IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.

Docket No. E-01345A-19-0236

Direct Testimony of Cheryl Roberto

# On Behalf of Sierra Club

**On the Topics of:** 

Default Bill Simplification Formula Rate Concept Alternative Ratepayer-Backed Securitization

October 2, 2020

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## LIST OF ATTACHMENTS

- Attachment CR-1: Resume of Cheryl Roberto
- Attachment CR-2:Rachel Gold et al., Leveraging Advanced Metering Infrastructureto Save Energy (ACEEE Revised Jan. 27, 2020), available athttps://www.aceee.org/sites/default/files/pdfs/u2001.pdf.
- Attachment CR-3: Public Discovery Responses
- Attachment CR-4: Melissa Whited & Cheryl Roberto, *Multi-Year Rate Plans: Core Elements and Case Studies* (Prepared for Maryland PC51 and Case 9618 Sept. 30, 2019), *available at* https://www.synapseenergy.com/sites/default/files/Synapse-Whitepaper-on-MRPs-and-FRPs.pdf.
- Attachment CR-5: Ron Lehr & Sonia Aggarwal, Utility Models: Questions for Regulators and Stakeholders to Ask and Answer as Utilities Evolve (Energy Innovation Feb. 2017), available at https://energyinnovation.org/wpcontent/uploads/2017/02/UtilityRegModels\_QuestionsList.pdf.

## 1 I. INTRODUCTION AND QUALIFICATIONS

2	Q.	Please state your name, title, and employer.
3	A.	My name is Cheryl Roberto. I am employed by Synapse Energy Economics, Inc.
4		as a Senior Principal. My business address is 485 Massachusetts Avenue,
5		Cambridge, MA 02139.
6	Q.	Please describe Synapse Energy Economics.
7	A.	Synapse Energy Economics is a research and consulting firm specializing in
8		electricity industry regulation, planning, and analysis. Synapse works for a variety
9		of clients, with an emphasis on consumer advocates, regulatory commissions, and
10		environmental advocates.

# 11 **Q.** Please summarize your professional and educational experience.

12 A. For more than 30 years I have managed, regulated, or guided the operation of 13 utilities and regulatory policy related to public utilities. From 2008 until 2012, I 14 served as a Commissioner of the Public Utilities Commission of Ohio ("PUCO"), 15 where I initiated a national pilot partnership with the U.S. Department of Energy 16 to support cost-effective deployment of combined heat and power systems. I 17 served as Co-Chair of the 2012 National Electricity Forum. As a member of the 18 National Association of Regulatory Utility Commissioners ("NARUC"), I served 19 on the Task Force on Environmental Regulation and Generation, the Committee 20 on Electricity, and Vice Chair of the Committee on Critical Infrastructure. 21 Immediately after my service as a Commissioner, I led a nation-wide program 22 advocating for regulatory reform as Associate Vice President of the

1		Environmental Defense Fund's Clean Energy Program. The goal of the program
2		was accelerating the adoption of renewable energy technologies; modernizing
3		U.S. energy infrastructure; and eliminating financial and regulatory barriers that
4		prevent widespread implementation of renewables, energy efficiency, and
5		innovative energy generation and distribution approaches. Prior to my service as a
6		Commissioner, I led the Department of Public Utilities for the City of Columbus
7		as its Director, serving, with a staff of 1,300, the 1.1 million residents of the
8		Central Ohio region. From 1987 through 2000, I practiced law as an Assistant
9		Attorney General in Ohio, Assistant Counsel in Pennsylvania, and Assistant City
10		Attorney in Columbus, Ohio. I hold a B.A. in Political Science from Kent State
11		University, and a J.D. from the Moritz College of Law at The Ohio State
12		University. My resume is attached hereto as Attachment CR-1.
13	Q.	On whose behalf are you testifying in this case?
14	А.	I am appearing on behalf of the Sierra Club.
15	Q.	Have you testified previously before the Arizona Corporation Commission?
16	А.	No, I have not.
17	Q.	Have you testified previously before any other tribunals?
18	А.	Yes. I have previously appeared before the Federal Energy Regulatory
19		Commission ("FERC") and the U.S. Senate Energy and Natural Resources
20		Committee. I have also provided testimony before the Public Utilities

1	Commission of Ohio, the Indiana Utility Regulatory Commission, and the
2	Colorado Public Utilities Commission.

## 3 Q. What is the purpose of your testimony?

- A. I have been retained by the Sierra Club to review the Arizona Public Service
  ("APS") application pertaining to its default simplified bill request and its formula
  rate concept alternative. I am also evaluating whether the APS application would
  be improved if APS were to seek ratepayer-backed securitization as an alternative
  to APS's extended cost recovery proposals or a potential earlier retirement of
- 9 Four Corners Units 4 and 5.

## 10 **Q.** What materials did you rely on to develop your testimony?

- 11 A. The sources for my testimony and exhibits are public documents, industry
- literature, and responses to discovery requests, as well as my personal knowledgeand experience.
- 14 **Q.** Did you prepare or direct the preparation of this testimony?

15 A. Yes.

### 16 **Q.** How is your testimony organized?

- 17 A. I have organized my testimony as follows:
- 18 I. Introduction and Qualifications
- 19 II. Summary of Conclusions and Recommendations
- 20 III. Default Bill Simplification

- 1
- IV. APS Formula Rate Concept Alternative
- 2 V. Securitization

# 3 II. <u>SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS</u>

# 4 APS Default Bill Simplification

# Q. Please summarize your primary conclusions regarding the APS proposal for Default Bill Simplification.

7 A. My primary conclusions regarding the APS proposal for Default Bill

- 8 Simplification are as follows:
- 9 • APS's proposal for default bill simplification amounts to a request for a 10 permanent waiver of A.C.C. R14-2-210, adopted to protect consumers. The 11 rule, as adopted, ensures customers receive important information about their 12 utility bill. Because APS is also proposing to default every customer into a 13 simplified bill, it is effectively seeking a permanent rule waiver applicable to 14 every customer. A waiver of this broad and permanent nature is functionally a 15 rule amendment. As an administrative process matter, is not appropriate to 16 amend a rule via a waiver. From a substantive perspective, it is difficult to 17 justify providing customers with less information, particularly given the 18 deficiencies in APS's current Customer Outreach and Education Program 19 efforts and the recommendations of the Alexander Report that was 20 commissioned to investigate those shortcomings.
- APS customer access to energy data is inadequate, as APS fails to provide
   customers the ability to access and share their data consistent with the Green
   Button Connect My Data standards described below in Section III.
   Specifically, customers are required to share personal account information
   when they wish to share energy usage data with third parties. They receive data
   in a format that is difficult to use. They do not have a seamless and secure
   method to authorize the transmittal of their energy usage data, and only their

1		energy usage data, to third parties. Further, APS does not provide energy data
2		in 15-minute intervals. It is critical that customers receive the energy data in a
3		form that allows them to make informed decisions and to share that data while
4		protecting their privacy. The data's value is realized primarily when utilities,
5		technology companies, and service providers process, analyze, and perhaps
6		even act upon the energy data on behalf of the customer. It is APS's
7		responsibility to do this well, but customers should also be able to seek
8		guidance outside of the utility from third party providers.
9 10	Q.	Please summarize your primary recommendations regarding the APS proposal for Default Bill Simplification.
11	A.	My primary recommendations regarding the APS proposal for Default Bill
12		Simplification are as follows:
13		• The Commission should reject the APS proposal for default bill simplification.
14		APS has not presented sufficient evidence to support what would function as a
15		permanent waiver of the consumer information protections of A.C.C. R14-2-
16		210. When or if customers have access to their energy data in a form that
17		complies with Green Button Connect My Data, it may be appropriate to
18		consider a rule amendment.
19		• APS customers have paid for the Advanced Metering Infrastructure ("AMI").
20		They should receive value from it. The Commission should direct APS to
21		implement Green Button Connect My Data as soon as practicable.
22		• The Commission should direct APS to comply with the U.S. Department of
23		Energy's Data Privacy and the Smart Grid: A Voluntary Code of Conduct.
24		• The Commission should direct APS to investigate and report on whether the
25		investment required to provide more granular data in the form of one-, five-, or
26		15-minute intervals to customers would be cost-effective.

1	• The Commission should direct APS to track and report quarterly metrics	that
2	will inform the Commission, APS, and customers on APS's progress tow	vard
3	leveraging the benefits of AMI for its customers. These should include:	
4	• Customer usage of energy portal - one-time or regular access.	
5	• Total number and percentage of customers opting out of or taking a	tariff.
6	• Number of third parties that successfully access customer data throu	ıgh
7	Green Button Connect My Data or other utility data-sharing method	•
8	percentage of customers able to authorize third-party service compa	ny
9	requests on first attempt (target: 95%); percentage of time third-part	У
10	service provider receives access when authorized by customers (targ	get:
11	95%).	
12	• Customer-initiated changes to their rate plans.	
13	• APS-initiated changes to customer rate plans.	
14	• Number of customers not on the "best" or "most economical rate" b	y rate
15	class.	
16	• Frequency and type of complaints.	
17	• Call Center performance.	
18	• Results of customer research on messaging and bill presentment.	
19	• Enrollment for limited-income programs.	
20	• Achievement of participation objectives for demand-side manageme	ent
21	programs.	
22	• Analysis of the impact of rate design on system benefits, such as pea	ak load
23	reduction and lower generation supply costs.	
24	• Key indicia of credit and collection activities, such as disconnection	
25	notices, disconnections, and payment arrangements.	

## 1 APS Formula Rate Concept Alternative

# Q. Please summarize your primary conclusions regarding the APS Formula Rate Concept Alternative.

4 A. My primary conclusions regarding the APS Formula Rate Concept Alternative are
5 as follows:

- 6 The APS Formula Rate Concept Alternative does not improve upon status quo 7 regulation. The Formula Rate Concept Alternative does nothing to address 8 challenges due to changes underway in the electric industry related to fuel for 9 centralized generation and the introduction of cost-effective distributed energy 10 resources. It would not provide additional tools to address public policy goals 11 around decarbonization and makes no meaningful contribution to performance. 12 Most significantly, it would reduce cost-containment features that exist under 13 current cost-of-service regulation in Arizona.
- 14 Alternative regulation could ensure that electric utilities navigate the changes 15 underway in the electricity industry while continuing to provide cost-effective 16 universal service. To achieve this, utilities must successfully harness and 17 optimize all available technologies. Utilities will own some of these 18 technologies, but other technologies will be owned by their customers or third 19 parties. Both status quo regulation and the APS Formula Rate Concept 20 Alternative, if adopted, would require APS to act against its financial interest 21 when supporting clean, efficient, distributed resources. Alternative forms of 22 regulation could help a utility thrive within the transition underway, contain 23 costs, help to achieve public policy goals such as decarbonization, and improve 24 utility performance.
- Performance-based regulation in the form of multi-year rate plans in
   combination with performance incentive mechanisms ("PIM"), which include
   well-crafted metrics, scorecards, and financial incentive mechanisms, is an
   alternative form of regulation that can be a powerful driver toward cost effective, decarbonized energy systems.

1 2 3		• PIMs can be used to express regulatory expectations and connect those expectations with financial consequences inside a multi-year rate plan or as part of traditional cost-of-service regulation.
4		• The design and implementation of an effective multi-year rate plan deserves a
5		robust stakeholder process as part of the Commission's forthcoming
6		investigation into performance-based regulation.
7		• PIMs have long been incorporated into both multi-year rate plans and into
8		cost-of-service-based regulation. PIMs offer the advantage of being able to be
9		implemented incrementally and iteratively. It is appropriate to consider PIMs
10		once the Commission identifies a regulatory policy goal and desired
11		performance objectives or outcomes. It would be appropriate for the
12		Commission to direct APS to begin tracking metrics now. This data collected
13		will inform the investigation regarding PIMs.
14 15	Q.	Please summarize your primary recommendations regarding APS Formula Rate Concept Alternative.
16	А.	My primary recommendations regarding the APS Formula Rate Concept
17		Alternative are as follows:
18		• The Commission should reject the APS Formula Rate Concept Alternative.
19		• More broadly, the Commission should not pursue any formula rate structure.
20		• The Commission should consider adopting performance-based regulation, in a
21		separate docket that investigates comprehensive performance-based regulation
22		and includes a robust stakeholder process. This could be an expansion of the
23		previously opened Docket No. E-00000A-20-0019 to investigate PIMs. <sup>1</sup>

<sup>&</sup>lt;sup>1</sup> In the Matter of the Investigation of the Arizona Corporation Commission into the Role of Performance Incentive Mechanisms in Regulated Investor Owned Electric Utility Rate Cases in Arizona, Docket No. E-00000A-20-0019 (Ariz Corp. Comm'n Feb. 6, 2020).

1		• The Commission should direct APS to begin tracking at least the metrics
2		outlined in my recommendations regarding Default Bill Simplification
3		beginning on page 28.
4	Rate	payer-Backed Securitization
5 6	Q.	Please summarize your primary conclusions regarding Ratepayer-Backed Securitization.
7	A.	My primary conclusions regarding Ratepayer-Backed Securitization are as
8		follows:
9		• A rate case is an opportune moment to evaluate whether portions of the
10		utility's capital need could be more cost-effectively managed through
11		ratepayer-backed bonds. In this matter, I see at least three opportunities to
12		consider ratepayer-backed bonds as a tool to improve customer outcomes.
13		• APS has suggested extending the cost recovery time for deferred expenses
14		related to the Four Corners SCRs and the Ocotillo Modernization Project
15		amortization schedules in order to mitigate bill impacts to customers. <sup>2</sup> The
16		deferral at December 31, 2020 for the Ocotillo Modernization Project is \$62
17		million. <sup>3</sup> The SCR deferral is \$33.2 million. <sup>4</sup> APS also proposes to extend
18		recovery time for the Cholla Unit 2 regulatory asset amortization. <sup>5</sup> If the
19		Commission agrees that APS should recover these deferrals, then instead of
20		extending the cost recovery—which lowers customers impacts in the near term
21		but increases overall costs-the Commission could consider whether these
22		should be funded by ratepayer-backed securities which could lower customers'
23		overall costs and similarly mitigate rate impacts.

<sup>&</sup>lt;sup>2</sup> Ariz. Pub. Serv. Application at 18, Docket No. E-01345A-19-0236 (Oct. 31, 2019), available at https://docket.images.azcc.gov/E000003517.pdf.
<sup>3</sup> Direct Testimony of Elizabeth A. Blankenship at 35:1-4 [hereinafter "Blankenship Direct"].
<sup>4</sup> Id. at 36:19-20.
<sup>5</sup> Id. at 41:4-9.

1	• Additionally, concurrent with my testimony, Tyler Comings filed testimony on
2	behalf of the Sierra Club finding that APS would enjoy substantial savings if it
3	were to retire Four Corners Units 4 and 5 as quickly as possible instead of in
4	2031. Securitization may be a useful tool in implementing an earlier-than-
5	anticipated retirement of Four Corners Units 4 and 5. This use is also
6	consistent with the additional analyses requested by Chairman Burns in this
7	proceeding <sup>6</sup> and the suggestion made by Chairman Burns within the Energy
8	Rules docket. <sup>7</sup>
9	• The Commission could conservatively expect that ratepayer-backed bonds
10	could reduce the cost of capital by over half, offering customers a substantial
11	savings opportunity.
12	• A commission adopting a finance order to authorize securitization could
13	consider the following design features to ensure that the transaction achieves
14	the intended benefits:
15	• The Commission retains authority to approve the investment banking firm
16	managing the offering.
17	• The Commission retains an independent advisor to oversee the transaction
18	and to advise the Commission.
19	• Proceeds of the ratepayer-backed bonds may be used only to replace
20	existing capital (including the cost of the bonds), not to undertake new
21	debt.
22	• Savings from securitization should be passed along to customers directly
23	or indirectly as a public benefit through funding of costs required to assure
24	a just transition during the early retirement of an asset, including but not
25	limited to severance pay and job training expenses for affected employees.

<sup>&</sup>lt;sup>6</sup> Letter from Chairman Burns, Docket No. E-01345A-19-0236 (Aug. 11, 2020), *available at* https://docket.images.azcc.gov/E000008353.pdf; Letter from Chairman Burns, Docket No. E-01345A-19-0236 (Sept. 1, 2020), *available at* https://docket.images.azcc.gov/E000008707.pdf.
<sup>7</sup> Letter from Chairman Burns at 2, Docket No. RU-00000A-18-0284 (Ariz. Corp. Comm'n Mar. 25, 2020),

<sup>&</sup>lt;sup>7</sup> Letter from Chairman Burns at 2, Docket No. RU-00000A-18-0284 (Ariz. Corp. Comm'n Mar. 25, 2020), *available at* https://docket.images.azcc.gov/E000005560.pdf [hereinafter "Mar. 25, 2020 Letter from Chairman Burns"].

1		• Bonds must be competitively marketed as opposed to sold through private
2		negotiation.
3		• Financing costs and weighted average interest of the bonds are capped at
4		levels to assure the expected benefits.
5		• The Commission retains authority to approve the bond structuring and
6		pricing.
7 8	Q.	Please summarize your primary recommendations regarding Ratepayer- Backed Securitization.
9	А.	My primary recommendations regarding ratepayer-backed securitization are as
10		follows:
11		• The Commission should consider retaining a qualified expert to conduct an
12		independent evaluation to determine whether there are large, well-defined,
13		non-recurring expenses on the utility's balance sheet that could cost-effectively
14		be funded by ratepayer-backed bonds.
15		• The Commission should consider the tool of securitization when evaluating the
16		opportunities to close fossil fuel generation units that have become or soon will
17		be non-economic.

#### 1 **III. DEFAULT BILL SIMPLIFICATION**

### 2 APS Proposal for Default Bill Simplification

3	Q.	What has APS proposed regarding Bill Simplification?
4	A.	APS proposes to begin issuing bills that include only a customer's current service
5		plan, total kWh usage with a split of on- and off-peak, as well as usage history,
6		and an account summary including the amount owed during the current month. <sup>8</sup>
7 8	Q.	What explanation has APS provided for its motivation in proposing "bill simplification"?
9	A.	Ms. Lockwood testified that APS has "heard from customers the desire to have a
10		simplified and easier to understand bill."9
11 12	Q.	Did APS undertake a stakeholder consultation process to conclude that its customers wanted a simplified bill?
13	A.	Not that I have seen. If APS conducted stakeholder consultation before arriving at
14		this conclusion, Ms. Lockwood did not describe it or explain how it was
15		considered in developing the proposed bill redesign. However, Barbara R.
16		Alexander, the independent consultant retained by Staff to review APS Customer
17		Outreach and Education Plan, noted in her report (hereinafter "Alexander
18		Report") that:
19 20 21 22 23		APS is also currently undergoing a process to change the design and presentation of material information on its customer bills. APS has consulted with stakeholders on its bill design options, and, unlike its development of messaging and communications in 2017, customer focus groups were convened to gather additional input. According to

<sup>&</sup>lt;sup>8</sup> Direct Testimony of Barbara Lockwood at 12:25-13:6 [hereinafter "Lockwood Direct"]. <sup>9</sup> *Id.* at 13:8-9.

1 2 3 4 5		APS, its new bill design is not finalized but will be implemented as part of the resolution of this pending rate case While APS's approach to include customer and stakeholder input is a positive step, the lack of any process for Commission review and input for this bill redesign should be remedied. <sup>10</sup>
6	Q.	What is the Alexander Report?
7	A.	This rate case was precipitated by a Commission order finding, among other
8		matters, that APS's Customer Outreach and Education Program ("COEP") was so
9		ineffective as to require Staff to select and hire an independent consultant, paid
10		for by APS, to develop a program to properly and adequately educate customers
11		on all aspects of APS's rate plans. <sup>11</sup> Barbara R. Alexander, the independent
12		consultant retained by Staff to review the APS COEP prepared a report describing
13		the numerous deficiencies she found. <sup>12</sup> This is the report that I reference as the
14		Alexander Report. In that report, she recommended that the Commission order
15		APS to create and propose a comprehensive COEP that, as a "key requirement,"
16		should include performance standards and reporting mechanisms that would allow
17		a meaningful and regular review of APS's progress. <sup>13</sup>
18 19	Q.	Did the Alexander Report include any recommendations regarding bill design?

20 A. Yes. The report recommended that:

<sup>&</sup>lt;sup>10</sup> Barbara R. Alexander, Barbara Alexander Consulting LLC, *An Evaluation of Arizona Public Service Company's Customer Education Plan and Its Implementation* 35 (May 19, 2020), *available at* https://docket.images.azcc.gov/E000006583.pdf [hereinafter "Alexander Report"].

<sup>&</sup>lt;sup>11</sup> Order No. 77270 at 8:12-15, Docket No. E-0134A-19-0003 (Ariz. Corp. Comm'n June 27, 2019), *available at* https://docket.images.azcc.gov/0000198805.pdf.

<sup>&</sup>lt;sup>12</sup> Alexander Report.

<sup>&</sup>lt;sup>13</sup> *Id.* at 36.

1 2 3 4		One aspect of the bill redesign that should be the focus of consumer and Commission attention is the presentation of demand charges, how they are calculated and what specific usage profile triggered the billed demand charge.
5	Q.	If the APS proposal is adopted, how would a customer's bill change?
6	А.	Referencing the sample bill provided on APS's website, it appears that the
7		simplified bill would no longer provide information regarding the customer
8		account charge, delivery service charge, demand charge, environmental benefits
9		surcharge, federal environmental improvement surcharge, system benefits
10		charges, power supply adjustment, metering charge, meter reading charge, billing
11		charge, demand charge on-peak, federal transmission and ancillary services,
12		federal transmission cost adjustment, Lost Fixed Cost Recovery (LFCR) adjustor,
13		and the Tax Expense Adjustor Mechanism. <sup>14</sup>
	0	

# 14 Q. Under APS's proposal, which customers would receive a simplified bill?

15	A.	All customers would receive a "simplified bill." APS suggests that customers
16		could, on their own initiative, opt out of a simplified bill to continue receiving
17		their current complete bill. <sup>15</sup> APS does not provide a description of the effort
18		required by a customer to continue receiving a customary bill.

<sup>&</sup>lt;sup>14</sup> See the sample bill information provided by APS: Ariz. Pub. Serv., *Example Bill – Saver Choice Plus*, https://www.aps.com/en/Residential/Billing-and-Payment/Understanding-Your-Bill/Sample-Bill (last visited July 30, 2020).

1	Q.	Does this proposal require any rule waivers?
2	A.	Yes. APS has requested that the Commission waive the requirements of A.A.C.
3		R14-2-210. <sup>16</sup>
4	Q.	When is it appropriate to waive a rule?
5	A.	From my experience as a Commissioner in Ohio, I find it appropriate to waive an
6		administrative rule during emergencies when the rule impeded an emergency
7		response. It can also be useful to authorize a limited waiver of a rule when the
8		rule impedes the successful operation of a pilot program.
9 10	Q.	Do the circumstances presented by APS suggest that a rule waiver is appropriate?
11	A.	No. APS seems to be requesting a permanent waiver of a rule adopted to protect
12		consumers. The rule, as adopted, ensures customers receive important information
13		about their utility bills. Because APS is also proposing to default every customer
14		into a simplified bill, it is effectively seeking a permanent rule waiver applicable
15		to every customer. A waiver of this broad and permanent nature is functionally a
16		rule amendment. As an administrative procedural matter, it is not appropriate to
17		amend a rule via a waiver. <sup>17</sup> From a substantive perspective, it is difficult to
18		justify providing customers with less information, particularly given the
19		deficiencies in APS's current Customer Outreach and Education Program efforts,
20		the recommendations of the Alexander Report commissioned to investigate those

 <sup>&</sup>lt;sup>16</sup> Lockwood Direct at 13:16-18.
 <sup>17</sup> Ariz. Rev. Stat. § 41-1030(A).

1		shortcomings, and the current inadequate access to energy data APS provides
2		(described below).
3	The I	mportance of Easy Access to Comprehensive Energy Data
4	Q.	What is customer "energy data"?
5	A.	A customer's energy data informs a customer how much energy they are using,
6		when, and at what price. It reflects their measured energy consumption and
7		related pricing information.
8	Q.	How is customer energy data generated?
9	A.	A customer's meter provides measured energy consumption. According to the
10		Energy Information Agency, an AMI metering system measures and records
11		electricity usage at a minimum of hourly intervals and provides that data to both
12		the utility and the customer at least once a day. AMI meters range from basic
13		hourly interval meters to real-time meters with built-in two-way communication
14		capable of recording and transmitting instantaneous data. <sup>18</sup>
15	Q.	Why would a customer access their energy data?
16	A.	Customers who understand when they use energy and how much it costs at that
17		time are able to: assess and choose the utility tariff most beneficial to them;
18		determine whether and which energy efficiency or demand-side management
19		measures would be cost-effective investments; determine whether battery storage

<sup>&</sup>lt;sup>18</sup> U.S. Energy Info. Admin., Frequently Asked Questions (FAQS): How many smart meters are installed in the United States, and who has them?, https://www.eia.gov/tools/faqs/faq.php?id=108&t=3 (last visited July 30, 2020).

- or a solar installation or other distributed energy resource would be worthwhile;
   and make decisions about when or how to charge an electric vehicle.
- 3 Q. How would a customer use their energy data to save energy?

4 Α. Simple timely feedback can help customers save energy. Research has 5 documented that customers with near real-time and behavioral feedback enjoy energy saving from 1 to 8 percent.<sup>19</sup> Customers save even more when energy data 6 7 is paired with customer engagement to guide them to energy efficiency programs 8 or measures most suited for their energy profile or to use energy when it is most 9 cost-effective for them. A dozen studies found customers saved from 6 percent to 10 18 percent of energy when they had access to meter data coupled with actionable feedback and smart controls.<sup>20</sup> 11

### 12 **Q.** With whom might a customer want to share their energy data?

13	А.	Energy data may provide little useful information to a customer on its own. The
14		value of the data will likely come from the activities of utilities, technology
15		companies, and service providers who process, analyze, and perhaps even act
16		upon the energy data on behalf of the customer. A customer may wish to share
17		their energy data with third-party providers of energy efficiency products and
18		services, other distributed energy resource providers, or energy consultants who

<sup>&</sup>lt;sup>19</sup> Attachment CR-2, Rachel Gold et al., Leveraging Advanced Metering Infrastructure to Save Energy 30 (ACEEE Revised Jan. 27, 2020), available at https://www.aceee.org/sites/default/files/pdfs/u2001.pdf [hereinafter "ACEEE Report"].

<sup>&</sup>lt;sup>20</sup> Michael Murray & Jim Hawley, More Than Smart & Mission:data Coalition, Got Data? The Value of Energy Data Access to Consumers 2 (Jan. 2016), available at https://static1.squarespace.com/static/52d5c817e4b062861277ea97/t/56b2ba9e356fb0b4c8559b7d/1454 553838241/Got+Data+-+value+of+energy+data+access+to+consumers.pdf.

I		can help them understand when and now to use energy cost-effectively. They may
2		also want to link their smart appliances and Home Area Network (HAN) devices
3		to energy data. <sup>21</sup>
4	Q.	Are there any privacy concerns related to sharing a customer's energy data?
5	A.	Yes, energy data is personal to a customer. Accordingly, customers should have
6		the opportunity to understand what information APS collects and the ability to
7		maintain control over the use of their data.
8	Q.	Is there an industry standard for energy data privacy?
8 9	<b>Q.</b> A.	Is there an industry standard for energy data privacy? Yes. The U.S. Department of Energy facilitated the development of a voluntary
8 9 10	<b>Q.</b> A.	Is there an industry standard for energy data privacy?Yes. The U.S. Department of Energy facilitated the development of a voluntarycode of conduct ("VCC") entitled Data Privacy and The Smart Grid: A Voluntary
8 9 10 11	<b>Q.</b> A.	Is there an industry standard for energy data privacy?Yes. The U.S. Department of Energy facilitated the development of a voluntarycode of conduct ("VCC") entitled Data Privacy and The Smart Grid: A VoluntaryCode of Conduct that describes how customer data should be treated to facilitate
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8 9 10 11 12 13	<b>Q.</b> A.	Is there an industry standard for energy data privacy? Yes. The U.S. Department of Energy facilitated the development of a voluntary code of conduct ("VCC") entitled <i>Data Privacy and The Smart Grid: A Voluntary</i> <i>Code of Conduct</i> that describes how customer data should be treated to facilitate access while maintaining privacy. <sup>22</sup> The VCC establishes principles for data privacy that describe requirements for: customer notice and awareness, customer
8 9 10 11 12 13 14	<b>Q.</b> A.	Is there an industry standard for energy data privacy? Yes. The U.S. Department of Energy facilitated the development of a voluntary code of conduct ("VCC") entitled <i>Data Privacy and The Smart Grid: A Voluntary</i> <i>Code of Conduct</i> that describes how customer data should be treated to facilitate access while maintaining privacy. <sup>22</sup> The VCC establishes principles for data privacy that describe requirements for: customer notice and awareness, customer choice and consent, customer data access, data integrity and security, and self-
8 9 10 11 12 13 14 15	<b>Q.</b> A.	Is there an industry standard for energy data privacy? Yes. The U.S. Department of Energy facilitated the development of a voluntary code of conduct ("VCC") entitled <i>Data Privacy and The Smart Grid: A Voluntary</i> <i>Code of Conduct</i> that describes how customer data should be treated to facilitate access while maintaining privacy. <sup>22</sup> The VCC establishes principles for data privacy that describe requirements for: customer notice and awareness, customer choice and consent, customer data access, data integrity and security, and self- enforcement management and redress.

<sup>&</sup>lt;sup>21</sup> See, e.g., Ivan O'Neill, Prices to Devices: Price Responsive Devices and the Smart Grid (Southern California Edison 2010), available at https://www.oasisopen.org/committees/download.php/40684/Prices%20to%20Devices%20White%20Paper%20-%20101229.pdf.

<sup>&</sup>lt;sup>22</sup> U.S. Dep't of Energy, Voluntary Code of Conduct Final Concept and Principles (Jan. 12, 2015), available at

https://www.energy.gov/sites/prod/files/2015/01/f19/VCC%20Concepts%20and%20Principles%202015 \_01\_08%20FINAL.pdf [hereinafter "Voluntary Code of Conduct"].

#### 1 Q. What frequency of energy data does a customer need to make decisions 2 about tariffs, energy efficiency, or other distributed energy products and 3 services?

4 The more frequent and granular the better. Customers benefit from hourly data Α. 5 but receive more value from data reported on a 15-minute basis—and even more value from one-minute interval data. For example, if customers or service 6 7 providers employ nonintrusive load monitoring (NILM), they can use meter data 8 to identify which appliances are consuming how much energy by comparing the 9 data with appliance signature databases. With one-minute meter data, NILM can identify as many as eight different appliance types.<sup>23</sup> This can help a customer 10 11 identify the most cost-effective appliance replacements for reducing or shifting their energy consumption. 12

13 Q.

### Does the format of the energy data matter?

14 A. Yes, it does. If the energy data is available in a format that can be read by a 15 computer, it is quicker to analyze. If the data is not machine-readable, it is 16 cumbersome to scrutinize. Energy data is only valuable when it can be translated 17 to useful or actionable information. If the energy data is in a standard format, it 18 can be swiftly transformed to information that can inform customer investment 19 and behavior.

#### 20 О. Is there an industry standard for energy data format?

21 A. Yes. The North American Energy Standards Board (NAESB) ratified the Energy 22 Service Provider (ESPI) Retail Energy Quadrant Book 21 (REQ.21) standard,

<sup>&</sup>lt;sup>23</sup> Attach. CR-2, ACEEE Report at 21.

1		commonly known at the Green Button standard, on April 8, 2019. <sup>24</sup> Compliance
2		with this standard requires the energy data to be in Extensible Markup Language
3		(XML). The data format portion of the standard is known as "Green Button
4		Download My Data."
5	Q.	What is the significance of XML formatted data?
6	А.	XML is an open standard which can be used by a number of applications. It can
7		also be used in a variety of databases and within different operating systems. Data
8		in Excel spreadsheets can only be used in Excel. The restricted application
9		options for Excel files impede the ability of customers or third parties to use the
10		data efficiently.
11	Q.	Is there an industry standard for sharing energy data?
12	А.	Yes. NAESB REQ.21 also includes a standard for protecting customer privacy
13		during the secure transmission of a customer's energy data to a third party. The
14		data transmission portion of the standard is known as "Green Button Connect My
15		Data." Green Button Connect My Data enables utilities to provide, at the direction
16		of the customer, energy usage data to third parties in a consistent format. This
17		allows customers to authorize the direct, secure transfer of their usage data to
18		third-party service providers that can assist the customer in viewing, analyzing,
19		and managing their energy consumption. Customers control the authorization
20		process, defining the length of that authorization, and can revoke it at any time.

<sup>&</sup>lt;sup>24</sup> Press Release, Green Button Alliance, NAESB Ratifies Standard for Green Button (Apr. 8, 2019), available at https://www.greenbuttonalliance.org/index.php?option=com\_dailyplanetblog&category=technical.

2		energy usage data while protecting any personally identifiable information.
3	Q.	How many utilities have implemented the Green Button standards?
4	A.	To date, 35 U.S. utilities have committed to implementing the Green Button
5		standards. An additional 38 U.S. companies providing third-party services have
6		committed to Green Button standards. The totality of these commitments covers
7		60 million homes and businesses. <sup>25</sup>
8 9	Q.	What happens if a customer's energy data does not comply with Green Button Connect My Data standards?
10	A.	If a customer's energy data does not comply with NAESB REQ.21 (Green Button
11		Connect My Data), then analysis is time-intensive and the transfer to a third party
12		may not be secure or may disclose private or personal information. Customers
13		may be reluctant to share energy usage data if personal information might be
14		revealed. This adds friction to the interaction between the customer and the
15		potential third-party energy services provider, delaying or derailing the
16		interaction. Without access to the guidance and interpretation of data offered by
17		third parties, customers may not be able to derive actionable information from
18		their energy data.

