NON-WIRES ALTERNATIVES AS A PATH TO LOCAL CLEAN ENERGY: RESULTS OF A MINNESOTA PILOT

EXECUTIVE SUMMARY

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Pilot Purpose

Non-wires alternatives describe a set of solutions to reduce peak electricity load in targeted locations using localized resources such as energy efficiency, demand response, solar photovoltaic generation, and energy storage. These resources reduce net peak load at a circuit or substation level to defer or eliminate the need for traditional "wires" investments in the transmission or distribution system. These solutions often require enhanced customer incentives within the target region and are cost-effective when they require lower investment than the capital cost of a traditional project.

LEARNING OBJECTIVES

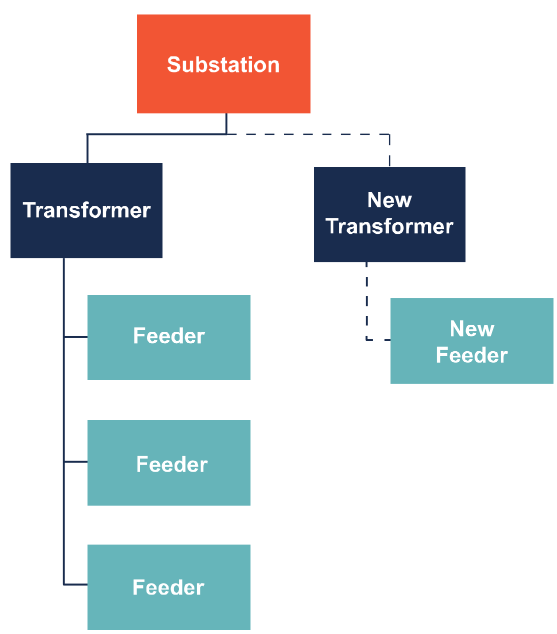
1. What types of distribution system needs offer the best opportunities for DERs?
2. To what extent can location-specific targeting with additional customer incentives lead to increased DERs?
3. What customer end-use characteristics make for the best opportunities?
4. What is the statewide potential for non-wires alternatives to defer distribution upgrades?
5. What type of program and policy changes are needed to support non-wires alternatives in Minnesota?

A growing number of projects have been undertaken in the United States, but most cases focus on high-cost transmission or distribution applications. Minnesota has relatively low energy costs, a robust penetration of energy efficiency and demand response, and a strong regulatory track record to spur clean energy technology deployment through pilots and evidence-based regulation. This pilot specifically aimed to test a non-wires project in a more typical context, with the idea that non-wires alternatives could be used as a standard part of the distribution planning and investment tool kit to lower costs, increase customer benefits, and drive uptake of carbon-saving distributed energy resources.

Project Need

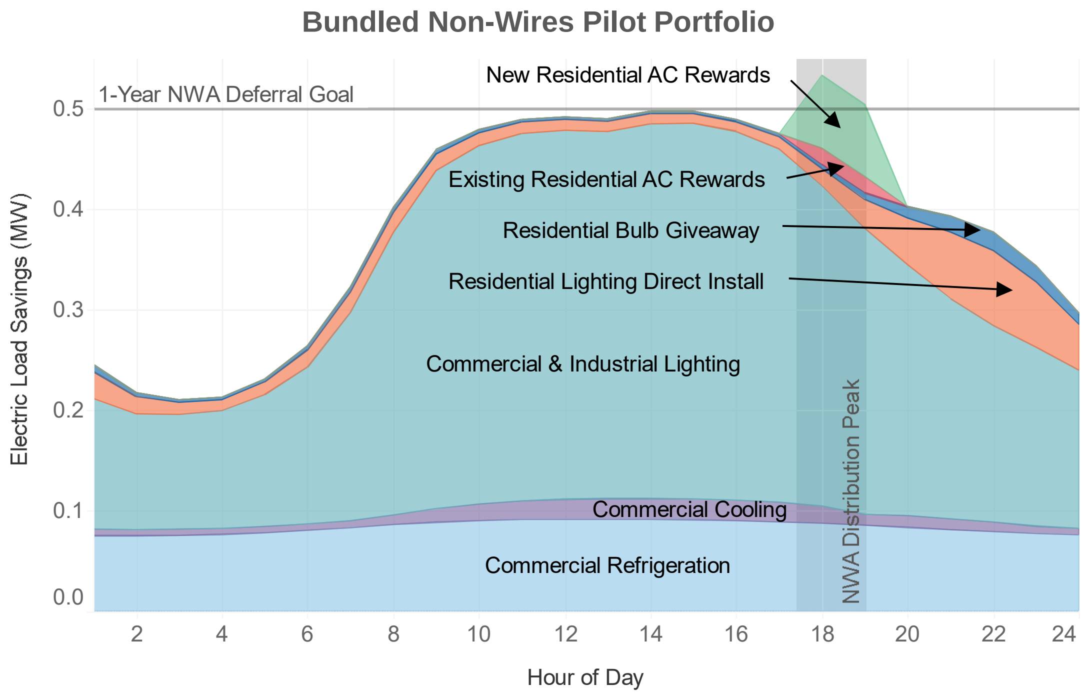
The pilot site was a low-risk (N-1) opportunity selected from Xcel Energy's 2017 five-year distribution forecast. Planners identified the need for a new transformer, new feeder, and feeder reconfiguration five years in the future at an estimated cost of $3.5 million. The feeders served an area located primarily within two municipalities.

