Chapter 8. Emerging Technologies

Minnesota Statutes, section 216B.2426 requires a discussion of distributed generation in utility resource plans. In addition, many stakeholders have shown significant interest in our activities and plans for energy storage, smart grid technologies and electric vehicles.

We see these emerging technologies as interrelated, in that there are important synergies between them that reinforce their potential impact, both positive and negative. Over the course of the planning period of this Resource Plan, one or more of these technologies has the potential to have a significant impact on the shape of the electric industry, and the provision of electric service to our customers. At this point, however, it is difficult to say with any certainty which of these will evolve to the point when large scale adoption will be economic and reliable – or when that evolution might occur. It will be critical for us to keep a close eye on the costs and benefits of the technologies we implement on our system, to ensure that our customers receive net benefits overall from these technologies.

Distributed Energy Resources

Distributed energy resources (DER) include both generation and energy storage installations in relatively small capacities on a distribution system.

Distributed generation (DG)

In Minnesota, distributed generation (DG) is defined generally as generation that is located on or near the site where the output is primarily to be used, interconnected to and operated in parallel with the electric grid, with a total capacity of no more than 10 MW. [1] Additionally, the capacity of the DG installation must be lower than the

[1] In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities under Minnesota Laws 2001, Chapter 212, Docket No. E-999/CI-01-1023, ORDER ESTABLISHING STANDARDS (September 28, 2004). Minnesota defines renewable projects between 10 and 40 megawatts as "dispersed" renewable generation (DRG). See Laws of Minnesota 2007, chapter 136, article 4, section 17.

minimum load of the distribution system to which it would be interconnected, so that the energy generated by the DG facility is used locally.[2]

New DG technologies continue to be reviewed, but current applications remain limited and are usually powered by internal combustion engines fueled by landfill gas, diesel or fuel oil. Solar DG technology is currently generating significant interest, however. Solar photovoltaic installations on the NSP system in Minnesota have grown to a total capacity of over 1 MW, the most of any utility in Minnesota, and will likely grow to over 20 MW through 2020. See the Renewable Energy Chapter 5 for additional information on our solar programs.

The Minnesota Legislature and the Commission have recognized the potential for DG, as well as the challenges. The Legislature directed the Commission to ensure that opportunities for distributed generation are considered as part of the resource planning process. Minn. Stat. § 216B.2426. In its July 28, 2006 Order Approving Xcel Energy's 2005-2019 Resource Plan in Docket No. E-002/RP-04-1752, the Commission directed the Company to initiate a study by qualified experts to determine what a comprehensive DG strategy would entail and to provide a report on the Company's progress in its 2007 Resource Plan.

As explained in the Company's 2007 Resource Plan, we contracted with Summit Blue Consulting (Summit Blue) to identify potential distributed technologies and customers, and seek to match specific technologies to specific customers. The goal of the study was to develop a recommended portfolio of customers and technologies that we could work from to promote installations and gain more experience with DG.

Preliminary results received from Summit Blue, however, did not provide a clear path forward. Based on an evaluation of Xcel Energy customers organized by SIC code,

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[2] See "Potential for and Barriers to State Jurisdiction Over Interconnecting Dispersed Generation Projects," Minnesota Office of Energy Security, June 6, 2008; and Phase II Report of the Technical Standards Workgroup Regarding Distributed Generation, MPUC Docket No. E999/CI-01-1023, Attachment 1, page 1.

Summit Blue identified approximately 100 MW of renewable DG and 1000 MW of gas DG that could potentially be installed on our system by 2020, without regard to cost effectiveness. The renewable DG focused largely on biogas production using wood and agricultural byproducts. As these results were being analyzed further, new developments in solar PV and smartgrid technologies, which were not included in the study, caused us to take a step back from the consultant's report to reassess. Small natural gas DG was more costly on our system than larger natural gas plants, and the renewable study did not reveal potential in areas that we now believe may hold the greatest promise.

Over the course of the last two years, we have supported several DG generation projects and initiatives through different mechanisms, including through the Renewable Development Fund. We continue to review those projects and initiatives and the information gained in order to evaluate ongoing DG potential. A brief summary follows:

- Working through the Renewable Development Fund advisory board, we supported a successful grant application to fund research at the University of Minnesota to evaluate and address economic and technical issues related to biomass integrated gasification combined cycle technologies in electrical generation at ethanol-producing plants. We also supported funding another project at the University of Minnesota, again through the Renewable Development Fund, to develop an efficient biomass feedstock system for the Koda Energy project, a 12 MW biomass cogeneration facility on our system at the Rahr Malting Plant in Shakopee, Minnesota. These research projects are on-going.

