MICHIGAN PUBLIC SERVICE COMMISSION

# Electric Undergrounding Report

## U-21388

**Prepared by MPSC Staff**

October 31, 2025

Presented to:

**Dan Scripps, Chair**
**Shaquila Myers, Commissioner**
**Katherine Peretick, Commissioner**

LARA
LICENSING AND REGULATORY AFFAIRS

# Contents

# Executive Summary

In late March 2025, northern Michigan experienced a catastrophic ice storm with reports of over one inch of ice causing widespread power outages and difficult restoration conditions. The Commission held a public forum in Gaylord on May 21, 2025, to solicit input from customers affected by the storm. The Commission and Staff heard directly from customers impacted by the storm, and undergrounding electric lines emerged as a key theme. On June 12, 2025, the Commission issued an order in MPSC Docket No. U-21388 directing Staff to conduct an Undergrounding Technical Workshop and file a report with recommended next steps addressing undergrounding and alternatives to undergrounding for the Commission's consideration. The Undergrounding Technical Workshop took place over two separate days – September 17th and September 19th - and included several subject matter experts involved as guest speakers.

Most Michigan customers have experienced below average reliability performance as extreme weather events continue to present reliability challenges for overhead electric infrastructure. These extreme weather events are becoming the norm in Michigan, which results in increasing utility storm restoration costs. Vegetation management maintenance spending is also on the rise or is likely to remain higher than historical spend levels. The changing landscape of increasing maintenance costs and reliability challenges associated with the overhead infrastructure warrants strong consideration for undergrounding, which is commonly viewed as an investment with high installation costs.

The Undergrounding Technical Workshop was informative by identifying opportunities and barriers to electric undergrounding infrastructure and alternatives to undergrounding. Studies suggest targeted, well-selected undergrounding programs present strong economic cases and cost-effective solutions to improve reliability and resilience of the electric system. Given the unique risks to Michigan and utility service territories, it is critical to gather data, utilize modern tools, work collaboratively to explore cost sharing opportunities, and analyze results to develop strategies that confirm where undergrounding offers cost-effective solutions to improve the performance of the electric system.

Staff offers 11 recommendations to the Commission, transmission owners, and Michigan utilities as next steps for undergrounding and alternatives to undergrounding for the Commission's consideration. These recommendations are stated in the body of the report and summarized in the Conclusion and Recommendations section.

# Introduction

In late March 2025, northern Michigan experienced a catastrophic ice storm with reports of over one inch of ice causing widespread power outages and difficult restoration conditions. Governor Gretchen Whitmer declared a state of emergency on March 31, 2025[1] which was later expanded on April 1, 2025[2] to include a combined 12 northern Michigan counties. The Michigan Public Service Commission (MPSC or Commission) held a public forum in Gaylord on May 21, 2025, to review the response to the storm and solicit input from customers affected by the storm. The Commission and Commission Staff (Staff) heard directly from customers impacted by the storm, and a key theme emerged for improving the performance of the electric distribution system during severe storms – undergrounding electric lines.

On June 12, 2025, the Commission issued an order in MPSC Docket No. U-21388 directing Staff to 1) conduct a technical workshop on undergrounding and alternatives to undergrounding for reliability and resilience[3] improvement no later than September 30, 2025, and 2) file a report with recommended next steps addressing undergrounding and alternatives to undergrounding for the Commission's consideration no later than October 31, 2025. The Undergrounding Technical Workshop (Workshop) took place over two separate days – September 17th and September 19th – and included presentations and discussion surrounding what is happening now (Day 1) and solutions for the future (Day 2). Workshop details, including agendas, presentations, and recordings, can be found on the Commission's Event Calendar and are linked below.

Day 1 – What is Happening Now?

Day 2 – Solutions for the Future

## Undergrounding Rules and History

The Commission has established administrative rules for undergrounding electric lines and explored the benefits and costs of undergrounding through prior MPSC cases. The mandatory undergrounding provisions of the Underground Electric Lines Rules[4] took effect on January 1, 1971, while the contribution in aid of construction (CIAC) provisions took effect when the rules were published in 1979. These rules prescribe undergrounding requirements for extensions of residential, commercial, and industrial lines and requirements for who bears the cost of underground facilities based on certain situations. Generally, if the customer options to

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[1] Executive Order 2025-2.
[2] Executive Order 2025-3.
[3] The Commission adopted the Federal Energy Regulatory Commission (FERC) definition of energy resilience in its December 21, 2023, order in MPSC Docket No. U-21388 to mean "[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."
[4] Michigan Administrative Rules R 460.511 – 460.519.

underground facilities, there is a CIAC paid for by the customer. If the customer options to underground existing overhead facilities, the customer shall pay the depreciation costs of existing overhead facilities, plus the cost of removal (less salvage) and make a CIAC. Alternatively, when the utility options to underground facilities or when required by ordinance in business districts, the utility bears the costs. These rules demonstrate that there is a level of cost sharing such that the utility does not bear all costs, unless the utility options to underground which involves passing on costs to other utility ratepayers.

The Commission has issued orders and explored undergrounding of the electric distribution system in previous MPSC cases.

In MPSC Docket No. U-15279, the Commission ordered Staff to study the costs and benefits of extending the Commission's existing underground line policy and provide additional information including, but not limited to, quantifying the degree to which safety and security of which systems can be improved, and examine the difference in storm restoration times compared to overhead facilities. Staff filed its report on November 21, 2007. Among the various findings in the report, Staff pointed out that aesthetics are an important benefit, yet difficult to quantify, and cost sharing could help lower costs and make it so all costs are not transferred to the entire utility system's ratepayers. Staff did not recommend extending the Commission's underground line extension policy and stated that undergrounding for the sake of reliability did not appear to be economically justified.

The Commission also gathered benefit and cost information associated with moving overhead lines underground in its August 25, 2021, order in MPSC Docket No. U-21122 by directing investor-owned utilities to provide cost, reliability, and safety details and asking utilities to provide the following:

1) A breakdown of the total cost to move a typical overhead back lot-constructed line and overhead front lot-constructed line underground, including a high, low, and average cost estimate depending on the varying circumstances encountered.
2) The difference in cost of maintenance of an overhead back lot, overhead front lot, and underground electric line, on an average annual basis.
3) The average measured reliability of an underground line compared to a comparable back lot and front lot overhead electrical line.
4) A comparison of the average rate and severity of safety incidents that occur both to the public as well as to utility workers associated with underground lines, overhead front lot lines, and overhead back lot lines.

The responses to the aforementioned requests filed to the docket generally revealed that construction costs to move overhead to underground ranged from $9.43 - $202.58 per foot and was highly variable depending on the system phase (single, 3-phase, etc.), installation type (plow, bore, direct-burial, etc.), cable type, soil type, and location of the lines. Maximum reported values suggested costs up to $2-3 million per mile in urban areas. To the second request, most utilities with data reported that underground maintenance costs are lower than overhead maintenance costs. The reported reliability improvements for overhead versus underground generally revealed reliability improvement for underground lines under both frequency and duration of outages. Safety incident information was often not available or inconclusive, however, available information generally revealed that incidents involving the underground system are related to dig-ins and pad mount transformer strikes, with more severe safety incidents associated with the overhead system.

In MPSC Docket No. U-20147, the Commission issued an order on September 8, 2022, providing guidance following responses to the following question posed in MPSC Docket No. U-21122:

> 6. Are there potential utility pilots or industry best practices that can improve customer safety and reliability by moving overhead lines on specific circuits or in segments of the electric distribution system underground at reasonable costs?

The Commission's guidance on the matter expressed interest in utilities to submit targeted undergrounding pilot proposals in either future rate cases or future distribution system plans (DSPs) using the objective criteria for pilots in MPSC Docket No. U-20645.[5] The Commission later, through its July 10, 2025 order in MPSC Docket No. U-20147, established DSP filing guidelines that involve the utility detailing efforts to address undergrounding improvements in Exhibit A, Section IV (h) (v).

The Commission also ordered an independent third-party audit of the DTE Electric (DTE) and Consumers Energy (Consumers) electric distribution systems. The Liberty Consulting Group (Liberty) issued recommendations suggesting the utilities analyze results of the pilots before expanding undergrounding programs. Liberty also pointed toward lower maintenance costs for the underground system, as detailed later in this report under Day 1 of the Workshop.

The Commission's DTE order issued on June 12, 2025, in MPSC Docket No. U-21305 considers prior orders regarding undergrounding and states:

> The Commission agrees with Liberty's recommendation and with the Attorney General's comment that the company should clearly define the criteria it uses to determine the viability of undergrounding in various contexts, including a clear BCA that compares undergrounding with leaving the lines overhead.
>
> *          *          *
>
> The Commission also stated that it "strongly encourages the company to better develop the business case for undergrounding—both at the pilot phase and for scaled deployment—and to continue to develop processes, gain efficiencies, and find synergies where possible to lower costs and to

[5] MPSC Docket No. U-20645, filing #U-20645-0015.

incorporate updated costs and better quantified benefits into its BCA/BCR [benefit-cost ratio] to support future cost recovery, considering projects on a full-scale basis."[6]

Similarly, the Commission's Consumers order issued on June 12, 2025, in MPSC Docket No. U-21305 states:

> The Commission remains skeptical of the costs of the undergrounding pilot at scale but is not opposed to further consideration of the project. More specifically, the Commission finds that additional evidence, including a BCA, is necessary to fully evaluate the proposed undergrounding and how it compares with other potential pathways to improved reliability performance, and encourages the company to review the results of its pilot and future plans with the Staff, including the circuit selection criteria.[7]

The Commission undoubtably encourages pilots which present a benefit-cost analysis (BCA) to support the future undergrounding investment strategy and appears to be optimistic about the potential benefits undergrounding programs may offer.

## Undergrounding Technical Workshop – Day 1

MPSC Staff facilitated the September 17, 2025 and September 19, 2025 Workshops, including several subject matter experts involved as guest speakers. Day 1 focused on what is happening now with presentations from Staff, Argonne National Laboratory (Argonne), DTE, Consumers, Alpena Power Company (Alpena), Great Plains Institute (GPI), and SOO Green HVD Link (SOO Green).

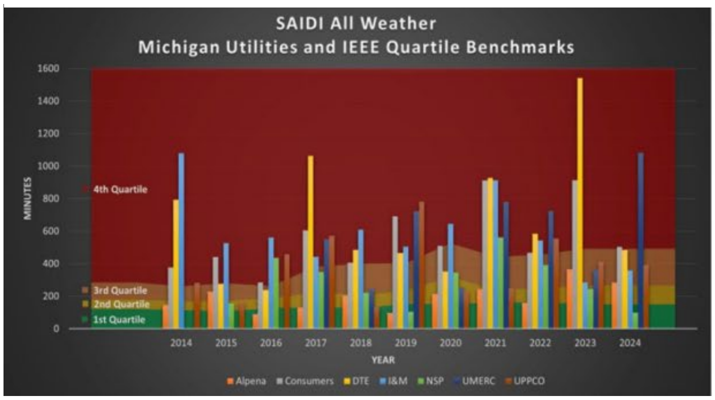
### Michigan Reliability and Storm Activity – Staff *(Appendix I, pp. 5-20)*

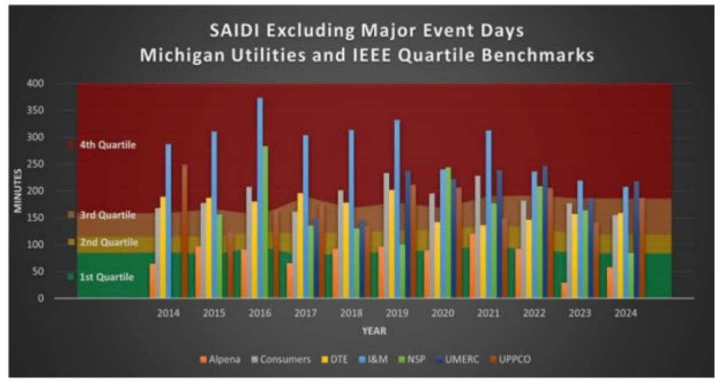
Staff's presentation offered context to the reliability performance of Michigan utilities, including and excluding major event days (MEDs), of the electric distribution system in Michigan by referencing the MPSC's Distribution System Reliability Metrics Webpage. Staff's presentation offered several graphs from this webpage to show system average interruption duration index (SAIDI), system average interruption frequency index (SAIFI), and customer average interruption duration index (CAIDI) data over the past 10 years while applying the IEEE Distribution Reliability Working Group benchmarking to establish quartiles. The webpage graphs

[6] MPSC Docket No. U-21305, June 12, 2025 Order, DTE, pp. 34-35.
[7] MPSC Docket No. U-21305, June 12, 2025 Order, Consumers, p. 27.

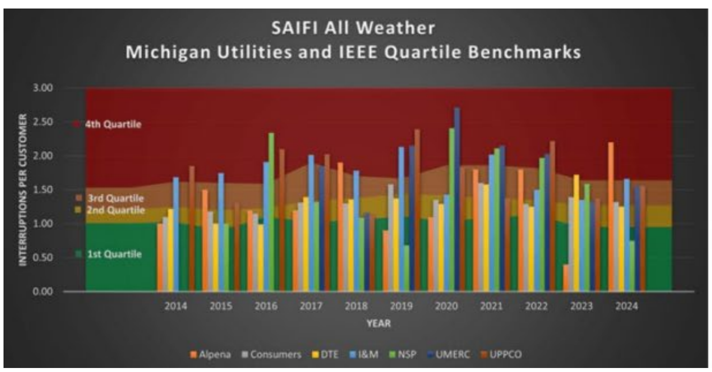
shown in Graphs 1-3 below demonstrate that most Michigan customers experience 3rd-4th quartile SAIDI and CAIDI and 2nd-3rd quartile SAIFI.

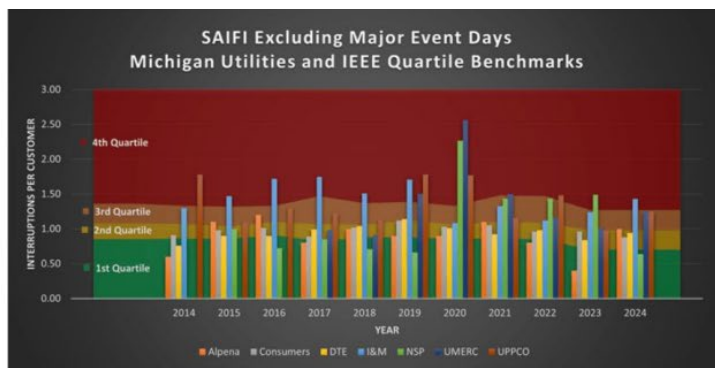
## Graph 1: Michigan Utility SAIDI



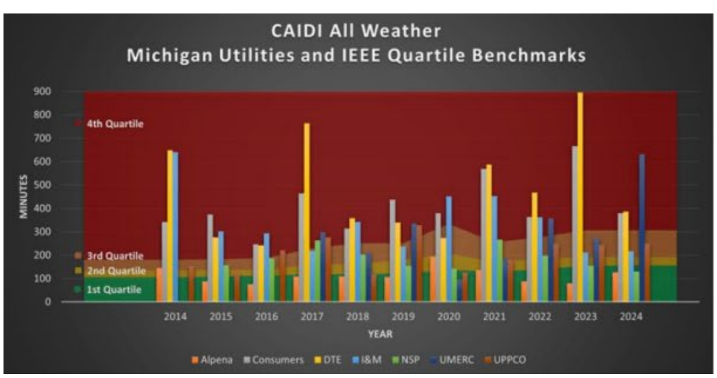



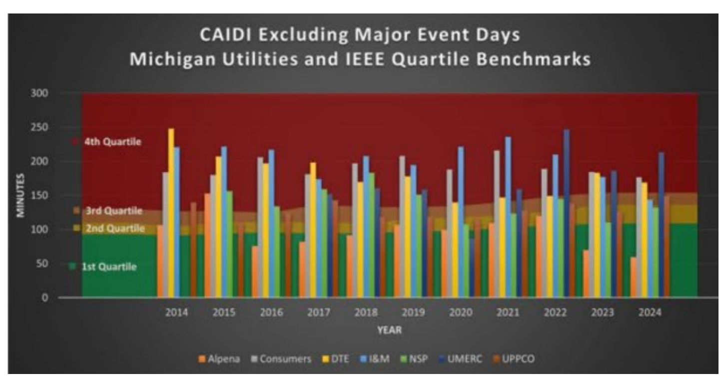

## Graph 2: Michigan Utility SAIFI




## Graph 3: Michigan Utility CAIDI



Staff further summarized findings from the Liberty audits of the DTE and Consumers system in MPSC Docket No. U-21305, which show that 1) operations and maintenance (O&M or OpEx) expenditures have increased over the past five years due to two key drivers - tree trimming (vegetation management) and storm restoration spending[8], 2) maintenace spending on the underground system is far less, considering the percentage of the systems located underground, than what is spent to maintain the overhead system. Through its reports, Liberty issued conclusions and recommendations to support undergrounding pilots and expansion, as necessary, after careful evaluation of costs and benefits; maintaining a 4-5 year tree trim cycle; and re-baselining restoration budgets to produce estimates that consider expected needs and balance company and customer interests in addressing volatile restoration costs. The Commission's order issued on June 12, 2025, largely supported Liberty's recommendations in the areas of undergrounding programs, tree trim frequencies, and storm restoration costs. The Commission's actions on these matters offer a strong indication that undergrounding analysis is important with a potential opportunity for improvement, and O&M tree trimming expenditures will likely either increase in the short-term or remain higher than historical spending levels.

Staff concluded its session with an overview of storms that occurred over the past several years along with a summarization of recent Commission investigations and actions initiated by storm activities in MPSC Docket Nos. U-17542 (2014), U-18346 (2017), U-20169 (2018), U-20464 (2019), U-21122 (2021), U-21305 (2022), and U-21388 (2023 and 2025).

Table 1 represents the approximate characteristics of recent storms.

***Table 1 - Michigan Storm Characteristics***

| When | Type | Characteristics | Customer Outages (~) |
|---|---|---|---|
| Dec. 2013 | Ice | 0.75" ice with 10-20 mph wind | >640,000 |
| March 2017 | Wind | 30 mph sustained with 60+ mph gusts | 1,108,000 |
| May 2018 | Wind | 70 mph gusts | 300,000 |
| Jan. 2019 | Polar Vortex | -25° F temps | >400,000 |
| Aug. 2021 | Wind | 70+ mph wind gusts | 892,000 |
| Aug. 2022 | Wind | 70+ mph winds | 462,000 |
| Feb-March 2023 | Ice | 0.25-0.65" ice, 6" snow, 35-45 mph wind | >1,400,000 |
| March-April 2025 | Ice, Wind | 0.5-1.5" ice and tornadoes | >756,000 |

[8] MPSC Docket No. U-21305, DTE Part I, pp. 66-68 and Consumers Part I, pp. 60-61.

**Takeaways:** 1) Opportunities to improve distribution system performance exist. 2) Potential opportunity to expand undergrounding of the electric system. 3) Changing landscape with increasing line clearing maintenance spend and maintenance storm response spend associated with the overhead system which may strengthen the business case for undergrounding. 4) Extreme weather events (ice, snow, wind, etc.) are not uncommon in Michigan.

## Extreme Weather Data – Argonne National Laboratory *(Appendix I, pp. 21-39)*

Argonne presented on the importance of applying extreme weather data and statistics through the use of artificial intelligence (AI) and machine learning (ML) to help make decisions and inform risk mitigation efforts. The vulnerability equation (Figure 1) was presented which sets a firm foundation for how weather exposure impacts the overall vulnerability of the system.

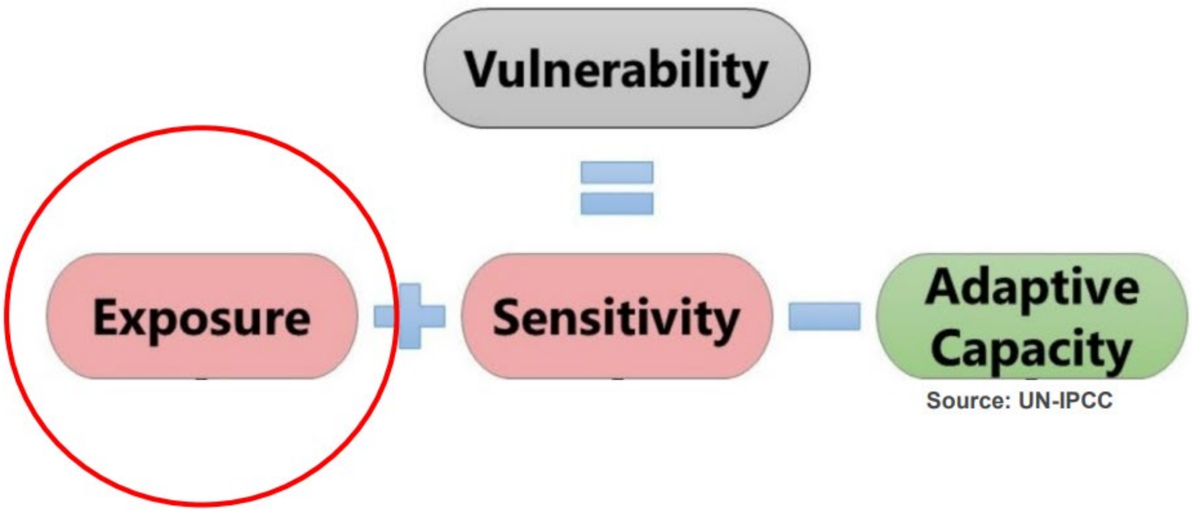



***Figure 1 - Vulnerability Equation***

Content was shared surrounding weather modeling, computing resources, and data that can be used to assess future weather impacts including temperatures and flooding. The ClimRR Portal[9], developed by Argonne in close collaboration with AT&T and the United States (U.S.) Department of Energy's Grid Deployment Office (GDO), was shared as an example of a central hub to explore future hazards data.

**Takeaways:** 1) With experienced extreme weather, serious consideration should be given to resilience solutions such as undergrounding. 2) Increasingly sophisticated weather data and forecasting tools are becoming more available and actionable.

[9] ClimRR Webpage: https://climrr.anl.gov/

**Recommendation**: Staff recommends the Commission direct utilities to identify Michigan-specific risks and provide detail in future DSPs about how the Michigan-specific risks were evaluated in weather modeling, forecasting tools, and used to inform future planning efforts.

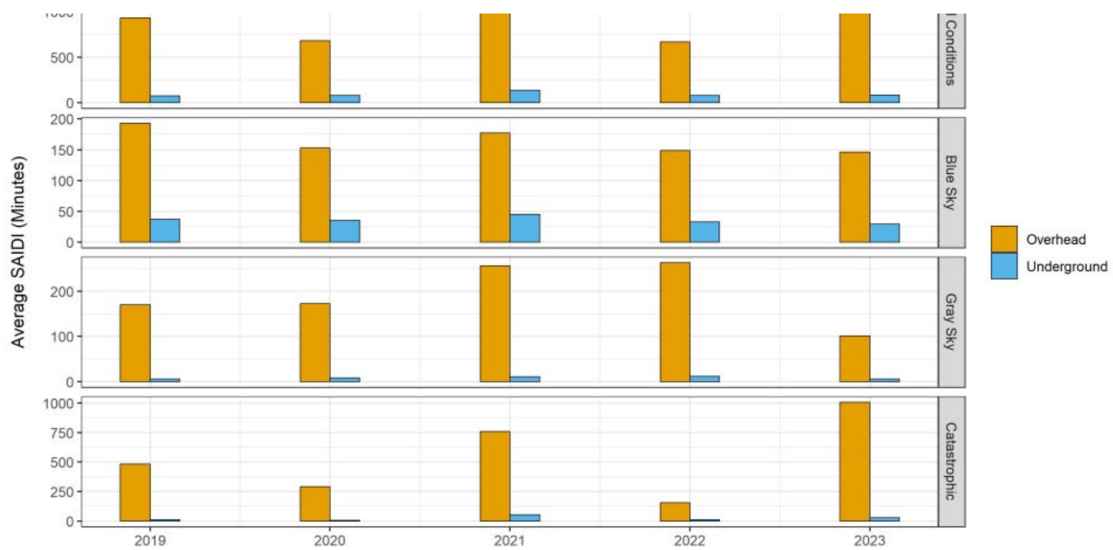
## Reliability Improvements from Undergrounding – Staff *(Appendix I, pp. 40-61)*

Next, Staff shared five existing undergrounding studies: Edison Electric Institute Study (2013), Shaw Consultants Study (2010), NEI Electric Study (2009), twentytwenty LLP Study (2019), and Electric Power Research Institute Study (2015) which generally suggest that undergrounding decreases outage frequency and slightly increases outage duration.

Staff took a deep dive into the data used for its targeted undergrounding BCA study (Study) in Michigan using Consumers' data (draft paper is attached as Appendix III of this report) on Day 1 to share what Michigan-specific data reveal when applying the blue sky[10], gray sky, and catastrophic definitions from the Commission's Service Quality and Reliability Standards for Electric Distribution Systems[11] .The Study itself was presented by Staff on Day 2 as articulated later in this report. The data suggest underground infrastructure offers SAIFI and SAIDI gains. CAIDI undergrounding performance is condition dependent with general gains under gray sky and catastrophic conditions and losses under blue sky conditions.

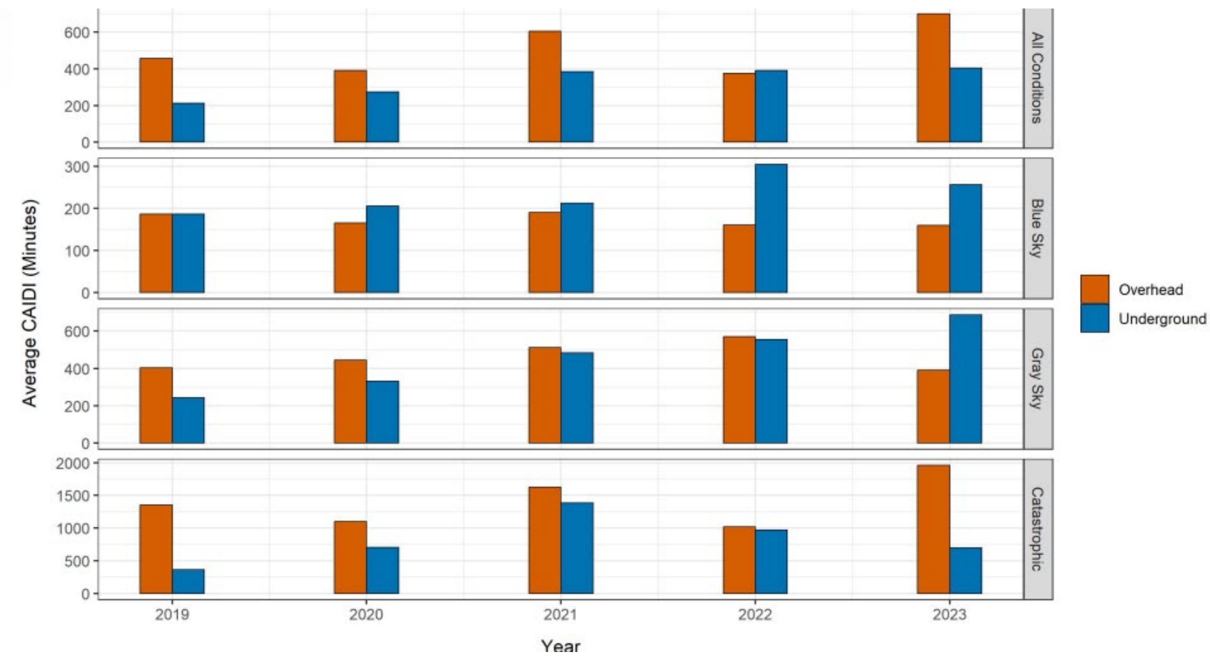
Graphs 4-6 below show the gains and losses based on the data used in Staff's Study.