Green Button Connect My Data enables customers the ability to share their

<sup>&</sup>lt;sup>25</sup> U.S. Dep't of Energy, Green Button: Open Energy Data, https://www.energy.gov/data/greenbutton#:~:text=What%20has%20been%20the%20success,signed%20on%20to%20the%20initiative (last visited July 30, 2020).

### APS Customer Access to Energy Data Is Inadequate 1

2	Q.	Has APS installed AMI meters for its customers?
3	A.	Yes. APS has installed 1,125,293 residential AMI billing meters. <sup>26</sup>
4	Q.	What type of customer energy data can the APS AMI meters generate?
5	A.	Each of the 1,125,293 residential AMI billing meters records usage in 60-minute
6		intervals. <sup>27</sup> APS currently has 290,618 residential meters that it could also
7		configure to supply one-minute, five-minute, or 15-minute interval data. <sup>28</sup>
8 9 10	Q.	If the APS residential AMI meters could generate customer energy data in intervals of one, five, or 15 minutes, why don't customers receive this energy data from APS?
11	A.	APS has not installed the communications infrastructure necessary to transmit the
12		data in more frequent intervals to APS. <sup>29</sup>
13 14	Q.	Why hasn't APS installed the communications infrastructure necessary to provide customers access to more frequent and granular data?
15	A.	When asked that question, APS responded that it "has not determined that the
16		value of receiving the data in smaller time increments would offset the costs to
17		implement." <sup>30</sup> However, APS also acknowledged that it has not actually evaluated
18		the costs and benefits of installing the communications equipment. <sup>31</sup> Nor has APS

<sup>&</sup>lt;sup>26</sup> APS Response to SC DR 4.1(b). All public discovery responses referenced in this testimony are <sup>25</sup> APS Response to SC DR 4.1(b). All public discovery responses references compiled and available within Attachment CR-3 ["Attach. CR-3"].
<sup>27</sup> Attach. CR-3, APS Responses to SC DR 4.3(d) and 4.4(d).
<sup>28</sup> *Id.* at APS Response to SC DR 4.4(a).
<sup>29</sup> *Id.* at APS Response to SC DR 4.3(a), (b) and 4.4(a).
<sup>30</sup> *Id.* at APS Response to SC DR 5.1(a)(ii), (b)(ii).
<sup>31</sup> *Id.* at APS Response to SC DR 5.1(b).

1		considered any alternative to its identified, but unevaluated, solution for
2		transmitting the data. <sup>32</sup>
3 4	Q.	Does APS provide customers with their energy data in a format that complies with the Green Button Connect My Data standard (NAESB REQ.21)?
5	A.	No. <sup>33</sup> The APS website does not provide customer data in an XML format. Nor
6		does APS offer any means for a customer to obtain their energy data in XML
7		format. <sup>34</sup>
8	Q.	How does APS provide customers with their energy data?
9	A.	APS provides customer energy data in an Excel file. <sup>35</sup> Because APS only offers
10		energy data in Excel spreadsheet form, the data cannot be used outside of an
11		Excel spreadsheet without manual conversion.
12 13	Q.	How successful are residential customers in accessing their energy data using the APS website?
14	A.	Fewer than 5 percent of APS residential customers access their monthly energy
15		data. <sup>36</sup>
16 17 18	Q.	Does APS provide customers with the ability to share their energy data in a format that complies with the Green Button Connect My Data standard (NAESB REQ.21)?
19	A.	No. <sup>37</sup>

<sup>&</sup>lt;sup>32</sup> *Id.* at APS Response to SC DR 5.1(c).
<sup>33</sup> *Id.* at APS Response to SC DR 4.7.
<sup>34</sup> *Id.* at APS Response to SC DR 4.6(b).
<sup>35</sup> *Id.* at APS Response to SC DR 4.6(a).
<sup>36</sup> *Id.* at APS Response to SC DR 4.2(a), (c).

1	Q.	How can APS customers share their energy data with a third-party provider
2		of energy products and services?

A. A customer may register on aps.com to create and download three reports: current
usage, last billed usage, and peak usage data. They can then send these reports to
anyone they wish. The customer may also grant guest access to their account on
aps.com for up to five guests.

## 7 Q. What energy data can a guest view?

8 A. Guests can view customer account information, usage graphs, charges, and bills.
9 This includes sensitive customer-saved bank account information and utility

10 account balances.<sup>38</sup>

# 11 Q. How does APS protect a customer's privacy from a guest user of their 12 account?

- 13 A. APS does not protect a customer's private account information from a guest user.
- 14 APS does not provide customers any means to share energy usage data with a
- 15 guest without sharing personal account information as well, including saved bank
- 16 account information or their utility account balance.<sup>39</sup>

# 17 Q. Does an APS guest user account comply with U.S. Department of Energy's 18 Data Privacy and The Smart Grid: A Voluntary Code of Conduct?

# 19 A. No. The VCC establishes that a customer should have a degree of control over

20 their customer data which includes both customer energy usage data and account

<sup>&</sup>lt;sup>37</sup> *Id.* at APS Response to SC DR 4.7.

 $<sup>^{38}</sup>$  Id. at APS Response to SC DR 5.4(a), (b).

<sup>&</sup>lt;sup>39</sup> *Id.* at APS Response to SC DR 5.4(a), (b).

1	data. Customer energy usage data is a customer's measured energy usage but does
2	not identify the customer, while a customer's account data includes information
3	personal to a specific customer such as their name, address, dates of service,
4	phone, email, bank account numbers, and meter numbers. The VCC requires that
5	a customer be allowed to authorize different types of disclosure among multiple
6	third parties and to limit disclosure to just that data to only that authorized third
7	party. As discussed above, APS does not provide any means for a customer to
8	limit a guest user to energy usage data only.

9 Q. How many APS customers have successfully shared their energy data?

10 A. That information is unknown because APS does not track it.<sup>40</sup> However, given 11 that only about 5 percent of APS residential customers access their energy data 12 via the APS portal on a monthly basis and that guest users would be included 13 within this number, we know that very few APS customers have successfully 14 shared their energy data via the portal.

# Q. How does APS noncompliance with the NAESB REQ.21 Standard (Green Button Connect My Data standard) impact customers?

APS's failure to create a seamless method for customers to authorize the secure
and private transfer of their energy data to potential service providers inhibits a
customer's ability to adopt distributed energy resources or secure other energy
saving products and services. As I described above, if a customer's energy data
does not comply with NAESB REQ.21, then analysis is time-intensive and the

<sup>&</sup>lt;sup>40</sup> *Id.* at APS Response to SC DR 4.9.

1	transfer to a third party may not be secure or private. APS customers do not have
2	an easy mechanism to transfer their energy usage data, and just that data, to a
3	third party in a secure fashion. This may make them reluctant to share data. This
4	adds friction to the interaction between the customer and the potential third-party
5	energy services provider, delaying or derailing the interaction. Without access to
6	the guidance and interpretation of data offered by third parties, customers may not
7	be able to derive actionable information from their energy data.

8 Q. Does APS support customers in identifying individualized products or
 9 services that would benefit that customer, using the customer's personal
 10 energy data?

APS did develop a rate analysis tool to guide customers to the tariff option that
was best for their energy use profile as part of the 2017 rate case. The tool,
however, was materially flawed, resulting in a public apology by APS and a
pledge to issue refunds funded by shareholders to affected customers.<sup>41</sup> APS does
not currently appear to provide any other customer-specific support regarding use
of personal energy data.

17 Recommendations Regarding APS Proposal for Default Bill Simplification and
 18 Customer Data Access

19Q.Do you have a recommendation about the APS proposal for default bill20simplification?

- A. Yes. The Commission should reject the APS proposal for default bill
- 22 simplification. APS has not presented sufficient evidence to support what would

<sup>&</sup>lt;sup>41</sup> Alexander Report at 7.

1		function as a permanent waiver of the consumer information protections of
2		A.C.C. R14-2-210. When or if customers have access to their energy data in a
3		form compliant with NAESB REQ.21, it may be appropriate to consider a rule
4		amendment.
5 6	Q.	Does APS's incident with its rate comparison tool evoke any additional insights?
7	A.	Yes. It is critical that customers receive the energy data in a form that is useful to
8		them so that they can make informed decisions. As I discussed previously, the
9		value of the data will likely come from the activities of utilities, technology
10		companies, and service providers who process, analyze, and perhaps even act
11		upon the energy data on behalf of the customer. It is APS's responsibility to help
12		customers understand and act upon their energy data, and they should be held to
13		account if they do not perform those responsibilities well, but customers should
14		also be able to seek guidance outside of the utility from whomever they choose.
15	Q.	Do you have any recommendations for Commission action that could help to
16		ensure customers receive the energy data they need to make informed
17		decisions or to engage the assistance of third-party service providers who will
18		guide them or act on their behalf?
19	A.	Yes. APS customers have paid for the AMI infrastructure. They should receive
20		value for it. I recommend that the Commission direct APS to implement NAESB
21		REQ.21, Green Button Connect My Data, as soon as practicable.

1 2	Q.	Do you have any recommendations for Commission action regarding the protection of customer privacy?
3	А.	Yes. I recommend that the Commission direct APS to comply with the U.S.
4		Department of Energy's Data Privacy and the Smart Grid: A Voluntary Code of
5		Conduct. <sup>42</sup>
6 7	Q.	Do you have any recommendations about the energy data available from AMI meters?
8	А.	Yes. As I previously explained, the more frequent and granular the data, the more
9		valuable it is. I recommend that the Commission direct APS to investigate and
10		report on whether the investment required to provide more granular data in the
11		form of one-, five-, or 15-minute intervals to customers would be cost-effective.
12	Q.	Do you have any other recommendations?
13	A.	Yes. I also recommend that the Commission direct APS to track and report
14		quarterly metrics that will inform the Commission, APS, and customers on APS's
15		progress toward leveraging the benefits of AMI for its customers. These metrics
16		should include the three metrics identified by ACEEE for AMI deployment: <sup>43</sup>
17		• Customer usage of energy portal; one-time or regular access
18		• Number and percentage of customers opting out of or taking a price offering
19		• Number of third parties that successfully access customer data through Green
20		Button Connect or other utility data-sharing method: percentage of customers
21		able to authorize third-party service company requests on first attempt (target:

<sup>&</sup>lt;sup>42</sup> Voluntary Code of Conduct.
<sup>43</sup> Attach. CR-2, ACEEE Report at 28, Table 4.

1		95 percent); percentage of time third-party service provider receives access
2		when authorized by customers (target: 95 percent)
3	Q.	Are there any other metrics that APS should track?
4	A.	Yes. I also recommend that the Commission require APS to track and report
5		metrics recommended in the Alexander Report:
6		• Customer-initiated changes to their rate plans
7		• APS-initiated changes to customer rate plans
8		• Number of customers not on the "best" or "most economical rate" by rate class
9		• Frequency and type of complaints
10		• Call Center performance <sup>44</sup>
11		• Results of customer research on messaging and bill presentment
12		• Enrollment for limited-income programs
13		• Achievement of participation objectives for demand-side management
14		programs
15		• Analysis of the impact of rate design on system benefits, such as peak load
16		reduction and lower generation supply costs
17		• Key indicia of credit and collection activities, such as disconnection notices,
18		disconnections, and payment arrangements. <sup>45</sup>

<sup>&</sup>lt;sup>44</sup> APS witness Leland Snook suggested that an appropriate Call Center performance metric could be an internal customer satisfaction metric, which is conducted among both residential and business customers who have recently interacted with APS in the Call Center, on the IVR or on aps.com. See Direct Testimony of Leland R. Snook at 23:24-27 [hereinafter "Snook Direct"]. <sup>45</sup> Alexander Report at 36-37.

#### 1 **IV.** APS'S FORMULA RATE CONCEPT ALTERNATIVE

2	Q.	What is APS's Formula Rate Concept Alternative?
3	A.	APS offers, but does not propose, a Formula Rate Concept Alternative. <sup>46</sup> Mr.
4		Snook testified that:
5 6 7 8 9		A formula rate provides incremental annual adjustments to rates, based on agreed upon, Commission-approved inputs to a formula that are established during a rate case. With the agreed upon structure in place, inputs are updated and reviewed annually and rates are adjusted accordingly. <sup>47</sup>
10 11	Q.	How would the rates be adjusted on an annual basis under the APS Formula Rate Concept Alternative?
12	A.	APS proposes to forecast its expenses and then true them up to actual expenses
13		each year. That is, APS will project what it expects to spend, but if it spends
14		more, the rate would be adjusted to cover the extra expense. If it spends less, then
15		the money is returned to customers after the reconciliation. However, the
16		forecasted budget only operates as a targeted spending level because there is no
17		incentive to spend less and no penalty for spending more.
18 19	Q.	What purpose does APS give for offering this Formula Rate Concept Alternative?

- 20 Mr. Snook has testified that "there has been discussion in a number of regulatory А.
- 21 proceedings about the pros and cons of adjustor mechanisms. With a formula rate

<sup>&</sup>lt;sup>46</sup> Snook Direct at 24:3-10. <sup>47</sup> *Id.* at 22:20-23.

1		option, APS is offering an alternative that could also provide similar benefits to
2		all parties involved while also simplifying future ratemaking process."48
3 4	Q.	Why does APS offer the Formula Rate Concept Alternative, if it is not proposing to adopt it?
5	A.	Mr. Snook has testified that APS is satisfied with the existing adjustors, which
6		serve to track actual expenses in seven different categories. 49
7 8	Q.	What benefits does APS suggest would result from the Formula Rate Concept Alternative as APS has framed it?
9	А.	Mr. Snook suggests that the Formula Rate Concept Alternative would provide an
10		opportunity for the Commission to scrutinize APS's earnings annually and
11		provide an immediate avenue for the Commission to incrementally adjust rates. It
12		would eliminate five of APS's seven adjustor mechanisms, improve rate
13		gradualism, and decrease regulatory lag. He suggests that it could potentially
14		increase time between rate cases. <sup>50</sup>
15 16	Q.	What design elements has APS included within its Formula Rate Concept Alternative?
17	А.	APS proposes that its Formula Rate Concept Alternative would include a
18		commitment to refrain from filing a rate case for three to seven years. The scope
19		of the formula would include all costs except fuel (Power Supply Adjustment
20		charge or "PSA") and FERC jurisdictional costs (Transmission Cost Adjustment
21		charge or "TCA"). It would retain the same authorized return on equity ("ROE")

<sup>&</sup>lt;sup>48</sup> *Id.* at 24:6-10.
<sup>49</sup> *Id.* at 24:4-10.
<sup>50</sup> Snook Direct at 22-23:26-9, Attachment LRS-4DR.

1		and capital structure throughout its term, but the cost of debt would be updated
2		annually. The revenue resulting from the formula rate would be adjusted based
3		upon forecasted plant and depreciation with a true up to actual plant and
4		depreciation. APS does not propose a "Dead Band" <sup>51</sup> around its ROE. It would
5		commit to an annual limit on increases of 2.5 percent. <sup>52</sup>
6 7	Q.	Does APS propose any performance mechanisms within its Formula Rate Concept Alternative?
8	А.	APS does not propose any performance mechanisms with financial consequences.
9		It does propose two performance metrics: Reliability as measured by the System
10		Average Interruption Frequency Index ("SAIFI"); and Customer Satisfaction as
11		measured by an internally tracked metric related to Call Center service. <sup>53</sup>
12	The	Value of Alternative Regulatory Mechanisms
13 14 15 16	Q.	Mr. Snook has indicated that APS sees some interest in Arizona for an alternative to existing adjustor mechanisms and value in simplifying future ratemaking processes. Do you see value in considering alternative regulatory mechanisms?
17	A.	Yes. Many jurisdictions are considering alternatives to traditional cost-of-service

- regulation. This interest is driven by a combination of the changing electric 18
- 19 industry landscape and public policy.

<sup>&</sup>lt;sup>51</sup> APS does not define a "dead band" but it is typically understood to include a range of value above and below the ROE which would not trigger any action.
<sup>52</sup> Attachment LRS-4DR (provided with Snook Direct).
<sup>53</sup> Snook Direct at 23:12-27.

1	Q.	What is the nature of the changes within the electric utility industry?
2	A.	The nation's electricity system is, by necessity, transforming rapidly. As a result
3		of interacting economic, technology, and policy factors, U.S. energy-related
4		carbon dioxide emissions have fallen over the past decade. <sup>54</sup> From the perspective
5		of centralized electricity generation, a massive and dynamic reduction in the price
6		of natural gas as well as falling prices in wind and solar generation have
7		supplanted coal-fired generation and even nuclear generation.55 Additionally,
8		roughly half of all growth in U.S. renewable electricity generation and capacity
9		since 2000 is associated with state renewable portfolio standards. <sup>56</sup> In
10		short, market- and policy-driven changes in fuel choices for centralized electricity
11		generation have markedly shifted the energy landscape.
12	Q.	Are there any other changes underway in the electricity industry?

A. Yes. The change in fuel for large- or utility-scale electricity generation units is not the only part of the transformation. The centralized, utility-scale generation that provided the last century of energy is no longer the only practical option. The costs of distributed generation technologies such as solar photovoltaics and battery storage are falling, resulting in increasing number of customers investing in their own grid-connected resources.<sup>57</sup> Communications and computer analytical

 <sup>&</sup>lt;sup>54</sup> Perry Lindstrom, *EIA expects U.S. energy-related CO<sub>2</sub> emissions to decrease annually through 2021*, U.S. Energy Info. Admin. (Jan. 17, 2020), https://www.eia.gov/todayinenergy/detail.php?id=42515.

<sup>&</sup>lt;sup>55</sup> U.S. Energy Info. Admin., U.S. Dep't of Energy, Annual Energy Outlook 2019 (Jan. 24, 2019), available at https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

<sup>&</sup>lt;sup>56</sup> Galen L. Barbose, U.S. Renewables Portfolio Standards: 2018 Annual Status Report (Lawrence Berkeley National Laboratory Nov. 2018), available at https://emp.lbl.gov/publications/us-renewablesportfolio-standards-1.

<sup>&</sup>lt;sup>57</sup> Solar Industry Research Data, Solar Energy Industries Association, https://www.seia.org/solar-industry-research-data (last visited Sept. 16, 2020).
1		capabilities make it possible for high penetrations of renewable resources to be
2		integrated into the grid. <sup>58</sup> Energy productivity is also rising. Between 1990 and
3		2015, the United States has grown its gross domestic product while using less
4		energy year over year, becoming more energy efficient. <sup>59</sup> The electricity system is
5		transforming from a one-way power delivery network in which customers
6		passively receive electricity to a two-way flow of both power and information in
7		which customers both receive and produce electricity. The two-way
8		system is brought to life by customers who receive information about their usage
9		(when and how much they use) and price signals indicating moment-by-moment
10		the value of electricity and incentivizing customer usage behavior.
11 12	Q.	Are these changes in the electricity utility industry occurring within Arizona?
13	А.	Yes. In fact, the Commission has a docket considering possible modifications to
14		the Commission's energy rules to explore subjects integral to this energy
15		transition. <sup>60</sup> These include: the renewable energy standard, electric energy
16		efficiency standards, net metering, resource planning and procurement, retail
17		electric competition, electric vehicles, interconnection of distributed generation
18		facilities, blockchain technology, technological developments in generation and

<sup>&</sup>lt;sup>58</sup> Yang Zhang, Tao Huang & Ettore Francesco Bompard, *Big data analytics in smart grids: a review*, 1 Energy Informatics (2018), *available at* https://energyinformatics.springeropen.com/articles/10.1186/s42162-018-0007-5.

 <sup>&</sup>lt;sup>59</sup> GDP per unit of energy use (constant 2017 PPP \$ per kg of oil equivalent) - United States, World Bank, https://data.worldbank.org/indicator/EG.GDP.PUSE.KO.PP.KD?

end=2015&locations=US&start=1990&view=chart (last visited Sept. 16, 2020).

<sup>&</sup>lt;sup>60</sup> Memorandum: Request for a New Docket, Docket No. RU-00000A-18-0284 (Ariz. Corp. Comm'n Aug. 17, 2018), *available at* https://docket.images.azcc.gov/0000191382.pdf.

delivery of energy, forest bioenergy, and baseload security.<sup>61</sup> As part of that
 docket, the Commission has issued an Electric Vehicle Policy Implementation
 Plan.<sup>62</sup>

## 4 Q. Are there public policy reasons in Arizona to consider alternative regulatory 5 mechanisms?

6 Α. Yes. There is an emerging consensus for decarbonization of Arizona electric 7 utilities for both climate and cost-effectiveness reasons. It appears that it is the position of the majority of the Commission that Arizona electric utilities should 8 9 achieve 100 percent clean energy by 2050 and 35 percent energy efficiency by 10 2030.<sup>63</sup> Commissioner Sandra D. Kennedy has stated, "the science is clear regarding the need for aggressive decarbonization."<sup>64</sup> Commissioner Kennedy 11 also cites data supporting that Arizona would enjoy economic and reliability 12 13 benefits from a decarbonization policy.<sup>65</sup> Commissioner Justin Olson has stated 14 that "because renewable energy in many cases is now the most cost-effective 15 method of generating electricity, requiring utilities to invest in the most costeffective methods would lead to significant increases in renewable energy 16

<sup>&</sup>lt;sup>61</sup> *Id*.

<sup>&</sup>lt;sup>62</sup> Electric Vehicle Policy Implementation Plan, Docket No. RU-00000A-18-0284 (Ariz. Corp. Comm'n July 19, 2019), *available at* https://docket.images.azcc.gov/0000199128.pdf.

<sup>&</sup>lt;sup>63</sup> Mar. 25, 2020 Letter from Chairman Burns; *see also* Letter from Commissioner Peterson, Docket No. RU-00000A-18-0284 (Ariz. Corp. Comm'n Mar. 20, 2020), *available at* 

https://docket.images.azcc.gov/E000005457.pdf (regarding 100% clean energy by 2050). <sup>64</sup> Letter from Commissioner Kennedy at 1, Docket No. RU-00000A-18-0284 (Ariz. Corp. Comm'n Mar.

<sup>25, 2020),</sup> *available at* https://docket.images.azcc.gov/E000005582.pdf.

<sup>&</sup>lt;sup>65</sup> *Id* at 2.

deployment."66 Chairman Burns has indicated that the Energy Rules should also 1 2 incorporate more robust renewable and distributed energy standards.<sup>67</sup>

#### 3 Q. Are there any factors specific to APS that may indicate alternative 4 regulatory mechanisms are worth considering?

5 A. Yes. As I mentioned previously, this rate case was precipitated by a Commission 6 order finding, among other matters, that APS Customer Outreach and Education 7 Program ("COEP") was so ineffective as to require "Staff to select and hire an 8 independent consultant, paid for by APS, to develop a program to properly and adequately educate customers on all aspects of APS's rate plans."68 9

### 10 **Q**. Would alternative regulation improve utility regulation in Arizona relative to 11 the status quo?

- It might. Alternative regulation could ensure that electric utilities navigate the 12 Α. 13 changes underway in the electricity industry while continuing to provide cost-14 effective, universal service. To achieve this, utilities must successfully harness 15 and optimize all available technologies, some of which they will own but others 16 will be owned by their customers or third parties. Continuing to reward utilities 17 for investing in assets that they own would maintain the utilities' existing 18 financial disincentive to support clean, distributed energy technologies, which are
- 19
  - often not part of a utility's rate base. Alternative forms of regulation could help a

<sup>&</sup>lt;sup>66</sup> Letter from Commissioner Olson at 1, Docket No. RU-00000A-18-0284 (Ariz. Corp. Comm'n Mar. 23, 2020), available at https://docket.images.azcc.gov/E000005533.pdf.

<sup>&</sup>lt;sup>67</sup> Mar. 25, 2020 Letter from Chairman Burns.

<sup>&</sup>lt;sup>68</sup> Order No. 77270 at 8:12-15, Docket No. E-0134A-19-0003 (Ariz. Corp. Comm'n June 27, 2019), available at https://docket.images.azcc.gov/0000198805.pdf.

1		utility thrive during the transition underway, contain costs, achieve public policy
2		goals such as decarbonization, and improve utility performance.
3	Forn	nula Rate Concept Is Not the Right Choice for Arizona
4 5	Q.	Would the Formula Rate Concept Alternative offered by APS improve regulation in Arizona relative to the status quo?
6	A.	No. The Formula Rate Concept Alternative does nothing to address ongoing
7		changes within the electricity industry. It would not provide additional tools to
8		address public policy goals around decarbonization and makes no meaningful
9		contribution to APS performance. Most significantly, it would reduce cost-
10		containment features that exist under current cost-of-service regulation in
11		Arizona.
12 13	Q.	How would the Formula Rate Concept Alternative offered by APS reduce the cost-containment features of existing Arizona utility regulation?
14	A.	As Mr. Snook acknowledges, Commissions have rarely adopted formula rates
15		outside of FERC. <sup>69</sup> This is largely due to recognition by Commissions that
16		formula rates have a "tendency to shift financial risks toward customers, a
17		concern that automatic adjustments may curtail the thorough review of utility
18		costs, and reduced incentives for utilities to control costs."70 These concerns have
19		been borne out by experience in jurisdictions where formula rate plans ("FRPs")
20		have been implemented. For example, in 2015, Act 725 in Arkansas required that

21 the Commission approve FRPs and capped revenue increases under an FRP to 4

 <sup>&</sup>lt;sup>69</sup> Snook Direct at 24:3-4.
 <sup>70</sup> Order No. 89226 at 53, Case No. 9618 (Md. Pub. Serv. Comm'n Aug. 9, 2019).

1		percent per year. Following passage of the Act, Entergy Arkansas, Inc. filed for
2		an FRP. After implementation of FRPs in Arkansas, the General Staff of the
3		Arkansas Public Service Commission observed that:
4 5 6 7		An FRP is an annual rider. It fundamentally accomplishes a higher level of certainty of recovery thus reducing risk to the utility The ability to increase revenues 4% each year is a considerable risk reduction for the utility. <sup>71</sup>
8 9 10	Q.	Does the experience in Arkansas or elsewhere provide an opportunity for lessons learned concerning the likelihood that a formula rate plan will operate to contain costs?
11	А.	Yes. Turning to the Arkansas experience, the FRP implementation there
12		eviscerated the Commission's ability to control costs. Customers experienced
13		maximum increases each year of the plan. The Arkansas Staff's report explained
14		how that FRP operated to the detriment of customers:
15 16 17		• It reduces the time afforded for review of utility costs, which can serve to incentivize spending as compared to a regulatory framework where more time is afforded to scrutinize costs.
18		• It allows projections on projections, which incentivizes spending as compared
19		to a regulatory framework where projections are based on historical
20		information modified by known and measurable changes. The effect of this is
21		compounded by the reduced opportunity to review expenditures.
22		• It incentivizes spending due to the annual rate adjustments. Once the FRP
23		framework is selected by a utility, an outcome of a 4 percent increase each year
24		(over the prior year) is less subject to challenge as long as the costs are
25		prudently incurred and calculated in accordance with the tariff. The traditional

<sup>&</sup>lt;sup>71</sup> General Staff's Initial Brief Pursuant to Order No. 18 at 17, Docket No. 16-036-FR (Ark. Pub. Serv. Comm'n Jan. 1, 2019), *available at* http://www.apscservices.info/pdf/16/16-036-FR\_382\_1.pdf.

1		regulatory tools in the Arkansas Commission are more limited under the FRP
2		framework, as the Commission has recognized.
3 4		• The unstated implication of the FRP statute is that the risk of an earnings review is effectively eliminated. There is no clear incentive to contain costs
5		between annual FRP 4 percent increases. While the FRP framework states the
6		rate change may be an increase or a decrease, the likelihood of a decrease is
7		highly unlikely. <sup>72</sup>
8	Q.	Why have you stated that the APS Formula Rate Concept Alternative does
9		not address the changes in the electric industry?
10	A.	One of the major challenges for traditional cost-of-service utility regulation
11		during the changes underway in the electric industry is that it encourages utility
12		behavior that we needed for the past century, not the utility behavior we need for
13		the coming decades. What I mean by this is that for the first century of utility
14		regulation, demand was growing. Our country required more generation plants
15		and transmission and distribution lines as quickly as they could be built. Utility
16		regulation was designed to reward utilities for investing in that growth. Utilities

17 were (and are largely still) paid for investing, not for the results they deliver.

- Going forward, for cost-effective universal service to remain a reality, utilities must harness all of the technologies that are available, some of which they will own but others will be owned by their customers or third parties. Continuing to reward utilities for investing in assets that they own would maintain the utilities' existing financial disincentive to support clean, distributed energy technologies.
- 23 This is colloquially known as the utility's "capital bias." That is, the utility has a

<sup>&</sup>lt;sup>72</sup> *Id.* at 18-19.

1		financial incentive to invest, regardless of whether a utility investment is the
2		optimum solution for cost-effective universal service. Nothing in APS's Formula
3		Rate Concept Alternative addresses this challenge.
4 5	Q.	Please explain why the APS Formula Rate Concept Alternative would not advance Arizona's public policy better than the status quo.
6	A.	For Arizona to be successful in decarbonizing its electricity grid, it will need to
7		tap all available clean energy solutions. Once again, some of those resources will
8		be owned or controlled by their customers or third parties. The APS Formula Rate
9		Concept Alternative exacerbates the utility incentive to invest in its own
10		traditional assets by codifying into a formula the same flawed incentive
11		structure—where the revenue requirement would be based on the utility's rate
12		base and authorized equity return on that rate base-the "capital bias." In fact, the
13		APS Formula Rate Concept strengthens the problematic connection with the
14		reward for investment by assuring the utility it will always receive its authorized
15		return on equity and by weakening prudency review.
16 17	Q.	Why did you suggest that the APS Formula Rate Concept Alternative would not improve APS performance?
18	A.	APS proposes to add only two metrics, with no financial consequence, to its
19		Formula Rate Concept Alternative. To the extent that the addition of these metrics
20		would improve APS performance, they could be added with or without the
21		adoption of APS Formula Rate Concept Alternative.

1 2	Q.	Do you have a recommendation regarding the APS Formula Rate Concept Alternative?
3	А.	Yes. The Commission should reject consideration of the APS Formula Rate
4		Concept Alternative. It does not improve upon the status quo. The Formula Rate
5		Concept Alternative does nothing to address changes within the electricity
6		industry. It would not provide additional tools to address public policy goals
7		related to decarbonization and makes no meaningful contribution to performance.
8		Most significantly, it would reduce cost-containment features that exist under
9		current cost-of-service regulation in Arizona.
10 11	Q.	Would some modification of the APS Formula Rate Concept Alternative be worth considering?
12	А.	No. I recommend that the Commission not pursue any Formula Rate structure.
13		They have not advanced the decarbonization of the energy grid and have largely
14		caused customers to experience unnecessary rate increases. I do not see any
15		formula rate construct being an improvement on status quo regulation in Arizona.
16	Com	prehensive Performance-Based Regulation Would Improve the Status Quo
17	Q.	You have indicated that Arizona could benefit from considering alternative
18		regulatory mechanisms, but you have rejected consideration of formula rate
19 20		plans. What alternative regulatory mechanisms would you recommend that Arizona consider?
21	А.	I recommend that the Commission consider adopting performance-based
22		regulation. Performance-based regulation includes several elements intended to

strengthen utility performance incentives that can be used alone or together.<sup>73</sup>
 These include multi-year rate plans ("MRPs") and performance incentive
 mechanisms ("PIMs"). MRPs in combination with well-crafted metrics,
 scorecards, and financial incentive mechanisms can be powerful drivers toward
 cost-effective, decarbonized energy systems.

6 Q. What are the key features of a Multi-Year Rate Plan?

7 Α. MRPs are widely used around the world and have been in place for many decades 8 in a variety of industries. MRPs are also known as "price cap regulation" or 9 "revenue cap regulation." These approaches have also been referred to as "hands-10 off regulation" because the utility's costs are not closely examined during the duration of the plan.<sup>74</sup> MRPs cap utilities' allowed revenue and allow utilities to 11 12 keep a portion of cost savings during the rate plan period. In doing so, they help to 13 shift utility financial incentives away from the bias toward capital investment and increasing rate base.<sup>75</sup> Instead, the utility's revenues are de-linked from its actual 14 15 costs in combination with a rate case moratorium (typically lasting from three to 16 five years). Revenues can be adjusted annually for changing business conditions 17 such as inflation or customer growth during the life of the plan based. These 18 changes can be based on an index or a cost forecast at the outset of the rate plan.

<sup>&</sup>lt;sup>73</sup> Mark Newton Lowry & Tim Woolf, *Performance-Based Regulation in a High Distributed Energy Resources Future* 1 (Lisa Schwartz eds. Lawrence Berkeley National Laboratory Jan. 2016), *available at* https://emp.lbl.gov/sites/all/files/lbnl-1004130\_0.pdf [hereinafter "Performance Based Regulation Report"].

<sup>&</sup>lt;sup>74</sup> See generally Attachment CR-4, Melissa Whited & Cheryl Roberto, Multi-Year Rate Plans: Core Elements and Case Studies (prepared for Maryland PC51 and Case 9618 Sept. 30, 2019), available at https://www.synapse-energy.com/sites/default/files/Synapse-Whitepaper-on-MRPs-and-FRPs.pdf.

<sup>&</sup>lt;sup>75</sup> Performance Based Regulation Report at 41.

### Q. What are the benefits of a Multi-Year Rate Plan?

2 Α. MRPs can reduce the frequency of rate cases, improve the culture of utility 3 management, improve utility performance, reduce the capital bias, and lower 4 utility costs. One of the most important benefits is that an MRP requires and 5 facilitates planning over a multi-year horizon on a fully integrated basis. Unlike a 6 mechanism that reconciles actual costs, this type of planning and cost recovery 7 provides better signals to the utility to operate efficiently. Instead of the utility 8 passing expenses directly to customers, as is done under the current rate setting 9 model, the utility will experience the budget as its own money at risk. That is, if 10 the utility achieves the objectives under budget, the utility is rewarded by the 11 ability to retain the savings. Additionally, revenues escalate between rate cases 12 independently of the size of rate base or the return on equity, thereby softening 13 the utility's natural bias to make capital investments to increase rate base.

