The lines they are a-changin' — lessons from a Midwestern non-wires alternative pilot

Rabi Vandergon, Jenny Edwards, Josh Quinnell, Ph.D., Jon Blaufuss,
Center for Energy and Environment
Jessica Peterson, Xcel Energy

ABSTRACT

The use of distributed energy resources as a method to defer infrastructure investments was initially led by states such as Vermont, New York, and California. Between the coasts in Minnesota, the non-wires alternative approach is rapidly emerging in both utility planning and regulatory frameworks. Coinciding with these developments is Minnesota's first non-wires alternative pilot led by a partnership between the Center for Energy and Environment and the largest investor-owned utility in the state, Xcel Energy. This paper explores findings from this pilot and how they mesh with an evolving integrated distribution planning requirement for Minnesota's regulated utilities.

Minnesota poses a challenging utility landscape for non-wires alternatives. Low avoided distribution costs and abundant land create specific difficulties for cost-effective non-wires projects. This paper discusses the pilot project from planning through implementation. We analyze forecasted distribution projects, customer demographics, substation and feeder data, and customer utility data. We explain the demand-side measure selection process, largely focused on energy efficiency, and the techniques used to procure energy efficiency and demand response participation in the residential, commercial, and industrial sectors. We highlight barriers and solutions around load forecasting and planning horizons, silos and internal incentive mechanisms, and marketing techniques. We illustrate findings from the use of existing system-level demand response resources at the distribution level. We finish with a look to the future — assessing the statewide potential for non-wires alternatives under an evolving utility business model and regulatory framework.

Introduction to Non-Wires Alternatives

Besides being a tongue twister, what is a non-wires alternative? Non-wires alternatives encompass a solution set of targeted load management strategies using distributed energy resources (DERs) such as efficiency, demand response, solar photovoltaic generation, energy storage, or other nontraditional techniques. These resources manage peak load at a substation or circuit level to defer or eliminate the need for transmission or distribution system investments.[1] These solutions are often driven by enhanced customer incentives within the target region and are cost-effective when they require lower investment than the capital cost of a traditional "wires" project.

On the West Coast in the late '80s and early '90s, Bonneville Power Administration and Pacific Gas and Electric were early leaders with consideration and implementation of non-wires alternatives (Chew et al. 2018). As time progressed, consideration of alternative solutions worked its way from the utility level to statewide. In 2006, Vermont's Public Service Board

[1] To clarify further, DERs are used for capacity deferral and are not intended as a replacement for aging infrastructure.

directed a large portion of the state's energy efficiency utility budget toward non-wires alternatives (Navigant 2010).

With these early successes proving the concept, other utilities and states followed the example. Maine tested the concept from 2013 through 2015 in the Boothbay Harbor area (GridSolar 2016). National Grid performed a pilot in Rhode Island in 2016 (National Grid 2015). On a larger scale, New York and California integrated non-wires alternatives into the utility regulatory framework for grid modernization. In New York, non-wires alternatives took shape within the Reforming the Energy Vision process and set the stage for the flagship Brooklyn Queens Demand Management project, deferring $1.2 billion in traditional upgrades. In California, non-wires approaches manifested through distribution resource plans and directives from the public utilities commission to procure DER. Today, Guidehouse Insights is tracking over 100 non-wires alternative projects in various stages of planning and implementation throughout the United States (Guidehouse Insights 2019).

Minnesota's Utility Landscape

Minnesota poses a set of unique circumstances for non-wires opportunities. On the transmission side, the state has seen expansion of transmission spending and anticipates the need for more in the future. The primary need, however, is delivering wind energy to load centers, which requires different solutions than reducing peak load constraints. Within the distribution system, costs of traditional investments are low compared to denser parts of the country. For reference, the total distribution budgets of the state's three investor-owned utilities were $904 million in 2018, less than the single Brooklyn Queens Demand Management project, and the portion for capacity related projects was $117 million (Minnesota Power 2019; Otter Tail Power Company 2019; Xcel Energy 2019). While the three investor-owned utilities represent over 60% of total electricity sales, they own less than one-third of the total distribution circuits in the state (US EIA 2019). As shown in Figure 1 below, most of these circuits reside with cooperative and municipal utilities. Given that there is not a blanket case for non-wires solutions, this increases the importance of guidelines to determine which projects make favorable applications.

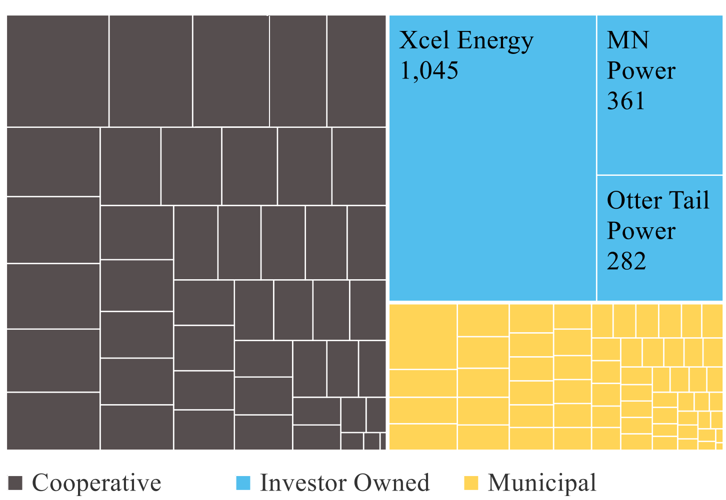

Figure 1. Share of distribution circuits for investor-owned electric utilities in Minnesota

Minnesota has existing building blocks that can be foundations for non-wires alternative policy. Most important are energy efficiency goals requiring the State of Minnesota to achieve annual energy savings equal to at least 1.5% of annual retail sales of electricity and natural gas through cost-effective energy conservation improvement programs (Minnesota Legislature 2007). Investor-owned utilities are required to provide a Conservation Improvement Program plan every three years including energy efficiency goals that help meet these state goals. Minnesota also has least-cost integrated resource planning, with utilities filing plans every two to three years (Minnesota PUC 2019). And more recently, the Minnesota Public Utilities Commission opened dockets to explore performance-based regulation and integrated distribution planning (IDP), the latter of which is foundational to utility grid modernization efforts and discussed in more detail below.