**Graph 4: Overhead vs Underground SAIDI by Condition**

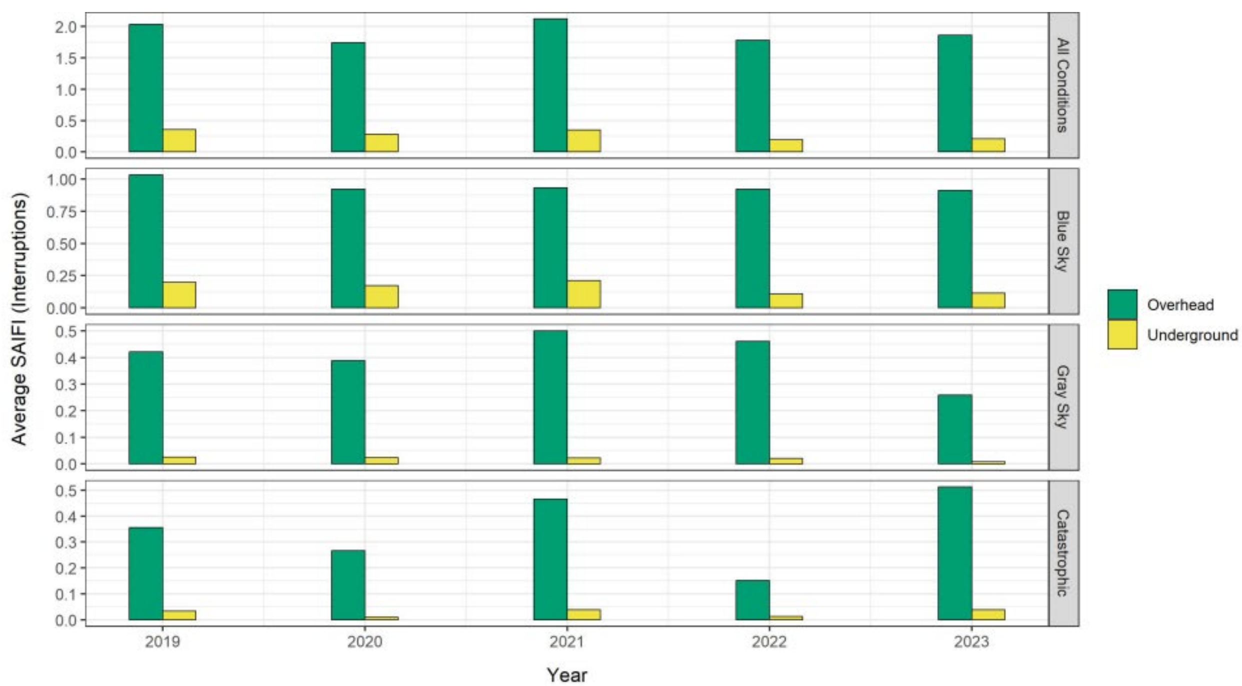



[10] For purposes of this report, "blue sky" is the equivalent definition of "normal conditions" as defined in the Service Quality and Reliability Standards for Electric Distribution Systems to mean conditions that result in sustained interruptions for 1% or less of customers.
[11] Michigan Administrative Rules R 460.701 – 460.752.

### Graph 5: Overhead vs Underground CAIDI by Condition



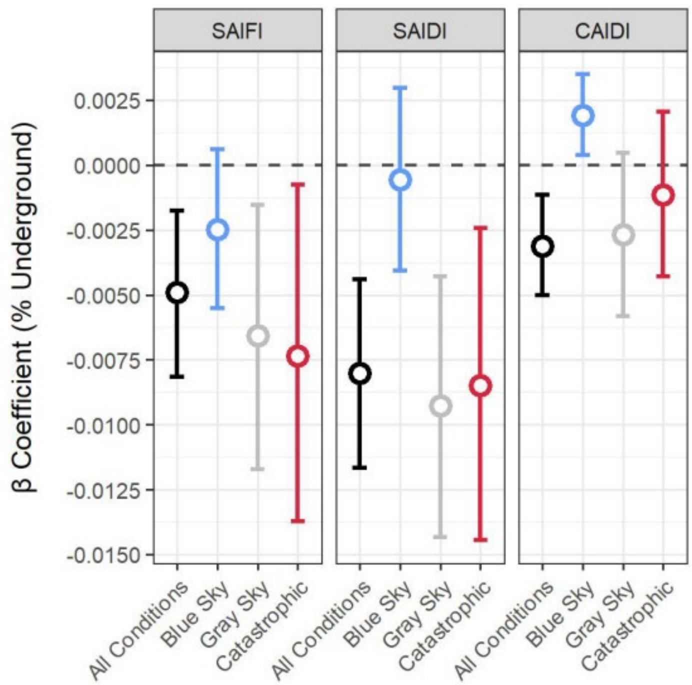

### Graph 6: Overhead vs Underground SAIFI by Condition




Statistical analyses using beta coefficients to inform reliability impacts of undergrounding were applied to assess the effect of undergrounding on SAIDI and

SAIFI while controlling for other variables such as tree density and customer counts. The reliability impacts of undergrounding in Michigan under different outage conditions are represented below in Graph 7.

**Graph 5: Underground Reliability Impacts**




**Takeaways:** 1) The benefits of undergrounding are well-established, particularly with regard to reducing outage frequency (SAIFI). 2) The concern that undergrounding results in disproportionately long outages appears overstated – data shows SAIFI gains typically outweigh any CAIDI losses, CAIDI can improve under storm conditions, and regression models support these findings. 3) Weather-condition differentiation is critical to understand performance. Reliability and resilience metrics should be tracked at the circuit level and reported by weather type (blue sky, gray sky, and catastrophic), ideally on an annual basis.

**Recommendation**: Staff recommends the Commission consider acquiring, no sooner than 2027, annual reliability data (SAIDI, SAIFI, and CAIDI) from utilities through the MPSC Docket No. U-21122 reporting template broken down by both weather type (blue sky, gray sky, and catastrophic) and circuit. Utilities should utilize this data to support system improvement investment decisions. Staff and utilities should work to update the template if the Commission directs this additional reporting to allow utilities to report annual data.

## Undergrounding In Michigan – DTE, Consumers, and Alpena

(*Appendix I, pp. 62-98*)

DTE, Consumers, and Alpena were part of a hybrid panel (all offered presentations and were asked panel questions) and shared their current and planned undergrounding strategies while also offering some valuable insight into the results of pilots and performance of portions of the system that have been undergrounded.

DTE discussed why undergrounding is important and the benefits of undergrounding. Cost and reliability improvement values were provided, which varied based on the portion of the system that was undergrounded (backbone vs. laterals vs. secondary/services). The Company then discussed its Appoline and Buffalo-Charles pilot experiences before sharing information gained that indicates undergrounding costs of ~$3,000,000 per mile between the two projects. DTE reported obtaining easements and property rights required extensive planning, accessibility challenges that existing structures pose in work areas, and the difficulty running services to meters located at the rear of the home. DTE concluded by stating it will work to incorporate the less tangible safety and resilience benefits into its BCA model; continue to learn through pilots; and explore technologies, standards, and construction methods to reduce undergrounding costs.

Consumers presented the basics of its system and began by outlining its plan to rejuvenate smaller cable before sharing that rejuvenating existing cable costs $32 per foot compared to replacement at $80 per foot. The cable rejuvenation warranties the cable up to 25 years from the date of rejuvenation to extend the life of the assets. Next, Consumers discussed its undergrounding pilots, involving eight different circuits. Consumers applied the following selection criteria designed to target areas that would benefit most from undergrounding, including:

1) Will be single-phase.
2) Have had at least one outage in the last 24 months.
3) Serve between 10 and 100 customers
4) Operated at one of the three standard wye voltages.
5) Not be considered for another reliability project.
6) Have an average CAIDI of 600 minutes or more.
7) Have a load after installation of 36% or less of the ampacity of the newly installed facilities.
8) Located in an area of dense trees.
9) Not supply an overhead system.

The costs varied based on location and circuit, but the average cost was between approximately $398,000 per mile (excluding the costliest project) and $443,000 per mile (including the costliest project). The highest-cost project was $902,000 per mile which involved working near busy roads, parks, and waterway crossings (requiring boring) while the lowest-cost project was $132,000 per mile which involved 100% plowing (no boring required), a rural area, and work away from busy roads. The pilot costs were lower than the expected costs of undergrounding filed in MPSC Docket

No. U-21122 in 2021 which were reported as $626,000 per mile. Consumers concluded its presentation with a look at alternatives to undergrounding – aerial spacer cable, tree wire, and keeping existing overhead. The alternatives comparison was broken down by utility cost test (UCT) and societal cost test (SCT) and demonstrated that, when comparing undergrounding at scale using the UCT, aerial spacer cable and tree wire were nearly equivalent while keeping existing overhead offered ~$1,500,000 less in present value revenue requirement (PVRR). However, when applying the SCT, undergrounding at scale had a better benefit-cost ratio (BCR) when compared to alternatives.

Alpena's presentation offered an overview of system characteristics and highlighted reliability challenges before discussing a specific undergrounding project. The project focused on undergrounding existing overhead primary along with some services involving areas that were known for repetitive outages and heavily wooded areas with rocky soil. The undergrounding project involved areas with a full easement where ground to sky tree trimming did not have a significant impact on outages. The project converted overhead to underground from 2011 to 2023 with an average cost per mile less than $100,000 (~$18 per foot). Challenges and cost drivers included rocky soil conditions and right-of-way access. The underground circuit has resulted in a reduction in outage minutes excluding MEDs.

*Additional Staff Commentary*: Staff is also aware of ongoing circuit conversion projects and plans to upgrade portions of the electric distribution system to modern circuit voltages and reduce the number of non-standard voltages within the system. These conversion projects offer a prime opportunity for utilities to collaborate with local communities/customers and other infrastructure owners to determine whether undergrounding portions of the circuit makes sense.

Further, on the matter of utility collaboration and cost sharing opportunities, Staff is aware of an ongoing project where a Michigan utility is in the process of undergrounding ½ mile of existing overhead infrastructure using city and Michigan Department of Transportation (MDOT) funds related to a shared-use path (a 10-foot wide sidewalk/bicycle path) that MDOT plans to install within the road right-of-way after the project is complete.[12] This is one example of the opportunities that exist to reduce cost burdens to ratepayers and coordinate with local communities and organizations.

Given the generally high cost of undergrounding, it is essential to consider alternative investment options that may achieve reliability and resilience improvements at lower costs. Within a BCA framework, cost-effectiveness remains a key goal—measured through BCRs that compare benefits per dollar spent across different options.

A key challenge identified by Staff following the Workshops is determining which options qualify as parallel alternatives. Staff defines a parallel alternative as one that delivers an identical system outcome, except where differences are fully reconciled

[12] Consumers burying power lines in downtown Midland.

through value streams within the BCA. Once those value streams are accounted for in the BCA results, the outcomes are effectively equivalent.

For example, if an undergrounding program includes capacity expansion to a higher voltage and an inspection program does not, the value of that capacity expansion should be explicitly included to ensure a fair comparison.

Providing a structured and transparent list of alternatives will help guide decision-making and facilitate more meaningful cost-effectiveness comparisons—ensuring that investment evaluations remain grounded in equivalent system outcomes.

**Takeaways:** 1) Information is essential for identifying and prioritizing undergrounding projects – "better data drives better decisions." 2) Costs vary widely depending on geography and project type - greater transparency is needed from pilot projects, especially around what drives higher costs and how they can be reduced. 3) Customer engagement should begin well before construction. 4) Cable rejuvenation is important to consider as a way to extend the life of underground assets (e.g., Consumers' extending the life of assets 25 years on top of ~40 year baseline assumption). 5) Pilot projects generate valuable lessons and should be encouraged to include both successes and challenges. 6) Opportunities to underground may exist under other utility programs (i.e. conversions) in addition to potential targeted undergrounding programs. 7) Alternatives to undergrounding must be better understood and offer "apples-to-apples" comparisons– what parallel alternatives exist? What are their costs? How do their reliability/resilience outcomes compare?

**Recommendations**: 1) Staff recommends the Commission direct utilities to either complete pilot projects that align with the orders in MPSC Docket No. U-20147[13] and MPSC Docket No. U-21305[14] using the objective criteria for pilots in MPSC Docket No. U-20645 or conduct a comprehensive analysis to evaluate whether an undergrounding program is a cost-effective solution to improve performance of the electric distribution system. The primary objectives of these efforts must be aimed to determine if an undergrounding program is a cost-effective solution to improve electric distribution system performance, and if so, to develop an undergrounding strategy. Utility pilot and analysis findings, lessons learned (good and bad), and undergrounding strategy should be presented in future DSP filings and rate cases (where cost recovery is requested) and leverage economies of scale. 2) Staff recommends the Commission direct utilities to explore the potential of cable rejuvenation practices as a way to extend the life of existing underground cables and present their findings and long-term strategy in a future DSP filing. 3) Staff recommends the Commision direct utilities to develop and implement criteria in the next DSP filing designed to explore and take advantage (if appropriate) of undergrounding opportunities that exist during system conversion and other major infrastructure upgrade projects.

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[13] MPSC Docket No. U-20147, September 8, 2022 Order, p. 73.
[14] MPSC Docket No. U-21305, June 12, 2025 Order, DTE, pp. 34-35 and MPSC Docket No. U-21305, June 12, 2025 Order, Consumers, p. 27.

## Undergrounding Transmission – Great Plains Institute and SOO Green HVDC Link (*Appendix I, pp. 99-130*)

A transmission undergrounding session offered insight into community engagement, permitting, and economics considerations. GPI discussed the different types of opposition from transmission projects and broke down the opposition into four areas – harm, need, consultation, and compensation. Next, the presentation further explained that transmission projects can face significant opposition because there is either real or socially-perceived harm. Some examples include inhibiting transportation corridors, the lack of aesthetic appeal, decreased property values, and concerns about public safety. Transmission undergrounding can significantly reduce the real or perceived harms of transmission projects by maintaining the natural landscape aesthetic in a preserved or congested area, reducing land use and noise pollution where land is limited or many people are in close proximity to significant noise, maintaining property values and preserving dwellings in highly congested areas that may otherwise be in an overhead right of way, and eliminating or reducing public concerns about safety related to electromagnetic fields (EMF).

SOO Green focused its presentation on permitting and economics by discussing the details of a 350+ mile HVDC transmission underground project, identified as a rarity in the United States. The permitting, environmental reviews, and capital (financial, human, social, and natural) accounting were all presented for this project. The presentation concluded that while longer-distance underground projects tend to be more cost-effective in the transmission space, the break-even mileage is showing a reducing trend.

*Additional Staff Commentary*: The MPSC does not regulate transmission owners' construction of new transmission lines. However, Public Act 30 of 1995 (PA 30) does provide the MPSC with transmission siting authority. PA 30 requires an analysis of transmission routes that includes consideration of proposed and alternative routes, estimated costs, information supporting the need for the transmission line, estimation of quantifiable and non-quantifiable public benefits, and potential effects of the proposed transmission line on public health and safety. Transmission siting also typically utilizes criteria that includes engineering, environmental, and social impacts of the project. Traditionally, the bulk electric system is maintained in such a way to offer robust reliability performance. Transmission underground projects are driven by engineering, environmental, and social impacts, not reliability performance.

Due to the expected increase in transmission construction within Michigan, the Commission issued an order on July 10, 2025, in MPSC Docket No. U-21930[15], directing Staff to develop PA 30 voluntary application guidelines. These guidelines are intended to facilitate outreach, create consistency in applications, and facilitate data transfer to Staff and other intervening parties.

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[15] MPSC Docket No. U-21930, July 10, 2025 Order, p. 4.

**Takeaways**: 1) Traditionally, transmission is built robustly and performs at a much higher reliability as compared to distribution infrastructure. Therefore, transmission undergrounding remains niche and is unlikely to be widely adopted in the near-term. 2) Although transmission undergrounding is not the norm, the rare transmission undergrounding projects that do occur are typically driven by siting constraints. Although longer undergrounding projects tend to be more cost-effective, even those remain cost prohibitive and are undertaken for other reasons.

**Recommendation**: Staff recommends that transmission owners in Michigan continue to consider and evaluate the benefits of undergrounding infrastructure when a transmission line creates significant environmental and social impacts. Transmission owners should consider the appropriateness of undergrounding transmission within both PA 30 of 1995 applications and for existing lines when significant maintenance or rebuilds are necessary.

## Undergrounding Technical Workshop – Day 2

Day 2 of the Workshop focused on solutions for the future with presentations from Lawrence Berkeley National Laboratory (LBNL), Staff, Synapse Energy Economics (Synapse), Citizens Research Council of Michigan, Wisconsin Public Service (WPS), and GridCo Partners (GridCo).

### Valuing Investments in Reliability: A Case Study of Undergrounding – LBNL *(Appendix II, pp. 5-37)*

LBNL started the day with helpful content and discussion surrounding the information needed to value grid investments – costs, benefits (non-monetized and monetized), and other. The Interruption Cost Estimate (ICE) Calculator was discussed as the leading and only publicly available tool for estimating the customer impacts of power interruptions. Updates and upgrades to ICE Calculator 2.0 were released on April 28, 2025. LBNL discussed undergrounding research it performed to explore interest in undergrounding and factors that impact long-term reliability of the electric system. This research performed by LBNL demonstrates that an increase in percentage of underground lines has a statistically significant correlation with improved reliability. In addition, the research found that there is little to no analysis quantifying both the benefits and costs of improving electric utility reliability/resilience. LBNL presented a study in Texas aimed to determine if the state should underground all transmission and distribution lines. The Texas study revealed the PUC of Texas should not consider broadly mandating undergrounding when lines have reached the end of their useful life, yet concluded that policymakers should consider requiring facilities to be undergrounded in places where:

1) There are a large number of customers per mile
2) There is an expected vulnerability to frequent and intense storms
3) There is the potential for underground installation economies of scale

4) Overhead line easements are larger than underground line easements

Similarly, LBNL also shared an analysis framework and study in Cordova, Alaska (Cordova) to help determine if Cordova should underground all transmission and distribution lines. The conclusion from the Cordova study suggested 1) the assumed costs of undergrounding distribution and transmission far exceed the benefits from avoided outages, however, undergrounding can improve reliability and comprehensive benefits can exceed the all-in costs, 2) cost effectiveness depends on age and lifespan of existing overhead infrastructure, whether economies of scale can be achieved, the vulnerability of locations to severe and frequent storms, and the number of customers per mile, and 3) an analysis framework could be adopted to evaluate economics of other strategies to improve grid reliability and resilience.

**Takeaways**: 1) Publicly available tools can help quantify reliability and resilience, including the phased developments of the ICE Calculator 2.0, now funded for national expansion. 2) The value of undergrounding lies primarily in reliability and resilience, and ignoring these benefits makes the economics unfavorable. 3) Mandating undergrounding is not advisable as benefits depend on project-specific traits. 4) The Texas case study shows well-specified, well-selected projects can yield net benefits.

**Recommendation**: Staff recommends the Commission issue guidance that requires utilities to appropriately consider reliability impacts when analyzing proposed or potential projects or conducting BCAs. As the ICE Calculator 2.0 is, by default, the industry standard for quantifying the economic impacts of reliability events, the Commission should strongly encourage results of the calculator be at least one way reliability benefits are calculated for consideration in these analyses. Other methods may be considered but must be properly supported if used.

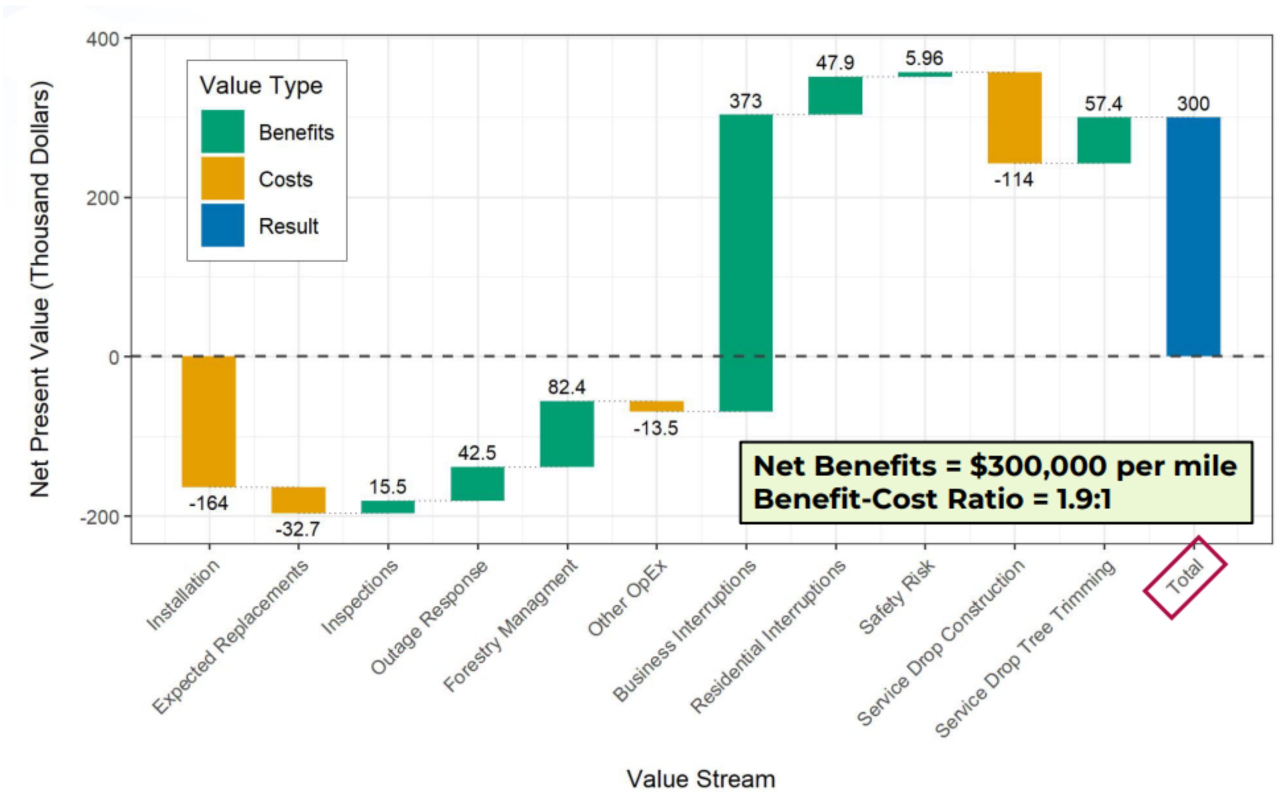
## Targeted Undergrounding Benefit-Cost Analysis in Michigan – Staff *(Appendix II, pp. 38-74)*

LBNL's case studies segue nicely into Staff's targeted undergrounding BCA study (Study) in Michigan using Consumers' data. Staff's Study was conducted to determine whether targeted undergrounding was reasonable. It was performing using a circuit-level BCA of overhead to underground conversions across Consumers' electric service territory. Staff's draft paper offers an overview of the Study and is provided as Appendix III of this report. [16] Staff's presentation started by covering the basics of a BCA and the fact that BCA is one of several decision-making tools that quantitatively weighs pros and cons while also acknowledging that attributing dollar values may be difficult and anything not explicitly included is given a dollar value of zero using the equation – benefits minus costs equal the net value.

[16] Supplementary information referenced in the draft paper is not finalized, and hence, not available for this report.

Staff then stepped through a review of each value stream and the results of its Study, indicating $300,000 per mile in net benefits and a BCR of 1.9:1. As evidenced in Graph 8 below, the benefits associated with business interruptions are a major contributor to the net benefits the Study showed. In fact, absent those benefits, the BCR would have been below one.

**Graph 6: Undergrounding Value Streams and Net Benefits**




Next, Staff presented the differences between a SCT and a UCT which indicate that a SCT considers the monetary value of reliability to customers based on losses during outages and safety whereas a UCT does not as shown below.

The presentation demonstrated the Study results vary based on the cost test applied as shown in Figure 2.

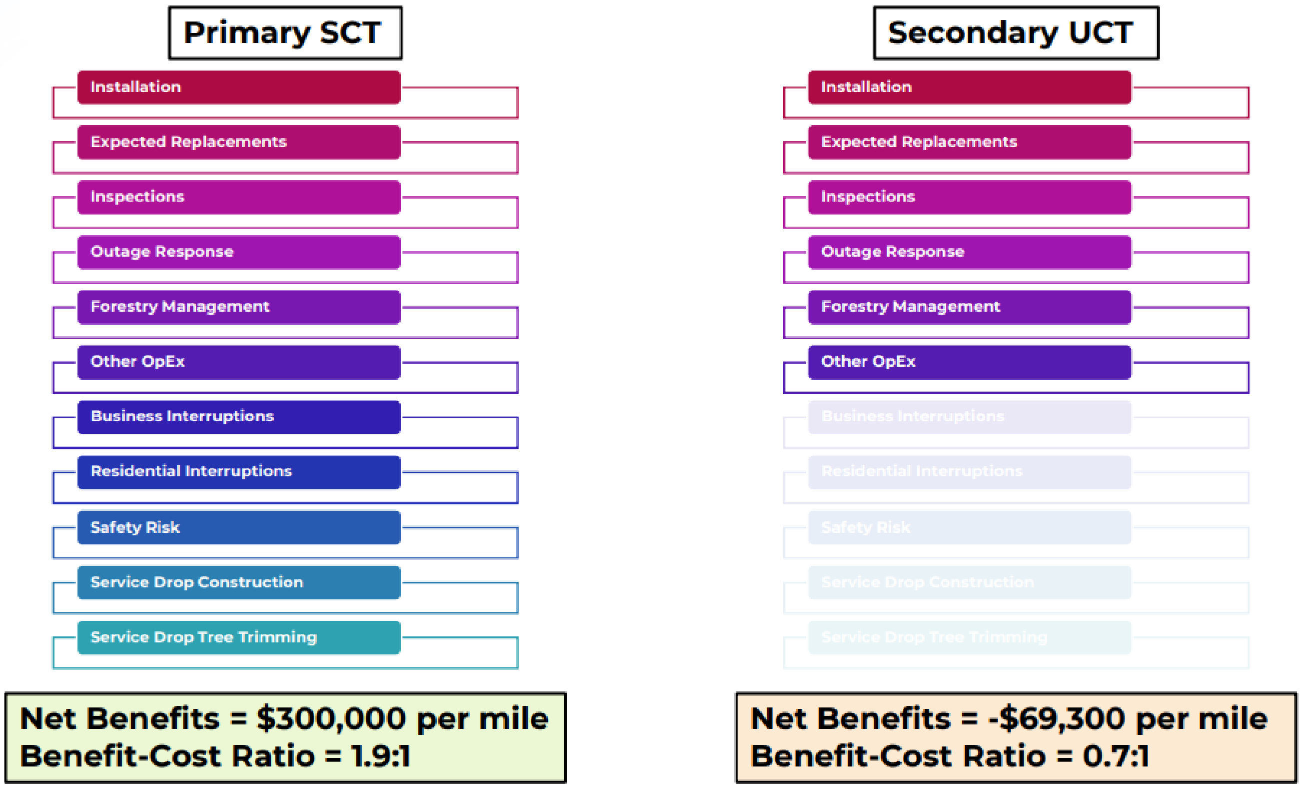



***Figure 2 – Cost Test Comparison***

Findings of the Study are outlined in detail in Appendix III. Staff's presentation on Day 2 of the Workshop demonstrates 1) benefits are primarily comprised of societal values and operating expenditures while the costs are primarily capital expenditures, 2) benefits are dominated by reliability and resilience improvements during storms, 3) the 10 percent of circuits most cost-effective according to the SCT results yield net benefits of over $1,500,000 per mile, 4) relative SCT performance of circuits is dominated by the reliability value streams (particularly business interruptions), 5) average net benefits per mile are positive in 92% of uncertainty simulations under the primary SCT, 6) results are most sensitive to reliability gains, extreme weather outcomes, and installation costs, and 7) selecting projects optimally yields a major advantage for cost-effectiveness.

*Additional Staff Commentary*: A clear takeaway from the Workshop was the importance of using BCA to understand the net value and cost-effectiveness of undergrounding conversion investments. To that end, Staff has identified value in developing principles and guidelines for conducting BCAs specific to undergrounding. Importantly, the Commission has already laid out principles in prior proceedings—most notably in MPSC Docket No. U-20898, which provided guidance on BCA for distributed energy resources (DERs) in the October 2023 order. Building on that foundation, Staff also finds that the translatable components of those guidelines could inform BCAs for undergrounding and other non-DER investments. However, there are non-translatable components that may require further guidance or development. Components of the BCA for DERs effort underway in MPSC Docket No. U-20898 that are transferable to underground and other non-DER BCA applications include:

- Pilot projects should be evaluated both as pilots and "at scale."
- The seven-step BCA methodology adopted in MPSC Docket No. U-20898 should apply, consisting of:
  - Gathering information and data
  - Describing the pilot at scale
  - Estimating costs for the pilot at scale
  - Identifying impacts
  - Calculating the present value of costs and benefits using the Jurisdiction-Specific Test (JST), UCT, participant cost test, total resource cost test (TRC), and potentially others
  - Providing recommendations

While not an exhaustive list, this provides a basis for the meaning of translatable components.