### 14 Q. How does it differ from a Formula Rate Plan?

15 Α. Both MRPs and FRPs feature formulas, thereby creating some confusion 16 regarding the differences between the two approaches. The primary distinction is 17 that FRPs formulaically ensure that revenues track costs, often measured as 18 deviations in the return on equity from the utility's authorized return on equity. If 19 a utility's earned return is above its authorized return on equity, it will be required 20 to reduce its rates. Likewise, if a utility's earned return is below its authorized 21 return on equity, the Commission will permit the utility to increase its rates. In 22 contrast, MRPs do not reconcile revenues to actual costs. Rather, the utility must

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1		operate within its authorized revenue amounts and is rewarded for finding the
2		most cost-effective solutions for serving customers.
3	Robu	st Performance Incentive Mechanisms Are Valuable Additions
4 5 6	Q.	You mentioned that performance incentive mechanisms should be part of a comprehensive performance-based regulation approach. Why is it important to include performance mechanisms in a Multi-Year Rate Plan?
7	А.	Under an MRP framework, utilities retain some or all of the savings achieved
8		through cost reductions. This can create an incentive to cut costs at the expense of
9		service quality. To combat this incentive, regulators have historically coupled
10		MRPs with PIMs to prevent service quality degradation. PIMs are also
11		increasingly being used to promote other outcomes such as emissions reductions,
12		as well as to ensure that a utility follows through on its commitments such as
13		investments in grid modernization.
14	Q.	Please briefly describe performance incentive mechanisms.
15	A.	PIMs are Commission-established regulatory requirements that target
16		achievement of specific outcomes. <sup>76</sup> As a foundational step, Commissions must
17		identify regulatory policy goals together with desired performance objectives or
18		outcomes. Once the Commission establishes the desired outcomes, it may
19		establish PIMs at three levels of weight to motivate attainment of those outcomes:
20		metrics, targets, or financial incentives. Metrics are the building blocks of PIMs.

<sup>&</sup>lt;sup>76</sup> See generally, Melissa Whited, Tim Woolf, & Alice Napoleon, Utility Performance Incentive Mechanisms: A Handbook for Regulators (prepared for the Western Interstate Energy Board Mar. 9, 2015), *available at* https://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098\_0.pdf.

1	In the first instance, a utility measures outcomes or outputs related to its
2	operations. These measurements are metrics. When it is possible to define a
3	desired level of performance based on baseline metrics, the Commission can
4	establish a target for improvement. The metrics are subsequently compared
5	against the target. Sometimes this simply occurs on a "scorecard" to track and
6	inform how a utility is executing its responsibilities. In other instances, the utility
7	receives positive or negative financial consequences (incentives) for established
8	levels of performance relative to the target. A variation on a financial incentive is
9	a shared savings mechanism. When a utility is able to accomplish an outcome at
10	lower cost than alternatives, the utility is given an opportunity to "share" in the
11	savings as an incentive for the efficient behavior.

## 12 Q. Are Performance Incentive Mechanisms useful outside of a Multi-Year Rate 13 Plan?

A. Yes. PIMs can improve regulation as a part of traditional cost-of-service
regulation. Performance incentives can be used to express regulatory expectations
and connect those expectations with financial consequences inside an MRP or as
part of traditional cost-of-service regulation.

18 Q. Are PIMs Being Considered in Arizona?

A. Yes. At Commissioner Lea Márquez Peterson's request,<sup>77</sup> the Commission has
already opened an investigation into the role of PIMs.<sup>78</sup> Commissioner Boyd

<sup>&</sup>lt;sup>77</sup> Commissioner Márquez Peterson Request for New Docket, Docket No. E00000A-20-0019 (Ariz. Corp. Comm'n Feb. 6, 2020), *available at* https://docket.images.azcc.gov/0000200847.pdf.

1	Dunn has also suggested that performance-based rate design should be considered
2	in this rate case. <sup>79</sup> He has requested that parties "consider and present evidence on
3	whether a penalty or incentive-based ROE that is tied to meeting specific
4	customer satisfaction, education, and outreach metrics is just, reasonable, and in
5	the best interest of ratepayers." 80 Commissioner Dunn has directed that the
6	"evidence presented should weigh pros and cons of moving to this type of a rate
7	design and discuss possible scenarios for a performance-based metric."81 He
8	directed parties to "(1) identify the scope of the customer satisfaction, education,
9	and outreach problems, (2) propose and discuss possible metrics for tracking and
10	reporting performance on customer satisfaction, education, and outreach (3)
11	propose and discuss performance targets, and (4) propose and discuss the
12	financial penalty structure."82

Q. Do you recommend the Commission adopt a comprehensive performance based regulation plan with a multi-year rate plan and performance
 mechanisms in this docket?

A. No. While the Commission may ultimately find that an MRP with performance
 mechanisms is in the public interest, I recommend that the Commission establish
 a separate docket to investigate comprehensive performance-based regulation.

<sup>82</sup> Id.

<sup>&</sup>lt;sup>78</sup> In the matter of the investigation of the Arizona Corporation Commission into the Role of Performance Incentive Mechanisms in regulated investor owned electric utility rate cases in Arizona, Docket No. E-00000A-20-0019 (Ariz. Corp. Comm'n 2020).

<sup>&</sup>lt;sup>79</sup> Letter from Commissioner Dunn (Ariz. Corp. Comm'n June 17, 2020), *available at* https://docket.images.azcc.gov/E000007101.pdf.

<sup>&</sup>lt;sup>80</sup> *Id.* at 2.

<sup>&</sup>lt;sup>81</sup> *Id.* 

## 1Q.Is there any action that you would recommend the Commission take within2this docket?

3	• Yes. I recommend that the Commission direct APS to begin tracking metrics.
4	The design and implementation of an effective MRP deserve a thoughtful and
5	robust process as part of the Commission's forthcoming investigation into
6	performance-based regulation. PIMs, however, have long been incorporated
7	into both MRPs and into cost-of-service-based regulation. PIMs offer the
8	advantage of being able to be implemented incrementally and iteratively. It is
9	appropriate to consider PIMs once the Commission identifies a regulatory
10	policy goal and desired performance objectives or outcomes. As I have
11	previously testified, it would be appropriate for the Commission to direct APS
12	to begin tracking metrics now. This data will inform the investigation
13	regarding PIMs. At the very least, these metrics should include those I
14	recommend above related to energy data. I also recommend adding a simple
15	metric for energy efficiency: APS should report the kWhs of energy it assists
16	customers in saving relative to the kWhs of energy it sells.

## 17 Investigation of Performance-Based Regulation

# Q. If the Commission were to undertake a separate investigation of performance-based regulation, do you have any recommendations for the questions they should entertain?

21	A.	Yes. I have attached to my testimony as Attachment-CR5, "Utility Model:
22		Questions For Regulators And Stakeholders To Ask And Answer As Utilities
23		Evolve." <sup>83</sup> This list was developed by Energy Innovation and provides a good
24		start to the regulatory conversation considering the changes underway in the
25		electricity industry.

<sup>&</sup>lt;sup>83</sup> Attachment CR-5, Ron Lehr & Sonia Aggarwal, Utility Models: Questions for Regulators and Stakeholders to Ask and Answer as Utilities Evolve (Energy Innovation Feb. 2017), available at https://energyinnovation.org/wp-content/uploads/2017/02/UtilityRegModels\_QuestionsList.pdf.

1 2	Q.	Do you have any recommendation regarding the process the Commission may use to conduct an investigation of performance-based regulation?
3	А.	I recommend the Commission ensure that the forthcoming investigation allows
4		for a robust discussion involving stakeholders that begins with an articulation of
5		what customers, the larger community, and Arizona want to see from their electric
6		utilities. Then, it would be appropriate to conduct an assessment of the
7		opportunities for performance-based regulation to address to achieve these goals,
8		relative to the existing cost-of-service structure.
9	Reco	mmendations Regarding APS Formula Rate Concept Alternative
10 11	Q.	To summarize, what are your recommendations for APS Formula Rate Concept Alternative?
12	А.	My recommendations for the Commission are as follows:
13		• The Commission should reject consideration of the APS Formula Rate
14		Concept Alternative. It does not improve upon, and would, in fact, entrench,
15		the status quo. The Formula Rate Concept Alternative does nothing to address
16		changes within industry. It would not provide additional tools to address public
17		policy goals around decarbonization and makes no meaningful contribution to
18		performance. Most significantly, it would reduce cost-containment features
19		that exist under current cost-of-service regulation in Arizona.
20		• The Commission should not pursue any Formula Rate structure. Such
21		structures have not demonstrably advanced the decarbonization of the energy
22		grid and have largely caused customers to experience unnecessary rate
23		increases. I do not see any formula rate construct being an improvement on
24		status quo regulation in Arizona.
25		• The Commission should consider adopting performance-based regulation.
26		Performance-based regulation includes several elements intended to strengthen

1	utility performance incentives that can be used alone or together. These include
2	MRPs and PIMs. MRPs in combination with well-crafted metrics, scorecards,
3	and financial incentive mechanisms can be powerful drivers toward cost-
4	effective, decarbonized energy systems.
5	• I recommend that the Commission investigate comprehensive performance-
6	based regulation in Docket No. E-00000A-20-0019.
7	• I recommend that the Commission direct APS to begin tracking performance
8	metrics. The design and implementation of an effective MRP deserves a
9	thoughtful and robust stakeholder process as part of the Commission's
10	forthcoming investigation into performance-based regulation. PIMs, however,
11	have long been incorporated into both MRPs and into cost-of-service-based
12	regulation. PIMs offer the advantage of being able to be implemented
13	incrementally and iteratively. It is appropriate to consider PIMs once the
14	Commission identifies regulatory policy goals and desired performance
15	outcomes. It would be appropriate for the Commission to direct APS to begin
16	tracking metrics now. This data will inform the investigation regarding PIMs.
17	At the very least, these metrics should include those I recommended related to
18	energy data on starting on page 28. To those I would add a simple metric for
19	energy efficiency: APS should report the kWhs of energy it assists customers
20	in saving relative to the kWhs of energy it sells.

## 21 V. RATEPAYER-BACKED SECURITIZATION

## 22 Q. What is ratepayer-backed securitization?

A. At its core, ratepayer-backed securitization is refinancing. Just as a homeowner
 may benefit from refinancing their home mortgage when interest rates drop, the
 utility can reduce its traditional financing costs, and save customers money, by
 meeting some of its capital needs using less expensive ratepayer-backed bonds.

## Q. What are ratepayer-backed bonds?

Ratepayer-backed bonds are loans to the utility that customers have a legally
enforceable obligation to repay through monthly surcharges on their utility bills.

### 4 Q. How does ratepayer-backed securitization work?

5 Α. Fundamentally, ratepayers "buy out" a portion of the utility investors' investment 6 in the utility's debt and equity, replacing the higher cost capital with lower cost 7 capital raised on the ratepayers' obligation to pay. To accomplish this, a 8 Commission must issue a finance order that authorizes the issuance of ratepayerbacked bonds.<sup>84</sup> Then the proceeds of the bonds are used to replace the higher 9 10 cost capital on the utility's balance sheet. The finance order must authorize the 11 utility to charge its customers sufficient revenue to service the bonds and this 12 charge must be adjustable to account for revenue changes over time necessary to 13 ensure the bonds are repaid. Customers may not avoid or "bypass" this charge. 14 The Commission order must be irrevocable. These payments are assigned to and

<sup>&</sup>lt;sup>84</sup> A number of state legislatures have enacted laws providing explicit authorization to the state utility regulatory commission to issue finance orders for securitization for specifically enumerated purposes. As a constitutionally authorized body, however, the Arizona Corporation Commission has been granted the "full power to, and shall, prescribe just and reasonable classifications to be used and just and reasonable rates and charges to be made and collected, by public service corporations within the state for service rendered therein, and make reasonable rules, regulations, and orders by which such corporations shall be governed in the transaction of business within the state, and may prescribe the forms of contracts and the systems of keeping accounts to be used by such corporations in transacting such business, and make and enforce reasonable rules, regulations, and orders for the convenience, comfort, and safety, and the preservation of the health, of the employees and patrons of such corporations." *See* Ariz. Const. art. XV, § 3. Thus, it appears that the Arizona Corporation Commission has plenary authority to issue finance orders it deems necessary to provide just and reasonable rates.

1		flow through a limited purpose bankruptcy-remote entity set up for the sole
2		purpose of the transaction that is responsible for paying the bondholders. <sup>85</sup>
3 4	Q.	What makes the customer repayment obligation for ratepayer-backed bonds legally enforceable?
5	A.	To establish a ratepayer-backed bond, the regulatory commission must issue a
6		financing order that creates a non-bypassable tariff to collect the revenue
7		necessary to service the bond from the customers of a distribution system. These
8		payments flow through a legally separate corporate organization that cannot be
9		held responsible for the debts of the utility.
10 11	Q.	Why would ratepayer-backed bonds be less expensive than traditional utility financing?
10 11 12	<b>Q.</b> A.	Why would ratepayer-backed bonds be less expensive than traditional utilityfinancing?The difference in cost is a function of the difference in risk investors face.
10 11 12 13	<b>Q.</b> A.	Why would ratepayer-backed bonds be less expensive than traditional utility financing?The difference in cost is a function of the difference in risk investors face.Investor-owned utilities, like APS, traditionally raise the resources necessary to
10 11 12 13 14	<b>Q.</b> A.	Why would ratepayer-backed bonds be less expensive than traditional utility financing?The difference in cost is a function of the difference in risk investors face.Investor-owned utilities, like APS, traditionally raise the resources necessary tofund their operations through a combination of debt and equity provided by
10 11 12 13 14 15	<b>Q.</b> A.	Why would ratepayer-backed bonds be less expensive than traditional utility financing?The difference in cost is a function of the difference in risk investors face.Investor-owned utilities, like APS, traditionally raise the resources necessary tofund their operations through a combination of debt and equity provided byinvestors. Utility debt and equity investors require that the utility pay a premium
10 11 12 13 14 15 16	<b>Q.</b> A.	Why would ratepayer-backed bonds be less expensive than traditional utility financing?The difference in cost is a function of the difference in risk investors face.Investor-owned utilities, like APS, traditionally raise the resources necessary tofund their operations through a combination of debt and equity provided byinvestors. Utility debt and equity investors require that the utility pay a premiumfor the use of their money which varies based upon the risk the investors perceive
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 <sup>&</sup>lt;sup>85</sup> Joseph S. Fichera, *Managing Electricity Rates Amidst Increasing Capital Expenditures: Is Securitization the Right Tool? An Update* (National Regulatory Research Institute Jan. 2019), *available at* https://saberpartners.com/wp-content/uploads/2019/01/nrri\_securitization\_final\_fichera.pdf.
 <sup>86</sup> APS Witness Ann E. Bulkley explains this relationship at length in her Direct Testimony. *See* Direct

<sup>&</sup>lt;sup>86</sup> APS Witness Ann E. Bulkley explains this relationship at length in her Direct Testimony. *See* Direct Testimony of Ann Bulkley [hereinafter "Bulkley Direct"]. See, in particular, her description of a Bond Yield Plus Risk Premium Analysis at 49:7-17.

1 Commission, avoided by its customers, or diverted by the utility. Traditional 2 utility debt investment does not enjoy this level of security because it is always dependent upon the utility's ability to pay. While utility equity investment is 3 4 regarded as one of the lower risk equity investments available, utility equity 5 investors still risk that they will not recover their investment or that they may be 6 disappointed by the return they receive on the investment. Both circumstances 7 result in utility equity investors demanding more of a premium for the use of their 8 funds compared to either ratepayer-backed bonds or utility debt investors.

9 Q. Has securitization been used within the utility industry?

10 A. Yes. Securitization has been used within the utility industry for quite a while.

11 Since 1997 there have been a total of 66 securitization transactions undertaken by

12 investor-owned utilities.<sup>87</sup> These occurred in 17 states,<sup>88</sup> including two

13 transactions in Ohio that were filed while I was serving as a Commissioner on the

14 Public Utilities Commission of Ohio.<sup>89</sup>

<sup>&</sup>lt;sup>87</sup> Saber Partners, LLC, *List of Investor-Owned Utility Securitization ROC/RRB Bond Transactions 1997-Present*, https://saberpartners.com/list-of-investor-owned-utility-securitization-rocrrb-bond-transactions-1997-present/ (last updated 2019).

<sup>&</sup>lt;sup>88</sup> Id. Transactions occurred in Arkansas, California, Connecticut, Florida, Illinois, Louisiana, Maryland, Massachusetts, Michigan, Montana, New Hampshire, New Jersey, Ohio, Pennsylvania, West Virginia, Wisconsin, and Texas.

<sup>&</sup>lt;sup>89</sup> See Financing Order, Case No. 12-1465-EL-ATS (Pub. Utilities Comm'n of Ohio Oct. 10, 2012), available at https://dis.puc.state.oh.us/DocumentRecord.aspx?DocID=286bc283-55c9-45e1-9b6a-2b1469890895 [hereinafter "Ohio Edison Financing Order"]; Financing Order, Case No. 12-1969-EL-ATS (Pub. Utilities Comm'n of Ohio Mar. 20, 2013), available at https://dis.puc.state.oh.us/DocumentRecord.aspx?DocID=43a15eee-b18a-4f76-8fb8-4e459e4262ac [hereinafter "Ohio Power Financing Order"].

### Q. What were the circumstances of the two transactions in Ohio?

2 Α. Ohio electric distribution utilities were transitioning to retail competition during 3 this timeframe. The legislation guiding the transition authorized the utilities to 4 seek financing orders from the Commission for securitization of previously 5 approved but uncollected deferred regulatory assets associated with the transition. 6 These costs could include fuel, infrastructure, and environmental clean-up 7 expenses. The resulting bonds were called "Phase-In-Recovery Bonds" or "PIR 8 Bonds." Both referenced transactions involved PIR Bonds. The Ohio Commission 9 approved the transactions after finding that they would measurably enhance cost 10 savings to customers and mitigate rate impacts compared to the previously approved recovery methods.<sup>90</sup> 11 12 • In the first transaction, which involved First Energy Companies, the Public

Utilities Commission of Ohio ("PUCO") granted authorization for \$555 Utilities Commission of Ohio ("PUCO") granted authorization for \$555 million<sup>91</sup> in PIR bonds. The PIR bonds replaced a combination of existing riders which had been granted a rate of return of 6.85 percent.<sup>92</sup> The effective weighted average annual coupon rate and yield of the PIR Bonds was 3.14 percent, which resulted in a nominal cost savings of approximately \$106 million.<sup>93</sup>



<sup>&</sup>lt;sup>90</sup> Ohio Edison Financing Order at 48; Ohio Power Financing Order at 64.

<sup>&</sup>lt;sup>91</sup> Ohio Edison Financing Order at 5.

<sup>&</sup>lt;sup>92</sup> Application of Ohio Edison, *et al.* at Exhibit B, Case No. 12-1465-EL-ATS (Pub. Utilities Comm'n of Ohio May 3, 2012), *available at* 

https://dis.puc.state.oh.us/TiffToPDf/A1001001A12E03B70455J58177.pdf.

<sup>&</sup>lt;sup>93</sup> Report Regarding Financing Order, Case No. 12-1465-EL-ATS (Pub. Utilities Comm'n of Ohio June 13, 2013), *available at* https://dis.puc.state.oh.us/TiffToPDf/A1001001A13F14B55456H92545.pdf.

<sup>&</sup>lt;sup>94</sup> Ohio Power Financing Order at 10.

million and the nominal savings would be \$22 million.<sup>95</sup> The PIR bonds
replaced a regulatory asset that had been recovered through a "Deferred Asset
Recovery Rider"<sup>96</sup> at the utility's long-term debt rate, which was then 5.34
percent.<sup>97</sup> Ultimately, the weighted average coupon rate and yield was 3.28
percent, which yielded an estimated net present value savings of \$23 million.<sup>98</sup>

## 6 Q. Can you offer another example of securitization within the electric utility 7 industry?

8 A. Yes. The Michigan Public Service Commission authorized Consumers Energy

9 Company to securitize up to \$389.6 million for the retirement and demolition of

10 three coal-fired power plants which had a book value of \$361.2 million.<sup>99</sup>

11 Consumers Energy Company offered testimony in this case that: (1) it expected

12 the weighted average interest rate for the utility's securitization bonds would be

- 13 3.589 percent, which was below the utility's then cost of capital of 9.48
- 14 percent;<sup>100</sup> and (2) that removal of the coal plants and associated costs from rate
- 15 base and replacement of the traditional financing costs with the securitization
- 16 charges would result in a net present value of savings to customers estimated to be
- 17 \$133.5 million.<sup>101</sup>

https://dis.puc.state.oh.us/DocumentRecord.aspx?DocID=0124e09b-fb89-451b-ba8b-67b3acdc6136.
 <sup>97</sup> Opinion and Order at 7, Case Nos. 11-351-EL-AIR, 11-352-EL-AIR, et al. (Pub. Utilities Comm'n of Ohio Dec. 14, 2011), *available at* http://dis.puc.state.oh.us/DocumentRecord.aspx?DocID=82e5874e-671b-42bd-9329-58973af696a2.

<sup>&</sup>lt;sup>95</sup> Ohio Power Financing Order at 6.

<sup>&</sup>lt;sup>96</sup> Application of Ohio Power Company for Authority to Issue Phase-In-Recovery Bonds, Case No. 12-1969-EL-ATS (Pub. Utilities Comm'n of Ohio July 31, 2012), available at

<sup>&</sup>lt;sup>98</sup> Issuance Advice Letter For Ohio Power Company's Phase-In-Recovery Bonds at 12, Case No. 12-1969-EL-ATS (Pub. Utilities Comm'n of Ohio July 24, 2013), *available at* 

https://dis.puc.state.oh.us/DocumentRecord.aspx?DocID=64b17637-56e0-4fbe-bca5-47abface68b9. <sup>99</sup> Opinion and Order at 62, Case No. U-17473 (Mich. Pub. Serv. Comm'n Dec. 6, 2013), *available at* 

https://adms.apps.lara.state mi.us/Mpsc/ViewCommissionOrderDocument/10729.

 $<sup>\</sup>frac{100}{100}$  Id. at 14.

<sup>&</sup>lt;sup>101</sup> Id. at 15.

## Q. Has the Arizona Corporation Commission previously expressed a view regarding securitization?

A. Yes. In the context of approving Electric Competition Rules in 1998, the
Commission found that "[s]ecuritization is a financing method that can be utilized
to spread stranded costs over a longer period and thus minimize the annual
impact."<sup>102</sup>

7 **Q**. Have any current Commissioners expressed any interest in securitization? 8 Α. Yes. Chairman Burns issued a letter on March 25, 2020 within the Arizona 9 Corporation Commission Energy Rules Docket expressing his view that a number 10 of standards related to clean energy, energy efficiency, renewable energy, and 11 distributed renewable energy should be adopted. He stated that he anticipated that 12 some fossil fuel energy generators may retire prior to their originally expected 13 closure dates, if these regulations were adopted, although he noted this may occur 14 due to economics regardless. Therefore, he stated that the energy rules "should 15 contain a section regarding securitization and the use of a portion of the money 16 saved with securitization for assisting communities affected by the early closure of these fossil fuel energy generators."<sup>103</sup> Additionally, Chairman Burns issued a 17 18 second letter in the on-going APS rate case, directing APS to undertake an 19 examination of a variety of accelerated depreciation and securitization options for 20 recovering potentially stranded costs resulting from the earlier than anticipated

<sup>&</sup>lt;sup>102</sup> Opinion and Order at 22:15-16, Decision No. 60977 (Ariz. Corp. Comm'n June 22, 1998), available at https://docket.images.azcc.gov/0000121160.pdf.

<sup>&</sup>lt;sup>103</sup> Mar. 25, 2020 Letter from Chairman Burns.

1	retirement of the Four Corners Generating Plant. <sup>104</sup> Chairman Burns subsequently
2	expanded this request to address potentially stranded costs at the Cholla
3	Generating Station as well. <sup>105</sup>

4	Q.	Are there any downsides to ratepayer-backed securitization for customers?
5	А.	Yes. Once a regulatory asset is securitized, it is outside of the Commission's
6		control and review authority. Because of this, the Commission and stakeholders
7		must be diligent in carefully designing a securitization transaction that will yield
8		the expected benefits. For instance, in the AEP transaction I discussed above, the
9		savings from securitization could and should have been even greater. A post-
10		transaction report found that customers were required to pay at least an additional
11		\$3 million in unnecessary interest and fees as a result of poor implementation
12		decisions by the Commission-retained independent financial
13		advisors. <sup>106</sup> Additionally, the professional and investment services required to
14		implement ratepayer-backed bonds properly are an added expense to be
15		considered when evaluating whether a transaction is cost-effective. It is also
16		important to be cognizant of the potential for changing market conditions. For this
17		reason, a finance order must be carefully designed.

<sup>&</sup>lt;sup>104</sup> Letter from Chairman Burns, Docket No. E-01345A-19-0236 (Aug. 11, 2020), available at https://docket.images.azcc.gov/E000008353.pdf.

<sup>&</sup>lt;sup>105</sup> Letter from Chairman Burns, Docket No. E-01345A-19-0236 (Sept. 1, 2020), available at https://docket.images.azcc.gov/E000008707.pdf.

<sup>&</sup>lt;sup>106</sup> Saber Partners, LLC, Analysis of Ohio Power Co. Structuring and Pricing of \$267,408,000 Ohio Phase-In Recovery Bonds (prepared for Pub. Utilities Comm'n of Ohio, Case No. 12-1969-EL-ATS Aug. 18, 2013), available at https://saberpartners.com/wp-content/uploads/2017/03/Ohio-Power-Pricing-Analysis.pdf.

Q.

## Are there any other important issues a Commission should consider prior to authorizing ratepayer-backed securitization?

3 Α. Yes. I would also caution that the availability of securitization should not cause a 4 commission or stakeholders to relax their vigilance in evaluating the prudency of 5 utility investments. Before a commission considers a cost that can be recovered 6 through securitization, the utility must clearly establish that it has been prudently 7 incurred and should be recoverable. In the instance of a plant that is no longer a 8 cost-effective resource but has not been fully depreciated, the Commission must 9 first consider the extent to which the remaining plant balance is recoverable. The 10 utility will need to demonstrate that each investment it made in that plant was 11 prudent when it made the investment. For instance, if the utility made an 12 investment when it knew or should have known that the plant would not remain 13 useful throughout the recovery period, the Commission may determine that some 14 or all of the remaining balance will be disallowed. Also, if a plant is not "used and 15 useful" (in a physical or economic sense) then a full or partial disallowance of the 16 plant costs could be appropriate.

17

## Q. How would ratepayer-backed securitization impact investors?

A. Utility investors (either debt or equity) would receive full repayment of the capital
they had invested as it is replaced by the proceeds of the ratepayer-backed bonds.
Utility investors, however, would not continue to earn any return on this money
because it would have been returned to them and would no longer be used by the
utility. So long as utilities have adequate access to capital and confidence that
their investment will be recoverable, this lost earning opportunity is a disincentive

57

to utilities to seek securitization. Securitization, however, may be appealing to
 utility investors when the recovery of utility investment is uncertain, such as in
 the case of stranded assets, or when it provides an opportunity for new investment
 in replacement resources, where appropriate.

5

**Q**.

## When is securitization useful?

6 Α. Securitization can be a useful tool to reduce customer rate impacts whenever a 7 Commission has authorized the recovery of an expense and the recovery of that 8 expense could be more cost-effectively accomplished through ratepayer-backed 9 bonds. Utilities have sought and commissions have tended to authorize 10 securitization primarily for large, well-defined, non-recurring expenses. This is 11 likely due to the transaction costs involved, the fact that securitization once 12 finalized limits commission oversight, and the lost investment opportunity for 13 utility investors. Utilities have successfully used securitization in times of 14 transition such as when retail competition was adopted in Ohio, as I described 15 above, and when coal-fired generation plants are no longer economic, as I 16 described above in the Michigan example. Other examples include Allegheny 17 Energy, which used ratepayer-backed bonds to finance pollution control upgrades, 18 and Duke Energy, which calculated that it would save its customers \$700 million over 20 years when it securitized assets of a closed nuclear plant.<sup>107</sup> 19

<sup>&</sup>lt;sup>107</sup> Uday Varadarajan, David Posner & Jeremy Fisher, *Harnessing Financial Tools to Transform the Electric Sector* 13 (Sierra Club Nov. 2018), *available at* https://www.sierraclub.org/sites/www.sierraclub.org/files/sierra-club-harnessing-financial-tools-electric-sector.pdf.

### Q. How is securitization relevant to this matter?

2 Α. The Commission establishes a revenue requirement based in large measure upon 3 the utility's cost of capital during a rate case such as this one. It is an opportune 4 moment to evaluate whether portions of the utility's capital need could be more 5 cost-effectively managed through ratepayer-funded bonds. In this matter, I see at 6 least three opportunities to consider ratepayer-backed bonds as a tool to improve 7 customer outcomes. APS has suggested extending the cost recovery time for 8 deferred expenses related to the Four Corners SCRs and the Ocotillo 9 Modernization Project amortization schedules in order to mitigate bill impacts to customers.<sup>108</sup> The SCR deferral is \$33.2 million.<sup>109</sup> The deferral at December 31, 10 2020 for the Ocotillo Modernization Project is \$62 million.<sup>110</sup> APS also proposes 11 12 to extend recovery time for the Cholla Unit 2 regulatory asset amortization.<sup>111</sup> If 13 the Commission agrees that APS should recover these deferrals, then instead of 14 extending the cost recovery—which lowers customers impacts in the near term 15 but increases overall costs-the Commission could consider whether these should 16 be funded by ratepayer-backed securities which could lower customers' overall 17 costs and still mitigate rate impacts.

<sup>&</sup>lt;sup>108</sup> Ariz. Pub. Serv. Application at 18, Docket No. E-01345A-19-0236 (Oct. 31, 2019), available at https://docket.images.azcc.gov/E000003517.pdf.

<sup>&</sup>lt;sup>109</sup> Blankenship Direct at 36:19-20.

<sup>&</sup>lt;sup>110</sup> *Id.* at 35:1-4.

<sup>&</sup>lt;sup>111</sup> *Id.* at 41:4-9.

1	Q.	What cost of capital has APS assumed inside of this rate case?
2	А.	APS Company Witness Blankenship has testified that the Company is requesting
3		an adjusted weighted average cost of capital of 7.41 percent. <sup>112</sup>
4 5	Q.	What interest rate would you expect to be available for a ratepayer-backed bond?
6	А.	Because of the low risk of these bonds, I would consider the risk-free rate as a
7		relevant point of reference. APS Witness Bulkley has testified that she considers
8		an appropriate reference for the risk-free rate to be the projected yields on 30-year
9		U.S. Treasury bonds. <sup>113</sup> On July 24, 2020, this rate was 1.23 percent. <sup>114</sup> As an
10		additional point of reference, on July 16, 2020, the 30-year-fixed mortgage rate
11		fell below 3 percent. <sup>115</sup> While perhaps ratepayer-backed bonds would be viewed
12		as slightly more risky than U.S. Treasury Bonds, they are certainly less risky than
13		an individual home mortgage. Based on these data points, I would anticipate that
14		ratepayer-backed bonds would be available at somewhere between 1.23 percent
15		and 3 percent.

<sup>&</sup>lt;sup>112</sup> *Id.* at 12:24-25.

<sup>&</sup>lt;sup>113</sup> Bulkley Direct at 45:8-9.

<sup>&</sup>lt;sup>114</sup> U.S. Dep't of Treas., *Daily Treasury Yield Curve Rates*, https://www.treasury.gov/resource-center/datachart-center/interest-rates/pages/TextView.aspx?data=yieldYear&year=2020 (last visited Sept. 16, 2020).

<sup>&</sup>lt;sup>115</sup> Kathy Orton, *30-year fixed mortgage rate falls below 3 percent to lowest level in history*, THE WASHINGTON POST, July 16, 2020, *available at* 

https://www.washingtonpost.com/business/2020/07/16/30-year-fixed-mortgage-rate-falls-below-3-percent/.

1 Q. What is the significance of the APS requested cost of capital and the cost of a 2 ratepaver-backed bond? 3 A. I refer to this range to illustrate that the Commission could conservatively expect 4 that ratepayer-backed bonds could reduce the cost of capital by over half, offering 5 customers a substantial savings opportunity. 6 Q. Are there any other circumstances that have come to light in this matter for 7 which ratepayer-back bonds may be an appropriate tool?

8 Α. Yes. Concurrent with my testimony, Tyler Comings filed testimony on behalf of 9 the Sierra Club finding that APS would enjoy substantial savings if it were to 10 retire Four Corners Units 4 and 5 in 2023 instead of 2031. Early retirement could 11 create just the type of stranded assets for which securitization may be appealing to 12 utility investors. As I described above, Michigan consumers enjoyed substantial 13 savings when the Michigan Public Service Commission authorized ratepayer-14 backed bonds to finance expenses related to the closure of three coal-fired plants. 15 Securitization may be a useful tool here in implementing an earlier-than-

- 16 anticipated retirement of Four Corners Units 4 and 5. This use is also consistent
- 17 with the suggestion made by Chairman Burns within the Energy Rules docket.<sup>116</sup>

# 18 Q. What design features could be incorporated into a financing order 19 authorizing securitization to ensure the securitization achieves customer 20 benefits?

A. A commission adopting a finance order to authorize securitization could consider
the following design features to ensure that the transaction achieves the intended
benefits:

<sup>&</sup>lt;sup>116</sup> Mar. 25, 2020 Letter from Chairman Burns.

