another change to traditional rate design could be to impose mandatory demand charges on all customer classes, including residential and small commercial customers. Rates could then be designed to collect demand-related costs through these charges, as is currently the case for nearly all large commercial and industrial customers. This is now a feasible and practical option wherever AMI been deployed.

Demand charges have the advantage of being a familiar and accepted aspect of rate design that has not been applied universally. Demand charges can be as effective as energy charges for collecting the utility's costs of service, while sending price signals reflecting costs of utility assets and services.

However, noncoincident demand charges as typically applied (based on each individual customer's peak demand, regardless of whether it is coincident with the system peak demand) can send misleading price signals. This is because the only component of the distribution system that is sized to the demand of the individual customer is the line transformer, and this is but a small portion of the total cost of service. Residential and small commercial consumers have high diversity, meaning different customers use power at different times of the day. This is particularly true for multifamily customers, where the utility never actually sees individual customer demand even at the transformer level. Small customers "share" most of the capacity costs on a utility system. In addition, public understanding of demand charges is poor today even among large commercial customers currently paying these charges, and there is reason to believe that customer understanding would be poor among residential and small commercial customers.

An important feature of the demand charge as typically applied is the ratchet feature.[20] In most instances, the highest daily customer demand sets the capacity charged for the next year. For larger customers with consistent and managed daily use, this feature works. For smaller customers with more sporadic individual usage patterns, the ratchet can introduce a new burden. It is important to consider the length of time the ratchet will apply when it is used, so that it does not become a source of an "unavoidable charge" from the perspective of a customer. Generally, the shorter the duration of the ratchet, the more opportunity a customer has to respond effectively to it. Some jurisdictions have updated to the demand charge ratchet to apply monthly. In this design, the highest demand in the month sets the capacity charged for that month. The same observations apply here as with the annual ratchet, but the burden of a high-demand day affecting other days is limited, though not eliminated. Metering technology allows for charging a daily demand charge. With this design, customers pay for unusually high usage for the day it

[20] The ratchet feature adjusts the customer's monthly demand charge on the basis of its maximum demand during a preceding period, usually 12 months (Lazar RAP ????)

occurs, and customers are motivated to take action to avoid adding to their bill for demand (Selecky February 2014).[21]

Finally, customers with solar DG systems may be exporting power to the grid during system peaks, meaning they are reducing demand-related system costs. It would arguably be unfair to charge these customers based on their individual noncoincident peak demand.

A coincident demand charge can be applied. In this approach, the customer's use of capacity at the time of system peak sets amount charged, and reflects system costs to serve the peak. A daily, coincident peak demand charge converges in effect to a time of use rate.

It may not be appropriate to use demand charges in any customer class for recovery of system costs upstream of the line transformer. The utility of the future is more likely to use TOU pricing and demand response to provide short-duration capacity at specific points along its distribution system, rather than investment in generation, transmission, and distribution systems. For example, a critical peak energy price can more appropriately recover the cost of providing short-duration peaking capacity from the customers using that capacity.

Modifications to Net Metering

Net metering tariffs are not all alike. If regulators think that some or all net metering customers are overcompensated and not paying their "fair share" of utility service costs, or that problems will arise after the number of net metered customers reaches some threshold level, they may be able to re-design the net metering tariff without changing its essential simplicity. Some of these variations are intentionally crafted to limit or mitigate the impacts of DG on utility cost recovery. Net metering tariffs vary from one utility to the next. Variables include which DG technologies are eligible; whether meter aggregation is allowed (i.e., netting the consumption measured on more than one meter with the generation measured on a single meter); limits on the size of eligible DG systems (which may vary about DG technology), which may be expressed as absolute values or as a percentage of the customer's annual consumption; limits on the aggregate amount of energy or capacity that the utility will allow to enroll in net metering; creation and ownership of renewable energy credits; and treatment of net excess generation (i.e., what happens when the customer's generation exceeds consumption during a billing period) (Linvill November 2013).

The impact of net metering tariffs on utility cost recovery and the price signals the tariff sends to customers is highly dependent on the treatment of net excess generation. In some jurisdictions (e.g., Arkansas and Montana), the value of any net excess generation is forfeited by the customer to the utility. In other jurisdictions (e.g., Georgia and Minnesota), the utility makes a cash payment to the customer for the value of the excess generation, which is typically calculated as a function of the utility's PURPA avoided cost rate. Some tariffs place a time limit (e.g., 12 months) on how long a credit for net excess generation can be applied to the customer's bill. At the end of the designated time period, the utility may retire the value of the credit or make a cash payment to the customer—typically at a PURPA avoided cost rate. In other jurisdictions, credits for net excess generation may be rolled over indefinitely from one billing period to the next (DSIRE March 2015).

State policymakers, regulators, and utilities may be able to retain the simplicity of net metering tariffs as a way to meet the standard rates requirement imposed by FERC rules for DG systems, while modifying the treatment of net excess generation or other design details to mitigate concerns about lost revenues or cross-subsidies. The importance of addressing this question will only grow as DG system costs come down, retail rates go up, and net metered customers increase.

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[21] RAP has recommended a daily demand charge to apply in standby rates applicable to combined heat and power units. For more information, see Selecky February 2014.

Minimum Bills

One alternative to raising fixed customer charges is to add a "minimum bill" component to a traditional rate design (Lazar November 2014). The minimum bill concept guarantees the utility a minimum annual revenue level from each metered customer, even if his or her usage is zero. The vast majority of customers will have usage that exceeds those low thresholds. For these customers, a minimum bill "disappears" when the usage passes that level, and the customer effectively remains on the traditional rate design. But for customers with usage below the threshold levels, including customers who use DG systems to reduce their net usage, the minimum bill would ensure that every customer contributes to the utility's recovery of fixed system costs.

Compared to raising the monthly customer charge and reducing consumption rates, a minimum bill rate design has an advantage in that the per-kWh price is higher, more closely reflecting long-run marginal costs. This encourages usage that is better aligned with utility investment impacts from consumption and investment in energy efficiency. This means customer choices about usage and energy-related investments will be informed by electricity prices that reflect long-run grid value. The disadvantage is that, for the very small number of customers whose usage is below the "minimum," this rate design provides no disincentive at all to using the minimum amount of electricity. It can be perceived to have a disadvantage of encouraging additional usage by those with usage below the minimum billed amount, but there are very few of these customers, and their prospective additional usage increase is small. Users in this group may argue that the minimum bill is unfair to them.

Unbundled Rates

As noted before, cost of service studies generally take a functional approach where costs are categorized as generation, transmission, distribution and customer relations, and common. These costs are then classified as to whether they are customer related, demand related, or energy related. Rates can then be designed that recover costs through customer charges, energy charges, and in the case of large C&I customers demand charges.

Some rate analysts have suggested that a better approach, enabled by AMI and other new technologies, would be to further unbundle rates into more types of charges that better reflect the true drivers of costs. In particular, rates could be designed to separately charge customers (or credit customers) for the costs (or delivered value) of ancillary services such as voltage regulation and frequency regulation. Other demand-related and energy-related costs would continue to be recovered through demand and energy charges, ensuring the utility meets its revenue requirement, but this structure would send more accurate signals to customers about how their consumption drives costs.

Locationally Varying Rates

A utility's costs of serving customers can vary based on the location of the customer. This variation can be included in rates. One way to do this is to offer a credit for customer actions taken in high cost areas. This distribution system credit would overlay the generally applicable rate structure. In principle, locational rate design could meet the fundamental needs of recovering service costs through rates and sending accurate price signals. Locationally varying rates would require supporting information from cost of service studies.