Another translatable component is the discount rate. In MPSC Docket No. U-20898, utilities proposed using the weighted average cost of capital (WACC) as the discount rate, but the Commission—consistent with the impact to customers rather than the utility—ordered that a lower, social discount rate be used. [17,18] This same approach should be applied in the context of at least SCT/JST undergrounding BCAs.

There are several non-translatable components when applying BCA guidelines designed for DERs to undergrounding.

For DERs, candidate value streams are identified in the National Standard Practice Manual (NSPM) for BCA for DERs. No equivalent resource currently exists for undergrounding or non-DERs. While some value streams—such as reliability and resilience—are intuitively applicable to both DERs and undergrounding, others are unique. Although their contribution to total value may be smaller compared to other factors, excluding them entirely would implicitly value them at zero. Other candidate value streams that are not contemplated by the NSPM in DER BCAs include wildfire risk mitigation (both physical and smoke-related damages) and particular savings related to the utility system, like outage restoration and vegetation management.

Therefore, Staff recommends that utilities develop a comprehensive list of potential value streams associated with BCAs for undergrounding and other types of projects. This list should be informed by prior work, including but not limited to Larsen (2016), Industrial Economics (2023), and Staff's draft Study provided as Appendix III.

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[17] MPSC Docket No. U-20898, October 12, 2023 Order.
[18] MPSC Docket No. U-20898, February 1, 2023 Joint Submittal, filing #U-20898-0022.

Another consideration is that certain undergrounding value streams may be more appropriately measured based on miles of line rather than kilowatt-hours (kWh) or kilowatts (kW) as many DER value streams are.

The Staff Study in Appendix III provides an illustrative example of this approach. The author evaluates undergrounding across Consumers' system at the circuit level, comparing per-mile undergrounding costs and benefits to the alternative of rebuilding overhead. The analysis simplifies real-world complexity by assuming all assessed components are ready for decision-making at present, but in practice, each component could be evaluated by considering undergrounding now or in the future versus rebuilding overhead now or in the future.

**Takeaways (from Staff's Study and presentation)**: 1) Targeted undergrounding approaches yield strong economic cases, with significant net benefits for the most promising circuits. 2) Transparency on value streams is critical – utilities should clarify how much of reported net benefits come from reliability and resilience vs. capital expenditures, operating expenditures, etc. 3) Several value stream takeaways:

- Undergrounding costs ~2.5 times more than overhead
- Historically shorter asset lifespan makes cable rejuvenation important to consider
- Outage response costs will rise with more extreme weather
- Proposed vegetation management cycles are shorter than historical, increasing costs
- Overhead inspection costs may rise but are often unaccounted for
- Service relocations can raise project costs by ~50%; cost-sharing mechanisms could be explored

4) Storm SAIFI and customer density are strong predictors of project benefits.

**Recommendation**: Consistent with the BCA for DERs effort underway as part of MPSC Docket No. U-20898 and Staff's recommendation in the previous section, Staff recommends that reliability should be considered in undergrounding BCA. Staff recommends the Commission direct utilities to apply all cost tests (SCT, UCT, TRC, participant cost test, etc.) to non-DER investments and offer transparency into their models through planning and outreach efforts that involve interested parties.

## How to Manage Risk on a Budget – Synapse *(Appendix II, pp. 75-97)*

Synapse discussed an overall framework for assessing safety and affordability that revolved around three elements – robust BCA, ratepayers having finite resources, and equity issues. Next, wildfire risk was explored with details on how these relate to Michigan. Based on the Federal Emergency Management Agency (FEMA) National

Risk Index data resource[19], Michigan's wildfire risk is 272 times less than that of California. Synapse also provided some undergrounding and affordability data from California utilities that touched on alternatives and cost-effectiveness considerations for potential investments.

**Takeaways**: 1) Grid investments must balance resilience and reliability with budget realities—risk management should be systematic and data-driven. 2) Alternatives to undergrounding, like covered conductor, warrant more investigation for wildfire and ice storm risk. 3) Collecting and comparing cost data remains critical; California's high costs highlight the need for further understanding what drives high costs. 4) Michigan-specific risks must be better understood; "weather" as a data point may be too broad.

**Recommendation**: Staff recommends the Commission direct utilities to identify and apply Michigan-specific risks associated with the uniqueness of the service territory for BCA and alternatives analyses. This approach will allow the utility to better understand mitigation solutions.

## Policy Solutions to Support Undergrounding – Citizens Research Council of Michigan *(Appendix II, pp. 98-109)*

The Citizens Research Council of Michigan offered its unique perspective on the potential to improve coordination with projects, sharing information that stand-alone projects to underground lines cost 3-10 times more than updating or 'hardening" projects. The presentation suggests legislative direction is needed to facilitate infrastructure coordination as a means of reducing costs by pooling together resources for multi-agency construction projects that avoid duplicating efforts. The Michigan Infrastructure Council's (MIC) Dig-Once Portal is recognized as an effort to improve coordination; however, it is voluntary.

Staff acknowledges that certain utilities in Michigan are involved with and use the MIC Dig-Once Portal. The Commission has also issued orders encouraging collaboration with customers and communities ahead of planned infrastructure work. In its July 10, 2025, order in MPSC Docket No. U-20147, the Commission ordered utilities to perform outreach activities aimed to help utilities identify problems, goals, and potential solutions before DSPs are filed.

**Takeaways**: 1) Opportunities exist that could help reduce costs by streamlining coordination, improving information-sharing, or easing easement management.

**Recommendation**: Staff recommends the Commission direct utilities, as part of their future DSP pre-filing outreach or other outreach efforts, to solicit

[19] Data Resources | National Risk Index

coordination and cost-sharing opportunities that may improve coordination and, ultimately, reduce the costs of undergrounding projects.

## System Modernization & Reliability Project in Wisconsin: Peer Utility Perspective– WPS *(Appendix II, pp. 110-122)*

WPS shared its undergrounding initiative known as the System Modernization and Reliability Project (SMRP). This project began in 2014 and was designed to address challenges of medium to high-density forests, the need for reliability improvements, challenges of maintaining vegetation clearances and hazard trees, and aging overhead lines. WPS conducted a survey prior to the project indicating that ~1/2 of its customers were willing to pay for improvements through increased rates. Program goals were to:

- install 1,000 miles of underground to replace overhead lines (additional 1,000 miles were added as a later phase of the project)
- deploy distribution automation (DA) equipment on 400 miles of existing 3-phase mainline
- improve reliability -SAIDI – at a reasonable cost
- reduce O&M expenses

SAIDI improvements, calculated on a company-wide basis, were presented as reflected in Table 2:

***Table 2 - WPS SMRP Reliability Improvements***

| | Year of Installation | | | | | |
|---|---|---|---|---|---|---|
| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
| Pre-SMRP average SAIDI (minutes) | 22.84 | 21.09 | 21.67 | 22.83 | 18.61 | 23.02 |
| Post-SMRP average annual SAIDI (minutes) | 0.49 | 0.36 | 0.43 | 0.59 | 0.46 | 0.12 |
| Improvement (minutes) | 22.35 | 20.72 | 21.24 | 22.24 | 18.15 | 22.90 |
| Improvement (%) | 98% | 98% | 98% | 97% | 97% | 99% |

Project work started two years prior to construction, involving extensive coordination with U.S. Army Corps of Engineers, State Historic Preservation Office, Wisconsin Department of Natural Resources, U.S. Fish and Wildlife, and U.S. Forest Service. Over 50,000 landowners were contacted with easement refusals being an issue. WPS indicated that, with the challenges of customer and landowner contacts, the company was willing to cancel projects. This approach often resulted in cooperation in future years. The average cost to install the undergrounding infrastructure was ~$150,000 per mile using open-trench installation for direct burial cable (no conduit).

**Takeaways**: 1) Customer communication should begin well in advance (e.g., two years); utilities should avoid pressuring customers and revisit projects later if initial cooperation is lacking. 2) Distribution automation can reduce the duration of interruptions but does not prevent outages; alternatives must be clearly defined. 3) Undergrounding is feasible with the right approach. 4) Reliability improvements are noticeable for areas undergrounded.

**Recommendation**: See recommendation under the Day 1, "Undergrounding In Michigan – DTE, Consumers, and Alpena" section.

## Resilience Metrics & Valuation for Electric Grid Decision-Making – GridCo *(Appendix II, pp. 123-154)*

The Workshop concluded with a presentation providing an overview of new IEEE resilience metrics that may be used to measure the performance of resilience investments and restoration performance. These metrics apply the resilience definition from the Federal Energy Regulatory Commission (FERC) which is consistent with the definition adopted by the Commission through its December 21, 2023, order in MPSC Docket No. U-21388.[20]

FERC's resilience definition:

> "[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."

The primary focus of the IEEE resilience metrics presented on Day 2 was on extreme weather and natural phenomenon, not including cyber or physical security. The metrics are designed by the IEEE Distribution Resilience Taskforce which are currently in draft form and may be refined. GridCo shared four resilience metrics - X-Parameter Performance Ratio (X-PR), Sustained Interruption Reduction Index (SIRI), Restoration Performance (Storm Event), and REPAIR metric.[21]

**Equation 1: X-PR**

$$\text{X-Parameter Performance Ratio (X-PR)} = \frac{\text{Incidents Avoided}}{\text{Incidents Avoided} + \text{Sustained Incidents}}$$

**Equation 2: SIRI**

$$\text{SIRI} = \frac{\text{Avoided Sustained Customer Interruption (CI) by Automation/Hardening}}{\text{Avoided Sustained CI by Automation/Hardening} + \text{Sustained CI}}$$

[20] MPSC Docket No. U-21388, December 21, 2023 Order, p. 7.
[21] See Appendix II, pp. 134-139 for further details on metric calculations.

**Equation 3: Restoration Performance**

$$\text{Storm Event: } X = \frac{\sum \text{Customers Without Power for More than Z hours}}{\text{Avoided Sustained CI by Automation /Hardening} + \text{Sustained CI}}$$

**Equation 1: REPAIR**

$$\text{REPAIR} = \log\left(\frac{\text{Crew Hours}}{\text{Outages}} \times \frac{\text{AUPC}}{\text{CI}}\right)$$

Restoration Effectiveness (RE) + Area Index Resiliency (AIR)

GridCo concluded its presentation by stepping through four case studies showing how utilities in the U.S. have applied these metrics.

**Takeaways**: 1) SIRI and REPAIR metrics could incentivize effective resilience strategies. 2) continued information gathering and consideration of emerging metrics (including IEEE standards) is essential. Priority should be given to metrics grounded in robust, well-characterized data.

**Recommendation**: Given the nascent nature of these resilience metrics and the fact that these metrics may be refined, Staff does not recommend requiring utilities to report or apply these metrics to the MPSC Docket No. U-21400 Financial Incentives/Disincentives effort at this time. However, Staff does see value, especially in the SIRI and REPAIR metrics, as they permit transparency into the performance of infrastructure investments and restoration crews during storm events. 1) Staff recommends the Commission consider acquiring data from utilities relevant to the SIRI and REPAIR metrics. This recommendation is based on the assumption that these metrics will be adopted by IEEE.

## Conclusion and Recommendations

The Commission has shown an interest in the potential for expanding cost-effective undergrounding programs in Michigan through its previous orders. The March 2025 ice storm and subsequent order in MPSC Docket No. U-21388 are further examples of the Commission's efforts to explore undergrounding and understand opportunities and barriers. The Day 1 and Day 2 Workshops were informative in identifying these opportunities and barriers. Staff expresses its sincere thanks to the presenters and speakers who provided valuable content used to help the Commission and utilities shape the future of undergrounding assets in Michigan.

A list of Staff's recommended next steps to the Commission, transmission owners, and utilities[22] addressing undergrounding and alternatives for the Commission's consideration are as follows:

**1)** Staff recommends the Commission direct utilities to identify Michigan-specific risks and provide detail in future DSPs about how the Michigan-specific risks were evaluated in weather modeling, forecasting tools, and used to inform future planning efforts.

**2)** Staff recommends the Commission consider acquiring, no sooner than 2027, annual reliability data (SAIDI, SAIFI, and CAIDI) from utilities through the MPSC Docket No. U-21122 reporting template broken down by both weather type (blue sky, gray sky, and catastrophic) and circuit. Utilities should utilize this data to support system improvement investment decisions. Staff and utilities should work to update the template if the Commission directs this additional reporting to allow utilities to report annual data.

**3)** Staff recommends the Commission direct utilities to either complete pilot projects that align with the orders in MPSC Docket No. U-20147 and MPSC Docket No. U-21305 using the objective criteria for pilots in MPSC Docket No. U-20645 or conduct a comprehensive analysis to evaluate whether an undergrounding program is a cost-effective solution to improve performance of the electric distribution system. The primary objectives of these efforts must be aimed to determine if an undergrounding program is a cost-effective solution to improve electric distribution system performance, and if so, to develop an undergrounding strategy. Utility pilot and analysis findings, lessons learned (good and bad), and undergrounding strategy should be presented in future DSP filings and rate cases (where cost recovery is requested) and leverage economies of scale.

**4)** Staff recommends the Commission direct utilities to explore the potential of cable rejuvenation practices as a way to extend the life of existing underground cables and present their findings and long-term strategy in a future DSP filing.

**5)** Staff recommends the Commision direct utilities to develop and implement criteria in the next DSP filing designed to explore and take advantage (if

[22] For purposes of Staff's recommendations, "utilities" refers to the rate-regulated utilities in Michigan. Staff encourages cooperatives and municipally owned electric utilities to also consider these recommendations.

appropriate) of undergrounding opportunities that exist during system conversion and other major infrastructure upgrade projects.

**6)** Staff recommends that transmission owners in Michigan continue to consider and evaluate the benefits of undergrounding infrastructure when a transmission line creates significant environmental and social impacts. Transmission owners should consider the appropriateness of undergrounding transmission within both PA 30 of 1995 applications and for existing lines when significant maintenance or rebuilds are necessary.

**7)** Staff recommends the Commission issue guidance that requires utilities to appropriately consider reliability impacts when analyzing proposed or potential projects or conducting BCAs. As the ICE Calculator 2.0 is, by default, the industry standard for quantifying the economic impacts of reliability events, the Commission should strongly encourage results of the calculator be at least one way reliability benefits are calculated for consideration in these analyses. Other methods may be considered but must be properly supported if used.

**8)** Consistent with the BCA for DERs effort underway as part of MPSC Docket No. U-20898 and Staff's recommendation #7, Staff recommends that reliability should be considered in undergrounding BCA. Staff recommends the Commission direct utilities to apply all cost tests (SCT, UCT, TRC, participant cost test, etc.) to non-DER investments and offer transparency into their models through planning and outreach efforts that involve interested parties.

**9)** Staff recommends the Commission direct utilities to identify and apply Michigan-specific risks associated with the uniqueness of the service territory for BCA and alternatives analyses. This approach will allow the utility to better understand mitigation solutions.

**10)** Staff recommends the Commission direct utilities, as part of their future DSP pre-filing outreach or other outreach efforts, to solicit coordination and cost-sharing opportunities that may improve coordination and, ultimately, reduce the costs of undergrounding projects.

**11)** Staff recommends the Commission consider acquiring data from utilities relevant to the SIRI and REPAIR metrics. This recommendation is based on the assumption that these metrics will be adopted by IEEE.

# Appendices

# Day 1: Undergrounding Technical Workshop

## What is Happening Now?

September 17, 2025

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# Introduction – U-21388

**Late-March 2025**

**Storm**
Ice Storm Hits Northern Michigan

**May 21, 2025**

**Public Forum**
Town hall in Gaylord where undergrounding emerged as a key theme

**June 12, 2025**

**Order**
Staff to 1) conduct undergrounding workshop and 2) issue report with recommendations

**Sept. 2025**

**Workshops**
Staff lead workshops on September 17 and 19

**Oct. 31, 2025**

**Staff Report**
Staff to file a report with recommended next steps

Note: Staff explored undergrounding in U-15279 (2007) and issued a report indicating that the reliability benefits of undergrounding are uncertain and did not compare favorably to the costs.

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# Agenda

| What Is Happening Now? | | |
|---|---|---|
| 12:30-12:45 | Welcome & Introduction | Katherine Peretick, MPSC Commissioner |
| 12:45-1:00 | Michigan's Electric Grid: Reliability, Spending, & Utility Audit Overview | MPSC |
| 1:00-1:15 | Storm Activity & Commission Efforts in Michigan | MPSC |
| 1:15-2:00 | Extreme Weather Data | Tom Wall, Argonne National Laboratory |
| 2:00-2:30 | Reliability Improvements from Undergrounding | Luke Dennin, MPSC |
| 2:30-2:45 | Break | |
| 2:45-4:15 | Hybrid Panel<br>Undergrounding in Michigan:<br>Utility Perspective & Efforts Underway<br>Moderator: Olivia (Li) Szilagyi, MPSC | Michael Kelly, Consumers<br>Aaron Balch, DTE<br>Ken Dragiewicz, Alpena |
| 4:15-5:00 | Undergrounding Transmission: Community Engagement, Permitting Considerations, & Economics | Josh Rogers, GPI<br>Raj Rajan, SOO Green HVDC Link |
| | Closing | MPSC |

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# Housekeeping

- Meeting is Recorded
- Workshop Format
  - Questions and discussion at the end of presentations
  - Raise hand feature through Teams in the order received (primary)
  - Questions in the chat (secondary)
  - Presenters may follow up with questions not answered
- Please Mute Unless You Are Speaking

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# Michigan's Electric Grid: Reliability, Utility Audit, & Spending Overview

MPSC Case U-21388:
Undergrounding Workshop

**Tayler Becker**
Manager, Distribution Planning Section
Michigan Public Service Commission
BeckerT4@Michigan.gov

September 17, 2025

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# MPSC Distribution Reliability Webpage

- MPSC Case No. U-21122 - Accessibility and Transparency Through Monthly Data Submissions

- MPSC Reliability Metrics and Data Webpage
  - Review data
  - Request data
  - Download data

- Applies IEEE Distribution Reliability Working Group Benchmarking

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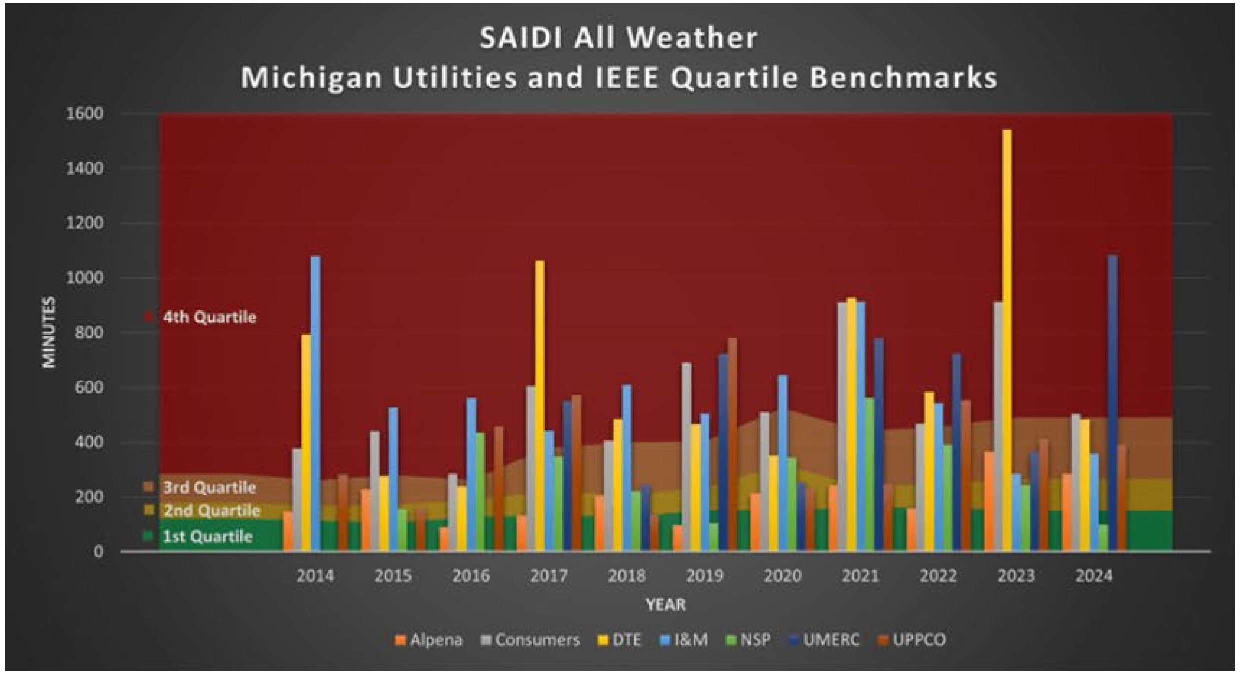
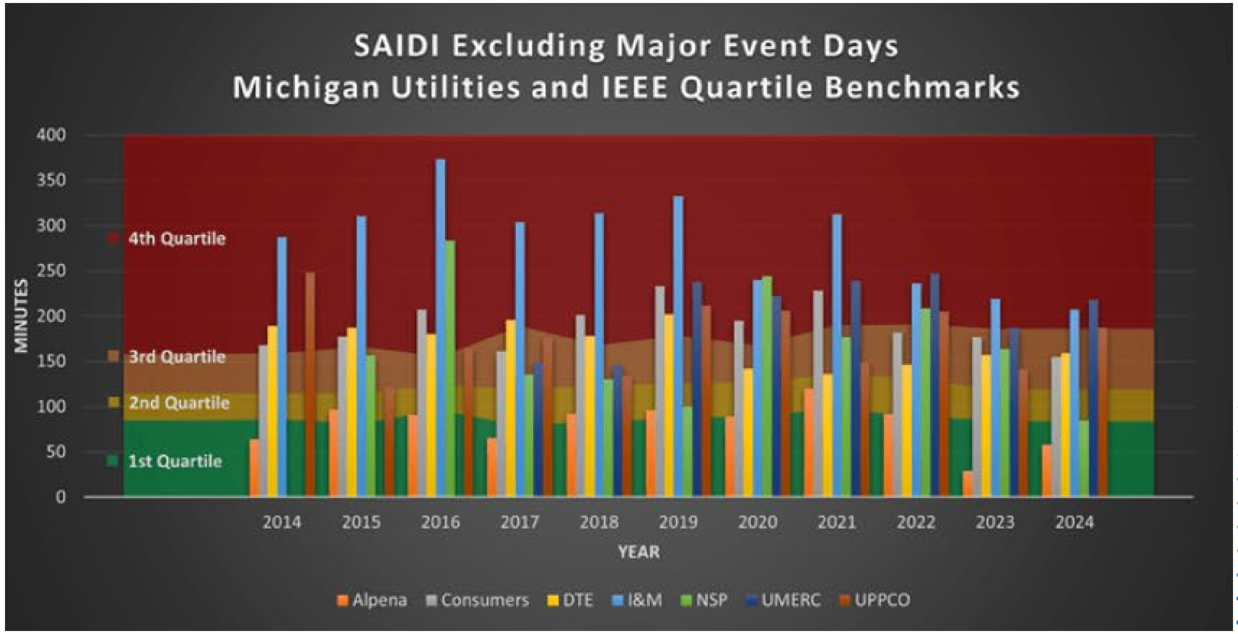
# Reliability - SAIDI

- **System Average Interruption Duration Index (SAIDI)** – represents the total number of minutes of interruption the average customer experiences
- Most Michigan Customers Experience 3rd – 4th Quartile SAIDI

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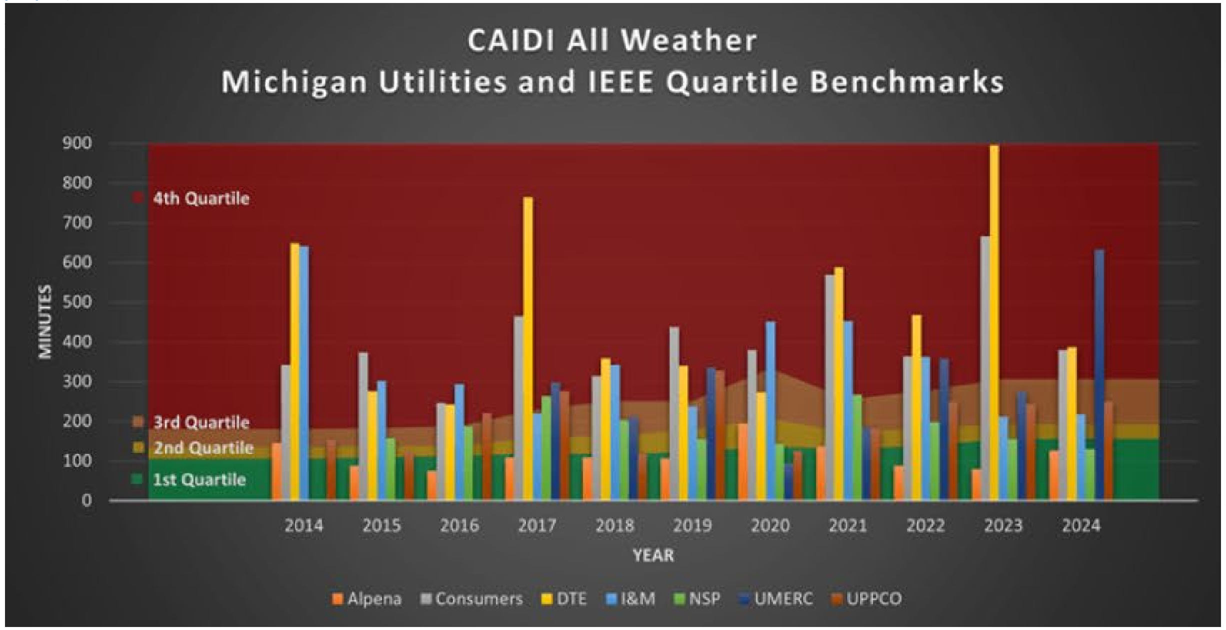
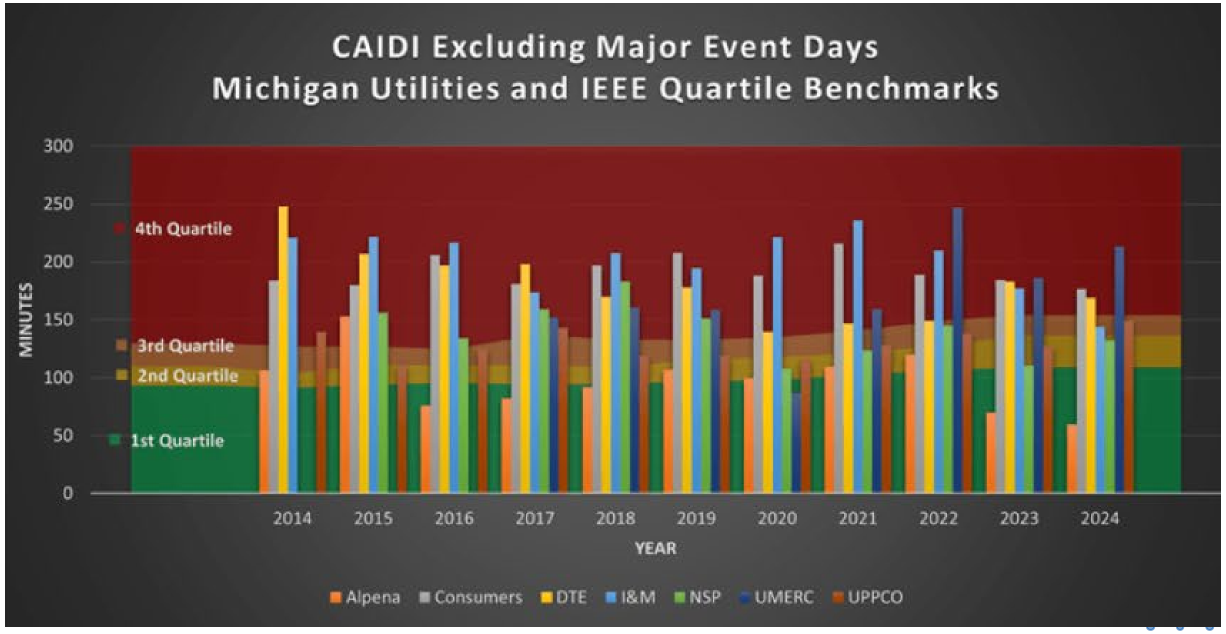
# Reliability - CAIDI

- **Customer Average Interruption Duration Index (CAIDI)** – represents the average time required to restore service
- Most Michigan Customers Experience 3rd - 4rd Quartile CAIDI

