Minnesota *Public Power Forward* Toolkit

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We extend our sincere thanks to Dan Ebert of the Ebert Group for providing the original inspiration for this project.

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Southern Minnesota Municipal Power Agency: page 23

Elk River Municipal Utilities: pages 33, 34

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Introduction

The electric industry is in a period of rapid transformation. New technologies have emerged, energy markets across the country have dramatically changed, and customers expect and demand 21st Century services. This creates opportunities and challenges for the electric utility industry – particularly smaller public power electric utilities – where meeting customer expectations for new services while maintaining the current high standards in reliability and affordability may not be easily accomplished.

With that in mind, the Minnesota Municipal Utilities Association (MMUA), Missouri River Energy Services (MRES), Southern Minnesota Municipal Power Agency (SMMPA) and the American Public Power Association (APPA) entered into the Minnesota Public Power Forward Partnership to assist Minnesota's public power utilities as they plan for the future. Using examples from the state and national level, we want to provide the public power community with the resources they need to take action on the following three areas.

Rate Design and Business Models — Public power utilities have historically relied upon rate designs that use volumetric rates to recover fixed costs, which can lead to revenue recovery challenges in the case of increased distributed generation (DG) on their system. There are some relatively simple steps we can begin to make today to strengthen our systems by reforming our rate designs. Rate design options for utilities to make up for this revenue shortfall include increasing fixed charges, instituting a residential demand charge, using time-of-use pricing, and using two-metered billing. In the past, utilities were fairly insulated from competition, but with the rise of new technologies, third-party competition for services is increasing, and the role of the utility is being debated.

New Technologies — We must understand how new technologies — particularly distributed generation, demand response, and energy storage — will impact our systems. While there is not currently much customer demand in our communities for these technologies, they are gaining traction in some public power communities and we do expect that demand to arrive in many public power communities over time. We should investigate the economic and reliability dimensions of these technologies by supporting pilots in our communities.

Information Technology (IT)/Operations Technology (OT) – Public power utilities can use IT and OT tools such as advanced metering infrastructure (AMI), meter data management, smart customer information systems (CIS), supervisory control and data acquisition (SCADA), and geographic information system (GIS) to collect, manage, and use data to support customers and to increase the reliability and operational efficiency of their distribution systems. Though these types of technology upgrades can currently be cost-prohibitive in some cases, as the world becomes increasingly digitized and technology costs come down, public power utilities have the opportunity to build a technology foundation. Joint action agencies and state associations can closely support members interested in technology transitions when investments are deemed necessary.

How to Use this Toolkit

The content of this toolkit is organized by subject area. Public power examples in addition to state association and joint action agency services are featured throughout.

Tips:

1. Download and share this resource with key personnel at your utility.
2. Read the toolkit and feel free to annotate your thoughts. Please do not feel that you have to read this all in one sitting.
3. Check out the resource section of the report for further reading or exploration.
4. Discuss the ideas and technologies presented with your colleagues.
5. Strategize ways to move your utility forward.
6. Pick top priorities for new initiatives or pilots.
7. Engage with your customers to achieve buy-in.
8. Develop goals, schedules, and metrics.
9. Create an implementation plan.
10. Launch project.
11. Share findings among your community and the broader public power community.
12. Keep learning through meetings, webinars, journals, news articles etc.
13. Stay engaged with your state association, joint action agency, and APPA.

Rate Design and Business Models

The "utility of the future" concept has received a lot of coverage in recent years. What does this mean, and what is its significant in terms of public power?

Utility of the future is a general concept related to the changing role of the electric utility. For years, electric service had been categorized by the concept of a vertically integrated utility providing electric service to an end-use customer using its own generation, transmission, and distribution facilities. There have been changes to this model over time. Wholesale deregulation permitted competitive suppliers to enter the marketplace to provide generation service. In some states, retail competition emerged, and customers can select from suppliers other than their incumbent utility.

New resources, particularly distributed energy resources (DERs), are fostering even greater changes or calls for change. Customers can self-supply electricity, usually through rooftop installed solar photovoltaic (PV) generation. They can also sell unused (or excess) generation back to the utility, meaning that distribution lines – designed for the one-way flow of power – are essentially called on to be two-way streets. This creates both financial and operating challenges for utilities, which will be further explained shortly.

DERs, which can also include energy storage, energy efficiency, demand response, and even electric vehicles (EVs), are changing the dynamics of utility service, so much so that there have been calls for major reform, the most prominent of which is perhaps the New York Restoring the Energy Vision (NYREV). This REV process is meant to foster the adoption of new technologies. Under this vision, a Distributed System Operator (DSO) acts as a conduit tying these resources together.

New York is far from the only state considering changes. Minnesota has its own "grid modernization" proceeding at the Public Utilities Commission. One of the fundamental questions being asked at these varying proceedings is what is the role for the utility in the future? Will the utility be a mere wires provider, providing nothing more than the grid service to your home? Or will utilities have a much greater role in integrating these new resources and technologies?

While those long-term questions are being answered, utilities need to address more pressing concerns related to DERs.

Rate Design

Public power utilities establish rates designed to yield revenues equal to their cost of service. For residential customers, rates have traditionally been relatively simple: a small customer charge (typically $10 or less per month) and an energy charge based on consumption, or kilowatt-hour (kWh) usage. For commercial and industrial customers, there may also be a demand charge.

The customer/fixed charge, which does not include any energy usage, recovers the costs of serving customers in areas such as meter reading and maintenance, customer service, and billing, along with a portion of the local distribution facilities costs. Historically, utilities have kept the customer/fixed charge artificially low and have not included all of their fixed costs in this component of the rate.

The demand charge includes the demand-related power supply and transmission costs and a portion of the local distribution facilities (substation, system loop, primary and secondary lines, feeders) that are capacity related.

The energy charge, when a demand charge is also present, includes the energy portion of the power supply bills, a portion of the distribution facilities costs if they are not fully recovered in the demand charge, and sometimes the franchise/transfer fee if that fee is based on a $/kilowatt-hour (kWh) methodology. When there is no demand component, such as may be the case for residential and small commercial classes, the energy charge also includes most of the local distribution facilities that would normally be included in the demand charge. Each component includes some overhead and administrative and general costs.

Distributed generation creates potential revenue recovery issues for utilities because the over-reliance on energy-related charges does not reflect the true nature of costs for utilities. While bills have very low fixed customer charges, a much higher percentage of a utility's costs are fixed.

Normally, when a customer consumes less energy, this is compensated by lower costs in serving that customer. But distributed solar customers are generally compensated through net metering. Under this arrangement, energy delivered by the customer to the utility causes the meter to run backwards. At the end of the month, the customer's net usage is then billed. In effect, a customer is compensated for excess generation at the retail rate of electricity.

The solar customer's net electric usage diminishes, and under this arrangement, their bill is dramatically reduced because their volume of usage is lower, which leads to reduced revenues to the utility through the energy charge. Yet the fixed costs to serve that customer have not diminished even as the revenue recouped from them has. The utility must provide distribution services to the solar customer, including the full provision of infrastructure and reliable, immediately-available electric service when the solar production is not online. This leads to a subsidization from non-solar customers to solar customers, as the former must make up for the lost revenue from the latter group.

Utilities have attempted to eliminate or diminish this subsidy through rate design changes. These have been explored in detail elsewhere, so these options will be briefly summarized below.[1]

Increased Fixed Charges

Utilities have attempted, and some have succeeded, at increasing their customer charge. This is the most straight-forward approach to recoup fixed costs through fixed revenues. It is a much simpler design for customers to understand. However, energy efficiency supporters argue that they undermine conservation efforts by making volumetric charges cheaper, while consumer advocates are concerned that they tend to most adversely affect low-use, and thereby low-income customers. While some utilities have been able to modestly increase customer charges, they are often denied the full request by boards and commissions.

Residential Demand Charge

A demand charge assigns a cost to the customer for the relative strain the individual customer places on system resources. Demand charges are designed to reflect the cost associated with meeting customer demand, and can be used to incent customers to flatten their loads or even to reduce their load during utility system peak periods.

Demand charges have traditionally only been applied to commercial and industrial customers. Utilities are increasingly considering applying demand charges to residential customers – in some cases just to solar rooftop customers, but some are considering applying them to all customers.

Aside from setting price signals to change customer usage patterns, demand charges also allow the utility to set energy charges that are closer to its actual economic costs, while recovering fixed costs from those that impose the greatest capacity costs on the utility. Customers can also avoid high demand charges by spreading out the times they use energy intensive appliances, or by shifting usage to periods when demand is not measured.[2]

It may be difficult for utilities to implement residential demand charges. Residential customers are not accustomed to this idea, and so may have difficulty adapting or understanding them. Some customers may lack the ability to curtail usage, and would thus be subject to higher charges.

Time-of-Use (TOU) Pricing

TOU or time-varying pricing (TVP), are terms which include various modes of pricing electricity differently at distinct periods of the day, and are becoming more widely explored options for all customers. Under TOU, the price of electricity more accurately reflects the actual cost of delivering service. As such, prices would be higher at peak periods, while reduced for other times. Some TOU pricing regimes have a simple on-peak, off-peak rate, while others have multiple pricing periods.

TOU or TVP rates are an attractive option because they may align utility costs and revenues more equitably, regardless of whether a customer has invested in distributed resources. TOU rates also would mean that credits applied under a net metering tariff would better reflect the actual value of energy supplied *to* the grid.

One of the difficulties with TOU pricing is it generally requires special metering, particularly AMI. Also, as with demand charges, there is concern that customers may not be able to adapt to time-varying rates. Another technical issue for utilities is that TOU rates could compound cost recovery issues if fewer peak price events occur than anticipated or if customers reduce consumption well more than anticipated in response to the peak rates.

Value of Solar (VOS)

Utilities have begun examining the actual VOS in their service territory. Though specific studies use different methodologies, these studies generally have the following core components:

- Energy[3]
- Emission reductions or Renewable Energy Credits
- Transmission and distribution loss savings
- Generation capacity
- Transmission and distribution capacity
- Ancillary services
- Other costs and benefits, including environmental, fuel price hedging, operation and maintenance expenses, and others[4]

By establishing a quantifiable value of a kWh of rooftop solar generation, utilities can better measure the relative subsidy of a net metering rate. If the utility were to adopt the VOS rate, the credit for solar production would be reflective of the actual value of solar to the system.

Net Billing

In lieu of net metering – where solar customers are compensated for excess generation at the retail rate – utilities may choose to compensate solar customers at a different rate. Utilities may issue credits at the wholesale power cost of supply, avoided cost, or some other predetermined credit rate. Under a net billing scenario, the customer's self-supply is disregarded, and the utility measures only the amount of energy consumed by the customer from the utility, and then separately measures (with a distinct meter) the amount of excess generation supplied by the customer to the utility. These amounts are then netted against each other to determine the customer's monthly bill.

Buy-All, Sell-All

As with net billing, the credit rate for customer-side generation is different than the retail rate of electricity delivered to the customer. As opposed to net billing, however, all electricity consumed by the customer and all electricity generated is accounted for. All of the electricity consumed by the customer – whether supplied at the customer's residence or by the utility – is billed at the retail rate, while all customer-side generation – whether consumed by the customer or sent to the grid – is credited at a separate rate. At the end of the month, these amounts are netted out.

Standby Charges

Standby charges or rates have traditionally been applied mainly to commercial and industrial customers who self-generate through Combined Heat and Power (CHP) systems, and are designed to compensate the utility for providing backup energy, particularly when CHP systems have unplanned outages or maintenance. Standby charges could be fixed monthly charges covering the utility's fixed costs, though some standby rates have demand and volumetric components. Some utilities have begun applying standby rates to distributed generation.

Case Study: MRES Retail Rate Design Services

Missouri River Energy Services (MRES) has offered cost-of-service and rate studies to its member utilities for over 20 years. Over time, members found that a regular schedule of reviewing rates has been very beneficial to ensure financial stability and to ensure that rates are cost-based, or moving toward cost-based. Most members are now on a three to four year cycle, with high level reviews in between if there are any significant changes. These regular rate reviews allow utilities to keep up with internal and external changes that might impact rates and to phase in any needed rate adjustments. The key highlights of the study and proposed recommendations are presented to the utility's governing board at a public meeting for consideration. The presentation also provides an excellent educational opportunity for the governing board and citizens that attend the meeting to learn about the benefits of their local, customer-owned electric utility.

Rate studies conducted by MRES address five main areas:

1) Sufficiency of total revenues to cover revenue requirements, which may include:
    a. Annual power supply and transmission costs, along with operating expenses
    b. Franchise fee and/or payment-in-lieu of taxes
    c. Five-year capital improvement plan and how the plan will be financed (through revenues, reserves, debt or a combination thereof)
    d. Adequate cash reserves for planned improvements and emergencies
2) Cost to serve each customer class
3) Retail rate design for various customer classes
    a. Protection of utility revenues
    b. Prevention of cross and interclass-subsidies
4) Impact of anticipated distributed generation, such as solar
5) Competitive position of the utility through rate comparisons

MRES takes a comprehensive approach to the rate studies we provide to our members. Going beyond ensuring that total revenues are sufficient to cover revenue requirements, MRES helps members plan for the future by anticipating and preparing for upcoming projects and expenditures, changing regulatory requirements, changing customer needs and expectations, and the changing electric industry as a whole.

Wholesale Demand and Energy Requirements

The first step in preparing a rate study is to examine the utility's power supply requirements, from MRES as well as from other suppliers such as the Western Area Power Administration. We review historical peak demands as well as energy requirements, and then estimate load growth using a power supply forecast prepared by MRES, along with the member's knowledge of any substantial loads coming onto or leaving the system. Energy consumption is broken down by customer class based on historical trends and the member's knowledge of specific increases or decreases in a customer class.

Projected Net Income and Cash Reserves

Revenue requirements must be compared to revenues to determine whether the electric utility will recover all of its costs and provide a margin to fund a reserve for system replacements, contingencies, and rate stabilization. Revenue requirements typically include purchased power costs, transmission expenses, operating expenses, franchise fee, transfers, revenue-financed capital expenditures, and debt service. Revenues include forecasted electric sales by customer class, service fees, sales of merchandise, capacity payments (if applicable), and investment income.

Franchise Fee / Payment-In-Lieu of Taxes

The franchise fee and/or payment-in-lieu of taxes are important components of the utility's revenue requirements. They can constitute a significant annual expense for the utility. The impact to the utility and the benefit to the city should be reviewed during the rate study process so that a methodology can be established (if one has not already been established) that is fair to both the utility and to the local government. MRES recommends developing a clear policy or specified methodology to determine the level of annual contributions. This allows both entities to prepare a more informed and accurate budget and thereby reduce the risk of unexpected expenses in the case of the utility, or a shortfall in revenues in the case of the city. MRES provides statistics and analysis to support this process.

Capital Improvement Plan

Development of a five-year capital improvement plan is also a key component of determining revenue requirements. Service reliability is top priority for customers. Utilities must be diligent about regularly analyzing the condition of their system and planning for major improvements, such as overhead to underground conversions, voltage upgrades, service line extensions, equipment replacements, new substations, etc. With a solid plan in place, that is reviewed and updated annually, the utility can prioritize projects and determine which will be revenue-financed and which will be financed with debt.

Cash Reserves

Maintaining adequate reserve levels is important to any business, and especially to the electric utility industry since it is very capital intensive. Reserves are needed to cover immediate costs in case of a catastrophe or emergency, such as a tornado, hurricane, ice storm, transmission failure, substation failure, etc. Sometimes, expenditures made during an emergency will later be reimbursed by the Federal Emergency Management Agency or the insurance company. However, utilities typically have to pay the costs of dealing with the emergency up-front and go through mountains of paperwork after the fact to get reimbursed. Reserves may also be used to fully or partially fund planned improvement projects in order to reduce debt and interest costs. Another benefit of the reserve fund is that bond rating agencies look favorably on adequate levels of reserves when assigning credit ratings.

In recognition of the importance of reserves for reliability and financial stability, MRES recommends that members adopt a reserve policy for the utility enterprise. The policy could include: an operations fund of 60 to 90 days of cash; a contingency/emergency fund that is based on the risk exposure of the utility; and a capital improvement fund of two to three years of average capital outlay to finance the five-year capital plan. The sum of these three funds typically ranges between 40 percent and 60 percent of annual operating revenues. However, depending upon the utility's financial situation and/or financing philosophy (reserves versus debt), some utilities require higher reserves as a percentage of revenues. In general, the larger the utility, the lower the percentage of reserves can be. All restricted reserves, due to bond covenants and other restrictions, are excluded from the cash reserves described above.

Cost-of-Service Study

MRES recommends that members set rates that are as close as possible to the actual cost to serve each customer class. Customer classes may include residential, residential heating, small commercial, large commercial, industrial, rural, street and security lighting, to name a few. To allocate costs to customer classifications, costs must first be categorized to the following components:

- Power supply, transmission and/or generation costs: demand-related and energy
- Distribution costs: substations, transformers, primary and secondary lines, and other expenses related to maintaining the distribution system
- Customer service costs: customer service, billing and records, and metering
- Indirect revenues and expenses: administrative and general expenses with other operating revenues and investment income as offsets

The functionalized costs are allocated to the utility's customer classes based on several allocation factors that are unique to each utility. The costs are summed by class and compared to the revenues of each class to determine the cost-of-service adjustment, if any. The analysis also provides unbundled rate components for each class. This information is used as a guideline for rate design along with other factors impacting the utility.

Rate Design

During the rate design phase, the costs for each customer class are analyzed to determine which component of the electric rate they should be attributed to. Most utilities across the nation have seen a decline in residential usage since 2010; therefore, an erosion of revenues can occur at utilities where a higher portion of the fixed costs are recovered through the energy rate rather than the customer charge. For the past several years, MRES has encouraged members to gradually increase their customer charge to prepare the utility for the possibility of customers adding distributed generation, such as solar panels, to the distribution system. As a result, MRES members have been steadily increasing their customer charges to more accurately reflect cost-of-service.

MRES recommends that members include a Power Cost Adjustment (PCA) provision on the rate schedule. If wholesale power and/or transmission rates increase at a greater percentage than assumed in the rate study, the PCA may be implemented to recover the additional power costs. This provision lowers the risk for both utilities and customers and eliminates the need for utilities to set their rates artificially high to compensate for the possibility of wholesale power supply and/or transmission cost increases.

Solar Impact on Rates

In the MRES service territory, solar production often has an average coincidence of 35 percent with MRES member peak demand and the coincidence ranges from 5 percent to nearly 60 percent. Therefore, for many MRES members, solar production provides little value to the utility in reducing peak demand. With very few solar installations in MRES member communities at this time, the loss of revenue is minor. However, members are encouraged to prepare now for likely increases in the impact of solar installations.

Green Energy Rate

A number of national corporations with a local presence in MRES member communities have adopted renewable goals, initiatives, or mandates for their companies in order to do their part in protecting the environment. Some have very ambitious goals of committing to 100 percent renewable power. For many of these companies, building renewable resources to meet their own needs is not possible or practical, or they can only go so far, depending on the footprint of their property, zoning restrictions, or other barriers.

To support customers in their desire for renewable energy, MRES offers its members and their customers a Green Energy Rate. Customers may request a specified amount of green energy (up to 100 percent of their electrical usage), for a mutually agreeable term of years. MRES will provide that green energy at a rate set annually by the MRES Board of Directors, which will cover the cost of acquiring and providing the energy from renewable resources selected by MRES, typically wind and/or solar resources.

Under a separate program, MRES offers it members and their residential and small commercial customers the opportunity to purchase green energy in blocks of 100 kWhs (up to 100 percent of their electrical usage). The green energy rate for this program is established by the MRES Board of Directors and the participating utility may add an administrative fee. The green energy is billed as a separate charge on the customer’s bill.

Economic Development Rate

MRES has experienced low load growth since about 2008, due in part to the downturn in the economy and sluggish growth in its member communities, and later to its success in helping members and their customers become more energy efficient. For many utilities outside the MRES membership, an increase in distributed generation is also contributing to low load growth.