1 2		• The commission retains authority to approve the investment banking firm managing the offering.
3 4		• The commission retains bond counsel and/or other an independent advisor to oversee the transaction and to advise the commission.
5		• Consumer savings and rate impacts are documented.
6 7		• Proceeds of the ratepayer-backed bonds may be used only to replaced existing capital (including the cost of the bonds), not to undertake new debt.
8 9 10 11		• Savings from securitization should be passed along to customers directly or indirectly as a public benefit through funding of costs required to assure a just transition during the early retirement of an asset, including but not limited to severance pay and job training expenses for affected employees.
12 13		• Bonds must be competitively marketed as opposed to sold through private negotiation.
14 15		• Financing costs and weighted average interest of the bonds are capped at levels to assure the expected benefits.
16 17 18		• Expected benefits should assure substantial, tangible, quantifiable net present value benefits, greater than without bonds, maximizing the net present value savings.
19		• The commission retains authority to approve the bond structuring and pricing.
20	Q.	What are your recommendations with regard to securitization?
21	A.	The Commission should consider retaining a qualified expert to conduct an
22		independent evaluation to determine whether there are large, well-defined, non-
23		recurring expenses on the utility's balance sheet that could cost-effectively be
24		funded by ratepayer-backed bonds. I also recommend that the Commission

- 1 consider the tool of securitization when evaluating the opportunities to close fossil
- 2 fuel generation units that have become or soon will be non-economic.

## 3 Q. Does this conclude your testimony?

4 A. Yes, it does.

## Attachment CR-1 Resume of Cheryl Roberto



## Cheryl Roberto, Senior Principal

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 croberto@synapse-energy.com

## **PROFESSIONAL EXPERIENCE**

Synapse Energy Economics Inc., Cambridge, MA. Senior Principal, 2019–present.

Provides expert consulting services for removing operational, regulatory, and policy barriers to the decarbonization of the energy system on behalf of mission-driven investors, regulators, and other stakeholders seeking to accelerate the transformation of the grid.

**Twenty First Century Utilities**, Washington, D.C. *Senior Advisor*, 2019 – present; *Managing Director: Utility Transformation*, 2015–2019.

Worked to transform, through acquisition and operation, regulated utilities with a 21<sup>st</sup> century model that drives mass adoption of clean, low-cost energy producing and energy saving technologies. Advanced utility of the future policies, operations, technologies, and governance inclusive of grid optimization, de-carbonization of utility-scale fleet, implementation of TFC Utilities' Million Rate Base Market Platform, and achieving sustainable business value.

## Environmental Defense Fund, Associate Vice President, EDF Clean Energy Program, 2013–2015.

Led national program advocating regulatory reform to help modernize U.S. energy infrastructure, accelerate deployment of clean technologies into the nation's electric system, and break down the regulatory and financial barriers to broad-scale adoption of renewable energy, energy efficiency, and other innovative ways to generate, distribute, and use energy. Managed a team of over 30 individuals and an annual budget of \$11 million dollars.

## Public Utilities Commission of Ohio, Columbus, Ohio. Commissioner, 2008–2012.

In addition to customary responsibilities of a Commissioner, initiated a national pilot partnership with the United States Department of Energy (U.S. DOE) for combined heat power; served as Co-Chair 2012 National Electricity Forum, Co-Chair, State and Local Energy Efficiency Action Network Driving Ratepayer-Funded Efficiency Working Group (also Chair Sub-Committee for Utility Financial Incentives), Co-Leader U.S. Agency for International Development (U.S. A.I.D.)/NARUC meeting with National Electricity Regulatory Commission of Ukraine (Kiev, Ukraine, September 2011), and a member of the National Association of Regulatory Utility Commissioners (NARUC):

- Task Force on Environmental Regulation and Generation (2012)
- Committee on Critical Infrastructure (also served as Vice Chair) (2010–2012)
- Committee on Electricity (2008–2012)

**Department of Public Utilities, City of Columbus**, Columbus, OH. *Director*, 2003–2006, *Deputy Director for Operations*, 2001–2003.

Led municipal water, wastewater, and electric utility with annual operating budget of \$400 million dollars, an annual capital budget of \$250 million dollars, and a staff of 1300 people serving the nation's 15th largest city and 22 Central Ohio political subdivisions. Established and successfully managed \$2.5 billion dollar capital engineering and construction program, the largest ever undertaken by the City of Columbus. Completed extensive restructuring of utility rate models and design for the first time in two decades to validate cost of service. Managed successful water quality-focused environmental initiatives involving extensive stakeholder outreach and public education, including the development and adoption of the Hellbranch Run Watershed protection Overlay and Clean Water Act Facilities Plan.

## Office of the Mayor, City of Columbus, Ohio, Columbus, OH. Policy Advisor, 2000.

Provided advice on public policy issues including health, environment, public utilities, housing, public safety, and development to support the launch of the Mayoral administration of Michael B. Coleman.

## Office of the City Attorney, City of Columbus, Columbus, OH. Assistant City Attorney, 1997–2000.

Represented City of Columbus for municipal law issues related to environmental, health, and safety matters including environmental permitting (NPDES, Title V, MS4), regulatory enforcement (industrial pretreatment, fire code, storm water development), compliance counseling (RCRA, OSHA, Clean Drinking Water), environmental liability management (PCB disposal, real estate), and contracts.

## Commonwealth of Pennsylvania, Assistant Counsel, Office of Chief Counsel, 1996–1997.

Served as counsel to the Department of Environmental Protection concerning Superfund, drinking water, wastewater, solid and hazardous waste, and air pollution.

## Cheryl L. Roberto, Esq. Owner, 1993-1996.

Built boutique law practice specializing in environmental matters; representative clients included City of Erie, Pennsylvania, Erie Sewer Authority, and Erie County Department of Health.

## State of Ohio, Columbus, OH. Assistant Attorney General, 1987–1992.

Represented the State of Ohio in Environmental and Consumer Protection matters through administrative proceedings, civil actions, and criminal prosecutions concerning wastewater, solid and hazardous waste, and air pollution.

## **EDUCATION**

## Moritz College of Law, The Ohio State University, Columbus, OH

Juris Doctor, 1987. Member, Journal of Dispute Resolution. Recipient, University Scholarship and Caris Fellowship. Founding Member, Board of Directors for the Student Funded Fellowship.

Kent State University, Kent, OH BA, Political Science, *cum laude*, 1984. Graduated with General Honors from the Honors College. Omicron Delta Kappa and Pi Sigma Alpha. Recipient of Manchester Cup, Junior Service Award, Sophomore Leadership Award, Honor's Scholarship. Honor's Dissertation adopted and implemented by K.S.U. Board of Trustees: "Student Leadership Compensation Model for Kent State University," KSU Library Archives, Honors Papers (1984).

## CONTINUING EDUCATION

Harvard University, John F. Kennedy School of Government, Cambridge, MA Executive Education Certificate of Completion: Strategic Management of Regulatory and Enforcement Agencies, 2012.

**University of Colorado**, Silicon Flatirons Center, Boulder, CO Institute for Regulatory Law and Economics, Seminar, May 2012.

Scott Hempling Attorney at Law LLC, Electricity Law Update Seminar, March 2012.

## American Law Institute/American Bar Association

42<sup>nd</sup> Annual Advanced Course of Study in Environmental Law, February 2012.

SNL Center for Financial Education, Essentials of Regulatory Finance, June 2011.

**National Regulatory Research Institute**, Electricity's Current Challenges: Capital Investment, Renewables, Energy Efficiency, "Modern" IRP, and Transmission. January 2011.

Michigan State University, East Lansing, MI

Advanced Regulatory Studies Program, "Ratemaking, Accounting, and Economics," September 2010.

## HONORS AND AWARDS

## Inspiring Efficiency Leadership Award, January 2013.

Presented by the Midwest Energy Efficiency Alliance to the organization or individual in the 13-state region who has served as a strong leader in support of energy efficiency in their city, state, region, company, or community.

## **BOARDS AND COMMISIONS**

- Executive Group for the State and Local Energy Efficiency Network (2012–present)
- Board of Directors of the National Regulatory Research Institute (NRRI) (2012)
- Financial Research Institute (FRI) Advisory Board (2011–2012), Chair, Hot Topic Hotline Committee (2012)
- Audubon Ohio, Board Member (2007–2008)
- Franklin County Planning Commission, Member (2001–2006)

- Solid Waste Authority of Central Ohio, Board Member (2003–2006); Engineering, Operations and Compliance Committee Chair
- Mid-Ohio Regional Planning Commission, Member (2003–2006); Greenways Steering Committee Chair; Member Public Works Integrating Committee
- Community Research Partners, Board Member (2000–2002)

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Resume updated March 2020

# Attachment CR-2

Leveraging Advanced Metering Infrastructure to Save Energy

# Leveraging Advanced Metering Infrastructure To Save Energy

Rachel Gold, Corri Waters, and Dan York January 3, 2020. Revised January 27, 2020. Report U2001

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# Revision

The original edition of this report did not include all six use cases for Southern California Edison; the utility initially reported only one use case (TOU rates) in the survey. SCE subsequently provided data clarifying how it uses AMI in support of the other five use cases. We have updated table 1 to reflect this change.

# About the Authors

**Rachel Gold** leads ACEEE's Utilities Program. Her research focuses on energy efficiency programs and policy and on utility regulation and ratemaking. She also provides technical assistance to utilities, state regulators, and efficiency program administrators. Rachel was previously in the electricity practice at Rocky Mountain Institute and on the regulatory affairs and market development team at Opower. She holds a master of public policy from the University of California, Berkeley, and a bachelor of science in biology and environmental studies from Brandeis University.

**Corri Waters** was a research assistant for ACEEE's Utilities Program. She supported the *Utility Scorecard* and conducted research on energy efficiency program design and cost effectiveness. Prior to joining ACEEE, Corri interned at the Maryland Clean Energy Center and served as the project manager for Pittsburgh's Black Environmental Collective. She earned a bachelor of science in mathematics with a minor in environmental and sustainability studies from Loyola University Maryland in 2018.

**Dan York** is an ACEEE senior fellow engaged primarily in utilities and local policy research and technical assistance. He focuses on tracking and analyzing trends and emerging issues in utility-sector energy efficiency programs. Dan has a bachelor's degree in mechanical engineering from the University of Minnesota. His master of science and PhD degrees, from the University of Wisconsin–Madison, are both in land resources with an emphasis on energy analysis and policy.

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# **Executive Summary**

## KEY TAKEAWAYS

- Advanced metering infrastructure (AMI) has grown rapidly and is in place in many states, covering nearly half of all meters in the United States. It is a key element of grid modernization.
- Providing customers with AMI data alone generally does not result in energy savings. AMI data need to be paired with customer engagement tools; pricing strategies; and programs with incentives and services that enable, motivate, and support customers to take actions and make changes to modify their energy use.
- Utilities are largely missing the opportunity to utilize AMI data to improve their energy efficiency and demand response offerings, in part due to regulatory, administrative, and technological barriers.
- Opportunities for leveraging AMI for energy savings include time-varying pricing (TVR); more granular energy usage feedback, including time and locational value; customer targeting and technical assistance; programs that align payment with metered performance; and more actionable insights from evaluation, measurement, and verification.
- Utilities can leverage AMI to support energy efficiency by investing in complementary systems and workforce, prioritizing the customer experience, and piloting new approaches and ways of leveraging AMI data.
- Regulators can encourage utilities to better leverage AMI by quantifying and incorporating benefits from saving energy in the AMI business cases in regulatory proposals, then adjusting shareholder compensation based on performance in realizing those benefits. They can also establish clear and reasonable protocols for data access, set performance standards for metered energy savings, and encourage innovation and pilots that could leverage AMI but might involve technology or business model risk.

# **BENEFITS OF ADVANCED METERING INFRASTRUCTURE**

Advanced metering infrastructure (AMI) consists of meters, communications networks, and data management systems that collect, transmit, and record electricity consumption data in daily or shorter intervals. AMI is considered a foundational element of electric grid modernization by many within the electric utility industry. More timely and more granular data can be used to influence customer behavior and energy consumption when used in ways that engage, motivate, and reward customers. For utilities and grid operators, AMI provides a variety of operational benefits, including reduced costs for metering and billing, faster responses to outages, and improved safety.<sup>1</sup> The operational benefits of AMI compared with traditional manual metering have typically been the primary rationale used

<sup>&</sup>lt;sup>1</sup> See US Department of Energy, *Advanced Metering Infrastructure and Customer Systems: Results from the Smart Grid Investment Grant Program* (Washington, DC: DOE, 2016), www.energy.gov/sites/prod/files/2016/12/f34/AMI%20Summary%20Report 09-26-16.pdf.

by utilities and regulators to invest in these systems.<sup>2</sup> The capabilities of AMI as an information resource and tool for customers to reduce their costs and achieve other benefits generally have been underutilized, as indicated by our utility surveys and interviews with industry experts.

Moreover, to the extent that AMI has been considered a means of influencing customer energy use, it has most often been viewed as a tool for affecting the timing of energy usage (e.g., for load shifting and demand response). Nevertheless, there are important ways that AMI can enable and support customer energy efficiency savings via several use cases. These strategic uses include:

- Enhancing the quality of insights on energy use from near-real-time feedback
- Providing time-varying pricing that reflects fluctuating energy costs at different times of day and year. Near-real-time feedback, combined with communications and possible automation, can better inform and motivate customers to respond to pricing signals and change their energy use accordingly.
- Targeting customers for programs best suited to their energy use profiles
- Promoting grid-interactive efficient buildings that extract more grid value from customer programs by providing more flexible demand<sup>3</sup>
- Supporting energy procurement and meter-based pay-for-performance (P4P)<sup>4</sup>
- Producing granular data needed for advanced measurement and verification of customer energy and demand savings (M&V 2.0.)
- Enabling conservation voltage reduction (CVR) on electricity distribution networks to reduce demand and energy use

This report places a special focus on the potential application of AMI tools to realize customer energy efficiency. Another potential benefit is use of AMI data for utility system planning, particularly for distribution systems. However we found no significant examples of the impacts of this use case on energy efficiency in our research.

<sup>&</sup>lt;sup>2</sup> Traditional metering is based on meters that are read manually, usually at monthly intervals. The data must be entered or uploaded to utility records and billing systems; they cannot be transmitted automatically via the various communications technologies employed with AMI.

<sup>&</sup>lt;sup>3</sup> Grid-interactive efficient buildings (GEBs) are grid-connected buildings with information, controls, and communications technologies able to respond to signals from the grid to modify energy demand.

<sup>&</sup>lt;sup>4</sup> P4P rewards energy savings on an ongoing basis as the savings occur, rather than providing up-front payments based on deemed or custom measure calculations. Meter-based P4P programs determine performance payments according to savings quantified using meter data, including daily or hourly data from AMI where available. See C. Best, M. Fisher, and M. Wyman, "Case Study: Policy Pathways to Meter-Based Pay-for-Performance in CA, NY, and OR," *Recurve*, September 3, 2019, <u>www.recurve.com/blog/policy-pathways-to-meter-based-pay-forperformance</u>.

# POTENTIAL ENERGY SAVINGS FROM AMI-LEVERAGED ENERGY EFFICIENCY

The energy savings possible through different uses of AMI to advance energy efficiency vary. The results for some applications have been well documented; these include (as percentages of total annual electricity use in kilowatt-hours):

- Near-real-time and behavioral feedback: 1–8%<sup>5</sup>
- Pricing with time-varying rates: 1–7%
- Conservation voltage reduction: 1–4%

Other uses of AMI have a high potential to improve energy efficiency programs and evaluation, thereby contributing to and supporting customer savings. For example, in program design AMI data can be used for customer targeting and recruitment. In program evaluation, AMI can provide accurate and timely data to facilitate P4P approaches as well as allow rapid feedback to management for program improvement.

## PRACTICES TO LEVERAGE AMI TO SAVE ENERGY

Leveraging AMI to save energy requires active efforts from utilities in their roles as energy efficiency program administrators, grid planners, and grid operators. Utilities are also the primary entities identifying AMI technologies, selecting vendors, and investing in these resources on behalf of the system and their shareholders. Utilities need the support of regulators and stakeholders to implement AMI in a manner that optimizes customer as well as operational benefits.

Utilities and program administrators need to break down traditional internal business and operations silos to manage and use AMI to its fullest capabilities to benefit customers and system operations. Utility and regulatory practices that support robust AMI utilization include:

- Crafting effective communications that inform, engage, and motivate customers
- Quantifying and incorporating benefits from energy savings in business cases
- Adjusting shareholder compensation for AMI based on performance in delivering customer benefits from AMI investments
- Setting clear and reasonable performance standards for data access and energy savings
- Encouraging innovation and pilots that leverage AMI, including innovative rate designs, new means of delivering energy use feedback, and new program design tools that use AMI data, such as P4P and targeting.

<sup>&</sup>lt;sup>5</sup> Feedback devices and programs show wide variation due to different designs such as opt-in versus opt-out. See R. Sussman and M. Chikumbo, *Behavior Change Programs: Status and Impact* (Washington, DC: ACEEE, 2016), www.aceee.org/research-report/b1601.

#### **C**ONCLUSIONS

We find that many utilities are underexploiting AMI capabilities and attendant benefits, thus missing a key tool to deliver value to their customers and systems. This is due in part to organizational barriers including silos and workforce challenges, data access and sharing issues, and difficulties communicating the benefits and costs of AMI to key stakeholders. AMI data can help utilities and third parties create better, more compelling, more cost-effective demand-side offerings. AMI also can enable energy efficiency to expand its role as a grid resource by providing temporal and locational value of energy savings in highly granular form. Utilities can learn from the experiences of other utilities that have been successful in rolling out AMI and associated pricing and customer programs. They must actively engage their customers and offer them a range of services to support their energy-saving investments and actions. AMI itself is just a tool that can enable energy markets to support energy efficiency and clean energy goals. When used effectively by utilities or third-party service providers, AMI can improve grid performance, save energy, and reduce customer bills.

## Introduction

Advanced metering infrastructure (AMI) has increased the availability of more granular and more readily available data on customers' electricity usage. Traditionally, consumption information was available at best on a monthly basis, with a one-way flow of data from the customer to the utility. Now, with more granular information and relevant insights about their energy usage, customers can become active participants in lowering their own bills; improving their health, productivity, and comfort; and providing value back to other participants on the grid. These data are a critical building block of a more active marketplace for demand-side resources in which customers, working with or through third parties and utilities, support the integration of renewables into the grid, foster reliability, and build resilience (Relf, York, and Kushler 2018).

Interval data can come from multiple sources, including AMI, communicating smart thermostats, customer submetering devices and sensors, and other advanced metering functionality (AMF). AMI is the most prevalent source of interval data about customers' electricity use. It consists of meters that collect electricity consumption data in daily or smaller intervals, as well as the communications networks and data management systems to transmit, store, and process the data. AMI has expanded to more than half of all meters in the United States and is projected to reach 90 million units, or close to 60% of all meters, by 2020 (Cooper 2017).<sup>1</sup>

Current technology and policy trends have made AMI increasingly important. Decreases in the cost of renewables and distributed energy resources (DER), along with policy efforts supporting decarbonization, are boosting the value of flexible demand-side resources and hastening their deployment. To take advantage of this opportunity, utilities, markets, and customers require good information about what services demand-side resources can provide. Utilities need more granular load forecasts to support high-quality distribution and integrated resource planning that better anticipates grid needs. They also need customers to be able to see and respond to variation in the cost of delivering energy throughout the day and year, which requires time- and eventually location-based pricing or valuation.

AMI rollouts, sometimes included as a part of smart grid or grid modernization plans, tend to highlight operational benefits to utilities. However many also cite potential customer benefits, including bill and outage management and opportunities, through their actions, to save energy via efficiency and demand response. For example, in the smart grid business cases arising out of the American Recovery and Reinvestment Act of 2009 (ARRA), many utilities cited potential energy efficiency and peak demand benefits such as savings from feedback, time-varying rates, and actions taken through customer interaction with in-home devices (DOE 2019).

<sup>&</sup>lt;sup>1</sup> EIA data for 2018 on AMI penetration show that penetration rates among residential and commercial customers closely track total penetration rates (EIA 2019a). AMI penetration rates for industrial customers show wider divergence from total penetration, likely a reflection of more-specialized needs and arrangements with their utilities.

In the years since ARRA, some efficiency program administrators have been finding it increasingly challenging to maintain cost-effective portfolios in the face of sustained decreases in average avoided costs as well as rising appliance and equipment standard baselines. With the rise in availability of more-advanced data analytics, utilities and implementers can use lessons learned from online and retail sales and advertising to more effectively target customers for energy efficiency opportunities based on not just demographics but also their interval usage. Such targeting and data analytics have the potential to increase savings and boost cost effectiveness (Borgeson and Gerke 2018).

Despite AMI's potential value to save energy, most discussion of its value focuses on operational benefits, and our research suggests that the value of AMI for customer energy efficiency programs and market enablement is underexploited. This creates two forms of potential risk for utilities. First, utilities with AMI that are held accountable for customer benefits and do not deliver may risk regulators' denying cost recovery for existing investments. Second, for those utilities without AMI, or for those that seek to invest further in grid modernization, the industry's poor performance in delivering customer benefits (or articulating how they will do so) may undermine these utilities' ability to gain approval for these large future infrastructure investments.<sup>2</sup> Recent rejections in Massachusetts, Kentucky, Virginia, and New Mexico are cases in point; the New Mexico rejection specifically noted that the AMI proposal from PNM (Public Service Company of New Mexico) failed to "take advantage of possible energy efficiency measures, identify sufficient operational benefits, or provide meaningful opt-out opportunities" (Massachusetts DPU 2018; Kentucky PSC 2018; New Mexico PRC 2018; Virginia Electric and Power Company 2019).

This report seeks to shed light on the ways utilities, program administrators, and third-party service providers are using AMI data in support of customer energy efficiency.<sup>3</sup> We begin by outlining the operational and customer benefits of AMI to identify the use cases for AMI to advance energy efficiency. We examine how and to what extent AMI data are currently used to drive energy savings in a variety of use cases. For promising use cases that are underexploited, we identify barriers to using these data in support of energy efficiency and discuss options to address those barriers from leading examples. Finally, using lessons learned from these leading utilities and market actors, we close by providing

<sup>&</sup>lt;sup>2</sup> US grid investment grew by 8% in 2018, with 60% of spending in the distribution grid, and analysts project continued growth in transmission and distribution to replace aging infrastructure, support renewables integration, and provide a source of growth for utilities with more limited capital investment opportunities due to flat load growth (IEA 2019; DOE 2015).

<sup>&</sup>lt;sup>3</sup> This report addresses two primary types of customer action to modify energy use in order to reduce costs. *Energy efficiency* signifies measures and technologies implemented by customers that reduce the amount of energy used whenever a given device is operated. *Demand response* encompasses various customer actions taken to reduce or shift electric load in response to signals or requests from a utility or system operator. This typically is done to provide load relief at a time of high system demand. Demand response measures primarily shift loads and do not necessarily reduce energy use. Some savings may occur. However energy efficiency by definition always reduces energy use for a given application.

recommendations for regulators and utilities seeking to leverage interval data and communications technologies as a tool to enable all cost-effective energy efficiency.

# **Research Objectives and Methodology**

The primary goal of this research is to show how utilities with AMI can better leverage its capabilities to increase energy efficiency program effectiveness, influence customer behavior to reduce energy use, support more robust energy efficiency markets, and deliver system benefits through energy efficiency. We set out to answer the following research questions:

- How do smart grid businesses characterize the energy savings case for AMI?
- Is there evidence that AMI deployment has saved energy or reduced peak demand?
- What missing opportunities are available to better leverage AMI data for energy savings? Could they use AMF technologies other than AMI?
- What are the barriers to better leveraging AMI data to save energy?
- What supportive investments and programs are needed to fully realize energy savings benefits from AMI?
- What rules can regulators adopt to help customers realize greater energy savings?

To answer these questions, we reviewed existing research and experience on AMI rollouts. Industry experts, including former regulatory staff and contacts from national labs, the US Department of Energy (DOE), and utilities, provided input on the history and current status of AMI, including barriers to and drivers of adoption. Through these resources we identified the range of AMI technologies and their potential implications for energy efficiency and customer benefits.

To characterize the current landscape of how utilities are leveraging AMI, ACEEE conducted a survey of the top 52 electric utilities by sales, the results of which are reported throughout this report. The data from this survey are also being used for ACEEE's forthcoming 2020 *Utility Scorecard*. Where information was available, we captured which utilities had the following programs or program measures in 2018:

- Real-time energy use feedback to customers
- Behavior-based programs with customer feedback and insights
- Time-of-use rates
- Program targeting, marketing, and technical assistance using insights from data disaggregation
- Grid-interactive efficient buildings<sup>4</sup>
- Conservation voltage reduction or volt/VAR optimization

<sup>&</sup>lt;sup>4</sup> Grid-interactive efficient buildings are energy-efficient buildings with smart technologies characterized by the active use of DERs to optimize energy use for grid services, occupant needs and preferences, and cost reductions in a continuous and integrated way (Neukomm et al. 2019).

We identified seven potential use cases of AMI. In addition to the list above, our literature review and interviews identified additional use cases: more real-time, iterative measurement and verification (M&V), and performance-based procurement of energy, capacity, and grid services.

To assess whether these AMI use cases can lead to energy savings, we built on our initial literature review, examining publicly available demand-side management program filings and case studies from the literature on AMI for examples of these use cases. We conducted structured interviews with nine program administrators or implementers to understand program details and structures and to identify lessons learned and challenges faced.

# Advanced Metering Infrastructure and Advanced Metering Functionality

The Energy Information Administration defines AMI this way:

Meters that have the capability to measure and record usage data at hourly or shorter intervals, and provide usage data to energy companies and may also provide the data to customers at least once daily. Data are used for billing and other purposes. Advanced meters include basic hourly interval meters and extend to realtime meters with built-in two-way communication capable of recording and transmitting instantaneous data (EIA 2019b).

Before and sometimes concurrently with AMI deployment, some utilities use automated meter reading (AMR) systems. AMR also involves electronic meters, to eliminate the need for manual meter reads, but features only one-way communications, whereas AMI by definition includes two-way communications (DOE 2012). The DOE's review of the Smart Grid Investment Grants, which provided \$3.4 billion in ARRA funding, builds on this definition, finding that AMI deployments around the country typically include the following:

- Customer-side smart meters that collect electricity consumption data in 5-, 15-, 30-, or 60-minute intervals
- Communications networks to transmit interval consumption data from the meter to the utility back offices
- A meter data management system (MDMS) to store and process the increased volume of data. The MDMS also integrates meter data with information and control systems, including head-end systems, billing systems, customer information systems, geographic information systems, outage management systems, and distribution management systems (DOE 2016, 10).<sup>5</sup>

To support new rate designs, these three elements are typically combined with customersited control technologies like programmable communicating thermostats and direct load

<sup>&</sup>lt;sup>5</sup> The term *AMI* typically refers to a combination of these technology solutions deployed by electric utility investments. Gas and water utilities also deploy advanced metering, but less frequently than electric utilities. Webb (2018) found examples of natural gas AMI metering in only three states – California, New York, and Maryland – typically for dual fuel utilities, so this paper focuses only on leveraging AMI in electricity systems.

control devices, and with information technologies like in-home displays, web portals, and text/email alerts.

The Advanced Energy Economy offers a broader term than AMI, *advanced metering functionality* (AEE 2017b). AMF includes the following capabilities, many of which align with the energy efficiency use cases described in this paper, but it is agnostic as to which technologies are used and who deploys them.

- Collection of customers' usage data, in near real time, usable for settlement in relevant retail and wholesale markets for energy and ancillary services
- Automated outage and restoration notification
- Two-way communication between customers and the electric distribution company
- With customers' permission, communication with and control of smart devices
- Large-scale conservation voltage reduction programs or volt-VAR optimization
- Remote connection and disconnection of customers' electric service (while maintaining consumer protections)
- Measurement of customers' power quality and voltage

While no alternatives provide all the same functions as a widespread AMI deployment, other technologies can provide some aspects of AMF. These include the online portals for tracking solar PV output and consumption provided by solar companies, the separate networks and control centers managed by demand response companies, and home or building energy management systems. Similarly, smart thermostats and electric vehicle charging infrastructure can provide consumption data for a large end use, which can be aggregated by separate companies. Additionally, new companies are emerging that use radio-frequency sensors to capture data from legacy electric, gas, or water meters; these wireless energy monitors are being tested by one Midwest utility and may provide another alternative to AMI (Dan Forman, CEO, Copper Labs, pers. comm., June 18, 2019).

Further, although AMI can provide all of the advanced metering functionalities, some utilities with AMI rely on adjacent systems such as customer broadband or Wi-Fi to deliver some of those capabilities where real-time communications are needed. For example, Green Mountain Power's controllable heat pump water and space heaters communicate over customer Wi-Fi (Gold, Guccione, and Henchen 2017). Some AMI meters are installed with limited bandwidth for load management actions, and furthermore, some manufacturers have found it difficult or costly to register their devices on utilities' smart meter networks and therefore prefer a technology available in most homes.

# **History of AMI**

Deployment of AMI began in the early 2000s as AMI technologies matured and their costs declined. Some of the earliest utility rollouts of AMI occurred during this period (Cooper 2017), although overall AMI penetration still was low. AMI received a large boost toward the end of the 2000s as a result of the Smart Grid Investment Grant funding included in the ARRA legislation of 2009. The number of meters quadrupled between 2007 and 2011, then investment proceeded at a slower pace from 2012–2016, doubling again during that period to reach nearly half of all meters, as shown in figure 1 (FERC 2019).



Figure 1. Estimates of advanced meter penetration rate (FERC 2019).

In 2007 there were about 6.7 million advanced meters in place, according to FERC. By 2016 this number had grown more than tenfold — to 70.8 million out of a total of 151.3 meters in the United States, a penetration rate of 47% (FERC 2019). And AMI continues to grow. The Institute for Electric Innovation estimates that AMI installations will reach 90 million by 2020, which will represent about 60% of all US households (Cooper 2017). Eventually virtually all customer metering is likely to be advanced, although this will take a decade or more, given past penetration rates.

A slight majority of the top 52 utilities in the United States had deployed AMI for most of their customers as of 2018 (EIA 2019a). A small subset (four) have penetration rates between 30% and 80% – possibly an indicator of a full AMI rollout in progress over several years or pilot programs in place. The remainder have AMI penetration of 17% or lower, with 10 of these at zero. These results show that utilities generally either have implemented AMI widely or have yet to do so to any significant degree.

A number of technological advancements have been critical for regulatory approval to support the growth of AMI, particularly customer communications through text messaging, online portals, paper and email reports, and, in early deployments, monitors and home energy displays (e.g., dashboards) that can provide energy use information in user-friendly, easily understood formats to customers. In addition, sensors, controls, and management systems can enable and automate responses using AMI data and customer inputs. AMI generates massive volumes of customer data. Consequently, advancements in information technology and management of large sets of data also have been necessary for the growth of AMI.

While AMI has grown rapidly in recent years and is well accepted in many states as a foundation of grid modernization, there are states and jurisdictions that have rejected AMI proposals by their utilities. Generally the reason cited is that AMI remains too costly relative to the benefits, or that utilities have not verified to the regulator's satisfaction the likelihood of those benefits (Walton 2018). In a few cases customer suspicions of alleged negative health impacts of AMI, such as radiation, have hindered rollouts (Hess and Coley 2012).

# **Benefits of AMI**

Typical benefits of AMI in utility business cases include a combination of operational gains that accrue to the whole system and benefits that customers can directly take advantage of. Operational benefits result in cost savings for utilities and may result in rate decreases for customers, depending on the scale of those benefits relative to the cost of AMI installation. In contrast, customer benefits can include greater control over their energy usage and bills, leading to increased satisfaction and the potential for customer cost savings (and possibly energy savings). Some customer benefits accrue to the system as a whole, such as system capacity and energy benefits, but customer action is required in order to realize those impacts. In this section we describe the key operational and customer benefits cited in the business cases for AMI in our literature review, and we note their connections to energy savings.

## **OPERATIONAL BENEFITS**

The inclusion of AMI in utility portfolios can lead to operational benefits that deliver reduced costs to the utility. DOE's 2016 review of the Smart Grid Investment Grant program in ARRA identifies four main operational benefits of AMI: reduced costs for metering and billing, reduced outage costs and less customer inconvenience, enhanced safety, and lower utility capital expenditures.

Lower costs for metering and billing come from the labor savings associated with fewer site visits to read meters and reduced truck rolls to check on lines, as well as lower labor costs from more accurate and timely billing, which reduces or eliminates estimated bills and reduces customer disputes (DOE 2016). AMI capabilities also can be used to provide customers with information on unusual usage patterns before they receive their bills, which may further reduce customer disputes. The Electric Power Board of Chattanooga (EPB) saved \$1.6 million in annual O&M costs by using automated meter reading and remote services instead of on-site services (DOE 2016). Remote meter reading provides the most value for utilities with large AMI deployments and low customer densities (DOE 2016). However utilities that already have AMR, which provides one-way communication from the electric meter to the utility, may have already realized savings from fewer manual meter reads for service calls. Further, if AMR systems are not fully depreciated, the business case for AMI would need to include the costs of writing off any systems that have not reached the end of their useful economic lives (DOE 2012).

AMI can support outage notification and restoration by providing utilities with "the ability to detect, isolate, and respond to outages quicker than current capabilities" (NEEP 2017). Because utilities are able to detect and isolate outages faster with AMI, they can strategically dispatch repair crews, decreasing outage duration and customer inconvenience (DOE 2016). Utilities can also combine AMI capabilities with outage management systems (OMS) and geographic information systems (GIS) to create more detailed outage maps to share with the public (DOE 2016). Deployed in this way, AMI can increase system reliability and resilience for communities, especially in areas that are prone to severe weather events.