Alternatives to Net Metering for DG Customers

A number of alternatives to net metering tariffs have been used or proposed for customers owning or leasing DG systems. The most common of these alternatives is a "buy all, sell all" tariff in which the customers pays for all of their electricity consumption under a standard rate design, and sells all of their generated electricity to the utility at a fixed or variable price. This latter transaction can be accomplished through a power purchase agreement, a feed-in tariff, or a PURPA-qualifying facility tariff where the price is based on the utility's avoided costs. An advantage of these alternatives is that they separate the customer's consumption of energy from his or her generation of energy and allow all customers in their class, whether owners of DG or not, to be charged in the same way. Customers purchase energy services at standard rates designed to ensure utility cost recovery and to send appropriate price signals. Customers sell energy to the utility at a standard rate that can be set equal to the cost the utility would incur to produce or purchase a comparable quantity of energy. Although these rate designs may address the lost revenue and cross-subsidy concerns associated with widespread DG deployment, proponents of DG argue that they fail on other grounds. First, there is a concern about the cost of metering. A virtue of net metering is avoiding an added meter to measure power flowing in each direction. Smart meters can be provisioned with two-way flow metering capability. The significant concern from the customer's perspective is the price paid for the DG output, and whether it reflects long-run values (including capacity, ancillary service, nonenergy and hard-to-quantify values) or short-run values that tend to smaller. As customers tend to be stable over years, this suggests longer-term values are appropriate to use. Another concern customers might have is the lost ability to express a preference to reduce the amount of energy they purchase from the utility through self-supply. To address this, a state could offer the buy all, sell all option along with net metering.

"Value of solar" tariffs represent another new idea in rate design for DG systems. Value of solar tariffs combine some of the features of a net metering tariff with some of the features of a buy all, sell all tariff. The basic idea is that the utility (or a regulatory body) administratively determines the average value to the utility of purchased solar energy. This will generally be established at some value greater than the avoided wholesale energy costs or fuel costs that are frequently used to set PURPA rates, because over the long-term, DG systems help utilities avoid infrastructure costs and not just wholesale energy purchases or fuel costs. However, value of solar tariffs differ from most "buy all, sell all" arrangements in that this value is not fixed for the duration of a lengthy contract. The tariff price is updated periodically to reflect changes in the value of solar. In addition, early manifestations of value of solar tariffs have not involved buying all energy at one price and selling all energy at a different price. Instead, a system of debits and credits similar to net energy metering is employed.

A few utilities have recently opted to address revenue and subsidy concerns arising from DG by imposing special charges on customers that have DG systems. One example of this is a dollar per kW of installed PV capacity charged to the customer per month (AZCC December 2013). Early examples of this rate design have faced two significant challenges. DG advocates have argued that imposing charges on one subset of customers is arbitrary or discriminatory. They have also argued that the amount of the charges cannot be justified based on demonstrable differences in the costs of serving customers with DG. As this approach is very new, it remains to be seen whether special charges can ultimately be designed that are truly cost-of-service-based, nondiscriminatory, and successful at sending appropriate price signals.

Another option, albeit untried, is to create a separate customer class for those with DG systems. Cost of service studies could probe deeply into the actual costs of serving these customers and rates could be designed that address any unique costs or price signals appropriate for DG systems.

Principles for Rate Design

Today, the utility landscape includes wholesale and retail competition in energy services, as well as the emergence of distributed energy resources. Today, entities other than utilities can sell energy and energy services directly to customers, and utilities are often in the position of purchasing energy or energy services from customers. New and more sophisticated metering technologies are available. Basic principles that guide rate design remain important, but may need to be extended to account for new situations. In a recent paper titled *Smart Rate Design for a Smart Future*, the Regulatory Assistance Project identifies a short list of three fundamental principles that can guide rate design in the modern era:

1. Universal service: Every American should have reliable, affordable service for essential needs available at a reasonable price. Customers should be able to "connect to the grid" for no more than the cost of "connecting to the grid."

2. Cost-based pricing: Customers should pay for grid services and power supply in proportion to how much they use, and when they use it.

3. Value of customer generation: Customers receiving power from the grid should expect to pay the costs that the grid operator and power suppliers incur to provide service. Customers supplying power to the grid should expect to receive fair and just compensation for the power they supply (Lazar July 2015).

These three principles can guide regulators in Michigan and elsewhere as they sort through their rate design options, always keeping in mind the fundamental needs of recovering the utility's costs of service and sending price signals to customers.

Rate Design in Michigan

The MPSC regulates the rates of eight investor-owned electric utilities and three electric cooperatives. Rate design in Michigan is based largely on the traditional model described earlier in this section. Typically, a utility initiates a rate case by submitting an application to the Commission to increase rates. Following a contested case hearing, the Commission will determine the utility's revenue requirement for a test year[22] (MPSC March 2014). Next, the Commission will determine the appropriate cost of service study to use. Typically, both the utility and Commission staff perform such a study during the case. The Commission Staff will run the revenue requirement determined by the Commission through the appropriate cost of service study model to determine how much of the revenue requirement will be allocated to each customer class. Michigan law requires the Commission to base utility rates on the actual cost of providing service to each customer class.[23] To this end, the legislature proposed allocating costs based on the 50-25-25 method (MCL 460.11(1)). This method assigns 50 percent of costs based on peak demand, 25 percent for energy use during peak times, and 25 percent for total energy use. Using this method, the utility assigns costs associated with production, transmission, and delivery to each customer class.[24] The last step is to design a rate that will recover the correct amount of revenue from each class. Rates have three primary elements: a power supply charge, a customer charge, and surcharges. See Exhibit 4 for an overview of the types of charges used in Michigan.

At the direction of the legislature in Public Act 169 of 2014, the MPSC initiated proceedings with DTE Energy and Consumers Energy to explore the possibility of modifying the current 50-25-25 method of cost allocation to determine if it, "could be modified to better ensure rates are equal to the cost of service, as well as being affordable and competitive for all customer classes" (MPSC June 30, 2015). On June 30, 2015 the MPSC announced it had authorized Consumers Energy and DTE Energy to implement a new cost allocation method that would assign 75 percent of production costs based on peak demand and 25 percent of production costs based on total energy usage (MPSC June 15, 2015).

EXHIBIT 4. Michigan's Rate Design Structure

Rate Design Elements	Residential Customers	Commercial and Industrial Customers
Power Supply Charge	Charge for each unit of sale (kWh or MWh)	Charge for each unit of demand (KW or MW)
Delivery Charge - Customer Charge	Fixed monthly charge	Fixed monthly charge
Delivery Charge - Distribution Charge	Per kWh Energy charge on each unit of sale	Per kWh Energy and Demand (for some Commercial & all Industrial rates) charge on each unit of sale
Surcharges	Power Supply Cost Recovery, Reconciliation for self-implementation, Low-Income Energy Assistance Funding, Renewable energy, and	Power Supply Cost Recovery, Reconciliation for self-implementation, Low-Income Energy Assistance Funding, Renewable energy, and

22 The MPSC allows utilities to use projections for a future test year.
23 Prior to PA 286 residential rates were subsidized by other customer class through rate skewing.
24 Customers are divided into three primary classes—residential, commercial, and industrial—depending on the characteristics of their energy use.

	energy efficiency	energy efficiency

SOURCE: MPSC. March 2014. *Cost of Service Ratemaking.* Available at: http://michigan.gov/documents/mpsc/2014marchMPSC_450649_7.pdf (accessed 7/21/15)

While the methodology described above is used to establish rates for most customers, the MPSC has approved a variety of different rates depending on other characteristics of a customer's usage, socioeconomic status, or voluntary participation. One example of an alternative rate is for qualified low-income households and senior citizens (MCL 460.11 (8)). Another alternative rate is available for customers participating in utility net metering programs (MCL 460.11 (77)). Recently the MPSC ordered DTE Energy and Consumers Energy to make time-of-use (TOU), also referred to as time-varying rates, and dynamic peak pricing available to customers who have Advance Metering Infrastructure (AMI). These new rates—enabled by smart meter technology—allow some customers to react to real time price signals that reflect that actual costs incurred by utilities, instead of the current static rate which treats all consumption equally. These rates could potentially save customers money and produce benefits for the overall grid (MPSC June 30, 2015).