Besides policy building blocks, Minnesota has a high level of existing enrollment in demand response programs. For example, as shown in Figure 2 below, Xcel Energy has the largest residential program for demand response in Minnesota and the Midwest (US EIA 2019). These enrollments at the system-wide level could provide benefits at the distribution level for non-wires alternatives. This concept and its role in the pilot is discussed further below.

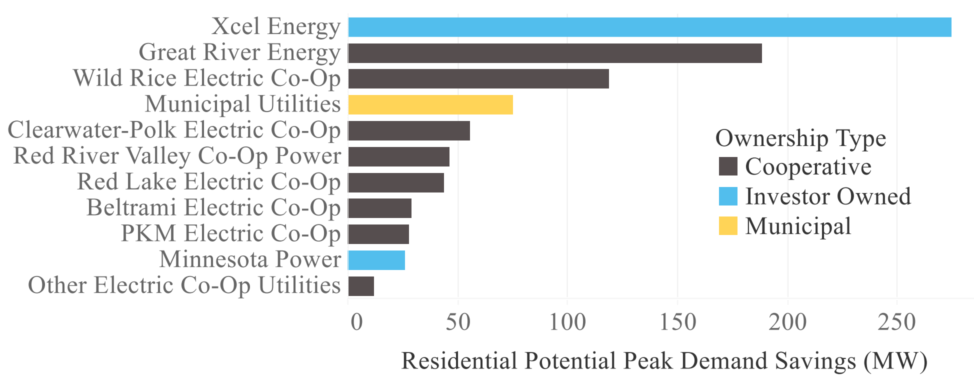

Figure 2. Residential potential peak demand savings (MW) by Minnesota utility

In Minnesota, non-wires alternatives were initiated at the utility level in August 2016, when Xcel Energy considered the procurement of a solar plus storage option to defer a substation upgrade (Minnesota PUC 2016). In autumn of the same year, Minnesota's Public Utilities Commission held a workshop for stakeholders as part of a grid modernization docket for rate-regulated utilities. Emerging from this discussion in 2017, the Commission created a questionnaire for utilities and stakeholders to better understand the distribution planning process and how it could be improved. Out of these interactions, in April 2018, the Commission created IDP dockets for the four rate-regulated utilities in Minnesota and opened these up to comments. The Commission ordered Xcel Energy, Minnesota's largest utility, to be first to file its plan on November 1, 2018, followed by the three remaining rate-regulated utilities November 1, 2019. As part of this filing requirement, the Commission directed only Xcel Energy to include non-wires alternatives analysis in these filings. The analysis was ordered to include all distribution system projects within five years of the filing year with a cost greater than $2 million (Minnesota PUC 2018).

Non-Wires Alternative Pilot

Project Background

Many non-wires alternative projects elsewhere in the country are spurred through regulatory reform, regulatory requirements, or a utility-led initiative. For this pilot, a unique proposal was put forth by Xcel Energy and Center for Energy and Environment (CEE) to the Legislative Citizen Commission on Minnesota Resources, which distributes environmental trust funds to mission-aligned projects. In the summer of 2017, as the Minnesota Public Utilities Commission began taking feedback from stakeholders on distribution planning, the three-year project proposal was fully funded by the legislature and written into law (Minnesota Legislature 2017). In addition to these legislative funds, the project used funds from the McKnight Foundation and from Xcel Energy's existing Conservation Improvement Plan. The project consists of a planning phase, an implementation phase, and a phase to create conclusions and recommendations to inform the consideration of non-wires alternatives within utility regulation.

The pilot laid out the following learning objectives:[2]

- What types of distribution system needs offer the best opportunity for DER?
- To what extent can location-specific targeting with additional customer incentives lead to increased DER?
- What customer end-use characteristics make for the best opportunities? Can the DER screening process be automated?
- What is the statewide potential for non-wires alternatives to defer distribution upgrades?
- What type of program and policy changes are needed to support non-wires alternatives in Minnesota?

Site Selection

The pilot began in 2017 by screening distribution projects within Xcel Energy's five-year distribution planning forecast. This encompassed a range of potential projects, not all of which were in the near term or included in the current budget. Specific criteria were determined to limit the number of projects that could be potential sites for the pilot. These criteria, determined by CEE, included:

1. Project need was not a result of reliability needs or asset health.
2. Project need was 3–5 years out.
3. Project served > 1,000 customers and project cost was over $500,000.
4. SCADA system was in place at the substation.[3]
5. No large community solar garden was scheduled to be added to location feeders.
6. Load was not dominated by a single large commercial or industrial customer.

Within that initial set, Xcel Energy provided nine potential projects for deeper review for a non-wires alternative pilot. These projects were mostly areas experiencing load growth,

[2] A more detailed discussion of each of these learning objectives may be found in the full pilot report.
[3] SCADA is a system for monitoring and reporting real-time data; it can be used to help monitor non-wires alternative impacts.

including sites that may exceed the load under an N-1 contingency event.[4] Regarding the fifth criteria above, focused on community solar gardens, the objective was to eliminate any external factors that may change the measurement of before and after peaks. However, as will be discussed further below, many community solar gardens were installed partway through the pilot, which allowed for additional learnings.[5]

Distribution data show that feeder loads contribute to system peak loads in unique ways. As loads aggregate over diverse transformers and substations they tend to mirror system peaks, whereas at the feeder-level, loads often closely reflect the underlying customer mix. For example, as shown in Figure 3 below, individual feeders may primarily be retail, residential, or commercial based on development patterns and their peak loads reflecting the schedule and behavior of those customers. These feeders contribute to system peaks, but themselves may peak at different times of day and require more specific risk mitigation strategies.