A qualitative benefit of leveraging AMI is increased safety for communities, businesses, and utility systems. "Sensors provide the opportunity for detection and reporting of methane leaks, corrosion potential, arc fault, and stray voltage" (NEEP 2017). With these data,

utilities can troubleshoot problems remotely and more quickly respond to system emergencies. Utilities can also use automated data collection to better comply with safety standards, reducing risks from noncompliance (NEEP 2017).

With AMI, utilities can give their customers the tools they need for energy efficiency and demand response, reducing consumption and shifting energy use from peak to off-peak times (DOE 2016). While demand response can involve direct control of loads, utilities can also use pricing tools, like time-based rates and incentives, and informational tools, like customer bill alerts, to encourage more-efficient consumption. Where customer usage is effectively reduced or shifted away from peak times, utilities can deliver system benefits including fuel savings, market price suppression, and avoided line losses (Lazar and Colburn 2013). These benefits can lead to lower utility capital expenditures through reduced need to invest in capital-intensive infrastructure, and avoided greenhouse gas (GHG) emissions (DOE 2016).<sup>6</sup> Although these are system benefits, they require customer action that can also result in customer bill savings and other benefits associated with energy savings.

Another potential benefit is use of AMI data for utility system planning, particularly for the load forecasting aspects of distribution system planning and integrated resource planning. For example, Burbank Water and Power used AMI data to size distribution transformers and circuits more accurately by using actual peak coincident load on transformers instead of the worst-case scenario as an assumption (Hamer 2015). However we found no significant examples of the impacts of this use case on energy efficiency in our research, so we did not examine it in depth in this report.

#### **CUSTOMER BENEFITS**

Customer benefits include feedback and pricing that encourage or enable them to lower their bills, and improved satisfaction from better communication with their utility about billing, outages, and the sources of energy use in their home. In addition, utilities can deliver more-effective and better-targeted programs using AMI data, which can provide bill savings both from reductions in purchased energy and from rate reductions enabled by utility cost savings.

Tools like smart thermostats, web portals, and mobile apps coupled with behavioral cues can give customers more information and control over their electricity consumption, costs, and bills (DOE 2016). Utilities can leverage insights from interval data to present customers with their usage information in near real time through online portals and applications, as well as through phone calls, text messages, email, and even paper mail. AMI also facilitates the introduction of behavioral demand response, peak-time rebates, and other time-varying behavioral and pricing signals, enabling customers to respond more deftly to pricing and control signals. In addition, bill alerts can increase energy savings (Fulleman 2019), and

<sup>&</sup>lt;sup>6</sup> We discuss how AMI is used to create time-based rates and give examples of time-of-use (TOU) programs in our section on Energy Efficiency Use Cases.

more accurate billing information can decrease complaints and help avoid bill arrearages (NEEP 2017). These features may be particularly useful to low-income customers.

These customer benefits require customer engagement and as a result may require additional back office tools to store and process data. Customer engagement systems and back office tools may raise initial AMI deployment costs, but without them AMI is unlikely to deliver on customer benefits. Green Mountain Power (GMP) qualitatively measures societal benefits of its AMI deployment, such as commercial and industrial outage cost reduction, decreased energy costs, and energy conservation connected to AMI-based web portals (NEEP 2017). As a result of system cost savings, GMP was able to lower customer rates. Additionally, GMP call center representatives report that customers gained a better understanding of energy usage from having access to granular data (NEEP 2017).

Customer-facing control and information technologies are typically required in order to realize the potential benefits from better customer decision making about their energy use (DOE 2016). Control technologies include programmable controllable thermostats and home and building energy management systems, and information technologies include web portals, smartphone applications, and in-home or voice-activated devices to make customer energy usage data more visible and actionable. Such technologies may be provided by utilities, by contracted agents of utilities, or by third-party solution providers interacting with customers; as a result, availability of granular data can create benefits for these market participants as well.

Now we describe the use cases of mechanisms for AMI that support energy savings. These use cases directly and indirectly lead to the operational and customer benefits we have just discussed.

## **Energy Efficiency Use Cases**

ACEEE's survey of the top 52 electric utilities by sales collected information on how they are leveraging AMI to save customers energy. Where information was available, we captured which utilities had the following programs or program measures:

- Near-real-time energy use feedback to customers
- Behavior-based programs with customer feedback and insights<sup>7</sup>
- Time-of-use (TOU) rates<sup>8</sup>
- Programs using data disaggregation
- Grid-interactive efficient buildings
- Conservation voltage reduction (CVR) or volt/VAR optimization (VVO)

<sup>&</sup>lt;sup>7</sup> Note that for the purposes of the initial survey, we focused on behavior-based programs that are energy efficiency measures. As a result, this data set does not consistently include behavioral demand response, which does produce some incremental energy efficiency savings (see Feedback section for details).

<sup>&</sup>lt;sup>8</sup> For the purposes of the survey, we looked at time-of-use rates only; the rest of this paper considers timevarying rates, which include but are not limited to time-of-use rates.

Definitions of each of the above use cases are provided in Appendix B. Table 1 shows which utilities included the above program measures in their energy efficiency portfolios in program year 2018. Utilities with less than 25% AMI penetration are not included in this table.

	Near-real- time feedback to	Behavior- based	Conservation voltage reduction	TOU		Data
Utility	customers	feedback	(CVR)	rates	GEBs*	disaggregation
Portland General Electric	٠	٠	٠	•	•	٠
Southern California Edison	•	•	•	٠	٠	•
Commonwealth Edison	•	٠	•	٠		٠
NV Energy		٠	۲	•	٠	٠
AEP Ohio (Ohio Power)	•	٠		٠		٠
AZ Public Service	٠	٠		٠		٠
Baltimore Gas and Electric	•	٠		٠		•
Consumers Energy	٠	٠		٠	٠	
CPS Energy	٠	٠	•		•	
DTE Electric	٠	٠		٠		•
PECO Energy	٠	٠	•			•
Salt River Project	٠	٠	•	•		
Duke Energy Carolinas (NC)		•	•	•		
Georgia Power	٠	٠		٠		
San Diego Gas & Electric	٠	•		٠		
WI Electric Power	٠	٠		٠		
Ameren IL		٠		٠		
Duke Energy OH		٠		٠		
Duke Energy SC		•		•		
PG&E		٠		•		
PPL Electric Utilities		٠	٠			
Alabama Power				٠		

Table 1. Prevalence of use cases for leveraging AMI to save energy among top 52 electric utilities by sales in program year 2018

Utility	Near-real- time feedback to customers	Behavior- based feedback	Conservation voltage reduction (CVR)	TOU rates	GEBs*	Data disaggregation
Duke Energy IN		٠				
Florida Power & Light				٠		
OK Gas and Electric				٠		
West Penn Power				٠		
Total	14	22	9	22	5	9

\* Grid-interactive efficient buildings. Where utilities have a third-party program administrator in their service territory, some programs may be offered by that entity. For use case definitions, see Appendix B.

#### **Portland General Electric**

Portland General Electric (PGE) is one of only two utilities that reported using AMI for all six of the surveyed use cases. The utility maintains a separate AMI operations department that is responsible for collection, storage, and analysis of data, as well as export to other departments like billing and customer programs. PGE first implemented AMI for all customers in 2011. It reports that the company has improved on customer-facing applications for the data over time and is working to expand use cases for AMI, particularly in transmission and distribution management applications (Kirk Page, lead network data operator, and Erik Cederberg, AMI manager, PGE, pers. comm., November 25, 2019). These applications include two customer portals, EnergyTracker for residential customers and Energy Expert for commercial customers, which provide near-real-time data, data disaggregation for key end uses, behavioral tools like goal setting, and connections to Energy Trust of Oregon energy efficiency programs. The utility is testing time-varying rates through its Flex (a time-of-use rate) and peak-time rebate offerings. PGE also uses AMI for billing alerts, EM&V for demand response programs, and some small conservation voltage reduction pilots.

In addition to PGE, Southern California Edison also leverages AMI for all six use cases. Commonwealth Edison (ComEd) and NV Energy both leverage AMI for five different use cases. Seventeen utilities leverage AMI for two to four use cases, and six utilities report using AMI for only one use case. Utilities that have less than 25% AMI penetration are not included in this table. AEP TX and Oncor Electric Delivery have greater than 25% AMI penetration, but they do not include any of the listed use cases in their portfolios.

Of the utilities with 25% or greater AMI penetration, behavior-based feedback and time-ofuse (TOU) rates were the most prevalent, with 22 utilities implementing each of these measures, respectively. Behavior-based feedback for energy efficiency, as described below, does not require AMI data but can use AMI data to enhance the customer experience. Similarly, while AMI enables more successful implementation of TOU pricing, AMI is not required for TOU rates since the periods and pricing are set in advance.<sup>9</sup> In contrast, AMI is

<sup>&</sup>lt;sup>9</sup> Some form of sub-daily metering is required, but AMR can serve this purpose.

required for effective deployment of more dynamic forms of pricing, such as peak-time rebates and real-time pricing. Real-time feedback and CVR were also prevalent use cases, with 14 and 9 utilities, respectively, implementing these measures. Nine utilities responded that they use data disaggregation to target and market relevant programs to specific customers, and four utilities offer grid-interactive efficient building programs.

Our interviews reflected these trends. Most utilities whose representatives we interviewed have programs that provide customers with feedback, and many use AMI to support time-varying rates. For example, NV Energy provides AMI data to customers via a website and mobile device app. Customers can access a portal that integrates billing and other services, including energy efficiency programs. There also is an online home energy assessment that identifies savings opportunities based on a disaggregation tool using AMI data. In addition to the use cases included in the *Utility Energy Efficiency Scorecard* survey, we identified three additional use cases of AMI: procurement and pay-for-performance (P4P), evaluation measurement and verification 2.0, and system efficiency.

Building on these results, our literature review and interviews with experts for the current study revealed seven total use cases by which AMI enables or supports energy savings, especially energy efficiency, although some also support customer benefits through demand response.

- Feedback
- Pricing
- Targeting for program design, marketing, and technical assistance
- Grid-interactive efficient buildings
- Procurement and P4P
- M&V 2.0
- Conservation voltage reduction

Figure 2 depicts these use cases. Starting at left, the first two cases are directly customer facing. The four in the middle are use cases where a utility or program administrator can deliver savings indirectly, by improving the performance and potential value of customer programs. Conservation voltage reduction, as well as planning (which we do not explore in this paper), are utility-facing use cases for AMI data that can indirectly deliver energy efficiency, but through operations or procurement rather than customer programs.



#### Figure 2. Use cases to leverage AMI for energy savings

Two of the use cases are driven primarily by customer actions: *feedback* of interval usage insights through information provision and *pricing* when customers respond to the more granular rates enabled by AMI. Utilities and third parties provide these informational, behavioral, and pricing signals, but customers are the primary actors. Other use cases are enabling mechanisms that work behind the scenes: usage segmentation and improved M&V are two ways that utilities, program administrators, and implementers can design more cost-effective, targeted programs. Other use cases focus on market animation and optimization of demand-side resources: using AMI data to enable procurement of and programs for those resources best positioned to meet system energy, capacity, and flexibility needs at least cost. Finally, AMI can support system efficiency through conservation voltage reduction, controlling voltage on distribution circuits and enabling some end use loads to draw less power.

We explore each of these potential use cases in the sections below, articulating how AMI can result in energy savings benefits. We document evidence of those savings where available from the literature or provided in our interviews with utilities and third-party service providers. In many cases, these use cases are largely underutilized by the utilities with AMI; as a result, much of the following section represents the opportunity rather than the reality on the ground today.

#### FEEDBACK

There are two principal types of feedback that can influence customer behavior related to energy use. Near-real-time feedback provides customers energy use data shortly after use is recorded. The exact interval between use and reporting varies according to technologies and practices in place but can be close to zero. Behavioral feedback applies the tools of behavioral science to enhance responsiveness to energy use feedback, whether by AMI or conventional metering. As we discuss below, providing customers near-real-time feedback based on AMI and using behavioral science tools can yield the largest impact on customer energy use.

AMI can provide highly granular feedback to customers on their energy use, which can both engage and empower them to take actions to reduce or otherwise modify such use. Rather than a single monthly reading that gets reported to customers about a month later (a lag due to manual reading of meters and monthly billing cycles), customers can receive near-real-time data on their energy use (depending on the meter's interval cycle and reporting technologies and methods). Data can be coupled and tracked with a variety of display technologies, such as a smartphone application or in-home display (smartphone apps being more prevalent). The AMI data also require appropriate software to convert it to information in a form that is readily understood by customers and that can motivate them to change their use. With timely data and clear reporting, customers can correlate different uses of electricity with the amount consumed. Such knowledge is fundamental to understanding and managing energy use within a home, business, or industry.

While energy use data alone can influence customer behavior, simply providing such data is insufficient to affect most customers' energy consumption. Experience shows that providing customers with personalized insights based on interval data (as a number of vendors do in their home energy reports or other communications) is much more effective at motivating customers and getting them to take actions to change their energy use. Such reports are a common application of behavioral feedback.

Studies on customer feedback suggest different degrees of impact. Buchanan, Russo, and Anderson (2015) conclude that there is limited evidence that feedback alone is effective in getting customers to reduce energy use. Karlin, Zinger, and Ford (2015), however, conclude that feedback is a promising strategy to promote energy conservation, but that this depends on how information is conveyed to customers (e.g., via social norms, anchoring, and other behavioral tools) to motivate them to take actions that affect their energy use. Sussman and Chikumbo (2016) find that most real-time feedback programs using opt-in designs report net electricity savings in the 5–8% range.

Program experience and studies of consumer behavior have shown that the best way to maximize the effectiveness of feedback is to provide it through an engaging medium, such as an interactive computer program, and in combination with additional strategies (Sussman and Chikumbo 2016). Strategies can include incentives, normative reporting (comparison with similar households, such as is provided in home energy reports), and personalization of information and messaging. To have the greatest impact, energy use feedback should be coupled with programs, services, and pricing that can motivate, assist, and reward customers for taking actions. In a pilot AMI program, CenterPoint Energy used a web portal to provide smart-meter customers with information on how to better manage their energy usage and costs, including education on steps to reduce peak demand. The pilot included prizes for successful responses. In 2011 the set of 198 participants reduced peak demand by an average of 5% during 10 events; some participants reduced consumption by as much as 35% (DOE 2016).

Mobile applications are another way to for utilities to provide feedback and can be an effective tool to engage customers. For example, DTE's behavior program uses a mobile

application, Powerley, that gives customers energy usage insights and allows customers to set savings targets, interact with feedback tools, and see recommendations of energy efficiency measures targeted to their consumption patterns. Customers can request an Energy Bridge that uses AMI to collect one-minute energy usage information and gives customers real-time energy usage feedback through the DTE Insight app. Paired with home energy reports, in 2018 DTE's residential behavior change programs achieved 62.7 GWh of energy savings and reduced demand by 23.6 MW (DTE Electric Company 2019).

Survey research by the Smart Energy Consumer Collaborative certain types of residential customers are more likely than others to use AMI feedback to understand their energy use and take actions to change it, particularly segments the Smart Grid Consumer Collaborative terms "green champions" and "savings seekers" (SGCC 2016). This also applies to commercial and industrial customers. Most small businesses lack the expertise, time, and resources to actively manage their energy use (Nowak 2016). Larger customers – with higher energy use and costs – may devote necessary resources to actively managing energy use, such as a dedicated energy manager and technologies that can use both AMI data and related on-site metering of systems and equipment.

Program staff and third-party service providers we interviewed affirmed these observations. One provider noted that the level of customer engagement with AMI data and technologies is the key to energy savings from energy efficiency improvement and behavioral changes. Although we found a lack of evidence in the literature documenting a direct causal link between customer engagement and energy efficiency, the two behavioral program providers we interviewed cited internal evidence that those customers who are engaged are more apt to act on insights gained from AMI to save energy.<sup>10</sup>

Where AMI data are disaggregated, the insights from sharing a breakdown of large end uses can be a means to get customers more engaged because it makes the customer experience more relevant.<sup>11</sup> Another provider noted how AMI can be used to start a discussion with customers about their energy use and how they can make changes to save money, which can help create strong long-term relationships between customers and their utilities. Customer engagement tools and platforms (e.g., web portals and mobile apps) also can be effective for cross-marketing programs – linking use patterns with available incentives and services that may benefit customers. Such tools also can provide high bill alerts. Evidence from one randomized trial of a high bill alert email offering for 50,000 Xcel Energy customers in Minnesota found 0.4–0.6% annual savings per customer (Fulleman 2019). These customers did not receive other behavioral energy efficiency communications. While these savings are small in magnitude per customer, they can be large in aggregate in an opt-out design such as the one used in Minnesota. Further, there may be additional

<sup>&</sup>lt;sup>10</sup> However, absent documentation, we note that there could be a reverse relationship, that saving energy causes people to pay attention to and engage with communications from the utility. There could also be a third variable explanation, for example that the type of people who pay attention might also be the type of people who would save energy anyway.

<sup>&</sup>lt;sup>11</sup> This disaggregation is sometimes called nonintrusive load monitoring. We explore the value of this disaggregation for targeting and program design in the Targeting for Program Design, Marketing, and Technical Assistance section.

benefits from layering high bill alerts with home energy reports; internal analysis from eight different Opower programs found high bill alerts can boost Home Energy Report savings by 0.3% (JD Toppin, Global Practice Lead, OPower Solutions Consulting, pers. comm., December 4, 2019).

While AMI rollouts and associated efforts to engage customers have focused largely on the residential sector, AMI also can be used to engage and benefit commercial and industrial customers. Feedback from more granular data provided by AMI can provide insights on their energy use, just as for residential customers. As an example, Efficiency Vermont uses AMI in conjunction with a strategic energy management (SEM) program for commercial/industrial customers. The program model is for continuous energy improvement, a standard for SEM programs. Efficiency Vermont account management staff recruit cohorts of facility energy champions and their teams to participate in the program. SEM training includes an initial assessment of a facility energy management practice and then workshops on topics in energy management such as goal setting, energy efficiency topics, monitoring energy performance, and employee engagement. In addition, early in the workshop progression, a facilitated energy "treasure hunt" occurs to identify low- and nocost savings opportunities, which are then pursued for implementation with help from the account management/energy consultant team working with the customer. These program elements are designed to engage customers and establish an ongoing relationship with them based on SEM. AMI provides vital, timely feedback that enables participants to monitor and validate results from actions they take to reduce energy use. AMI is an effective tool for EM&V and also is used to document savings and utility payments.

AMI feedback can also be used effectively for behavioral demand response programs, which use feedback to target reductions in peak power demand (kilowatts). This report does not focus on behavioral demand response, even though it requires AMI, because its primary function is to deliver peak demand reduction rather than energy savings. However a 2016 DTE program found 0.45% incremental electric energy savings in addition to 3.31% incremental coincident peak demand savings, demonstrating the potential for small additional energy savings beyond kW reductions from these programs (Kirchner 2017).

## PRICING

While AMI data combined with customer engagement can better inform customers and may lead to direct savings, time-of-use pricing used in conjunction with these insights from AMI is often the key to unlocking the greatest customer savings and benefits (Faruqui, Sergici, and Warner 2017). Aligning rates with market and system costs that can vary widely by time of day and season provides signals and incentives to customers to modify their energy use.

Utility economists and analysts long have advocated for time-varying pricing as a means to optimize generation resources and grid performance. This type of pricing also would provide market-based price signals to customers, enabling them to reduce their costs by changing energy use behavior and making energy efficiency improvements. But until AMI technology matured and became cost effective, such arguments for more-advanced pricing remained largely rhetorical.

Costs of power production and wholesale electricity markets are dynamic. Prices for electricity can vary widely due to system power demand and the different costs of production and delivery among electricity suppliers. Generally, the highest prices for wholesale power occur during times of peak demand – times when the most expensive generating resources need to be used and grid constraints may limit bulk power transfers. Historically and currently, retail electricity rates for most customers are flat; they do not reflect wholesale market prices and time of use. The same rate applies regardless of when the electricity is used; there is no seasonal or daily variation.

Time-varying, or dynamic, rates have long been advocated and have been used in certain cases to better reflect the dynamic nature and costs of wholesale electricity markets. There are a few types of time-varying rates, outlined in Baatz (2017):

- *Time-of-use rates.* TOU rates may vary by time of day and season to align with daily and seasonal variations in power generation costs and market demand. TOU rates also send price signals to customers related to future investments. High rates that occur at times of peak power demand can encourage customers to reduce use during peak periods, thereby helping utilities avoid or defer investments in new infrastructure.
- *Real-time pricing.* RTP is a structure in which customer rates vary directly with real-time wholesale market rates.
- *Critical peak pricing.* CPP assesses a higher energy rate (often over \$1 per kWh) during an announced event for a limited number of hours, on the basis of higher wholesale electricity prices and allocation of costs for capacity needed at peak load. The announced events are often limited to a certain number per year.
- *Peak-time rebate.* While not technically a rate structure, PTR awards customers with a rebate for energy saved during announced peak events, typically announced in advance. It provides a financial signal and incentive to customers as to varying costs according to time of use.
- *Variable peak pricing.* VPP charges customers a higher rate for a predefined peak period. The price component on-peak can change each day, with a constant off-peak price.

AMI enables the implementation of TOU rates while providing a way for customers to track their usage in the specified time-based intervals and understand how they can respond to the rate. AMI can also support a bill comparison tool and "shadow" billing, which helps customers predict what their bills would be if they switched to a different rate. However the periods and pricing are set in advance for TOU, not based on real-time prices, so AMI is not required (Colgan et al. 2017).<sup>12</sup> In contrast, critical peak pricing, peak-time rebates, variable peak pricing, and real-time pricing all rely on advanced metering data due to the nature of these rate structures and their dependence on timing of events or wholesale market fluctuations. These rate structures also require some means in place to notify customers of changes in prices, such as via text messages, mobile device applications, or in-home

<sup>&</sup>lt;sup>12</sup> Colgan et al. (2017) note, "Meters with multiple registers can be read with conventional meter reading equipment," which is why TOU is possible without AMI.

displays. For time-varying prices to have an impact on customer behavior, their effect on customer energy bills needs to be reasonably predictable. Customers also need general education to understand how pricing is structured, how it may affect them, and how they can take advantage of such programs to reduce costs.

Some of the first time-varying rate experiments occurred in the 1970s (Faruqui and Malko 1983). However application of time-varying rates by utilities did not occur to any large degree until the early 2000s, triggered in part by California's energy crisis of 2000–2001 and the emergence and availability of AMI technologies that could be deployed at scale and reasonable cost. Numerous studies of time-varying rates provide overwhelming evidence that customers respond to changes in volumetric (kilowatt-hour) rates (Baatz 2017). For example, a meta-analysis of more than 60 residential pricing pilots from 57 utilities across nine countries and four continents concluded that there is compelling evidence that customers respond to price changes (Faruqui, Sergici, and Warner 2017).

Recent deployments at utility scale in the United States and Canada are demonstrating that customers are accepting and benefiting from time-varying rates. Rollouts of TOU rates in Arizona, Oklahoma, Sacramento, Ontario, and Fort Collins, Colorado, have been well accepted. Customers see opportunity to save money by changing their behavior (Faruqui and Bourbonnais 2019).

Results from the Smart Grid Investment Grant program, which was part of ARRA, demonstrate clearly the impacts possible from implementation of time-varying rates (DOE 2016). Table 2 presents examples of these results.

Utility	Bill savings	Program year(s)
Baltimore Gas and Electric	<ul> <li>\$9.08 average credit paid per customer for four energy savings days</li> <li>\$2.8 million in bill savings for all 700,000 participants in the Smart Energy Manager Program, which included behavioral demand response</li> </ul>	2013
Burbank Water and Power	<ul> <li>More than \$1 million in bill savings for all 25,000 participants in TOU rate program across all program years</li> </ul>	2011-2014
Green Mountain Power	<ul> <li>For customers on peak-time rebate and critical peak pricing, average savings across 14 events of \$2.52-\$4.88</li> <li>Estimated total annual bill reduction of \$50/customer</li> </ul>	2012-2013
Oklahoma Gas and Electric	<ul> <li>Average annual savings of \$191.78 for residential customers and \$570.02 for commercial customers in the VPP pricing pilot program</li> </ul>	2012

Table 2. Customer bill savings from selected time-varying pricing programs

Utility	Bill savings	Program year(s)
	<ul> <li>Average summer bill savings exceeding \$77 on the TOU-CPP rate</li> </ul>	
Sacramento Municipal Utility District	<ul> <li>Average annual bill savings of nearly \$40/year for customers who checked out and used an in-home display from the utility</li> </ul>	2012-2013

Source: DOE 2016

Reducing costs is clearly the primary motivation for customers to change their energy use in response to TOU pricing. The corresponding reductions in overall energy consumption and peak demand reveal the magnitude of the responses. Table 3 shows results from a previous ACEEE review of 50 studies of TOU and other time-varying pricing mechanisms (Baatz 2017).

Rate treatment	Number of studies	Average peak demand reduction	Average reduction in overall consumption	Median peak demand reduction	Median reduction in overall consumption
CPP	13	23%	2.8%	23%	2.6%
PTR	11	18%	2.3%	18%	0.6%
TOU	17	7%	1.2%	6%	1.0%
TOU+CPP	8	22%	2.1%	20%	2.3%
TOU+PTR	1	18%	7.4%	18%	7.4%
All	50	16%	2.1%	14%	1.3%

Table 3. Average and median peak demand reduction and reduction in overall consumption from 50 time-varying pricing studies

Clearly TOU pricing and other time-varying pricing mechanisms can be effective in changing customer use of electricity to optimize grid performance and yield cost savings to customers. To put the above savings in context, most state energy efficiency resource standards set annual energy savings targets in the range of 1–2% from all customer energy efficiency programs in a utility portfolio. The results shown in table 2 also reveal that while time-varying pricing does yield reductions in overall energy consumption (kWh), the biggest impacts are on peak demand (kW) reductions. In this way, time-varying pricing functions primarily as a demand response strategy – a means to shape demand and create a more flexible grid.

Customer responses can be automated with various information and control technologies. Such technologies include in-home displays, web portals, and text/email messaging that provide energy use data in formats that are visually appealing, easily understood, and able to guide customers toward beneficial actions to change their use. For example, web portals can provide customers both historical and near-real-time usage data. Home HVAC controls, such as a smart thermostat, can be programmed to adjust settings and operation of equipment such as central air conditioners to respond automatically to price or other signals from grid operators or third parties. This type of functionality can also be achieved without AMI, although AMI deployments can deliver much greater scale for customers served and impacts. Faruqui, Sergici, and Warner (2017) find a 69% reduction in on-peak usage where these rates are paired with AMI and other technologies – from 6.5% for every 10% increase in the peak-to-off-peak price ratio to 11% for every such increase.

AMI can also be used by utilities for prepay plans. These require customers to pay in advance of receiving electricity. Such plans are controversial as electricity is cut off when a customer's balance reaches zero. There usually is only a very short grace period (e.g., one day) compared with those under traditional billing plans.<sup>13</sup> Research by ACEEE and Slipstream found that customers reduce their consumption by about 9% on prepay plans, but the reason for these savings is unclear (Sussman 2019). The combination of enhanced feedback and threat of shut-off is particularly likely to reduce energy use, but other factors may also explain these findings. Although customers generally like prepay plans, such programs can pose risks to certain customers – those who are extremely budget constrained and vulnerable to loss of service.

#### TARGETING FOR PROGRAM DESIGN, MARKETING, AND TECHNICAL ASSISTANCE

With limited budgets and concerns about the rate impacts of programs, program administrators need to maximize the value of each program dollar spent, especially with continuing cost-effectiveness challenges at some utilities. Energy efficiency targeting is one means of improving program effectiveness (increasing savings, lowering the cost of serving or recruiting customers) by selecting customers with particular characteristics as the focus of marketing efforts. Borgeson and Gerke (2018) describe three strategies for targeting. Utilities can focus on customers who: (1) are able to participate (e.g., have the relevant end uses), (2) are likely to participate, or (3) are likely to save more than others when they do participate.

Some strategies do not rely on AMI, instead using other forms of data – monthly usage data, demographic information, past program participation, and other characteristics – to target customers. Examples from national labs, software companies, and utilities suggest that interval data can add value to program targeting by helping to answer whether a customer can participate, and whether she is likely to save more if she does.

#### Identifying Whether a Customer Is Able to Participate

Where interval data enable segmentation of end uses, they might be used to determine whether a customer can participate in a program; for example, for a residential pool pump program, interval data might locate customers who have a pool. This segmentation uses nonintrusive load monitoring (NILM), which employs data from a single point of monitoring, like a smart meter, to provide an itemized accounting of end-use energy consumption (Baechler and Hao 2016). NILM analysis compares these data with appliance signature databases that catalog physical measurements of appliance load (Armel et al. 2013).

<sup>&</sup>lt;sup>13</sup> Prepay plans also typically have certain blackout periods (times when power cannot be shut off), such as overnight, on holidays, and on weekends. Customers are usually shut off at the earliest time legally permittable under applicable regulations and rules.

Most AMI data are reported on a 15-minute, hourly, or daily basis, and at this level of disaggregation, some software vendors for NILM have faced challenges recognizing loads and identifying key events for complex equipment, like different phases of operation (Baechler and Hao 2016). Software vendors report significant improvements in performance since 2016, suggesting the importance of continued testing that measures how well NILM can recognize loads. The ability to disaggregate end uses increases with the granularity of the data. Hourly data can identify loads that correlate with outdoor temperature (like HVAC), continuous loads, and time-dependent loads (like pool pumps and outdoor lighting). One-minute data can identify as many as eight different appliance types, with increasing numbers of appliances for data in the multiple kHz or MHz range (Armel et al. 2013). Some devices, like the Sense Home Energy Monitor, are installed in the home and use a Wi-Fi network instead of an AMI meter to perform the disaggregation.

Despite these reliability challenges, the market for NILM is growing, with about 60 vendors offering these services as of 2016 (Baechler and Hao 2016). Because NILM techniques can identify some of the largest end uses, like heating and cooling, as well as unique time-dependent loads like pool pumps, they can be used to identify customer eligibility for some types of programs. These techniques can also be used to assess whether customers are good candidates for meter-based P4P programs (described below). For example, the Sacramento Municipal Utility District (SMUD) identified which buildings had good "fitness" for the Time-of-Week and Temperature model developed by Lawrence Berkeley National Laboratory (LBNL), finding that restaurants did well but that colleges and schools varied more, depending on whether classes were in session, which was not included in that model. Model quality is one contributor to the overall robustness of meter-based savings results (Berkeley Lab 2018). We found in our interviews that opportunities to use the outputs of NILM to improve energy efficiency program performance are generally underutilized, although some utilities and vendors are working together to pilot such use of these algorithms.

#### Identifying Whether a Participant Is Likely to Save More than Others

Usage data, especially interval data, can also be used to prescreen potential program participants on the basis of their usage patterns so recruitment efforts can focus on the most promising customers. In this way, targeting has the potential to improve cost effectiveness by increasing savings and reducing the likelihood that there will be customers who fail to achieve energy savings benefits from the program.

Most estimates of energy efficiency savings are based on average cases or at best a range. Scheer et al. (2018) investigated the metered savings performance of several energy efficiency programs across both residential and commercial sectors. In each case the authors identified characteristics derived from customers' preprogram AMI data that were highly predictive of actual metered savings outcomes. Figure 3 shows results for customers in California's Central Valley who participated in Pacific Gas and Electric's (PG&E) Advanced Home Upgrade pathway (AHUP) of the Energy Upgrade California program. AHUP is a home retrofit program consisting of building shell and HVAC measures. The figure's two panels show the distribution of metered annual MWh savings for customers in the top half and bottom half of two targeting criteria: summer usage and summer-to-shoulder kWh ratio. Customers in the top half of this targeting scheme saved nearly 3.5 times more than customers in the bottom half. Similar patterns were observed for every program studied (with different targeting schemes, depending on the program). This research clearly highlights the potential to improve savings and cost-effectiveness by basing targeted interventions on customers' usage patterns.



Figure 3. Distribution of pre/post annual cooling electricity usage for Advanced Home Upgrade participants in California's Central Valley. Top: top half of customers as gauged by the targeting criteria. Bottom: bottom half of customers as gauged by the targeting criteria. *Source:* Scheer et al. 2018.

Although monthly data can and should be used to target programs for which AMI data are not available, interval data allow more precise targeting and enable targeting schemes that rely on segmentation of usage, like discretionary kWh, peak-period usage, baseload kWh, load-shape characteristics, and more precise determinations of heating and cooling kWh. For HVAC programs, the PG&E team found that targeting based on total usage was less effective than using interval data, which enabled researchers to better isolate the portion of usage from cooling and derive additional parameters (Scheer, Borgeson, and Rosendo 2017; Borgeson and Gerke 2018). These techniques were not limited to residential programs; PG&E research also estimated the potential impact of targeting across a range of residential and small and medium-size business programs and estimated that such targeting would increase average participant savings by 53% and 76% (Scheer et al. 2018). These research exercises informed targeting strategies that are now being deployed within PG&E's meter-based P4P programs.<sup>14</sup> These programs will provide in-field experience with targeting to maximize total savings and savings depth. In the meantime, it is clear that PG&E sees targeting as an important strategy, as described in its *Energy Efficiency Business Plan 2018–2035*: "AMI data offers PG&E the ability to better understand site-specific customer energy usage and to tailor offerings that benefit customers most in need of specific energy efficiency offerings . . . PG&E plans to target customers who are expected to yield the greatest energy savings, energy bill reductions, and/or grid-value" (PG&E 2018, 1–9).