Section V. Decoupling

Introduction

With the growing demand by customers to influence how they consume energy, traditional regulatory policies are being reviewed and updated. Slow to flat growth in energy demand is attributed in part to the impact of energy efficiency. Energy efficiency is available to all customers through programs, self-driven investments, productivity gains in devices and processes, and conservation behavior. Another customer-driven activity includes demand response, which is available for all customers where utility programs are in place and for industrial customers where they can sell their demand response into an organized market. (For Michigan customers, this would include customers of Indiana and Michigan Company selling demand response into PJM). Distributed generation, although gaining traction, is less available to the average customer due to its cost, but it does have an impact on the utilities' load and sales forecasts. Each of these distributed energy resources, to varying degrees, represents customers bringing their capital to energy investments that substitute in aggregate for utility investment that would otherwise have been necessary to serve avoided demand.

As deployment of these options, among others to come, continues to grow, utility sales growth rates are declining. Since much of their revenues depends on sales, utilities see decline in growth as problematic. Reduced sales means less revenues to cover the costs of operating the grid and returning a profit to shareholders.

A natural inclination for utilities is to resist these changes and to maintain the status quo. The significance of the drivers described here is that it seems to pit the utility's fiduciary duty to its shareholders to increase revenues against public policy objectives to move towards cleaner, diverse energy sourced from consumers. The solution lies in aligning the utility's interests with the public interest.

An effective way to address this balance is through decoupling. Other mechanisms such as straight-fixed variable rates (SFV) and a lost revenue adjustment mechanism (LRAM) attempt to address the lost revenue issue. But SFV conflicts with providing price signals, and LRAM focuses only on programmatic sales reductions and does not remove the utility incentive to increase sales. While the focus will be on decoupling, these other two mechanisms will be discussed as well.

Note that decoupling can be adopted as a means of addressing financial consequences to the utility that result from implementing energy efficiency on a comprehensive basis. It should not be adopted without that utility commitment from management on down, to engage in comprehensive energy efficiency.

Energy Efficiency and the Regulatory Stool

Most jurisdictions across the nation have recognized the value of energy efficiency as a least cost option as part of a utility resource portfolio. In addition to being the lowest cost option, energy efficiency has multiple benefits for the utility, customers, and society (Lazard September 2014). Utilities experience reduced line losses, capital requirements, and credit and collection costs. Customers find opportunities to reduce their electric bill while increasing their home's comfort and productivity. And society as a whole benefits from a cleaner environment and economic development (Lazar October 9, 2013).

Because of the benefits of increased energy efficiency, there are three legs to the regulatory stool that can be addressed to motivate management to become enthusiastic participants instead of reluctant ones. They are program cost recovery to compensate the utility for its investment; recovery of lost revenues; and, financial incentives to motivate innovation to produce more cost-effective savings. Cost recovery for energy efficiency is no different than cost recovery for any other legitimate expenditure for which the utility is entitled. Lost revenue recovery mechanisms address the need to ensure continued safe and reliable service based on cost structures established in the last revenue investigation. Impacts of reduced revenues can be significant. For example, a decline in sales of 1 percent can translate into a loss in revenues of close to 12 percent and an associated reduction in the return on equity of close to 10 percent (Lazar 2015).[25] Incentive payments are designed to provide incentives for utilities to increase their profits through engaging in energy efficiency (and potentially enabling other customer energy investments). An incentive payment, while smaller than a return on a power plant, is designed to help spur utility resource decisions in favor of distributed energy resources.

The Mechanics of Decoupling

Decoupling can be used to successfully align utility and customer interests by removing the utility incentive to increase sales by separating revenue requirements from sales. It adjusts utility rates (prices) between rate cases to account for changes in sales volumes and relies on the revenue requirement from a recent rates case as a fulcrum. While some prefer the term "revenue regulation" instead of decoupling because of the priority on revenue rather than prices, this piece will use the term "decoupling." Most decoupling mechanisms contain a method to update allowed revenues for customer growth and/or attrition factors.[26] The goal is to eliminate the "throughput incentive," the motivation in traditional regulation for the utility to promote more sales and resist less sales owing to effects on net income. A well-designed decoupling mechanism will provide predictable revenues independent of sales. A mechanism allowing revenue updates could have similar results to frequent rate cases. A mechanism with no attrition adjustments to increase revenue requirements may result in more periodic rate cases where both increases and decreases in utility costs can be examined and netted against one another.

The basic framework of decoupling is to allow the utility to recover the revenue requirements authorized by the commission in a rate proceeding, assuming no imprudence on the utility's part. Because the utility can count on receiving its full revenue requirement it changes the regulatory paradigm in which the utility has been traditionally granted the opportunity to recover (and in some instances, over-recover) its revenue requirements. In broad brush terms, decoupling functions so that if a utility recovers less than its full revenue requirements due to a reduction in sales the utility will recover those lost revenues through a rider added to customers' rates. Exhibit 5, featured below gives an example of how decoupling works:

EXHIBIT 5. Periodic Decoupling Calculation

From the Rate Case	
Target Revenues	$10,000,000
Test Year Unit Sales	100,000,000
Price	$0.10000
Post Rate Case Calculation	
Actual Unit Sales	99,500,000
Required Total Price	$0.10050
Decoupling Price "Adjustment"	$0.00050

SOURCE: Lazar, Jim, Rick Weston and Wayne Shirley. June 2011. *Revenue Regulation and Decoupling: A Guide to Theory and Application*. Available at: http://www.raponline.org/document/download/id/902. (accessed 4/15/15)

Under this example, the revenue requirements are established, and the rate of $.10 is set based upon test year sales. As the level of sales drop in the post-rate case calculation from 100,000,000 to

[25] This is based on an analysis of a southwest utility.

[26] In attrition decoupling, the utility's allowed revenue requirement is the amount allowed in the first year after the rate case, plus the addition or reduction that results from the attrition review. The attrition review allows for adjustments to known and measurable changes to the utility's costs and revenues since the last rate case but only in small increments or decrements. Revenue Regulation and Decoupling: A Guide to Theory and Application, Jim Lazar et al, June, 2011, p.19.

99,500,000 under the illustration, the lost revenues associated with the 500,000 kWh in lost sales are acquired through an "adjustment" to future rates of $0.0005025/kWh to make the utility whole. Decoupling is generally symmetric—if sales go up, resulting in revenue in excess of planned amounts, the price adjustment is negative. Generally adjustments to rates have been in the 1 to 3 percent range, with the bulk around 1 percent (RAP June 2011).[27]

Options/Decision Points in Designing Decoupling

In establishing a decoupling mechanism, there are many options available to regulators in terms of how to design the mechanism so as to conform to state policy objectives (Migden-Ostrander July 2014). The questions regulators should consider when designing appropriate mechanisms are discussed below.

How should the decoupling mechanism be designed?