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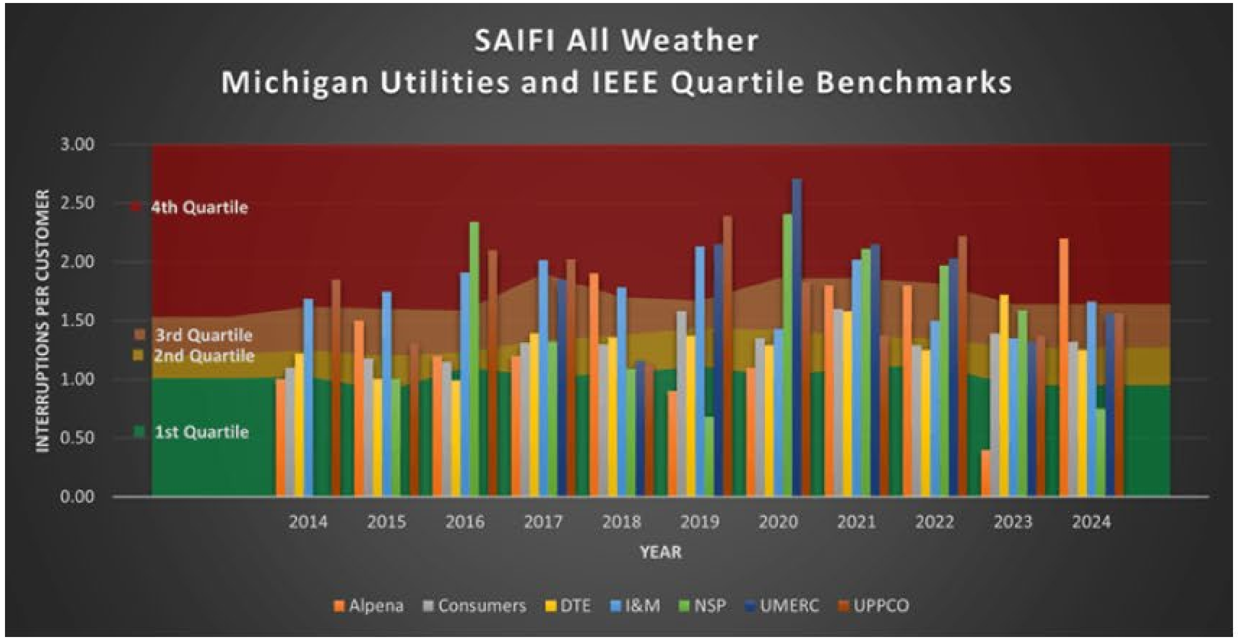
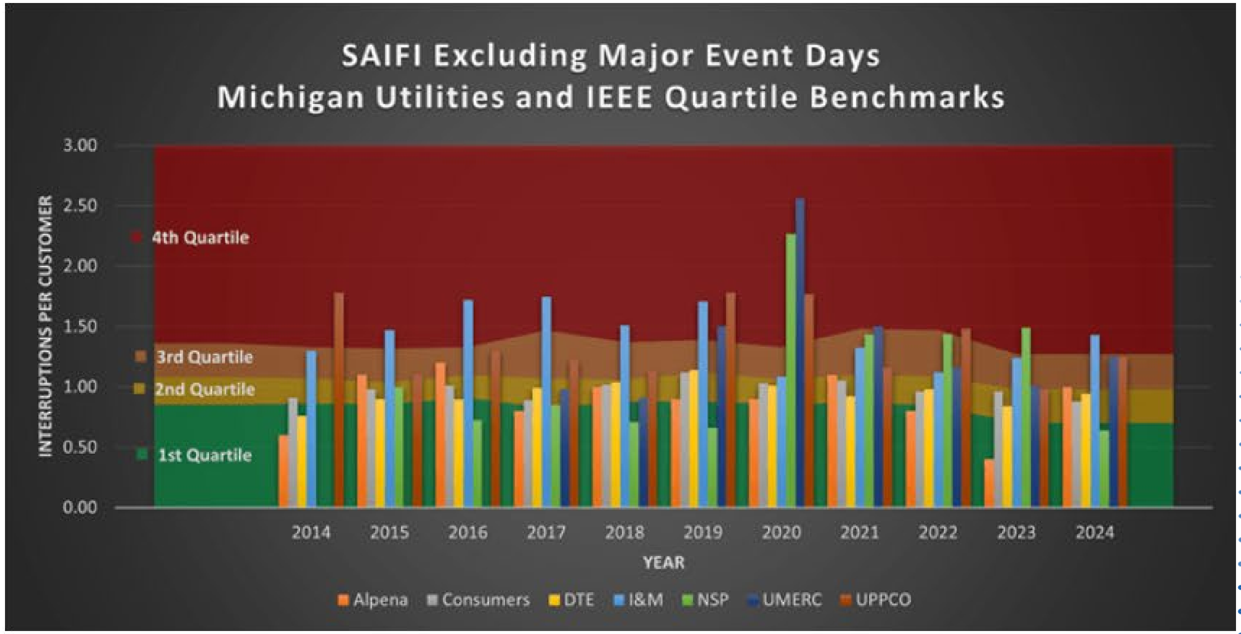
# Reliability - SAIFI

- **System Average Interruption Frequency Index (SAIFI)** – represents the average number of times a customer experiences an outage
- Most Michigan Customers Experience 2nd – 3rd Quartile SAIFI

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# Utility Audit – U-21305

- October 5, 2022 Commission Order in MPSC Case No. U-21305
  - August 29, 2022 Wind Storm
  - Fatal and critical injuries
  - 3rd party review of DTE and Consumers electric distribution systems.
    - Part 1 – physical audit
    - Part 2 – program and process audit
- September 23, 2024 Liberty Reports Issued
- June 12, 2025 Commission Orders (DTE and Consumers)

**Reports**

DTE Part 1, Part 2

Consumers Energy Part 1, Part 2

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# Utility Audit – Undergrounding

## Comparison of Circuit Miles in Service Territory

| Circuit Miles | Consumers | DTE | AIC | ComEd | LBWL |
|---|---|---|---|---|---|
| Overhead Distribution Miles | 51,574 | 28,548 | 32,048 | 34,648 | 2,126 |
| Overhead Distribution % | 84% | 687% | 82% | 52% | 70% |
| Underground Distribution Miles | 9,630 | 13,357 | 7,311 | 31,982 | 919 |
| Underground Distribution % | 16% | 32% | 19% | 48% | 30% |
| **Total** | **61,204** | **41,905** | **39,359** | **66,630** | **3,045** |
| Service Territory (square miles) | 28,300 | 7,600 | 67,700 | 11,428 | 97 |

DTE Part 1, page 55 & Consumers Part 1, page 47

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# Utility Audit – Undergrounding Quotes

- “DTE has **twice** the overhead distribution circuit miles compared to underground circuit miles. However, the operations and maintenance costs for overhead circuit operations and maintenance proved **12 times** that for underground circuits. DTE’s O&M spending for distribution overhead lines has increased significantly over the last four to five years while underground line O&M has remained constant.” (DTE Part 1, page 3)
- “Benchmarking also indicates that large scale programs produce cost efficiencies and that undergrounding **single phase laterals proves less costly**, given the standards required for three-phase and backbone circuits.” (DTE Part 2, page 82)

- “Consumers spends approximately **5 percent** of its electric LVD maintenance spending on underground facilities which comprise approximately **13 percent** of the LVD system. Consumers spends approximately **98 percent** of service restoration costs on overhead facilities which comprise **87 percent** of its LVD system.” (Consumers Part 1, page 3)
- “Consumers O&M spending for distribution overhead lines has **increased significantly** over the last four to five years while underground line O&M has remained constant”. (Consumers Part 1, page 3)
- “Historic cost differences between overhead and underground construction have traditionally militated strongly against undergrounding, except in special circumstances, although, undergrounding use is expanding as a resiliency measure.” Consumers Part 2, page 70)

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# Utility Audit – Line Clearing and Storm Spend

## Changes in DTE O&M *(millions)*

| Category | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|
| Regional Customer Operations | $50.4 | $54.9 | $57.8 | $57.4 | $50.4 | $50.8 | $50.8 | $52.4 | $70.7 | $65.5 |
| Substations | $30.1 | $34.1 | $31.7 | $30.8 | $29.5 | $27.4 | $24.5 | $20.6 | $24.2 | $17.5 |
| System Operations | $18.6 | $20.0 | $9.3 | $9.3 | $10.7 | $9.6 | $12.0 | $8.1 | $8.3 | $6.8 |
| Storm & Storm Functions* | $107.5 | $44.8 | $44.4 | $69.8 | $51.5 | $50.2 | $46.5 | $79.7 | $59.9 | $183.8 |
| Engineering | $16.2 | $15.6 | $13.4 | $13.8 | $15.5 | $14.3 | $11.7 | $11.1 | $12.7 | $8.7 |
| Customer Excellence Tree Trim** | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.8 | $6.0 | $0.2 | $0.1 | $0.1 |
| Scheduling & Coordination/Miss Dig | $5.2 | $4.6 | $4.6 | $4.6 | $5.9 | $6.2 | $6.0 | $8.1 | $7.2 | $8.8 |
| Operational Technology | $0.0 | $0.5 | $0.8 | $2.1 | $3.3 | $3.3 | $3.4 | $2.8 | $1.9 | $3.6 |
| Customer Trans/Automation*** | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $7.4 | $3.3 |
| VP Staff | $2.1 | $4.0 | $3.5 | $2.8 | $3.9 | $3.1 | $3.7 | $3.7 | $6.0 | $2.8 |
| Inventory Reserve | $0.5 | $0.7 | $5.6 | $0.5 | $2.2 | -$1.1 | $2.9 | $5.0 | $4.1 | $1.9 |
| Canceled Capital Projects | $0.0 | $0.0 | $3.5 | $2.8 | $2.8 | $1.1 | $3.0 | $2.0 | $1.3 | $3.2 |
| Telecom | $6.4 | $5.3 | $4.5 | $4.9 | $5.6 | $6.0 | $7.1 | $7.6 | $7.8 | $7.6 |
| Accounting Transactions | -$4.1 | $3.4 | $5.4 | -$0.2 | -$0.2 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| Tree Trim | $35.4 | $57.0 | $74.2 | $84.3 | $89.1 | $152.6 | $178.7 | $180.4 | $250.9 | $174.5 |
| **Total** | **$268.3** | **$244.8** | **$258.8** | **$282.7** | **$270.1** | **$324.5** | **$356.3** | **$381.8** | **$462.6** | **$488.1** |

## Changes in Consumers O&M *(millions)*

| Category | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|
| O&M Assoc w/Construction | -$2.0 | -$1.8 | $1.1 | -$2.5 | $0.9 | -$1.7 | $0.0 | -$0.3 | $0.0 | $0.0 |
| Non-Forestry Reliability | $4.5 | $3.1 | $3.1 | $3.2 | $3.8 | $3.4 | $4.2 | $5.4 | $6.4 | $6.2 |
| Forestry Reliability | $40.4 | $37.3 | $50.9 | $50.3 | $52.4 | $53.6 | $55.9 | $86.6 | $102.0 | $109.1 |
| Ops, Mtc & Mtr w/o Svc Rest | $49.0 | $42.7 | $33.6 | $32.9 | $35.6 | $33.2 | $28.8 | $35.8 | $35.7 | $34.7 |
| Service Restoration | $47.0 | $38.2 | $35.5 | $50.2 | $53.9 | $92.1 | $71.3 | $159.7 | $113.3 | $188.0 |
| Field Operations | $22.6 | $25.6 | $22.5 | $27.1 | $29.7 | $26.9 | $22.7 | $31.2 | $36.4 | $31.1 |
| Compliance and Controls | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.5 | $1.4 | $1.7 | $1.7 | $1.2 |
| Operations Performance | $5.7 | $3.8 | $4.8 | $7.9 | $8.0 | $7.0 | $5.7 | $4.0 | $6.8 | $3.9 |
| Operations Management | $9.5 | $7.4 | $7.6 | $6.5 | $6.8 | $5.7 | $6.1 | $7.3 | $9.5 | $7.4 |
| Unallocated | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| **Total** | **$176.7** | **$156.3** | **$159.2** | **$175.5** | **$191.2** | **$220.8** | **$196.1** | **$331.4** | **$311.7** | **$381.6** |

Data indicates two key drivers in the growth of O&M expenditures in last five-years

1) Tree Trimming
2) Storm Restoration

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# Utility Audit – Recommendations Summary

- **Undergrounding**- pilot undergrounding and expand, as necessary, after careful evaluation of costs and benefits
- **Line Clearing** – move to a 4-5 year line clearing cycle for LVD
- **Storm Restoration** – re-baseline restoration budgeting to produce estimates that consider expected needs and balance company and customer interests in addressing volatile restoration costs

- June 12, 2025 Commission Orders largely supported Liberty's recommendations in these areas

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# Projected Spending – Distribution Plans

- **DTE 2023 Plan**
  - Undergrounding conversions: 2024-2025 pilots totaling $20 million
  - Tree trimming: ramp up to $140 million per year in 2025
  - Storm response
    - Emergent replacements: 2024-2025 average of ~$375 million per year
- **Consumers Amended 2023 Plan filed in 2025**
  - Underground conversions: ramp up from 2026-2029 to $160 million (400 miles) per year
  - Line clearing: ramp up from 2026-2030 to $236 million per year to achieve 5-year clearing cycle
  - Storm response:
    - Demand failures: level off from 2025-2029 to ~$200 million per year
    - Storm restoration: ramp up for 2025-2029 to $160 million per year

# Summary

- Opportunity to Improve Distribution System Reliability Performance
- Potential Opportunity to Expand Undergrounding
- Changing Landscape Which May Strengthen Business Case for Undergrounding
  - Increasing line clearing spend for overhead
  - Increasing storm response spend for overhead

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# Storm Activity & Commission Efforts in Michigan

MPSC Case U-21388:
Undergrounding Workshop

**Tayler Becker**
Manager, Distribution Planning Section
Michigan Public Service Commission
BeckerT4@Michigan.gov

September 17, 2025

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MICHIGAN PUBLIC SERVICE COMMISSION

# Storms

| When | Type | Characteristics | Customer Outages (~) |
|---|---|---|---|
| Dec. 2013 | Ice | 0.75" ice with 10-20 mph wind | >640,000 |
| March 2017 | Wind | 30 mph sustained with 60+ mph gusts | 1,108,000 |
| May 2018 | Wind | 70 mph gusts | 300,000 |
| Jan. 2019 | Polar Vortex | -25° F temps | >400,000 |
| Aug. 2021 | Wind | 70+ mph wind gusts | 892,000 |
| Aug. 2022 | Wind | 70+ mph winds | 462,000 |
| Feb-March 2023 | Ice | 0.25-0.65" ice, 6" snow, 35-45 mph wind | >1,400,000 |
| March-April 2025 | Ice, Wind | 0.5-1.5" ice and tornadoes | >756,000 |

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# Commission Actions

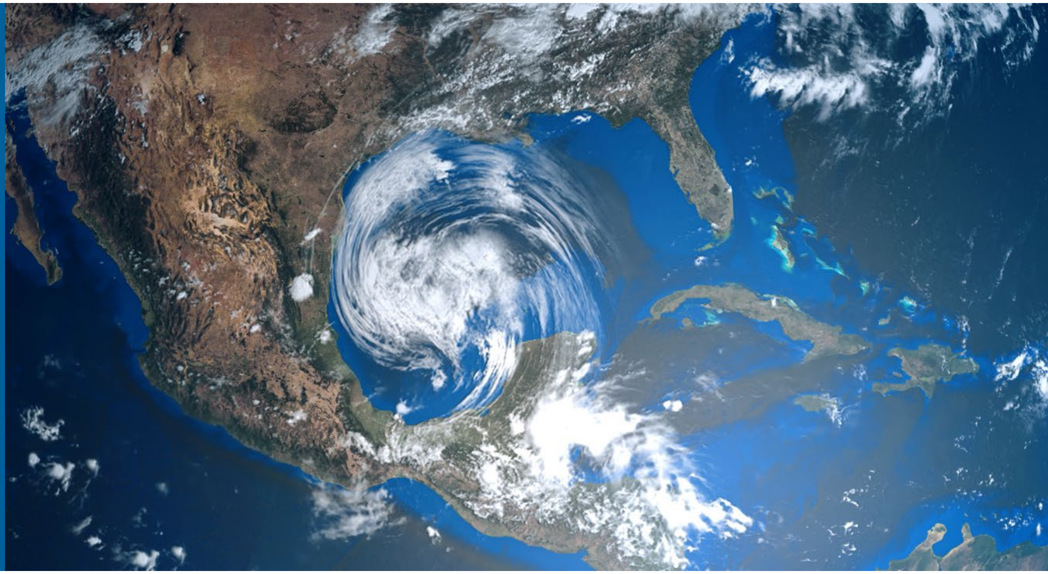
- U-17542 (2014): December 2013 Ice Storm Investigation
  - Outcomes: hazardous tree removal, power quality reports, and transparent outage credit information
- U-18346 (2017): March 2017 Wind Storm Investigation
  - Outcomes: increased tree trimming, cont. smart meter integration, and infrastructure improvements
- U-20169 (2018): May 2018 Wind Storm
  - Outcomes: increased wire down personnel, track down wire causes, youth education, and reporting
- U-20464 (2019): Polar Vortex Investigation & SEA Report
  - Outcomes: several dockets initiated on rule changes, DR, mutual aid, curtailment, distribution planning, etc.

# Commission Actions Cont.

- U-21122 (2021): August 2021 Storms
  - Outcomes: MPSC Reliability Webpage and outage reporting template
- U-21305 (2022): August 2022 Storms
  - Outcomes: 3rd party audit with several conclusions and recommendations
- U-21388 (2023): February 2023 Storms
  - Outcomes: resilience technical conferences and Staff resilience report
- U-21388 (2025): March 2025 Ice and April 2025 Wind
  - Outcomes: undergrounding technical workshop

CENTER FOR
RESILIENCE AND
DECISION SCIENCE
Argonne National Laboratory

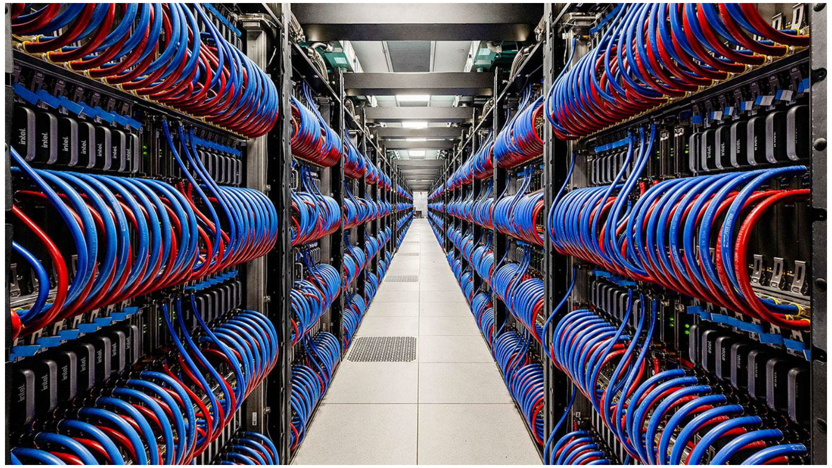
# INTRODUCTION TO EXTREME WEATHER DATA FOR POWER UTILITY DECISION MAKERS



**TOM WALL, PH.D.**
Director, Center for Resilience and Decision Science
Department Manager, Infrastructure Security and Resilience

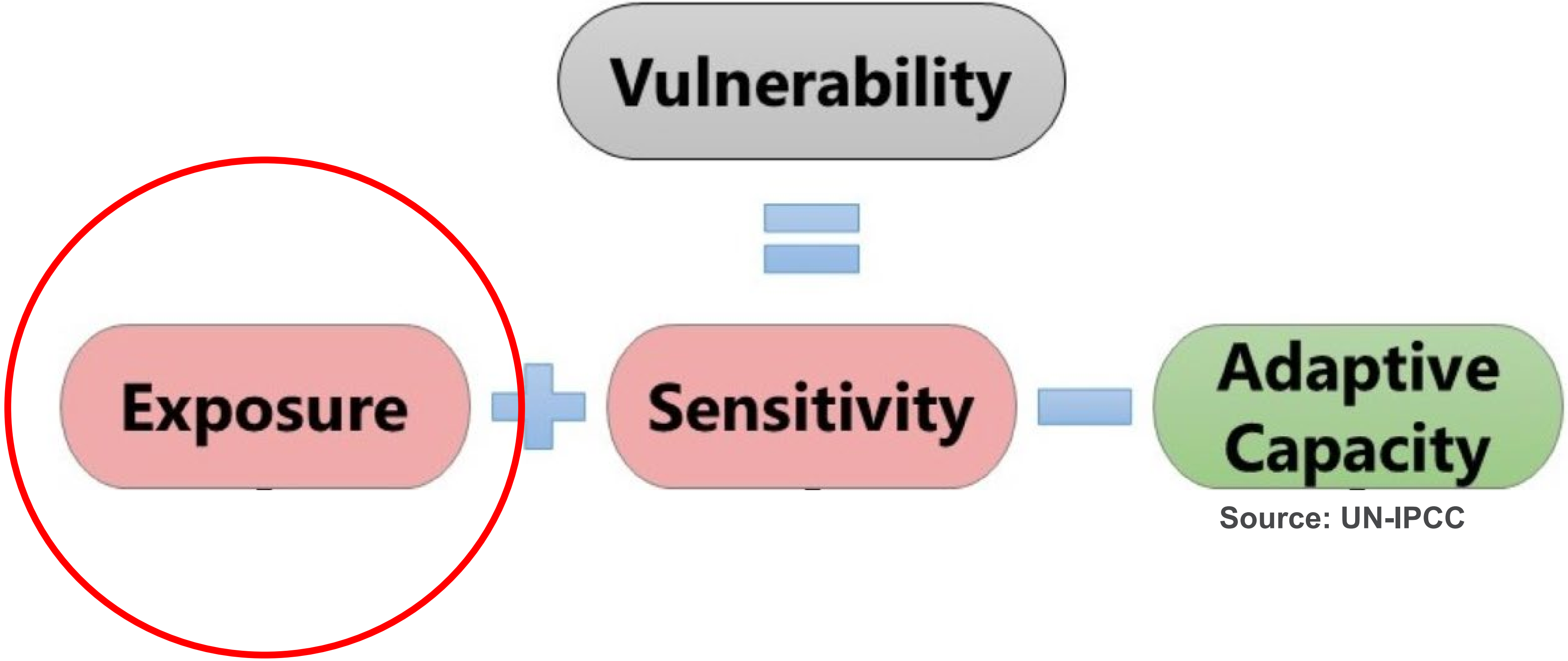
# CENTER FOR RESILIENCE AND DECISION SCIENCE

- The Center for Resilience and Decision Science (CRDS) conducts research and analysis to enable unmatched future weather-risk-informed decision-making and risk mitigation planning for public and private stakeholders facing a variety of challenges around the world.
- The CRDS is comprised of a multidisciplinary scientific team that collaborates with research partners to ensure that weather risk-informed decision-making is contextualized in socio-economic, infrastructure, environmental, and fiscal realities so that mitigation actions are grounded in science and practicable for immediate implementation.
- **Relevant expertise include**: artificial intelligence, advanced computing, atmospheric science, decision science, engineering and infrastructure analysis

# WEATHER MODELING AND DATA 101

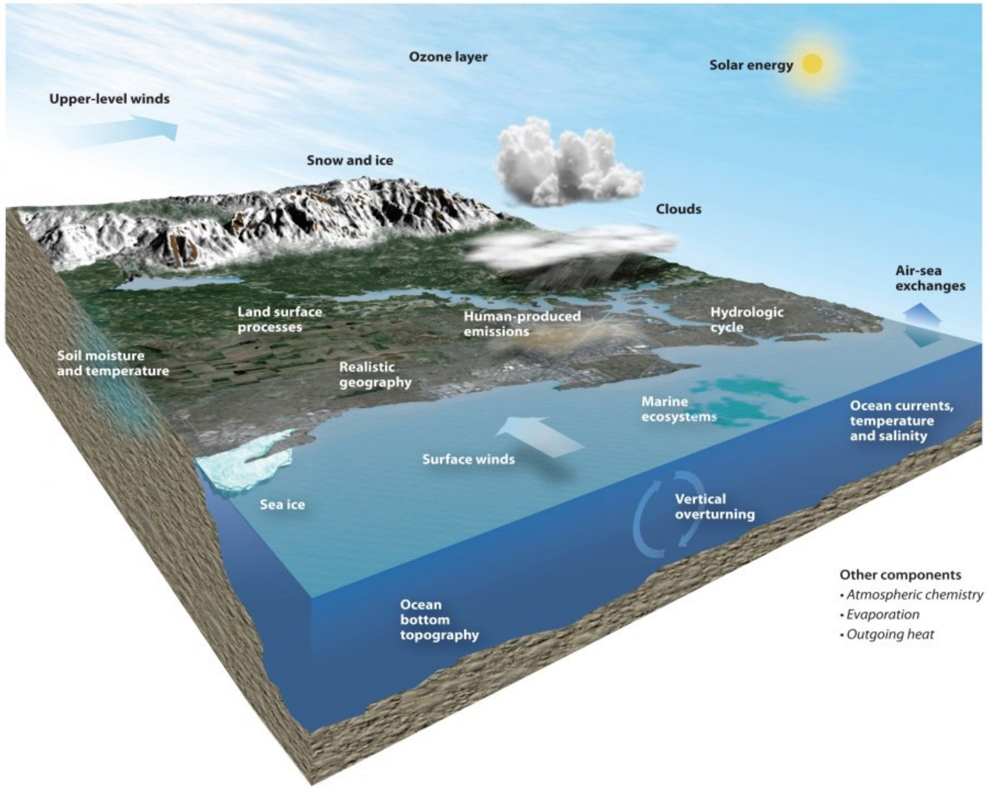
## Importance of Place-Based Data in Assessing Asset Vulnerability

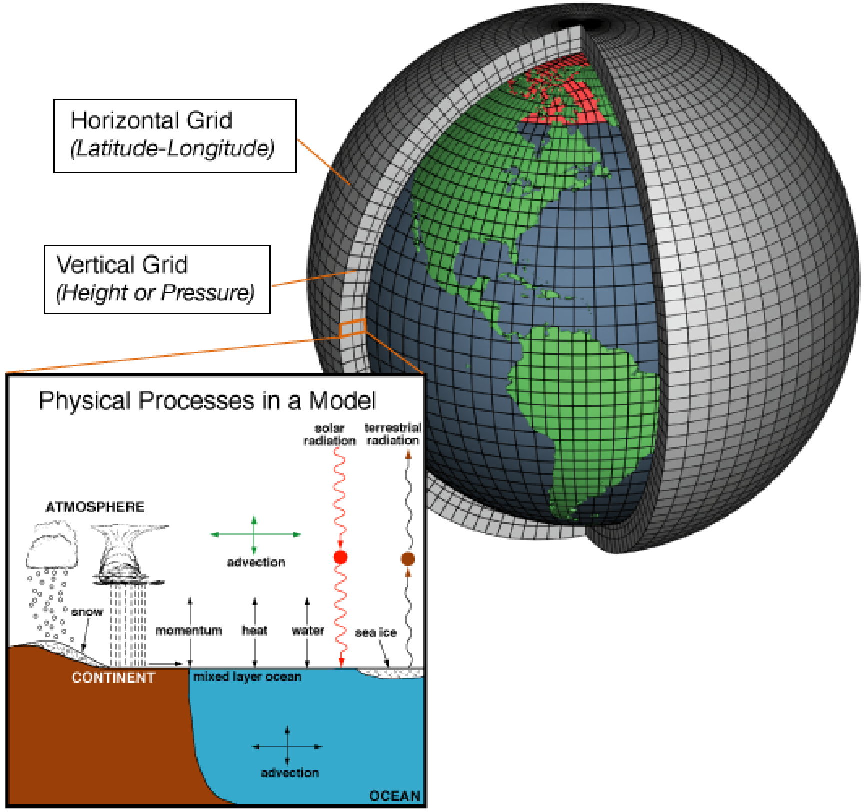



Source: UN-IPCC

# WEATHER MODELING AND DATA 101

## Mathematical representations of the weather systems are based on physical laws and understanding of processes



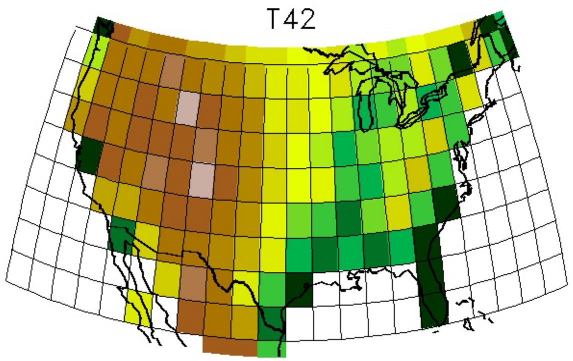




Source: UCAR and NOAA

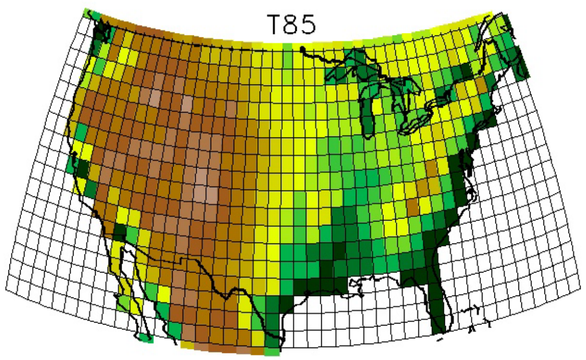
# WEATHER MODELING AND DATA 101

## Model Resolution is Dependent on Computing

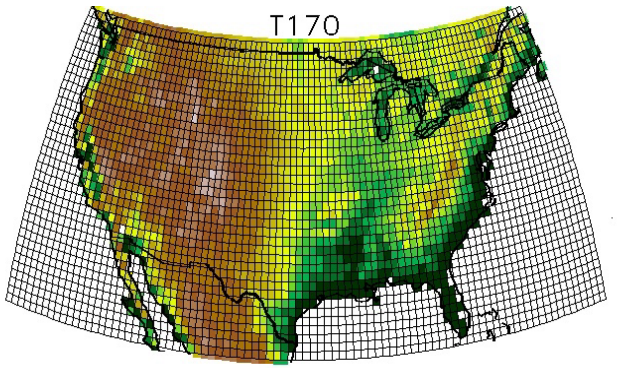
- As computing resources have improved over time, models have become increasingly complex and more detailed
- Smaller grid squares or “pixel sizes” enable more place-specific and detailed projections of locally relevant weather
- But hang on, because artificial intelligence (AI) and machine learning (ML) is accelerating…