In an effort to not only help existing customers use energy wisely through energy efficiency, but to also help member communities with smart and efficient growth, MRES developed an Economic Development Rate Discount. The rate discount will provide MRES members with a tool to help attract new high load factor retail customers and encourage the expansion of facilities by existing customers.

The Economic Development Rate Discount can be applied to new or expanded loads that meet at least two of the following criteria: monthly energy usage of 125,000 kWh or higher, monthly peak demand of 250 kilowatts (kW) or higher, and a monthly load factor of 50 percent of higher. The economic development rate discount will begin on January 1, 2019 and is offered for a maximum of four years and, with declining value in years three and four. However, the term of the discount may be less than four years, depending on annual Board authorization.

Summary

Regular cost-of-service and rate studies, along with the ability to offer unique rate incentives to meet customer needs and utility objectives, will help public power utilities remain financially strong while maintaining affordable and competitive prices.

Third-Party Competition

The growth in DERs may potentially lead to greater third-party competition. Typically, public power electric utilities have been insulated to some degree from competition, but now customers have the option of purchasing, and in some cases, leasing distributed solar panels. In many states, companies such as Solar City, Sunrun, and others can market directly to customers, and can provide onsite generation services, which in turn reduces the amount of direct sales for the utility.

Some states restrict the ability of third-parties to lease solar panels, but there are proceedings in most of these states to remove these restrictions. Therefore, public power electric utilities need to consider ways to either incorporate third parties into their business models or develop products and services which distinguish them from third parties. For example, CPS Energy in San Antonio, Texas has developed a Solar Host program. Homeowners can apply to "host" solar panels on their rooftops at no cost. CPS Energy adds the power generated from these panels to its resource mix, and Solar Host customers receive a bill credit.[5]

Programs such as these have multiple benefits for the utility. The utility's involvement in the location of rooftop solar PV placement provides the utility with greater awareness and insight into its load. The program also provides a measure of revenue stability, while also making the utility a trusted energy partner.

New Business Models and Financial Options

Solar rooftop leasing is one option for utilities to develop new business models and financial tools. Utilities – especially public power utilities – have different avenues open to them to meet the challenges a more distributed future. As outlined in APPA's *Value of the Grid*[6], DERs/DG are growing in reach, and will continue to play a role in the future of the electric industry. Despite growth in DERs, complete grid defection, where customers disconnect from all utility service and rely on self-supply, is unlikely as it is both cost prohibitive and not technically feasible for most. The countervailing trend of electrification, especially the electrification of vehicles, also lessens the threat of grid defection.

That being said, grid architecture will certainly have to evolve to accommodate and integrate DERs and electrified resources. We will need enhanced communication systems so that distributed resources can work in sync with each other and with existing resources. The grid will remain essential, but not unchanged.

Several different visions of the utility role in managing the grid in light of these changes have been put forward. Peter Fox-Penner, Director, Institute for Sustainable Energy, and Professor of Practice, Questrom School of Business at Boston University, has discussed different models. Under the "Smart Integrator" scenario, the utility would not own any generation assets, but would instead run a "smart transmission system and/or distribution system that integrates, sets prices for, and balances all types of generation, storage, and demand response."[7]

Alternatively, utilities could be organized as "Energy Services Utilities." These utilities would be organized like today's vertically integrated utilities, but would employ greater use of "smart grid, dynamic pricing, and decentralized services."[8] A hybrid model would be a smart integrator where the DG is owned by their communities.[9]

Fox-Penner also writes of community energy systems (CES). These are very similar to public power utilities, "except that a CES is added into an area where the wires may be owned and operated on an open access basis by a separate Smart Integrator." As he describes it, it is the "unlikely child of public power and retail choice."[10]

To be clear, utilities in Minnesota believe current state statutes preclude these alternative business models at this time. No other entity is able to provide service to customers at the retail level within a utility's specified service territory. However, that may not always be the case.

APPA laid out its own roadmap for the future in its submittal to Phase II of the Smart Electric Power Alliance (SEPA) 51st State.[11] This roadmap outlines the first steps public power utilities need to take as they respond to changing customer preferences:

- Initial measures likely to lead to sustainable long-term business practices and customer relationships.
- Experimenting with various approaches to utility-controlled community-scale solar to identify business and operational challenges.
- Starting to realign retail customer rates with economic costs and cap exposure to NEM regulatory arbitrage.
- Modeling and managing risks to the utility and customers driven by external factors.
- Constant communication with governing boards, customers, and community stakeholders on the utility's plans.[12]

The roadmap calls on public power utilities to more fully integrate DERs into utility operations, develop better use/application cases, and encourages adoption of pilot programs. The roadmap highlights community solar as one avenue through which utilities can deliver solar options to customers who may otherwise lack the means or interest in managing their own rooftop systems. Community solar also offers utilities an opportunity to gain operational experience.[13]

While APPA's roadmap suggests that many traditional elements of the utility business model will remain relevant in the future, it identifies key elements of the transition to the future state:

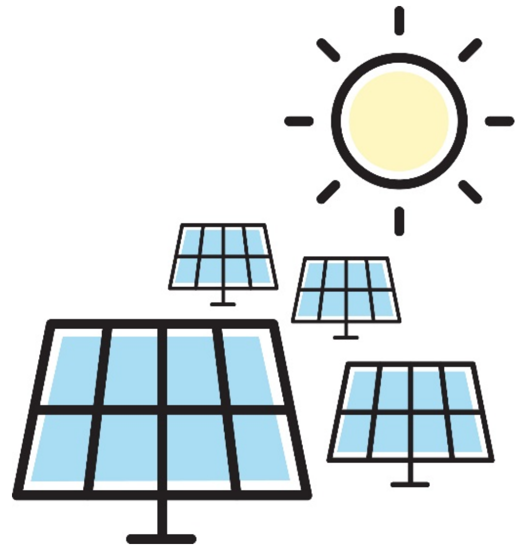
- Recognizing the real economic costs and risks of alternatives —and reflecting them in utility specific rates and service offerings. Subsidies can create an unsustainable, high-DER future.
- Aligning customer interests with those of the utility and third-party suppliers at the grid edge and wholesale/bulk power levels.
- Capturing the benefits of DER integration for customers and utility system planning and operations.
- Developing the utility business and operational technology infrastructures to sustain these offerings over time.[14]

In the end, the roadmap suggests a careful integration of core services with new product offerings. While this convergence of new and old business models may prove challenging, it can also present an opportunity for public power utilities to develop both new revenue streams and a means of connecting to and engaging with their customers.

Technology

This section will present a variety of technologies and Minnesota specific case studies. APPA's Demonstration of Energy & Efficiency Developments (DEED) program supports activities related to energy innovation that improve efficiencies or lower costs and enhance the value of providing electricity and services to the customers of publicly owned electric utilities.[15] The Smart Energy Program is a new APPA best practices designation program designed to provide national recognition to utilities for the work they are doing in energy efficiency, distributed generation, and renewable integration.[16]

Community Solar



Utilities have already begun demonstrating ways in which they can be at the forefront of this new paradigm. One particular way in which utilities are meeting customer demand for new forms of energy is through community solar programs. Community solar is a way to purchase solar without installing it on your rooftop or property. It's an easy way to join the solar movement at a level that is affordable to the customer. It also allows customers an opportunity to gain a level of price certainty by locking in the cost of a portion of their future energy usage.

There are different definitions of community solar. Generally speaking, a community solar project is defined as a solar power installation that is jointly owned or leased by community members or, if owned by a third party, that provides shared benefits (including purchased power, credits against electric utility bills, and fixed rates for power) to participating community members. The predominant model of community solar, especially for public power utilities, is a utility-sponsored project, usually involving a third-party developer, to which customers subscribe through purchase, lease or subscription of a number of panels and receive a credit for their share of the production. The unifying theme for all the models is utility customers can earn bill credits for solar production without having to buy or lease solar panels and install them on their own rooftops.

There are two primary ways in which customers participate in community solar. Under a capacity-based program, participants can own, lease, or subscribe to a certain number of panels or a proportion of the project. In return, participants receive bill credits proportioned to their share of the project. Typically, participants pay upfront, before the project has been fully constructed and is producing energy. Participants either pay a dollar amount per watt, per panel, or in some cases they purchase an array(s). Participants own their portion for the term of the agreement, which can range from a few years to the life of the system. Ownership shares, leases, and subscriptions may be transferred or sold to another utility customer. In return, the participant receives a bill credit for the energy (kWh) produced by their share of the community solar project each month.

Energy-based pricing, or pay-as-you-go, reflects an arrangement whereby the participant pays for the system through a $ per kWh charge determined by the cost of energy from the solar project. This rate is typically priced at a premium over the current retail rate. Since the rate is normally locked in, this solar rate may fall below the retail rate should the utility's rates increase in the future, as is likely.

The solar project rate is billed to the customer for the energy allocated from the project to the customer.

There are other considerations when developing a community solar project. APPA's guidebook walks through the major considerations, and a separate paper examines some of the tax and securities issues.[17]

Case Study: Community Solar Programs in Minnesota

In 2013, the Minnesota Legislature passed into law the Community Solar Gardens Statute. This Statute, 216B.1641, only applied to the largest IOU in the State. Several public power utilities also decided to take advantage of the interest from this legislation to offer programs of their own.

Not every solar garden has had immediate success with selling out all the available panels. For instance, after 2 years of planning and marketing, Detroit Lakes Select Solar Program was delayed an additional year before starting operation due to lack of subscribers and still has 8 available panels. In sharp contrast was Moorhead's Capture the Sun program that sold out all the panels before construction began and had a second set of panels added to the original construction order. The developer was the same for both Moorhead and Detroit Lakes (DL) projects, so the real emphasis is on the community dynamic. Moorhead has triple the numbers of customers of DL and is home to several large regional colleges while DL having some regional industrial customers, the utility serves mostly a small commercial/residential community.

Below is a snapshot of several MN public power programs.

Austin Utilities SolarChoice

Pricing is set on a per panel basis. Each customer may purchase the output from enough panels to cover up to 75% of their average monthly usage over the most recent 12 month period.

- 6-year plan: $340 per 335 watt panel (or 12 monthly payments of $28.34 per panel)
- 12-year plan: $660 per panel (or 12 monthly payments of $55.00 per panel)

One 335 watt panel is expected to produce 515 kWh in year 1 and average 501 kWh per year for the first 12 year.

Rochester Public Utilities SolarChoice

Pricing is set on a per panel basis. Each customer may purchase the output from enough panels to cover up to 12 times their minimum month's usage over the most recent twelve month period. The SOLARCHOICE program agreement term is for 12 years.

- One-time cost of $650 per 335 watt panel
  or
- 12 monthly payments of $55 per panel

Saint Peter Municipal Utilities SolarChoice

Pricing is set on a per panel basis. Each customer may purchase the output from enough panels to cover up to 50% of their average monthly usage over the most recent 12 month period. A minimum of 1/2 panel can be purchased for any of the plans.

- 5-year plan: $295 per 335 watt panel
- 10-year plan: $580 per panel

- 20-year plan: $1,134 per panel
- 25-year plan: $1,400 per panel

Moorhead Public Service (MPS) Capture the Sun

As noted above, Moorhead's Capture the Sun Program has been a huge success. Over the last 4 years, 2015- 2018, MPS has installed 8 complete arrays. Of those, 3 full arrays are allotted to 3 businesses that took advantage of the program when MPS rolled their commercial energy and demand charges together to develop a better rate of return.

MPS plans on filling the present site with one more array in 2019, and is searching for a new site to continue the program.

- Upfront purchase: $410 per 335 watt panel
- Payment plan: $35/month for 12 months per panel ($420)

Detroit Lakes Community Solar Garden

Select Solar is a renewable energy project developed by Detroit Lakes Public Utilities. Customers may purchase up to six solar panels and receive the solar production as a monthly bill credit. Community solar is ideal for customers who want to harness the power of the sun's energy, but lack the suitable site for a solar array on their own. It's also great for those who want to hedge against future energy prices without installing their own system.

Costs/Production:

- Each 450W panel is $1,075
- Each panel is estimated to produce 540-635 kWh per year ($55-$65)
- Contract for ownership is twenty years, lifetime energy production of 10,590 kWh per panel

Princeton Public Utilities SolarChoice

Residential

- 5-year plan: $325 per panel
- 10-year plan: $642 per panel
- 20-year plan: $1,252 per panel

Small Commercial

- 5-year plan: $342 per panel
- 10-year plan: $675 per panel
- 20-year plan: $1,316 per panel

Large Commercial/Industrial

- 5-year plan: $200 per panel
- 10-year plan: $395 per panel
- 20-year plan: $770 per panel

Preston Public Utilities SolarChoice

Residential

- 5-year plan: $257 per panel (or 12 monthly payments of $21.42 per panel)
- 10-year plan: $520 per panel (or 12 monthly payments of $43.33 per panel)
- 20-year plan: $1,066 per panel (or 12 monthly payments of $88.83 per panel)
- 25-year plan: $1,349 per panel (or 12 monthly payments of $112.42 per panel)

Commercial

- 5-year plan: $272 per panel (or 12 monthly payments of $22.67 per panel)
- 10-year plan: $550 per panel (or 12 monthly payments of $45.83 per panel)
- 20-year plan: $1,127 per panel (or 12 monthly payments of $93.92 per panel)
- 25-year plan: $1,426 per panel (or 12 monthly payments of $118.83 per panel)

Case Study: SMMPA Community Solar Program Services

Over the past several years, Southern Minnesota Municipal Power Agency (SMMPA) has worked with its member utilities to develop a template retail community solar program and provide a solar energy source to supply member retail customer interest. The path from concept to implementation has demonstrated both the power of joint action, the evolving nature of the solar energy industry and benefits to public power of anticipated customer needs and developing products to satisfy those needs.

How did it get started?

In 2013, the Minnesota State Legislature adopted a solar energy standard for investor-owned utilities. This development prompted SMMPA members to create a "Solar Working Group" to put forth a recommendation that would clearly demonstrate that public power entities could and would advance solar energy even without a mandate.

In 2014, the Solar Working Group recommended, and the SMMPA Board approved, an approach to issue an RFP for 5 megawatts (MW) of capacity and associated energy from a utility scale solar array with the aim of awarding a contract in 2015 for an in-service date in 2016.

Further, the recommendation also indicated that SMMPA would have an appetite for up to an additional 2 MW of smaller solar to be located in member communities. SMMPA would purchase the energy from these smaller facilities at the same price per megawatt-hour (MWh) as the purchase power agreement (PPA) price for the 5 MW facility. If the PPA price the member paid for the smaller facilities was greater than the 5 MW PPA (which due to economies of scale it presumably would be), the member community would be responsible for the difference. By allowing for this additional 2 MW of appetite, these smaller facilities could supply solar energy for community solar programs in those communities that were interested, or provide a sample solar facility in a community that was not hosting the larger 5 MW facility.

How did we structure the program?

In 2015, the Solar Working Group asked SMMPA staff to assist interested members in developing community solar programs. In some communities there was perceived customer interest in having an alternative to rooftop solar. Initially, SMMPA solicited some indicative quotes for smaller and mid-sized solar arrays. The results presented a pretty stark difference in cost between the most recently signed PPA for the 5 MW facility and the smaller arrays. Member communities had expressed a desire to design community solar programs such that there would be minimal or no cross subsidization between participating and non-participating customers, but with the pricing for the smaller arrays, developing a program that would meet that objective and still be marketable appeared challenging. SMMPA then reached out to another solar developer that had experience with community solar program development to explore pursuing a larger facility that would serve as a solar source for multiple member community programs.

SMMPA landed on a proposal for a 3 MW facility where the PPA price was roughly the same, or slightly lower than, a recently signed 5 megawatt solar PPA. In prior projects, the developer had deployed a process wherein the off-taker (SMMPA in this case) would begin marketing the community solar program but would not commit to construction of the new facility until such time that 25% of the output was subscribed. The developer and SMMPA signed a letter of intent that specified that condition as well as a two-year period of time in which to attract the necessary subscriptions. In the developers experience with other cities, it generally becomes clear within the first six months as to whether the necessary subscription level will be met. However, given that there would be multiple communities launching their programs at different times, two years appeared appropriate. The proposed PPA was for 25 years, so in calculating the 25% subscription level was prorated to adjust for customer subscriptions of less than 25 years. Another suggestion from the developer, given that one facility would serve multiple communities, was to erect small 4 kilowatt (kW) “billboard” solar arrays in communities offering the program. The developer offered significantly discounted pricing for the “billboard” projects with the provision that if the 3 MW project was never constructed, the participating communities would be billed an additional amount for the billboard project that would bring it closer to market value and still allow the member community to retain ownership.

Retail Program Development

The SMMPA staff began working on alternative pricing structures for a template retail program that would meet the objective of minimizing any cross subsidization. Initially the staff explored three different models: an up-front one-time subscription payment, a fixed price “pay-as-you-go” per kWh charge and a “buy all/sell all” approach. Additionally, pricing was calculated for each model based on SMMPA retaining the renewable energy credits (RECs) or the retail customer retaining the RECs.

After reviewing the results, the Solar Working Group asked SMMPA staff to zero in on one specific model – the up-front subscription payment where SMMPA retained the RECs. This simplified the process and resulted in a program design that was very similar to what neighboring cooperative utilities were offering. In this design, customers would make an upfront payment to subscribe for the output from a set number of panels for a specific term length and would then receive a monthly bill credit equivalent to the output of that number of panels in a given month times the current retail energy price.

Program Design

SMMPA staff was tasked with creating a template design for interested members while still providing members the ability to modify the template as they saw fit. The cost of the subscription was essentially prepaying for the amount of electricity expected to be produced from the number of subscribed panels for the term of the agreement. In determining the subscription cost, certain assumptions about future wholesale and distribution costs were made with the net result being a net present value calculation to arrive at a panel subscription cost. The basic concept was to put in place a pricing mechanism that would result in a breakeven proposition for the utility and the retail customer. If future cost increases exceeded the assumed levels, the participating customer would benefit and conversely the utility would benefit if the increases were less than projected. Based on the upfront subscription model and assumed pricing, SMMPA staff worked with counsel to draft a template customer agreement/contract.

Member utilities varied several program design elements. Some members offered terms ranging from 5 to 25 years, others opted for one set term. In the case of two participating member utilities whose power supply contracts will expire in 2030, the maximum term was set to coincide with the contract termination, resulting in a maximum term of 12 years.

Participating members allowed customers to subscribe for something less than 100% of their historical energy usage. The primary reason this was put in place was to avoid having the customer receive a monthly credit exceeding their total energy usage. This amount ranged between 50% and 75% of the most recent one year’s historical energy use. This calculation would set an upper limit on the number of panels a customer could subscribe to.

Several members offered a payment plan (typically over 12 months) as an alternative to paying the full amount in a single, up-front payment. Most participating members expressly stated that customers wishing to participate must be current in paying their monthly utility bill.
Two of the five participating members limited participation to residential customers only; the other three offered the program to all rate classes.

Marketing

All participating members agreed to use a single product name – SolarChoice – as they began marketing the program. Austin Utilities was the first SMMPA member to begin marketing using a combination of community meetings, news releases, newsletter articles and website promotion in April of 2017. Saint Peter, Rochester, Princeton and Preston followed over the next several months. Members used the template brochure that was originally developed by Austin Utilities.

Community meetings were one of the more popular and effective marketing approaches. SMMPA provided member utilities with yard signs and window clings that could be distributed to participating customers. Rochester used TV advertising to promote their program.
Preston, SMMPA’s smallest member, launched its program in fall of 2017 and held a community open house. Preston never intended to conduct a major marketing effort, but rather wanted to

have a program in place for anyone who expressed an interest. Several other SMMPA members may take a similar approach in 2018 as there is value in simply having community solar as an option.

Results

In order to meet the 25% threshold to move forward, 2,481 panels would have to be subscribed for an equivalent of 25 years. Roughly one year into the program, 20% of the threshold has been met. The shorter terms (5 or 6 years) have proven more popular than the longer terms. That time frame tends to coincide with the average length of time people spend in a home.