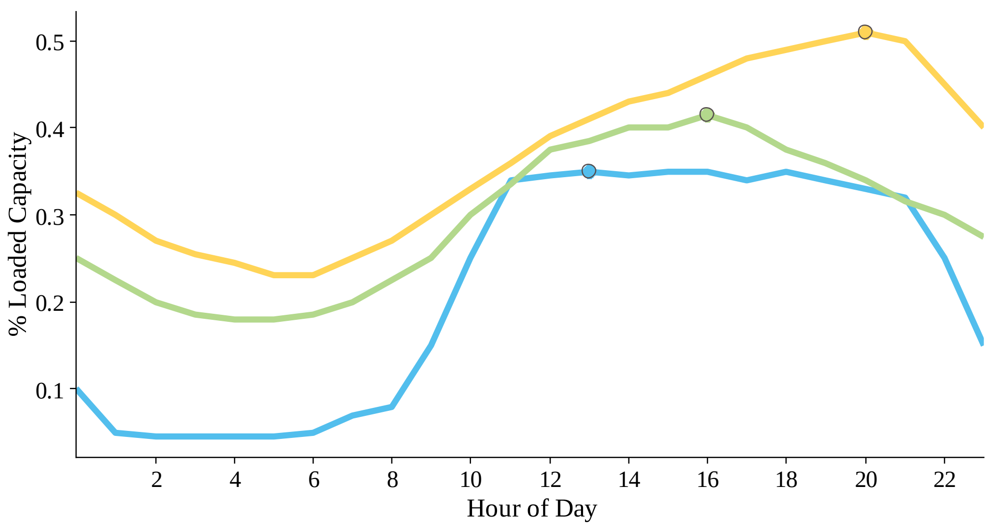

Figure 3. Percentage of loaded capacity on feeders using mock data

In addition to existing distribution project data, the pilot team developed metrics to evaluate non-wires alternative opportunities. The first metric was the project cost per load at risk ($/MVA). Distribution projects with medium-to-high cost per load at risk offered a benchmark for the cost per energy savings necessary for non-wires alternatives. The second metric was the load at risk per customer (MVA/N). Projects with low-to-medium load at risk per customer offered a benchmark for the average savings per customer needed for non-wires alternatives. The last metric was the project cost per customer ($/N). Low-to-medium cost per customer offered a benchmark of non-wires alternatives against revenues and other financial metrics. Two of ten potential distribution projects had relatively desirable values for all three metrics.

---

[4] An N-1 contingency event exists when the loss of one grid asset will cause overloading on the remaining assets. Since this initial exploration of project sites, Xcel Energy now prefers N-0 distribution projects as opposed to N-1 distribution projects as viable opportunities for non-wires alternative projects (Xcel Energy 2019).
[5] Xcel Energy has a buy-all, sell-all program that allows third parties to build community solar gardens, which Xcel Energy will then interconnect and use to provide a bill credit to their customers. There is no current limit to the number of community solar gardens built in the state, which helps explain why many were built in this three-year period.

After examining qualitative and quantitative details connected to the list of 10 sites, CEE proposed to focus on a location approximately 60 miles outside of the Twin Cities metropolitan area. A useful aspect of this chosen location was that most of the customers on the feeders and the transformers related to the non-wires alternative need were located within two cities. This allowed the pilot to employ a method of marketing exclusively to these cities, which is discussed further below.

After selecting the primary pilot site for implementation, the analysis team evaluated the duration and magnitude of the peak. The 2017 distribution forecast identified this project as having a potential need for a new feeder and transformer upgrades in five years from the time of forecast (in 2022). The pilot timeline was for customer implementation in 2019. Due to the limited project implementation timeline, a one-year deferral goal of roughly 500 kW in demand reduction was chosen to test the non-wires alternative concept in the pilot area.

Of further note, since the initial review and choice of pilot location, the pilot location was removed from Xcel Energy's project forecast. Removal can occur when forecasted load does not materialize, and it is possibly associated with all non-wires alternative projects. In this instance, pilot planning was too far along to identify another location, so the pilot continued with the project assumptions identified in the 2017 forecast. This change demonstrates the value of accelerated planning timelines and non-wires alternative measures that can be deployed quickly.

Measure selection

Measures were chosen for the pilot to address the goal of reducing the peak below the one-year deferral need. The measures chosen were selected from existing efficiency and demand response programs as part of Xcel Energy's Conservation Improvement Program. These programs have undergone cost-effectiveness testing, and so this prior screening allowed for a relatively straightforward regulatory pathway toward pilot implementation. Measures were chosen based on load shapes that would align with the non-wires alternative pilot area peak and meet the one-year deferral need. The measures shown in Figure 4 were selected for the pilot.