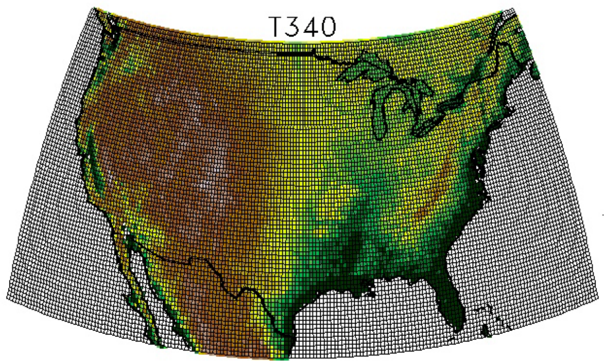

**Mid-1990s** 200~300 kms




**2000s** 100~150 kms




**Current** 50~100 kms



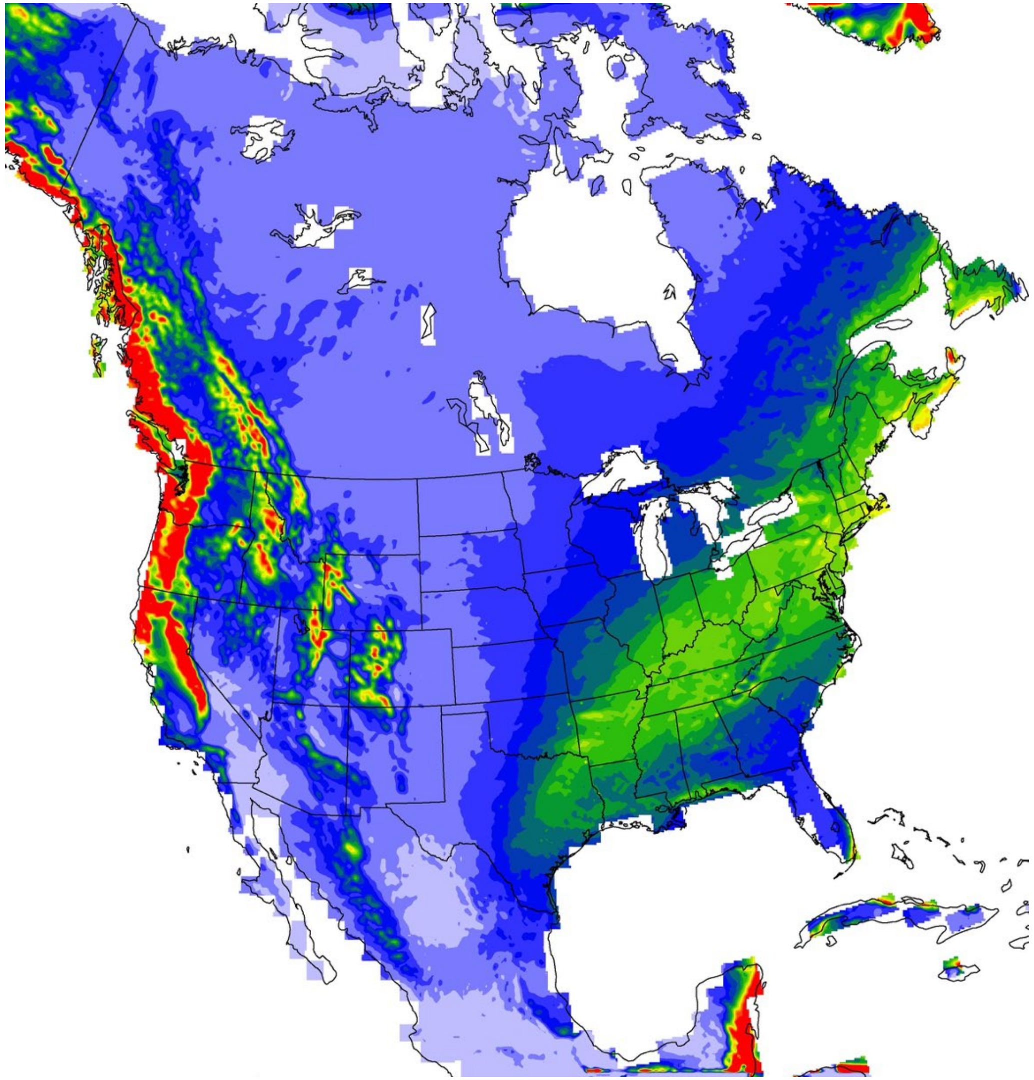

**Future.** 25~40 kms

**Source: UCAR**

# LOCAL WEATHER PROJECTIONS THROUGH DYNAMIC DOWNSCALING

## ARGONNE'S DYNAMICALLY DOWNSCALED, REGIONAL WEATHER MODELING IS A UNIQUE NATIONAL RESOURCE

- High resolution, neighborhood level (12km)
- Scientific transparency: widely published and scientifically peer reviewed modeling and outcomes
- Dynamical downscaling offers improvements over statistical downscaling
  - Physics-based, addresses non-stationarity
  - Produces 60+ unique variables
- RCP8.5 (upper limit) + RCP4.5 (mid-century peak)
- Three member ensemble of general circulation models
- Three timeframes: historical, mid-century, end-of-century



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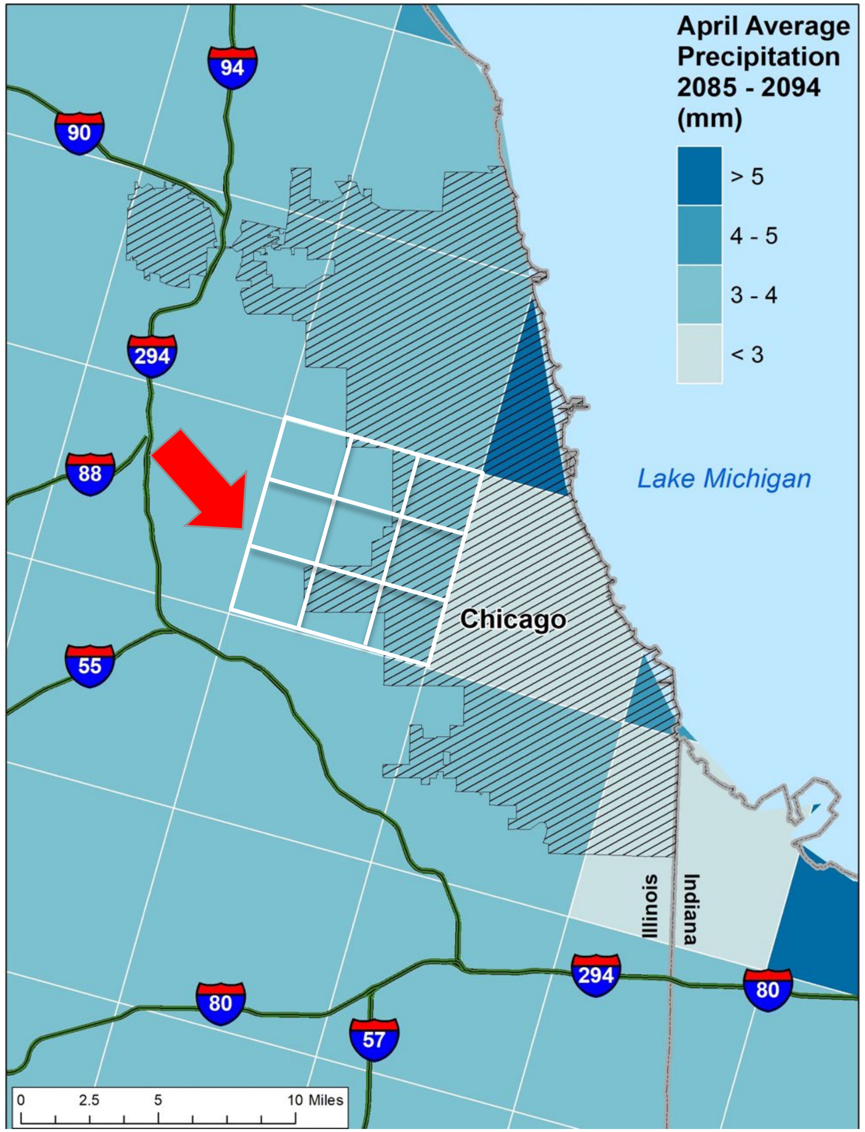


# COLLABORATORS IN APPLIED WEATHER RESEARCH

U.S. DEPARTMENT OF ENERGY | Office of Science

U.S. DEPARTMENT OF ENERGY | OFFICE OF Cybersecurity, Energy Security, and Emergency Response

U.S. DEPARTMENT OF ENERGY | OFFICE OF ELECTRICITY

GDO GRID DEPLOYMENT OFFICE

FEMA

Homeland Security

exelon

comed AN EXELON COMPANY

BERKSHIRE HATHAWAY ENERGY

NVEnergy

MIDAMERICAN ENERGY COMPANY

ALTALINK A BERKSHIRE HATHAWAY ENERGY COMPANY

PACIFICORP

SDGE

PG&E

Ameren

NEW YORK STATE OF OPPORTUNITY. | NY Power Authority

AT&T

AMERICAN PUBLIC POWER ASSOCIATION

EAGLE ROCK ANALYTICS

Baringa

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

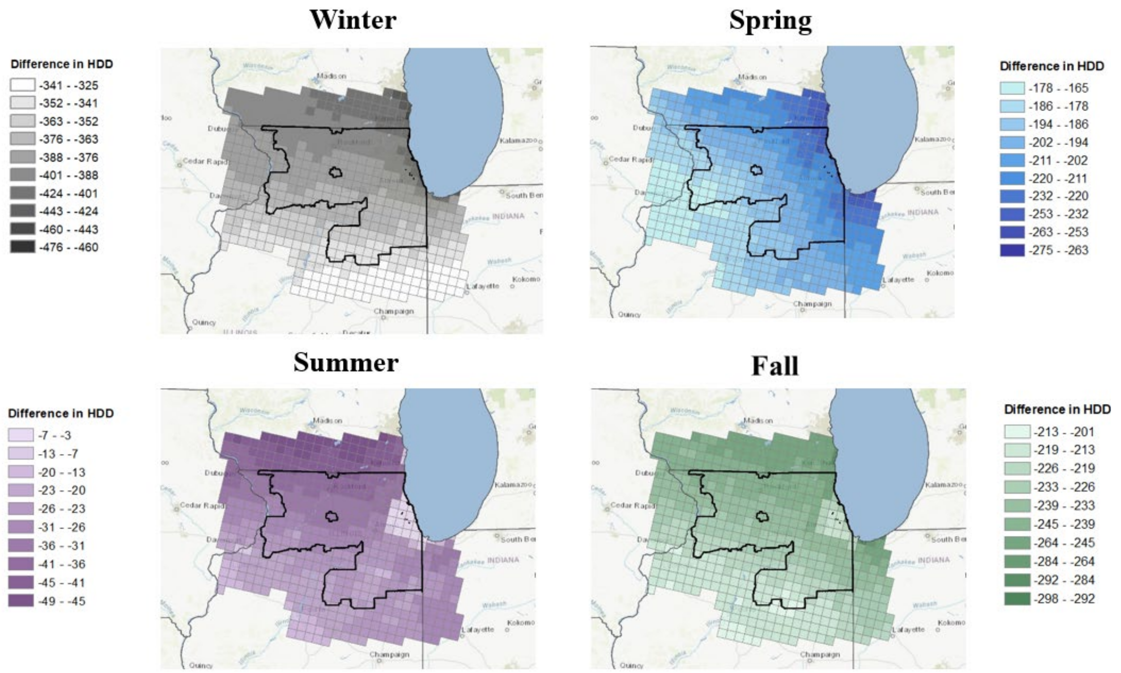
IBM

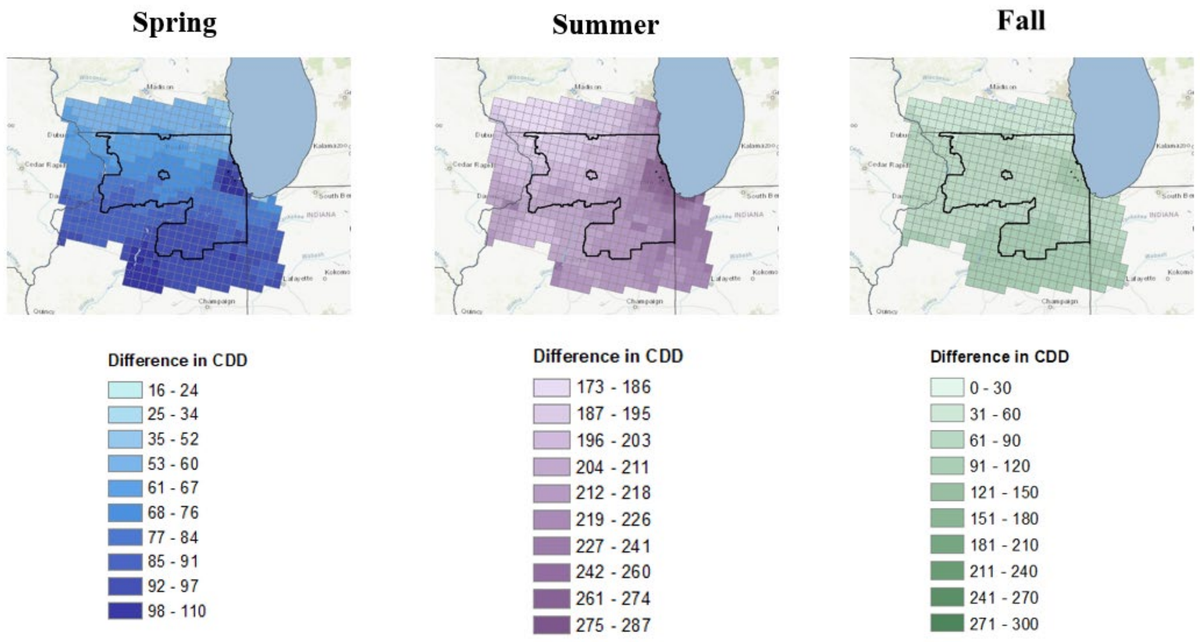
asean

# EXAMPLE APPLICATION TO INFORM DECISIONS

## Argonne, ComEd assess future weather impacts in Northern Illinois

- **Heating Degree Days:** Annual decrease between 761 to 1060 territory-wide (Winter average decrease ~408)
- **Cooling Degree Days:** Annual increase between 258 to 399 territory-wide (Summer average increase ~230)



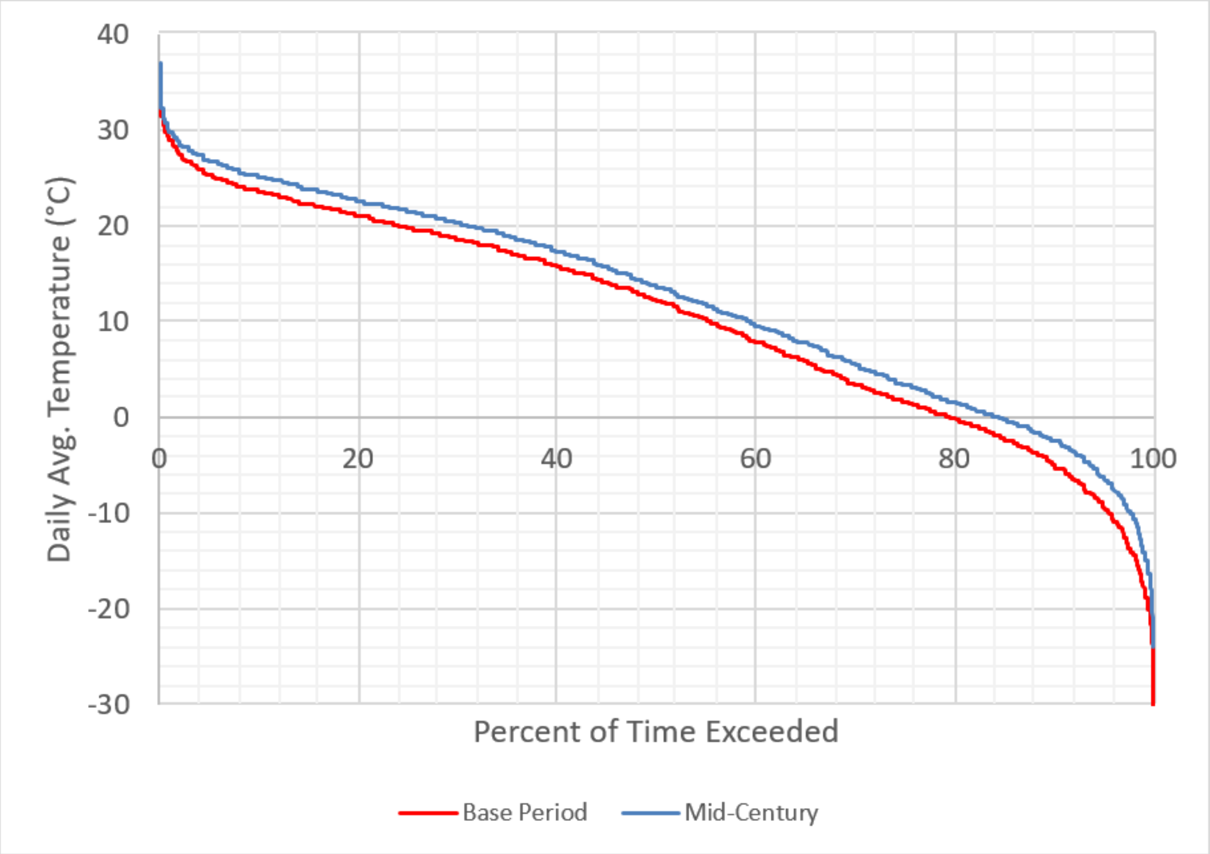
# EXAMPLE APPLICATION TO INFORM DECISIONS

## Argonne, ComEd assess future weather impacts in Northern Illinois

- Temperature extremes are critical for
  - Reliable operations of existing assets
  - Design and investment in future assets
  - Load forecasting

- Different **daily average** temperature thresholds are needed for different applications

- In northern Illinois:
  - Baseline: 35°C (95°F) exceeded ~1 days/decade
  - Mid-century: 35°C (95°F) exceeded ~4 days/decade



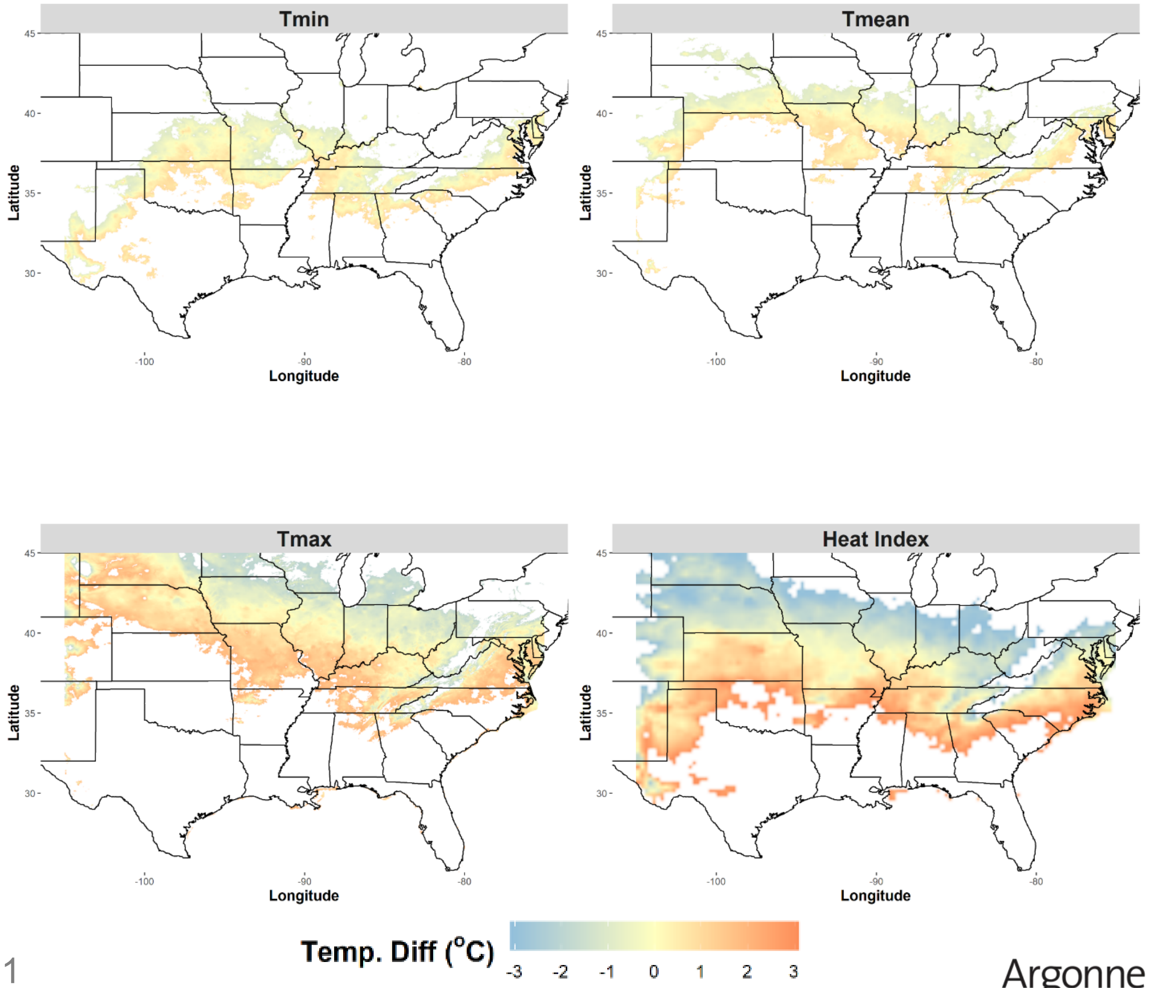

**Percentage of time (days/year) that daily average temperatures exceed a given threshold for the baseline and mid-century periods**

# EXAMPLE APPLICATION TO INFORM DECISIONS

## Argonne, ComEd assess future weather impacts in Northern Illinois

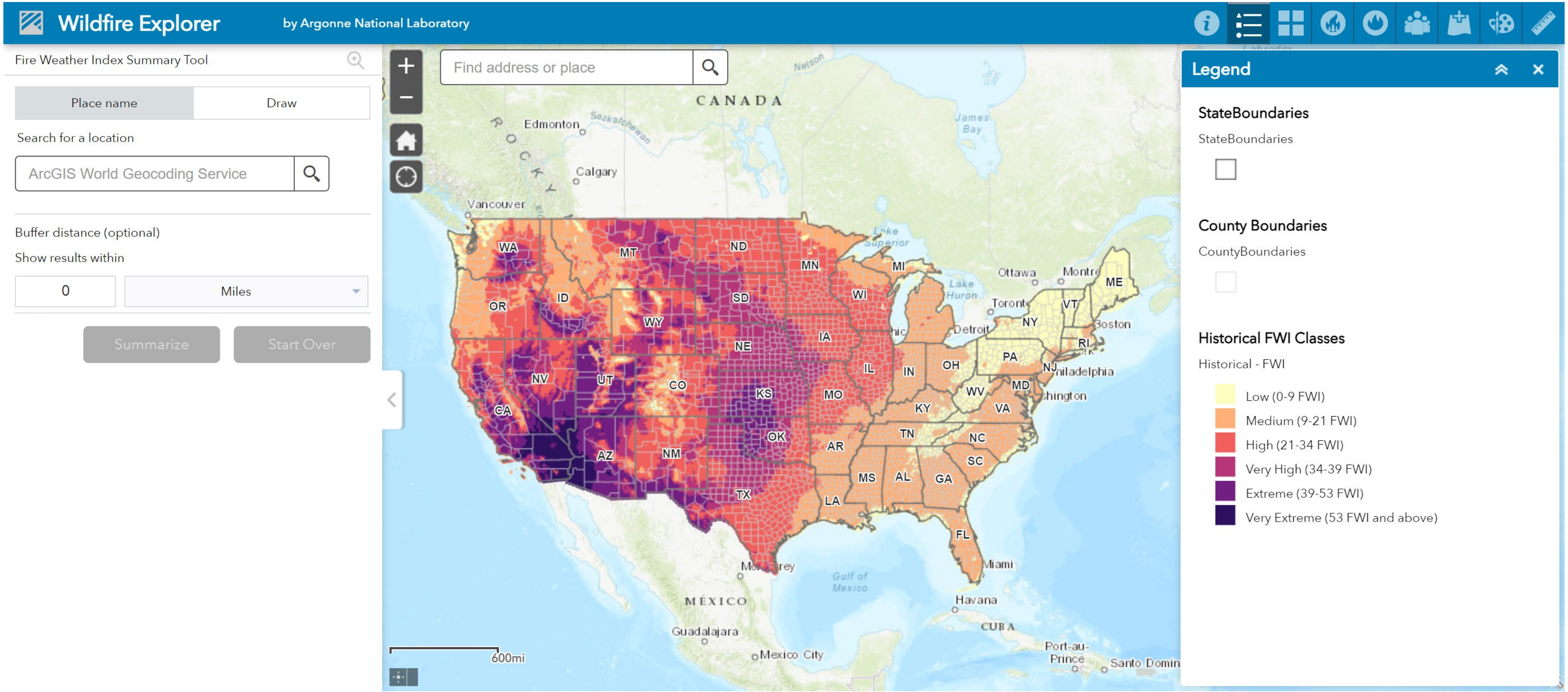
- Enables ComEd to better assess how future weather will affect regional communities, grid assets, future loads, and decarbonization efforts.

- High-resolution model outcomes tailored to ComEd's planning and analysis needs, and community and industry engagement activities.