- We created a cross-functional team within the Company to look at operational issues related to increasing penetration of DER, including DG, on our distribution systems, and how those could be mitigated or avoided. This team was populated with members from multiple Xcel Energy units, including distribution system engineering, resource planning, market operations, risk analytics, business planning, strategic technologies and environmental policy. The issues this group has been examining include safety, security, privacy, system reliability, cost, and customer impacts of higher levels of DG on Xcel Energy distribution systems. The evaluation of issues identified by the team thus far is summarized below in the section titled "Benefits and challenges associated with DER."

- We initiated the concept for the SolarTAC (Solar Technology Acceleration Center) and helped found the facility, along with SunEdison, Abengoa Solar, the Electric Power Research Institute and the National Renewable Energy Laboratory. SolarTAC is an integrated, world-class test facility where the solar industry, energy companies and scientists will share the site to test, validate, and demonstrate new solar energy technologies, as well as fully integrated solar systems prior to commercial deployment. The site will be used for both photovoltaic and concentrated solar power projects. The field tests of these technologies will include solar energy demonstrations, as well as projects relating to wider issues of expanding and integrating solar power at scale, including thermal storage and grid interconnect testing. Additional information about SolarTAC can be found at www.solartac.org.

- In addition, we decided to move ahead with a number of DG projects, in order to get real-world experience with DG on our system. Again, working through the Renewable Development Fund advisory board, we supported the provision of grants to several solar projects. We then provided further support for those solar projects through power purchase arrangements with those projects. We have also instituted Solar*Rewards, described in the Renewable Energy chapter, which we expect will result in the greatest number and capacity of solar DG projects on our system. We also entered into a power purchase arrangement with Koda Energy, the biomass-powered cogeneration project at the Rahr Malting facility.

- In late July 2010, we announced that we will be providing research and analytical support for the first planned pilot field installation of a combined heat and power (CHP) generation system that uses solar energy as its only input fuel. The system has several novel features, including energy storage and a control system that maximizes customer value by optimally apportioning the system's energy output between heat and electricity depending on the season and weather conditions (both current and forecasted).

We will be happy to update the Commission on these projects as they move forward.

Additionally, the Minnesota Legislature has more recently indicated its interest in analyzing the potential impact of and opportunities for "dispersed generation," or those generation projects between 10 MW and 40 MW. 2007 Minn. Laws ch. 136, art. 4 § 17. The Legislature directed utilities subject to Minn. Stat. § 216B.1691 to participate in a two-phased transmission study of the siting potential for dispersed renewable generation. The Legislature required the Commissioner of Commerce to submit a report regarding each phase of the study to the Commission. The report on the second phase of the study was submitted on September 15, 2009, and concluded that additional investments in the local and regional transmission system in Minnesota are required to support significant additions of renewable resources.

As is noted elsewhere in this Plan, we see potential for DG on our system but need to do additional work to assess the cost-effectiveness of newer DG applications. We believe that by analyzing specific DG technologies and opportunities and the experiences gained with implementation of those projects, we can learn more about DG on our system than from a system-wide generic and academic review of DG. For example, while we continue to review the cost-effectiveness of solar as a system resource, we have found that on-site "behind the meter" solar DG can be a very useful tool to reduce the effective load of a facility. In this kind of an application, DG has the same effect on our system as more traditional DSM measures. This is the basis for the Solar*Rewards program, and we will explore this potential further, as we work to achieve the 1.5% statewide DSM goal, described in the DSM chapter.

Distributed energy storage

Electricity is the only commodity that is produced and consumed simultaneously, operating under a just-in-time delivery system. To maintain operations, grid operators must balance generation to match load. This is a very sophisticated real-time, just-in-time balancing act of supply and demand that is a result of variable end-user demands and the continually changing weather system. Today's electrical grid operates effectively without storage, but as constraints on the transmission system grow and we install higher levels of intermittent resources, it is becoming more challenging and costly to continue along this path. The grid would be more efficient and reliable if it incorporated cost-effective ways of storing electrical energy because storage can serve as a source of both generation (when the energy storage facility is discharging) and load (when the energy storage is being charged).

Pumped hydroelectric and compressed air energy storage (CAES) technologies are considered bulk power energy storage systems. New classes of batteries have been developed that are considered suitable for smaller applications and are referred to as distributed energy storage systems. The term distributed energy storage means deployment of these devices close to load centers, transmission system points of reinforcement, or renewable generation sources, typically in or near utility substations. In other contexts, the term "distributed" denotes location on distribution feeder circuits or at consumer premises behind the meter.

Appendix F provides a description and a status update of various energy storage technologies.