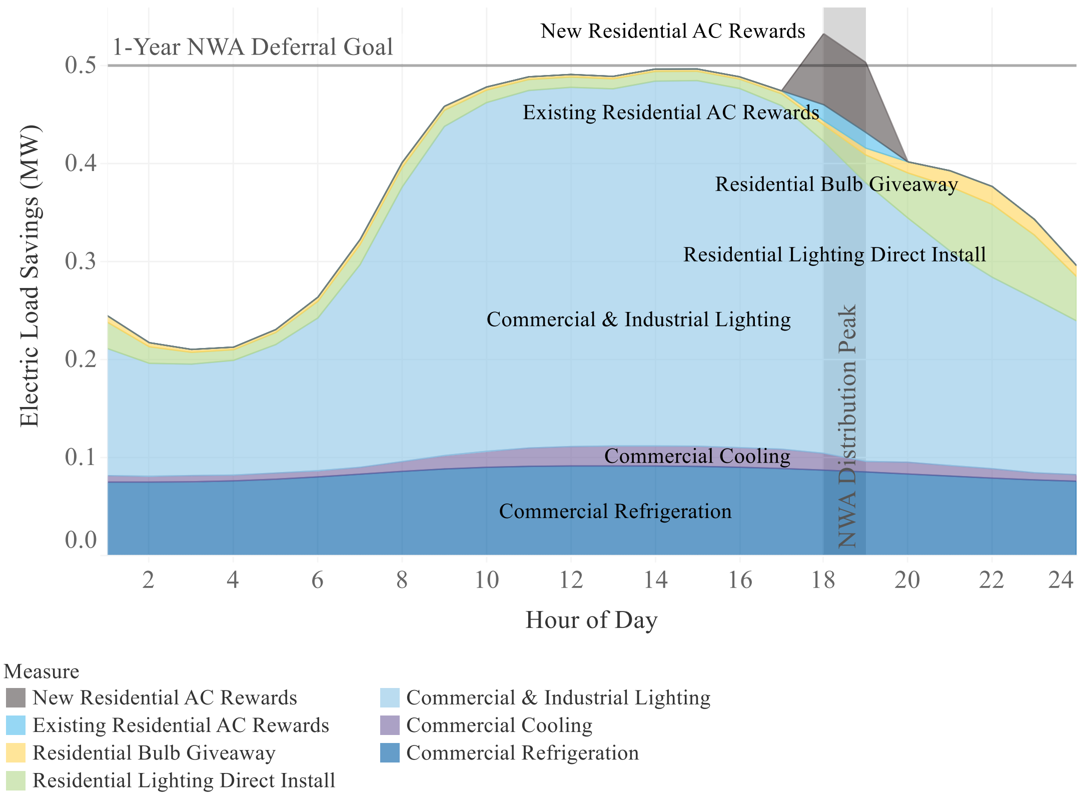

Figure 4. Savings load shapes of selected measures for the pilot

Energy efficiency and new demand response. Each program was reviewed to determine whether an increased incentive or a lower participation cost would be most appropriate for testing as part of the pilot. For example, costs for residential home visits to perform direct installations of light bulbs and thermostats were reduced to zero cost for homeowners. For businesses, rebate incentives were increased, which reduced the length of payback on the investment.

Increased marketing in the two pilot cities began in the summer of 2019 to heighten awareness of conservation in the area. For example, light bulbs were handed out to residents at local events such as community meetings and the farmers' market encouraging a first step towards changes in the home. Residential direct installation visits were marketed as free for customers in the chosen cities, and if their heating and cooling system was compatible, customers qualified for a free ecobee smart thermostat if they also enrolled in Xcel Energy's smart thermostat demand response program, AC Rewards.

In the commercial sector, enhanced rebates were offered at $300 per coincident kilowatt (kW). This coincident kW varied for cooling and refrigeration measures dependent upon the coincidence factor of these measures and how these load shapes aligned with the distribution peak. In addition, this incentive varied depending upon the business type and associated load shapes for indoor lighting measures. For example, schools and convenience stores have different lighting load shapes and, therefore, had different coincidence factors in the non-wires alternative pilot area.

As mentioned above, due to the geographic nature of the distribution system and the need at the substation, the non-wires pilot was marketed toward all residents and businesses of two cities where the project took place. This simplified the marketing materials and created a clear message to customers. Some savings spillover occurred due to this method of marketing, where customers were given additional incentives that were not located on the feeders of interest. These are discussed further below.

Existing demand response. A useful finding while conducting pilot planning was the high degree of existing enrollment in demand response programs. Over 40% of homes were previously enrolled in air conditioning load control programs. While typically used as a system-level resource, the project team proposed these be tested at the distribution level, as the level of enrollment could reduce peak demand enough to eliminate the full need for the traditional-wires solution (beyond one year).

As the pilot began, an additional opportunity was presented as Xcel Energy launched a smart thermostat pilot for business customers, which would operate in a similar manner as the residential smart thermostat program the utility currently offers. While this was not part of the planning process, this thermostat pilot was quickly incorporated into the outreach strategy, as it represented an additional load reduction opportunity from the many smaller businesses in the area. Business customers were offered free thermostats in exchange for signing up for the pilot. Since the implementation period, the thermostat pilot became a full program, and the pilot participants were incorporated into this new offering.

Project Results

Residential program teams visited 151 homes and installed a total of 3,540 light bulbs and 73 smart thermostats. These visits represented a 600% increase in program participation in the two impacted cities compared to the previous three-year average. The thermostat installations were seven thermostats below the goal of 80. As expected, installation crews encountered problems that resulted in no thermostat installation. Roughly one-quarter of these visits consisted of the customer having incompatible HVAC wiring systems to accommodate the smart thermostat. Another barrier encountered during 14% of these visits involved the complication of customers who were previously enrolled and did not want to change from Xcel Energy's direct load control air conditioner demand response program to the smart thermostat demand response program. Other barriers to installation encountered included participants having an eligible smart thermostat already installed, already being enrolled in the program, not having WiFi, not having air conditioning, renting, being wary of smart thermostats, declining the thermostat or AC Rewards without reason, or having an ineligible thermostat previously installed.

In the business sector, the initially planned six-month pilot project timeline created difficulty for participation. There was relatively slow participation from business customers due to the unanticipated challenge of the length of decision-making time and the time needed for coordination among project partners. Due to the lag in business participation, the project team at CEE worked with Xcel Energy and the Department of Commerce to grant an extension of the pilot for the business sector for an additional six months, through June 2020. This extension allowed for a more realistic, one-year timeline that more closely matches future non-wires alternative project schedules and customer recruitment windows for Minnesota utilities. Despite meeting the pilot deferral goal for capacity reduction, participation was likely suppressed from March through June as the unforeseen 2019 coronavirus pandemic (COVID-19) shut down much of the business activity in the pilot area. The results from the full one-year pilot are shown in Figure 5 below.