# INFORM LOCAL DECISIONS AT NATIONAL SCALE

## ClimRR Portal




**https://climrr.anl.gov**

# INFORM LOCAL DECISIONS AT NATIONAL SCALE

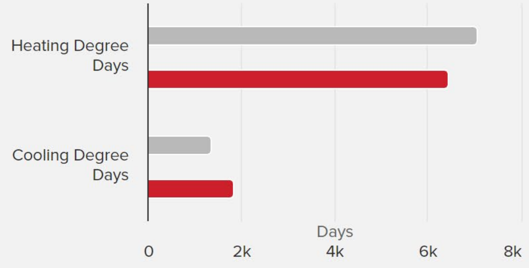
## ClimRR Portal

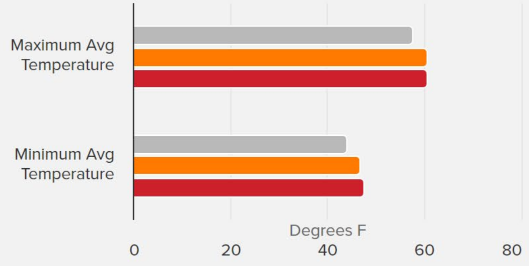
Coordinates: -97.93, 51.20
Located in DuPage County, Illinois

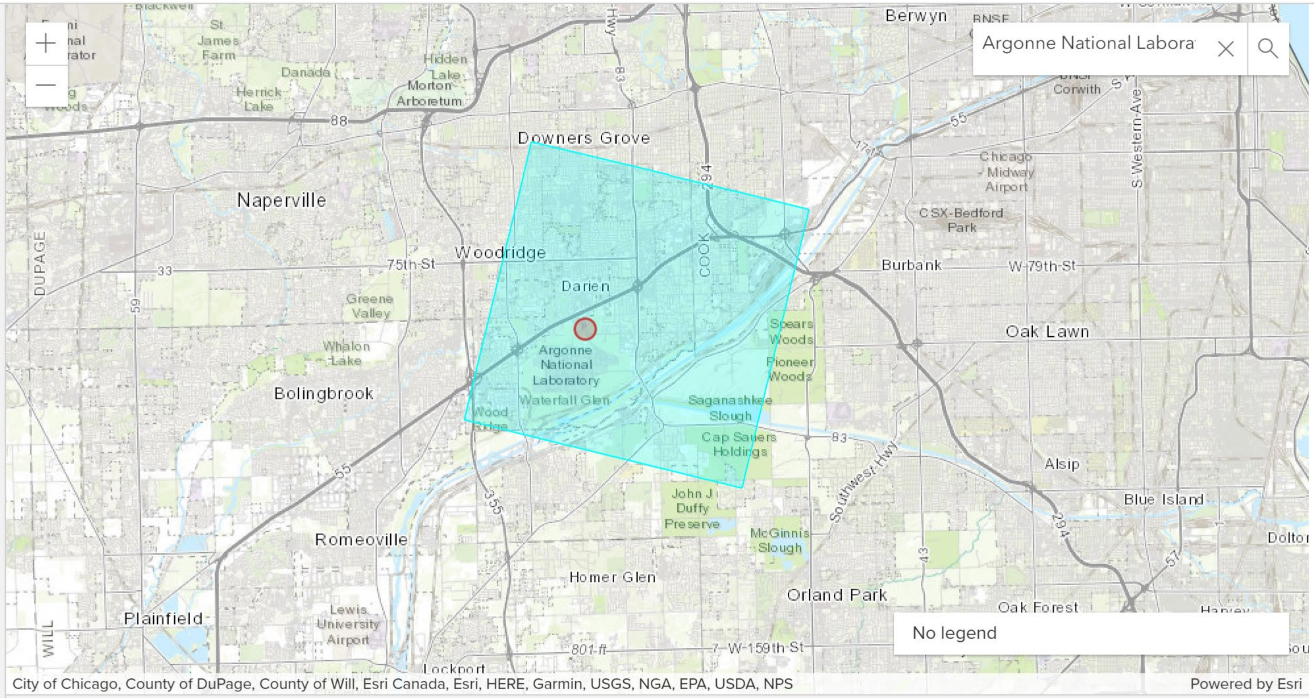
Data Catalog Guide | Tool Guide

Open Data Filters and Map Layers Menu

Generate Report



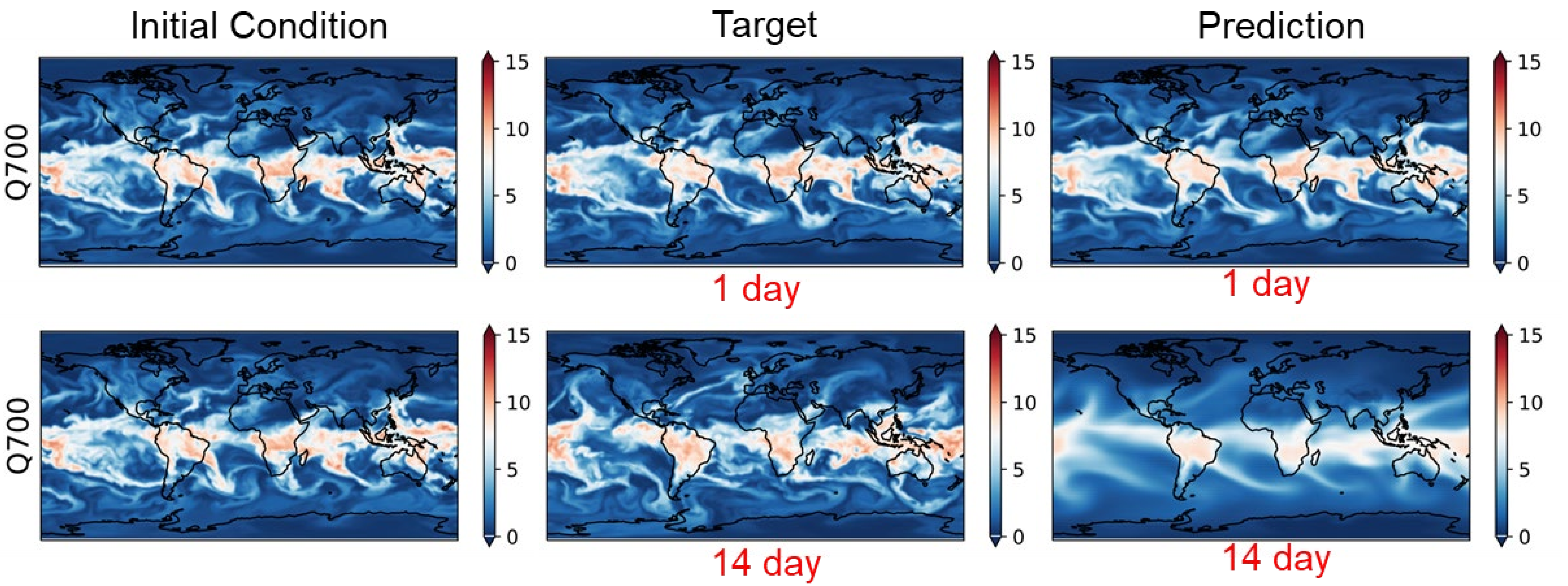

| Climate Projection | Historical | Mid Century RCP 4.5 | | Mid Century RCP 8.5 | |
|---|---|---|---|---|---|
| Heating Degree Days (Days) | 7,059.01 | - | | 6,441.85 | vs Historical: -617.16 |
| Cooling Degree Days (Days) | 1,349.38 | - | | 1,833.21 | vs Historical: +483.83 |
| Maximum Avg Temperature (Degrees F) | 57.59 | 60.68 | vs Historical: +3.09 | 60.54 | vs Historical: +2.95<br>vs RCP 4.5: -0.13 |
| Minimum Avg Temperature (Degrees F) | 44.18 | 46.93 | vs Historical: +2.75 | 47.74 | vs Historical: +3.56<br>vs RCP 4.5: +0.82 |

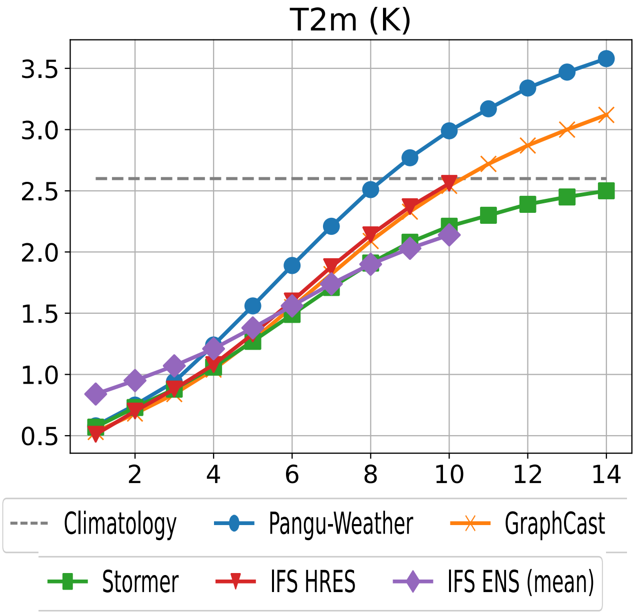
**https://climrr.anl.gov**

# AI/ML FOUNDATION MODELS FOR WEATHER

## STORMER & AERIS Subseasonal-to-Seasonal Weather Models

- Our state-of-the-art machine learning weather forecast models, Stormer and AERIS, run at ~30km resolution and can make 14-day global weather forecasts in 2 seconds
- Funded by DOE-CESER to provide near-real-time awareness of weather hazards to utilities for emergency planning and response



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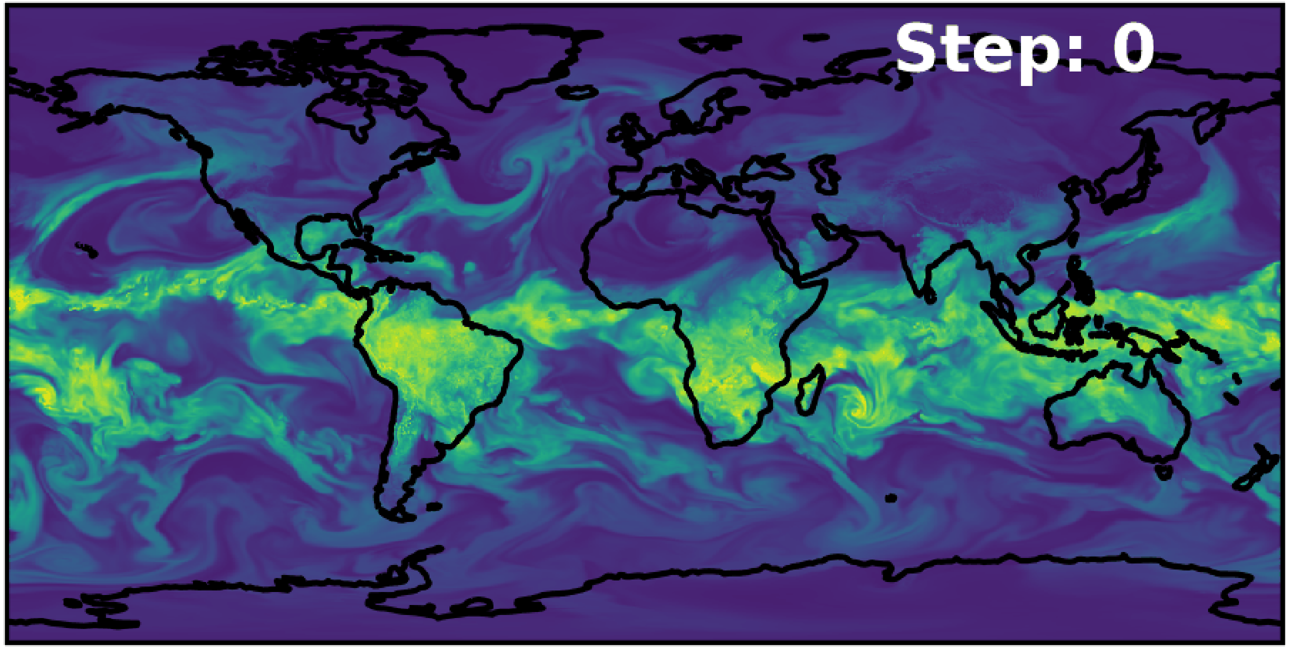
Achievements of scaling to **37B parameters**:

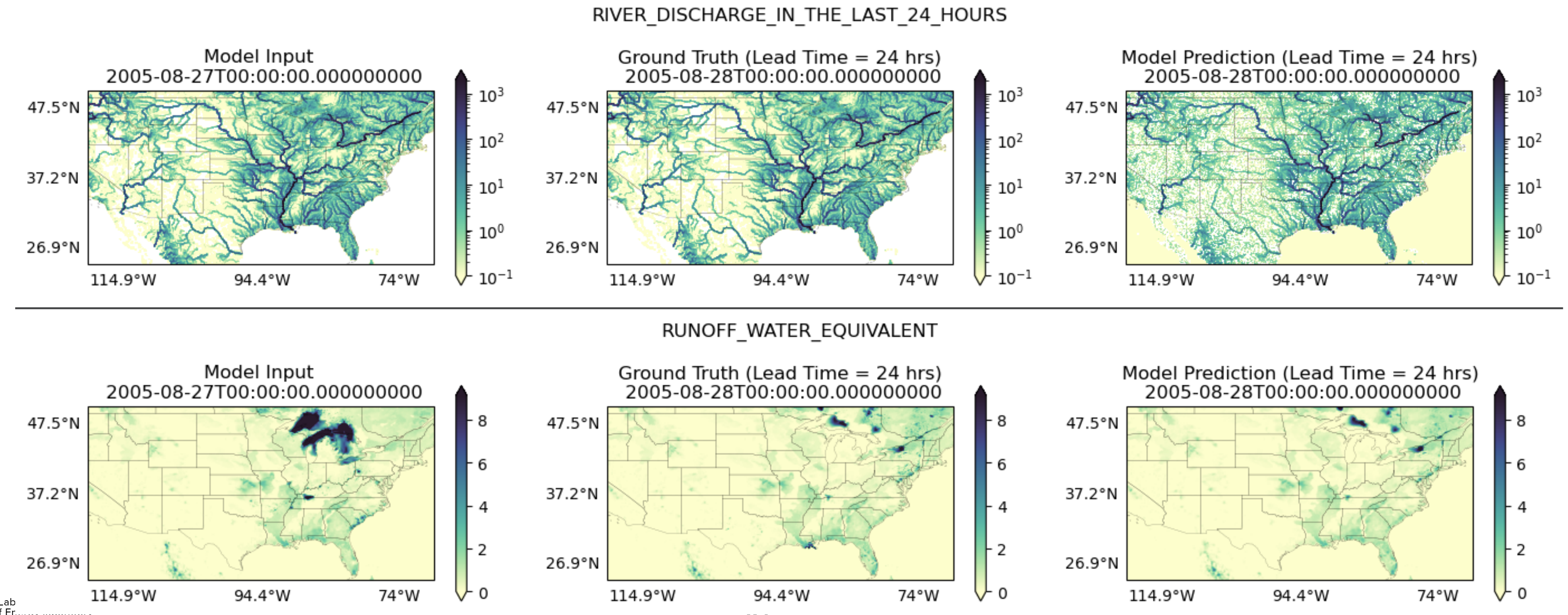
- One of the largest AI weather models
- Perfect linear scaling (log-log) across model sizes
- 9000 nodes (100,000 GPUs) – 90% of Aurora (currently 3rd fastest supercomputer globally)



# AI/ML FOUNDATION MODELS FOR FLOODING

## Near-Real-Time Prediction of Flooding from Current Meteorology

- Leverage multiple AI/ML approaches (Fourier Neural Operator & Shifting Windows Transformer) to project local-scale flooding up to 72-hours in advance of initiating meteorology and storm systems
- Also funded by DOE-CESER to provide near-real-time awareness of flood hazards to utilities and communities for emergency planning and response



# THANK YOU

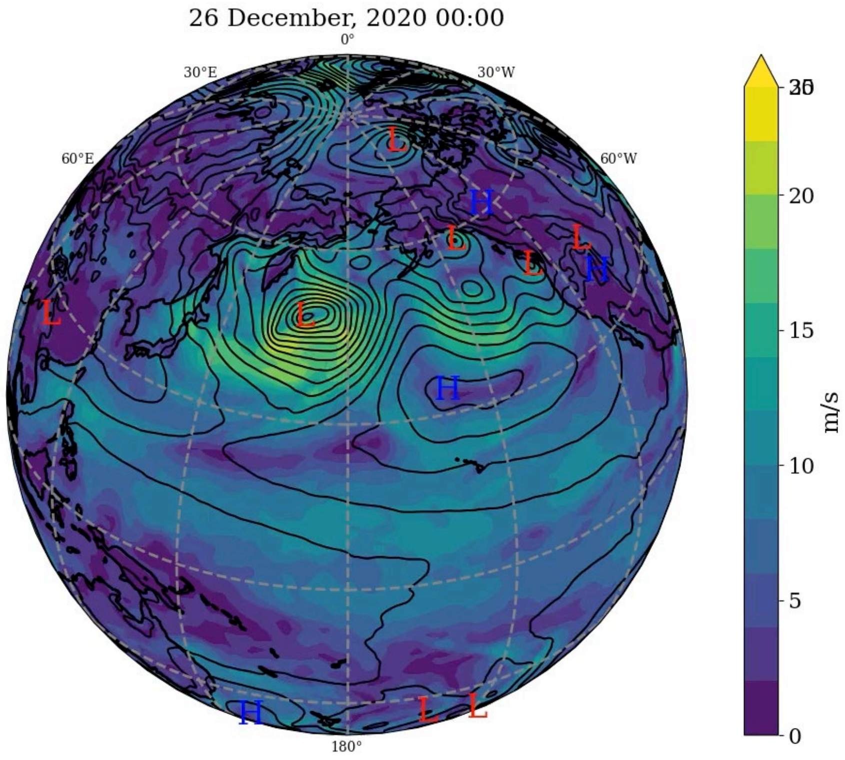
CENTER FOR
**RESILIENCE AND DECISION SCIENCE**
Argonne National Laboratory

Argonne
NATIONAL LABORATORY

# CRDS ONGOING RESEARCH EFFORTS

- **STORMER AI/ML Weather Model:** Argonne launched STORMER, an AI/ML-based weather model, and is updating for enhanced sub-seasonal to seasonal forecasting and long-term weather modeling
- **Generative AI-Based Regional Flood Model:** AI/ML based flood models to provide near-real-time awareness of future flooding from impending storm or typhoon events
- **Enhanced Local-Scale Physical Flood Modeling:** Applying lessons learned from national-scale WRF-Hydro modeling to project future flooding at 10m-50m, and incorporating urban stormwater systems
- **Capital Investment Decision Support Tool for Resilience:** Collaboration with LBNL, ComEd and other utilities, to evaluate power system weather vulnerabilities and conduct BCA of capital investments to increase resilience
- **Technical Assistance – Power Utilities and Emergency Managers:** Ongoing efforts with municipal and cooperative utilities, and emergency managers, to apply weather data in resilience planning

**STORMER:** Training using observation-based reanalysis (ERA5)



# Reliability Improvements from Undergrounding Distribution Power Lines

MPSC Case U-21388:
Undergrounding Workshop

**Luke Dennin, Ph.D.**

U.S. Department of Energy Fellow
Michigan Public Service Commission

September 17, 2025

MPSC
MICHIGAN PUBLIC SERVICE COMMISSION

# Agenda for the Talk

1. **Literature review**
   - What do we know from existing information?

2. **Data from Consumers Energy**
   - What does Michigan-specific data tell us?

3. **Statistical analysis**
   - Can we extract usable information for analysis?

# 1. Literature review

What do we know from existing information?

# Critical to this talk are IEEE reliability metrics

1. **SAIFI**
   - **S**ystem **A**verage **I**nterruption **F**requency **I**ndex
   - A measure of outage frequency

2. **CAIDI**
   - **C**ustomer **A**verage **I**nterruption **D**uration **I**ndex
   - A measure of outage duration

3. **SAIDI**
   - **S**ystem **A**verage **I**nterruption **D**uration **I**ndex
   - A combined measure, total time without power

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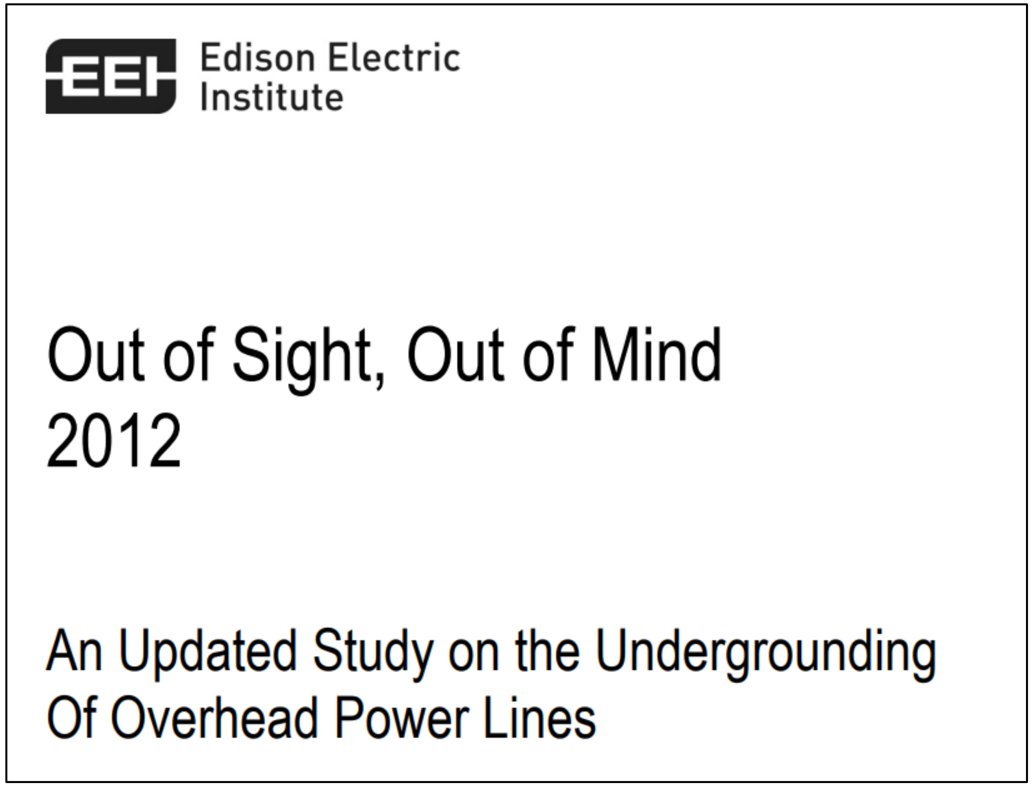
# Studies suggest undergrounding decreases outage frequency and slightly increases outage duration

## Study 1 of 5:

**Hall (2013): Edison Electric Institute Study**

- Overhead lines had much higher SAIFI than underground.
- CAIDI was only slightly higher for overhead.
- Combined effect meant SAIDI strongly favored undergrounding.



Edison Electric Institute

Out of Sight, Out of Mind
2012

An Updated Study on the Undergrounding
Of Overhead Power Lines

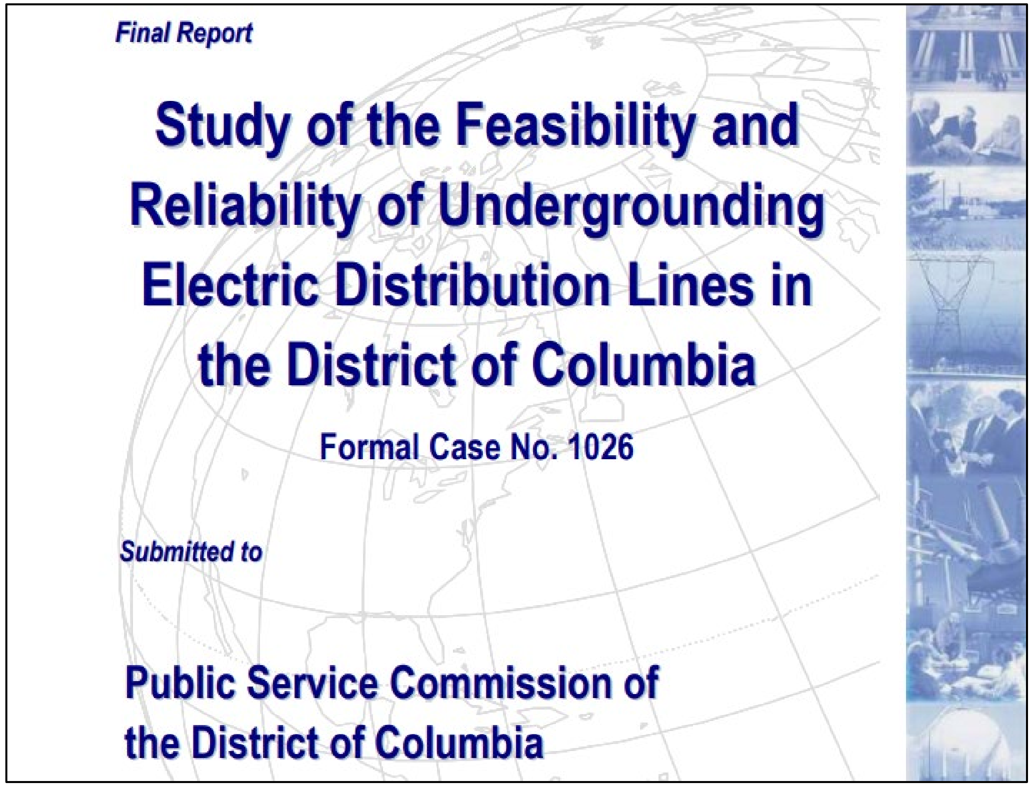
***Source:*** *Hall (2013) – Link*

# Studies suggest undergrounding decreases outage frequency and slightly increases outage duration

## Study 2 of 5:

**Shaw Consultants (2010): Washington D.C. Study**

- Undergrounding reduced SAIFI.
- But increased CAIDI for non-storm events.
- During storms, overhead CAIDI nearly tripled, while underground lines were protected.




**Source:** *Shaw Consultants (2010) – Link*

# Studies suggest undergrounding decreases outage frequency and slightly increases outage duration

## Study 3 of 5:

**NEI Electric (2009): New Hampshire Study**

- Estimated an up to 10x reduction in SAIFI with undergrounding.
- But also an up to 10x increase in CAIDI.

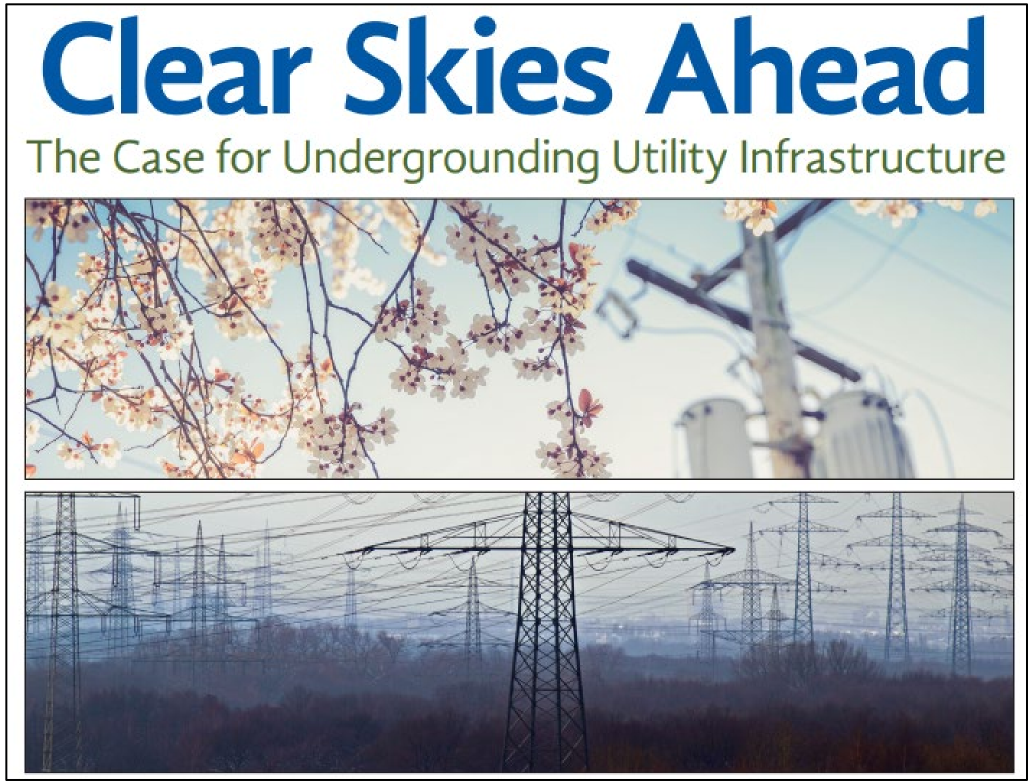

***Source:*** *NEI Electric (2009) – Link*

# Studies suggest undergrounding decreases outage frequency and slightly increases outage duration

## Study 4 of 5:

**twentytwenty LLP (2019): 7-State Meta-Analysis**

- 94% reduction in storm-related outages.
- 74% reduction in overall outages
- 52% increase in outage durations
- 61% net reduction in total outage time



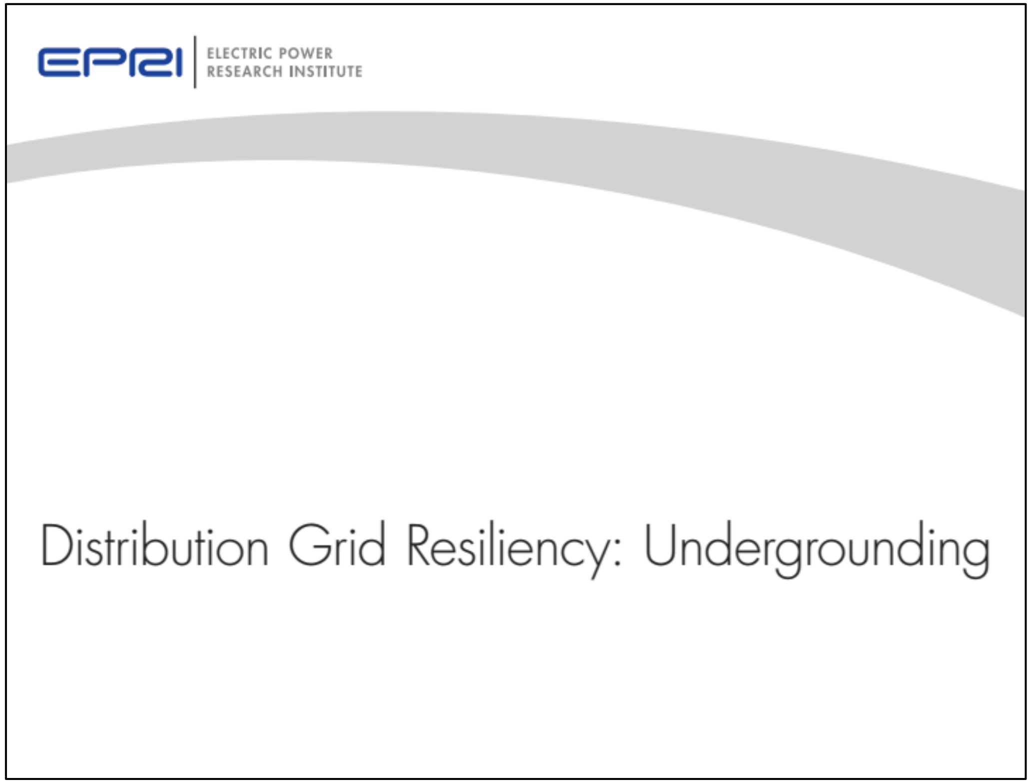

***Source:*** *twentytwenty LLP (2019) – Link*

# Studies suggest undergrounding decreases outage frequency and slightly increases outage duration

## Study 5 of 5:

**Tripolitis et al. (2015): Electric Power Research Institute Study**

- "[Undergrounding] is different from other options in that by removing aerial infrastructure from exposure, damage from wind, ice, and trees is 100% prevented from affecting that infrastructure."