Benefits and challenges associated with DER

The potential benefits of DER are multiple and well-known, but deployment must be balanced against, and managed appropriately to avoid, potential negative impacts. Appropriately equipped, placed, installed and managed, DER can provide potential benefits to the system, such as:

- Increased electric system reliability
- Reduction in peak capacity needs
- Provision of ancillary services such as reactive power and voltage support
- Improvements in local power quality
- Reduction or deferral in the need for additional transmission or distribution infrastructure
- Increased system robustness and diversity

However, there are also a number of potential negative impacts from increased DER penetrations which cannot be overlooked. The issues that Xcel Energy is paying close attention to include:

Cost: The cost of energy from many types of DER installations can be prohibitive. A recent analysis from the financial advisory and asset management firm Lazard provides a comparison of the levelized cost of energy (LCOE) from various generation resources, after available federal incentives have been utilized to reduce overall costs.[3] According to Lazard, a new natural gas-fired fuel cell DG installation would have a low-end LCOE of $111 per megawatt-hour (MWh), much higher than a new natural-gas fired combined cycle facility, which has an estimated low-end LCOE of $69 per MWh.

[3] Lazard, Levelized Cost of Energy – version 3.0 (June 2009). Lazard is one of the world's preeminent financial advisory and asset management firms, and its Levelized Cost of Energy analysis is widely cited and relied upon by the National Renewable Energy Laboratory and others.

The LCOE of solar PV (after federal incentives) with a capacity factor between 20% and 27% is estimated by Lazard to be between $131 and $196 per MWh. In Minnesota, the levelized cost of solar energy would be much higher due to the lower capacity factor for solar PV experienced here – in the 12% to 15% range.[4] Although solar PV costs have declined significantly over time,[5] these reductions have not yet been substantial enough to make solar PV a cost-effective generation resource in the Upper Midwest, absent additional subsidies.[6]

Safety – Historically, and in most cases presently, the flow of energy is from a central power plant to customer load. This single direction of energy flow has determined the systems used to provide for system reliability. Most utilities have primarily accomplished this through the use of sophisticated relays, breakers, reclosers, fuses, grounding and some power quality devices such as capacitor banks. With the advent of DER creating bi-directional flow on the distribution system, the system design requirements are drastically changing. Because DER introduces new sources of energy at new points on the electric system, the existing system must be modified to assure the safety of our customers and employees. As higher penetration levels of DER are proposed, regulations and standards will need to be further developed that require these new energy sources to be able to be a part of the solution to working safely by way of appropriate connect and disconnect systems

Security – As mentioned above, because DER introduces new sources of energy at new points on the electric system, its introduction into our technology infrastructure creates the additional possibilities of both physical and logical (cyber) threats to security. A proliferation of DER installations on a distribution system adds more potential points of access which must be protected against intrusion.

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[4] See, e.g. the Minnesota Solar Electric Rebate Program Report 2002-2008 which found that solar energy production among projects in the state's solar rebate program had an average capacity factor of 13.4%. Minnesota Office of Energy Security, April 8, 2009, at page 4.

[5] See "Tracking the Sun II: The Installed Cost of Photovoltaics in the US from 1998 to 2008", Lawrence Berkely National Laboratory (October 2009).

[6] Note, however that we have found solar DG to be a very useful tool in helping us reach aggressive DSM goals in Minnesota. As we note in the DSM chapter, we are interested in exploring the possibility of expanding the use of this DSM tool.

Privacy – The introduction of DER on our system also creates new risks regarding customer energy usage and personal information being accessed without the customer's knowledge or authorization.

Reliability standards – As noted above, with the advent of DER creating bi-directional flow on the distribution system, the system design requirements are drastically changing. In the electric distribution system these changes will result in requirements for an extremely complex matrix of system sensors, voltage and var control systems, sophisticated protection systems and a highly developed system of intelligence both localized and centralized. As DG penetration increases, concerns about voltage regulation, islanding, and grid stability become much more significant. DER provides new sources of energy at new points on the electric system, and as such, creates new challenges and opportunities in keeping the system reliable. Because of these new sources of energy, the existing protection system will need to be modified to assure reliability. This need will increase as DER penetration increases. Regulations and standards will need to be developed that require these new energy sources to be able to help provide a reliable distribution system.

As policies to encourage the installation of DER proliferate, continual review of the codes and standards that govern these new systems must also ensue. Each DER installation must meet minimum standards. However, the importance of these standards increases as the penetration rate of DER on a distribution system rises. Areas that need attention include safety; power system integrity; metering; and measurement of DG output; among others. The goal must be the implementation of standards in a uniform and coordinated way, for the protection of our workers and customers, and the provision of reliable service for our customers.

Equitable cost distribution In implementing and managing DER in the grid mix, we must work to minimize cases where one customer class benefits to the detriment of another customer class. Examples of this exist today where all customers are paying for some of the cost savings gained by specific customers who install net-metered generation on their homes. The costs of the distribution and transmission system are included in the price per kilowatt hour for energy provided to customers. However, owners of net-metered systems can generally avoid paying some or all of these costs through the netting out of their generation and consumption. This provides an implicit subsidy to the owners of that generation, by allowing those owners to avoid paying their fair share of the full cost of the distribution and transmission systems, while still enjoying all of the benefits of being connected to the grid. This will likely become a larger issue as the penetration of net-metered generation systems increases.