Analysis of the historical load at the site identified that a 500 kilowatt (kW) reduction between 17:00 and 19:00 could defer the project need by one year. This deferral amounted to a present value of $140,000–$170,000, the resulting upper bound for cost-effective non-wires alternatives.



Non-Wires Planning

This pilot applied energy efficiency and demand response measures via existing programs or technology pilots, which helped shorten the approval and implementation timeline. During pilot planning, researchers modeled the peak summer day load profiles of individual technology measures, then calculated the savings potential that coincided with the local early evening peak. Final measures, shown below, included commercial and residential lighting, commercial cooling and refrigeration, and smart thermostat programs.



Enhanced incentive levels were available to customers within the two pilot communities. The cost for a residential home visit to install light bulbs and thermostats was reduced from $70 to zero cost for homeowners. Smart thermostats were provided for free when a customer enrolled in a demand response program — a $165 value.[1] In the commercial sector, enhanced rebates were offered at $300 per coincident kilowatt. The enhanced outreach tactics are shown below.

Residential Outreach Tactics	Business Outreach Tactics
• Community ambassador initiative • Coordination with Cities on promotions • Direct mail to high-potential households • Utility email campaign • Event tabling • Manufactured home park outreach • Social media promotion	• Door-to-door business blitz • Coordination with Cities on promotions • Direct engagement by utility account representatives • Direct mail to businesses • Trade ally engagement

[1] Note that these were the customer benefits at the time of the pilot — costs and incentives may have since changed.

Pilot Achievements

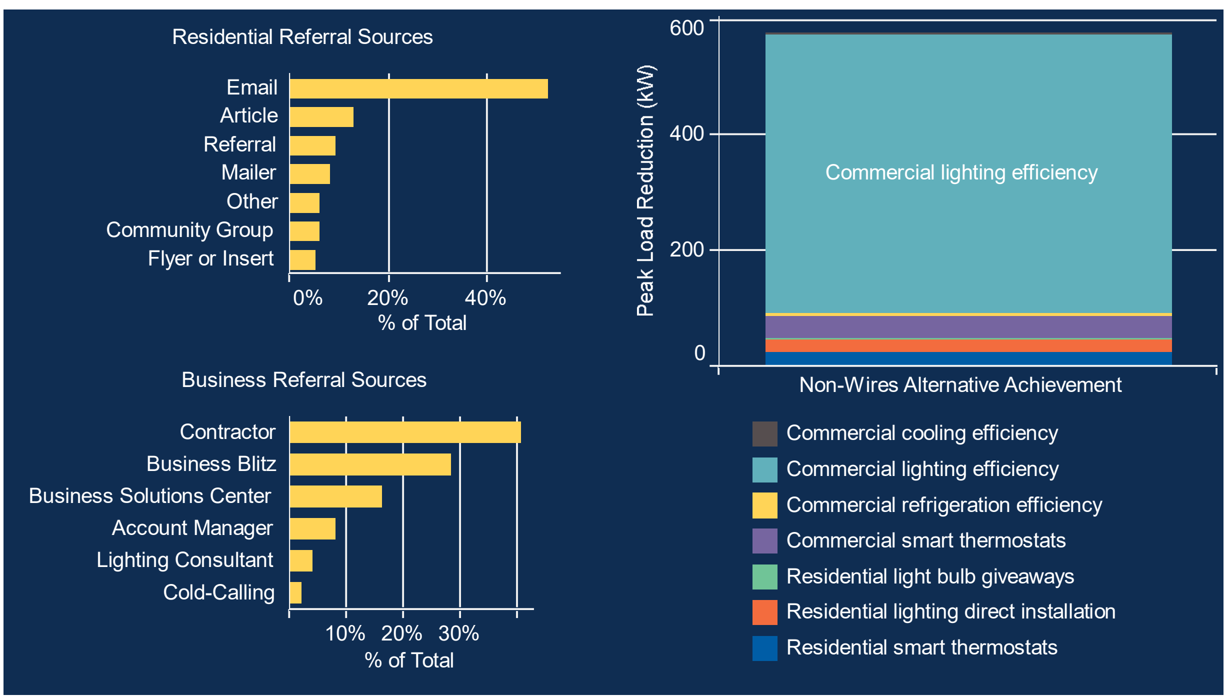
The pilot launched in June 2019 with a marketing blitz featuring local community leaders. Residential incentives ended in December 2019, while commercial eligibility was extended to June 2020. Despite the impacts of the COVID-19 pandemic, which affected program participation in 2020, the pilot yielded total net incremental deemed savings of 576 kW over the historical efficiency baseline on the local distribution system. This exceeded the pilot goal of 500 kW.