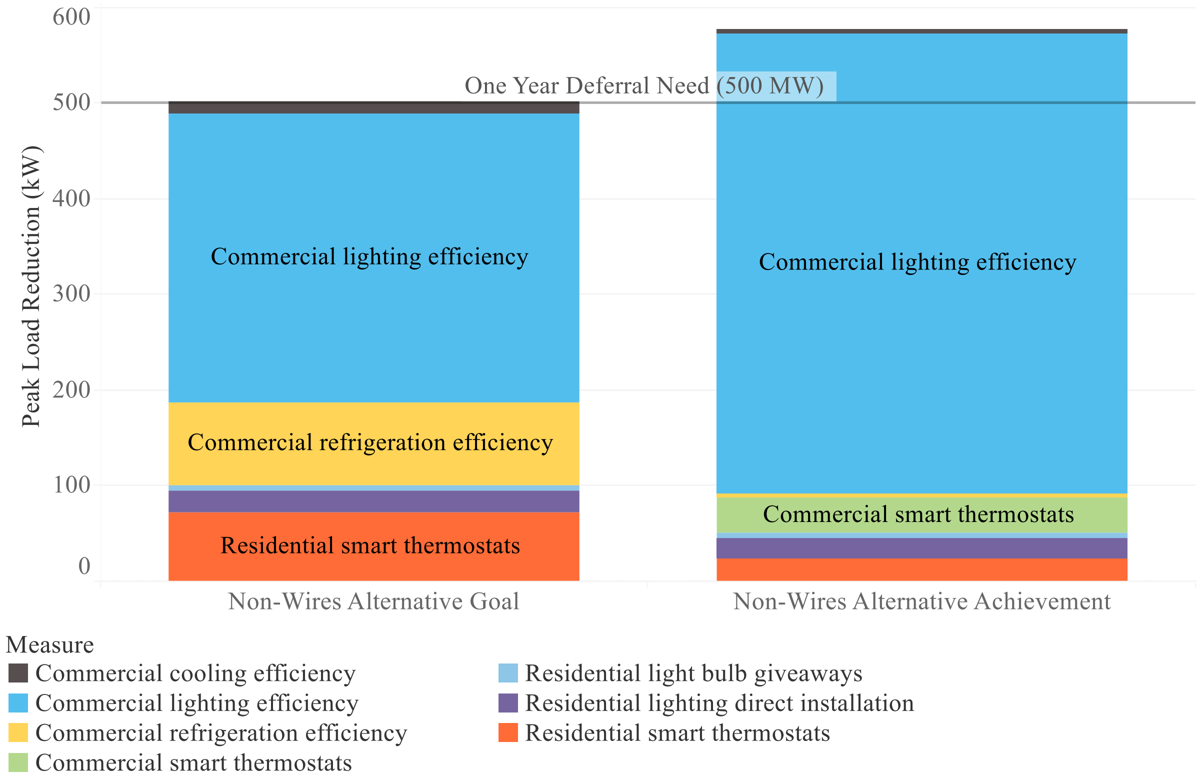

Figure 5. Pilot participation

Deemed savings results. Despite COVID-19 impacts during the extension period, commercial savings during the implementation period (June 1, 2019–May 31, 2020) exceeded the pilot goal. However, commercial projects receiving bonus incentives were lower than anticipated, as not all completed projects were submitted through CEE's implementation program staff. There may have been confusion regarding how to take advantage of bonus rebates offered as part of the pilot. For example, many of the rebates submitted were instant rebates through the Xcel Energy website. To qualify for and receive bonus incentives, pilot participants were asked to contact the CEE program staff implementing the pilot. Speculatively, many of the completed projects that did not receive bonus incentives may have been influenced by higher than normal marketing activity from the pilot. One complicating factor is that some jobs may have been completed prior to the pilot program period and thus were ineligible for bonus incentives — although they may appear as if they were completed during the program period due to the data set characteristics.

Participation in the commercial refrigeration and commercial cooling programs was also below what was expected. The small business refrigeration program is relatively new, and so trade ally relationships are still being established, which could have played a role in the lower than expected results. In addition, larger kW savings opportunities for both cooling and refrigeration measures are often replace-on-fail measures, and so are difficult to market with bonus incentives. In other words, adding a bonus rebate to increase program participation in these programs may not have been enough to convince customers to participate.

Out of the 67 residential smart thermostats installed in the pilot area, 75% of these customers were previously enrolled in Xcel Energy's direct load control air conditioning program. This outcome resulted in the acquisition of 17 new load control customers out of the total 73 thermostats installed during the 151 home visits. For the remaining 50 thermostats, enrollment in Xcel Energy's smart thermostat program removed the opportunity to call upon these legacy direct load control customers for the purpose of distribution peak mitigation, which reduced the net savings from residential cooling. However, the kW savings per customer is higher for the smart thermostat program than for the direct load control program, therefore some savings for these customers were achieved.

The programs with the most participation showed consistent results in terms of savings spillover where participants received financial benefits in exchange for savings, but were not located on the feeders related to the non-wires alternative pilot. Commercial lighting, residential lighting direct installation, and residential smart thermostat installation all resulted in between 11%–12% participation spillover. This was a result of creating a simple marketing approach directed at all residents of both cities. Some customers who lived in these cities were not on the feeders related to the non-wires pilot, which resulted in some participation spillover. However, this spillover resulted in program participation that had already undergone cost-effectiveness testing, even with the inclusion of bonus rebates or cost reductions. Therefore, the outcome produced beneficial results regardless of being outside the target area.

The spillover of savings out of the non-wires alternative area could be avoided through a customer eligibility tool. Such a tool could be hosted on Xcel Energy's website and could allow customers to enter an address to determine eligibility. The pilot budget did not allow for this type of expenditure, though if non-wires opportunities were offered at scale, this type of eligibility test could prove cost-effective. Another option to prescreen customers for eligibility would be to publicly display regions where customers may qualify for an opportunity. Con Edison in New York uses this approach for both residential and commercial programs as part of the Brooklyn Queens Demand Management project (Con Edison 2019).

Demand response results. An unusually mild 2019 cooling season prevented a robust analysis of the demand response resource at the distribution level. Nonetheless, two events were called, one was an event that called upon residential air conditioner-specific demand response resources in the pilot region (Event 1). The second event consisted of a test of Xcel Energy's Northern States Power system resource (Event 2). Analysis of each of these events on the pilot feeders yielded mixed results. The first event occurred during a dynamic weather period. Rapid changes in weather made it difficult to distinguish natural reductions in air conditioning duty cycles from the reduction triggered by the demand response resource. Conversely, the second event showed a potential load reduction of between 2 MW and 3.2 MW, or 4%–8% of project area load, during the two-hour event. The upper range of savings during Event 2 was over double the capacity needed for the full three-year non-wires alternative project.