Smart Grid

In order to mitigate many of the operational problems described in the previous section and be able to take full advantage of the potential that DER technologies pose, electric distribution systems will need to get "smarter", to be able to provide detailed real-time power flow analysis and provide operating guidance for system components to manage the complexity of bidirectional power flow. In addition, utilities may need to develop the capability and be authorized to monitor, control and dispatch installed DER systems on their distribution networks to assure reliable, high quality power to our customers is maintained – a kind of distribution-level "independent system operator" or ISO such as we currently have in various regions of the country to manage the high voltage transmission network.

This section will describe many of the activities and technology deployments we have underway to make our distribution systems "smarter."

In its order dated June 5, 2009 in Docket No. E999/CI-08-948, the Commission ordered that beginning on April 1, 2010 and annually thereafter, utilities shall file reports on past, current, and planned smart grid projects, with a description of those projects, including: total costs, cost effectiveness, improved reliability, security, system performance, and societal benefit, with their electric service quality reports.

Order Point 3 of the June 5, 2009 order established the following working definition of smart grid:

> A smart grid encompasses information and control technology to improve the reliability, security, and efficiency of the electric grid. A smart grid allows deployment and integration of distributed and renewable resources, "smart" consumer devices, automated systems, and electricity storage and peak-shaving technologies.

It is important to note that, while there are a number of activities ongoing in Xcel Energy service territories and all over the United States and globally to develop and install "Smart Grid" technologies, the utility industry has been working for many years to "smarten" the electric system. For example, System Communication and Data Acquisition ("SCADA") systems were once considered innovative, but are now a fundamental component of every electric utility's distribution network. The technologies that are being tested and deployed today are extensions of innovations that were installed in years past.

SmartGrid City

Xcel Energy is a recognized leader in the installation, testing and operation of smart grid technologies. Xcel Energy's SmartGridCity™ project in Boulder, Colorado recently completed construction of the infrastructure and launched the remaining software to enable all SmartGridCity operational functions. This step makes it the first fully-functioning smart grid enabled city in the world that increases reliability, provides customers with greater energy use information, and allows participating customers and Xcel Energy to control in-home energy management devices remotely when demand calls for it. The smart-grid infrastructure is the backbone of the entire smart system we have installed in Boulder. This network is now connected to nearly 47,000 premises throughout the city.

This launch ties together all the automated functions of SmartGridCity including: switching power through fully-automated substations; re-routing power around bottlenecked lines; detecting power outages and proactively identifying outage risks. The deployment integrated more than 20 applications, 95 new interfaces and more than 300 test cases.

The latest software launch is proving some smart grid theories about reducing power outages on the Company's distribution system and adding real-time monitoring capabilities of the electric grid status. Early results indicate that smart grid technology is allowing us to predict equipment failure and proactively make necessary repairs before an outage occurs.

Boulder customers with smart meters can view their electricity consumption in up to 15-minute intervals through a Company-provided web portal, which gives them a window of information for further conservation ideas to more closely manage monthly bills. In 2010, we will focus on maximizing customer value and choice through in-home energy management options, various pricing pilot programs and additional plug-in hybrid electric vehicle tests.

SmartGridCity™ is essentially a living laboratory that helps us determine:

- Which energy-management and conservation tools our customers want and prefer
- Which technologies are the most effective at improving the way we deliver power
- How best to incorporate smart-grid technology into our business operations to improve efficiency, reduce carbon dioxide emissions, and modernize the energy delivery system.
- How to roll out the most promising smart-grid components on a wider scale.

While the lessons learned in Boulder will help identify which smart grid technologies to deploy elsewhere on the Xcel Energy system, the Company is deploying and testing cost-effective technologies we believe can reduce costs or improve reliability for our customers:

Smart Grid Projects on the NSP-Minnesota System

In addition to our Boulder project, we have also implemented a number of strategic smart grid projects on the NSP-Minnesota system. For example, we have installed automated switch teams on our distribution system. These teams automatically sectionalize and isolate the faulted portion of a circuit. After sectionalizing and isolation, power is restored to the un-faulted portion of the circuit. While not being totally "self-healing," this does allow the maximum number of customers to be automatically restored after an event. This product has been proven to be commercially viable. NSP-Minnesota has 56 of these switches operating in 21 teams. In 2009, NSP-Minnesota added five switches at a cost of approximately $400,000.