Lessons Learned

SMMPA and its members are pleased with the outcome of the programs. By using an existing facility to serve interested customers in the interim time between program launch and the potential time a new facility would be built allows customers to get into the program immediately. Absent an aggressive marketing push to commercial and industrial customers, it does not appear there will be enough subscriptions to reach the threshold that would cause the new 3 MW facility to be constructed. SMMPA does not view this as failure. SMMPA members heard within their communities that there was a demand for community solar, but it was always unclear as to how strong that demand was and that question has been answered. Participating members are providing a solar option for those customers that may be interested in solar but are unable or unwilling to pursue rooftop solar. SMMPA and its members continue to view this as a positive result of the program showing an interest in providing options for diverse segments of the community.

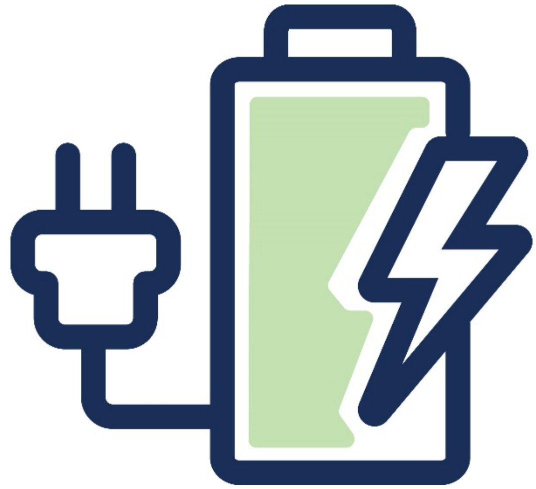
For several members, the timing of the program launch was impacted by various IT initiatives. While implementing the community solar option into existing billing systems was not a major obstacle for participating SMMPA members, attempting to fit that into billing system conversions and/or major updates did prove challenging.

Going Forward

There are several SMMPA members that have expressed an interest in launching programs in 2018 – regardless of whether they are tied to a new or existing solar facility. At least one community is contemplating a “pay-as-you-go” program design where an initially higher, but fixed, price per kWh is offered over various term lengths. The decision to market to the C&I market segment is still pending for several members. Others are simply interested in having the program available even if it is not actively marketed.

SMMPA’s Solar Working Group is expected to continue to be active and drive future potential renewable program offerings. The Working Group approach has proven to be a very effective means of gaining consensus on strategic renewable energy direction.

Energy Storage



Energy storage is becoming a more economical solution to the problem of renewable resource intermittency. Storage saves generated energy and then discharges it later, which can help with renewable energy source fluctuations and improve overall system reliability and resiliency. The fast-ramping of energy storage makes matching generation and demand in short time frames with renewables or other distributed energy resources viable. Storage also provides a number of ancillary services to the grid such as supporting voltage and frequency control, managing peak load, and providing energy reserves.

Energy storage encompasses different technology types such as electro-chemical storage, electro-mechanical storage, pumped hydro storage, and thermal energy storage. These different technologies have varying characteristics, including their energy density, capacity, and lifetime. Moreover, certain technologies are better positioned to provide specific types of services.

Evaluating energy storage economics can be challenging. Different technologies come with certain capital and maintenance costs, but that is only one piece of puzzle. It is also important to consider the services that the storage system can provide. In some cases, users may be able to "stack" services, and leverage multiple value streams. However, for reliability and regulatory reasons, not all services can be stacked. In any cost-benefit analysis, it can be helpful to compare the energy storage outcome against traditional resource options.

As technology advances and costs go down, storage adoption continues to grow, particularly in the area of battery storage, a type of electro-chemical storage. APPA has created a primer for understanding energy storage that covers the various types of storage technologies, the services storage can provide a utility, and the economics of deploying energy storage.[18] The report also explains how public power utilities are implementing storage systems and how state and federal policies incentivize energy storage.

Case Study: Shakopee Public Utilities Energy Storage Pilot

Shakopee Public Utilities (SPU) was looking for a way to bring more awareness within its community about renewable energy resources and their benefits to the environment along with giving its customers control of their homes to monitor, track and efficiently use the electricity they pay for. The public power project was based on discussions with Shakopee Public Utility and the Shakopee Utilities Commission with the goal of pursuing the deployment of a small energy storage system (ESS) as part of their planned renewable generation project at the Shakopee High School Environmental Learning Center (ELC). The overarching goal was to determine if the technology would be useful to store the energy generated at the different times of the day from the distributed energy resources (DER) installed by the utility to demonstrate the zero-energy building concept to the students and the community.

Shakopee Public Utilities, at their own cost, installed 8 kw of solar photovoltaics on the roof of the ELC along with installation of a 2.5 kw wind generator adjacent to the building. The electrical output from the DG sources was fed directly to the ELC where they were connected to a 10 kw ESS. A separate dashboard was developed to show the real-time inputs from the different DG sources for educational purposes.

Construction and testing of the ESS by the manufacturer caused a significant delay (8 months) in the installation of the unit. Once the ESS was installed and operational, the focus shifted to development of the dashboard. A separate vendor from the ESS manufacturer was found who developed the software. Compatibility issues quickly arose between the data provided from the ESS and the software for the dashboard. After 2 months of troubleshooting, it was decided to install separate digital meters at the output of each DER source along with a router to compile the data input into the ESS and use the existing building meter from the ESS output.

The ELC is a separate building from the high school and is heated during the fall and winter with electricity. As shown in Table 1 below, after the heating season is over, the building provides electricity back to the grid along with helping to defray the winter heating costs.

The Environmental Learning Center ESS was capable of aggregating multiple inputs from different distributed generation sources. The inability of the ESS to display and gather useful data and the high cost of the unit are large drawbacks. The lack of display information was overcome by installation of advanced metering from the distributed resources and the development of a separate software solution. Until utilities can be assured of the cost effectiveness of the units, ESS such as the one installed at the ELC will continue to be just demonstration projects.

Table 1

Month	Elec Use (kWh)	Billing
October	-617	+ $59.51
November	588	$70.11
December	3148	$327.45
January	5121	$524.53
February	3811	$417.22
March	2921	$323.35
April	640	$79.78
May	502	$60.99
June	-304	+ $20.78
July	-1596	+ $167.20

Case Study: Austin Electricity Peak Demand Reduction with Energy Storage

As increasing amounts of renewable generation sources like wind and solar displace more traditional sources of energy from thermal plants, the ability of an electric distribution system to respond to disturbances decreases. Furthermore, renewable generation is intermittent and fluctuates with time, which will also translate into periods where storing the energy from wind which has a higher off-peak output period may counterbalance the on-peak voltage fluctuations caused by photovoltaic systems. This public power project was based on discussions with Austin Public Utility and the Austin Utilities Commission with the goal to pursue the deployment of small energy storage technology to determine if off-peak electricity storage with on-peak electricity discharge was cost effective for the utility and provided any electricity conservation benefit.

Scope

The project aimed to find the balance between placement and cost of installing one or several Energy Storage Systems (ESS) on a power system grid to mitigate problems related to renewable energy integration by charging the units during lower cost off-peak periods and discharging them back onto the grid during higher on-peak pricing periods without including the fluctuations caused by renewable resources. It should also be noted that, presently, Minnesota does not have a robust peak period pricing system that would provide a better Return On Investment (ROI) to a utility to install ESS, but this study would be able to provide a basis for conducting analysis at a later date.

Analysis

In the initial plan of study, the control strategy for the ESS was not included. However, it was discovered early on that without a defining charge/discharge control scheme for the ESS, sizing and placement of the ESS on the grid would be difficult. Therefore, a control strategy was added before placing the ESS on the grid.

Another early discovery about the ESS is that the battery locations needed to take into account the effect of temperature on battery efficiency (i.e. elevated temperature has an inverse relationship with battery efficiency). Ventilation was discussed with the ESS supplier, but in the instance of the units installed at the Public Utility building, the initial location provided less than optimum cooling, so the location in the building was changed prior to unit installation.

Four 9.2 kilowatt 12 volt lead-acid battery units were installed in Austin, two in the Public Utilities building and two at the Austin Public Library.

Secure, real-time, web-based Data Acquisition and Control for the ESS was determined to be a function the manufacturer had not developed. A SCADA solution had to be developed by a separate vendor which included hardware, secure cloud technology, and graphical user interface to collect ESS unit data while at the same time collecting the meter data from the ESS. This is a recurring theme among many ESS projects throughout the United States as each utility has site specific technologies that the ESS developers do not often take SCADA into account in their designs.

The ESS units were installed, initial setup and testing occurred in December 2012 and the units were placed in operation in January 2013. Based on Austin Public Utilities load curves, it was determined that the best control settings would be the off-peak charging period from 11:00 pm to 8:00 am Monday (Sunday night) thru Friday. The discharge period needed to be adjusted for the different seasons with the winter (October thru May) period being a 50% discharge from 5:00 pm to 7:00 pm, also Monday through Friday. The summer schedule (June through September) Monday through Friday was set at a 60% discharge from 2:00 pm to 4:00 pm since the summer peaks on the Austin electrical system were at a different time and higher than the winter peaks.

It was discussed and understood that operating on a higher summer discharge percentage would possibly reduce the battery life from ten years down to two to three years. The decision to operate at a higher discharge rate was based on the life of the study along with wanting to find the limits of what the units could achieve.

The 50% winter discharge was set at 2 kilowatts (kW) per unit, that when compared with the 9.2 kw of each unit at first doesn't seem to make sense when the expected discharge would be 4.6 kw (9.2 kW divided by 50%). The USEFUL battery capacity is less than the unit rating due to the depth of discharge as discussed in the paragraph above which would give the unit approximately 850 cycles of total battery life. Charging and discharging Monday through Friday, October through May, would use 160 cycles per year of the 850 possible cycles. This in effect gives the batteries a 5.3-year life expectancy.

The 60% summer discharge was set at 3.8 kw per unit. As noted, charging and discharging Monday through Friday, June through September, will add an additional 80 cycles per year. Combining the cycles for the year, the units will cycle 240 times, giving the batteries a life expectancy of 3.5 years. Adding in the increased depth of discharge also reduces battery life, so the final approximate battery life is 2 to 3 years. This is important when considering the financial benefits of the technology.

Using the winter discharge first, with the off-peak wholesale energy rate of $ 0.05 per kWh or 5 cents per kWh, and the on-peak wholesale energy rate of $ 0.064 per kWh or 6.4 cents per kWh provides the difference between the two rates of $ 0. 014 per kWh or 1.4 cents per kWh. With the units discharging 2 kW on-peak for 2 hours gives a unit discharge of 4 kWh. This results in a cost savings of 5.6 cents per unit per day. Multiplied by the four units, the cost savings is 22.4 cents per day in energy or $1.12 per week. With a demand charge (kW) of $12 per kw without having any time-of-use rate involved, there isn't any cost savings due to the equal charging and discharging. The possible savings in demand charge becomes effective based on the charge Austin Utilities pays to their wholesale power provider that is set during a 15 minute period each month. If the monthly peak is set during the discharge period as planned, the peak would be 8 kw lower, which becomes a $96.00 cost saving. If that occurred each month for the 8 month winter period, the combined savings is $ 768.00. Adding in the 8 month energy savings of $ 35.84, the combined winter season savings is $ 803.84.

Calculating the summer discharge savings with the same rate structure since the rates are not seasonal, but with the higher discharge of 3.8 kw, the energy savings is based on 7.6 kWh per unit. This results in a cost savings of $ 0.106 or 10.6 cents per unit per day. Multiplied by the four units, the cost savings is 42.6 cents each day or $2.13 per week. Using the same demand charge and the utility reaching its monthly demand peak during the discharge period each month for the 4 summer months, the monthly peak would be 15.2 kw lower. This results in a monthly savings of $ 182.40 or $ 729.60 during the summer period. Adding the energy and demand savings, the summer period results in a savings to the utility of $ 763.68.

Over the period of one year, the cost savings to the utility of the units in operation is $1,567.52. With the unit price and installation, each unit is $23,695.00 or a combined $94,780.00 for all 4 units.

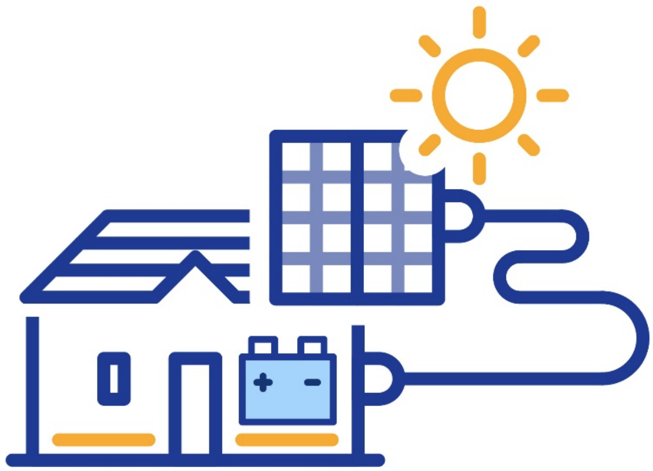
Conclusion

From the discussion above, the payback period for the 4 units is 60 years based on Austin Utilities rates and rate structure. A robust time-of-use rate structure discussed earlier, including time-of-use rates for demand charges, would significantly lower the payback period, but would have to be of such a scale as to save the utility over $2,600.00 each month so the units could be paid off at the 3-year end of life of the batteries. Also not included in the cost of the units was any maintenance or upkeep required to test the batteries on an annual or biannual basis to verify the condition of the batteries. The ESS is a useful tool for a utility to manage peak energy periods, but based on the present price of installed units and the structure of electric rates in Minnesota, use of an ESS for peak reduction alone did not prove cost-effective in this situation.

An interesting set of data that emerged from the study showed a decrease in energy use in both the Austin Public Library and the Austin Public Utilities Building. The study was not set up in a way to evaluate what caused the change or if the ESS was a contributor to the reduction. Heightened awareness by the building managers of energy use, conservation actions taken in the buildings and education of building personnel could all have contributed to the change and may be worth another study at a later date.

Behind-the-Meter Solar and Storage

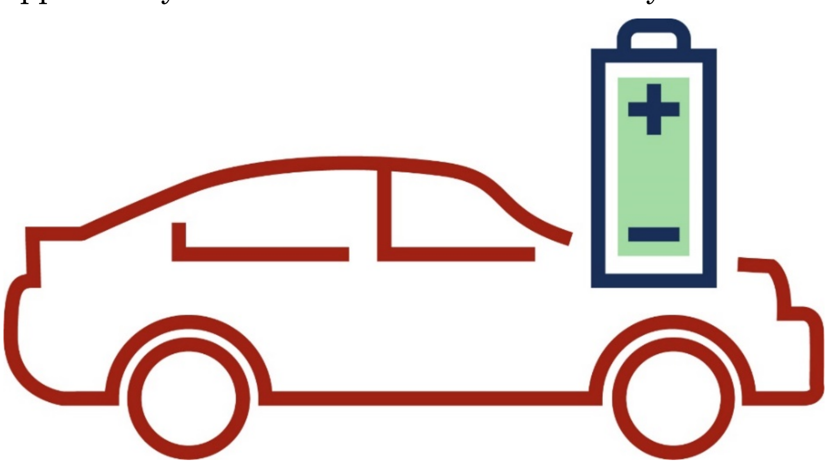
Battery storage and solar PV are increasingly deployed in the residential sector, separately and in concert (known as solar plus storage). One of the main drivers for customers installing batteries is to help maintain power during outages. For solar PV, customers may have an environmental interest in renewable energy, want to rely on the grid less for power, or are interested in savings on their energy bill. Customers who own solar PV may also want batteries to further utilize their self-generated power and minimize grid reliance. Solar plus storage can help customers shift their energy usage, enabling customers to minimize the impacts of demand charges and take advantage of lower costs tiers in time-of-use rate structures.



APPA is currently developing a report on behind-the-meter storage that will discuss state and national developments, customer motivations, utility impacts, and member case studies.

Electric Vehicles (EVs)

The number of electric vehicles on the road continues to increase as interest grows and prices decrease. Electric vehicles present both a challenge and an opportunity for electric utilities. In a period of declining sales, electric vehicles are an opportunity to increase the sale of electricity as owners plug in their vehicles to recharge. Yet, as adoption increases, they could present a challenge if a large number of customers who own these vehicles charge them at roughly the same time, particularly if this occurs during the system peak. Some utilities are developing specific electric vehicle charging rates as a means of encouraging customers to charge their vehicles during off-peak periods. Others are using general residential time-of-use rates to support the same



cause. With vehicle-to-grid technologies, utilities can manage charging and change the rate of power consumption during charging.

The main barriers to EV adoption include the purchase cost, customer awareness, charging infrastructure availability, and model availability. Utilities have taken measures to promote electric vehicle adoption such as purchasing electric vehicles for their own fleet, deploying charging infrastructure within their community, providing incentives for electric vehicles or their supply equipment, starting pilot programs, and educating customers and dealers.

The APPA report, *Understanding the U.S. Plug-In Electric Vehicle Market*, examines key plug-in electric vehicle market trends and technologies with the potential to impact public power utilities — including forecasted sales, regional factors, and energy consumption.[19] APPA has also created the Public Power EV Activities Tracker, which summarizes key efforts undertaken by member utilities – including incentives, EV deployment, charging infrastructure investments, rate design, pilot programs, and more. To explore how to create an EV program of your own, you can also use APPA's *Creating an Electric Vehicle Blueprint for Your Community: Public Power Strategies.*

Case Study: Elk River Municipal Utilities Electric Vehicle Grant Project

EV adoption has been strong along the east and west coasts, especially in California, as well as in large metropolitan areas. However, EV adoption in other parts of the country is happening at a slower pace. This includes public power communities throughout Minnesota. An increase in EV deployment in these communities has the potential to reduce transportation emissions in addition to increasing opportunities for public power utilities to realize the benefits of increasing growth in their electric loads in a controlled manner.

Elk River Municipal Utilities (ERMU), an outlying public power utility in the Minneapolis/St Paul region, established an EV charging initiative for their customers, and the local community, to gauge the acceptance and utility planning required to take advantage of the opportunities. The utility developed their own unique brand (EV/ER Power Your Future) and hosted numerous public events to promote the brand and EV technology. ERMU leveraged the newly created EV/ER brand on their social media platforms and found that the EV community is a small and generally tight knit group. This regional group, not all ERMU customers, is very supportive and is willing to help utilities promote the technology. The social media effort was rewarded with over 18 volunteer EV owners attending the unveiling of one of the level 2 charging stations along with over 100 customers attending the other events promoting the program.

As part of the initiative, ERMU installed 3 public charging stations and developed time of use rates for EV charging for both the public charging stations and their customers home and business chargers. As an added environmental incentive, ERMU purchases Renewable Energy Credits for all the EV charging in the community, creating a carbon free program. The 3 public stations are two-240 volt level 2 chargers, and one-480 volt DC fast charger. The DC fast charger was installed at a large regional grocery store fuel station and two level 2 chargers were installed at public parking lots that are owned by the City of Elk River. Extensive planning located the stations in high traffic areas that allow for easy access to transportation corridors and local retail shops. Access to local shops or entertainment is important and a key component of planning. Having electric infrastructure at or very near the site is also incredibly important to control costs. Also important is using DC fast chargers along high volume transportation corridors of 50 kw or higher. The time of use rates that are in place at the public charger have a connection fee and on-peak and off-peak energy rates. Residential and commercial customers that purchase level 2

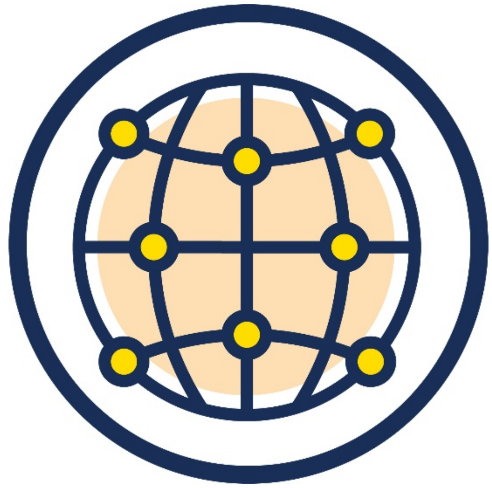
chargers are eligible for the on and off-peak energy rates for charging their vehicles at home or place of business.