Decoupling sets a target revenue authorized by the commission that the utility will collect regardless of sales levels. The decoupling mechanism adjusts the target revenue between rate cases. Many factors would allow for increases between rate cases to adjust for changing costs. While these may be favored by the utility as a means of capturing cost increases, they are controversial among consumer advocates who argue that any adjustments to revenue requirements ought to occur in a rate case where any cost decreases can be netted against cost increases. Jurisdictions using a future (Forecasted) test year address the issue of changing revenue requirement for a year, but the concerns discussed here emerge eventually. Some of the mechanisms that have been developed include:

- **Stairstep—**These increases can be determined during a rate case and generally reflect forecasts of cost changes. Increases in the revenue requirement are factored into the decoupling mechanism based on evidence presented during the hearing.
- **Indexing—**Indexing ties adjustments to multiple factors like inflation, productivity, customer growth, and changes in capital expenditures.
- **Revenue per customer (RPC)—**The RPC calculates the amount of revenue required to serve each customer, broken down by customer class and existing and new customer status. This is one of the most common methods of decoupling.
- **No revenue adjustment—**This requires the utility to request a revenue investigation when it requires additional revenue to cover its costs.
- **Hybrid—**This generally uses stairstep increases to account for projected capital costs and indexing to account for O&M expenses.

What costs should be included in a revenue decoupling mechanism?

When creating a decoupling mechanism, one of the first considerations revolves around what should be included. Typically, costs that are recovered through mechanisms that track actual costs, like fuel or purchased power, are excluded System benefit charges or costs associated with residential customer assistance programs are also excluded. Since these costs are tracked separately, there is a risk that including them as part of a decoupling adjustment could result in double recovery of some of those costs. While the exclusion of these specific costs is more common, an Idaho Power and Light decoupling plan excludes all variable costs (Migden-Ostrander July 2014). Costs included, then, by most decoupling mechanisms are the embedded fixed costs of the utility. These may include for utilities that own generation, embedded fixed costs of power production if these are not already included in a power cost recovery rider.

[27] 64 percent of all adjustments are within plus or minus 2 percent of the retail rate which amounts to approximately $2.30 per month for the average electric customer. Across all electric and gas utilities and all adjustment frequencies, 62 percent of the adjustments were surcharges while 38 percent were refunds (Morgan February 2013 p. 2-3).

Should revenue regulation apply to all functions (generation, transmission, and distribution)?

A question to consider is to which functions should decoupling apply. For example, if the utility is vertically integrated, should decoupling apply to all functions? A vertically integrated utility will be concerned about generation lost revenues, but that does not necessarily mean that decoupling has to be established to cover all functions. For example, if the utility has the opportunity to sell generation into the market, or if it has a fuel adjustment clause, it may not require the same decoupling treatment as it does for distribution revenues. For restructured utilities, the decision to apply decoupling only to the regulated distribution utility may be easier, since the generation function is subject to competition and the transmission function is largely unaffected.

Should revenue regulation apply to all customer classes?

Decoupling generally applies to residential and commercial customers because it is the nature of these loads to represent large populations having similar enough characteristics. Some utilities have applied decoupling to industrial customers while others have not. Where industrial customers are not included, the typical reason is that the actions of individual large customers to increase or decrease demand, can have outsized and undue effects on other customers in the class. Among six utilities studied recently by RAP, four applied decoupling to all customers while two did not (Migden-Ostrander July 2014). In any event, it is as important as ever to conduct a cost of service study to ensure proper allocation of rates among customer classes and to consider specific effects for the industrial class.

Should there be symmetry such that a reconciliation adjustment occurs for both over- and under-recoveries?

Symmetry refers to making the decoupling mechanism reciprocal such that the utility receives its commission-authorized revenue requirements, and both under-collections as well as over-collections are recovered through a rider. This is viewed as an important fairness issue that also provides consumers a level of protection. Under traditional regulation, if a utility over-recovers, rarely is there an ability to reduce rates. Theoretically, a commission can initiate an investigation or a customer group can file a complaint and assume a very difficult burden of proof. Symmetry in a decoupling case gives customers something that they have never had—an ability to ensure that they are not overpaying the utility such that the utility's revenues exceed its commission-determined revenue requirements.

Should recovery of indicated surcharges be conditioned on acceptable performance on energy-efficiency goals?

Decoupling benefits utilities by reducing risk and increasing its certainty that it will recover its revenue requirements. Earnings are more stable so that the utility can eventually carry a lower equity ratio and still protect bondholders. A formative purpose of decoupling is to remove a disincentive for the utility to engage in comprehensive energy efficiency. The rationale is expanding to provide a utility with a financial incentive to enable all distributed energy resources. The commission can reserve the authority to suspend a decoupling mechanism if the utility fails to provide acceptable performance relative to its energy-efficiency goals or other important performance metrics.

Should the reconciliation be normalized to exclude the effects of weather and economic cycles?

A virtue of full decoupling is that the utility concern about sales is removed. Sources of sales variation out of the control of the utility, like weather and the economy, are captured and the cost of risk management can be reduced. Some are uncomfortable with a regulatory mechanism that removes risk from these external sources. To address this, some states have normalized sales results to remove the effects of weather and in some cases the effects of changed economic factors. Normalization diminishes the benefit of decoupling to the utility and causes it to retain risk management costs that flow through to customers. Most decoupling mechanisms do not adjust for weather normalization (Morgan February 2013).

To calculate the revenue requirements, should the current or accrual method be used?

Regulators have options when ensuring that actual revenue equals target revenue under decoupling. Under the current method, rates are adjusted monthly so that targeted revenues equals actual revenues. For example, in July when sales are up (perhaps due to a hot summer) rates may go down, since the actual revenues would otherwise exceed the targeted revenue. Under the accrual method, there is no fluctuation in the rate but after a period of time, there is a reconciliation adjustment to account for the difference in targeted and actual revenues. Most utilities use the accrual method as it appears easier to administer and produces less volatility in the customer's bill from month to month.

Should the adjustments be made in rate cases or through a rider?

While most utilities seek more frequent recovery through a rider, another option is for the adjustment to revenues to occur in a rate case instead. For example, Pacific Gas and Electric adjusts its base rates annually, while Wisconsin Public Service Corporation makes the adjustment in an annual rate case (Migden-Ostrander July 2014). Utilities like riders, due to the cost recovery that comes with it. Consumer advocates, however, generally hold the view that riders are a one-way street of cost increases. They believe that riders can cause confusion for customers who are trying to calculate their bill. Most utilities address decoupling adjustments through a rider.

Should there be an annual cap on the amount of the adjustment? If so, should there be an opportunity to carry over any additional amounts and for how many years?

Consumer advocates and regulators are sometimes concerned that without a cap on the size of the adjustment, a decoupling mechanism could produce a significant increase in rates. While typical adjustments are in the 1 to 3 percent range, they can go higher. Thus, some regulators may impose a cap on the size of the increase in the service of rate stability. These caps can be expressed as a percentage of revenues, as National Grid does, an absolute dollar amount or a percentage of rates. If a cap is imposed, regulators will also need to decide if the unrecovered portion can be carried over and for what term, whether the opportunity to recover the lost revenues expires at the next recovery period or longer, or, as is typical, if it continues until full recovery has occurred.

Depending on the period of time between true up and recovery, should there be carrying charges? If so, how should they be calculated?

Where recovery mechanisms are not structured for reconciliations to occur frequently, some commissions have felt that it is appropriate to add carrying costs. Carrying charges applied to uncollected or surplus revenues can be used to account for the time value of money and the lost opportunity or value to having those revenues in hand. As discussed above, carrying costs may also apply to any unrecovered adjustment amount that exceeds a cap. The carrying cost rates can vary and can reflect the high degree of certainty that deferred reconciliations will occur. Options include the customer deposit rate and the short-term debt.

Should there be a requirement authorizing the frequency of rate case? How long should a decoupling mechanism last?