Community solar garden impact. The development of 30 MW_{AC} of community solar gardens from 22 projects across feeders over the project period radically changed peaking characteristics on this system and substantially lowered the load at risk. These changes are shown in Figure 6 below, which illustrates the average load on 10 peak days before and after solar projects were added. During the top 10 peak days of 2019, solar reduced peak loads by 12% and shifted them by four hours, on average. Without solar (shown by the dashed black line), peak loads increased modestly and shifted earlier in the day, but these distribution peaks are substantially altered across all feeders due to solar additions (shown by the solid black line).

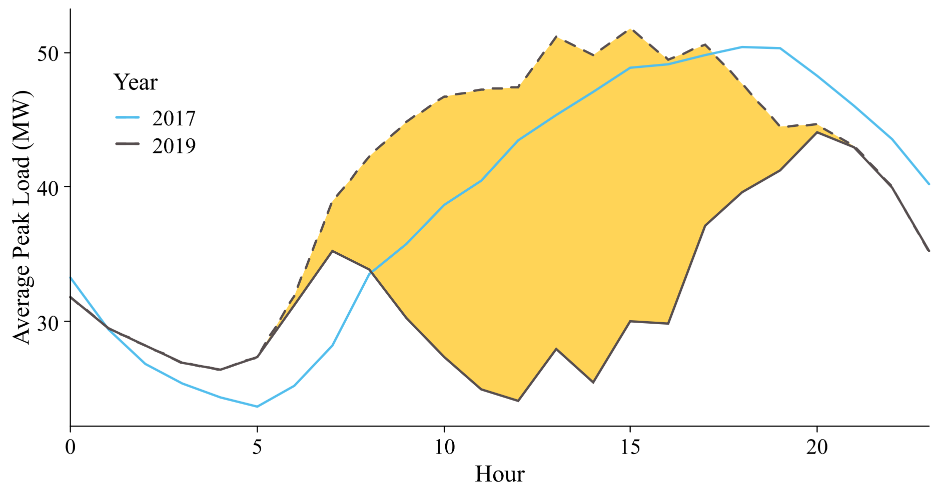

Figure 6. The impact of community solar photovoltaic generation on transformer load

By itself, this new solar generation is unlikely to satisfy reliability criteria during times of interest. However, by shifting peaks later in the day, these large output solar garden projects enable new strategies for mitigating peak demand. For example, the shifted peaks have improved coincidence with residential lighting retrofits, one of the successful measures implemented in this project.

Community-focused implementation and customer lessons. In the commercial sector, a variety of engagement methods took place to approach customers including door-to-door canvassing, direct recruitment through Xcel Energy account managers and call center staff, trade ally engagement, and presentations at City and chamber of commerce meetings. Although email proved very cost-effective for implementation in the residential sector, email addresses were not available for many customers, and when available, they often were not for the decision-makers responsible for energy efficiency improvements. The results of various engagement methods are shown in Figure 8 below.

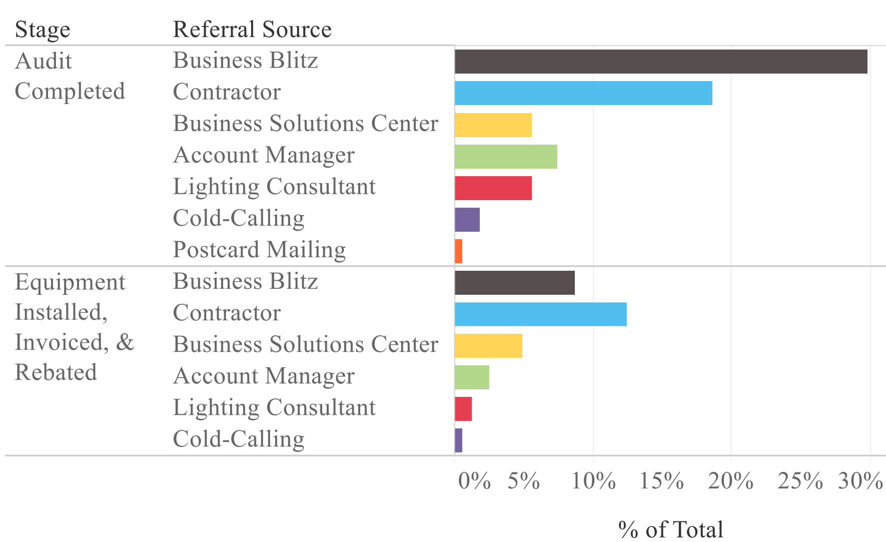

Figure 8. Audit and job completion rates in business sector by engagement type

Contractors brought in the largest number of completed projects during the pilot window. These existing trade ally relationships proved key to quickly deploying a bonus incentive program, as many were eager to use the bonus incentive as a tool to sell more jobs. While critical to achieving high savings, relationships with contractors are built on trust and experience, which typically takes time. The timeframe to build trust is often longer than a one-year non-wires alternative project implementation period. The success of lighting installations in the pilot can be, in part, attributed to established contractor relationships. Newer programs, such as commercial refrigeration for small businesses had lower completion rates in the pilot, which could be in part due to the ongoing establishment of contractor relationships. Investment in these relationships in the near term will have benefits as more of these projects arise in the future.

One challenge encountered when working with contractors and lighting consultants is that they typically have a much larger service area than the non-wires alternative program or that they may not typically serve the area in general. In these cases, they were not able to dedicate additional time to customer interactions in the non-wires alternative area.

In the residential sector, a variety of outreach and engagement methods were employed, as shown in Figure 7 below. These included postings on the City's websites, in City newsletters, on social media, tabling at local events, and direct emails to customers from Xcel Energy. While the marketing methods varied by community, email proved to be the most successful at garnering sign-ups for home visits.