For effective targeting, program designers will need to balance increased savings from more rigorous targeting criteria with increased pressure on program recruitment from a smaller segment of the population. Targeting may also raise equity concerns by eliminating customers with lower likelihood of savings; to mitigate these concerns, program designers will need to ensure that targeting strategies also focus on desired customer attributes such as disadvantaged community designations. It should also be noted that energy efficiency is often a priority or first-in-the-loading-order resource expected to deliver cost-effective savings that benefit the entire rate base. Targeting the customers who can drive the greatest value can enhance benefits for all customers. Finally, the value of targeting is dulled by traditional deemed approaches, which average savings across all customers and thus reduce the motivation and accountability for improved results from targeting.

### Using Targeting to Improve Technical Assistance

Utilities can take insights about which customers are most likely to participate in and benefit from programs directly to the customers themselves in the form of improved technical assistance. Although these insights can be used in feedback as described above, they can also be used in customer interactions with utility representatives or contractors. If such insights are integrated with databases and the workflow of customer call center representatives, large account managers, and contractor trade allies, they can be used to help customers diagnose high bills and connect customers to utility offerings.

PECO offers an example of a utility using data from AMI to target customers and better market programs. It recently began an effort working with a third-party implementer to disaggregate end uses with AMI data in an e-audit tool and then use these data in email campaigns that target small and medium-size businesses. In addition, large account representatives use these assessments, including highly visual "heat maps" of buildings' energy use at different times of day, to facilitate conversations with customers about how they are using energy (Mike O'Leary, Manager of Energy Efficient Programs, PECO, pers. comm., August 29, 2019).

The targeting, marketing, and program design described above can be used by a range of market actors, including utilities themselves, other program administrators where third-party (e.g., Energy Trust of Oregon) or hybrid (e.g., NYSERDA) models exist, and program

<sup>&</sup>lt;sup>14</sup> PG&E did not self-report data disaggregation as one of its use cases in our survey, suggesting either that it has discontinued the practice or that the survey respondent was not aware of these activities within the company's large energy efficiency program team.

implementers who acquire savings on behalf of program administrators. In addition, the "platform" model of distribution utilities explored in New York's Reforming the Energy Vision process envisions other service providers using these data directly in the marketplace, perhaps absent "programs" per se (New York PSC 2016).

### **GRID-INTERACTIVE EFFICIENT BUILDINGS**

Many states increasingly face growing peak electricity demand, transmission and distribution infrastructure constraints, and an increasing share of variable renewable electricity generation (Neukomm, Nubbe, and Fares 2019). These stresses to the grid create an opportunity to expand the role of flexible, controllable electricity loads to support reliability and lower system costs. Traditional demand response can serve this role, but so too can grid-interactive efficient buildings (GEBs).<sup>15</sup> These buildings are energy efficient, can be demand flexible, and can be optimized with multiple technologies (possibly including customer-sited generation and storage) for customer and grid benefits. GEBs essentially combine the AMI use cases discussed above: pricing, feedback, and targeting. The technologies required for GEBs also can enable other use cases, namely P4P and M&V 2.0.

To serve these multiple roles, GEBs require information and communications technologies – interval data from either AMI or building automation systems (to understand the best ways to respond to grid needs) combined with controls both for the building and for communications back to utility or aggregator offtakers of the building's services. These data and controls can be used to support GEBs in utility program offerings or can be a part of GEB projects implemented by third-party aggregators and building owners.

To date there are only limited examples of GEBs, especially through utility programs. ACEEE's recent brief (Perry, Bastian, and York 2019) on this topic concludes that no programs or pilots can be considered a holistic GEB program. However we identify a number of utility programs and pilots that promote aspects of the GEB vision for programs, as shown in figure 4.

<sup>&</sup>lt;sup>15</sup> GEBs are grid-connected buildings with information and communications technologies able to respond to signals from the grid to modify energy demand. They actively use distributed energy resources (DERs) and optimize energy use for grid services. Utilities can use GEBs to manage grid operations and lower system costs while delivering customer value in the form of reduced bills, improved productivity, and enhanced comfort. The energy efficiency aspects of GEBs can also make large contributions toward meeting state, municipal, and utility energy efficiency and emissions goals.



Figure 4. Various types of grid-interactive and energy efficiency offerings scaling up to fully integrated programs

In our survey, four utilities said they are running GEB programs, and these appear to be automated demand response programs (ADR) that also offer energy efficiency measures and integrated energy efficiency and demand programs that use smart thermostats to deliver customer and grid benefits. For example, PG&E's ADR program offers additional incentives to participants who install energy efficiency measures at the same sites that participate in demand response events. This program also requires participating facilities to undergo an on-site audit that identifies both demand response and energy savings opportunities (Perry, Bastian, and York 2019). While these programs do not require AMI, advanced metering can support GEB development through its ability to quantify and capture the time value of savings. This yields concrete value streams both to customers with GEBs and to grid operators.

One opportunity to better value the multiple services that energy efficiency provides is to base utility procurement on the actual performance of energy savings, capacity, or flexibility resources. Where these P4P models value peak savings, they typically leverage AMI data to measure the performance of demand-side resources.

#### **PAY-FOR-PERFORMANCE**

P4P, an emerging model for energy efficiency program design, rewards energy savings on an ongoing basis rather than providing up-front payments based on deemed or custom measured calculations. These meter-based P4P programs determine performance payments based on savings quantified using meter data, including daily or hourly data from AMI where available (Best, Fisher, and Wyman 2019). Meter-based P4P programs aim to produce a series of benefits for program administrators (typically utilities) and their customers (Best, Fisher, and Wyman 2019).
Some of the benefits of meter-based P4P are not AMI dependent. Monthly billing records can still be used to calculate avoided energy consumption. Using standardized methods of accounting for savings and delivering performance payments can help increase investor and utility confidence that energy efficiency is a quantifiable, reliable resource, which may help energy efficiency programs scale.<sup>16</sup> Meter-based P4P can also reduce the need to oversee program implementers by setting competitive procurement requirements and then letting implementers determine how to best incentivize customer adoption. Finally, these program designs can break down silos between programs and enable integration within customer offerings by letting a broader range of technologies participate if they can meet program savings requirements.

Currently, the meter-based P4P landscape includes some program administrators without AMI, like Energy Trust of Oregon and the NYSERDA–National Grid collaboration launching in 2020. Others, like PG&E, the DC Sustainable Energy Utility (DC SEU), and NYSERDA's collaboration with Con Edison, do leverage AMI. In interviews, NYSERDA cited additional potential benefits from meter-based P4P with AMI: alignment with greenhouse gas reductions and grid needs and continuous improvement in program design. AMI also enables program administrators with meter-based P4P to offer data to implementers to support program targeting that relies on usage segmentation, like peakperiod usage, baseload kWh, and load-shape characteristics, as described above.

With daily, hourly, or 15-minute interval data, program administrators can set performance payments that scale based on the value offered to the grid or on GHG reduction at different hours of the day or different locations. This is currently being done in multiple PG&E residential P4P programs where savings achieved during the summer peak period are assigned a 3x payment kicker. Similarly, program administrators can offer localized incentives in night-peaking residential areas or midafternoon-peaking commercial areas on the same summer day. While utilities can use average load and savings shapes to value savings happening during system peaks, interval data offer a more accurate, granular understanding of the time value of energy efficiency and localized impacts on the grid. For example, figure 5, below, shows how a California home-upgrade program delivers significantly more annual avoided GHG emissions per MWh of savings than a commercial program (that consists of mostly lighting and refrigeration measures), given the time dependence of marginal emissions rates through the day on each day of the year. This value will be most important in states and service territories focused on carbon or on grid constraints, or where measured load shapes do not provide sufficient information.

<sup>&</sup>lt;sup>16</sup> One example of a standardized method used in meter-based P4P is CalTRACK (caltrack.org), which provides detailed, executable approaches to calculating changes in consumption. When operationalized with an open-source code base, it significantly improves transparency for market actors over traditionally custom-designed evaluations using professional guidelines like Uniform Methods or various state EM&V protocol documents.



Figure 5. Avoided GHG emissions for 1 MWh of savings from Pacific Gas & Electric's Advanced Home Upgrade program and Commercial Deemed program. Each data point multiplies 365 hourly kWh savings measurements with associated marginal emissions to calculate annual avoided GHG at each hour of the day. *Source:* Golden, Scheer, and Best 2019.

Meter-based P4P with AMI allows program administrators to create actionable insights about how to improve programs while they are happening by tracking meter-based impacts close to real time rather than months after the end of a yearlong program. Interval data also generally allow for better modeling of energy consumption. With better models, evaluators, utility planners, and investors can have more confidence in the savings, and program administrators, and perhaps even policymakers can better forecast results before the end of program cycles in order to make key adjustments (for example, to targeting strategies and quality assurance requirements).

Even those programs that do leverage AMI for some purposes may not use its full functionality in initial pilots. Program implementers may roll up their AMI data to a less frequent interval, or they may select not to include use cases for AMI in early program designs to reduce the complexity of performance payment calculations. Establishing new frameworks such as P4P can be difficult, and more complex design elements can be introduced over time if necessary. Further, leveraging AMI in support of P4P requires data access for program administrators like NYSERDA and DC SEU as well as the implementers or "aggregators" who run the program. In addition, it requires investment in staff capacity on procurement, contract structuring, and the other tools required to structure performance payments and create the platform for a P4P marketplace. Finally, fully leveraging this use case requires commitment from evaluators and utilities to use the data to optimize programs in real time.

### **MEASUREMENT AND VERIFICATION**

AMI creates new opportunities for measurement and verification of energy savings from utility energy efficiency programs. Most past methods of M&V have relied on monthly use data, customer surveys, statistical modeling, and possibly some on-site metering (primarily for large commercial and industrial customers). The lag time of one to two years from the end of a program year in determining impacts can result in inefficiencies and higher costs because of the slow feedback and delayed ability to detect problems. By contrast, AMI yields near-real-time measurement of actual energy use. Program managers can use such timely and highly granular customer energy use data to monitor program results closely to assess ongoing performance, detect problems, and take corrective actions as indicated.<sup>17</sup>

The advent of AMI and related information and communication technologies has given rise to M&V 2.0, a major advance in how program managers and evaluators measure and verify energy savings.<sup>18</sup> NEEP (2016) views M&V 2.0 as the ability to use granular data, analytics, and computation on a large scale to streamline the M&V process. These advanced M&V methods hold great potential to determine energy savings in near real time to benefit stakeholders. LBNL researchers (Franconi et al. 2017) cite numerous benefits from these methods, including:

- More timely and detailed information on program results
- Ability to inform ongoing building operations
- Early input on energy efficiency program design
- Consistency and improved accuracy of impact measurement
- Ability to assess impacts by location and time of day
- Increased confidence in M&V results

AMI data enable program managers, implementers, and evaluators to gain a more comprehensive understanding of a program and measure impacts, particularly energy use at different times of the day. It also is important that all users of AMI employ common data platforms that provide secure nodes for accessing data and ensuring consistency. The more continuous M&V possible with AMI data and advanced, automated analytics can be used to spot problems more quickly and make any indicated changes to improve program performance. Another benefit of early feedback is the ability to identify which types of customers are achieving better measured performance. Such data can in turn be used to enhance program targeting – concentrating efforts on those customers most likely to benefit from certain measures. Programs can use performance dashboards that draw on AMI data to show program results in near real time.

Use of M&V 2.0 methods does not appear to be systematic for any utilities or states and did not come up as a use case in any of our utility interviews. However LBNL is working with states and utilities across the country to formally test the value proposition associated with

<sup>&</sup>lt;sup>17</sup> Granularity of data can take several forms. For AMI and related building data, these primarily are measurement interval, volume, and end-use detail.

<sup>&</sup>lt;sup>18</sup> See also Nowak, Molina, and Kushler (2017) for a discussion of definitions, recent trends, challenges, and examples.

these tools. Pilots are being conducted with Sacramento Municipal Utilities District, multiple gas utilities in California, Eversource and United Illuminating in Connecticut, Seattle City Light and Bonneville Power in Washington State, and BC Hydro in British Columbia (Berkeley Lab 2019). These pilots are largely ongoing, with limited published results, and tend to focus on comparing M&V 2.0 tools with traditional M&V methods. Early results for most projects find a good fit to the model for a subset (~50–75%) of buildings, with uncertainty exceeding ASHRAE guidelines in a significant number of buildings.<sup>19</sup> LBNL tends to find the most value in delivering early feedback on savings as they accrue and in identifying nonroutine events and underperforming projects (Berkeley Lab 2016b, 2016a; NEEP 2019). Efficiency Vermont is also testing the use of AMI data for M&V in a pilot comparing homes with energy efficiency measures against a control group. This effort will yield efficiency savings load shapes, hopefully with time-differentiated impact estimates for efficiency programs that can be used in valuing energy efficiency at different times of day and year (Fink 2017).

## UTILITY SYSTEM EFFICIENCY (INCLUDING CONSERVATION VOLTAGE REDUCTION)

Much of the impetus for AMI is improving and optimizing grid or system efficiency. As discussed earlier, AMI can be coupled with pricing, incentives, and customer programs to modify system demands and reduce loads at the peak periods when meeting demand is expensive. By flattening demand through overall reductions or shifting loads from peak to off-peak periods, grid efficiency is improved and costs reduced.

AMI technologies can provide utility systems with data, control, and communication capabilities beyond customer power demand and energy use. One such capability is voltage monitoring, which measures voltage levels and some power quality parameters, enabling utilities to develop accurate voltage profiles across feeder lines. These profiles can be used to diagnose customer voltage issues remotely and to optimize voltage across the grid (DOE 2016).

This ability to monitor voltage can be used by system operators to implement CVR as a means to reduce distribution power losses. CVR involves measuring and analyzing voltages on distribution feeders in order to find ways to reduce voltages while still maintaining service requirements (including voltage and phase balance) at levels that allow equipment to operate without problems. Lower voltages can improve end-use equipment efficiency and reduce line losses on both the customer and the utility sides of the meter. Voltage optimization can also improve effective capacity (kW) and help with reactive power management (Schwartz 2010). The Central Lincoln People's Utility District in Oregon implemented a pilot CVR program that yielded a 2% energy savings for all customers (DOE 2016). On the basis of this result, the utility plans to implement the program system wide.

Dominion Energy offers another example of utility CVR. Since 2009 Dominion has installed more than 450,000 smart meters in its service areas in Virginia and North Carolina and has

<sup>&</sup>lt;sup>19</sup> AHSRAE Guideline 14, Measurement of Energy, Demand, and Water Savings, provides guidelines for minimum performance in reliably measuring the energy, demand, and water savings achieved in conservation projects.

used a subset of the information provided by these meters to implement CVR. Dominion has software that measures the energy savings from CVR, and the utility is now achieving an average of 2.9% savings year-round. Dominion has also been actively marketing voltage optimization services to other utilities, including PG&E, Hawaiian Electric, Nevada Power, Hydro Ottawa, and several municipal utilities. The company estimates savings on a circuit by alternately raising voltage and then restoring the voltage to normal and seeing how loads change in response. Savings vary from utility to utility and have ranged from 2–4%, with lower savings for circuits in the moderate climates along the Pacific Coast and higher savings higher in East Coast applications. The Potomac Electric Power Company (Pepco) provides another example of CVR energy savings. Pepco's impact analysis shows that a 1.5% voltage reduction on its Maryland distribution system provides an annual nonresidential energy reduction of 0.9%; for residential customers the savings are 1.4% (Sergici 2016).

#### Potential Energy Savings from AMI-Leveraged Energy Efficiency

As these cases demonstrate, AMI can be – and is – a powerful tool to help customers reduce their energy consumption and energy costs. As such, AMI also provides important benefits to grid operators, as discussed earlier. The energy savings possible through different uses of AMI to advance energy efficiency vary. Some have been well developed and documented; these include:

- Near-real-time and behavioral feedback: 1–8%<sup>20</sup>
- Pricing with time-varying rates: 1–7%
- Conservation voltage reduction: 1–4%

Other uses of AMI also have strong potential to improve energy efficiency programs and evaluation, contributing to and supporting customer savings. For program design, examples include the use of AMI data for customer targeting and recruitment. For program evaluation, AMI can provide accurate and timely data to facilitate P4P approaches, as well as allow rapid feedback to management for program improvement.

While AMI can be used as a tool for helping customers reduce energy use, as we have discussed, our research on past performance shows no obvious connection between performance in demand-side energy savings and penetration of AMI. There are leading utilities for customer energy efficiency programs with and without AMI. For example, Eversource MA and National Grid MA, which do not have AMI, held the top two spots in the 2017 *Utility Scorecard*, but in third and fourth place were utilities that do have AMI, PG&E and Baltimore Gas and Electric (BGE). Similar patterns exist throughout the spectrum of energy efficiency performance (Relf, Baatz, and Nowak 2017). Nonetheless, it is clear that many of these use cases are underexploited, and with better adoption and further evidence, a stronger statement may be possible about the relationship between AMI and energy savings. Further, as energy efficiency program delivery evolves as a climate and

<sup>&</sup>lt;sup>20</sup> Feedback devices and programs show wide variation due to different designs, such as opt-in versus opt-out. See Sussman and Chikumbo (2016).

grid resource, the capabilities of AMI highlighted in these use cases will become increasingly valuable.

## Barriers to Leveraging AMI to Save Energy

As illustrated above, AMI can yield significant potential utility and customer benefits, including energy savings and peak demand reduction. However our survey of the top 52 electric utilities by sales, as well as interviews across the industry, suggest that utilities are largely underutilizing this resource. Our interviews with program administrators and literature review further revealed common limiting factors for leveraging AMI.

There are myriad barriers to adoption of AMI in the first place, including the challenges of justifying these investments where AMR has already been deployed, issues with measuring some of the benefits of AMI, and communications challenges with regulators, consumer advocates, and customers (NEEP 2017). Unclear business cases for AMI adoption can lead to denial of AMI applications, as seen in recent rejections in Massachusetts, Kentucky, New Mexico, and Virginia. However this section highlights barriers to the use of these systems for utilities, regulators, and customers, as well as technological issues limiting their use by those groups.<sup>21</sup>

#### Utility

Utilities that do not perceive a need to know and understand their customers are less likely to implement programs that leverage AMI; unfortunately, our interviewees found this blind spot prevalent across the industry. When utilities neglect to do customer research using AMI, they miss out on the benefits of customer targeting, feedback, and more robust M&V. This barrier is driven by a few challenges. First, monopoly utilities with a guaranteed customer base may lack a core competency in customer acquisition and engagement, which may discourage some utilities from focusing on customer-facing offerings or using customer data to gain insights. Second, utility business models encourage utilities to focus on capital investments. Utilities may need to make up for lost revenues intended to cover fixed costs from reductions in sales through decoupling or lost revenue adjustment mechanisms (LRAM). They may also need additional earnings opportunities to make up for avoided capital investments due to lower sales and peak demand levels through performance incentive mechanisms.<sup>22</sup> Last, utilities are often reluctant to share data with nonutility vendors that offer additional services and products because these services and products may not offer value to their utility business model. Even where utilities are willing to share data, they may lack clear ownership and access policies around data collection, data storage, and customer data access portals.

In our literature review we found limited evidence for direct energy efficiency savings from AMI outside of feedback augmented by behavioral energy efficiency and demand response or automation technology, pricing, and CVR; many of the promising use cases were

<sup>&</sup>lt;sup>21</sup> We have outlined customer barriers here regardless of particular customer characteristics; however it is important to note that barriers may differ across the spectrum of customer segments.

<sup>&</sup>lt;sup>22</sup> For more information on utility business model tools such as decoupling, LRAM, and performance incentives and how they encourage energy efficiency investment, see Molina and Kushler 2015.

enabling or indirect in nature, and many had limited examples. The lack of concrete evidence for savings directly stemming from AMI can make it difficult for utilities to build a good case for AMI deployment. Utilities rarely prioritize testing the success of measures or programs with and without AMI, so it is difficult to isolate the incremental value of AMI use cases. Further, regulators rarely require such detailed demonstration of benefits. Nonetheless, behavioral program vendors noted in interviews that where utilities have access to AMI, they typically do use it to provide more relevant insights to customers.

AMI deployments require utility investment and workforce development to implement the new technology, and this can challenge utilities without such infrastructure and workforce. Utilities should allow "sufficient time to plan AMI deployments including logistics, asset management, records management, workforce management, and integration with communications, MDMS, OMS, and other affected systems" (DOE 2016). When AMI is in place, utilities may have to hire staff with new skills or train existing staff in data science, marketing, communications, customer service, and engineering to incorporate these data into their work flow. According to a DOE case study, PECO invested time to coordinate internal and external communication systems and processes to aid workforce development and customer communication for their AMI deployment. Internally they "held regular meetings, developed standard messaging, and implemented a dedicated intranet page to help with workforce management and training" (DOE 2016). PECO also created uniform talking points, presentations, and other materials to share with the public and local media (DOE 2016).

#### Regulatory

AMI produces a much higher volume of customer data than traditional analog meters. Having additional data creates opportunities for energy savings but also raises data privacy and cybersecurity concerns. "AMI deployments raise new questions about the security of customer data, the types of entities that can access it, and how the data will be protected from cybersecurity breaches and other data privacy intrusions" (DOE 2016). Thus, standards, tools, and other techniques are needed to ensure that data privacy and cybersecurity are not compromised. Our interviewees stated that there is technology to support cybersecurity and privacy, but utilities and states struggle to create and apply clear rules that allow customers to easily access their data and vendors to provide energy services. Green Button is one such set of standards, although application can be inconsistent (AEE 2017a).<sup>23</sup> An additional challenge in creating these rules is consumer advocates' resistance to approving AMI programs or third-party access to data (Chris Villarreal, president, Plugged In Strategies, pers. comm., July 12, 2019).

AMI requires significant investment of ratepayer dollars. In most states, utilities request preauthorization of these expenses, and consumer advocates and some regulators balk at the potential ratepayer impacts, especially where there are insufficiently beneficial business cases. Primary hesitations tend to consist of concerns about delivering uncertain benefits

<sup>&</sup>lt;sup>23</sup> Green Button comes in two forms: Green Button Download My Data, which allows customers to download their energy use data and upload it to a third-party application, and Green Button Connect My Data, which enables customers to automate the secure transfer of their usage data to third parties.

relative to costs and concerns about equity and uneven distributional impacts. However there are notable exceptions. For example, the Illinois Citizens Utility Board has supported AMI rollout and has endeavored to ensure that the AMI offered to Ameren and ComEd customers is used in service of energy savings, including by conducting research tracking the impact of real-time pricing across customer classes (Thill 2019).

#### Technology

Utility systems designed for small volumes of monthly data and systems without necessary integration can limit the potential of AMI data. To fully take advantage of large interval load data sets produced by AMI, utilities need to improve data processing and management, models for assessing system conditions and predicting demand impacts and energy savings, and some software platforms (DOE 2016). Many of these data processing capabilities are delivered through service-based solutions, which are often lower cost and cloud based. Utilities typically have a disincentive to use such resources, as they are usually not valued as an asset; using their own capital resources could artificially raise the cost of AMI deployment.<sup>24</sup> More-advanced analysis strategies and software platforms will allow utilities to effectively utilize AMI data for multiple use cases such as creating more time-varying rates, customer targeting, meter-based P4P tracking, and planning.

Another technology gap stems from utility reluctance to adhere to consistent data formats and transmission protocols, such as Green Button Connect My Data, and to adopt comprehensive interoperability standards to support connections among smart meters, customer devices, and communications and information systems (DOE 2016). This creates a barrier for third-party data sharing. Continued advancements in mobile apps are also needed to share real-time data and energy usage insights with customers (DOE 2016). There are limited examples of utilities using such applications.

#### Customer

Families and businesses themselves are key actors in leveraging AMI to save energy on their bills; most energy savings require some action by customers, such as responding to a rate, purchasing energy efficiency equipment or services, or setting up automated devices. Barriers for customers include lack of engagement, interest, or motivation. Customers need access to educational materials and support services to understand program structure and elements and how to save energy and earn rewards. Customers also need personal energy usage insights delivered to them in an accessible and timely manner. Personalized insights and tips for energy usage reduction, delivered within 24 hours of an energy savings event through the customer's preferred mode of communication (e.g., phone call, text, e-mail, or mobile application), can motivate customers to save energy more than impersonal, delayed information.

<sup>&</sup>lt;sup>24</sup> Exceptions are found in New York, which allows a rate of return for prepaid software services, and Illinois, which is considering extending the potential opportunity to earn a partial rate of return to pay-as-you go services.

# Practices to Leverage AMI to Save Energy

Leveraging AMI to save energy requires action from utilities in their roles as energy efficiency program administrators, grid planners, and grid operators. They are also the primary entities identifying AMI technologies, selecting vendors, and investing in these resources on behalf of the system and their shareholders. State utility regulators review the prudence of AMI investments, provide oversight to determine whether to allow expenses or incentives associated with these investment, and in limited instances set performance standards for AMI investments. The ecosystem of third parties can provide critical services that leverage AMI in data science, customer segmentation, customer marketing and program implementation, and resource aggregation to meet planning needs. Of course, customers too have a key role to play, as many of the use cases for AMI to save energy require their initial investment or continued participation.

Below, we outline the practices our research found among utilities and regulators that can ensure successful deployments that leverage AMI for customer energy savings, including some practices that address the barriers outlined above.

## UTILITIES AND PROGRAM ADMINISTRATORS

Implementation of AMI by a utility is much more complicated than simply changing out meters. Effective deployment and use of AMI require coordination across multiple departments or units within the typical utility structure, including:

- *Information technology and accounting*. Data management, recordkeeping, and customer billing
- Planning. Customer and load data for forecasting
- *System operations*. Monitoring and managing system resources to meet loads
- *Marketing/communications*. Educating and informing customers about AMI
- *Customer service* (including programs for energy efficiency, demand response, and DER). Using AMI capabilities to help customers change behavior and take other actions to reduce or shift energy use to lower their energy costs
- *Regulatory affairs*. Gaining approval needed by regulators to adopt AMI
- *Rate design*. Exploiting new opportunities to create time-varying rates

Utilities and program administrators need to break down traditional silos that contain these various functions in order to manage and use AMI to its fullest capabilities to benefit customers and system operations. That includes investing time to coordinate internal and external communication systems and processes, as PECO did for its initial communications rollout for AMI, and as PGE continues to do in its efforts to leverage multiple use cases of AMI.

The highly granular data that AMI provides are beneficial only if they can be effectively managed, analyzed, and used to inform and motivate customers to take actions to achieve desired outcomes. Utilities and program administrators need to invest in data scientist capacity accordingly, bolstering capabilities such as big data management, analytics,

security, and communications. AEE (2017) stresses the need for utilities to invest in back office and data management systems to allow customers full access to their data in a form that is easy to understand and identifies opportunities for beneficial changes. AMI data also need to be readily available not just to customer billing and records departments, but also to demand-side management program staff, system planners, and system operators. Utilities should engage the range of actors within and outside the utility who might identify use cases for the data, create systems for those who will be handling and entering it, and establish guidelines for accessing and interpreting it (e.g., definitions for each entity in the data warehouse).

Some early experiences with utility rollout of AMI demonstrate the need for effective communications. Moving from traditional, manually read meters to billing based on AMI is a large change for customers. Without effective communications, customers may resist the changes out of concerns about data privacy, security, or increased costs. Utilities need to build strong business cases for AMI that clearly show how customers will benefit. They also need to provide the tools and services necessary to enable customers to take advantage of AMI and realize its benefits. Utilities should tell the story of what steps are needed to save money from the capabilities of AMI and associated pricing or incentives.

An effective approach for rollout of AMI with time-varying pricing is to make participation opt-out as opposed to opt-in. Investor-owned utilities in California are taking this approach for time-of-use rates, as are leading municipal utilities such as SMUD (DOE 2016) and Fort Collins Utilities (DOE 2013).<sup>25</sup> BGE has successfully combined opt-out peak-time rebates with behavioral demand response in its Smart Energy Rewards program. The program has more than 1.1 million customers enrolled – a result that BGE achieved by registering customers automatically when AMI meters were installed. Customers can opt out, but the large majority have not done so; 70% have participated since 2015 (BGE 2019). This program is not focused on energy efficiency but has delivered 1,280 MW in peak demand savings across five summers between 2013 and 2017 (AEE Institute 2018). The 2018 forecasted annualized energy savings for the Smart Energy Rewards program is 4,719 MWh. Additionally, \$16,064,171 in total bill credits were paid to customers (BGE 2019).<sup>26</sup>

A more typical approach to rollouts of TOU pricing with AMI is to have customers opt in. Such an approach generally yields much lower participation, although participants are often more engaged. SMUD conducted pilot programs to test different approaches to introducing TOU rates, using both opt-in and opt-out designs. SMUD's evaluation of these pilots found higher enrollment rates for opt-out approaches without significant differences in dropout

<sup>&</sup>lt;sup>25</sup> Fort Collins Utilities technically did not offer opt-out; rather it offered options to customers with a standard AMI rollout that would address their privacy or other concerns. One option was to reprogram the AMI to not collect interval data (a single electric data point/day); the other option was to record interval data but not transmit it via radio broadcast, thus necessitating manual meter reading at an additional cost of \$11/month.

<sup>&</sup>lt;sup>26</sup> Customers earn \$1.25 per kWh saved during an Energy Savings Day between 1 p.m. and 7 p.m. during the control season. Energy reductions are measured against a baseline determined by a customer's average energy usage for nonevent days with similar temperature and humidity conditions (AEE Institute 2018).

rates or peak demand reductions.<sup>27</sup> Benefit–cost analysis of these pilots revealed greater net benefits and more favorable business cases for opt-out than for opt-in (DOE 2016).

#### REGULATORS

Regulators can align the behavior of monopoly firms (their investment in AMI) with the public interest (the potential benefits of AMI, including saving energy) by setting performance standards for utilities and then enforcing them with positive and negative consequences (Hempling 2013). In the case of smart grid deployment, regulators must first assess the costs and benefits of smart grid investments relative to their affordability, safety, and reliability and to environmental and other performance standards. This includes quantifying and incorporating the benefits from saving energy into regulatory proposals. Some utility applications fail to include a cost-benefit analysis in their business case; regulators can require such an analysis to support their decision making.<sup>28</sup> They must then monitor performance to ensure that those benefits are delivered, using the tools available to them, including mandates for specific actions and adjustments to compensation. Finally, regulators can set standards and oversee investments in a way that encourages utilities to innovate on behalf of ratepayers.

#### Quantifying and Incorporating Benefits from Saving Energy in Business Cases

As early as 2009, the National Association of Regulatory Utility Commissioners (NARUC) issued a resolution on smart grids calling on member commissions to ensure that any smart grid technology deployment plans continue to be subject to record-based reviews. These reviews should "ensure proposals – and in particular the utility's proposal for recovery of its capital outlays – are both cost-effective and actually result in benefits to ratepayers" (NARUC 2010).

Regulators, coop boards, and municipal oversight bodies have reviewed such plans since 2009, choosing to approve tens of millions of meters in dozens of AMI proposals but also rejecting some notable ones. As these oversight bodies review AMI proposals, they should use a robust cost-effectiveness framework that considers the role of customer benefits, including customer energy efficiency, in justifying the utility investment. The Electric Power Research Institute (EPRI) offers one such framework, which evaluates a range of benefits including customer and environmental ones, and which was used by PG&E and San Diego Gas & Electric in California in their proposals (EPRI 2010). The EPRI framework includes key benefits from energy savings, including avoided energy costs, energy procurement, and price mitigation. Including these can help properly value investments in AMI and can help motivate regulators to put in place metrics or requirements that these savings materialize.

Where those customer benefits are core to the business case, utility proposals should clearly outline how they will achieve those benefits, and approval of investments should be contingent on inclusion of an adequate plan for how new capabilities will be used to advance energy efficiency. Proposals should include any complementary investments on the

<sup>&</sup>lt;sup>27</sup> See Cappers et al. 2016 for more information and analysis of default designs for rate structures.

<sup>&</sup>lt;sup>28</sup> For example, Indiana Michigan Power in Michigan filed their rate case in May 2019, including a request for cost recovery of their AMI investment. They did not include a cost–benefit analysis in that filing (Case U-20359).

utility back end or in customer communications, which would be necessary to realize those customer benefits. For example, the communications capabilities of AMI should be able to send pricing or load control signals through the meter to devices in the home if demand response programs are envisioned as a use case for AMI. Similarly, billing systems must be capable of integrating the rates into customers' bills.

#### Adjusting Shareholder Compensation for AMI Investment Based on Performance

In addition to approval of new technology needs, regulators and other oversight bodies determine whether and to what extent ratepayer funding can be spent in support of those investments. As they review AMI proposals, states apply different levels of scrutiny, which may or may not include a societal perspective depending on which cost-effectiveness test is used (NEEP 2017). State regulators have a range of financial options for encouraging utilities to deliver on expected benefits from AMI, including energy savings and customer benefits. These include performance-based regulation to align investments with desired outcomes, making additional earnings from AMI conditioned on realization of claimed benefits. Regulators can also consider delay or denial of some compensation to shareholders when benefits are not delivered, such as when a program fails to produce a reduction in the authorized revenue requirement that was expected due to projected operational savings from AMI.<sup>29</sup> However there is a risk that this will chill investment, as local distribution companies will be less likely to invest where cost recovery is uncertain or not timely or where regulators place conditions on recovery.

Maryland regulators successfully tied shareholder compensation to delivery of expected benefits in an early AMI deployment. BGE's initial petition to deploy AMI (Case 9208) was rejected in 2009 due to concerns about the cost-benefit analysis. The utility resubmitted the application with an updated business case, including a consumer education and communication plan to better support energy conservation (NEEP 2017). Although BGE was granted approval for the deployment, cost recovery in base rates was deferred until the investments proved cost beneficial. In response, BGE deployed one of the most successful behavioral demand response and peak-time rebate programs in the country, Smart Energy Rewards, described in the Practices to Leverage AMI section below.

Regulators can also use performance-based regulation (PBR), especially performance incentive mechanisms (PIMs), to tie compensation to desired policy outcomes rather than spending. PIMs are commonly used for energy efficiency programs, but an increasing number of states are looking to these mechanisms to encourage outcomes such as reliability, peak demand reduction, greenhouse gas reduction, beneficial electrification, and targeted DER deployment.