Regulators and stakeholders view rate cases as an important opportunity to align costs with revenues and rates. Surcharges and built-in cost adjustments reduce the need for rate cases because they allow recovery of a variety of costs; however, they may not capture structural cost increases or decreases. Some states, therefore, require periodic rate cases to examine the appropriateness of the revenue requirements and subsequent rates. A rate case also affords the opportunity to adjust the sales level to reflect the impact of energy efficiency and reset the whole mechanism.

Should there be an adjustment to the cost of capital to reflect the reduced risk?

Some argue that there should be a downward adjustment to the utility's return on equity to reflect the fact that the utility has a reduced risk of not achieving its revenue requirements. Utilities oppose this, as it preemptively impacts shareholders and discourages a cooperative transition to a new form of regulation. The commission should consider whether it wants a down payment on long-term savings that accrue from decoupling associated, for example, with better resource procurement, better asset allocation, and lower long-term risk, or if it is willing to let these savings emerge over time. These longer-term benefits may only accrue when the financial community perceives that the transition to decoupling is long-term or permanent. Experience is mixed with most litigated cases having little or no ROE adjustment, while some settlements include an adjustment as part of the deal.

Other Mechanisms for Addressing Lost Revenues

Some jurisdictions have addressed the concern for revenue adequacy in a low/no growth sales environment through a lost revenue adjustment mechanism or through straight fixed variable rates. Both of these methods, while addressing lost revenues, suffer from significant infirmities with respect to conservation and energy efficiency and other policy goals. For example, the LRAM does not reduce the utility incentive to increase sales and straight fixed variable rates reduce the customer value in conservation and energy efficiency and may distort the price signal sent to customers.

Lost Revenue Adjustment Mechanism (LRAM)

Under an LRAM, the utility is allowed to recover the lost revenues associated with its energy-efficiency programs. This is accomplished by verifying the energy saved with each program and multiplying the kWh charge for the appropriate customer class by the total number of kWh saved (or in the case of the utility—not sold). Some argue that this is a more accurate way to calculate lost revenues because it is based on actual lost sales. On the other hand, determining the energy savings can be contentious at times and subject to drawn out litigation if the consumer advocate thinks the utility is over-representing the energy reductions. In any case, it is subject to some error despite the cost incurred to achieve precision. Moreover, an LRAM does not reduce the incentive of the utility to increase sales. While collecting lost revenue on its energy-efficiency programs, the utility may still look for ways to increase sales. If successful, the utility could end up exceeding its revenue requirements through new sales and recovery of lost revenues. Finally, customers have many ways to cause reduced sales which would be excluded from the LRAM. Just as with decoupling, there are a number of issues regarding the design of the LRAM that are critical, such as determining for how many years the utility is entitled to recover lost revenues on an energy efficiency program, and the carrying cost rate.

Straight Fixed Variable Rates

In the last year SFV rates (which have been more often utilized with gas companies) are being considered for electric rates. Moving to this design generally results in a much higher monthly customer charge and a lower volumetric rate. A recent example is in Wisconsin, where the commission authorized a monthly customer charge of $19 (PSCW December 24, 2013).[28] The rationale for a high customer charge is that it will collect a fixed sum from each customer, irrespective of the customer's use and whether it has opted for onsite generation or other measures. Further, it is administratively simple.

However, the problems with SFV are manifold. First, it is a departure from the standard regulatory practice of including in a customer charge only those costs that are specific to an individual customer

[28] The original proposal from the utility was to raise the customer charge in 2017 to $69.37 per month.

taking service, like metering and billing costs. SFV transfers shared facilities costs from volumetric rates to the customer charge in a manner not seen in regulation until recently. SFV is unlike decoupling, which tries to match actual revenues with authorized revenues or LRAM, which attempts to provide the utility with the revenues lost that are directly attributable to energy-efficiency programs. It is an imprecise regulatory tool.

Moreover, SFV runs counter to policy considerations that either promote conservation or seek to protect low-use/low-income customers. This creates the risk that a lower volumetric rate will lead to increased consumption due to some elasticity in demand. This growth in demand can translate into higher costs for all customers as the utility increases costs to meet demand. In this way, SFV erroneously addresses only short run costs without considering the policy and economic concerns of mitigating long-run marginal costs. Moreover, by dramatically increasing the customer charge, the incentive for customers to conserve is similarly reduced. Investments in energy efficiency and other distributed energy resources mean less savings on utility bills and longer paybacks. For low-use customers for which there is some correlation with low-income customers, a SFV rate raises their bills (Colton April 2002). Low-use customers end up subsidizing high-use customers, who may receive an overall bill reduction. A customer living in a one-bedroom, 800 square-foot apartment pays the same customer charge as a customer living in a five-bedroom, 3,000 square-foot apartment.

Finally, it is useful if the volumetric rate is roughly in alignment with long-run marginal cost, the cost to the utility or society to serve additional consumption. A volumetric charge below long-run marginal cost signals customers not to invest in resources that would benefit the commonweal, and to use the utility resources instead. This usage in turn prompts capital investment that would in the long run be more expensive to society than the customer investments would have been. Likewise, a very high volumetric rate motivates expensive customer investments to avoid this cost when the utility investments would cost less. If regulation is intended to help society properly allocate resources in order to minimize overall costs, using long-run marginal cost as a guideline for volumetric rates represents a path to success.

Decoupling is the only mechanism that addresses the throughput incentive and provides utilities with recovery of lost revenues while allowing rates to send the correct price signals to customers. Note that decoupling does not motivate a utility to deploy clean energy; it does remove a disincentive to block customer investments that reduce sales.

If public policy is to recognize the emergence of customer-driven clean energy solutions, decoupling is a proven way to align the utility's interests with that of public policy and its customers. Decoupling will enable the pursuit of customer alternatives such as energy efficiency, demand response and distributed generation while other adaptations to regulation to further account for these resources are considered. A decoupling mechanism is adaptable to a wide range of specific considerations to meet the needs and objectives of the utility and the stakeholders.

Electric Utility Revenue Decoupling in Michigan

In its December 23, 2008 order in case number U-15244 the MPSC directed, "Detroit Edison to include in its next general rate case testimony on the economic feasibility, possible design, and one or more proposals for the institution of rate decoupling by Detroit Edison." The Commission continued stating, "not only will this provide the Commission with an opportunity to vet decoupling proposals in the crucible of a contested case proceeding, it will also provide the Commission with additional information for submission to the Legislature that is based on actual, not hypothetical, circumstances" (MPSC October 23, 2008). In response, on January 26, 2009 DTE Energy filed an application to amend its electric rates that included a proposed revenue decoupling mechanism (RDM) (MPSC January 26, 2009).

Following a contested rate case proceeding, the Commission authorized DTE to implement a pilot decoupling program, similar to the program previously approved for Consumers Energy (MPSC January 11, 2010). The Commission's approval was accompanied by the following statement about revenue decoupling, "the principal purpose of decoupling is to transform the current regulatory paradigm that gives a utility a strong incentive to sell as much electricity as possible, without regard to the negative effects upon overall costs and individual customer bills. Decoupling can be utilized to manage changes in electricity sales attributable to updated building codes, expanded energy efficiency programs (including federal and state weatherization programs), upgrades in appliance efficiency, and other similar demand side policies" (MPSC January 11, 2010).

Two entities decided to challenge the Commission's approval of DTE's RDM, and brought the case to the Michigan Court of Appeals. On April 10, 2012 the Michigan Court of Appeals ruled that the MPSC did not have the authority to approve revenue decoupling for electric utilities and reversed the Commission's decision authorizing DTE's RDM (Michigan Court of Appeal April 10, 2012). The Court of Appeals made it clear that in order for the Commission to allow electric utilities to implement revenue decoupling, the Michigan Legislature must first empower the Commission by updating relevant statutes. In their decision the court affirmed the MPSC's authority to implement revenue decoupling for natural gas utilities, but to date, Michigan statutes have not been updated to allow for revenue decoupling for electricity.