The cost of charging infrastructure can be very expensive for commercial applications, but very reasonable for home or business installations. The total installed cost of the commercial DC fast charger was approximately $60,000 and each commercial level 2 charger was about $13,000. Individual 240 volt units for use at home or a business can be purchased and installed for $500 to $2,000 each. The question of payback on public charging stations will be determined years in the future.

In the past 6 months ERMU has provided 138 charging sessions at 2 of the 3 charging stations. Based on an average connection fee of $3.50 and the total installation costs, it would take over 20,000 charging sessions to recover the capital outlay. Each session varies greatly in the energy supplied but including the revenue to recoup all the costs would decrease the number of sessions. Customers are price sensitive and do not like fixed charges or parking fees since in many locations they are used to free charging at public stations. Charging for public EV services is not very popular but drivers support organizations that install public charging stations and understand the need for fees. These fees drive up the cost per kWh for public charging especially when they are only stopping for a few minutes and want to “top-up”. Topping up is simply plugging in and getting a few kWh when you stop to shop for 10 to 15 minutes. The DC fast charger is the preferred charging method because charging capacity is so much greater than the level 2. It’s also important to work with many stakeholders in the region and state to develop a large network of support to reduce range anxiety and promote the charging infrastructure needed on a regional basis and to develop the customer confidence in purchasing an EV. The customers need to feel comfortable once they leave their home or community that they can charge anywhere. The long term objective of strategic electrification in the transportation sector is to have customers purchasing EV’s and charging them in their homes. Industry experts estimate that 80 to 90% of charging occurs at home in off-peak hours.

The initiative also conducted an electric vehicle suitability assessment of ERMU and the City of Elk River municipal vehicles. They studied 20 (8 ERMU and 12 City) fleet vehicles for 9 months and provided the Utility and the city with financial benchmarks to determine which vehicles could possibly be converted to either all electric or hybrid style vehicles. The study also included a Total Cost of Ownership calculation to see if the conversion to electric would be cost effective over the entire vehicle life span. One surprising takeaway from the assessment is that the “communal” vehicles, those that are available for multiple staff members to sign out and use, are the LAST vehicles that are cost effective to convert to EV’s.

Microgrids



Microgrids gained notoriety in the aftermath of Hurricane Sandy, but the concept and implementation of microgrids is not new. Public power is notably familiar with microgrids, since many systems began by generating their own power for the communities they serve. Within a microgrid, a control system balances generation with demand and the distribution system ultimately delivers electricity to customers. Microgrids are versatile in that they can operate connected to the grid, or separately as an island.

Resilience to prolonged outages is a main driver of microgrids, and critical infrastructure like hospitals and military installations, as well as universities and data centers have installed microgrids for this reason. There are also efficiency gains due to the proximity of generation and demand. Technical challenges associated with microgrids include power quality assurance, implementing inverter based systems, and accommodating bidirectional power flow.

Demand Response

Demand Response programs are those where through price signals or direct utility control, a customer reduces their electricity usage, usually during periods of system peak. One typical example is air conditioning control, where the utility cycles a customer's air conditioning on and off. Instead of direct load control, utilities may induce customers to reduce their energy usage through price signals or energy savings programs where, if the customer reduces their consumption by a certain amount, the customer receives a bill credit or incentive payment.

Case Study: Shakopee Public Utilities Residential Electricity Conservation- Smart Home Project

Shakopee Public Utilities wanted to give their residential customers the opportunity to have control over the electricity they use in their homes beyond an on-off switch using new technologies to study if such a program would provide energy saving benefits. A 'Smart Home' is the term commonly used to define a residence that has appliances, lighting, heating, air conditioning, TVs, computers, entertainment audio and video systems, security and camera systems that are capable of communicating with each other and can be controlled remotely by either time schedule or web-based device such as a 'Smart Phone'. Since most homes do not have the equipment installed during initial construction, this study looked at the costs and benefits to a divergent set of homeowners of equipment that is commercially available.

Shakopee Public Utilities canvassed their customers and received 125 applications to participate in the Smart Home Study. The applications were broken into separate categories to identify the age of the home and the demographics of the owners. The applications were then provided to a team of local non-governmental organizations to choose the participants.

The age of the homes was broken into; pre-1970, 1980 to 2000, and new construction. The final demographic selection was: Empty Nesters/Retired, Urban Professionals, family with young adults, and family with young children.

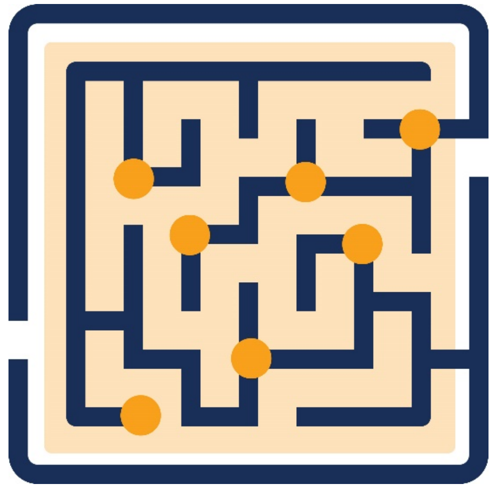
Eight homes were chosen, and the equipment installation occurred over 45 days between all the homes. The equipment installed was based on set up to suit each of the homeowners needs along with whatever devices they wanted to control. The electric use of each home was then gathered over the following 12 months. A comparison was made based on the three previous years monthly averages (Set 1) to limit the effect of weather and another comparison based solely on the single previous year (Set 2). The first comparison (Set 1) showed a 4% combined energy savings in kwh for all the homes while (Set 2) had a combined energy savings in kwh of 5.4%.

Analyzing the overall Smart Homes Costs, including installation and all equipment software and set up fees against the electricity use or reduction, shows the total electric saving of each home and the total project. The total cost per kilowatt-hour of the overall project is $16.19/kwh versus the 3-year average of electricity use and $12.01/kwh against the prior year electric use.

The Smart Homes Project showed potential as a useful tool for homeowners and utilities. With improving communication devices and lowering equipment costs, the technology is capable of giving homeowners the tools necessary to control their electric use. None of the study participants have requested removal of the equipment, which demonstrates that for a certain customer base, the concept becomes a convenience where the energy savings is a secondary concern.

IT/OT

Smart Grid



The Smart Grid has been defined in many different ways. One thing that all the definitions seem to have in common is that the Smart Grid can benefit customers, utilities, and the electrical grid as a whole.

The concept behind smart grid is having a more resilient, digitized grid with robust two-way communications and awareness across the system. This can be achieved through the integration of modern technologies and infrastructure. Smart Grid technologies will enable utilities to better monitor their systems, get information and react to problems faster, improve reliability, and gain efficiencies. It will provide customers with more options, information and tools to help them better understand and manage their electric usage.

Smart grid benefits include the following.

- Enhanced transmission efficiency
- Faster power restorations following outages
- Lower operations and maintenance costs
- Lower peak demand
- Enhanced ability to integrate intermittent resources to the system
- Greater ability to integrate customer-sited generation into the system
- Better security

Geographic Information Systems (GIS)

GIS enables users to capture, analyze, and manipulate locational data. This technology can help utilities in real-time through active monitoring and in strategic planning and long-term asset management. Specific to the electric industry, GIS enables utilities to monitor both overhead and underground circuits. GIS can also be linked to CIS to track outages, work orders, and vegetation management. Furthermore, GIS can help with site feasibly assessments, analysis of renewable energy potentials, and environmental planning.

Smart Meters

Smart meters refer generally to advanced metering infrastructure (AMI). These two-way meters allow the utility to measure customer energy usage throughout the day. They also can automatically notify a utility when a customer is experiencing a power outage. Customers can also gain more granular insight into their own energy usage, thus enhancing their energy efficiency efforts. Utilities can use AMI to do remotely connect/disconnect load control and monitor abnormal usage.

Automatic Meter Reading, or AMR, also enables the utility to measure a customer's electric usage without having to send a meter reader to the customer's residence or business, but it does not offer the same two-way functionality of AMI. AMI, in addition to the benefits outlined above, allows utilities to implement granular pricing options. These meters can also be used for fault detection and to generally monitor the distribution system.

Smart Grid Security

As with any new technology or process, it is important to evaluate the security implications. In the realm of smart grid, the addition of more devices and data are what drives security concerns. More smart devices mean more potential entry points for a malicious cyber-attack. The volume of smart devices will also make monitoring, both from a physical and cyber perspective, more challenging. Smart meters among other smart devices generate significant amounts of data that the industry does not want in the hands of bad actors, such as a disgruntled employee or terrorist organization. Cyber security is a major concern of many top leaders and utility executives. Despite the challenges, there are proactive and reactive measures that utilities can take to improve their cyber security posture and effectively respond to a cyber event. APPA has a variety of physical and cyber security resources for members.[20] APPA has released the Public Power Cybersecurity Scorecard, which is an online self-assessment tool to help public power utilities understand their security posture. Based on the DOE Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2), the scorecard provides utilities with a starting point to address cyber risks.

Case Study: SMMPA Cyber Security Services

In 2014, SMMPA began a concerted effort to better protect itself from cyber security attacks. SMMPA had been doing annual penetration tests and deployed antivirus/malware software for a number of years but was seeking to take cyber security to the next level. SMMPA hired a consultant to do a thorough analysis of all of SMMPA administrative systems to determine what needed to be done and help develop a comprehensive plan to implement the recommendations. Over the next two years, the SMMPA team implemented those recommendations and reported the results to the SMMPA Board. This led the Board to ask SMMPA staff – can you help us tackle the cyber security challenge at our utilities? This would require a partnership with trusted vendors helping translate the steps SMMPA had successfully taken into similar actions for member utilities. These efforts fell under the following areas:

Education and Awareness

The issue of cyber security can become overwhelming very quickly. The first question for most utilities is, where do I start? While SMMPA had a primary vendor it had worked with in its own cyber security assessment, the Agency recognized that may not be the best fit for its member utilities. SMMPA sought the council of Hometown Connections and quickly concluded that becoming a Marketing Affiliate would allow SMMPA to best leverage the resources available through that organization. SMMPA hosted a cyber security workshop for member utilities to better understand the range of cyber services available through Hometown Connections. The main topics covered at this workshop were monitoring and cyber insurance. The discounted pricing available through Hometown Connections was discussed, but it was not a primary focus of the session.

SMMPA also hosted an executive cyber security training session made available by APPA via a DOE grant. This full day session provided members with an executive-level overview of how to get started with a cyber security program. The session had applicability from the smallest to the largest SMMPA members. Feedback from smaller members indicated that a “cyber-in-a-box” type program would be a helpful next step. We will discuss that effort in more detail later in the paper.

At its 2017 Annual Meeting, SMMPA conducted a cyber security table top exercise using the cyber security hack of part of the Ukrainian electrical system as a backdrop. APPA staff conducted the session and gave meeting participants a real-world example of how the cyber security threat can become very real in the electric power industry.

SMMPA also cosponsored a cyber security training/awareness session with Austin Utilities as part of its major accounts customer meeting. The session exposed the audience to the threats faced by the electric power industry, as well as highlighted the steps the industry, SMMPA and Austin Utilities are taking to minimize the threat.

Employee Training

In the recommendations that accompanied the SMMPA cyber assessment, the importance of employee training came up time and time again. Your employees are your best defense and your greatest threat. Understanding that cyber training cannot be a "one and done" approach, SMMPA sought out an education series that would convey the right messages, be engaging enough to ensure employees actually participated and fit it into already tight work schedules. SMMPA came across a series of cyber security training videos by Ninjio. Theses 3-4 minute animated videos are professionally produced and based on real world cyber events that most employees are already aware of. The videos do a behind- the-scene review of how these type of data breaches can occur and how each of us can be exposed both professionally and personally. There is a short quiz at the end of each video. A new video comes out once a month and a portal system is available to track employee participation. SMMPA deployed this service internally and after two months of experience, provided a demonstration to the Board and member representatives at the Board meeting. SMMPA was asked to extend the contract to make the training videos available to member staff, and subsequently to other city departments. The vast majority of SMMPA members are taking advantage of the service. The cost of the subscription for member city employees is absorbed by SMMPA.

Cyber Mutual Aid

SMMPA is participating in the industry Cyber Mutual Aid program[21] and has offered to serve as an agent for its member utilities in both seeking out expertise should such a need arise and providing expertise should a request be received.

Cyber-in-a-Box

Based on the request from a smaller SMMPA member to develop a comprehensive, yet manageable, cyber security program, SMMPA worked with Hometown Connections vendor AESI to develop such a package. AESI visited several SMMPA member utilities to better understand the needs and constraints these smaller utilities face in deploying a cyber security program. The initial challenge was to find a way to do a cyber security assessment in a way that was affordable to the small utilities. AESI developed a template for an assessment that could be done remotely and require a relatively small time commitment from what is typically a small utility staff. Layered on top of that would be template cyber security policies, a monitoring service from N-Dimensions, and an affordable cyber security insurance program sized to meet the general needs of a smaller utility. An employee training package was also made available, but the Ninjio videos have thus far met the needs of SMMPA member utilities. Additional services, like penetration testing, could be added to the package on an ala cart basis. SMMPA is at the beginning stages of making this "cyber-in-a-box" package available to its members.

Conclusion

Developing a cyber security program is a daunting, and increasingly expensive, task for any organization. SMMPA is attempting to make it easier for member utilities to understand what to do, how to educate employees and make available services that are reasonably affordable for its members.

Case Study: MRES Technology Roadmap

The question that members of Missouri River Energy Services (MRES) have been asking themselves is: "When is the right time to start investing in Smart Grid technologies?" MRES is working to help its members think through that decision by developing a technology roadmap that includes an examination of the need for Smart Grid technologies, the benefits and costs, the barriers to implementation, and the priorities and rationale for making investments.

MRES Smart Grid Vision

The technology roadmap started with the development of an MRES Smart Grid Vision to:

- Gain economies of scale and provide support to MRES members with the implementation of Advanced Metering Infrastructure (AMI) and other Smart Grid technologies through hosted services
- Evaluate and communicate the benefits and costs of AMI and Smart Grid technologies to help members make informed investment decisions
- Assist members in eliminating barriers, such as financing, installation, and cyber security concerns

The Challenges - Why Consider Smart Grid Now?

The timing of a utility's investment in AMI is a critical part of their Smart Grid strategy. There are numerous factors that are prompting utilities to consider installing AMI now. Some of those include:

- **Increasing customer expectations:** Nationwide, customers want more access to their utility information and more control over when and how they receive information. They want to use their mobile devices and they want proactive alerts about their level of usage, their bill, power outages, etc. Overall, they want higher levels of customer service than ever before.

- **Integration of solar generation on distribution systems:** Interest is rapidly growing in customer installations of solar generation. Utilities need to prepare for those installations by having a metering plan and a rate structure in place so that generation and usage is tracked properly and there are no cross-subsidies between customers.

- **New products and services for customers:** From solar roofs to electric vehicles to battery "walls," new players in the market are offering products and services that customers want, and that have the potential to change the face of the electric industry. The electric grid and the local utility are still needed, but the utility must be prepared to integrate with these new technologies and to make sure the value of grid service is accounted for.

- **Aging infrastructure:** Many utilities are finding that vendors no longer support or provide replacement equipment for systems that the utility has used for many years. This is often the case with load management equipment, electric meters, water meters, and handheld or drive-by meter reading equipment. Soon, utilities may have no option but to upgrade.

- **Flexible rate design:** Perhaps the most important factor that utilities will want to consider is the ability that AMI gives them to be flexible with rate design. AMI can enable a variety of rate structure options, such as residential demand rates, time-of-use rates, critical peak pricing, standby charges, etc. New rate structures will be needed in the future to respond to changes in market prices, to send price signals reflective of costs, and to ensure the utility can recover its costs to operate and maintain the distribution system.

The Benefits – What's In It for Utilities?

Technology advances in telephone, internet, personal computing, mapping, and more have transformed our lives in many ways. The electric industry has been slower to modernize, but exciting new technologies paired with AMI and communication systems, can now provide benefits to customers, utilities, communities, and the nation.

- **Benefits for the Front Office**
  AMI, often referred to as the backbone of the Smart Grid, can bring many billing, metering, and customer service efficiencies to a utility. With AMI's ability to get instantaneous and accurate meter readings on demand, it provides much more than the cash register function that old meters delivered. AMI means no more estimated bills, less rereads and no special trips to read meters when customers move in or out.

  In addition, AMI can significantly speed up the billing cycle, allowing a utility to produce bills immediately after collecting the reading, rather than waiting up to a month for all of the meters in town to be read. In turn, the faster billing cycle can improve the utility's cash flow and reduce the number of uncollectable accounts.

  Another popular feature of AMI is the ability to connect and disconnect meters from the utility office. Utility workers no longer need to put themselves in danger by physically visiting customer sites to shut off meters for non-payment.

  Customer service representatives (CSRs) love the functionality of an AMI system too. Reports and a dashboard are available to CSRs to immediately answer billing questions, resolve high bill complaints, instantaneously check customer usage, see power outages on a map, see dead meters, and identify water leaks, meter tampering, and energy theft. The CSRs can also identify voltage problems and other power quality issues.

- **Benefits for Rate Making and Analytics**
  The interval data produced by the AMI system gives the utility new information and tools to segment customers, to more accurately determine cost-of-service, and to develop new rate options. MRES plans to implement a wholesale time-based or dynamic rates by 2023. An AMI system would allow MRES members to pass those rate signals along to their retail customers and more accurately match electricity charges to costs. Time-of-use and time-of-generation data will also be necessary in the future for the utility to accurately recover its costs from customers who have installed their own generation, such as solar panels.

- **Benefits for the Distribution System**
  The AMI system can provide a wealth of operational data that utilities can use to make the distribution system more efficient and responsive. Not only does interval data come in from every meter in town, sensors can be placed throughout the distribution system to provide information on transformers, breakers, circuits, reclosers, etc. Reports can be generated daily or on-demand, alerting electrical staff to various problems throughout the system.

- **Outage Management**
  Reliability is one of critical foundations of a public power utility. AMI can enhance the utility's reliability in a number of ways. First, the AMI system can provide linemen with real-time notification of outages when they occur, can identify the outage area, and in some cases can pinpoint the cause of the outage. This feature may not immediately seem worthwhile for small communities, but when a lineman gets that outage alert at 3:00 a.m. on a cold winter morning, and can drive straight to the outage to make repairs, it can save valuable time, work, and money. When the problem has been repaired, the lineman can also easily verify on a map that power has been restored to all customers.

- **Power Quality**
  If it is a power quality problem that the utility is concerned about, the AMI system can give the utility the information it needs to provide better regulated power. For example, each meter throughout the system is also a voltage monitor. Over-voltage and under-voltage alarms, daily minimum and maximum readings, and on-demand and interval voltage data will allow the utility to optimize voltage throughout the system. And, the utility can adjust voltage during peak times to reduce peak demand, while ensuring that no customer receives voltage below the standard bandwidth.

  Hand-in-hand with voltage control, comes volt-ampere reactive ((VAR) control to help utilities monitor and improve power factor while reducing the need for and/or optimizing capacitors. Maintaining a high power factor can help a utility maximize transformer and line utilization, improve voltage performance, and help defer the need for system improvements.

These advantages of AMI, paired with other Smart Grid technologies, can ensure a worthwhile investment for utilities, allowing them to improve efficiency, make better use of existing assets, and enhance reliability and power quality. MRES can assist its members in evaluating the costs and benefits of AMI to help them determine the value and payback.

The Benefits – What's In It for Customers?

Today's customers live in exciting and transformative times. Technology impacts every aspect of their lives. How will utilities keep up with the changing needs and desires of their customers and offer compelling choices for electric service? AMI and other Smart Grid technologies can empower customers and create the foundation for enhanced customer service, more customer information, and additional customer options.