PILOT AT-A-GLANCE

- Goal: save 500 kW between 17:00 and 19:00 to defer project by one year
- Results: 576 incremental kW saved
- 151 homes participated in six months
- 61 businesses participated in one year
- 481 kW saved from commercial lighting
- Total pilot labor and incentives cost of $163,000

Commercial lighting made up the largest portion of savings at 481 kW. This included a higher than usual baseline participation in traditional programs. Direct contractor outreach led to the largest number of completed jobs, followed by the door-to-door business blitz outreach. The largest return on residential marketing tactics came from Xcel Energy's email campaign, followed by community articles and personal referrals. Residential programs saved 51 peak-coincident kilowatt, divided equally between lighting and smart thermostats.

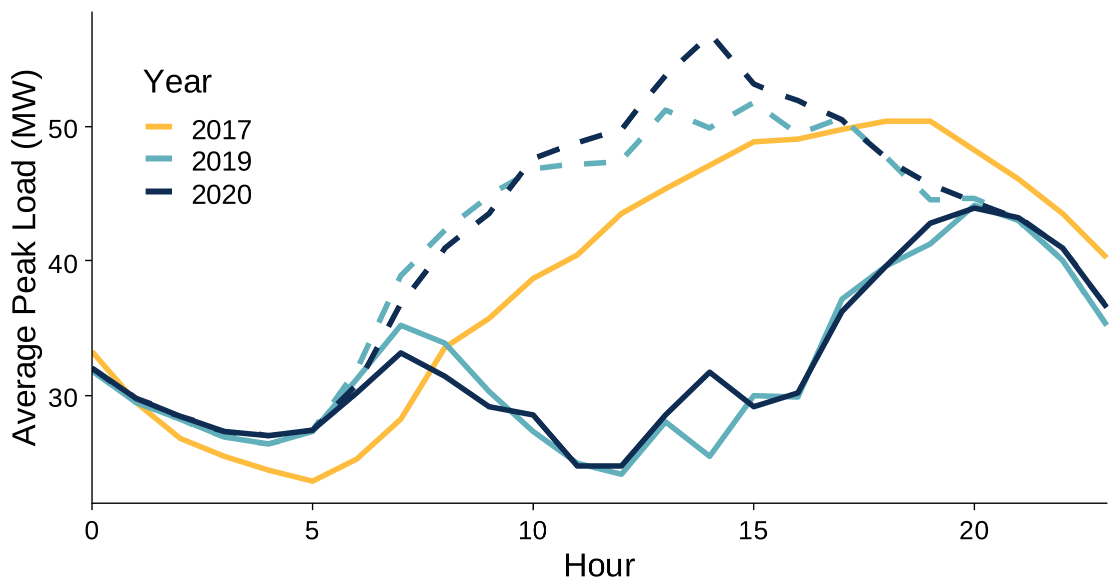
The pilot was delivered at a cost of $163,000, within the range of the one-year deferral value for traditional wires costs. Incentives made up 53% of the cost, and labor made up the remaining 47%. Future non-wires costs could be reduced by further leveraging labor expenses of existing programs, and by reducing incentive spillover, which amounted to 11% in this pilot.



Demand Response

Over 40% of homes in the pilot area were already enrolled in a direct load control air conditioning demand response program. This resource was designed to meet capacity needs across the whole power system, but the pilot also tested the use of demand response to meet localized grid needs.

Those needs changed with the unforeseen addition of 30 MW_{AC} of community solar gardens from 22 projects across pilot feeders. This solar resource was not online during 2017, the base year for pilot planning. During the 10 peak days of 2019 and 2020 (shown below), solar reduced peak loads by 12% and shifted them by four hours. Without solar (shown by the dashed line), peak loads would have increased modestly and peaked earlier in the day.



This pilot called three local demand response events during the summer of 2020. Dynamic weather decreased the statistical confidence in attributing load reduction to the demand response events. However, these events demonstrated reliability in forecasting the conditions that would lead to high system loads during underperforming solar output and successfully coordinated short-notice, geotargeted demand response calls with the utility. Despite the lack of statistical confidence, system loads were less than load forecasts in all but one event.