Section VI. Infrastructure Planning, Analysis, and Review

Introduction

One of the biggest challenges facing Michigan and every other state is to ensure that adequate infrastructure is built and maintained to meet the current and future energy demands of its businesses and residents. Because energy infrastructure cannot be built overnight, states have adopted (or are currently considering) a wide variety of public policies requiring some form of planning, analysis, review, or approval of utility infrastructure investments. The most relevant and notable of these policies are characterized below, with examples. Michigan's own experiences with current policies, as well as examples of best practices from other states, can inform which policies would best satisfy the state's energy policy goals.

Integrated Resource Planning

Michigan currently requires utilities to develop and file an IRP only when a utility submits an application for a certificate of need (CON). In contrast, more than half of all U.S. states currently require some or all of their utilities to periodically file IRP updates as a routine matter. Nearly all of these states require that IRP updates must be submitted every two or three years; for details, see Appendix A (Wilson June 2013). This includes a number of states that have vertically integrated utilities operating in a competitive wholesale electricity market (e.g., Minnesota, Vermont, and Virginia). Examples can also be found in states that allow retail competition[29] and states that have neither retail nor wholesale competition. One obvious policy option for Michigan to consider would be to require periodic IRP updates from all regulated utilities, regardless of whether they need a CON. The downside to this change, of course, would be the substantial burden it places on utilities and regulators. The advantage is that periodic IRP updates would better ensure that Michigan's utilities have solid infrastructure plans that are based on (and consistent with) reasonably current information about demand forecasts, costs of supply-side and demand-side resources, public policy objectives (e.g., a statewide energy plan if one were adopted), etc.

Michigan could also change the content, public involvement, and PSC review requirements associated with IRPs to better conform to the best practices. This is possible regardless of whether the state chooses to require periodic IRP updates. Some of the best IRP practices may be increasingly important as the power sector continues to evolve and customer-owned resources become more prevalent. A few of these key elements are noted below.

The deployment of customer-owned and customer-leased distributed generation (DG) is growing rapidly in the United States. For example, residential installations of solar photovoltaics (PV) expanded at a 50 percent annual growth rate from 2012 through 2014 (SEIA March 2015). This rapid growth in DG poses new challenges for utility planners in terms of load forecasting, capacity requirements, and ancillary service needs. Comparable challenges face regulators, who may require or benefit from better visibility of investment needs at the distribution level than they now have. The best IRP processes give due consideration to the potential for customer-operated DG, or at least evaluate different scenarios for deployment. For example, to support its 2015 IRP, PacifiCorp (which owns electric utilities in six Western states) hired Navigant to prepare a *Distributed Generation Resource Assessment for Long-Term Planning Study* (Corfee June 9, 2014). The fact that DG deployment is mostly out of the control of utilities makes it

29 In most states that allow retail competition, distribution utilities are still required to offer "default service" to customers who, for whatever reason, do not actually choose a supplier or cannot obtain service from a competitive supplier. Some of these states (e.g., Delaware and Rhode Island) require their distribution utilities to use an IRP process or a similar "portfolio management" approach to procure those default services (SEE Action September 1, 2011).

more important, not less important, that it be reviewed in the IRP process. Appropriate consideration of DG can help utilities avoid procuring unnecessary resources at ratepayer expense.

Another IRP best practice that is increasingly important is the need to review utility plans in light of current and expected environmental requirements. A host of federal air and water regulations that could have profound impacts on utility infrastructure and costs have been promulgated in recent years or are expected in coming years. These include rules for cooling water intake structures, coal combustion residuals, and emissions of mercury, nitrogen oxides, sulfur dioxide, and carbon dioxide. The IRP process can be used to ensure that Michigan utilities have resource plans that will position them to comply with those regulations and meet their customers' energy needs at the least total cost. In Arizona and Colorado, for example, the IRP rules require utilities to evaluate the water consumption and air emissions associated with each new resource and the generating system as a whole, and to consider the likelihood of new environmental regulations.

Finally, the best IRP practices explicitly consider risk by evaluating the costs of different possible resource portfolios across a range of possible scenarios. For example, the IRP rules (or Commission orders in individual IRP proceedings) in many states require utilities to evaluate a range of possible costs associated with greenhouse gas emissions. When risks and uncertainties are duly considered, regulators may find that the preferred resource portfolio is not always the one that is the least costly under baseline assumptions; it may sometimes be a portfolio that is slightly *more* expensive under baseline assumptions but also *low* in cost across a range of other plausible scenarios. Practicing this kind of "risk-aware regulation" adds to the time, cost, and complexity of the IRP process, but provides regulators with a powerful tool for dealing with uncertainty" (Binz April 2012).

Transmission System Planning

The current transmission system planning processes affecting Michigan are summarized in the *Baseline Research Report*. As a practical matter, as long as Michigan utilities to participate in interstate wholesale electricity markets, transmission system planning will be somewhat beyond the control of state regulators and policy makers. The state will retain its regulatory authority over transmission *siting* and *permitting* within its borders, but the *need* for most transmission infrastructure assets and issues of *cost allocation* will be regulated by FERC based on Order No. 890 and Order No. 1000.

Within this framework, however, Michigan may be able to take advantage of two potentially powerful tools that are included in FERC Order No. 1000. First, and most importantly, Order No. 1000 requires local and regional transmission planners to consider transmission needs *driven by public policy requirements established by state or federal laws or regulations*. Michigan retains the ability to determine its own energy policies and priorities, and will have the opportunity to ensure that those policies are accounted for in each transmission planning process. If, for example, Michigan chooses to increase its renewable portfolio standard requirements, the need to meet those state requirements can be factored into regional transmission planning. The framework for this is already established, but it will be up to Michigan to ensure that its relevant energy policies are identified at the start of each planning process and that the resultant plans will satisfy those requirements.

A second tool within FERC Order No. 1000 is the requirement that transmission planners allow "nontransmission alternatives" (NTAs) to be proposed and evaluated as an alternative to local or regional transmission solutions. Nontransmission alternatives could include, for example, energy optimization or demand response programs *beyond those required by public policy* that could potentially eliminate or defer the need for a new transmission line. A 2012 report published by the Regulatory Assistance Project cites ten initiatives and policies from the U.S. where geographically targeted efficiency programs have been or are being tested as a means of deferring transmission and distribution system investments (Neme February 2012). It is important to note here that transmission planners are not required under Order No. 1000 to independently investigate whether energy needs could be met at a lower cost through an NTA; they are only required to evaluate the NTAs that are proposed to them. Michigan could conceivably initiate a formal process for identifying potential NTAs that align with the state's energy goals, or do so as an adjunct to an IRP or distribution system planning (see below) process. The evaluation of possible NTAs could provide another opportunity for regulators to practice risk-aware regulation.

Distribution System Planning

The idea of distribution system planning is not new. Electric utilities have always analyzed and planned for meeting their distribution system infrastructure needs. Distribution-level planning occasionally factors into IRPs or transmission plans, especially in states that follow IRP best practices. But in most jurisdictions, those plans don't drill down to the distribution system level. Distribution planning is more often done by utilities in a separate and less visible fashion, without formal direction from regulators.