Here are some of the services and features that can be offered to customers through AMI and a web-based/mobile Customer Portal:

- **Enhanced Customer Service**
    - Online and mobile access to set up or discontinue service
    - Faster answers to billing questions through access to real-time meter readings
    - Online payment management
    - Flexible billing dates
    - Elimination of inaccurate and estimated readings
    - Choice of rate options to help customers manage costs and save money
    - Faster reconnects
- **Enhanced Customer Information**
    - Direct access to usage information and history with graphs, average costs, etc.
    - Insight about time of usage, historical trends, and comparison of usage to previous month or year
    - Tools to manage energy costs and improve energy efficiency
- **Notifications and Alerts**
    - Fast notification of water leaks to reduce the impact on costs
    - High electric usage alerts to trouble-shoot potential problems as soon as possible
    - Customer specified alerts, such as when level of usage or costs reaches a set point
- **Enhanced Dependable Service**
    - Automatic detection of outages and faster response time
    - Proactive alerts about power outages, the expected duration of outages, and when power is restored
    - Mapping of outages and visual display
    - More consistent voltage
    - Better power quality with fewer sags, spikes, and interruptions

Future Service Options

AMI and Smart Grid technologies also pave the way for future electric service options, such as prepaid electric service. Prepaid service has not been widely offered in cold weather climates due to the fear of a customer running out of funds and effectively shutting off their own electricity. New technology in prepaid metering solves this problem by limiting, rather than shutting off, the electricity if a customer runs out of funds.

In areas where prepaid electric service is widely offered, customers are attracted by the ability to have more control over their electric usage and costs, and to eliminate the fear of unknown monthly bills. They can make smaller, more frequent payments to help with budgeting, and they can avoid deposits, late fees, service terminations, and reconnect fees. The prepaid option is especially attractive to renters and college students who move frequently.

Offering customers convenience, service options, flexibility, and easily accessible and usable information will help utilities increase customer satisfaction and build customer relationships. AMI and other Smart Grid technologies are the tools utilities need to meet customer expectations.

Getting Started

Services provided by MRES start with a member need or request that can best be addressed through joint action, or members working together on a solution. MRES Smart Grid services originally started in 2010, when a member task force helped guide the development of a hosted load management service called Coordinated Demand Response (CDR). The CDR program utilized cellular communications between MRES and participating members, and an RF Mesh communications network within member communities, to enable automated direct load control using a single master station at MRES.

Once the communications networks were in place for CDR, the next logical step was to add AMI, which could utilize the same communications infrastructure. Again, MRES hosted the software to gain economies of scale, share resources and expertise, and eliminate redundancy of equipment.

Hosted Platform Structure

The structure of the MRES hosted service provides the following member benefits:

- Shared software costs through the use of a single headend or master station
- A virtual machine for each member providing data privacy
- 24/7 secure access to the system from any computer or mobile device
- Discounted hardware costs through negotiated group pricing (member owns all hardware within their community)
- MRES operational support with setup, control strategies, and troubleshooting
- Availability of reports and data analytics
- MRES ownership and maintenance of communications system from headquarters to member community
- Hardware and software updates and patching by MRES
- Cyber security expertise for member systems and data by MRES
- MRES IT support and troubleshooting for technical issues

Smart Grid Summits and Member Focus Group

When MRES members had installed AMI and were ready to take the next step toward Smart Grid technologies, MRES held three Smart Grid Summits to discuss which “add-on” technologies would be the most useful for members and their customers. MRES worked with independent consultant Katama Technologies, Inc. (KTI), a Hometown Connections partner, to develop a list of available Smart Grid applications. The Smart Grid Summits were followed by a focus group meeting of the members who were already in position to move forward. The focus group ranked the various Smart Grid technologies in order of importance and urgency to their utility. The technologies considered were:

- Meter data management
- Online/mobile customer portal
- Customer notifications and alerts
- Prepay option
- Outage management and visualization “lite”
- Voltage monitoring
- Data analytics, such as transformer loading, loss analysis, etc.

- Rate research and modeling

Meter data management (MDM) was found to be a “must have” in order to properly verify, edit and manage the large amount of data that will be collected from each utility. In addition, the MDM provides the interface between various software applications, so it is the key to allowing the systems to successfully “talk to” each other. In addition to the MDM, MRES members ranked the online/mobile customer portal and outage management lite as the Smart Grid applications they wanted to add first. MRES has issued a Request for Proposals and expects to purchase and install these technologies by the end of 2018.

Overcoming Barriers

One barrier to implementing new technology that was identified by several MRES members was a limited ability to keep up with information technology (IT) support. Since cybersecurity and data privacy are major concerns for anyone sending data across a communications network, MRES can help to overcome that barrier by taking care of the cybersecurity and data privacy of the system and by providing system upgrades, patches, troubleshooting, and training.

Other barriers that MRES is addressing include financing and equipment installation. A third-party, low-interest, financing arrangement is offered through the MRES AMI vendor which allows members to spread costs over a 10 or 15-year period. A third party vendor is also available to help members with local equipment installation.

Going Forward

MRES intends to repeat this process as members are ready for next steps, adding the next most desired Smart Grid technologies when members are ready for them. The MRES hosted service will allow members to cost-effectively realize the benefits of AMI and the Smart Grid in the timing that works best for their customers and their communities. Working together, MRES and its members will enable a future that includes system efficiencies, greater reliability, and more customer information, access, and options.

Communicating the Value of Public Power

Public power utilities excel at providing reliable, affordable electric service and many other energy services. One thing that public power utilities are not always known for is tooting their own horn. The local public power utility brings many benefits to its customers and community. If only they knew. APPA survey data found that on average customers only think about their electric utility for 9 minutes a year, so it is critical to break through the noise, inoculate against bad times, win customer loyalty, and have customers talk to you first.

APPA, MRES, SMMPA, and MMUA are all stressing the importance of communicating these values. As examples, APPA has an entire strategic initiative revolved around Raising Awareness of Public Power. MRES's communication services are featured on the following page.

Case Study: MRES Communications Services

As a strategic priority, Missouri River Energy Services (MRES) is working to help member utilities address the lack of customer understanding about the benefits of having a local, community-owned, not-for-profit municipal utility in their community. Because the electric industry is facing several challenges right now, it is more important than ever for public power utilities to connect with customers and to distinguish and position the utility as a "trusted energy advisor" in the community. Some of those challenges include:

Challenges

- **Lack of customer understanding of public power** – APPA reports that only one in five customers under the age of 55 know that their provider is a public power utility or what public power means. Over the years, many utilities have discontinued their customer education programs due to tight funding or other reasons. The result is that many customers no longer understand the meaning or value of their community-owned utility.
- **Changing demographic of customers** – As of 2016, Millennials (now ages 22-37) are now the largest portion of the population, surpassing Baby Boomers. Millennials have different priorities, interests, and methods of engagement than their predecessors. Utilities need to find new ways of reaching this demographic.
- **Changing customer expectations and options** – Industries such as banking, retail services, and entertainment (think Amazon, Google and Apple) are rapidly and dramatically changing expectations regarding customer service. Customers expect 24/7 access to information and the ability to transact business. In addition, they want options, apps, and one-stop quick, easy customer service. If utilities do not provide customers with the service they want and expect, someone else will.
- **Disruptive technologies** – The utility is no longer a true monopoly with captive customers because customers can make choices that bypass the utility. For example, customers can install solar arrays on their houses or businesses to purchase less electricity from the utility, or even produce excess power to sell back to the utility. When battery technology is refined and comes down in price, this option will become even more attractive and cost-effective. Solar roofs and electric vehicles are other disruptive technologies that have the potential to completely change how utilities do business.
- **Buy-Out Attempts** – Over the past year, several MRES members have received buy-out offers from a neighboring investor-owned utility or cooperative. The best defense against a buyout attempt is a well-run utility and customer-owners who understand the value of public power ownership. Utilities need to have a strong and proactive communication plan to educate customers and policymakers on the benefits of their local public power utility **before** they receive a buy-out offer.

Opportunities

These challenges also present opportunities for public power utilities to educate customers on the many benefits that the utility provides to both customers and to the community and to distinguish and position themselves as a trusted energy advisor. Public power utilities have a great story to tell. We just do not tell it enough for customers to gain an understanding. Most utilities have a mission or vision statement that addresses serving customers or having a customer focus, providing great customer service, and being customer- or community-owned.

Now is the time to tell customers about all the services you provide and invite them to engage with your utility.

MRES Initiatives

In thinking about how MRES could assist our members in telling their stories, our Board of Directors and staff developed a set of Value of Public Power goals, including:

- Increase awareness of everything member utilities do for their communities and their customers
- Further position member utilities as the "trusted energy advisor" in their communities
- Enhance members' relationships with their customers through new and existing communication and partnership opportunities
- Develop materials that will be a resource of information for customers, communities, key leaders, and employees on the value and role of the local public power utility
- Create a flexible, modular approach that allows members to customize and implement communication materials in their own way

Value of Public Power Topics

MRES assembled a focus group of 15 of our member communicators to provide insights, expertise, and guidance on the development of the Value of Public Power campaign. The focus group devised an extensive list of topics and key messages that highlight the benefits of having a local, community-owned electricity utility, including:

- Community-ownership / community support (financial and in-kind services)
- Reliability / dependable local service
- Affordability / competitive rates
- Cost-based rates / not-for-profit operation
- Customer focus / customer service
- Customer programs (energy efficiency, technical services, etc.)
- Local governance / local control / customer voice in decisions
- Economic development / support of local businesses
- Caring for the environment / renewable energy
- Electrical safety
- Local employment
- Investments in local infrastructure
- Support for other city services
- Community sponsorships and engagement

Barriers - Time and Money

In the past, educating customers often meant spending time and money on advertising. MRES worked to develop solutions that will overcome those barriers and help members tell their story by using consistent messaging in a low-cost or no-cost way. Social media, websites, customer portals, email, and local cable TV stations provide advertising mediums that are affordable and accessible to all utilities, no matter how large or small.

As APPA CEO Sue Kelly noted in her November 10, 2016 blog: "If your utility does not have a social media presence, a mobile-friendly website, and a good email marketing platform, you have no bridge to your future employees – or customers."

If a member does not yet use Facebook and Twitter, MRES offers training to help set up those accounts. In addition, MRES also posts the Value of Public Power social media posts on its own platforms to make it convenient for members to share that messaging.

If traditional advertising methods still work best in a member community, MRES offers a cost-share program under which MRES will reimburse 50 percent of eligible Value of Public Power advertising costs, up to an annual limit based on total electric meters.

Marketing Packages

With the guidance of the member focus group, MRES developed a quarterly package of turn-key communication materials that its members can use in a variety of ways to match whatever works best in their communities. Each package contains fun, visually engaging materials that focus on several aspects of municipal electric service. These materials are designed to be fast, easy and inexpensive to use.

The resources are in the form of infographics, web and social media content, videos, press releases, letters to the editor/columns, and radio scripts. Also included are traditional marketing pieces, such as bill stuffers and newspaper ads. Each piece can be customized with the utility/city logo and contact information. Members are also encouraged to share this information with employees, governing boards, city leaders, local media, and other key audiences.

Communicating the Value of Public Power must be an ongoing effort to ensure that the message consistently reaches target audiences. Fresh, engaging, and easy-to-understand messaging is key to reaching various customer demographics. MRES recommends posting daily content on social media platforms and scattering marketing pieces on other platforms throughout the quarter.

Buy-Out Offers

If a buy-out offer or sell-out attempt occurs, additional and immediate steps must be taken to evaluate, quantify, and communicate the benefits and value of the local utility. A municipal utility is much more than the amortized value of its meters, wires, and substations.

MRES offers members a Municipal Power Advantage® (MPA) report to determine the value, in dollars and cents, of all the benefits the municipal electric utility provides to the community. The detailed report includes a three-year financial analysis of tangible financial benefits, including:

- Amounts paid to non-electric funds
  - Payments in lieu of taxes or franchise fees
  - General fund transfers
  - Capital equipment contributions
  - Economic development transfers
- Donated electric service and labor
- Wholesale power supply costs as compared to regional suppliers
- Value of energy efficiency incentive programs
- Competitiveness of retail rates as compared to regional utilities
- Other tangible benefits – customer loan programs, operational efficiencies, etc.

The MPA report also examines intangible benefits, such as integrated utility operations, local governance, access to tax-exempt financing, reliability, environmental stewardship, customer service, and circulation of local funds. MRES offers communications materials and presentations to governing bodies in conjunction with the report.

In May of 2018, APPA released an updated version of its buy-out/sell-out guide called "The Future of Your Utility / Positioning Your Community to Succeed in a Sellout Evaluation." This publication is an excellent resource for all public power utilities and should be utilized **before** a buy-out attempt occurs.

What's Next?

In an effort to make the Value of Public Power campaign as meaningful and relevant as possible, MRES is working with two communications interns during the summer of 2018 to produce customized videos on Value of Public Power topics for MRES members. Using still photos, video clips, and interviews taken within the community, we hope these videos will strongly resonate with customers and make them proud to be a customer-owner of their public power utility.

Minnesota Perspective

Minnesota, one of the largest Midwestern states in area, is home to about 5.5 million people, with more than half of the population living in the Twin Cities metro area. The topography varies from boreal forest, lakes, and wetlands in the Northeast to gently rolling farmland in the southern half of the state.

With an average temperature of 42.8 degrees Fahrenheit, Minnesota's climate is colder than most states. Winters are severe, particularly in the northern part of the state, where nighttime temperatures of 30 degrees below zero are not uncommon. Winter-long snow cover and frozen ground are the norm. Summers are warm and humid, with temperatures reaching into the 90s and occasionally hitting 100, particularly in the southern part of the state. With an annual temperature range of 130-140 degrees in many parts of the state, utilities are challenged to maintain facilities and meet customer demand under widely varying weather conditions.

Minnesota's Electric Utilities

Investor-Owned Utilities (IOUs)

Minnesota is served by three IOUs. Xcel Energy, the largest utility in the region, is by far the largest electric utility in Minnesota, with more than 1,250,000 customers and 2016 sales of 30 million Megawatt-hours (mWh).[22] Xcel serves the Twin Cities metro area in addition to a variety of other areas in southern Minnesota.

Minnesota Power, headquartered in Duluth, also serves the Iron Range mines and northeast Minnesota's paper mills. It has 145,000 customers and had 2016 sales of 8 million mWh.[23] Minnesota Power also provides wholesale power and transmission service to most of the municipals in northeast Minnesota.

Otter Tail Power Co. is headquartered in Fergus Falls and serves many small communities in northwest Minnesota and the Dakotas. Otter Tail has 61,000 Minnesota customers and had 2016 Minnesota sales of 2.5 million mWh.[24]

Cooperative Utilities (Co-Ops)

Minnesota's 44 distribution co-ops range in size from 1,900 customers to 130,000 customers, and serve a total of 827,000 customers.[25] The average size of Minnesota co-ops is 18,807 customers, and the median is 7,486.

Generation and Transmission Cooperatives (G&Ts)

A variety of G&T co-ops provide wholesale power and transmission services to Minnesota's distribution co-ops.

- The largest G&T in Minnesota is Great River Energy (GRE), headquartered in Maple Grove, which serves 28 co-ops. GRE is the second largest electric power supplier in Minnesota and one of the largest generation and transmission cooperatives in the country.
- Minnkota Power Cooperative, headquartered in Grand Forks, ND, serves 8 Minnesota co-ops in northwest Minnesota, as well as 3 North Dakota co-ops.[26]
- Dairyland Power Cooperative, headquartered in La Crosse, WI, serves 3 co-ops in southeast Minnesota.[27]
- East River Electric, L&O Power Cooperative, and Basin Electric Power Cooperative also provide power to co-ops in western Minnesota.

Public Power Utilities

Minnesota has 124 public power utilities, ranging in size from Rochester, with more than 52,000 customers to Whalan, with 38.[28] These communities have a total population of about 783,000. Minnesota has 87 county seat communities, and 49 of them are served by a public power utility. Although Minnesota has a lot of public power utilities, most of them are small. Seven of our public power utilities have more than 10,000 customers. Almost 75% of our public power utilities have fewer than 2,500 customers, and more than half are smaller than the smallest Minnesota electric co-op. The average Minnesota public power utility has 3,017 customers. The median number of customers is 1,256. Minnesota's public power utilities serve approximately 375,000 customers in total.[29]

Municipal Joint Action Agencies

Most, but not all, Minnesota public power utilities belong to a joint action agency, which provides wholesale power and transmission services to its members. Some agencies provide a variety of other services as well.

- Central Minnesota Power and Services (CMPAS), headquartered in Blue Earth, MN, serves 12 Minnesota public power utilities.[30]
- Heartland Consumers Power District, headquartered in

Madison, SD, serves 6 Minnesota public power utilities, in addition to public power in South Dakota and Iowa.[31]

- Minnesota Municipal Power Agency (MMPA), headquartered in Minneapolis, serves 12 Minnesota public power utilities.[32]
- Missouri River Energy Services (MRES), headquartered in Sioux Falls, SD, serves 24 Minnesota public power utilities, in addition to public power utilities in Iowa, North Dakota, and South Dakota.[33]
- Northern Municipal Power Agency (NMPA), headquartered in Thief River Falls, MN, serves 10 Minnesota public power utilities and 2 North Dakota public power utilities. NMPA and Minnkota Power Cooperative have pooled their generation resources to serve the membership of both organizations. NMPA also owns a load-ratio share of the Minnkota transmission system.[34]
- Southern Minnesota Municipal Power Agency (SMMPA), headquartered in Rochester, MN, serves 18 Minnesota public power utilities.[35]
- Upper Midwest Municipal Power and Energy Group (UMMEG), headquartered in Cumberland, WI, serves 2 Minnesota public power utilities, in addition to public power in Wisconsin and Iowa.[36]

Figure 1 shows the relative size of the three segments of the industry. IOUs serve about 55% of the Minnesota customer base, co-ops serve 31%, and public power utilities serve 14%.

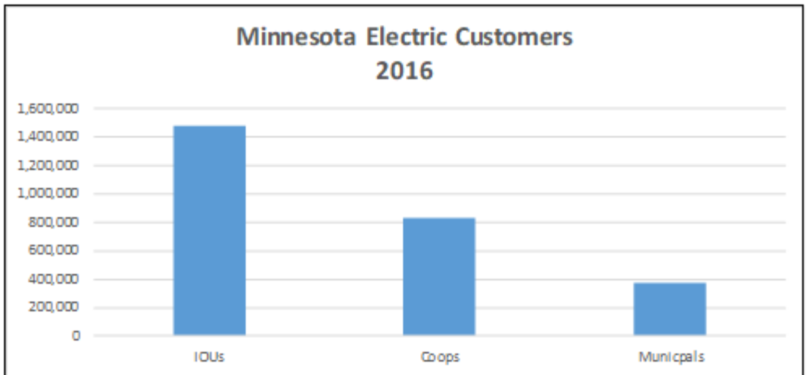


Figure 1

Western Area Power Administration (WAPA)

The Upper Great Plains Region (UGP) of WAPA produces hydroelectric power from the dams on the Missouri River system. UGP sells power in Iowa, Minnesota, Montana, Nebraska, North Dakota, and South Dakota to wholesale customers such as municipal utilities, rural electric cooperatives, public utility and irrigation districts, Federal, state, and military agencies, Native American tribes and U.S. Bureau of Reclamation and U.S. Army Corps of Engineers customers.[37] UGP provides an allocation of power to 48 Minnesota public power utilities and 15 Minnesota co-ops in the western part of the state. Most allocations were established many years ago and have not been adjusted upward as loads have grown. A few utilities have been able to acquire small allocations in recent years. Allocations range from covering virtually all of a public power utility's sales to covering as little as one percent. On average, the WAPA allocations cover 37% of the public power recipients' sales.

Although the WAPA hydropower is renewable by some standards (except for power purchased by the agency to meet its commitments in drought years), it is not considered renewable energy under the Minnesota Renewable Energy Standard. As a partial recognition of the renewable nature of WAPA power, WAPA sales are exempted from application of the RES.

A Changing Industry

Renewable Energy Standard (RES)

Minnesota has long been a typical Midwestern, coal-dependent state, but that is changing. In 2007, the Minnesota Legislature enacted a RES that calls for most of the state's power suppliers to be 25% renewable by 2025.[38] Xcel, due to its ownership of nuclear generation, is required to be 30% renewable by 2020.[39] To avoid placing an undue burden on small public power utilities and co-ops, the mandate falls on power suppliers (IOUs, G&Ts, public power JAAs, and power marketers) rather than on distribution utilities. Minnesota's power suppliers are on track to meet the 2025 goal, and some are ahead of schedule.