Another tool that NSP-Minnesota uses to aid restoration is Remote Fault Indicators. These devices are deployed at key points on the distribution system, and monitor the current flow. When the device "sees" high current flow, indicating that there is a fault downstream of the device, it calls-in to indicate that it has seen fault current flow pass through it. This information is then displayed to the System Operator, who couples it with other information, enabling restoration to begin on the un-faulted portions of the circuit. This allows restoration to begin without first physically patrolling the area, greatly reducing the outage time. NSP-Minnesota has 140 of these devices in use. NSP-Minnesota optimizes its assets by using its System Communication and Data Acquisition ("SCADA") system and an automated capacitor control program[7]. The capacitor control program is fed information from the SCADA system, and based on this information, the capacitor control system switches capacitors on and off. NSP-Minnesota is constructing a new capacitor control program in 2010 with the objective

[7] The SCADA system monitors the entire delivery system to aid the System Operators.

of reducing line losses. NSP-Minnesota protects against physical and cyber attack by its operating practice of having no external connections to its SCADA system.

In addition to these efforts, we have implemented a number of other projects since 2008 which incorporate aspects of the Commission's working definition of smart grid, which we summarize below:

Wind-to-Battery Storage

This project tests a one-megawatt battery energy storage system connected directly to a wind farm in an effort to store wind energy and return it to the grid. It is expected to demonstrate long-term emission reductions from increased availability of wind; help reduce impacts of wind variability; and allow us to meet Minnesota Renewable Energy Standard.

Location: MinWind Farm, southwest Minnesota
Status: Operational Summer 2009; Research ongoing

Neural Networks and Coal Slagging

This project creates a state-of-the-art system that helps reduce coal slagging and fouling (build up of hard mineral in the boiler). Slagging results in several million dollars in lost revenue each year. The backbone of the system is a software platform capable of acquiring, managing and displaying data and models, then recommending a controlled set point for optimized performance.

Boiler sensors plug directly into the Distribution Control. Neural networks will model the slagging/fouling by using historical data to "learn" boiler behavior. The system also captures and incorporates knowledge directly from the plant engineers and operators – effectively capturing, modeling, and using hundreds of years of collective experience.
Location: Sherco Plant, Minnesota
Status: Implemented in 2008

Smart Distribution Assets

This project tests existing meter communication equipment that can automatically notify Xcel Energy of outages and help the utility restore outages more quickly. By using this Advanced Meter Technology, our Control Center will be able to detect isolated outages in advance of customer calls and dispatch crews to the correct location faster.

Location: Minneapolis/St. Paul Metro Area, Minnesota
Status: Implemented December 2008.

Smart Substation

This project retrofitted the existing Merriam Park substation with cutting-edge technology for remote monitoring of critical and non-critical operating data, including an analytics engine that processes massive amounts of data for near real-time decision-making and automated actions. We monitor breakers, transformers, batteries and substation environmental factors (such as ambient temperatures, variable wind speeds, security cameras, etc.). Expected benefits include reduced maintenance and installation costs, improved employee safety and equipment life, faster restoration times, and increased system reliability. This system will also test and demonstrate cutting edge security technology.

Location: St. Paul, Minnesota Status: Installation completed in November 2009

Energy Feedback Pilot

As part of its Conservation Improvement Program ("CIP"), Xcel Energy launched a pilot program to determine how various feedback methods affect customer energy usage. This pilot program focuses on how and to what extent residential customers will change their behavior in response to more current and detailed information on their energy use. This project will test several promising feedback methods on a large scale to measure their effectiveness in reducing residential electricity and natural gas use, including:

- Monthly paper reports coupled with sophisticated communications designed to influence behavior;
- The same monthly reports supplemented with daily to weekly emailed feedback based on data acquired through Xcel Energy's Cellnet automated meter reading infrastructure ("AMR");
- Real-time feedback provided by in-home countertop displays that show energy use and cost data; and
- The same real-time feedback combined with the sophisticated monthly feedback noted in the first bullet.

Table 8.1 Energy Feedback Table

	Frequency of feedback	Estimated Sample size	Electricity, natural gas or both	behaviorally optimized	hardware	Accuracy	Applicability to other utilities	accommodate various rate
Monthly Reports	Monthly	17,275	Both	Yes	No	Utility grade	Any	Yes
Monthly & Daily to Weekly Reports	Monthly & Daily to Weekly	17,500	Both	Yes	No	Utility grade	AMI with daily data	Yes
In Home Displays	Real Time	225	Electric	No	Yes	Very good	Any Electric	Yes
In Home Displays and Monthly Reports	Monthly & Real Time	225	Both	Yes	Yes	Very good	Any Electric	Yes

Test results are monitored and quantified after each test year. If evidence is strong that the feedback is reducing energy use, a permanent program may be implemented. Future projects may also test additional strategies that complement feedback, such as community-based social marketing, energy workshops, energy use counseling, home performance audits, and/or alternative rate structures.

Over the 2010-2012 CIP Triennial Plan period, the Company expects its 35,225 participating customers to save a total of 19,306,590 kWh and 187,413 Dth at a total cost of $1.2 million. We estimate that the total program will produce nearly $225,000 in net economic benefits, as measured by the Societal Test used to evaluate DSM programs. We do not anticipate any security, reliability or system performance impacts from this program.