The explosive growth in recent years of customer-operated distributed energy resources (including energy optimization, demand response, and distributed generation) is creating new challenges and new opportunities that argue for placing greater attention on distribution infrastructure planning. The advent and success of electric vehicles—a potentially significant new source of electric demand that also has the potential to provide balancing and ancillary services—adds to these challenges and opportunities. The biggest challenges stem from the fact that utilities don't always know the types, locations, and capabilities of distributed resources and electric vehicles on their systems. They also cannot control what their customers do. This makes it increasingly difficult for them to plan for meeting distribution infrastructure needs and for operating their systems on a routine basis. Opportunity, on the other hand, comes from the fact that distributed resources and electric vehicles can reduce system costs, provide new capabilities, and shift some risks from utility ratepayers and shareholders to willing customers and third parties. It may also turn out that as distributed resources grow in number, their aggregated capabilities become predictable within a range of manageable forecasting error. This phenomenon has been observed with wind generation, where the error in forecasting generation from thousands of turbines spread over a large geographic area has proven to be much smaller (as a percentage) and more manageable than the error in forecasting generation from any one turbine

One policy option for Michigan to consider is whether to require a formal, transparent, and comprehensive approach to distribution system planning. The value of this kind of planning is likely to grow as deployment of distributed energy resources grows, or if Michigan adopts some form of statewide energy plan affecting distribution systems and distributed resources. California and New York offer examples of how this new kind of planning might be done.

California enacted a new law in 2013 requiring investor-owned utilities to file distribution resource plans with the California Public Utilities Commission (CPUC) by July 1, 2015, to identify optimal locations for the deployment of distributed resources. These plans shall:

1. "Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electrical grid or costs to ratepayers of the electrical corporation.

2. Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.

3. Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

4. Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.

5. Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service" (AB 327 2013).

The CPUC initiated a rulemaking process in August 2014 to establish policies, procedures, and rules to guide the planning process. The CPUC rulemaking order references and relies on a paper published by Greentech Leadership Group that offers a framework for distribution system planning and operations (Greentech August 12, 2014). That paper outlines four key principles for distribution system planning:

1. "Distribution planning should start with a comprehensive, scenario driven, multi stakeholder planning process that standardizes data and methodologies to address locational benefits and costs of distributed resources;
2. California's distribution system planning, design and investments should move towards an open, flexible, and *node-friendly network system* (rather than a centralized, linear, closed one) that enables seamless DER integration;
3. California's electric distribution service operators (DSO) should have an expanded role in utility distribution operations (with CAISO) and should act as a technology-neutral marketplace coordinator and situational awareness and operational information exchange facilitator while avoiding any operational conflicts of interest; and
4. Flexible DER can provide value today to optimize markets, grid operations and investments. California should expedite DER participation in wholesale markets and resource adequacy, unbundle distribution grid operations services, create a transparent process to monetize DER services and reduce unnecessary barriers for DER integration."

On February 26, 2015, the New York Public Service Commission (NY PSC) issued an order adopting a new regulatory policy framework and implementation plan, as part of its *Reforming the Energy Vision* (REV) docket (NYPSC February 26, 2015). Like California, the NY PSC will now require utilities under its jurisdiction to file what it calls Distributed System Implementation Plans (DSIPs). As noted in the order, "Each utility already files with the Commission, annually, a five-year capital plan detailing system needs and the utility's plans to meet them. The DSIP will build on this process, adding information related to the development and effectuation of its role as [a Distributed System Platform Provider or DSP], and integrating DSP plans into system plans. The DSIP will serve numerous purposes. It will serve as a source of public information regarding DSP plans and objectives, including specific system needs allowing market participants to identify opportunities. It will also serve as the template for utilities to develop and articulate an integrated approach to planning, investment and operations. And it will enable the Commission to supervise the implementation of REV in the context of system operations."

The NY PSC directed its staff to issue detailed guidance regarding the contents of DSIPs by August 3, 2015. At a minimum, the DSIP is to include "actual and forecast system loads and capital spending projections, at a level of specificity sufficient to inform market planning and participation by third parties; actual and forecast levels of DER including detailed analysis of system needs amenable to being met by DER; plans for encouraging market development of DER; plans for increasing DER deployment in underserved markets; specific plans including cost estimates for building DSP capabilities; and a description of internal organization of DSP and traditional utility functions."

The NY PSC ordered utilities to file their initial DSIPs by December 15, 2015. Interested parties will then have an opportunity to review and comment on these plans. The intention is that subsequent DSIPs, after these initial ones, will include increased detail and will reflect developments in markets and technology capabilities.

Loading Order Policies

Another policy option available to Michigan would be to establish a "loading order" policy prescribing an order of preference for adding resources to meet electricity demand. A loading order can be flexible and tailored to whatever energy policy priorities the state chooses, including "risk-aware regulation." This kind of policy could affect utility infrastructure planning, analysis and review in the context of an IRP proceeding, a CON proceeding, or other regulatory decisions. Two examples of loading order policies, from California and Wisconsin, are summarized below.[30]

California

The California Energy Commission (CEC) adopted a loading order as part of its 2003 Energy Action Plan.

The Action Plan established a "loading order" of energy resources to guide decisions made by the CEC and the California Public Utilities Commission (CPUC):

> *"First, the agencies want to optimize all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand. Second, recognizing that new generation is both necessary and desirable, the agencies would like to see these needs met first by renewable energy resources and distributed generation. Third, because the preferred resources require both sufficient investment and adequate time to "get to scale," the agencies also will support additional clean, fossil fuel, central-station generation. Simultaneously, the agencies intend to improve the bulk electricity transmission grid and distribution facility infrastructure to support growing demand centers and the interconnection of new generation."*

The loading order is used by the CPUC to review long-term procurement plans submitted by regulated utilities. In 2012, the CPUC issued an order clarifying how the loading order should be interpreted:

> *"It appears necessary to reiterate here the centrality of the loading order, and to direct the utilities to procure all of their generation resources in the sequence set out in the loading order. While hitting a target for energy efficiency or demand response may satisfy other obligations of the utility that does not constitute a ceiling on those resources for purposes of procurement. We understand that opportunities to procure additional energy efficiency or demand response resources may be more constrained than just signing up for more conventional fossil generation, but the utilities should still procure additional energy efficiency and demand response resources to the extent they are feasibly available and cost effective. If the utilities can reasonably procure additional energy efficiency and demand response resources, they should do so. This approach also continues for each step down the loading order, including renewable and distributed generation."*

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[30] Although not shown below, the NY PSC has arguably established a *de facto* preference for customer-sited resources through the REV process described above. This shares some of the features of a loading order. Delaware is another state, not mentioned below, that has established a loading order via legislation that is similar to California's and Wisconsin's (SB 106 2009).

Wisconsin

Wisconsin adopted an energy priorities statute in 2004 that applies to regulated utilities and to actions by state and local governments. The relevant portions of the energy priorities statute are shown below (WA 20 June 30, 2013).

- (3) Goals… (b) Renewable energy resources. It is the goal of the state that, to the extent that it is cost-effective and technically feasible, all new installed capacity for electric generation in the state be based on renewable energy resources, including hydroelectric, wood, wind, solar, refuse, agricultural and biomass energy resources…
- (4) Priorities. In meeting energy demands, the policy of the state is that, to the extent cost-effective and technically feasible, options be considered based on the following priorities, in the order listed: (a) Energy conservation and efficiency. (b) Noncombustible renewable energy resources. (c) Combustible renewable energy resources. (d) Nonrenewable combustible energy resources, in the order listed: 1. Natural gas. 2. Oil or coal with a sulphur content of less than 1%. 3. All other carbon-based fuels.
- (5) Meeting energy demands. (a) In designing all new and replacement energy projects, a state agency or local governmental unit shall rely to the greatest extent feasible on energy efficiency improvements and renewable energy resources, if the energy efficiency improvements and renewable energy resources are cost-effective and technically feasible and do not have unacceptable environmental impacts. (b) To the greatest extent cost-effective and technically feasible, a state agency or local governmental unit shall design all new and replacement energy projects following the priorities listed in sub. 4

The Public Service Commission of Wisconsin (PSCW) typically makes a finding of fact with respect to the energy priorities statute in every proceeding involving utility procurement of new resources. Before approving utility procurement of a gas turbine, for example, the PSCW would expressly consider whether the need to be met by the gas turbine could be met cost-effectively by energy efficiency or renewable energy resources.