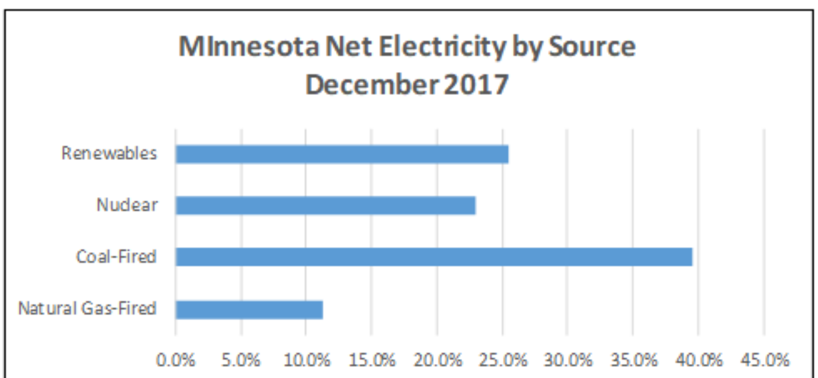


Figure 2

The Department of Energy's Energy Information Administration (EIA) data shows that coal's share of utility-scale electricity generation in Minnesota declined from 49% in 2014 to 39% in 2017.[40] As of December 2017, coal-fired generation represented 39.5% of Minnesota retail sales, renewables were second to coal at 25.5%, nuclear produced 22.9% of energy sold, and natural gas produced 11.3%.[41]

A lot has happened in the decade since Minnesota's RES was enacted. Minnesota was a national leader in 2007, but a variety of states have passed similar or more stringent mandates in the years since. Minnesota's power suppliers are now much more experienced at accommodating variable renewable resources in their portfolios, and the Midcontinent System Operator (MISO) system operator has become more adept at operating a wholesale power market that includes substantial renewable resources. Widespread use of fracking has led to much lower natural gas prices, which have in turn resulted in much lower wholesale power prices. The cost of power from new wind resources has kept pace with the overall reduction in power costs, and in recent years wind has generally been the least-cost resource for a utility looking to add new generation. The cost of utility-scale solar has also come down considerably in recent years.

In addition to these industry developments, both scientific and public opinion have continued to coalesce around the conclusion that climate change is a significant threat, and that society needs to take steps to reduce greenhouse gas emissions where possible. In response to these developments, renewable advocates have begun calling for a strengthened RES that would require Minnesota power suppliers to be 50% renewable by 2030. Utilities would argue that markets are moving the industry away from coal and toward natural gas and renewables, so Minnesota utilities' generation portfolios will continue to become more renewable and less carbon intensive without the need for additional mandates.

Conservation Improvement Program (CIP)

Minnesota's electric utilities are also required to make substantial efforts and investments in conservation. Under Minn. Stat. §216B.241, a public power utility with more than 1,000 customers[42] must spend 1.5% of its gross operating revenues on energy conservation improvements. Further, a public power utility with more than 1,000 customers is expected to achieve annual energy savings equivalent to 1.5 percent of gross annual retail energy sales. A utility may only take credit for savings from a measure in the year in which it is implemented. Savings over the lifetime of the measure following the year in which it is implemented are not considered. At least one percent of each year's savings must be from conservation improvement projects. The remaining savings may be from electric utility infrastructure projects that result in increased energy efficiency greater than that which would have occurred through normal maintenance activity. If a utility exceeds 1.5% in energy savings in a year, the excess over 1.5% may be carried forward to the succeeding three calendar years. Savings from electric utility infrastructure projects may be carried forward for five years.

Like the RES, Minnesota's CIP program in its current form dates to 2007. Some public power utilities have been able to meet the energy savings requirement, but others have struggled. A small town public power utility with little or no industrial or commercial load and little new construction has few opportunities to find the energy savings necessary to meet the 1.5% savings goal. Utilities have argued that the lack of recognition of life-cycle savings understates the energy savings achieved by the program. The program includes a mandate to provide low-income programs, but utilities have had little success in developing effective low-income programs.

MMUA and the Minnesota Rural Electric Association (MREA) have established a task force to re-imagine CIP for a new era. The two organizations are beginning the conversation in the 2018 legislative session and hope to bring a new CIP proposal to the Legislature in 2019. A summary of this effort is included at Appendix A.

Greenhouse Gas Emissions-Reduction Goals

In 2007 the Minnesota Legislature enacted a series of increasingly stringent greenhouse gas reduction goals. "It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050."[43]

According to Minnesota Pollution Control Agency data, the electric utility industry has done a good job of reducing its greenhouse gas emissions. From 2005 to 2014 greenhouse gas emissions from electricity generation were reduced by 17%. Unfortunately, other sectors of the economy are not doing as well. During the same period emissions from transportation were down by 7% and emissions from agriculture were down 2%. Emissions from other sectors have been rising. Industrial greenhouse gas emissions were up 20%, residential emissions were up 19%, Commercial emissions were up 20% and waste emissions were up 8%. Overall, Minnesota's greenhouse gas emissions declined by about 4% from 2005 to 2014.[44] The overall reduction was 6.43 million tons CO_2-equivalent. Without the 9.97 million-ton CO_2-e savings achieved from electric generation, the rest of the Minnesota economy experienced a 3.44 million-ton CO_2-e increase in emissions.

Distributed Generation (DG)

Solar generation has arrived in Minnesota, although rooftop solar is not spreading as fast as it has in other states with sunnier climates. There are likely several reasons for this. First, Minnesota's lower sun angle and cloudier climate result in solar unit capacity factors in the 14% range, compared to capacity factors of 20% or more in sunnier areas such as California. Second, electric rates in Minnesota are significantly lower than in some areas of the country where solar is booming. Third, snow cover is a fact of life in Minnesota winters, which can reduce the output of a rooftop installation. And Minnesota's building code requires that roofs have the structural integrity to withstand 50 to 60 pounds per square foot of snow loading.[45] In some cases, a home or business may need additional reinforcement to enable the roof to handle the additional weight of a solar installation and still meet the snow loading standard.

Figure 3 shows the average number of days per year with at least 80% cloud cover for 20 major U.S. cities.[46] Some areas of the country, such as Phoenix and Las Vegas, experience fewer than 100 cloudy days per year. Others, such as Miami or Denver, experience a little more than a hundred cloudy days. Minneapolis, with an average of 169 cloudy days, is not the cloudiest city on the list, but it is cloudier than most. This provides a good example of why solar installations in Minnesota aren't as productive as installations in some other parts of the country.

City	Cloud Cover Days
Phoenix, AZ	70
Las Vegas, NV	73
Sacramento, CA	100
Los Angeles, CA	103
Miami, FL	115
Denver, CO	120
New York, NY	132
Dallas, TX	133
New Orleans, LA	146
Atlanta, GA	149
Kansas City, MO	149
Nashville, TN	156
Philadelphia, PA	160
Washington, DC	164
Minneapolis, MN	169
Chicago, IL	176
Detroit, MI	185
Cleveland, OH	202
Pittsburgh, PA	203
Seattle, WA	226

Figure 3

Utility-Scale Solar

In 2013 the Minnesota Legislature established a new requirement that IOUs generate or procure sufficient electricity from solar sources so that by the end of 2020, at least 1.5 percent of the utility's retail electricity sales in the state are produced from solar energy. At least 10 percent of this energy must be generated by facilities with a capacity of 20 kilowatts or less.[47] This new requirement has spurred the development of large, utility-scale solar developments throughout the state. The legislation also established an energy goal of the state of Minnesota that, by 2030, ten percent of the retail electric sales in Minnesota be generated by solar energy.[48]

Although public power utilities and co-ops are not subject to this requirement, they are also bringing solar projects on line. A number of co-ops have developed community solar garden projects. Moorhead Public Service developed a very successful public power utility community solar project, and other public power utilities are considering similar projects. Public power joint action agencies are also working on community solar projects that their members' customers could subscribe to.

While customer-owned solar installations are occurring at a slower rate in Minnesota, they are happening, and they can pose challenges for small municipals. In order to help municipals prepare for and incorporate customer-owned solar installations, MMUA has developed a variety of helpful materials, including:

- A model *Distributed Generation and Net Metering Policy*, with adopting resolution and instructions.
- A model *Cogeneration and Small Power Production Tariff* and standard contract, with adopting resolution and instructions.

- A model *Interconnection Application and model Notification to Customers*.
- A model Solar Ordinance with adopting resolution and instructions.

These resources are available behind login on the MMUA website in the Library under Distributed Generation.

The e21 Initiative

Since 2014 Minnesota's utilities have been involved with other stakeholders in a project intended to consider new ways for utilities to operate to meet the challenges of a changing industry. In describing the initiative, the e21 website states, "e21 brings together key interests including utilities, consumer advocates, energy technology companies and other businesses, environmental and academic organizations, and government to enable Minnesota's continued leadership in shaping an electric system for the 21st century."[49]

While e21 has focused largely on investor-owned, rate-regulated utilities, the subject matter under consideration is, of course, of interest to public power and cooperative utilities. MMUA has been represented in e21 by Director of Engineering and Policy Analysis Robert Jagusch. The project has proceeded in three phases.[50]

> *Phase I.* In its first phase (Feb. to Dec. 2014), e21 developed recommendations for Minnesota to evolve toward a more consumer-centric, performance-based regulatory approach and utility business model.
> *Phase II.* e21's second phase (January 2015 to December 2016) was devoted to developing the next level of detail necessary for implementation of its Phase I recommendations. e21 published a set of white papers on performance-based compensation, integrated systems planning, and grid modernization.[51]
> *Phase III.* e21's third and final phase (January 2017 to present) brings stakeholders together to learn about innovative pilot projects and activities in Minnesota and beyond, support stakeholder engagement in those projects, and shorten the distance between good ideas and implementation.

Markets

The Midcontinent Independent System Operator (MISO) and its Upper Midwest predecessor organization, the Mid-continent Area Power Pool (MAPP), had long operated a voluntary market for excess energy. This "economy energy" market often provided power suppliers the opportunity to purchase wholesale electric energy at a lower price than they could achieve from operating a comparatively inefficient power plant. This system was used by individual public power utilities as well as large power suppliers and worked quite well.

On April 1, 2005, the bulk power system in Minnesota and other midwestern states in the MISO footprint experienced a paradigm shift, when MISO launched its Energy Markets and began centrally dispatching generating units based on bids and offers cleared in the market.[52] Utilities no longer take power from the units they own. Instead, they sell the output of the generation they own into the MISO market and purchase the energy they needed from the MISO market. Most energy is purchased and sold on the Day-Ahead market. Supplemental purchases are made to match actual needs on the Real-Time market.

In the first few years following the MISO market launch, gas prices were relatively high, which led to relatively high wholesale electricity market prices. Some public power utilities with significant exposure to market prices suffered through an adjustment period to the new regime as their customers experienced high and volatile prices.

As shale gas began to make its way to market, lower natural gas prices led to a substantial decline in electricity prices. One study estimates that the natural gas supply boom resulting from the advent of shale gas resulted in $25 billion in annual savings to the electric power industry during the period 2007-2013.[53] Since the advent of the mandatory MISO electricity markets in 2005, the MISO Minnesota Hub day ahead on peak price has shown a close correlation with the U.S. natural gas electric power price. That correlation has grown closer since 2008 and has been nearly to perfect since 2014. The increasing correlation likely reflects the increased use of natural gas-fired generation resources to back up new wind resources that have come on line to meet the increasing renewable energy requirements of Minnesota's RES. The close relationship between wholesale natural gas prices and wholesale power prices can be seen in Figure 4.

MISO's market prices in recent years, particularly in 2015-2017, are historically low, and are causing operators to rethink some long-standing assumptions about power supply. A number of older coal plants have been retired in recent years, in part because of the challenge of meeting more stringent air quality regulations, but also because their operating costs were too high to clear the market. Other older coal plants, such as Xcel's Sherco 1 and 2 and Otter Tail's Hoot Lake plant, are scheduled for retirement in the next decade. In the last several years, some large coal plants have experienced major outages, and the plant owners were able to purchase replacement power on the market at a lower cost than the output of the plant.

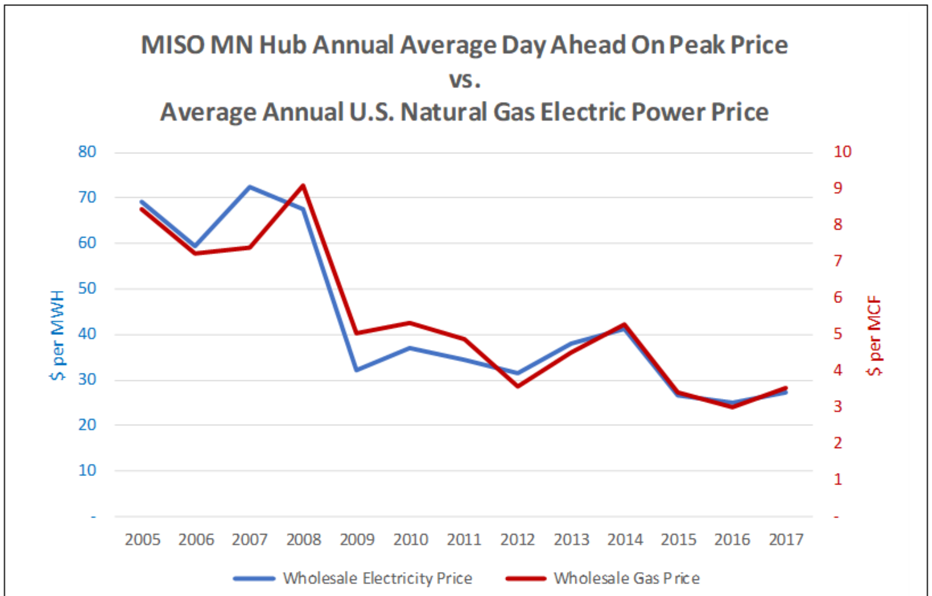


Figure 4

What do these market prices mean for the future of power supply? Are today's prices a boom or a paradigm shift? Will gas prices remain at or near current levels if utilities across the country invest in substantial amounts of new gas-fired generation? Gas prices have been quite volatile in the past. What can we expect in the future?

The gas futures market indicates that we can expect relatively stable gas prices through the middle of the next decade.[54] As Figure 5 indicates, the yearly average of Henry Hub monthly index futures shows stable gas prices out through June of 2025. This is certainly encouraging, but it leaves a lot of uncertainty for a utility considering an investment in a gas-fired generating facility with a useful life of 40 years or more.

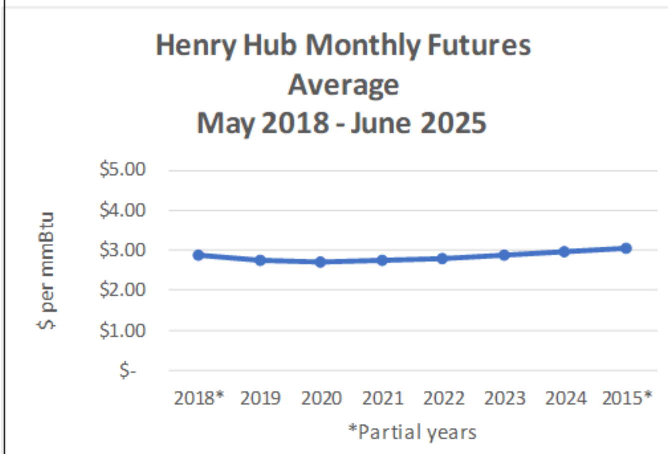


Figure 5

The MISO market also provides some interesting data regarding wind. Of MISO's three regions, MISO North (serving Minnesota, Iowa, and the Dakotas) is clearly the windy region. In Summer 2017, wind made up 19% of the generation mix in MISO North, as compared with 2% in MISO Central and 0% in MISO South.[55]

Wind has become an important and growing energy source in our Upper Midwest region, but its intermittency continues to limit its usefulness in meeting peak demand. As the MISO graphic in Figure 6 showing the 2017 monthly energy contribution from wind demonstrates, wind resources have their lowest production in July and August, the hot weather months when energy use is the highest.[56]

This issue is particularly evident when looking at peak hour data. MISO's wind generation percentage in the peak load hour was 3.1% in Summer 2015, 2.9% in Summer 2016, and 1.6% in Summer 2017.[57] Both the level and the variability of wind's contribution demonstrate that, even as renewables continue to play increasing role as an energy source and demand response efforts have an increased

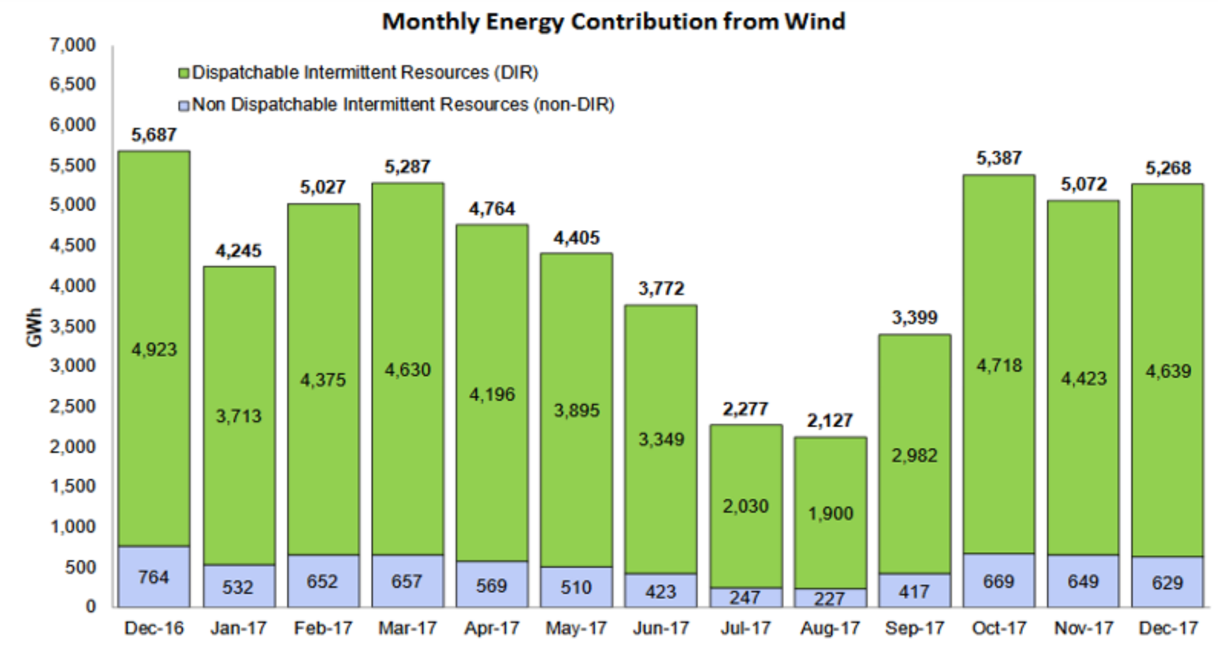


Figure 6

impact on mitigating peak load, MISO will continue to rely on dispatchable resources to meet peak demand for the foreseeable future.

Responding to a Changing Industry

Public Power Forward Survey

In order to gauge how Minnesota's public power utilities are responding to the many changes taking place in the industry, the Minnesota Public Power Forward project team developed a survey that was sent to all of the state's public electric utilities. The survey went through several iterations, and preliminary testing was done to ensure that the survey was understandable and could be expected to elicit the appropriate information. The survey questions are attached at Appendix B.

Survey responses were received in late May and early June 2017. The response rate was 34%, which should be sufficient to provide a reasonably accurate picture of Minnesota public power utilities' level of readiness to succeed in a changing industry.

Survey Results

Results were analyzed for all respondents and by the following groups of utilities, segregated by size:

- 10,000 or more electric customers (Group 1)
- 5,000 to 9,000 electric customers (Group 2)
- 1,000 to 4,999 electric customers (Group 3)

- Less than 1,000 electric customers (Group 4)

A full summary of survey results is attached as Appendix C.