Location: Minneapolis and St. Paul, Minnesota
Status: Approved by the OES in October 2009 and scheduled to run through 2012.

Energy Innovation Corridor
We are currently proposing installation of a smart grid project as part of our Energy Innovation Corridor petition in the Central Corridor between Minneapolis and St. Paul.9 Called the "Smart VAR Management pilot program," this project seeks to demonstrate the effectiveness of "smart" capacitors with real time controls and two way communications to manage reactive power (Voltage Ampere Reactive power or VARs) on a portion of our distribution system, by installing 245 smart capacitor banks and transformers on the eight substations that serve the Central Corridor Utility Zone. We expect this project to result in system peak reduction, reduced energy losses, reduced fuel costs and increased power quality on this portion of Xcel Energy's distribution system. If successful, we will look to expand the application of this technology elsewhere on our system.

We are working with a number of partners on two other smart grid projects. While these plans have not yet come to fruition, we continue to explore options to move these projects forward.

Future Smart Grid Opportunities

Solar Firming

This project would fully integrate a large solar PV installation, a large advanced battery technology and a significant amount of demand response with a central coordinating control on a distribution feeder. The purpose of this project would be to combine these three strategies – solar PV, battery storage, and load response – in a number of ways to study, measure and better understand the synergies between them and to "firm up" solar PV generation. In theory, solar firming could result in delaying the need for expensive infrastructure improvements in congested areas or in reducing the cost of service on a per customer basis, by allowing more customers to be served by existing feeders. In addition to increasing our experience and understanding of solar generation in a northern climate, the objectives of this project would have been to study, measure and understand:

- The effect battery storage and customer load management can have on mitigating the variability of solar generation;
- The effect solar generation and battery storage can have on deferring the need for infrastructure improvements and connection costs in congested areas; and
- The potential effects increased amounts of solar generation may have on the portion of the electric distribution system on which it is installed.

We applied for a U.S. DOE grant for this project with a number of project partners (NREL, the City of Minneapolis, the Metropolitan Council, and the University of St. Thomas); while the grant reviewers were very supportive of the project, we were ultimately not awarded the grant. We continue to explore alternatives for this technology demonstration.

Plug-In Hybrid Electric Vehicle (PHEV) Infrastructure Project

In the PHEV Infrastructure Project, we are working with multiple public and private sector partners to develop the infrastructure in the Central Corridor necessary to demonstrate the feasibility of the transition to electric transportation. Unfortunately, as with our Solar Firming project, our initial efforts to find funding for this project have been unsuccessful. We joined Ford Motor Company in applying to the DOE for funding to support the development of a large demonstration fleet of plug-in electric and hybrid plug-in electric vehicles. However, the U.S. DOE and Ford were not able to reach terms on a grant. As discussed more fully in the next section on Plug-In Electric Vehicles, we are continuing to identify and work with partners on developing a PHEV/Electric Vehicle demonstration project in the Central Corridor.

Smart Grid on the Transmission System

On March 30, 2010, the Midwest Independent System Operator ("MISO") announced the launch of a three-year program to install more than 150 high-tech monitoring devices that will monitor the state of the electrical grid in its footprint 30 times each second, in an effort to increase the efficiency and reliability of power delivery.

MISO is the first Regional Transmission Organization within the Eastern Interconnection to move forward and execute an Agreement with the U.S. Department of Energy to implement Synchrophasors, also known as Phasor Measurement Units ("PMU"), to more accurately measure voltage and current. PMU measurements could increase available transmission for MISO members and improve system-wide reliability and stability. This could ease the integration of highly variable sources of energy, such as wind, onto the grid.

The planned roll-out and installation of PMUs within MISO's membership area will occur during the next three years. The first phase of the project, which began March 30, 2010, involves transmission owners placing 15-20 PMUs at strategic substations throughout the MISO footprint. After the pilot period, transmission operators will install the remaining PMUs between August 2011 and March 2013.

Xcel Energy has committed to MISO to install the necessary communications infrastructure at several of our substations to provide data as part of the Eastern Interconnection Synchrophasor Project. We have already installed the necessary communications infrastructure at our substation near the High Bridge Plant, and it is currently delivering data to the Eastern Interconnection. According to MISO, the entire project is scheduled to be in place by March 31, 2013.