***Source:*** *Tripolitis (2015) – Link*

# 2. Data from Consumers Energy

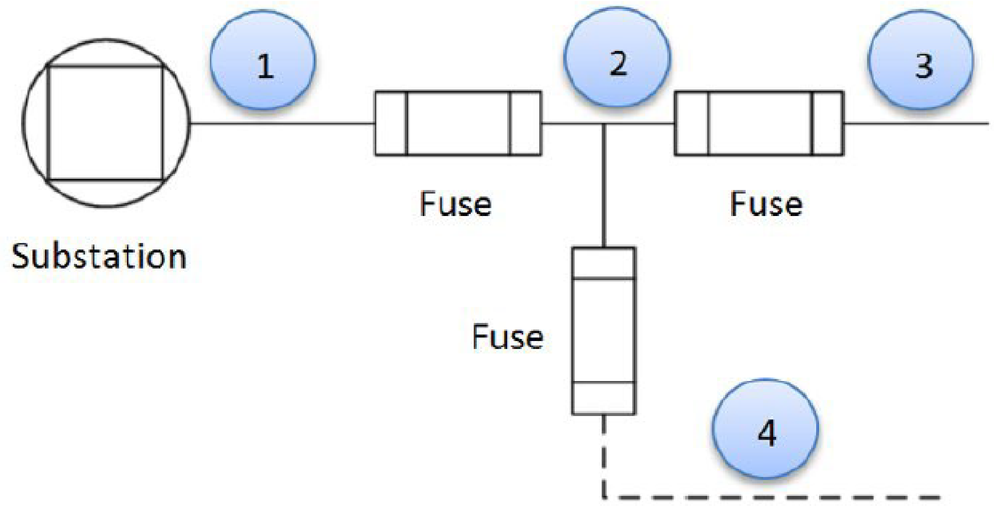
What does Michigan-specific data tell us?

# Here, we'll look at two groups of protective zones

- **Group 1: Overhead**
  - 108,541 (71%) protective zones
  - More than 50% overhead
  - Average stats:
    - 12 customers & 0.48 miles
    - 26 customers per mile
- **Group 2: Underground**
  - 44,937 (29%) protective zones
  - 50% or more underground
  - Average stats:
    - 14 customers & 0.21 miles
    - 64 customers per mile

***FIGURE 39***

*ILLUSTRATION OF CIRCUIT SUBDIVIDED INTO ZONES*




***Source:*** *Consumers Energy Company (2023) – Link*

# Critical to this talk are outage conditions

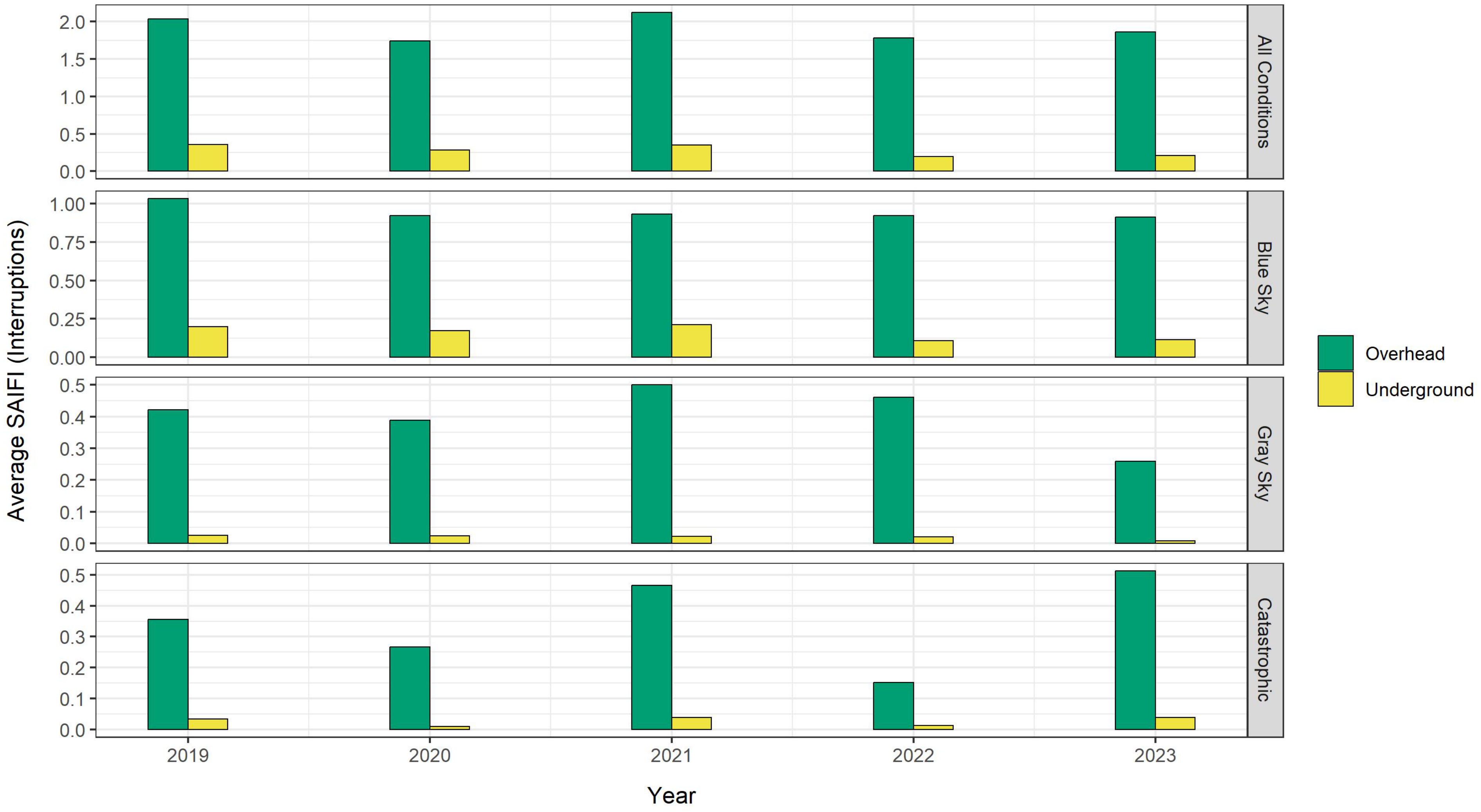
**Definitions from MPSC's service quality and reliability standards – Link:**

1. **Blue sky**
   - ≤1% of customers out

2. **Gray sky**
   - >1% and <10% of customers out

3. **Catastrophic**
   - ≥10% of customers out

# Undergrounding suggests SAIFI gains

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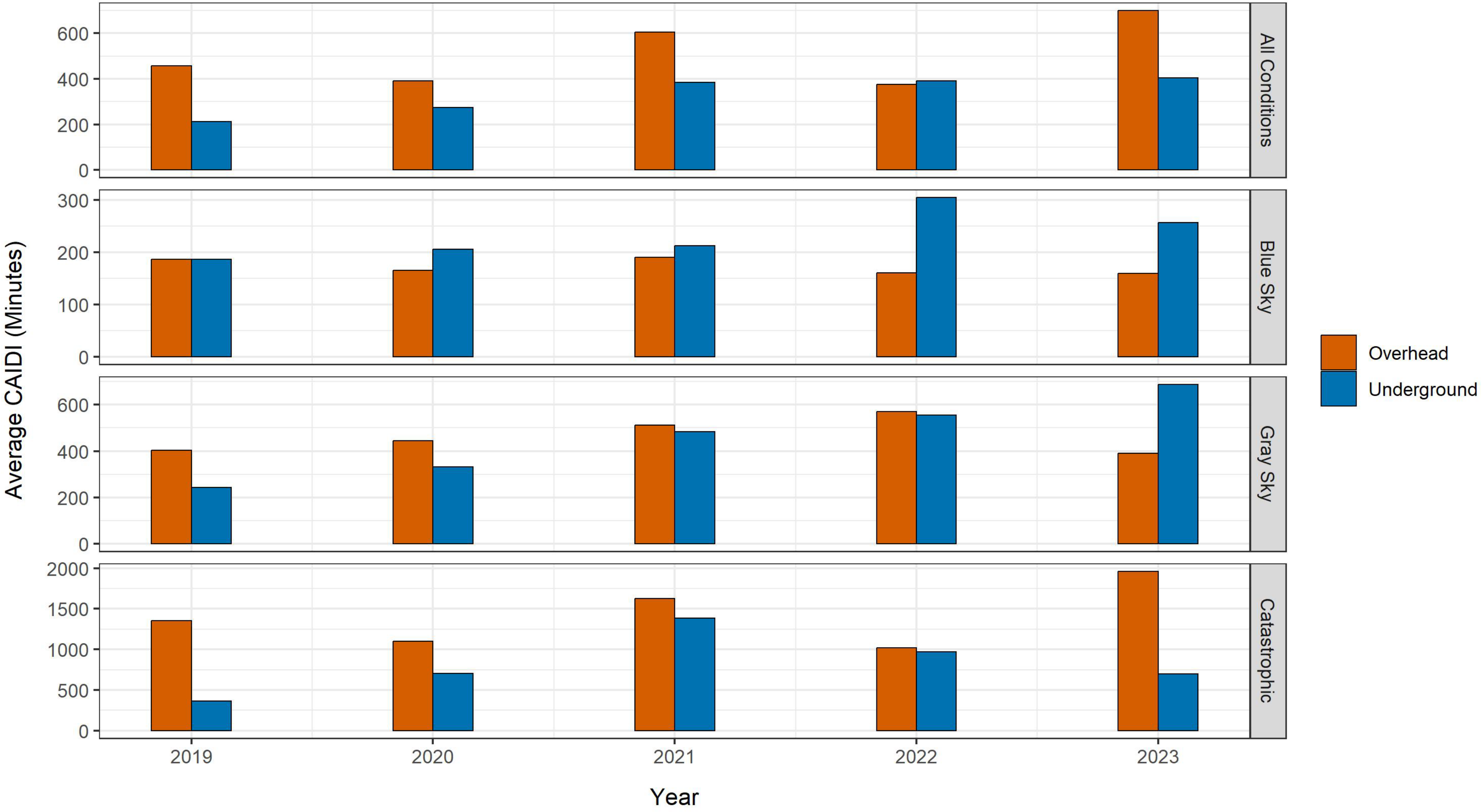
# CAIDI is more outage condition-dependent

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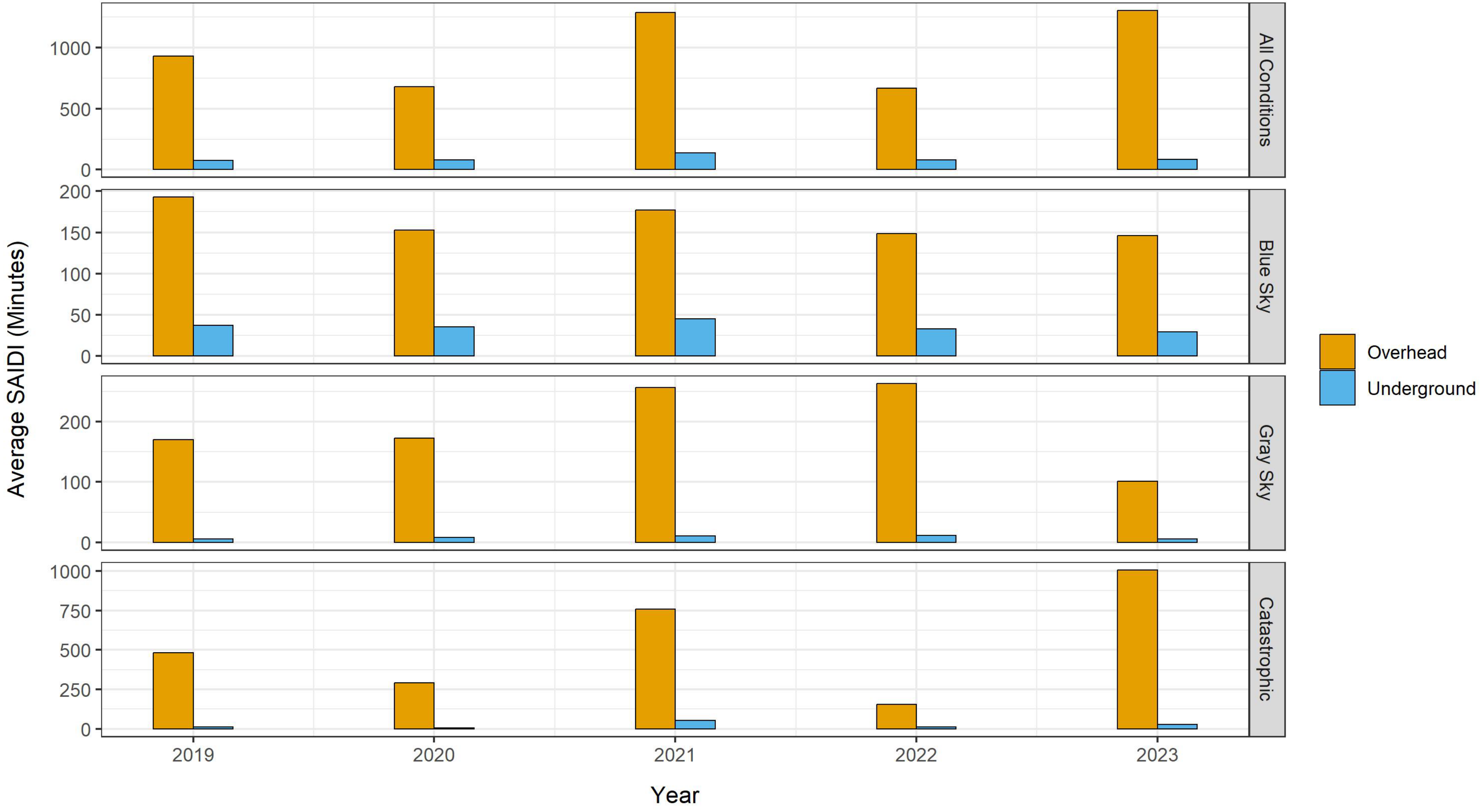
# Undergrounding suggests SAIDI gains

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# Let's again look at our two groups of zones

- **Group 1: Overhead**
  - 108,541 (71%) protective zones
  - 50% or more overhead
  - Average stats:
    - 12 customers & 0.48 miles
    - 26 customers per mile
- **Group 2: Underground**
  - 44,937 (29%) protective zones
  - 50% or more underground
  - Average stats:
    - 14 customers & 0.21 miles
    - 64 customers per mile

***Are there other reasons for the differences in the reliability metrics?***

***Is there omitted variable bias?***

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# 3. Statistical analysis

Can we extract usable information for analysis?

# As the share of underground increases, what is the expected change in the reliability metrics?

## Larsen et al. (2020) – LBNL Study

- **Approach:** Regression analysis of reliability metrics vs. underground line share.

- **Data:** >80 utilities, up to 16 years, annual (temporal) and service territory (spatial) granularity.

- **Objective:** Assess effect of undergrounding on SAIFI and SAIDI, controlling for other variables (e.g., high-wind days, distribution expenditures).

**Beta coefficients informing reliability impacts**

| Result | SAIFI | SAIDI |
|---|---|---|
| $\beta$ Coefficient | -4.26E-03 | -5.74E-03 |
| Significance | ** ($p < 0.05$) | N/A ($p > 0.10$) |
| 1%-pt ↑ in UG | -0.426% ↓ | -0.574% ↓ |

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# What do these reliability improvements look like in Michigan under different outage conditions?

## Dennin (2025) – MPSC Study

- **Approach:** Regression analysis of reliability metrics vs. underground line share.
- **Data:** >1,900 circuits, 5 years, 3 outage conditions + an all-condition model:
  - Blue Sky: <1% of customers out
  - Gray Sky: <10% of customers out
  - Catastrophic: >10% of customers out
- **Objective:** Assess effect of undergrounding on SAIFI and SAIDI, controlling for other variables (e.g., tree density, customer counts).

**Beta coefficients informing reliability impacts**

| Condition | SAIFI | SAIDI |
|---|---|---|
| All Condition | -4.87E-03*** | -8.02E-03*** |
| Blue Sky | -2.48E-03* | -5.61E-04 |
| Gray Sky | -6.51E-03** | -9.24E-03*** |
| Catastrophic | -7.36-03** | -8.51E-03*** |

***Note:*** *** p < 0.01; ** p < 0.05; * p < 0.10; ‘ ’ p ≥ 0.10

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# What do these reliability improvements look like in Michigan under different outage conditions?

## Dennin (2025) – MPSC Study

### CAIDI $\beta$ Coefficient Derivation:

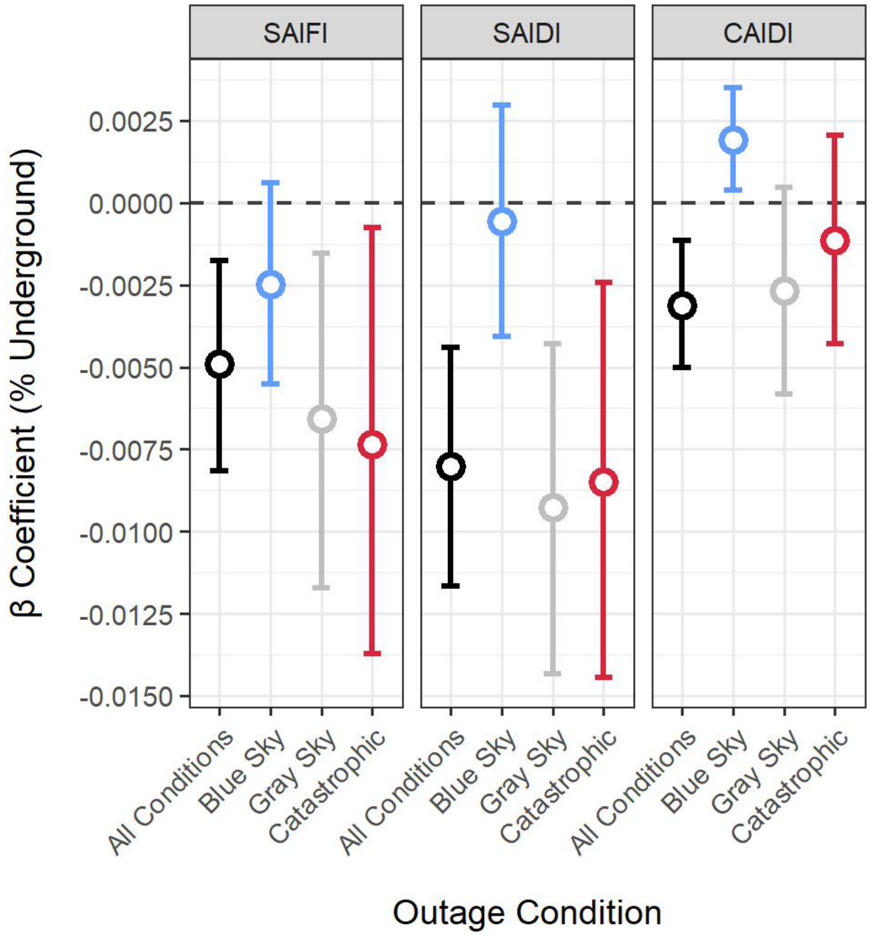
$$SAIDI_t = SAIFI_t \times CAIDI_t$$

$$ln(SAIDI_t) = ln(SAIFI_t) + ln(CAIDI_t)$$

$$\Delta ln(SAIDI_o) = \Delta ln(SAIFI_o) + \Delta ln(CAIDI_o)$$

$$\beta^{(u)}_{SAIDI_o} x_u = \beta^{(u)}_{SAIFI_o} x_u + \beta^{(u)}_{CAIDI_o} x_u$$

$$\beta^{(u)}_{CAIDI_o} = \beta^{(u)}_{SAIDI_o} - \beta^{(u)}_{SAIFI_o}$$



# This approach enables modeling experiments, like one-mile conversion project benefit-cost analyses…

## Dennin (2025) – MPSC Study

- **Example:** Theoretical Circuit
  - **Mileage:** 50 miles
    - 49 overhead (98%)
    - 1 underground (2%)
  - **One-mile conversion project:** 1 overhead mile to underground → +2%-point increase
    - The $\beta$ coefficient informs the percentage change in reliability metrics per 1%-point increase in undergrounding (interpretation: $\beta$ x 100 % change per 1%-point ↑)

| Gray Sky Metric | Baseline Metric Value | Beta Coefficient | % Change in Metric Value | Post-UG Metric Value |
|---|---|---|---|---|
| SAIFI | 1.03 | -6.51E-03 | -1.302% | 1.016 |
| SAIDI | 383 | -9.24E-03 | -1.848% | 375.6 |
| CAIDI | 373 | -2.73E-03 | -0.546% | 371.0 |

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# Thank you! Questions?

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**Washington, D.C.**

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# DTE Undergrounding Pilot Learnings

## MPSC Undergrounding Technical Workshop

September 17, 2025

# DTE identified tangible benefits from undergrounding by addressing challenges of increasingly unfavorable weather, decreasing customer sentiment, and financial challenges

**Why Undergrounding is important**

- We are seeing increasingly adverse weather, with the number of high wind days growing by nearly 5% each year
- Customer and stakeholder sentiment associated with electric reliability is becoming much less tolerant of long duration outages
- In addition, DTE continues to face challenges with rising reactive costs driven by storm and emergent trouble that impact customer affordability

**Benefits of Undergrounding**

- Relocating overhead distribution underground eliminates interference from trees and the risk of downed wires, improving safety and reliability
- Reducing or eliminating truck rolls to address trouble on small or single outages
- Eliminating significant reactive costs associated with Tree Trim maintenance on high-cost segments
- Shortening or eliminating the long-tail of storms by preventing small outages on completed projects

# The benefit and cost of undergrounding is dependent on the segments of the circuit to be undergrounded



## Backbone

- SAIDI improvement of 50 to 60%
- Small resiliency improvement ~ 7% of outage events
- Cost to underground
- $2M - $4.2M/mile versus OH $1.1M to $1.7M/mile

## Laterals

- SAIDI improvement of 20 to 25%
- Better resiliency improvement – ~20 to 25% outage events
- Cost to underground
  - 3 phase - $1M to $2M/Mile versus OH $0.5M to $1M/Mile
  - 1 phase - $0.8M to $1.5M/Mile versus OH $0.5 to $1.0M/Mile

## Secondary & Services

- SAIDI improvement of less than 1%
- Best resiliency improvement ~ 40 to 50% outage events
- Cost to underground
  - Secondary ~ $70/K per mile versus OH ~ 50/K per mile
  - Services - $4K to $7K per customer versus OH $1K per customer

DTE

# DTE has completed two urban strategic undergrounding pilots and captured learned from each one to apply to potential future projects

## Appoline – Detroit

- Urban environment with medium customer density
- Scope to convert rear-lot overhead to rear-lot underground
- **Learnings:**
  - Additional cost to clean up the rear lot alleys in an urban setting
  - Importance of upfront customer communications
  - Challenges of undergrounding of services from the rear lot

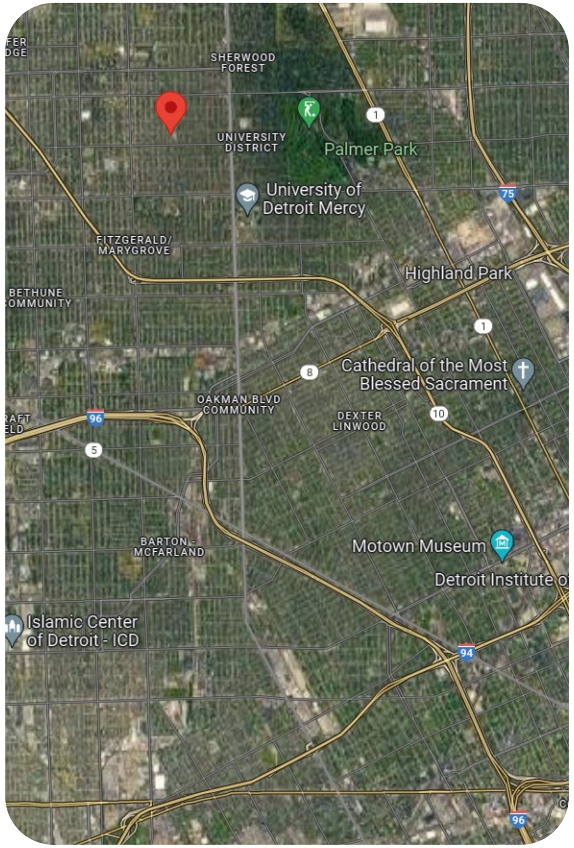
## Buffalo-Charles - Detroit

- Urban environment with low customer density
- Scope to convert rear-lot overhead to front-lot underground
- Work with DTE Gas to reduce implementation cost
- **Learnings:**
  - Importance of all easements/agreements procured prior to construction
  - Optimized Customer UG service agreement process with DTE Legal (notice letters)

# The first underground distribution pilot was the Appoline project in Detroit, it was completed in 2023

- The Appoline project's scope was to rear-lot underground ~1,300 feet of rear-lot overhead, impacting 61 customers
- The primary goal of the project was to identify safety benefits by relocating the overhead distribution lines to underground
- The conversion was completed for all customers in the Appoline project in November 2023