Advanced Metering Infrastructure (AMI). The survey asked whether respondents had installed any two-way advanced metering known as AMI on the system. As Figure 7 shows, 38% of respondents had deployed some AMI. In Group 1, 50% had deployed AMI, and in Group 2, 60% had deployed. Group 3 had a 40% had deployment rate, but none of the Group 4 utilities had deployed AMI. About a third of the systems with some AMI on the system stated that their AMI system is fully deployed. Roughly half of the systems with no AMI deployed were exploring options for introducing AMI on the system. Of those considering AMI deployment, some expected to move forward quickly, while others thought that deployment was 2 to 3 years out. 65% of the systems with AMI deployed had access to a Meter Data Management system to assist in managing the data flow from the AMI, either on their own or with a third party.

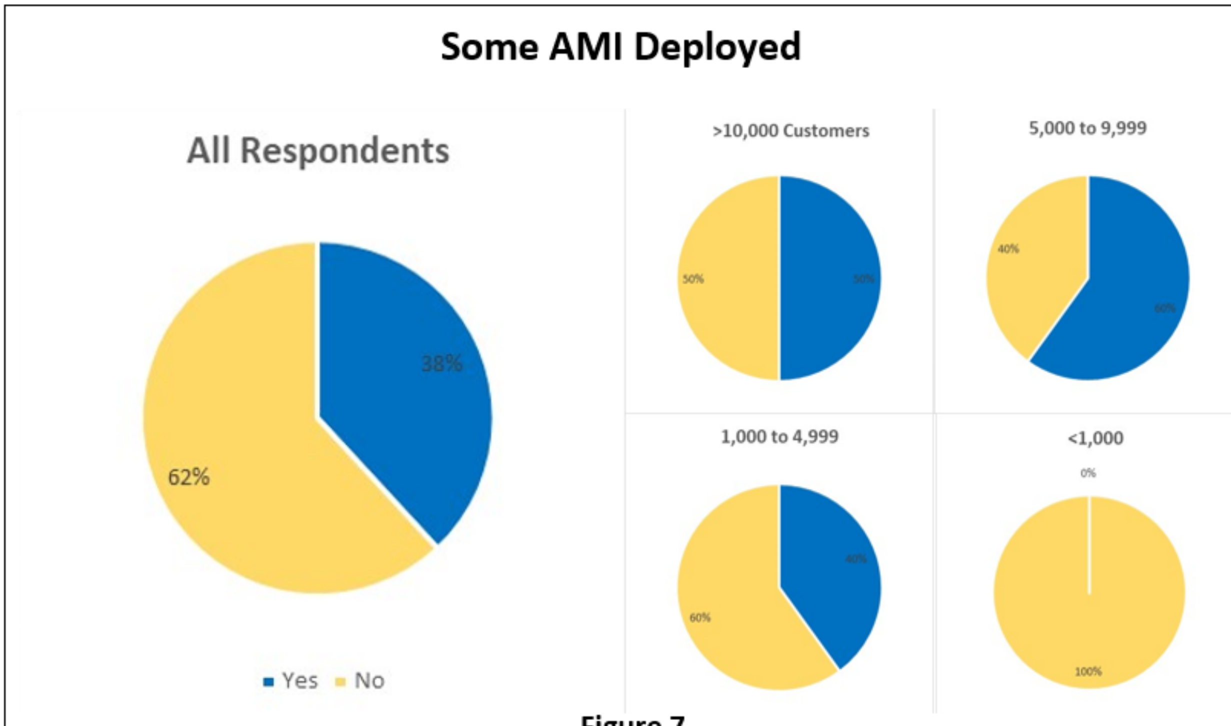


Figure 7

The survey results show that many of Minnesota's public power utilities are installing AMI or actively considering it, but only a relatively small percentage are at full deployment. Not surprisingly, the Group 4 utilities are lagging behind their larger cousins. Converting to AMI is a complex, expensive, labor-intensive process and the benefits of an automated system may be less significant in a very small system. The transition to new technology has begun, but it will likely be some years before the transition is largely complete.

Customer Information System (CIS). Of the systems that reported using a CIS, 57% reported that the system had been updated within the last three 3years. 21% had updated within the last 6 years, 4% had updated within the past 9 years, and 18% reported that it had been more than 9 years since the last system update.

Good customer data will be increasingly important in a more complex and competitive environment. Upgrading or updating these systems will be an important step for all public power utilities going forward.

Geographic Information System (GIS). As Figure 8 shows, slightly more than half (54%) of respondents reported using a database supported GIS. Usage declined substantially among smaller utilities. In Group 1, GIS usage was universal, and it was 90% in Group 2. In Group 3, usage was substantially lower at 41%; and in Group 4, it was only 12%.

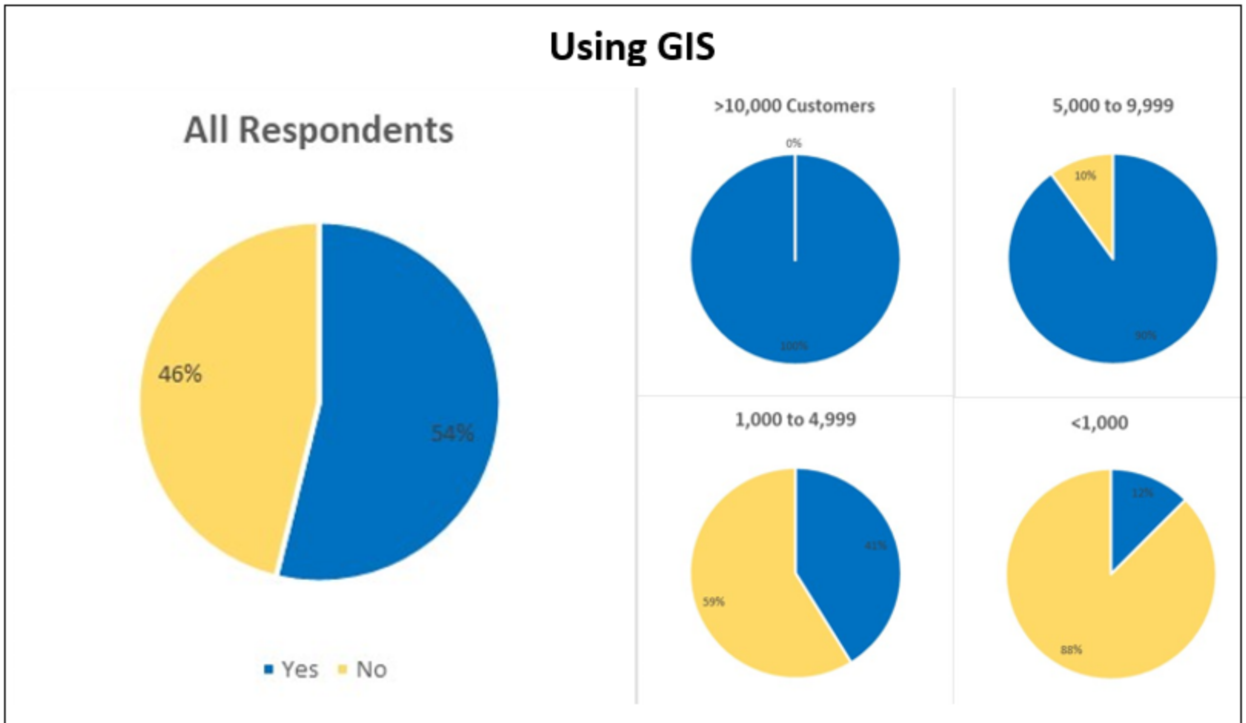


Figure 8

With more than half of respondents using GIS, the transition to this important business tool is well underway. As GIS systems become more sophisticated, they have the capability to add efficiencies to many aspects of a utility's operations, including mapping, inventory control, operations, and accounting.

Cost of Service Study (COSS). Overall, nearly two-thirds of all respondents had conducted a full cost of service study to determine rates within the last 3 years.

Another 27% had conducted a study within the past 6 years. Groups 1 and 2 were evenly split between having done a cost of service study within the last 3 years and the last 6 years. In Group 3, 74% had done a cost of service study within the last 3 years and in Group 4, 63% had done a cost of service study within the last 3 years. See Figure 9.

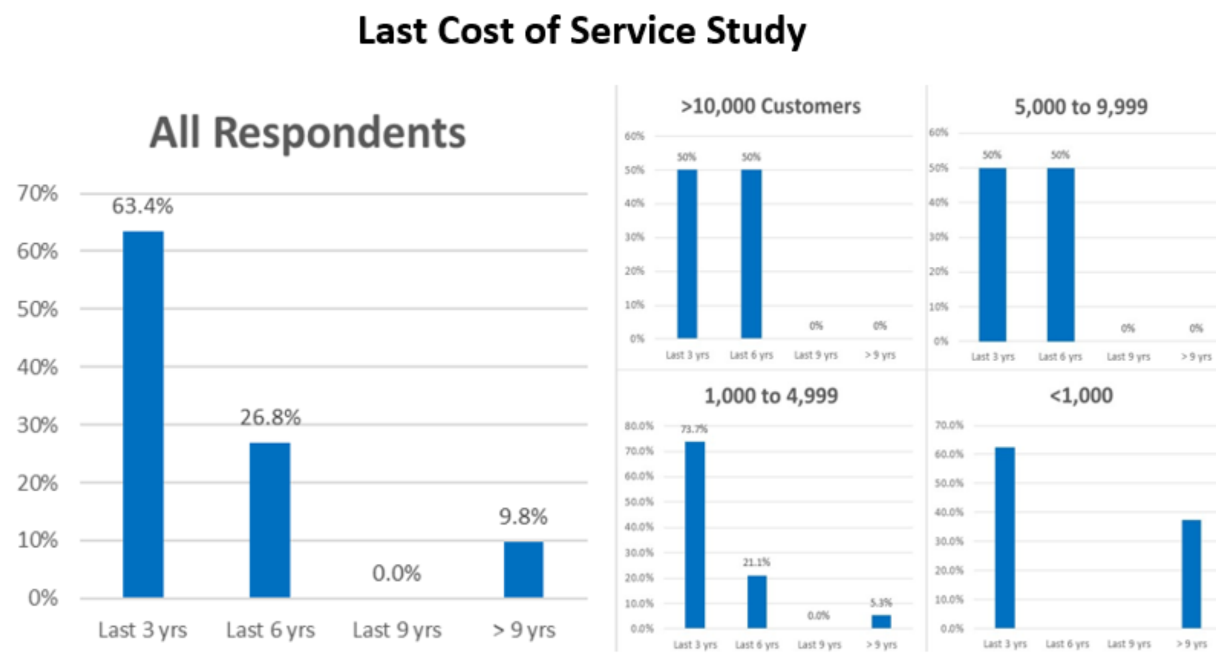


Figure 9

The survey results make clear that Minnesota's public power utilities recognize the value of getting rates right. One of the key issues in ratemaking in the current environment is to make sure that the customer charge is high enough to capture a significant portion of the utility's fixed costs in providing service to the customer. When the customer charge is right-sized, the utility's revenue stream is protected if a customer installs distributed generation which significantly reduces the utility's energy sales to the customer.

Service Charge.[58] 50% of all respondents have a customer service charge in the $10 to $15 range. 12% have a service charge that exceeds $15. In Group 1, 50% of respondents have a customer charge in the $10 to $15 range and 25% have a customer charge that exceeds $15. In Group 2, 50% are in the $10-$15 range, with 10% above $15. In Group 3, 60% have customer charges in the $10 to $15 range, and 30% are in the $5 to $10 range. In Group 4, 63% are at $5 or less, and the remainder are greater than $15. See Figure 10.

With most respondents having had a recent rate study, it is not surprising that more than half of all respondents have a customer charge in the $10 to $15 range or

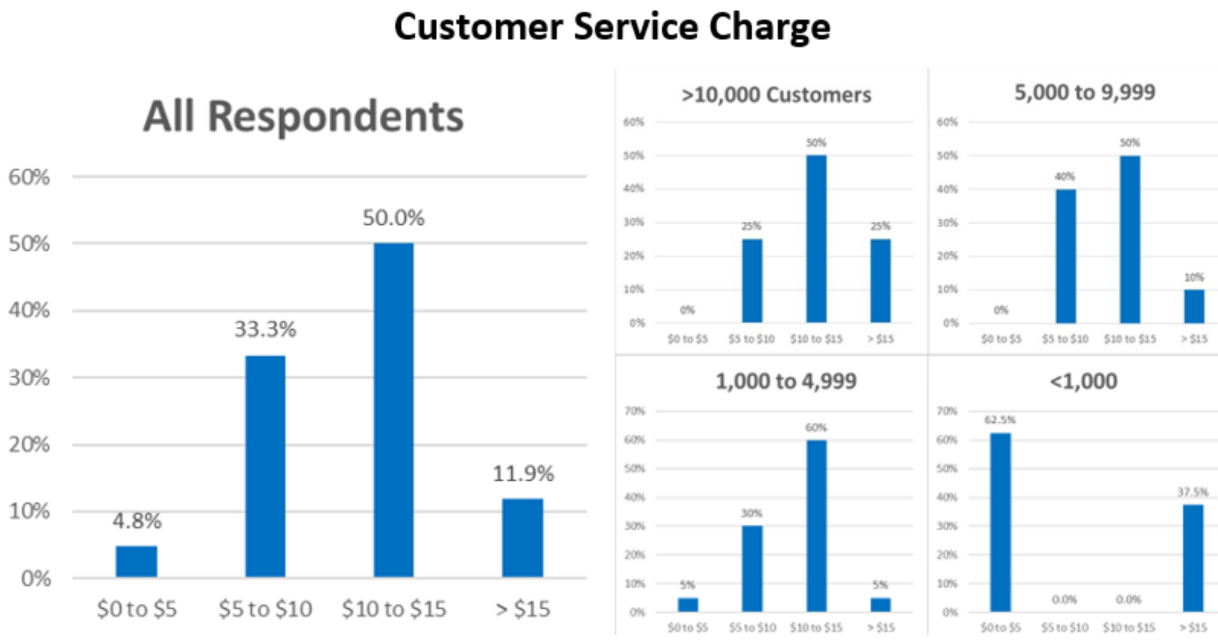


Figure 10

higher. As DG installations become more common, we will likely see more municipals adjust their customer charge upward. The Group 4 utilities would be well-advised to gradually begin moving their customer charges up toward the $10 to $15 range.

Demand Response (DR). A significant segment of the respondents is engaged in DR activities. 47% offer air conditioner control, 42% offer water heater control, and 35% offer electric heat programs. In Group 1, all respondents offer air conditioner control and 50% offer water heater control and electric heat programs. In Group 2, 50% offer air conditioner control, 40% offer water heater control, and 30% offer electric heat programs. In Group 3, 43% have air conditioner and water heater programs, and 33% have electric heat programs. Turning to Group 4, 25% have air conditioner programs and 37% have water heater and electric heat programs. Many public power utilities have been doing demand response for decades, although it is typically known as "load management." As older, fossil-fueled generating units are retired and our bulk power system becomes increasingly reliant on non-dispatchable energy sources, demand response will likely take on a new level of importance as utilities are encouraged to tailor their load to match available resources. See Figure 11.

The survey results show that Minnesota's public power utilities have begun the process of adapting to a new, more complex and competitive utility operating environment. We now turn to a discussion of emerging technologies and business

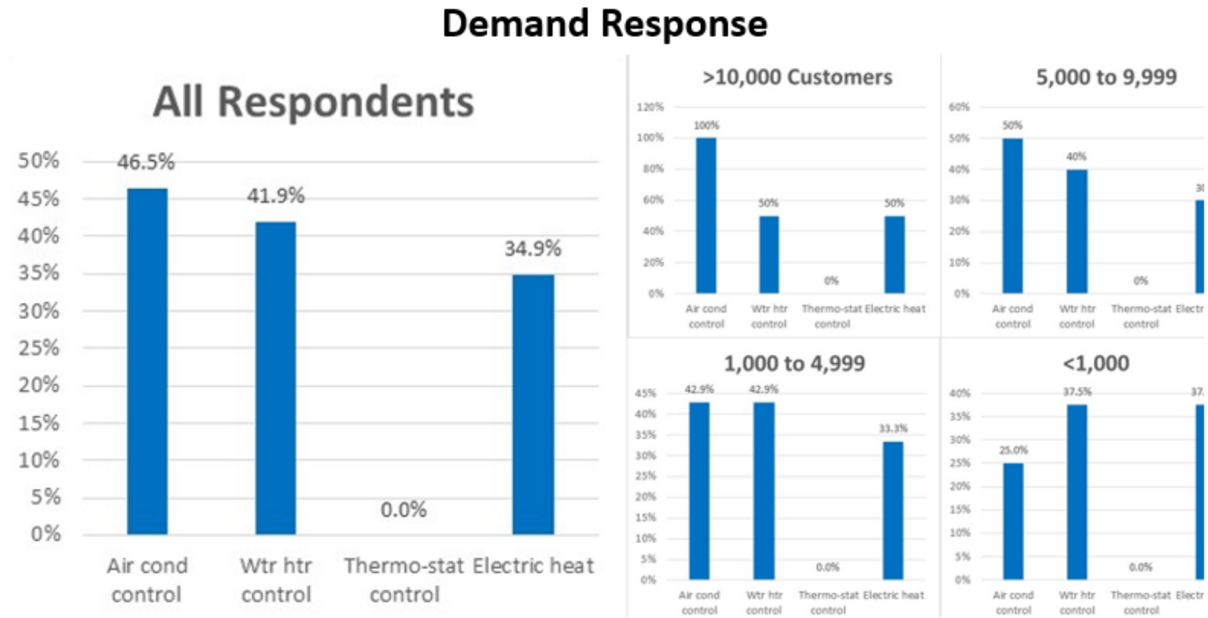


Figure 11

models that will enable our public power utilities to complete the transition to a 21st Century utility.

Resources

American Public Power Association Resources

1. Community Solar A-Z: Guide for Public Power Utilities, November 2016
   https://www.publicpower.org/resource/community-solar-z
2. Creating a Smart City Roadmap for Public Power Utilities, December 2018
   https://www.publicpower.org/system/files/documents/APPA-Smart-City-Roadmap-FINAL.pdf
3. Creating an Electric Vehicle Blueprint for Your Community, September 2018
   https://ebiz.publicpower.org/APPAEbiz/ProductCatalog/Product.aspx?ID=8314
4. Cyber Security Essentials
   https://ebiz.publicpower.org/APPAEbiz/ProductCatalog/Product.aspx?ID=4909
5. Cybersecurity Information Engagement Plan, November 2017
   https://www.publicpower.org/system/files/documents/cybersecurity-information-engagement_plan.pdf
6. Cybersecurity Scorecard
   https://www.publicpower.org/topic/cybersecurity
7. Distributed Energy Resources and Public Power, October 2017
   https://www.publicpower.org/resource/distributed-energy-resources-and-public-power
8. Legal Implications of Community Solar Securities and Tax Law Considerations, January 2017
   https://www.publicpower.org/resource/legal-implications-community-solar-securities-and-tax-law-implications
9. Managed Cybersecurity Service Providers for Electric Utilities
   https://www.publicpower.org/system/files/documents/cybersecurity-service_providers_guide.pdf
10. Physical Security Essentials
    https://ebiz.publicpower.org/APPAEbiz/ProductCatalog/Product.aspx?ID=6860
11. Public Power EV Activities Tracker
    https://www.publicpower.org/resource/public-power-ev-activities-tracker
12. Public Power Forward webpage:
    http://publicpower.org/Topics/Landing.cfm?ItemNumber=45624
13. Rate Design Options for Distributed Energy Resources, November 2016
    https://www.publicpower.org/system/files/documents/ppf_rate_design_options_for_der.pdf
14. Understanding Energy Storage, December 2017
    https://www.publicpower.org/resource/understanding-energy-storage
15. Understanding the U.S. Plug-In Electric Vehicle Market, November 2017
    https://www.publicpower.org/resource/understanding-us-plug-electric-vehicle-market
16. Value of Solar Primer, November 2016
    https://www.publicpower.org/system/files/documents/ppf_value_of_solar_primer.pdf
17. Value of the Grid, July 2018
    https://www.publicpower.org/resource/value-grid

Minnesota Municipal Utilities Association Resources

18. A model *Distributed Generation and Net Metering Policy*, with adopting resolution and instructions.*
19. A model *Cogeneration and Small Power Production Tariff* and standard contract, with adopting resolution and instructions.*
20. A model *Interconnection Application and model Notification to Customers*.*
21. A model Solar Ordinance with adopting resolution and instructions. *
    *Available to members only.