Smart Grid Policy

In addition to these demonstration projects, we have been participating in the Minnesota Smart Grid Roundtable (otherwise known as the Smart Grid Coalition), an effort jointly led by Bill Glahn, Director of the OES at the Minnesota Department of Commerce, and Dr. Massoud Amin, Director of the Technological Leadership Institute at the University of Minnesota. Other entities involved in the Roundtable include Honeywell, IBM, Lockheed Martin, Great River Energy, Minnesota Power, and the Minnesota Department of Employment and Economic Development. Those discussions, in addition to our experience with the SmartGridCity project, have identified a number of potential issues that must be resolved in order to ensure that smartening the electric grid provides net benefits to electric utility customers. Those issues include:

- Cost of project infrastructure and operation
- Privacy, security and ownership of customer usage data
- Standardization of Smart Grid devices and technologies
- Coordination and integration of communications systems
- Regulatory and policy support for Smart Grid investments

We look forward to future discussions on these topics, within the Roundtable, with our regulatory commissions, the state legislative bodies in which we serve, and in other venues.

Electric Vehicles

Transportation in the United States is undergoing a dramatic transformation due to the combined needs to increase energy efficiency in transportation, reduce greenhouse gas emissions, and increase the nation's energy independence. We believe that we should support this transformation and prepare for a changing transportation industry.

The cost for electricity to power plug-in hybrids for all-electric operation has been estimated at less than one quarter of the cost of gasoline. Compared to conventional vehicles, electric vehicles can reduce air pollution, dependence on petroleum and greenhouse gas emissions that contribute to global warming. Plug-in vehicles use no fossil fuel during their all-electric range if their batteries are charged from nuclear or renewable electricity. It has also been calculated by the Electric Power Research Institute that a 20 mile range electric vehicles charged by the grid, based upon the national average emissions rate, produces 38% less CO2 emissions than conventional gasoline powered vehicles right now with this benefit expected to increase as more and more emissions free generation is added to the electric grid. Other benefits to the nation include improved national energy security, and benefits for the driver include fewer trips to the filling station and reduced fuel costs.

Supporting the development of public and private charging infrastructure and education is critical to the success of the conversion to an electrified transportation sector. In various pilots and demonstrations, we are working with multiple public and private sector partners to develop an understanding of the infrastructure, costs and regulatory policies necessary to facilitate the transition to sustainable electric transportation. These projects will help us and the public to gain awareness that electric vehicles are used like ordinary gas powered vehicles and will allow Xcel

Energy to prepare for large scale adjustments that may be required of the company to serve the transportation sector load as numerous car manufacturers begin to sell their electric vehicles to the public over the next several years. These projects will teach all sectors a lot about how these vehicles will operate and integrate in to the community.

In 2009, we joined the industry-wide plug-in electric vehicle market readiness pledge developed by the Edison Electric Institute. It is a commitment to make electric transportation a success, and we will support the pledge through partnerships with vehicle manufacturers, infrastructure support, deployment in our company fleet, education and outreach to customers about electric transportation benefits and support of appropriate incentives to encourage electric vehicle use. Six plug-in hybrid Ford Escape sport-utility vehicles are being evaluated in various applications in the Xcel Energy fleet. They show great promise, and several automobile manufacturers are pursuing plug-ins as a way to extend the electric battery range on hybrid vehicles and reduce liquid fuel consumption. Three hybrid bucket trucks are in service—one in the Denver metro area and two in the Twin Cities. One of them is an experimental design incorporating plug-in capability for battery recharging. These trucks offer improved fuel economy and significantly decreased emissions. Their engines can be turned off at a job site, reducing idling emissions and noise.

In Minnesota, we are currently working on a proposal for the deployment of plug-in electric vehicles. The proposal contemplates that Xcel Energy's Chairman's fund will subsidize the cost of these vehicles for St Paul, Minneapolis, Hennepin County, Ramsey County, the State of Minnesota, Metropolitan Airport Commission, and Hour Car. Xcel Energy would also purchase two vehicles for its fleet. Under this proposal, each fund recipient would also install charging infrastructure and collaborate with Xcel Energy in the development of codes and standards for electric charging infrastructure. As part of the overall effort, we have budgeted $75,000 of the cost for interconnect and metering cost related to the charging infrastructure. We are currently working with the coalition partners to identify technologies and locations for infrastructure deployment. We anticipate the infrastructure will be bid out by the State of Minnesota and cover the State and Cooperating Agencies. There are a number of issues to work through. If successful, the first vehicles will arrive in December, 2010.

These demonstration activities will inform how we prepare for greater levels of penetration of electric vehicles expected over the mid to long term. Of equal importance to these activities may be the actions to prepare distribution infrastructure and design rate tariffs for vehicle charging underway in Boulder and elsewhere – these actions will likely be critical to ensuring that electric vehicles do not have negative impacts on ratepayer costs or electric service reliability.