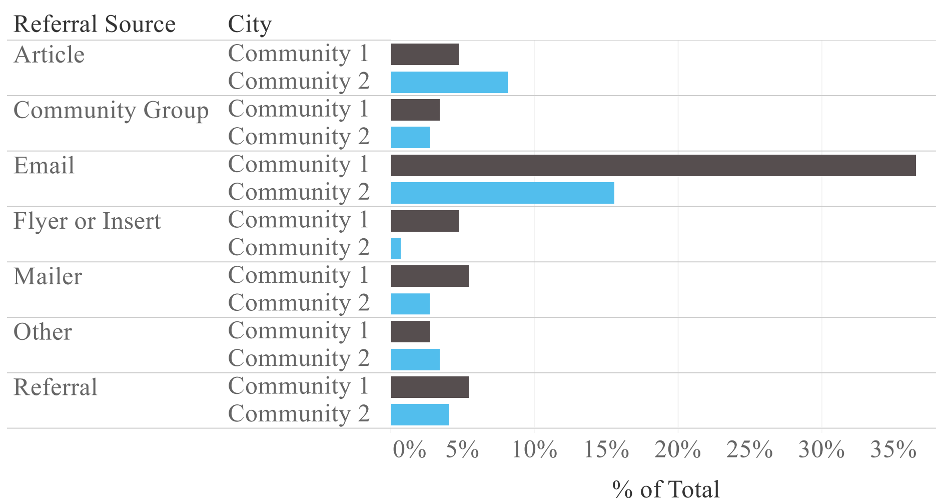

Figure 7. Community engagement methods for residential sector participation

Distribution operation lessons. One discovery during the planning phase was the high rate of customer demand response enrollment at the pilot site. This was mostly commercial and residential customers on direct load control air conditioning programs, as well as industrial customers on an interruptible load tariff. These customers are enrolled and called upon as a system-level resource for the purpose of managing costs of peak summer demand. Calling upon only the residential customers on the feeders within the non-wires alternative area could provide sufficient load reduction to completely eliminate the need for the traditional wires solution posed in the original distribution need. However, using this resource would stress test participation in these programs. For example, if this capacity resource was needed 20 times in a cooling season, there could be a high level of attrition in program participation. Therefore, it is important to consider the number of events that could be needed on the distribution system as well as the number of consecutive days.

Xcel Energy tested this concept with both the customers enrolled in direct load control as well as customers enrolled in the smart thermostat program. As mentioned in the results section above, the weather conditions in 2019 were not ideal for these tests. However, this concept of using system resources at the distribution level is included as part of Xcel Energy's planning process and is identified in the most recent IDP (Xcel Energy 2019).

Program-based lessons. A few main takeaways surfaced from the pilot. First, within the current program operation framework, program managers may have little difficulty meeting annual savings goals with non-targeted, system-level customer participation. Therefore, channeling additional resources to a specific target area may be of less interest. In other words, the default motivation would be to have customers move forward with projects without bonus incentives. To counter this disincentive, the additional value from the distribution deferral could be channeled in part toward internal incentive mechanisms for programs to offer a positive feedback loop.

The second takeaway centered around the pilot's length of operation. The compressed pilot timeline of six months was too short. The extension to a one-year timeline was more realistic, especially for business customers, but this still posed challenges especially for large, complex projects. On the other hand, a time-limited deadline may spur action that otherwise would not have happened.

The last lesson relates to marketing to specific customers on non-wires alternative feeders. Communicating eligibility at the city level, even though it included some non-feeder customers, made communication much easier. However, future non-wires alternative projects may not align with municipal boundaries. Without the ability to market opportunities specifically to both cities, it would have been challenging to communicate an eligible customer list to city partners, chamber of commerce contacts, trade allies, customers, and utility customer service personnel because the customer list and pilot service area was not public.

Pilot costs. Figure 8 below shows preliminary results of the pilot costs compared to the avoided costs of the traditional distribution investment. The avoided cost is calculated as the net present value of deferring the distribution investment for one year, which aligns with the 500 kW goal. The variation in avoided costs is due to changes in cost forecasts as well as variations in avoided cost methodology.[6] As the figure shows, pilot costs came in at the mid-point of that range, evenly split between bonus incentives and additional labor. One of the drivers for labor costs was that the pilot was located outside of the Twin Cities metro area, which added travel time.

[6] The lower (default) value used the discrete approach methodology outlined in the Minnesota Transmission and Distribution Avoided Cost Study (Xcel Energy et al. 2017). This approach places the full capital cost of a proposed upgrade in the project year. The deferral value is the reduction in net present value if the project is extended by one year or more. Our calculations assume the same discount rate as the study, 7.14%, as well as the same project cost escalation rate of 1.0236%.

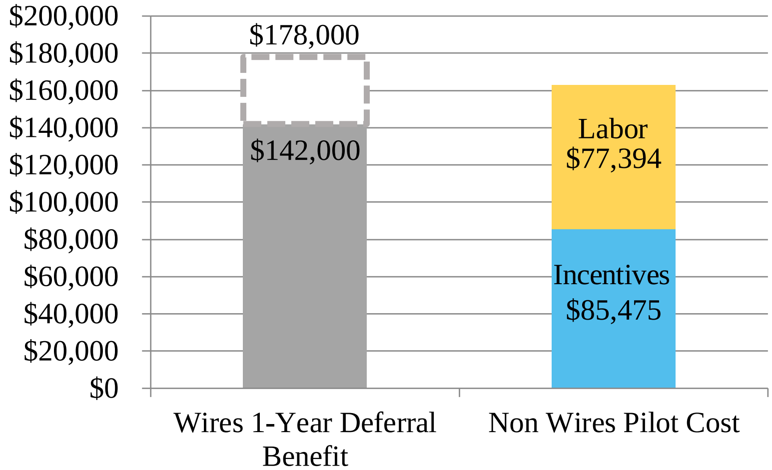

Figure 8. Comparison of the net present value of traditional and alternative solutions

Policy Recommendations

This pilot launched during an opportune window of policy evolution in Minnesota. Within the previous two years there had been new initiatives at the Public Utilities Commission focused on grid modernization and performance-based incentive mechanisms. Today, existing regulatory frameworks like Minnesota's Conservation Improvement Programs and Integrated Resource Planning are evolving to tackle the consequences of increased intermittent renewable electricity, and its implications for avoided costs and capacity requirements. Integrated Distribution Planning can align these opportunities and ensure technology investments in the distribution system look forward and achieve all customer benefits. This pilot provides several lessons for how policy can best support cost-effective non-wires alternatives in Minnesota.[7]

Expanded project criteria: From initial project screening, and from information filed in subsequent IDPs, there is a large variation in the projected cost of traditional wires solutions. This cost, in terms of dollars per load at risk, is unsurprisingly a major driver of project value. However, we also found that customer type (including business segments and housing stock) and the saturation of program participation were two major considerations for project cost and success. Project screening, which occurs in the IDP process, would benefit by expanding criteria as well as prioritizing eligible projects by overall net benefit.