Environmental Planning

Another policy option that Michigan could consider, alone or in combination with options described above, would focus not on utility resource planning processes but on air quality planning processes. This option recognizes that Michigan and other states are constantly developing and modifying State Implementation Plans (SIPs) for meeting national ambient air quality standards and other types of compliance plans (e.g., for federal greenhouse gas standards for existing power plants). These environmental plans can significantly impact electric utility infrastructure.

The Regulatory Assistance Project (RAP) suggested in a March 2013 discussion paper that states might benefit from an Integrated, Multi-pollutant Planning for Energy and Air Quality (IMPEAQ) process (James March 4, 2013). An IMPEAQ process would adhere to traditional IRP principles by trying to identify – through optimization and/or systems modeling—least-cost pathways to reduce emissions of multiple pollutants. In doing so, the IMPEAQ process would also seek to minimize impacts on electric reliability and energy costs. It offers an additional twist to the idea of "risk-aware regulation," with the emphasis here on risks to utilities arising from current and future environmental compliance obligations.

Similarly, in a 2011 IRP docket before the Oklahoma Corporation Commission (OCC), the Sierra Club proposed that the OCC adopt "Integrated Environmental-Compliance Planning." The proposed approach would, in many ways, work like an IRP. It would consider supply side, demand side, and delivery options in an integrated manner, but would also focus more closely on the requirements of forthcoming public health and environmental regulations and the imminent need to take actions such as retiring, retooling, or investing in new resources.

Among U.S. states, Maryland is a leader in advancing multi-pollutant approaches. Working with a regional association of air quality regulators (NESCAUM), the University of Maryland, and Towson University, the

Maryland Department of the Environment (MDE) has leveraged Maryland's 2015 ozone SIP requirements and state-legislated 2012 greenhouse gas (GHG) reduction requirements to build a multi-pollutant analytical framework. MDE's framework allows it to:

- Quantify the emission reductions of multiple pollutants for a broad suite of energy efficiency and renewable energy efforts;
- Model the reductions in ozone, fine particulates and other air pollutants;
- Estimate the public health benefits associated with those reductions; and
- Quantify the economic benefits and costs (Aburn March 25, 2013).

Markets/No Planning

If Michigan were to move toward fully competitive retail and wholesale markets—for example, emulating the ERCOT portion of Texas—there would be those who advocate to remove all utility infrastructure planning requirements. Markets and market rules can be designed to ensure resource adequacy and resource quality, without the additional burden of regulated planning processes.

One argument against this "no planning" option is that one can't simply assume that markets will satisfy resource adequacy and resource quality needs in a manner consistent with public policy objectives. The market design and rules are extremely important, and Michigan would not have full control of wholesale market rules unless a single-state wholesale market were created (as has been done in New York). Furthermore, even an ideal wholesale market will probably not address the needs for distribution system infrastructure. Distribution system planning, as previously described, may be necessary.

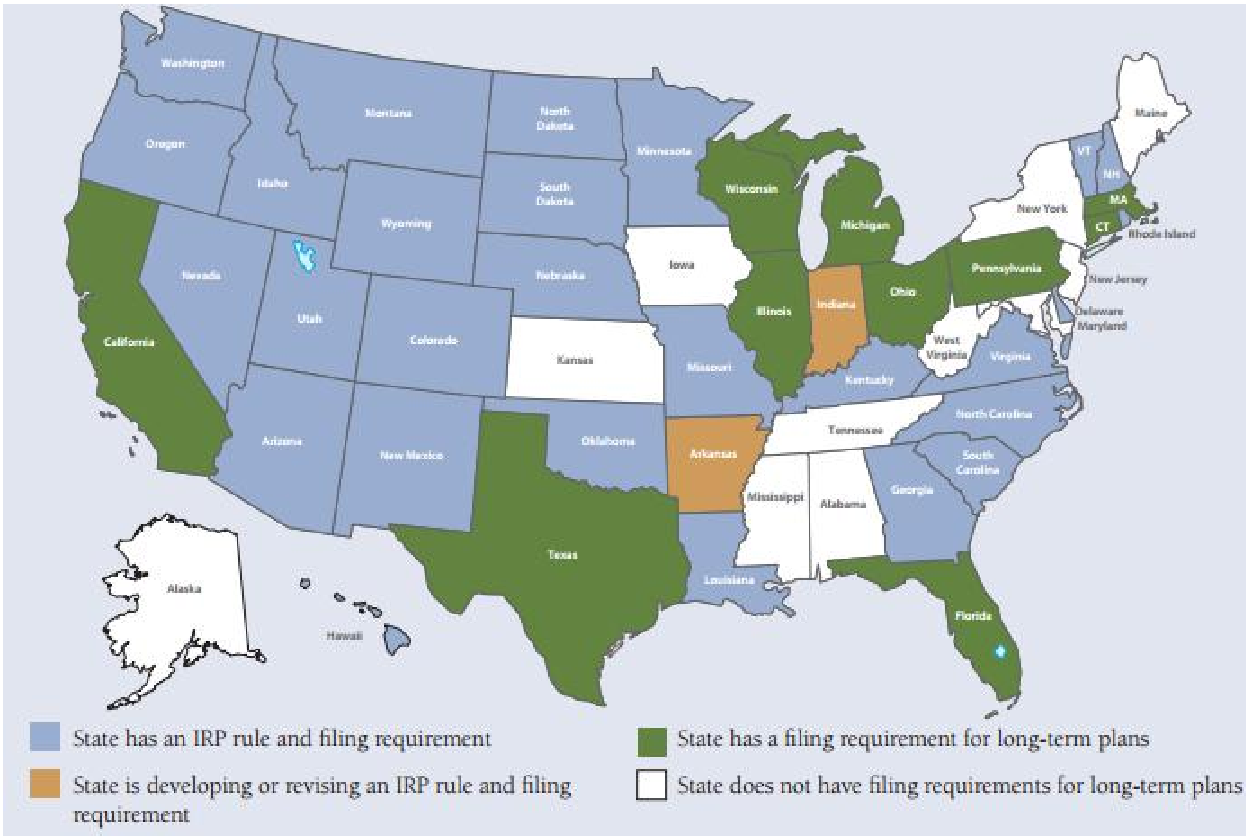
Planning Processes

Utility planning is going on all the time, but formal processes supervised by regulators offer a window into that activity and an opportunity to protect the public interest. If Michigan adopts new or modified mandatory planning requirements, it would be an unfortunate outcome if the process devolved to a game or charade designed to avoid regulatory criticism while the real planning work continues in parallel beyond the public view. One of the best practices for utility planning is to provide *meaningful* opportunities for public engagement. As expert as the utility may be in the practice of utility planning, transparency during the process accomplishes three objectives: 1) It forces the utility to address viable unconventional and innovative ideas that may be outside the paradigm of its process or the experience of its staff; 2) It provides perspective to regulators; and 3) It produces confidence that actual investment choices are serving the public interest.

Michigan also has a choice whether or not to prescribe that the content and conclusions of a periodic utility planning process should be *approved* by regulators. Some states stop short of this, and instead merely require regulators to *accept* a plan if it was developed through a proper process. Such plans contain conclusions, of course, but their value will be revealed in subsequent rate cases or CON cases.

Appendix A

States with Integrated Resource Planning or Similar Processes



SOURCE: Rachel Wilson and Bruce Biewald. June 2013. *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans*. Available at: http://www.raponline.org/document/download/id/6608. (accessed 4/15/15)

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