The two charts below show estimates for the number of plug-in hybrid electric vehicles that could be sold over the next decade (Figure 8.1), as well as the potential energy consumption on the Xcel Energy system (all eight states) at various levels of electric vehicle penetration (Figure 8.2).[8]

[8] For the purposes of these analyses, the total number of automobiles in the U.S. is estimated to be 247 million in 2010; 275 million in 2015 and 305 million in 2020, and the scenarios are based on the following data sets:

- **Internal Low** - coordinated to match actual hybrid adoption. U.S. Department of Energy, Alternative Fuels & Advanced Vehicles Data Center, HEV Sales by Model.
- **EPRI Low** - Dr. Mark Duvall Grid Integration of Plug-In Hybrid Jan. 26, 2009
- **Internal Low** - Obama Administrations stated target of 1 million vehicles by 2015; matches 20% of new cars sales by 2020, Plug-in Hybrids Cars Zooming Ahead, Kiplinger Business Resource Center, June 26, 2008
- **EPRI Low** - Mark Duvall 25% of new car sales by 2020 www.ornl.gov/info/ornlreview/v41_1_08/regional_phev_analysis.pdf

Figure 8.1
Estimates of PHEV Penetration Rates

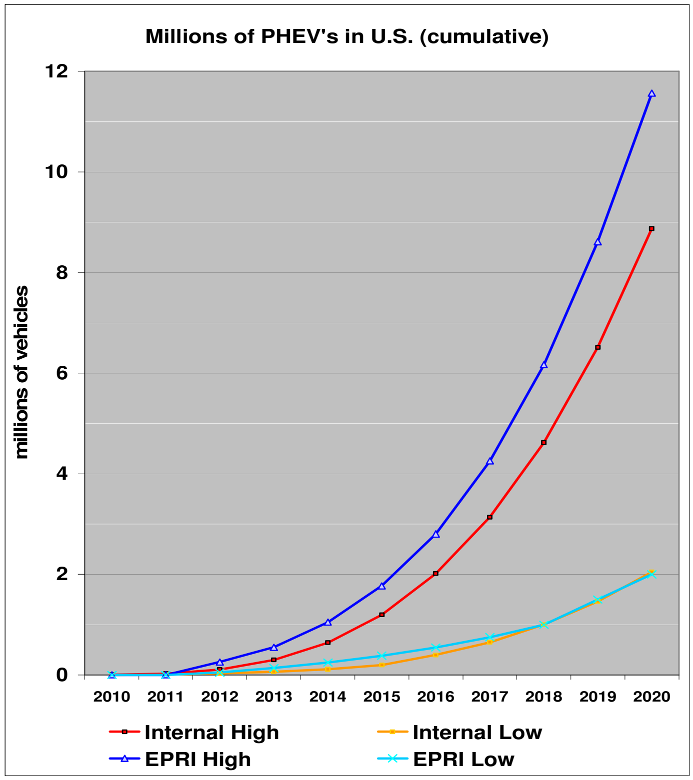
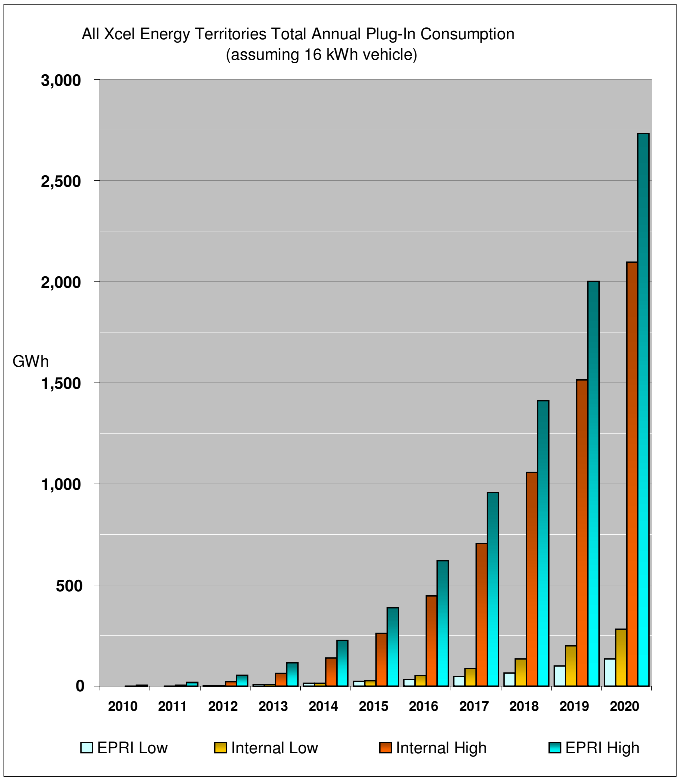


Figure 8.2
Estimates of Total Annual Plug-In Energy Consumption



Conclusion

Each of these emerging technologies holds the promise of significant benefits to Xcel Energy customers, and each poses some measure of risk of negative impacts. It is important to keep a close eye on the costs and benefits of the technologies we implement on our system, to ensure that our customers receive net benefits overall from these technologies. Over the course of the planning period, one or more of these technologies is likely to become reliable and economic, which is likely to have a remarkable impact on the provision of electric service, and on utility operations generally.