Calculation of avoided costs: Utilities should adopt location-specific avoided costs that reflect the projected traditional costs in the three- to five-year planning horizon of mid-range distribution plans. Given that these values are dynamic and may change with system and market conditions, this exercise does not need to be completed for the whole distribution system, but rather just for projects that have been identified through screening.

Acquisition of DERs through third parties: While a policy priority in some other states, Minnesota does not have an explicit goal to support private industry through non-wires projects, and energy efficiency and demand response have a successful history being implemented through utilities. Given that this pilot had a low avoided cost and focused on existing programs, there was little added value to a competitive solicitation. This experience may be different for

[7] A more detailed discussion of Minnesota-specific policy opportunities is included in the full pilot report.

utility- or third-party-owned DERs such as battery systems, where the resource acquisition and deployment process is quite different.

Proactive application to new growth and electrification scenarios: While electricity demand in Minnesota has been relatively flat for the past decade, projections anticipate a change, especially around growth in new customer loads such as electric vehicles. This new adoption is likely to be concentrated in particular geographic regions, which might see distribution system strains. Non-wires alternatives provide cost-effective and scalable options to manage peak demand in targeted locations.

Consider performance incentives for non-wires projects: Minnesota's current performance-based ratemaking process has asked utilities to develop incentive structures for increasing demand-side resources, such as demand response. To expand the application of demand response to manage distribution capacity requirements, these performance incentives could include the net benefits of distribution deferrals.

Conclusions

Non-wires alternatives can offer many benefits to Minnesotans. When investor-owned utilities build infrastructure such as transformers and feeders, the Public Utilities Commission allows the utility to claim a rate of return on these investments to pass onto shareholders. These costs are passed along to ratepayers in the form of rate increases. If a non-wires project's net present value is lower than the traditional wires solution, this can reduce costs for ratepayers. In addition, many non-wires alternatives offer benefits connected with DER such as customer engagement and carbon reduction. To realize these benefits, policies need to be established as suggested above.

Choosing non-wires alternative criteria is an important decision regulators and utilities in Minnesota will be faced with when selecting sites for distribution plans and when implementing projects. Best practices are available from this pilot and other states who have tested and are operating non-wires alternative projects. Some of the criteria discussed above include the amount of community solar garden production on feeders, the planning horizon for traditional wires projects, and the composition of customers.

A coincidental finding of the pilot is that community solar gardens demonstrate that development projects can impact distribution project needs and planning. Currently Xcel Energy uses battery costs as a non-wires alternative proxy for traditional wires solutions in its integrated distribution plan. This proxy is logical in terms of the reliability and simplicity posed by a battery. In future iterations of planning, the consideration of other types of distributed energy resources such as solar combined with other measurable assets like demand response may offer more competitive options in terms of cost comparisons with traditional wires solutions.

As mentioned in the introduction, Xcel Energy is one of three investor-owned electric utilities in Minnesota and one of four rate-regulated utilities. However, most of the state is composed of distribution circuits feeding customers of municipal and cooperative electric utilities that do not have shareholders. These utilities are self-motivated to conduct non-wires alternative projects in terms of lower costs for their members. As the non-wires alternative market matures and processes become more streamlined, this sector of the utility landscape may adopt these approaches. However, barriers will be encountered related to customer demographics, the costs of traditional wires solutions, and economies of scale for smaller utilities.

References

Chew, B., E. Myers, T. Adolf, and E. Thomas. 2018. "Non-Wires Alternatives: Case Studies from Leading U.S. Projects." sepapower.org/resource/non-wires-alternatives-case-studies-from-leading-u-s-projects/.

Con Edison. 2019. "The Neighborhood Program - For Renters and Homeowners." 2019. www.coned.com/en/save-money/rebates-incentives-tax-credits/rebates-incentives-tax-credits-for-residential-customers/residential-neighborhood-program.

US EIA (U.S. Energy Information Administration). 2019. "Annual Electric Power Industry Report, Form EIA-861 Detailed Data Files." U.S. Energy Information Administration. www.eia.gov/electricity/data/eia861/.

GridSolar. 2016. "Final Report Boothbay Sub-Region Smart Grid Reliability Pilot Project."

Guidehouse Insights. 2019. "Non-Wires Alternatives Tracker 3Q19." Navigant Research. 2019. guidehouseinsights.com/reports/non-wires-alternatives-tracker-3q19.

Minnesota Power. 2019. Minnesota Power's 2019 Integrated Distribution Plan.

Minnesota Legislature. 2007. § 216B.2401 Energy Savings Policy Goal.

Minnesota Legislature. 2017. "M.L. 2017 Projects." Legislative-Citizen Commission on Minnesota Resources. 2017. www.lccmr.leg.mn/projects/2017-index.html.

Minnesota PUC (Minnesota Public Utilities Commission). 2016. Order Certifying Advanced Distribution-Management System (ADMS) Project Under Minn. Stat. § 216B.2425 and Requiring Distribution Study.

———. 2018. Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy 12.

———. 2019. "Resource Planning (IRP)." mn.gov/puc/energy/resource-planning/.

National Grid. 2015. "2016 System Reliability Procurement Report."

Navigant. 2010. "Process and Impact Evaluation of Efficiency Vermont's 2007−2009 Geotargeting Program." Navigant Consulting, Inc.

Otter Tail Power Company. 2019. Otter Tail Integrated Distribution Plan.

Xcel Energy, Minnesota Power, Otter Tail Power Company, the Mendota Group LLC, and Energy & Environmental Economics. 2017. Minnesota Transmission and Distribution Avoided Cost Study.

Xcel Energy. 2019. Integrated Distribution Plan (2020−2029).