Missouri River Energy Services Resources

22. Coordinated Demand Response / Advanced Metering Infrastructure webpage: https://www.mrenergy.com/services/coordinated-demand-response
23. Retail Rate Studies webpage: https://www.mrenergy.com/services/retail-rate-studies
24. Municipal Power Advantage webpage: https://www.mrenergy.com/services/municipal-power-advantage

Southern Minnesota Municipal Power Agency Resources

25. Ninjio Cyber Security Training Videos https://ninjio.com/
26. SolarChoice Community Solar Programs: Austin Utilities http://www.austinutilities.com/pages/solarchoice/
27. SolarChoice Community Solar Programs: Preston Public Utilities http://prestonmn.org/solarchoice-residential-program/
28. SolarChoice Community Solar Programs: Princeton Public Utilities http://www.princetonutilities.com/
29. SolarChoice Community Solar Programs: Rochester Public Utilities https://www.rpu.org/education-environment/solar.php
30. SolarChoice Community Solar Programs: Saint Peter Municipal Utilities http://www.saintpetermn.gov/community-solar-program
31. SMMPA Energy Efficiency https://smmpa.com/energy-efficiency/
32. SMMPA Protecting Pollinator Program https://smmpa.com/protecting-pollinators

Other Resources

33. Alliance to Save Energy: Forging a Path to The Modern Grid: Energy-Efficient Opportunities in Utility Rate Design, February 2018 http://www.ase.org/sites/ase.org/files/forging-a-path-to-the-modern-grid.pdf
34. Consumer Federation of America: Public Power and Rural Electric Leadership on Community Solar Initiatives http://consumerfed.org/wp-content/uploads/2016/04/Community-Solar-Energy-White-Paper-4-15-16.pdf
35. Department of Energy: Alternative Fuels Data Center

https://www.afdc.energy.gov/
36. Department of Energy: Modernizing the Electric Distribution Utility to Support the Clean Energy Economy, August 2016 https://energy.gov/sites/prod/files/2017/01/f34/Modernizing%20the%20Electric%20Distribution%20Utility%20to%20Support%20the%20Clean%20Energy%20Economy_0.pdf
37. OMPA: Distributed Generation Toolkit http://ompa.com/wp-content/uploads/2015/02/Distributed-Generation-toolkit.pdf
38. Lawrence Berkley National Lab: Distribution System Pricing with Distributed Energy Resources https://rmi.org/insights/reports/review-alternative-rate-designs/?preview=true
39. National Association of Regulatory Utility Commissioners: Distributed Energy Resources Rate Design and Compensation, November 2016 https://pubs.naruc.org/pub.cfm?id=19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0
40. Rocky Mountain Institute: A Review of Alternative Rate Designs https://rmi.org/insights/reports/review-alternative-rate-designs/?preview=true
41. Sandia National Laboratories: Energy Storage Procurement Guidance Documents for Municipalities, September 2016 http://www.sandia.gov/ess/publications/SAND2016-8544O.pdf
42. Smart Rate Design for a Smart Future, July 2015 http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf

Appendix A: MMUA-MREA CIP Reform Effort

MREA
Minnesota Rural Electric Association

MMUA
Minnesota Municipal Utilities Association

SUSTAINABLE CIP IMPROVEMENTS FOR CONSUMER-OWNED UTILITIES

BACKGROUND

Minnesota's Conservation Improvement Program (CIP) has achieved significant success toward reducing Minnesotans' energy spending, catalyzing green industries in the state, postponing new electric generation construction and reducing greenhouse gas emissions, including carbon dioxide. From a cooperative and municipal utilities' point of view it has helped our members and citizens use electricity more wisely and has facilitated the successful widespread adoption of new efficient technologies.

CURRENT STATUS

The continuing effectiveness of the program however, depends increasingly upon incremental changes to it and the law governing it. Its scope and design no longer match its purposes, given its successes, its limitations and the evolution of our energy industry and society. Many of the things it incentivizes have now been deployed to a point of saturation. People buy energy-efficient appliances without rebates. LED lighting is increasingly not only the preferred option, but the only option. Perversely, beneficial electric usage (including electric vehicles) is discouraged since it results in higher energy sales. The existing CIP program fails to support and advance emerging green technologies. Many consumer-owned utilities are only capable of advancements the current program does not recognize. In its current format the CIP program is unsustainable and increasingly ineffective.

The current Conservation Improvement Program has reached maturity. In order to continue meeting the multiple goals of the program we need to develop an improved, sustainable Conservation Improvement Program for our new energy environment.

PRINCIPLES FOR A NEW APPROACH

For municipal utilities and cooperative electric associations, the Conservation Improvement Program should be replaced with an initiative that:

- Reflects that consumer-owned utilities have a valuable role to play in Minnesota energy policy that can be better actualized through an improved approach
- Recognizes multiple purposes: generation (kW) avoidance, end use carbon emissions reduction, customer cost savings, utility efficiency, economic growth
- Emphasizes end use emissions reduction and energy efficiency rather than an absolute reduction in kilowatt hours
- Rewards efficiency and end use emissions reduction caused in other problem sectors beyond the Electric and Industrial sectors (E.g., Transportation, Agriculture, Public, etc.)
- Recognizes efforts that advance any of Minnesota's energy policy priorities, including utility innovation, distributed generation support, consumer education, Minnesota energy sustainability and resiliency
- Establishes safety and reliability as bedrock concerns
- Uses reasonable, credible metrics for illustrating success
- Ensures the needs of low-income consumers are effectively addressed while placing an increased focus on multi-family residential buildings.

REQUESTED ACTION

The goal of MREA and MMUA is to develop a sustainable CIP for cooperative and municipal utilities. MREA and MMUA will work with their respective memberships and stakeholders on improvements to CIP in 2018. MREA and MMUA hope to bring a cooperative and municipal CIP to the legislature in the 2019 session. MREA and MMUA appreciate legislative support of a sustainable CIP for cooperative and municipal utilities.

CONTACT:
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Appendix B: Public Power Forward Survey

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MMUA

Minnesota Municipal Utilities Association

MMUA Public Power Forward Survey Edit title

Please take a few minutes to answer this short 10 question survey. Your input will help us develop an accurate picture of MInnesota's public power systems.

1. How many electric customers does your utility have?
   - 10,000 or more
   - 5,000 to 9,999
   - 1,000 to 4,999
   - Less than 1,000

2. Have you installed any two-way advanced metering known as Advanced Meter Infrastructure (AMI) on your system? If your answer is yes, please indicate whether you have a full or partial deployment in the comment box below.

- Yes
- No

- Comment:

500 characters left.

3. If you have not installed any AMI, are you currently exploring options for introducing AMI on your system? If you are considering AMI, please give us your impression of the technology you have investigated in the comment box below.

- Yes
- No
- Not applicable

- Comment:

500 characters left.

4. If you are using AMI, do you have access to a Meter Data Management (MDM) system on your own or with a third party to assist in managing the data flow from your AMI?

- Yes
- No
- Not applicable

5. What Customer Information System (CIS) do you use?

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6. When did you last update your CIS system?

- Within the last 3 years
- Within the last 6 years
- Within the last 9 years
- More than 9 years ago

7. Do you use a database supported Geographic Information System (GIS)?

- Yes

- No

8. When did you last conduct a full cost of service study to determine your rates?
   - Within the last 3 years
   - Within the last 6 years
   - Within the last 9 years
   - More than 9 years ago

9. What is the level of your residential customer service charge?
   - $0 to $5
   - $5 to $10
   - $10 to $15
   - More than $15

10. Do you have any residential demand response programs in your community? Please include a brief description of your program(s) in the comment box below.
    - [ ] Air conditioner control
    - [ ] Water heater control
    - [ ] Thermostat control
    - [ ] Electric heat

☐ Other

- Comment:
-

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Appendix C: Public Power Forward Survey Results

Public Power Forward Survey Results Summary

	Electric Customers				Installed AMI?		Exploring AMI?			Access to MDM?			Last CIS System update?			
	10,000 or more	5,000 to 9,999	1,000 to 4,999	Less than 1,000	Yes	No	Yes	No	N/A	Yes	No	N/A	Lst 3 yrs	Lst 6 yrs	Lst 9 yrs	> 9 yrs
All	4	10	21	8	16	26	14	12	13	11	5	22	16	6	1	5
	9.3%	23.3%	48.8%	18.6%	38.1%	61.9%	35.9%	30.8%	33.3%	28.9%	13.2%	57.9%	57.1%	21.4%	3.6%	17.9%
>9,999	4	0	0	0	2	2	3	0	1	4	1	3	2	1	0	1
	100%	0%	0%	0%	50%	50%	75%	0%	25%	50%	13%	38%	50%	25%	0%	25%
5,000-9,999	0	10	0	0	6	4	4	1	3	5	1	4	4	3	1	1
	0%	100%	0%	0%	60%	40%	50%	13%	38%	50%	10%	40%	44.4%	33.3%	11.1%	11.1%
1,000-4,999	0	0	21	0	8	12	5	7	7	6	3	7	7	2	0	3
	0	0	100%	0	40%	60%	23.8%	33.3%	33.3%	35.3%	17.6%	41.2%	58.3%	16.7%	0.0%	25.0%
<1,000	0	0	0	8	0	8	2	4	2	0	0	8	3	0	0	0
	0%	0%	0%	100%	0%	100%	25%	50%	25%	0%	0%	100%	37.5%	0.0%	0.0%	0.0%

	Use GIS?		Last COSS?				Res. customer svce charge?				Res. demand response programs?			
	Yes	No	Last 3 yrs	Last 6 yrs	Last 9 yrs	> 9 yrs	$0 to $5	$5 to $10	$10 to $15	> $15	Air cond control	Wtr htr control	Thermo-stat control	Electric heat
	21	18	26	11	0	4	2	14	21	5	4	2	0	2
All	53.8%	46.2%	63.4%	26.8%	0.0%	9.8%	4.8%	33.3%	50.0%	11.9%	100%	50%	0%	50%
>9,999	4	0	2	2	0	0	0	1	2	1	4	2	0	2
	100%	0%	50%	50%	0%	0%	0%	25%	50%	25%	100%	50%	0%	50%
5,000-9,999	9	1	5	5	0	0	0	4	5	1	5	4	0	3
	90%	10%	50%	50%	0%	0%	0%	40%	50%	10%	50%	40%	0%	30%
1,000-4,999	7	10	14	4	0	1	1	6	12	1	9	9	0	7
	41.2%	58.8%	73.7%	21.1%	0.0%	5.3%	5.0%	30.0%	60.0%	5.0%	42.9%	42.9%	0.0%	33.3%
<1,000	1	7	5	0	0	3	1	3	2	2	2	3	0	3
	12.5%	87.5%	62.5%	0.0%	0.0%	37.5%	12.5%	37.5%	25.0%	25.0%	25.0%	37.5%	0.0%	37.5%

Public Power Forward Survey Comments

Full or partial AMI deployment

Full Deployment

very small deployment

started roll out winter of 2016-2017

We are fully deployed and we also have 600 customers who participate in load management.

Residential complete, commercial and industrial about 20% complete. Anticipate being fully deploy by fall.

Will Be in next couple of years

Looking to start the process of converting to AMI. Currently have an AMR system

Very close to full deployment

Fully deployed

Full Deployment

We were about to in 2015 but a few customers spoke up about concerns of personal privacy and that brought our plans to a halt.

We will achieve complete deployment of AMI electrical meters in 2017. We expect to complete deployment of AMI water meters in 2018.

partial nothing is going to our billing yet

We installed a amr system three years ago

partial deployment, small number of 2-way electric meters installed on accounts with history of frequent late payment and disconnections

Full deployment Electric, Water, Load control

very small portion...less than 200 customers

We are over 50% complete with plans on implementing AMI throughout the system within one year.

Partial deployment

Public Power Forward Survey Comments

Impression of AMI technology

Have only met with one distributor so far. Timeline is early 2018.

Installing AMR right now, which can be converted to AMI in the future.

Will be deploying AMI system on both Electric and Water Utilities in 2017-2018

We have a AMR system and were looking at a hybread system that way we don't have to change all the meters. Just few key ones.
AMI (Mesh network, Cellular, radio)

The ability to gather the data is at a level of where our expectations are. It is the retrieval of data by our customers that raises concerns.
Two way Broadband, hybrid broadband, cell net.
Fiber backbone.
We are probably 3 years out form deploying AMI. Will start more research in late 2018.

In addition to our small scale as described in the previous section, we have budgeted for a full scale deployment and are considering a proposal from a consultant to assist with the transition from AMR to AMI. We are disappointed that the meter transmitting devices (ERT's) seem to be proprietary and are not capable of communicating with open source type vendors. This leads to compromise in capabilities or significant expense for a full scale redeployment of transmitters. devices.
I checked yes because we will begin to look into AMI in a small way, but we haven't done anything so far.
Kind of. This is likely a 2020 project and will not begin to research until probably 2019 because technology is changing too quickly.

Public Power Forward Survey Comments

What CIS do you use?

Mueller Systems

none

Incode software for billing, GL, A/P, Payroll

We only have billing software

Tyler Technologies - Incode

in-code

Banyon Data Systems

Incode

Encode

NISC

Bayon utility billing system

Affinity

Civic/Casselle

BS & A

Census

Tyler Technology

Neon Link

Tyler Technologies InCode

Acs400

Incode

springbrook

Powermanager

Clarity from Civic Systems

daffron

NISC

Omni Pro

Cogsdale

Public Power Forward Survey Comments

Residential demand response programs comments

We have an off peak program that is controlled by Minnkota Power Cooperative at times of high demand

N/A

adding a/c soon

None

We have used the Cannon system since 1993 and are changing out the receivers to use the same communication system as our AMI.

Our OP program is through NMPA and Minnkota Power. We use ripple receivers to control load.

Dual fuel, and commercial programs as well

We do not have a residential demand response program.

The threshold Setting on our Load Control is set monthly by our Electric Supervisor and Missouri River Energy Services.

No money in capacity. Efficiency of equipment out preforms the need for demand response.

We offer off peak rates with load control for all of the above

None

Phasing out these programs over the next few years because of a scheduled change in wholesale power provider in 2018. Will likely introduce new programs to replace load control. Researching residential time of use as well as residential demand. Also looking at smart thermostats.

We have just under 40% of our local AC units load managed and 100% of water heaters sold about 35% saturation.

End Notes

[1] Options in MN may be more limited based on current legislation and regulation.
[2] For a more detailed explanation of demand charges and ways they may be applied, see APPA's *Rate Design Options for Distributed Energy Resources*, pp. 9-12. The period for measuring demand can vary by design. The peak demand can be the highest peak at any time (during a 15-minute interval) of the month, or it can be the highest usage during established peak periods (for example, 3-7 pm on weekdays), or some other period.
[3] The value of reduced power supply costs is dependent on the coincidence of the solar production with the utility's peak demand. This varies by utility, primarily based on demographics.
[4] Ibid., p. 10.
[5] See https://www.solarhostsa.com/ for more details on CPS's program.
[6] Available at https://www.publicpower.org/resource/value-grid
[7] Peter Fox-Penner. *Smart Power: Anniversary Edition* (New York: Island Press), 2014, p. 170
[8] Ibid.
[9] Ibid., p. 172.
[10] Ibid., p. 287
[11] American Public Power Association. *APPA's Roadmap to the SEPA 51st State*, April 2016. Available at https://sepa.force.com/CPBase__item?id=a12o000000TOYIXAA5. An infographic summarizing the roadmap is also available at: http://www.publicpower.org/files/Media/images/APPA_Road%20map%20info_2pgv3.jpg
[12] Ibid., p. 13.
[13] Ibid.
[14] Ibid., p. 15.
[15] Learn more at https://www.publicpower.org/deed-rd-funding.
[16] The program is current in a pilot stage and will be officially launched in 2019.
[17] The *Community Solar A-Z Guide* is available at https://www.publicpower.org/resource/community-solar-z
L*egal Implications of Community Solar Securities and tax law Considerations*, prepared by K&L Gates LLP for the American Public Power Association, is available at https://www.publicpower.org/resource/legal-implications-community-solar-securities-and-tax-law-implications
[18] *Understanding Energy Storage* is available at https://www.publicpower.org/resource/understanding-energy-storage
[19] *Understanding the U.S. Plug-In Electric Vehicle Market* available at https://www.publicpower.org/resource/understanding-us-plug-electric-vehicle-market
[20] Explore physical and cyber security resources at https://www.publicpower.org/topic/cybersecurity.
[21] To learn more, visit http://www.electricitysubsector.org/CMA/,
22 Energy Information Administration Form EIA-861, 2016.
[23] Ibid.
[24] Ibid.
[25] Ibid.
[26] http://www.minnkota.com/our-members , accessed March 26, 2018.
[27] Dairyland Power Cooperative Annual Report 2016, Member & System Map.

[28] Form EIA-861.
[29] Ibid.
[30] http://www.cmmpa.org/about-cmpas/members/ .
[31] http://www.hcpd.com/about/who-we-serve/ .
[32] https://www.mmpa.org/communities/overview/.
[33] https://www.mrenergy.com/about/members-list.
[34] https://www.nmpagency.com/Members_01.html.
[35] https://smmpa.com/.
[36] American Public Power Association Directory, 2015-2016, p. 195.
[37] www.wapa.gov/regions/UGP/Pages/ugp.aspx, accessed March 27, 2018.
[38] Minn. Stat. 216B.1691, Sub. 2a(a).
[39] Minn. Stat. 216B.1691, Sub. 2a(b).
[40] EIA, Minnesota State Energy Profile, accessed March 26, 2018.
[41] Ibid.
[42] Until 2017, the requirements of §216B.241 applied to all electric utilities. In 2017 the statute was amended to exempt cooperatives with 5,000 or fewer customers and municipals with 1,000 or fewer customers. Laws of Minnesota 2017, chapter 94, article 10, section 11.
[43] Minn. Stat. §216H.02 Subd. 1 (2007)
[44] https://www.pca.state.mn.us/air/greenhouse-gas-emissions-data, accessed June 1, 2018.
[45] Minn. R. 1300.1700 (2007).
[46] https://www.currentresults.com/Weather/US/cloud-fog-city-annual.php, accessed May 1, 2018.
[47] Minn. Stat. § 216B.1691, subd. 2f.
[48] Ibid.
[49] http://e21initiative.org/about-e21/ , accessed April 20, 2018.
[50] http://e21initiative.org/progress/, accessed April 20, 2018.
[51] http://e21initiative.org/wp-content/uploads/2018/01/e21_Initiative_PhaseII_Report_2016.pdf , accessed April 20, 2018.
[52] https://www.misoenergy.org/stakeholder-engagement/learning-center/miso-history/ , accessed April 25, 2018.
[53] Catherine Hausman and Ryan Kellogg, "Welfare and Distributional Implications of Shale Gas," Brookings Papers on Economic Activity, Spring 2015, https://www.brookings.edu/wp-content/uploads/2015/03/HausmanText.pdf, accessed April 26, 2018.
[54] http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html, accessed April 26, 2018.
[55] MISO 2017 Summer Assessment Report, October 2017, p. 11 https://cdn.misoenergy.org/2017%20Summer%20Assessment%20Report103564.pdf , accessed June 1, 2018.
[56] https://cdn.misoenergy.org/201712%20%20Monthly%20Market%20Report123038.pdf , accessed June 1, 2018.
[57] MISO 2017 Summer Assessment Report, Table IV 1.1, p. 13, https://cdn.misoenergy.org/2017%20Summer%20Assessment%20Report103564.pdf , Accessed June 1, 2018. These figures represent wind's contribution to meeting MISO's peak load hour system-wide. Presumably, the percentages would be higher for MISO North alone.
[58] Service charge, fixed charge, and customer charge are often used interchangeably in the industry.