The Regulatory Assistance Project (RAP) recommends consideration of PBR methods to advance two desired outcomes: delivering investments on budget and completing their deployment on time. For example, French regulators used PBR in the smart-grid rollout of Électricité Réseau Distribution France (ERDF), a distribution system operator. They used

<sup>&</sup>lt;sup>29</sup> There are numerous cases, such as in Washington, Massachusetts, and Pennsylvania, where regulators have disallowed full recovery of undepreciated assets to protect ratepayer interests (Peskoe 2016).

metrics around cost controls, deployment timing, and system performance when installed, as well as metrics to measure whether operational improvements, such as reduced line losses and meter reading, were actually occurring (Littell et al. 2019). RAP notes the potential for gaming risk with PBR, and suggests using benchmarking, rules around including costs in rate base only when "used and useful," and careful review of timelines and budgets to mitigate that risk.<sup>30</sup>

We are not aware of any PIMs associated with *leveraging* AMI, where PIMs are specifically focused on measuring service results, such as energy or demand savings outcomes from these investments. Littell, Shipley, and O'Reilly (2019) offer multiple examples of potential goals and outcomes for AMI. We reproduce in table 4 their examples that are potentially relevant to the energy savings use cases described in this work. Regulators could also consider metrics to encourage outcomes from use cases like targeting and technical assistance or from grid-interactive efficient buildings, measured in program adoption or the value of grid services procured through GEBs.

Goal	Outcome	Performance criterion/functionality	Metrics to track
Feedback. Customer understanding of energy use	Higher customer satisfaction or understanding of energy use	Operation of customer energy usage portal	Customer usage of energy portal; one-time or regular access
Pricing. Vibrant real-time or TOU energy market for residential users	Customer costs more reflective of system costs; efficient pricing	Customer on a real- time or time-varying rate plan	# and % of customers opting out of or taking price offering
Data access. Authorized access to customer data by third-party energy providers	Utility supports system for customers to share data with third parties	Third-party energy service company ability to access Green Button data	Number of third parties that successfully access customer data through Green Button Connect or other utility data-sharing method; % of customers able to authorize third- party service company requests on first attempt (target: 95%); % of time third-party service provider receives access when authorized by customers (target: 95%)

Table 4. Goals, outcomes, and performance criteria and metrics associated with AMI deployment. *Source:* Littell, Shipley, and O'Reilly 2019.

Although we have yet to see the emergence of PIMs for leveraging AMI to advance energy efficiency, some of the customer engagement metrics proposed as earning adjustment mechanisms in New York's Reforming the Energy Vision proceeding could be relevant. These included metrics that measure increased customer engagement

<sup>&</sup>lt;sup>30</sup> "Used and useful" is a standard for assets that are required and that operate in an effective and efficient manner (CPUC 2017).

through online portals, use of utility-provided data feeds, and use of download options, and metrics that measure the prevalence of customer-oriented products that use AMI data (New York PSC 2016).

#### Setting Performance Standards for Data Access and Energy Savings

Although there are operational benefits that accrue immediately upon deployment of AMI, most customer-focused benefits require further actions by utility regulators. In such areas as energy savings and data access, regulators can directly set standards for expected utility performance associated with AMI rollouts.

Despite the potential for energy savings and the limited application of AMI as a tool to support energy savings across US utilities, we saw few examples of state regulators requiring utilities to verify that they delivered peak kW or seasonal or annual kWh savings from AMI investments. Southern California Gas (SoCalGas) is a notable exception. In its 2010 approval of the utility's AMI proposal, the California Public Utilities Commission required that SoCalGas set a goal to save 1% of residential gas usage and that it track and attribute the conservation impacts of the AMI rollout, reporting every six months from August 2013 to February 2018 (CPUC 2010). The utility met this requirement through a combination of seasonal home energy reports targeted at winter heating and particularly cold-weather-sensitive customers, weekly "bill tracker alerts," and standard home energy reports (Schellenberg 2017). As shown in figure 6, the utility tested a wide variety of combinations, with successful results (greater than 1.0% savings) in some of the tests in the first two years of the program and savings greater than 1.4% in the last two program years (SoCalGas 2018). While the highest savings rates were beyond typical gas savings from home energy report programs, the average savings were close to typical. This suggests strong impacts for some individuals from the season-specific and end-use-specific messaging that required AMI data, but average savings overall, consistent with the discussion of feedback above.



Figure 6. Average household savings from test cells in SoCalGas heating season-focused behavioral programs from 2013–2014 to 2016–2017 program years. *Source:* Schellenberg 2017.

Another form of performance standards are data access and customer privacy protections, which are critical to ensure that customers realize energy savings benefits from AMI. Customers and their third parties must be able to gain access to data in a timely fashion.

ACEEE's *State Scorecard* offers a road map for regulators to follow to enable interval data access, building on a framework created by Mission:data (Murray, Kier, and King 2017). First, regulators can require utilities to provide energy usage data to customers in a standardized electronic format, like Green Button Connect. Only six states have done so as of 2019 (Berg et al. 2019). Second, regulators can ensure that third parties have access to data by providing guidelines for how customers can share access. Sixteen states have such guidelines, and ten states require provision of individual energy usage data to third parties provide aggregated data to owners of separately metered commercial or multifamily properties and public agencies, enabling benchmarking and identification of opportunities for energy efficiency improvements. Four states have such a requirement for multi-tenant building owners, and eight require utilities to provide this data to public agencies (Berg et al. 2019).

#### **Encouraging Innovation to Leverage AMI**

Much of the potential value from AMI derives from differences in the time and locational value of energy savings on the grid. Regulators will need to ensure that valuation and transaction mechanisms are available to unlock that value while protecting vulnerable customers.

Time-varying pricing can enhance the value of energy efficiency and peak demand reductions (Baatz 2017), enabling demand-side resources to lower system costs and customer bills. States without time-varying rates can leverage lessons learned from other states, focusing on designs that limit peak period duration and critical peak pricing period frequency, and coupling rates with communications that support responsive decisions and with technologies that automate customer response, such as programmable thermostats (Sherwood et al. 2016). Such rates primarily deliver peak demand reductions and system efficiency but also support some energy savings. Where utilities lack experience with such pricing, regulators can encourage or require pilots with defined plans for scaling based on lessons learned.

Similarly, regulators can use pilots and innovation plans to encourage utilities to test other use cases that leverage AMI, including targeting and segmentation, new ways of providing feedback, P4P, and grid-interactive efficient buildings. They can also pilot new M&V approaches alongside existing methods to understand their impact before rolling them out as the default method. These pilots can help address utilities' risk aversion and reluctance to innovate without preapproval (Fairbrother et al. 2017).

## **Conclusions and Recommendations**

Technological advancements and market developments have fueled the rapid growth of AMI since the early 2000s. It is the foundation of the grid modernization needed to replace aging infrastructure and integrate DERs. The business case for AMI has relied primarily on operational benefits for utilities, which include:

- Reduced metering and billing costs
- Enhanced ability to detect, isolate, and respond quickly to outages
- Improved safety

The granular interval data provided by AMI also offer many potential advantages to energy efficiency, demand response, and bill management benefits for customers. AMI data can help utilities and third parties create better, more compelling, more cost-effective energy efficiency offerings by:

- Enhancing the quality of and insights from near-real-time feedback on energy consumption and using AMI data for behavioral feedback
- Providing time-varying pricing that reflects varying energy costs at different times of day and year. Near-real-time feedback, combined with communications and possible automation, can better inform and motivate customers to respond to pricing signals and change their energy use accordingly.
- Targeting energy efficiency and other demand-side programs, incentives, and services to those customers most likely to benefit from them
- Improved M&V, to support greater accuracy in impact estimates and more continuous learning through near-real-time feedback to program managers
- Promoting grid-interactive, efficient buildings that extract more grid value from customer programs by providing more flexible demand

- Supporting energy procurement and meter-based pay-for-performance programs that better align outcomes, address siloing between resources, and support acquisition of energy efficiency and other demand-side options as a resource
- Enabling conservation voltage reduction on electricity distribution networks to reduce demand and energy use

We find that many utilities are underexploiting AMI capabilities and its attendant benefits, thus missing out on a key tool to deliver value to their customers and systems. In particular, they underutilize AMI's ability to support customer energy efficiency through information, pricing, and technical assistance insights, and its ability to improve program design through targeting, P4P, and more robust evaluation. When they neglect to use AMI data, they also largely undervalue the potential grid benefits from efficiency programs in grid-interactive efficient buildings.

Some of AMI's benefits can be provided by other technologies like building energy management systems, home energy managements systems, smart thermostats, and other ownership models besides utility deployment. However only AMI appears to be capable of delivering all the use cases outlined for energy efficiency.

Utilities can learn from the experiences of other utilities in rolling out AMI and associated pricing and customer programs. One key to successful rollouts is customer engagement, beginning with market research, stakeholder and community outreach, and customer targeting. Continued engagement efforts include providing customers with education, accessible support, and personalized energy usage insights. Utilities need to clearly demonstrate and articulate AMI's benefits for their customers' energy use. They need to build a strong business case for both customers and regulators that tells a clear story about how AMI will be used to deliver customer benefits, including energy savings.

Another key to gaining the greatest benefits from AMI is to couple it with well-designed, customer-friendly time-varying pricing, including meaningful marketing and education for those rates. This structure gives customers the best opportunity to reduce costs by modifying their energy use. Time-varying pricing is also critical for grid flexibility; it sends appropriate price signals to customers about system costs at different times. These signals enable them to shape and shift load to optimize grid performance and reduce system costs.

AMI also can enable conservation voltage reduction as a means to reduce distribution power losses. The few successful examples of CVR demonstrate its effectiveness. We encourage greater use of this capability of AMI.

As utilities develop and implement AMI, they also need to include complementary investments to realize the full spectrum of customer and grid benefits. This may involve acquiring new areas of expertise, whether by internal staffing or contracting with qualified, experienced vendors. Key functions include data management and system integration.

Successfully leveraging AMI to advance energy efficiency also requires supportive regulation. Regulators should:

- Ensure that proposals by utilities for implementing AMI include and accurately quantify a full set of customer benefits, including saving energy and reducing costs
- Require utilities to demonstrate how they use AMI technology to help achieve customer energy efficiency
- Require that AMI cost recovery be contingent on delivery of benefits claimed in proposals.
- Create performance incentives or other mechanisms to align spending with desired outcomes, including energy savings, or processes, such as data access or use of AMI data for program design
- Support and approve time-varying pricing, such as TOU rates, in concert with AMI rollouts.
- Set standards or requirements to deliver the expected savings or other benefits from AMI
- Establish clear data access rules that ensure data security and provide options for customers, third parties, and residents in buildings served by multiple meters, such as many multifamily buildings
- Allow for pilots and innovation activities designed to test and scale applications that leverage AMI data for customers, the market, or the utility
- Encourage utilities to implement CVR as part of their AMI rollouts.

Rollouts are premised on the ability of this technology and associated systems to deliver benefits to customers and utilities, not the least of which is saving energy. To achieve this result, however, takes more than simply giving customers more detailed energy use data. Utilities must actively engage with their customers and offer them a range of services to support their energy savings investments and actions, such as behavioral feedback.

AMI is considered by many to be a foundation of grid modernization and all its many benefits to customers, grid operators, and resource providers. One such benefit that is currently underutilized is reducing energy use through increased energy efficiency of customer end uses and the distribution network. To realize this benefit, utilities need to fully leverage AMI as a powerful tool toward the many uses and applications for energy efficiency that can be advanced by AMI's data and communications capabilities.

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# Appendix A. Interviewees

We interviewed each of the individuals below to gain background knowledge and confirmation of our primary desktop research. We gratefully acknowledge their contributions and note that these interviews do not imply affiliation or endorsement.

### **General Expertise**

Advanced Energy Economy, Ryan Katofsky

US Department of Energy, Buildings Technology Office, Monica Neukomm, Johanna Zetterberg, Steve Dunn, Amy Jiron

Edison Electric Institute, Adam Cooper Lawrence Berkeley National Laboratory, Peter Cappers, Annika Todd Mission:data, Michael Murray Plugged In Strategies, Chris Villarreal Smart Energy Consumer Collaborative, Patty Durand, Nathan Shannon

#### Service Providers

Copper Labs, Dan Forman

Opower, Oracle, Marisa Uchin and JD Toppin

Recurve, Carmen Best

Uplight, Monty Prekeris and Bryan Dreller

#### **Utilities and Program Administrators**

Baltimore Gas and Electric, Leigh Jarosinski Detroit Edison, Joel Miller NYSERDA, Megan Fisher and Kyle Monsees PECO, Mike O'Leary and Jeff Myers PGE, Erik Cederberg and Kirk Page VEIC, Dan Fredman

# Appendix B. Use Case Definitions

Table B1 details use case definitions from the survey of electric utilities we used in this report and from the 2020 Utility Energy Efficiency Scorecard. These descriptions represent publicly available data and program information from 2018, largely based on 2018 regulatory filings, 2018–2020 planning documents, and additional filings on utility and public utility commission websites. For utilities that do not operate on the calendar year, we used data from the 2017–2018 program year.

Ta	ble	B1.	Use	case	de	finit	ions

Program measure	Description
Energy use feedback to consumers in real time	Allowing consumers to better understand their behavior and adjust their energy usage to increase savings. Includes programs that provide feedback in near real time. Typically requires advanced metering infrastructure (AMI) installation.
Behavior-based feedback	Reducing energy consumption through social science theories of behavior change by providing information to customers, by leveraging interpersonal interactions, or by providing consumer education. Excludes programs that rely on traditional program strategies such as incentives, rebates, or regulations.
CVR or VVO	Improving the efficiency of a utility's transmission and distribution system through voltage reduction systems, whether explicitly included in the utility's energy efficiency portfolio or not.
TOU rates	Charging different prices for electricity during different times of the day and year.
GEBs	Incentivizing buildings that reduce energy waste and carbon emissions while offering flexible building loads to the grid. This may include integrating energy efficiency and demand response to better value the many benefits of grid- interactive efficient buildings.
Data disaggregation	Extracting end-use-level and/or appliance-level data from an aggregate or whole building energy signal to engage consumers and to target relevant programs to specific customers.

Source: ACEEE survey of top 52 electric utilities' energy efficiency offerings and performance in 2018

# Attachment CR-3 Public Discovery Responses

## **APS Responses to Data Requests**

- 1. APS Response to SC DR 4.1
- 2. APS Response to SC DR 4.2
- 3. APS Response to SC DR 4.3
- 4. APS Responses to SC DR 4.4
- 5. APS Response to SC DR 4.6
- 6. APS Response to SC DR 4.7
- 7. APS Response to SC DR 4.9
- 8. APS Response to SC DR 5.1
- 9. APS Response to SC DR 5.4

Sierra Club In 2018, APS reported on Form EIA-861 or EIA-861S that it has 4.1: installed 1,264,448 meters of which 1,251,355 constituted Advanced Metering Infrastructure. https://www.eia.gov/electricity/data/eia861/

- a) Is this information still current? If not, how many total customers have advanced metering infrastructure?
- b) How many residential customers have advanced meters?
- Response: a) As of May 31, 2020, APS had a total of 1,431,985 meters installed. Of those, 1,418,282 are AMI meters. Of these, 1,286,237 are billing meters and 132,045 are solar production meters (non-billing).
  - b) The Company has deployed 1,125,293 residential AMI billing meters.

- Sierra Club In response to Staff Set 11 Question 1, APS provided an Excel 4.2: spreadsheet which stated 698,368 customers have registered on the APS website.
  - a) Is it accurate to state that 55% of APS customers have registered for the APS website? If not, what percentage of APS customers have registered for the APS website?
  - b) Please provide the number of residential customers who have logged into the APS website at any time in 2019. Please provide the data as unique residential customers, rather than total site visits by residential customers. If the data requested are not available, please provide the data that most closely matches that requested.
  - c) Please provide the number and percentage of residential customers who have viewed their hourly energy usage data on the APS website at any time in 2019. Please provide the data as unique residential customers, rather than total site visits by residential customers. If the data requested are not available, please provide the data that most closely matches that requested.
- Response: a) Please see below for the percentage of customers that have registered on aps.com.

Current:

Residential – 721,027 / 1,145,039 (customer count) 62.9% Commercial – 34,427 / 136,126 (customer count) 25%

2019:

Residential – 700,803 / 1,135,033 (customer count) 61.7% Commercial – 33,338 / 136,414 (customer count) 24.4%

b) There were 604,202 unique customer usernames that logged into aps.com from January 1, 2019 – September 28, 2019. This number includes both residential and commercial customers.

There were 1,420,625 customer logins from January 21 – May 8, 2020.

The way logins are measured changed with the introduction of the new website (launched on September 28, 2019). Instead of counting the username once regardless of how many times a customer logged in, aps.com now counts total logins. This accounts

Response to for the discrepancy in numbers across the timeframes stated. SC 4.2

(continued):
 c) The requested data is not available. In 2019, there were roughly 52,667 residential customers on average per month who view their usage analytics page on aps.com. The current year to date (January – May 2020) monthly average is 45,200 residential customers.

To be more specific, there were 401,243 visits by residential customers to the usage analytics page from September 30, 2019 – June 8, 2020.

- Sierra Club Of the total AMI meters, how many have the capability of reporting energy usage in increments of:
  - a) 1 minute
  - b) 5 minutes
  - c) 15 minutes
  - d) Hourly
- Response: a) APS currently has 317,141 meters capable of being programmed to supply one-minute interval data. However, additional communications infrastructure would be needed to send the data to APS if a smaller time increment than 15 minutes was programmed into the meter.
  - b) The 317,141 meters mentioned in subpart a could also be programmed to supply five-minute interval data. Additional communications equipment would also be necessary for this increment of data.
  - c) In addition to the 317,141 meters mentioned in parts a and b that could be programmed to record 15-minute interval data, APS also has 160,944 interval meters for commercial and industrial customers that are currently configured to record data in 15-minute increments.
  - d) The 1,125,293 residential billing meters referenced in Sierra Club Data Request 4.1 record usage in 60-minute intervals.

- Sierra Club Of the residential AMI meters, how many have the capability of 4.4: reporting energy usage in increments of:
  - a) 1 minute
  - b) 5 minutes
  - c) 15 minutes
  - d) Hourly
- Response:

   a) APS has 290,618 residential billing meters that could be configured to supply one-minute, five-minute, or 15-minute interval data. Additional communications equipment would have to be installed in order to send the data to APS.
  - b) Please see the Company's response to part a.
  - c) Please see the Company's response to part a.
  - d) All residential AMI meters (1,125,293) record usage data in 60-minute intervals.

- Sierra Club Is the energy data provided to customers via the APS website 4.6: provided in Extensible Markup Language (.XML)?
  - a) If not, in what format is the energy data provided?
  - b) If not, do APS customers have any means to obtain their energy data in .XML format?
- Response: a) Excel.
  - b) No, not at this time.
- Sierra Club Does the energy data provided to customers via the APS website comply with Green Button Download My Data standards? If not, in what way is it noncompliant?
- Response: The website does not currently incorporate the voluntary Green Button standards, most notably XML delivery consistency and data sharing authorization.

- Sierra Club Please provide the number of residential customers who have 4.9: shared their data with a third party in 2019.
- Response: APS does not have information about how customers may use or share their own usage data.

- Sierra Club In response to Sierra Club 4.3(a) and 4.3(b), APS stated "However, additional communications infrastructure would be needed to send the data to APS if a smaller time increment than 15 minutes was programmed into the meter." Please provide the following information.
  - a. Does APS have plans to install the referenced "additional communications infrastructure" necessary to send energy usage data to APS in time increments less than 15 minutes?
  - i. If so, when?
  - ii. If not, why not?
  - b. Has APS evaluated the costs and benefits of installing the referenced "additional communications infrastructure"?
  - i. If APS has evaluated the costs and benefits, please provide a copy of such analysis including any work papers.
  - ii. If APS has not evaluated the costs and benefits, please explain why not.
  - c. Has APS considered any alternative to installing the additional communications infrastructure to provide the customer with energy usage data in smaller time increments than 15 minutes?
  - i. If so, what was evaluated? Please provide a copy of such analysis and any work papers.
  - d. If not, why not?
- Response: a. No.
  - i. N/A
  - ii. APS has not determined that the value of receiving the data in smaller time increments would offset the costs to implement.
  - b. No.
    - i. N/A
    - ii. APS has not determined that the value of receiving the data in smaller time increments would offset the costs

Sierra Club 5.1 Response (continued): c. No.

to implement.

i. N/A

d. APS has not determined that the value of receiving the data in smaller time increments would offset the costs to implement.

- Sierra Club In response to Sierra Club 4.8, APS responded that a customer 5.4: could share their energy data with a 3rd party by adding the 3rd party as a guest on their account. Please provide the following information.
  - a. Does the customer's guest have the same access to Energy Data that the customer has? If not, why not?
  - b. Does the customer's guest have access to Customer Account Data other than Energy Data? If so, what Customer Account Data can the guest access?
  - c. Can the customer's guest access information related to the customer's:
  - i. Social security number;
  - ii. State or federal issued identification number;
  - iii. Financial account number in combination with any security code providing access to the account;
  - iv. Consumer report information provided byEquifax, Experian, TransUnion, Social Intelligence or another consumer reporting agency;
  - v. Individually identifiable biometric data;
  - vi. First name (or initial) and last name in combination with any one of the following:
    - 1. Date of birth
    - 2. Mother's maiden name
    - 3. Digitized or other electronic signature;
  - vii. DNA profile.
  - d. Can the customer authorize a time-limited guest access? If so, for what period of time?
  - e. How does the customer revoke a previously authorized guest access?
  - f. Does APS customer guest access comply with DataGuard Energy Data Privacy Program Voluntary Code of Conduct Final Concepts and Principles (Final, January 8, 2015)?
  - i. If not, how does it diverge?
  - ii. If not, why not?

Response: a. Yes.

b. Yes. What a guest can see and do is dependent on the type of access (permission) granted to the guest as outlined below. This information is available to all customers at: https://www.aps.com/Business/Account/Account-Management/Guest/Permissions

#### View only access

These guests can only view the customer account information pages, usage graphs, charges, bills, etc. They can make a payment, but can't perform any activity or subscription. This is the most common type of guest role.

- Make, edit and view scheduled payments (guests can only view/edit payments that they have made)
- Make one-time payments
- Make payments without login
- View AutoPay enrollment status
- View saved bank account
- View account balance

#### Limited access

These guests, in addition to the activities of the view only access role, are able to perform start/stop orders and change service plans, if applicable. This access is less common and is primarily meant for property managers who are responsible for multiple properties.

- Make, edit and view scheduled payments
- Make one-time payments
- Make payments without login
- View AutoPay enrollment status
- View saved bank account
- View account balance

In addition to view only access:

• Make service orders (start, stop or move service)

#### Full access

These guests, in addition to the activities of the view only access role, are able to perform start/stop orders and change service plans, if applicable. This access is also less common and is primarily meant for property managers who are responsible for multiple properties.

• Make service orders (start, stop and move service)

Response to SC 5.4 (continued):

- Make, edit and view scheduled payments
- Make one-time payments
- Make payments without login
- View AutoPay enrollment status
- View saved bank account
- View account balance

In addition to limited access:

- Enroll and manage AutoPay
- Make a payment arrangement

c.

i – vii: No.

d. Yes, but guest access must be manually revoked.

e. To manually revoke guest access, a customer would follow these steps:

1. Log in to the APS account and click the 'Manage accounts' icon. Alternatively, the customer can hover over 'Accounts and services' in the navigation and select 'View all accounts'.

2. To the right of each listed account number, there is a 'Guests' column which allows the customer to view how many guest users are on that particular account. Click on the three dots icon (ellipsis) icon and select 'Show details'.

3. Select the 'Guest users' tab to view the list of guests on the account. To the right of each guest's email address, the access type and status will be listed.

4. Select the 'Revoke guest' link located on the far right.

5. A message will appear to verify the request. Click the 'Remove' button and a confirmation message will appear indicating the action requested is complete. Guest user preferences will be removed when access is removed.

f. APS does not use the DataGuard Energy Data Privacy Program Voluntary Code of Conduct Final Concepts and Principles. APS does, however, use NIST CSF and GAPP Generally Accepted Privacy Principles for data security and privacy. Both frameworks cover the intent of DataGuard Energy Data Privacy Program Voluntary Code of Conduct Final Concepts and Principles.

## Attachment CR-4

## Multi-Year Rate Plans: Core Elements and

**Case Studies** 

## **Multi-Year Rate Plans**

Core Elements and Case Studies

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AUTHORS

Melissa Whited Cheryl Roberto



485 Massachusetts Avenue, Suite 2 Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

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### 1. CORE ELEMENTS OF MULTI-YEAR RATE PLANS

Multi-year rate plans (MRPs) are widely used around the world and have been in place for many decades in a variety of industries. MRPs are also known as "price cap regulation" or "revenue cap regulation." These approaches have also been referred to as "hands-off regulation" because the utility's costs are not closely examined during the duration of the plan. Instead, the utility's revenues are de-linked from its actual costs in combination with a rate case moratorium (typically lasting from three to five years).

Jurisdictions typically implement MRPs to achieve some or all of the following goals:

- Provide the utility with cost containment incentives
- Encourage innovation by allowing the utility to manage business decisions with greater flexibility.
- Reduce regulatory costs and burdens.
- Provide utilities with greater regulatory guidance and assurance regarding investments in new and innovative technologies to better align utility investments with energy policy goals.

Modern MRPs generally cap allowed revenues, rather than prices, in order to reduce the utility's throughput incentive and encourage the utility to focus on cost reductions rather than increasing revenues. The utility is typically allowed to retain some or all of the savings that it achieves through cost reductions during the duration of the rate plan.<sup>1</sup>

Under an MRP's rate case moratorium, the utility must refrain from filing a new rate case for the duration of the plan. This moratorium generally lasts three to eight years and ensures that the utility cannot simply come in for a new rate case if costs and revenues diverge. This shifts the risk associated with poor utility cost management to utility shareholders, rather than ratepayers, which strengthens the utility's cost containment incentives.

During the rate plan, revenues may either be held at a fixed level or be adjusted according to a predefined formula called an "attrition relief mechanism" or "ARM." An ARM may be based on an external cost index (such as inflation), cost forecasts, or a combination of the two. Importantly, the formula does not track the utility's *specific* costs. As explained in the Edison Electric Institute's survey of alternative

<sup>&</sup>lt;sup>1</sup> However, as discussed in sections 3.1 and 4.2, when the utility's allowed revenues for capital investments are based on capital cost forecasts rather than external indexes, jurisdictions often require the utility to return any under-spend to ratepayers.

regulation mechanisms, "[t]he rate adjustments provided by ARMs are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* growth."<sup>2</sup>

In this manner, an MRP is similar to traditional cost of service regulation with a revenue decoupling mechanism, since the utility's costs do not necessarily equal revenues between rate cases, but the utility is still allowed to recover its allowed revenues (regardless of changes in sales). The primary differences from cost of service regulation with decoupling are:

- Allowed revenues can be increased annually through an ARM instead of frozen, and
- The utility agrees to not file another rate case for a set number of years (i.e., a rate case moratorium).

Because revenues do not increase in lock step with costs, the utility has an incentive to reduce costs to increase its profits for the duration of the rate plan. At the end of the MRP term, these cost reductions can then be passed on to ratepayers when rates are reset in a rate case.

To summarize, there are four key design elements that are critical to MRPs:

- 1) Revenue Cap: Revenues are capped at certain pre-determined levels.
- 2) Attrition Relief Mechanism (ARM): The initial year revenues may be escalated based on an index or cost forecast determined at the outset of the rate plan. Cost trackers may be added to the ARM for certain costs, particularly "exogenous" costs that the utility has no control over.
- 3) **Rate Case Moratorium:** A "stay-out" provision limits the ability for rates to be reset during the plan.
- 4) **Incentive to Improve Efficiency:** Utilities are incentivized to reduce costs during the plan by retaining some or all of the savings from efficiency gains.<sup>3</sup>

While MRPs can provide strong cost containment incentives and reduce regulatory burden, they also present two key risks. First, the utility's costs may deviate substantially from its allowed revenues during the rate plan. Second, the revenue adjustments provided by an index may not provide adequate revenue for new and unusual investments.

To address the first concern, regulators have often implemented consumer protection measures, such as earnings sharing mechanisms, to ensure that the utility does not over-earn excessively. For example, the utility may be allowed to earn 200 basis points above its allowed ROE, but beyond that it must share some of the extra earnings with customers.

<sup>&</sup>lt;sup>2</sup> Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (Edison Electric Institute, November 11, 2015), 34.

<sup>&</sup>lt;sup>3</sup> Conversely, ratepayers are protected from poor utility performance during the rate plan by being insulated from some or all of any increase in costs above the revenue cap.

To address the second concern, certain costs may be pulled out of the MRP and treated separately. For example, Massachusetts removed Eversource Energy's grid modernization investments from the MRP and is allowing recovery of those costs through a separate "Grid Modernization Factor."

#### **MULTI-YEAR RATE PLAN EXAMPLE: MASSACHUSETTS**

**Overview:** Eversource Energy operates under an MRP that uses a revenue-indexing mechanism to adjust base rates, plus reconciliation of certain exogenous costs. The MRP has a five-year stay out period.

**Revenue Index:** Eversource's MRP allows for an adjustment of Base Rates using the rate of input price inflation representative of the electric distribution industry, less offsets for productivity and a consumer dividend.

**Annual Adjustments:** Effective January 1 of each year, the utility's Base Revenue Requirement is adjusted through an adjustment formula equal to the percentage change in the US Gross Domestic Product Price Inflation (GDPPI), plus a productivity adjustment of 1.56% minus a consumer dividend of 0.25%, plus an adjustment for exogenous costs.

**Reconciliation of Exogenous Costs:** Exogenous costs must (1) be beyond the utility's control; (2) arise from a change in accounting requirements or regulatory, judicial, or legislative directives; (3) be unique to the electric industry as opposed to the general economy; and (4) meet a threshold of "significance" of \$5 million. The utility must present supporting documentation and rationale to the commission for consideration. Once allowed by the commission, the cost is recovered or returned in a separate factor to be reviewed and approved by the commission.

**Recovery of Pre-authorized Grid Modernization Costs:** All grid modernization-related capital and O&M expenditures are recovered separately and are subject to a targeted cost recovery cap. Specifically, the level of expenditures eligible for cost recovery through the Grid Modernization Factor shall not exceed the preauthorized three-year budgets.

**Customer Protections:** Earnings Sharing provides an important protection for customers in the event that expenses increase at a rate much lower than the revenue increases generated by the MRP revenue index. If the utility's actual ROE exceeds the utility's allowed ROE by 200 basis points, 75% of any additional earnings must be shared with customers.

See: NSTAR Electric Co. d/b/a Eversource Energy, Tariff Sheets M.D.P.U. No. 59A, filed February 16, 2018.

### 2. CONTRAST TO FORMULA RATE PLANS

#### 2.1. What is a Formula Rate Plan?

Both MRPs and formula rate plans (FRPs) feature formulas, thereby creating some confusion regarding the differences between the two approaches. The primary distinction is that formula rate plans formulaically ensure that revenues track costs, often measured as deviations in ROE from the utility's target ROE. If a utility's earned return is above its ROE target, it will be required to reduce its rates. Likewise, if a utility's earned return is below its target return it will be allowed to increase its rates. In contrast, MRPs do not adjust revenues to equal costs during the plan.<sup>4</sup>

A report by Edison Electric Institute describes a formula rate plan as "essentially a wide-scope cost tracker designed to help a utility's revenue track its cost of service."<sup>5</sup> The report explains how this works as follows:

Earnings surpluses or deficits occur when revenue and cost are not balanced. FRPs have earnings true up mechanisms that adjust rates so that earnings variances are reduced or eliminated.... The earnings true up mechanism plays a key role in an FRP. Some mechanisms compare the earned ROE to the target ROE and then calculate the rate adjustment needed to reduce the ROE variance. Others adjust rates for the difference between revenue and a pro forma cost of service calculated using a rate of return target.<sup>6</sup>

In other words, formula rate plans true up revenues to costs once the ROE deviates from the allowed ROE by a certain amount. These true-ups are generally accompanied by some form of commission review and approval, but these reviews are more streamlined than those that occur in a general rate case.

<sup>&</sup>lt;sup>4</sup> With the possible exception of a limited set of cost trackers or reconciliations for specific types of costs.

<sup>&</sup>lt;sup>5</sup> Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (Edison Electric Institute, November 11, 2015), 47.

<sup>&</sup>lt;sup>6</sup> Ibid.

#### **ALABAMA POWER'S FORMULA RATE PLAN**

**Overview:** Alabama Power Company operates under an FRP called the "Rate Stabilization and Equalization plan." Each year, the Alabama Public Service Commission compares the utility's projected ROE for the next year to its authorized ROE. If necessary, the utility's base rates are adjusted to keep the expected ROE within the authorized range, following a review of the reasonableness of the utility's costs.

**Reconciliation Process:** By December 1 of each year, the utility provides the commission with its projected ROE for the next year, together with an analysis of the main causes of any deviations from its authorized ROE and the need for any rate adjustment. During December, parties review and discuss the need for the rate adjustment, with any adjustments going into effect in January.

**Customer Protections:** Several customer protection measures are in place. Annual rate adjustments are capped at 5% to reduce rate shock. Once the utility's revenues are adjusted to match its projected costs for the upcoming year, the onus is on the utility to keep costs in check. If the utility fails to achieve its allowed ROE, no further reconciliation is made. However, if the utility's ROE exceeds its allowed ROE, then the excess is refunded to customers.

See: Laurence Kirsch and Mathew Morey, "<u>Alternative Electricity Ratemaking Mechanisms Adopted by</u> <u>Other States</u>" (Christensen Associates Energy Consulting, May 25, 2016), p. 11.