Policy Insights

Numerous lessons from this pilot have implications for how state policy can support the use of distributed energy resources to defer grid expenditures. A review of both Minnesota's policy frameworks and those of three leading states — New York, California, and Rhode Island — uncovered common policy building blocks. This pilot offered several insights for how Minnesota could increase the practical advancement of non-wires projects. These recommendations encompass the use of data to help inform planning and evaluation, ways to ensure that cost-effective DERs are identified, and ways to incentivize utilities for pursuing alternatives.

State Policy Building Blocks	Corresponding Minnesota Pilot Findings
Integrated distribution planning	• Project screening should both identify and prioritize potential projects, given desired outcomes. • Incorporate historical load data to forecast the timing, duration, and frequency of peak capacity needs. • Expand the use of scenario planning to identify likely futures, including additions of community solar and electric vehicles.
Identification of costs and benefits	• Produce location-specific avoided costs for distribution deferrals and include cost ranges or uncertainty for projects more than two years into the future. • Clarify the method for quantifying the value of grid deferrals.
Disclosure of grid needs, locational values, and data access	• Disclose grid needs for projects selected through screening, rather than for the whole system. • De-emphasize access to locational values that change frequently, especially if there is no near-term project identified. • Include developer data from solar garden production. • Provide aggregate customer data in line with privacy guidelines.
Investment in grid modernization technologies to support deployment	• Use data for more granular representation of peak events at the feeder level and better identification of the customer end uses that contribute to peak load during initial project planning. • Increase certainty and automation in deploying demand-side solutions at a local scale. • Improve real-time evaluation and attribution of savings.
Acquisition of DER through third parties	• Competitive procurement may be cost prohibitive for smaller projects, especially when solutions can be delivered through existing programs. • Demand response and other active technologies will need nimble dispatch protocols if site conditions change. • For larger projects or aggregate sets of projects, a utility could decide to solicit bids from third-party vendors. If so, RFPs should include communication and data integration needs.
Utility incentives versus mandates	• Continue to use integrated distribution planning to identify non-wires alternatives as part of least-cost planning framework. • For existing programs, consider enhancing financial incentives to motivate implementation in a particular location.
Stakeholder engagement	• Stakeholders offer valuable insight into non-wires alternatives at the portfolio level and can review projects as part of distribution plans. • External stakeholders with technical expertise add value in reviewing eligible projects and determining the societal benefit of proposed solutions. • Stakeholder engagement should include community partners that will help facilitate and promote local implementation.

Minnesota Program & Policy Recommendations

Minnesota's total statewide technical potential for non-wires alternatives today is likely between $1 million and $4 million per year, based on current utility spending. While modest, this is an opportunity to leverage needed infrastructure investments to decrease the environmental impact of Minnesota's energy system.

Minnesota has strong foundational policy requirements to advance clean energy and incentivize utilities under the shared benefits model. Most, if not all, of the policy requirements to support non-wires alternatives can be integrated into the following policy platforms.

Estimated Environmental Benefits of Non-Wires Alternatives in Minnesota

7,100–31,000
MWh/year

4,000–17,000
Tons CO_2e/year

2.4–10.1
Tons SO_2/year

2.8–12.2
Tons NOx/year

Conservation Improvement Programs establish the program structure, measurement and verification requirements, avoided cost methodology, and incentive structure for utility energy efficiency and demand response programs. CIPs offer trusted programs that can be deployed quickly to meet grid constraints. CIPs can be augmented to capture the benefits of non-wires deferrals by including the enhanced benefits of energy efficiency in eligible locations where distribution upgrades are pending.

Integrated Distribution Planning requirements are the principal vehicle for how non-wires alternatives will be considered alongside traditional distribution system investments. Large reforms are not warranted, but several enhancements may increase experience with non-wires alternatives. These enhancements include expanding project screening criteria, requiring a more comprehensive assessment of different types of distributed resources, and exploring competitive procurement.

There is also an opportunity to link **Integrated Resource Planning** with integrated distribution planning for consistent forecasting and scenario planning for DERs. For example, the opportunity to lower solar integration costs with demand response must be tested and evaluated at a distribution scale but may impact the technology cost assumptions in resource planning.

MAJOR PILOT LEARNINGS

- Small-scale, demand-side non-wires alternatives are feasible to implement within reasonable budgets and timescales using existing program portfolios.
- Minnesota has a modest statewide technical potential estimated at between $1 million and $4 million per year, though this is expected to grow as more end uses electrify.
- Distribution planners need more tools to accurately model non-wires resources in their forecasts, and advanced metering infrastructure will improve both planning and evaluation.
- Demand-side management is a valuable resource for real-time distribution operations — though better system integration is needed, especially with community solar.
- Increased experience with planning and deploying non-wires alternatives will allow Minnesota's utilities to accurately evaluate the resource when future large distribution projects are needed.
- Minnesota has numerous existing policy frameworks that can support the use of cost-effective non-wires technologies.