#### ENTERGY ARKANSAS, INC.'S FORMULA RATE PLAN

**Overview:** As required by 2015 Ark. Acts 2015 725, §3, formula rate plans in Arkansas use a formula based on the difference between a utility's target and earned return. If the utility's earned return exceeds its target return by 50 basis points, it is required to reduce its rates. Likewise, if the utility's earned return falls below its target return by 50 basis points, it is allowed to increase its rates.

**Cost Forecasts:** The utility may choose to use a projected test year or a historical test year. If a projected test year is used, the utility must file its cost forecasts in July of each year for the next calendar year period.

**Reconciliation Process:** If a projected test year is used, rate changes must include an adjustment to net any differences between the prior formula rate review test period change in revenue and the actual historical year change in revenue for that same year.

**Regulatory Review:** The review of cost forecasts, reconciliation, and approval of new rates occurs in a 180-day process that includes a public hearing.

Customer Protections: Annual rate adjustments for each rate class are capped at 4%.

See: AR Code § 23-4-1207 (2015)

#### 2.2. Concerns with Formula Rate Plans

Commissions have generally been reluctant to adopt formula rate plans due to the problematic incentives they provide and recognition that these plans shift risk onto ratepayers. For example, the Maryland Public Service Commission noted that problems with formula rate plans include "tendency to shift financial risks toward customers, a concern that automatic adjustments may curtail the thorough review of utility costs, and reduced incentives for utilities to control costs."<sup>7</sup>

These concerns have been borne out by experience in jurisdictions where FRPs have been implemented. For example, in 2015, Act 725 was passed in Arkansas requiring that the Commission approve formula rate plans, but capped revenue increases under an FRP to 4% per year. Following passage of the Act, Entergy Arkansas, Inc. filed for a formula rate plan. In each subsequent year, Entergy has requested rate increases exceeding 4%, leading to concerns that the formula rate plan has not provided appropriate cost containment incentives. As explained by the Commission Staff,

An FRP is an annual rider. It fundamentally accomplishes a higher level of certainty of recovery thus reducing risk to the utility.... The ability to increase revenues 4% each year is a considerable risk reduction for the utility.<sup>8</sup>

More specifically the Staff noted that an FRP:

- Reduces the time afforded for review of utility costs, which can serve to incentivize spending;
- Allows projections on projections, which incentivizes spending as compared to a regulatory framework where projections are based on what is otherwise historical information from which to make known and measurable changes;
- Incentivizes spending due to the annual rate adjustments. Once the FRP framework is selected by a utility, an outcome of a 4% increase each year (over the prior year) is less subject to challenge as long as the costs are prudently incurred and calculated in accordance with the tariff. The traditional regulatory tools in the Commission's toolkit are more limited under the FRP framework as the Commission has recognized;
- The unstated implication of the FRP statute is that the risk of an earnings review is effectively eliminated. There is no clear incentive to contain costs between annual FRP 4% increases. While the FRP framework states the rate change may be an increase or a decrease, the likelihood of a decrease is highly unlikely.<sup>9</sup>

<sup>&</sup>lt;sup>7</sup> Maryland Public Service Commission, Order 89226, PC51, August 9, 2019, at 53.

<sup>&</sup>lt;sup>8</sup> AR PSC Staff, Initial Brief Pursuant to Order No. 18, Docket 16-036-FR, January 1, 2019, at 17.

<sup>&</sup>lt;sup>9</sup> *Id.,* at 18-19.

In its order, the Arkansas Commission agreed with Staff, stating that "many of the FRP processes, including a reduction in the time afforded for review, the use of projections, and annual rate adjustments do little to incentivize a utility to control its costs as compared to traditional ratemaking."<sup>10</sup>

In contrast, multi-year rate plans provide strong efficiency incentives precisely by *avoiding* cost true-ups. As noted in a Brattle report filed by the Joint Utilities in Maryland, "Multi-year rate plans typically have reconciliations **more limited in scope** and typically focused on capital expenditures, **to the extent that reconciliations are included at all** [emphasis added]."<sup>11</sup>

#### FORMULA RATES AND MINNESOTA'S MRP

When Minnesota was developing its rules for multiyear rate plans, various parties proposed different approaches to revenue adjustments during the rate plan.

- The Minnesota utilities favored favor formula rates, arguing that these rates could be more useful because they would adjust to reflect the latest data.
- Other parties opposed the use of automatic formulas for the purpose of adjusting rates to reflect new costs. They argued that formula rates would reduce a utility's incentive to operate efficiently and would be burdensome to supervise. Instead, these parties favored fixed multiyear rates. The rate case would establish the rates to be charged in each year of the multiyear rate plan; the rates for the first year might differ from the rates for later years, but the base rates for all years would be known by the end of the rate case.

Ultimately the Minnesota Public Utilities Commission declined to approve multiyear rate plans that rely on formula rates, noting that such rates reduce a utility's incentive to manage its costs. Moreover, the Commission observed that formula rates are unnecessary to achieve the purpose of a multiyear rate plan, stating that "Fixed multiyear rates permit prices to adjust over time to reflect anticipated changes in a utility's circumstances, yet can be established in a fact-driven ratemaking process built on a substantial evidentiary record." Consequently, the Commission directed utilities to propose fixed rates for each year of their plan when filing a multiyear rate plan.

*See:* <u>Minnesota Public Utilities Commission, Docket No. E,G-999/M-12-587, Order Establishing Terms,</u> Conditions, and Procedures for Multiyear Rate Plans, June 17, 2013, at 6-7.

<sup>&</sup>lt;sup>10</sup> Arkansas Public Service Commission, Order No. 21, Docket 16-036-FR, July 5, 2019.

<sup>&</sup>lt;sup>11</sup> The Brattle Group, Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates, Joint Utilities' Joint Initial Comments, Maryland PC51, March 2019.

### 3. ESCALATING REVENUES DURING THE MRP

Attrition relief mechanisms escalate a utility's allowed revenues over the course of an MRP. The ARM can be based on either an external price index or a cost forecast. With cost forecasts, information asymmetry is a serious concern, which has led many jurisdictions to opt for an index-based approach. We discuss both approaches below.

#### 3.1. Revenues Escalated Based on Cost Forecasts

An ARM based on forecasts increases revenue by predetermined percentages in each plan year based, at least in part, on a utility's cost projections. The percentages can be different in each year, or the total increase can be levelized across the years.

To determine the revenue requirement for each year, both older capital investments (i.e., depreciation expense) and new capital additions must be accounted for. Depreciation expense is straight-forward to calculate, as older capital simply continues to depreciate. As noted in a recent report published by Lawrence Berkeley National Laboratories, the controversial issue lies in estimating the value of plant additions during the plan. The report explains that shortcuts are sometimes taken when estimating plant additions. For example:

- Plant additions may be set for each plan year at the utility's average value in recent years
- Plant additions may be set for each plan year at the value calculated in the test year of the most recent rate case
- Operation and maintenance expenses can be forecasted using index-based formulas.<sup>12</sup>

ARMs based on cost forecasts enable the utility's revenues to accommodate unusual investment trajectories, such as a capital investment surge. Since the ARM generally operates as a cap on revenues, it provides an incentive for the utility to ensure that actual investment costs are kept under the cost cap. However, forecasted ARMs are notoriously challenging for regulators, as it is difficult to ensure that the forecasts are reasonable due to asymmetry of information.

The National Regulatory Research Institute describes this issue as follows:

Information asymmetry reflects the relatively less knowledge that a regulator has (relative to the utility's) on the correlation between forecasted costs and utility-management competence. When a utility files a cost forecast, how does the regulator know whether it reflects competent management? The analyst or auditor can evaluate the

<sup>&</sup>lt;sup>12</sup> Mark Lowry et al., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (Lawrence Berkeley National Laboratory, July 2017), at 4.2, https://escholarship.org/uc/item/4r13j347.

forecast applying state-of-the-art techniques; still, however, a level of uncertainty remains that leaves unknown the utility's level of managerial competence embedded in the forecast.<sup>13</sup>

Sophisticated approaches to reducing forecast bias are available, such as the menu approach used in the United Kingdom. Under this approach, the utility can choose among various combinations of allowed revenues and earnings sharing mechanisms, such as a plan with high revenues but for which it retains only a small portion of any cost savings, or a plan with low revenues but under which it can retain a higher portion of cost savings.

Regulators may also conduct independent benchmarking and engineering studies to determine the reasonableness of cost forecasts, but such endeavors are costly. In addition, regulators can check the accuracy of past cost forecasts and create performance incentive mechanisms for forecasting accuracy. Where cost forecasts are used to set allowed revenues, they are often accompanied by a one-way (downward) reconciliation mechanism, as is done in Minnesota and New York.

#### MRP BASED ON COST FORECASTS WITH ONE-WAY RECONCILIATIONS

In 2017, the Minnesota Public Utilities Commission approved a settlement regarding Xcel Energy's multiyear rate plan application. The utility's initial application requested revenue increases supported by substantial documentation of the utility's proposed cost of service. During settlement proceedings, the annual revenue requirements were adjusted downward substantially, and generally became divorced from actual project costs.

The Minnesota Commission ultimately found the settlement reasonable, despite it no longer being tied to specific project costs, as the yearly rate increases were less inflation and significantly less than what Xcel initially proposed. Further, the settlement prohibited Xcel from filing another rate case until for four years or from seeking to institute any new riders for four years.

As an additional consumer protection measure, the settlement adopted a one-way capital-spending true-up, meaning that Xcel will make refunds if it spends less than it budgeted but cannot increase rates if it spends more. The true-up is based on aggregate capital spending, rather than individual projects. The Commission found that a true-up based on the aggregate amount of capital spending was reasonable given that Xcel's budget included approximately 1,800 capital projects. Nonetheless, the Commission also required that Xcel work with the Commission and Department of Commerce Staff to develop an annual capital-projects true-up compliance report that provides more granular data regarding project spending.

*See:* Minnesota Public Utilities Commission, Findings of Fact, Conclusions, and Order, Docket E-002/GR-15-826, June 12, 2017.

<sup>&</sup>lt;sup>13</sup> Costello, "Multiyear Rate Plans and the Public Interest," 35–36.

#### **3.2.** Revenues Escalated Based on External Indexes

External indexes have historically been the preferred means by which to set a utility's allowed revenue requirements for future years of an MRP. In some cases, different categories of costs are escalated at different rates based on separate cost indexes. For example, IHS Global Insights provides cost escalation forecasts that are specific to the utility industry and are broken out by category of cost.

Indexes may be coupled with a "productivity factor." This productivity factor is often denoted as "X" and generally reflects the multifactor productivity of a group of peer utilities. In addition, a stretch factor (or "consumer dividend") may be added to the productivity factor in order to provide customers with a share of the benefit of the stronger performance incentives that are expected under the plan.<sup>14</sup> Further, "Y" and "Z" factors for unusual costs or costs outside of the utility's control may be added, as discussed in Section 4.1 below. The resulting escalation formula may look something like this:

Revenue Requirement  $_{Year 2}$  = Revenue Requirement  $_{Year 1}$  \* (1 + Inflation – X) + Y + Z

The California Public Utilities Commission has repeatedly rejected ARMs based on the utility's specific cost forecasts, opting instead to use inflation forecasts for different types of costs. In 2019, the California Commission adopted a capital escalation rate equal to the unweighted average of capital escalation rates across seven categories of costs, as shown in the table below:<sup>15</sup>

	Year		
	2019	2020	
Total Steam Production Plant	2.51%	2.54%	
Total Hydraulic Production Plant	2.45%	2.40%	
Total Other Production Plant	2.11%	2.64%	
Total Transmission Plant	2.63%	2.62%	
Total Distribution Plant	3.14%	3.18%	
General Plant	1.82%	1.81%	
Total Nuclear Palo Verde	2.55%	2.46%	
Unweighted Average Across 2019-2020			

Unweighted Average of Capital Escalation Rates

Escalating allowed revenues based on an external index permits the utility to continue making necessary investments and avoid revenue attrition, while avoiding concerns regarding strategic behavior (i.e., gaming of forecasts) and information asymmetry that are present in forecast-based ARMs.

#### **3.3.** Conclusions Regarding Revenue Escalation Approaches

To summarize, index-based revenue adjustment mechanisms have many advantages over cost forecasts:

<sup>&</sup>lt;sup>14</sup> Mark Lowry et al., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (Lawrence Berkeley National Laboratory, July 2017), 4.2, https://escholarship.org/uc/item/4r13j347.

<sup>&</sup>lt;sup>15</sup> California Public Utilities Commission, D.19-05-020, Decision on Test Year 2018 General Rate Case for Southern California Edison Company, May 24, 2019, at 284.

- External cost indexes do not require that specific costs be reviewed and pre-approved at the beginning of the MRP. In contrast, basing revenue adjustments on a cost forecast essentially asks that the regulator pre-approve investments and their associated costs. This unduly shifts risks from the utility to the regulator and ultimately to ratepayers. Further, it increases the administrative burden for regulators and stakeholders.
- External cost indexes do not rely on utility cost forecasts that may be subject to error or may be over-inflated.

An index-based mechanism avoids the above challenges, but still allows utility revenues to increase over the term of the MRP, allowing for longer time between rate cases, without unduly shifting risk to ratepayers.

### 4. **RECONCILIATION OF COSTS IN MRPS**

Full reconciliations of costs and revenues in an MRP would be antithetical to the definition of an MRP. If revenues are trued up to equal the utility's actual costs, it erodes the utility's efficiency incentive, since the utility no longer benefits from implementing cost efficiencies and endures little risk if its costs exceed expectations. Broad annual true-ups would also essentially create annual rate cases, increasing the regulatory burden exponentially and erasing the benefits of the stay-out period.

However, some jurisdictions incorporate limited cost true-ups in MRPs. These true-ups often take the form of cost trackers for categories of costs that meet specific criteria and are limited in scope, such as costs that are outside the utility's control, or for a specific unusual capital investment.

When considering whether to implement any type of cost reconciliation mechanism, it is important to consider the impact on a utility's efficiency incentive and the impact on regulatory burden.

- If revenues are reconciled to actual costs, then the utility has reduced incentive to contain those costs.
- Under a broad reconciliation mechanism, the review required to determine that costs are reasonable imposes additional regulatory burden.

As emphasized by NRRI, "Regulators should avoid resetting annual rates based on a utility's actual cost in the absence of a prudence review...."<sup>16</sup> This means that any annual true-up based on actual costs would require a thorough examination of the utility's costs for prudence, which increases the regulatory burden. For these reasons, trackers and reconciliations should be used sparingly.

<sup>&</sup>lt;sup>16</sup> Ken Costello, "Multiyear Rate Plans and the Public Interest," National Regulatory Research Institute, at 23.

#### 4.1. Types of Costs that Are Often Reconciled in MRPs

In MRPs, cost reconciliations generally take some or all of the following forms:

- A. Reconciliations for certain unusual, large investments
- B. Reconciliations for recurring pass-through or mandated costs
- C. Reconciliations or deferrals of one-time extraordinary costs

#### A. Reconciliations for Unusual, Large Costs ("K-Factor" Costs)

Large, unusual investments can be difficult to predict and incorporate into an MRP. Further, some investments may have impediments associated with their implementation, such as excessive risk or high capital costs. For example, the Massachusetts Department of Public Utilities found that utilities "may hesitate before making investments beyond what they deem necessary to ensure safe and reliable service, and that this reluctance may even exist "when the investments are cost-beneficial for a company but involve high capital costs, combined with regulatory lag and the potential for disallowed costs."<sup>17</sup>

For these reasons, large, unusual investments are sometimes addressed outside of an MRP's standard revenue requirement through a capital cost tracker or other reconciliation mechanism, often generically referred to as a "K-factor." In Massachusetts, such a factor was established for certain "foundational" grid modernization investments, as discussed in the box below.

<sup>&</sup>lt;sup>17</sup> Massachusetts Department of Public Utilities, Order D.P.U. 12-76-A, Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid, December 23, 2013, at 25. Available at <u>https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9241637</u>

#### **RECONCILIATION OF GRID MODERNIZATION COSTS IN MASSACHUSETTS**

Utilities may hesitate before making investments with high capital costs, particularly when combined with regulatory lag and the potential for disallowances. To encourage grid modernization, the commission in Massachusetts approved a targeted cost recovery mechanism called the "Grid Modernization Factor" or "GMF" for investments that are preauthorized by the commission.

**Pre-authorization of investments and budgets:** All grid modernization-related capital and O&M expenditures are subject to a targeted cost recovery cap. Specifically, the level of expenditures eligible for cost recovery through the GMF shall not exceed the preauthorized three-year budgets.

**Cost Recovery:** Costs are only eligible for recovery after the expenses have been incurred and the investments have been placed in service. The utilities file annual GMF rate adjustment and reconciliation filings comprised of: (1) actual, eligible preauthorized expenditures from the prior grid modernization plan investment year; and (2) a reconciliation component in the second year and beyond. Interest on over- or under-recovery of the revenue requirement is calculated on the average monthly balance using the customer deposit rate.

Annual Reconciliation Filings: On an annual basis, the utilities must file testimony and supporting exhibits with full project documentation of all grid modernization capital projects placed into service during the plan investment year and documentation of O&M expenses. The utilities must demonstrate that the costs sought for recovery are preauthorized, incremental, prudently incurred, in service, and used and useful (where applicable). Additionally, the filing shall also describe any cost variances as defined in the Companies' capital authorization policies, provide a demonstration that the proposed factors are calculated appropriately, and provide bill impact estimates.

*See:* Massachusetts Department of Public Utilities, Order D.P.U. 15-122, May 10, 2018, at 216-235. Available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9163507

#### B. Reconciliations for Recurring Pass-Through or Mandated Costs ("Y-Factor" Costs)

Recurring costs that are volatile and outside of utility control may be fully or partially reconciled during an MRP using cost trackers or deferral mechanisms. In Alberta, these costs are referred to as "Y-Factor" costs. The Alberta Commission established the following criterial for costs eligible for Y-Factor treatment:

- 1) The costs must be attributable to events outside management's control.
- The costs must be material. They must have a significant influence on the operation of the company otherwise the costs should be expensed or recognized as income, in the normal course of business.
- 3) The costs should not have a significant influence on the inflation factor in the [MRP revenue] formulas.
- 4) The costs must be prudently incurred.

5) All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts.<sup>18</sup>

New York allows reconciliations only for costs that "are difficult to forecast with certainty and are largely beyond the direct control of utility management."<sup>19</sup> In New York, reconciliation and/or deferral accounting mechanisms have been used for costs including:

- Taxes
- Pensions/other post-employment benefits (OPEBs)
- Environmental remediation costs
- Regional Greenhouse Gas Initiative ("RGGI") costs
- System Benefits Charges
- Energy Efficiency Portfolio Standard charges and Demand Side Management costs
- New York Public Service Law §18-a regulatory assessment (for commission costs)
- Market supply charges
- Cost of the Low Income customer charge discounts<sup>20</sup>

We note, however, that some of these reconciliations have been only partial in order to preserve some incentive for the utility to manage the costs efficiently. In Consolidated Edison's MRP, if property taxes varied in any Rate Year from the projected level provided in rates, only 80% of the variation would be deferred and either recovered from or credited to customers, subject to a cap on the Company's share equal to 10 basis points on common equity for each Rate Year.<sup>21</sup>

In its order approving ConEdison's MRP, the New York Public Service Commission explained that asymmetrical and partial reconciliations for certain costs "provide the Company an incentive to manage such costs to the extent practicable." The Commission further noted that such reconciliation provisions decrease the volatility of a company's earnings and transfer risk to ratepayers, which allows the Commission to reduce the allowed return on equity in rate proceedings. The Commission explains that this "is one of the prime reasons returns allowed in New York are and can be lower than those in many other jurisdictions."<sup>22</sup> It is reasonable that any reconciliations and reduced risk to the utility be accompanied by a commensurate reduction in the utility's allowed ROE.

<sup>&</sup>lt;sup>18</sup> Alberta Utilities Commission, Decision 2012-237, September 12, 2012, at 135.

<sup>&</sup>lt;sup>19</sup> Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, February 21, 2014, at 26. Available at <u>http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1714A09D-088F-4343-BF91-8DEA3685A614}</u>

<sup>&</sup>lt;sup>20</sup> Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, February 21, 2014.

<sup>&</sup>lt;sup>21</sup> Joint Proposal, CASE 09-E-0428- Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, November 24, 2009, at 18.

<sup>&</sup>lt;sup>22</sup> Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, February 21, 2014, at 29-30.

#### C. Reconciliations of One-Time Extraordinary Costs ("Z-Factor Costs")

In an MRP, true-ups can be appropriate for exceptional costs that have a material effect on the utility's costs, are beyond the control of utility management, and which were incurred reasonably (such as extraordinary storm response costs). For example,

- New York's MRPs allowed cumulative major storm damage expenses in excess of a certain threshold to be deferred. The expenses would be subject to New York Department of Public Service Staff review.<sup>23</sup>
- California has utilized "Z-factors" to reconcile items that meet the following criteria:
  - 1. The event must be exogenous to the utility;
  - 2. The event must occur after implementation of rates;
  - 3. The costs are beyond the control of the utility management;
  - 4. The costs are a normal part of doing business;
  - 5. The costs must have a disproportionate impact on the utility;
  - 6. The costs and event are not reflected in the rate update mechanism;
  - 7. The costs must have a major impact on overall costs;
  - 8. The cost impact must be measurable; and
  - 9. The utility must incur the cost reasonably.<sup>24</sup>

#### 4.2. One-Way Reconciliations of Costs

As discussed above, the most common means of adjusting allowed revenues during the rate plan is the index approach. However, some jurisdictions use cost forecasts, or a combination of external indexes and cost forecasts. Where cost forecasts are used, they are frequently accompanied by one-way (downward) reconciliations of costs.

A key challenge associated with the use of cost forecasts is that the utility has an incentive to inflate cost projections. As the Alberta Public Utilities Commission noted, unless there is a reconciliation mechanism, basing revenues on cost forecasts "creates the opportunity for the distribution utility to benefit from exaggerating its forecasts and puts more pressure on the Commission to ensure the forecasts are reasonable." Further, the Alberta Commission notes its "concerns about over-forecasting and asymmetrical information and finds that an incremental capital mechanism that includes a forecasting component but lacks a true-up is problematic because it incorporates the unacceptable forecasting incentives..."<sup>25</sup>

A one-way reconciliation mechanism reduces the benefit that the utility receives from inflating its cost projections and protects customers from utility under-spend. The one-way nature of the reconciliation

<sup>&</sup>lt;sup>23</sup> Joint Proposal, CASE 09-E-0428- Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, November 24, 2009, at 24.

<sup>&</sup>lt;sup>24</sup> California Public Utilities Commission, D1408032, Authorizing PG&E's GRC Revenue Requirement for 2014-2016, at 661.

<sup>&</sup>lt;sup>25</sup> Alberta Utilities Commission, Decision 20414-D01-2016, December 16, 2016, at 53.

also encourages the utility to keep costs below the projections and ensures that over-spends are not approved until a prudency review in the subsequent rate case. However, the one-way nature of the reconciliation still incentivizes the utility to inflate its capital projections to ensure that it does not exceed its capital cost forecast. Just as importantly, it provides no incentive to increase efficiency.<sup>26</sup>

Minnesota and New York both use cost forecasts to project revenue requirements associated with capital investments, but have coupled the forecasts with a one-way (downward) reconciliation mechanism. New York's approach is discussed in the box below.

#### NEW YORK'S "CLAW-BACK MECHANISM"

A one-way reconciliation mechanism is used in New York and referred to as the "Net Plant Reconciliation Mechanism" or "claw-back mechanism." The New York Public Service Commission describes this mechanism for Consolidated Edison as follows:

If the Company's actual average net plant in service for each of the three categories of capital expenditures is less than that category's projected average plant-in-service balance..., the Company will defer the carrying costs associated with the difference for the benefit of ratepayers. If the Company exceeds the net plant-in-service targets, it must absorb the related carrying costs during the term of the rate plan. Con Edison must justify the need for, the reasonableness of, and its inability to reasonably avoid any such over-target expenditures in its next rate case filing. In addition, the revenue requirement associated with any such Commission-approved over-target expenditures from Rate Year 1, after the term of the rate plan and for the book life of the investment, will be calculated based on an assumption that the over-target expenditures were not financed by both common equity and debt, but rather solely by debt.

*See:* New York Public Service Commission, Order Establishing Three-Year Electric Rate Plan, Case 09-E-0428, March 26, 2010, at 11.

<sup>&</sup>lt;sup>26</sup> The California Public Utilities Commission (CPUC) has objected to such claw-back mechanisms precisely because it erodes the utility's incentive to be efficient. The CPUC explains:

<sup>&</sup>quot;...we are extending to utility management an opportunity and incentive to find ways to conduct operations for less than projected. When it can do this it flows the benefit to the utility's bottom line, which means profit. In the short term, between general rate proceedings, the shareholders benefit when the company's management can 'do it for less,' and correspondingly, ratepayers ultimately benefit because the productivity improvement will be reflected periodically when there is a comprehensive review of the utility's revenue requirement. Keeping this incentive for utility management is a cornerstone of ratemaking, which leads us to look askance at proposals for immediate 'give backs' of all cost savings to ratepayers. If ratemaking ever becomes so conceptually upside down that utility management loses the economic incentive to exercise its business acumen, California will be in a sad posture and will suffer under utility management which is lethargic with a 'cost plus' mentality."

See: California Public Utilities Commission, D.85-03-042, 17 CPUC2d 246, at 254, as cited in D.19-05-020, Decision on Test Year 2018 General Rate Case for Southern California Edison Company, May 24, 2019, at 152.

## 5. OTHER COMPONENTS OF MRPs

#### 5.1. Earnings Sharing Mechanisms

Earnings sharing mechanisms are primarily implemented to ensure that utility earnings do not become excessive during multi-year rate plans. The vast majority of these earnings sharing mechanisms are one-way adjustments that cap the potential over-earning of the utility and require that the utility share some of its over-earnings with customers. As noted by the Brattle Group, earnings sharing mechanisms that apply to "utility over earnings (but not under earnings) are in place in 10 states."<sup>27</sup> Only one state (Hawaii) is considering an earnings sharing mechanism for under-earnings as well.

Four states with MRPs have no earnings sharing mechanisms at all, allowing the utility to retain all overearnings or suffer any under-earnings. Where earnings sharing mechanisms are used, there is the risk that the utility's efficiency incentives will be blunted. Thus, to preserve utility incentives, many of the states with earnings sharing mechanisms also apply a deadband where a utility is not required to share excess earnings with customers.

In Massachusetts, the deadband for earnings sharing is 200 basis points for Eversource. If the utility's ROE exceeds its allowed ROE by 200 basis points, it must return 75% of additional earnings (beyond 200 basis point) to ratepayers. In Iowa, the commission set MidAmerican's allowed ROE at 10% and then required that earnings between 11% and 14% be shared 80% with ratepayers. Beyond an earned ROE of 14%, all of the excess earnings are to be returned to ratepayers.<sup>28</sup>

#### 5.2. Rate Plan Duration

MRPs are usually last between three and five years, although the plans in the United Kingdom last for eight years. There are several distinct advantages to plans that are shorter in duration:

- Shorter plans require less up-front investment in time and resources (modeling, review).
- Shorter plans present less risk associated with getting the forecasts wrong.

However, shorter plans also provide much weaker incentives for a utility to reduce its costs, as any cost reductions will quickly pass on to ratepayers at the time of the next rate case (unless efficiency carryover mechanisms are used).<sup>29</sup>

<sup>&</sup>lt;sup>27</sup> Pepco Exhibit J, Witness Zarakas, in FC 1156, The Application of the Potomac Electric Power Company Authority to Implement a Multiyear Rate Plan for Electric Distribution Service in the District of Columbia, at 13.

<sup>&</sup>lt;sup>28</sup> Iowa Utilities Board, Order Approving Settlement, with Modifications, and Requiring Additional Information, Docket No. RPU-2013-0004, March 17, 2014.

<sup>&</sup>lt;sup>29</sup> Efficiency carryover mechanisms allow for the utility to retain a share of its savings from efficiency improvements for a set period of time when a multiyear rate plan expires. For more information, see Mark Lowry et al., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (Lawrence Berkeley National Laboratory, July 2017), at 4.8-4.10, https://escholarship.org/uc/item/4r13j347.

In contrast, longer plans provide greater innovation incentives (due to more time for utility to reap rewards from innovation and efficiencies). Longer plans also reduce the frequency of rate cases and therefore possibly reduce overall costs of regulation.

#### 5.3. Reopener Provisions

Reopeners permit a reassessment of the utility's revenues and costs with the potential to make adjustments. A utility would be expected to request a reopener if it was under-earning, while a regulator or other stakeholder would be expected to request a reopener if they felt the utility was over-earning. However, use of reopeners can dilute incentives for the utility to operate efficiently, since the utility knows it can simply come back in and ask for more revenues, or the utility knows that if it operates too efficiently, its higher earnings will be taken away prematurely. Establishing clear criteria for reopening rate plans at the outset can help avoid reopening rate plans except when absolutely necessary.

In Minnesota, a utility that receives Commission approval of its multiyear rate plan must delay filing a new rate case until after the plan expires. However, utilities still retain the discretion to request rate relief from the Commission under Minn. Stat. § 216B.16, subd. 19 (c).

#### 5.4. Performance Incentive Mechanisms

Under an MRP regulatory framework, utilities retain some or all of the savings achieved through cost reductions. This can create an incentive to cut costs at the expense of service quality. To combat this incentive, regulators have historically coupled MRPs with performance incentive mechanisms (PIMs) to prevent service quality degradation. Increasingly, PIMs are also increasingly being used to promote other outcomes, such as emissions reductions, as well as to ensure that a utility follows through on its commitments, such as investments in grid modernization.

# Attachment CR-5

## Utility Models: Questions for Regulators and Stakeholders to Ask and Answer as Utilities Evolve





## UTILITY MODELS:

# QUESTIONS FOR REGULATORS AND STAKEHOLDERS TO ASK AND ANSWER AS UTILITIES EVOLVE

BY RON LEHR & SONIA AGGARWAL ● FEBRUARY 2017

Every utility regulatory model has embedded incentives. This list is intended to help state policymakers and other stakeholders pinpoint questions they can ask and answer to explore how incentives from cost of service regulation and performance regulation relate to today's power system goals.<sup>\*</sup>

#### QUESTIONS FOR STATES WITH COST OF SERVICE REGULATION

- What types of utility activities or investments does the current financial structure incent? Is it equipped to provide comprehensive and coordinated solutions across issues facing utilities today and in the future?
- What do customers want? What role does customer satisfaction play in utility profitability?
- What policy, financial, market, and operational considerations, constraints, and opportunities should be analyzed to determine an appropriate role for utilities going forward? Should they be the sole providers of electricity services or should they enable a role for customers and third-party providers?
- Are current financial incentives for utilities aligned with efficient utility operations, adequate and reliable service for consumers, and just and reasonable rates? Are they aligned with goals for environmental performance?
- In addition to well-known monopoly incentives, have utility monopsony incentives been analyzed? Are there ways to regulate monopsony incentives in the public interest?

http://energyinnovation.org/resources/our-publications/going-deep-performance-based-regulation/ http://westernenergyboard.org/wp-content/uploads/2015/03/03-09-15-Synapse-WIEB-Utility-Performance-Incentives

<sup>\*</sup> For more information, see:

http://americaspowerplan.org

- How will today's regulation lead utilities toward constructive responses to new challenges that require innovation, such as new technology, changing customer preferences, security, and storm damage recovery? Does today's regulation reward adaptation and innovation?
- How does current utility planning handle risk management? What does this mean for customers? For utility investors?
- What is the state of communications and trust among those engaged in regulation? Are communications open and broad-ranging or constrained to taking positions in formal, litigated cases? Are there opportunities to improve the amount and quality of utility stakeholder communications?
- If commission time and resources are constrained, is there potential to reorient away from case dispute resolution and toward longer-term policy and planning?
- Could formula-based approaches or revenue caps with periodic, planned rate cases provide a more efficient way to set rates?

#### QUESTIONS FOR STATES ASSESSING PROPOSALS FOR PERFORMANCE REGULATION

- What standards, metrics, or measurements are already in place and how has the utility performed against those? How do these complement newly proposed incentives?
- Have the overall goals of the performance regulation program been clearly defined?
- Have particular outputs and quantitative metrics been associated with overall program goals? Can these metrics be tracked and verified with existing or easily-obtained data?
- How do the new goals and metrics relate to existing standards and metrics?
- Who are the stakeholders—those with a stake in utility goals sufficient to motivate their inclusion in discussions about defining those goals? Have they been adequately consulted?
- How will future performance be reported? Would a template or a scorecard be appropriate?
- Is there sufficient knowledge about historical and likely future utility performance to set ambitious but reasonable targets for new metrics? How far into the future should targets be set in order to give utilities adequate time to pursue sustainable new business activities?
- Would incentives and penalties be appropriate to focus utility endeavors on new goals? Would it be appropriate to incent or penalize performance on some of the metrics and track others for future consideration?
- What is an appropriate overall financial impact on the utility for the full set of incentives and penalties? How does this relate to the level of ambition of the targets? Is a higher return appropriate for utilities if they take on more risk to facilitate the transition?

- Are the costs and benefits of performance incentives reasonably balanced? Are symmetrical or asymmetrical performance rewards and penalties better suited to the circumstances? What would capture utility management attention? How should effects on utility investors be factored into this calculus?
- What is the trade-off between tying metrics as closely to goals as possible and ensuring performance is firmly within the utility's control? Are there ways utilities can influence outcomes they may not directly control?
- Are there factors against which utility performance should be normalized, such as weather or regional economic development?
- Beyond normalization, are there other ways to build in opportunities for metrics, targets, or financial incentives to evolve in response to changing circumstances and measured performance, without introducing unnecessary risk into the program?