**Appoline Project – Bagley Neighborhood**



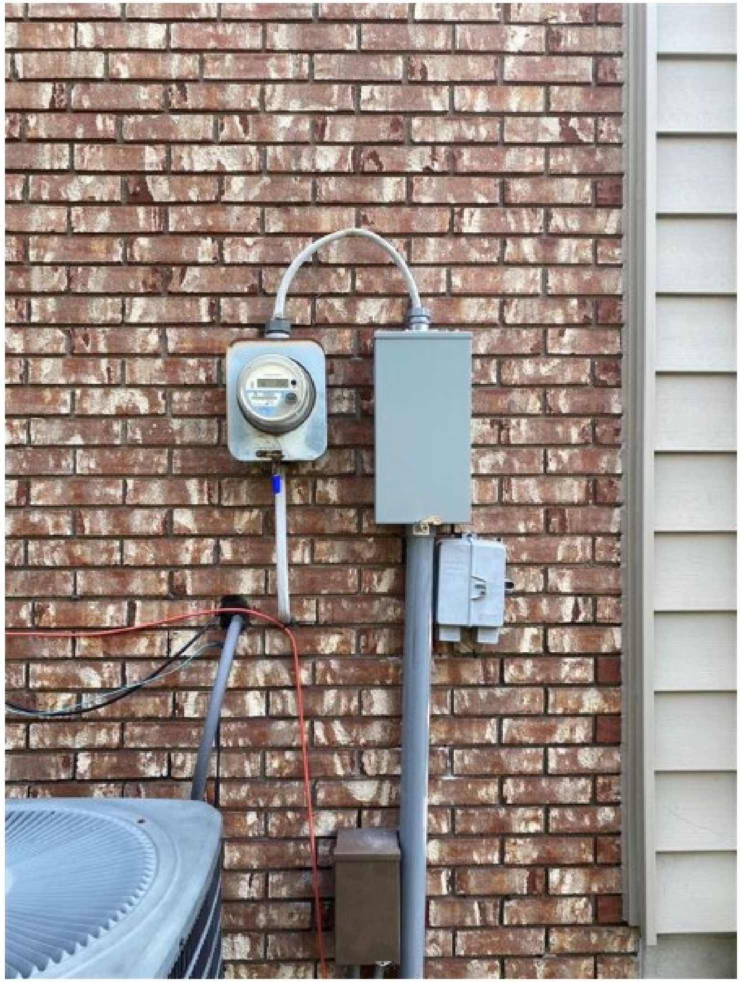

# The second underground distribution pilot was the Buffalo-Charles project in Detroit, it was completed in 2024

- 16 cable pole locations for 8 new primary feeders and approximately 2,500’ of new overhead conductor to facilitate primary feeders were installed per block to enable scalable construction based on easement procurement
- 17,500’ of new URD cable, 77 pad-mounted transformers, 260 pedestals, and 455 underground residential services were installed
- Approximately 2.4 miles of rear-lot overhead lines were removed from the area (marked in red)

**Buffalo-Charles Neighborhood Project**


DTE

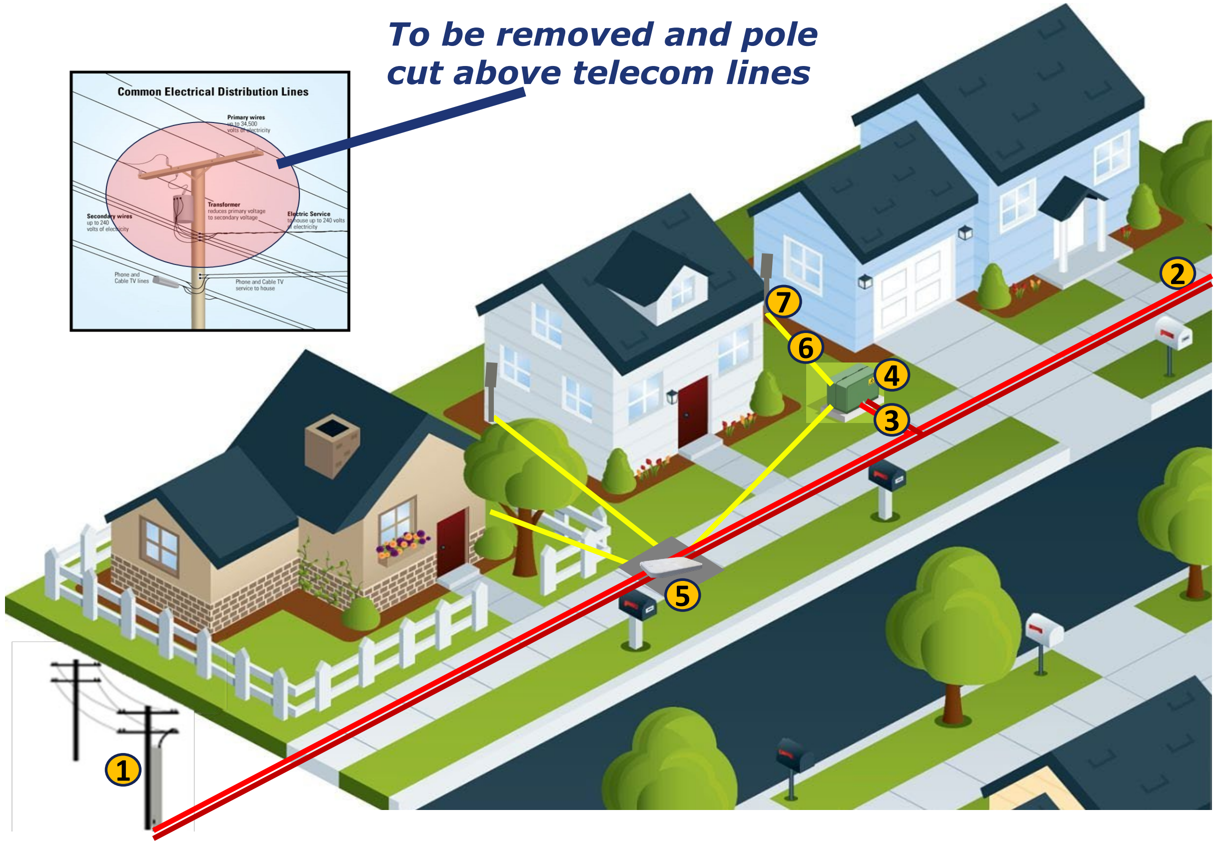
# Overhead to underground service conversions were performed using junction boxes to limit scope of work to utility side of meter



- Services were undergrounded by boring to the location that was feasibly nearest the meter and brought into a junction box mounted on the customer’s home. Service entrance cable was brought out of the top of the junction box and routed back to the meter.
- Installing the junction box minimized the impact to the customer by removing the need for them to spend time and money to upgrade their service equipment
- Each junction box requires a signed agreement from the customer.
- Typical service size is 2/0 Aluminum cable

# The actual costs of pilots have lateral undergrounding costs at approximately three to five times the cost of an overhead rebuild. Both pilots took approximately two years to complete.

| | Appoline | Buffalo Charles |
|---|---|---|
| Project Type | Rear OH to Rear UG (Services Only) | Rear OH to Front Lot UG (primary, Secondary & Services) |
| Project Status | Complete | Complete |
| # of Customers | +/- 61 | +/- 455 |
| Actual Cost per mile | 2.9 M | 3.2 M |




DTE

# Through the pilot projects DTE Electric identified construction synergies that may improve cost and further quantify benefits

**Lessons the Company has learned from these pilots**

- Obtaining easements and properties rights to construct new assets above and underground requires extensive planning
- Field construction is more complicated and longer in duration to safely avoid conflicts with other utilities and mature trees
- Structures (such as sheds, pools, patios, etc.) and other obstacles can prohibit or prevent construction in established areas
- Homes with rear-lot overhead typically have their meters located on the rear of the home, providing for longer and more challenging service runs

# Strategic Undergrounding next steps

- Incorporate the less tangible benefits of safety and resiliency into the BCA model by utilizing a risk valuation framework (Probability x Consequence) to gain broader regulatory support and identify future projects with forecasted benefits that exceed the cost

- Continue to learn from our UG pilots and industry peers to further drive productivity and cost efficiency improvements

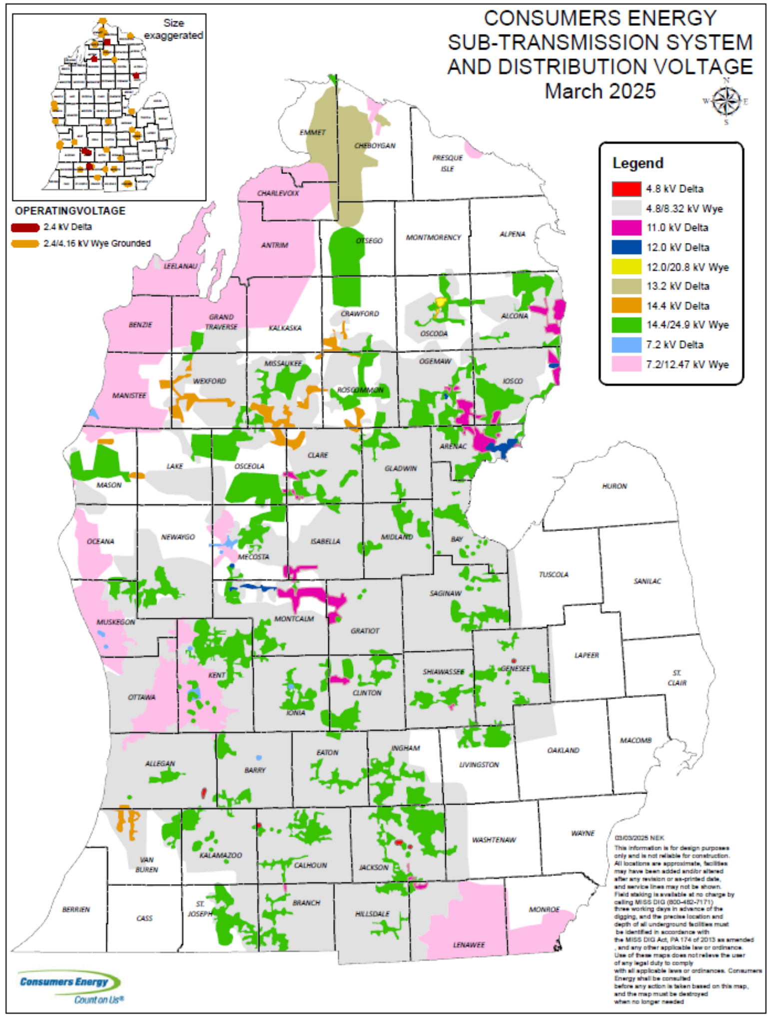
- Continue to evaluate new technologies, standards, and construction methods to reduce undergrounding costs relative to OH rebuild

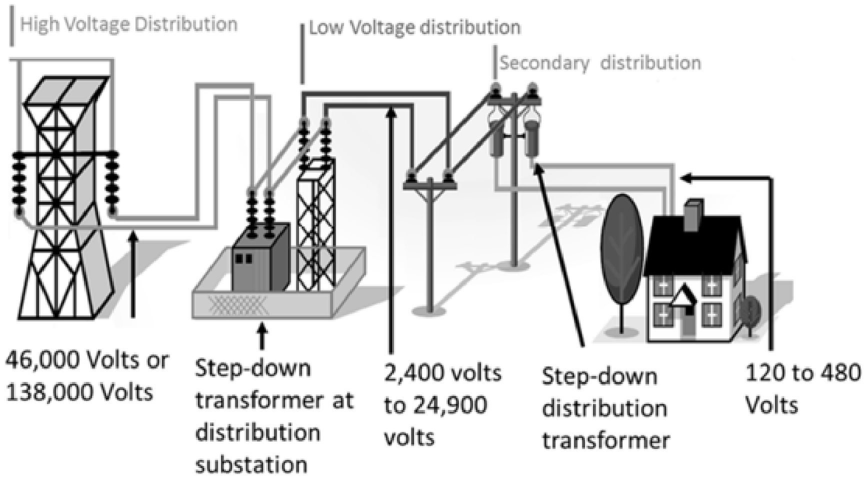
# Underground Pilots & Performance

September 17, 2025

Consumers Energy
Count on Us®

# Consumers Energy's distribution system serves 1.9 million customers over 1.6 million poles, almost 116,000 line miles, and 1,135 substations




## 28,600 Sq. Miles

- 20% larger than peer average
- Each overhead line worker covers 25 sq. miles and 45 line miles

## 1.6 Million Poles

- 0.1MM HVD
- 1.1MM Primary
- 0.4MM Secondary

## 1,135 Substations

- 144 HVD
- 163 Dedicated Customer
- 828 General Distribution
- 30 Serving Municipalities and Co-ops

## 115,905 Line Miles

- 4,600 miles of HVD
- 51,735 miles of primary overhead,
- 9,885 miles of primary underground,
- 31,210 miles of secondary overhead,
- 18,475 miles of secondary underground

# Agenda

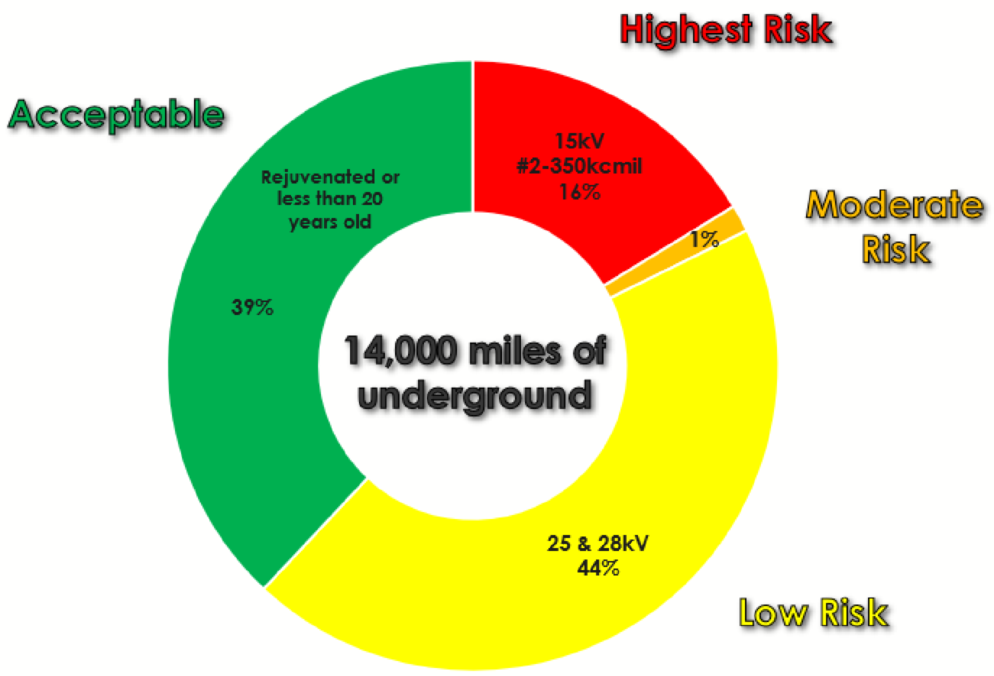
- Historic Undergrounding and Cable Rejuvenation
- Overhead to Underground Conversion Pilot

# Approximately 16% of the Company primary distribution system is underground, nearly 10,000 system line miles, or 14,000 miles of cable

## Underground History:

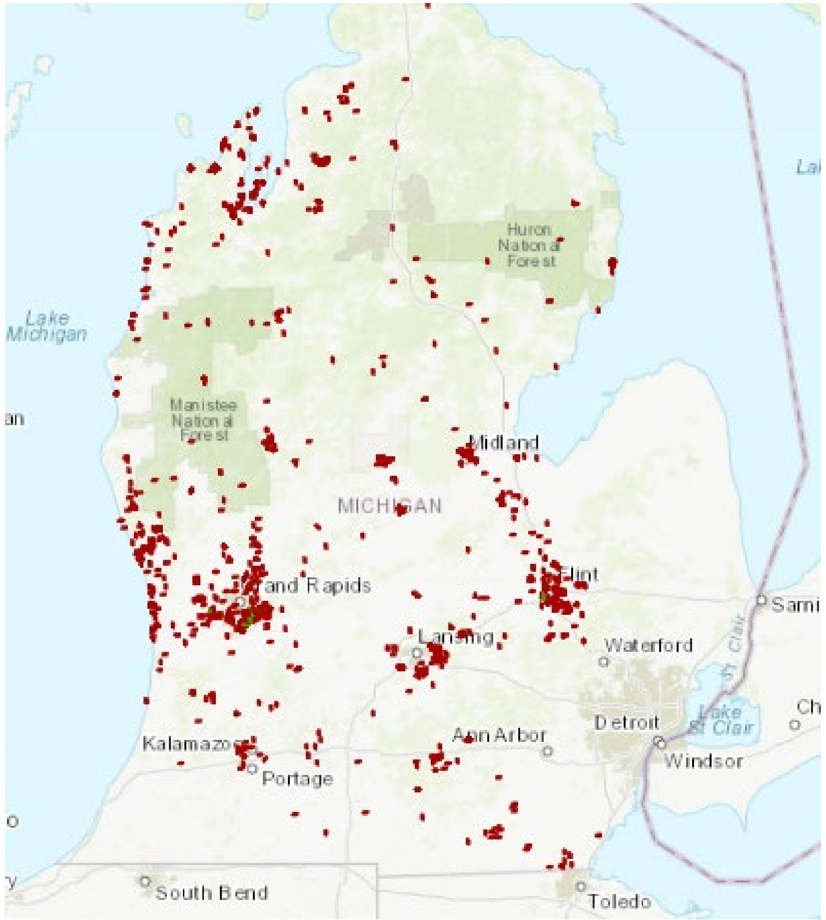
| | |
|---|---|
| 1960s | First installations of Underground (Bare Neutral, 15 kV) |
| Early 1970s | Transitioned to installing all 28 kV cable – Strand filled |
| Early 1990s | Changed to Jacketed cable (Covered Neutral) |
| Late 1990s | Changed to 25 kV rated and tree retardant insulation providing better and more durable insulation |
| Now | Cable rejuvenation of smaller 15 kV cable installations feeding residential and small commercial areas |

*Underground Cable Risk*



# The Company plan to rejuvenate approximately 2,300 miles of the smaller cable that is serving subdivisions and small business

**Vintage Cable Locations**

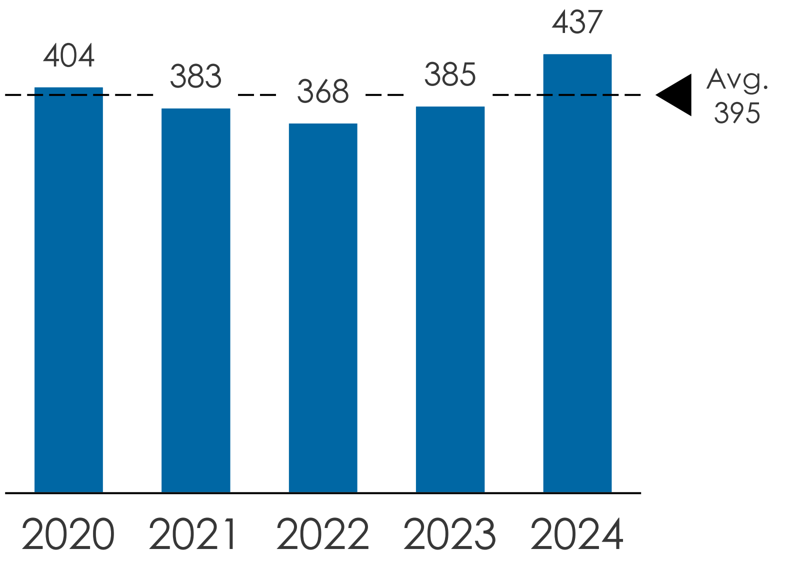



The Company has targeted only two communities at this point—Grand Rapids and Flint, with projects planned additionally in the Traverse City area in 2026

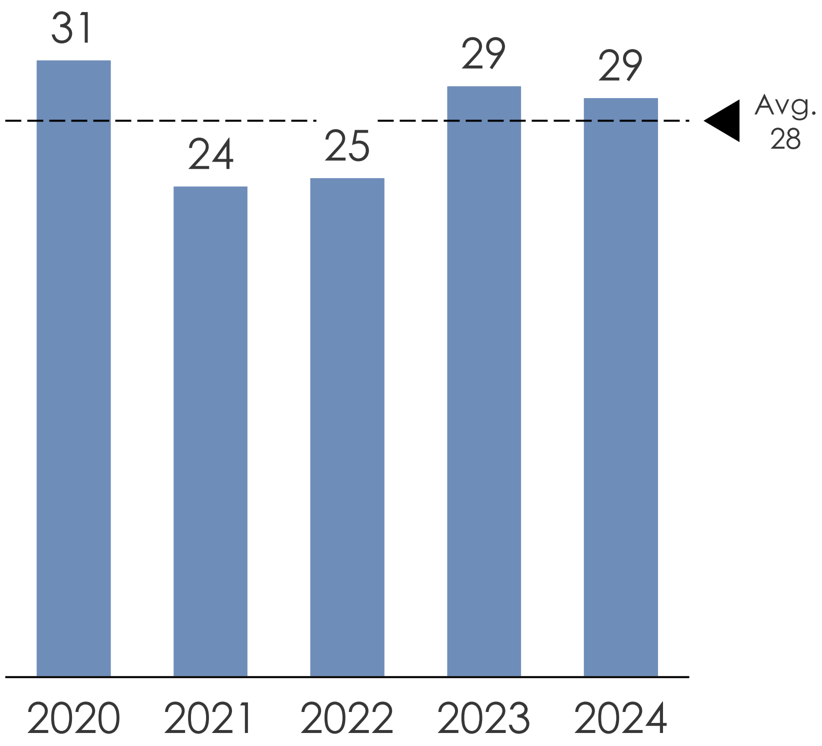
The Company plans to rejuvenate the highest risk 15kV cable at a rate of approximately 250 miles per year through 2033

# Underground cable faults accounts for 395 incidents per year, impacting 28,000 customers, on average

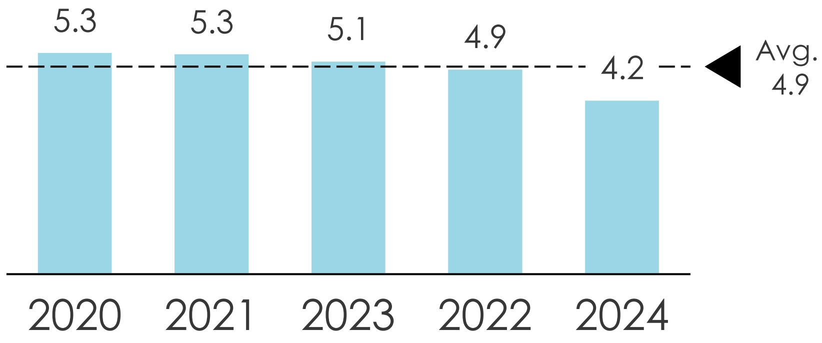
## Underground Incidents
(# of Incidents)




## Outages
(thousands # of Customers)

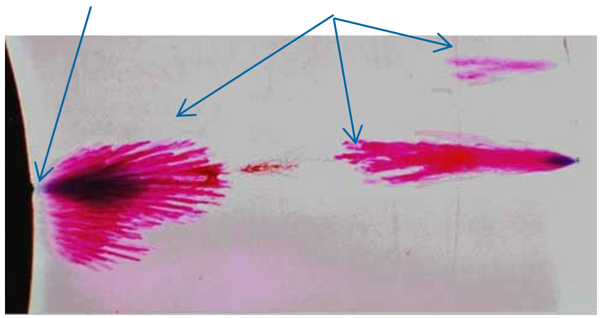



## All-weather SAIDI
(minutes)

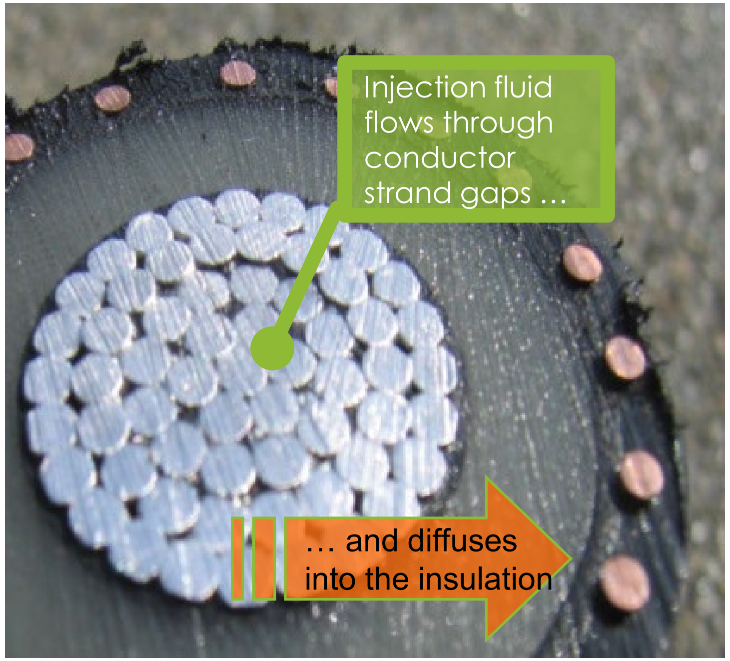


# Cable rejuvenation is lower cost than replacing with new cable

### Testing and Rejuvenating




*Flawed cable insulation*




Rejuvenating at $32/foot compared to Replacement at $80/foot

### Cable Rejuvenation Process

1. Take a cable out of service
2. Perform neutral and air flow testing
3. Inject a fluid like insulation that solidifies over time,
4. Put cable back into service all at a lower cost than replacing the cable with new

Any cable that fails the testing portion of the process gets replaced with new, jacketed cable

No injected cable failures to date

# Agenda

- Historic Undergrounding and Cable Rejuvenation
- Overhead to Underground Conversion Pilot

# In 2023, Consumers proposed converting ~10 miles of overhead to underground to test cost effectiveness to traditional hardening

## Circuit Segments originally proposed for Undergrounding

| Community | Substation | Circuit | LCP | Overhead Miles | Customers | CAIDI | Project Cost | Other |
|---|---|---|---|---|---|---|---|---|
| Saugatuck | Saugatuck | Douglas | 063 | 0.6 | 54 | 665 | $240,000 | |
| Fennville | Blue Star | Pier Cove | 622 | 1.2 | 39 | 604 | $480,000 | |
| Parshalville | Dean Road | Hogan | 951 | 2.0 | 73 | 868 | $800,000 | |
| Tawas | Tawas | Tawas | 482 | 0.8 | 67 | 641 | $300,000 | Federal Disadvantage Community |
| Hudsonville | Hager Park | Wellington | 536 | 0.6 | 12 | 1834 | $240,000 | |
| Greenville | Peck Road | M-91 | 473 | 2.1 | 72 | 640 | $840,000 | |
| Trowbridge | Merson | Merson | 412 | 2.0 | 66 | 1119 | $800,000 | Federal Disadvantage Community |
| Genesee | Geneseeville | Rogers | 100 | 1.0 | 48 | 949 | $420,000 | MI Environmental Justice |
| **Total** | | | | **10.3** | | | **$4,120,000** | |

# The segments were identified based on nine selection criteria where undergrounding could be considered to improve resiliency

**Selection Criteria:**

1. will be single-phase,
2. have had at least one outage in the last 24 months,
3. serve between 10 and 100 customers[1],
4. be operated at one of the three standard wye voltages,
5. not be considered for another reliability project,
6. have an average CAIDI of 600 minutes or more[1],
7. have a load after installation of 36% or less of the ampacity of the newly installed facilities,
8. be located in an area of dense trees[1], and
9. not supply an overhead system

The criteria were designed to target areas that would benefit most from undergrounding, particularly those prone to outages due to environmental factors like dense tree cover

1. Criteria has been updated in latest case U-21870

# Ultimately, the Company landed slightly shy of its 10 miles goal in completing approximately 9 miles in the test year

## Status of Projects

| | Community | Substation | Circuit | OH Miles | Customers | Status |
|---|---|---|---|---|---|---|
| Originally Proposed | Saugatuck | Saugatuck | Douglas | 0.6 | 54 | Complete |
| | Fennville | Blue Star | Pier Cove | 1.2 | 39 | Halted |
| | Parshalville | Dean Road | Hogan | 2.0 | 73 | Halted |
| | Tawas | Tawas | Tawas | 0.8 | 67 | Late |
| | Hudsonville | Hager Park | Wellington | 0.6 | 12 | Complete |
| | Greenville | Peck Road | M-91 | 2.1 | 72 | Halted |
| | Trowbridge | Merson | Merson | 2.0 | 66 | Halted |
| | Genesee | Geneseeville | Rogers | 1.1 | 48 | Complete |
| Subsequently Added | Port Sheldon | Pigeon Lake | Olive | 1.2 | 37 | Complete |
| | Hillsdale | Carleton Road | Beck Road | 1.0 | 15 | Complete |
| | Standish | Duquite | Saganing | 1.5 | 20 | Complete |
| | Newaygo | Conklin Park | Holly | 1.4 | 10 | Complete |
| | Honor | Honor | Indian Hill | 1.5 | 43 | Complete |

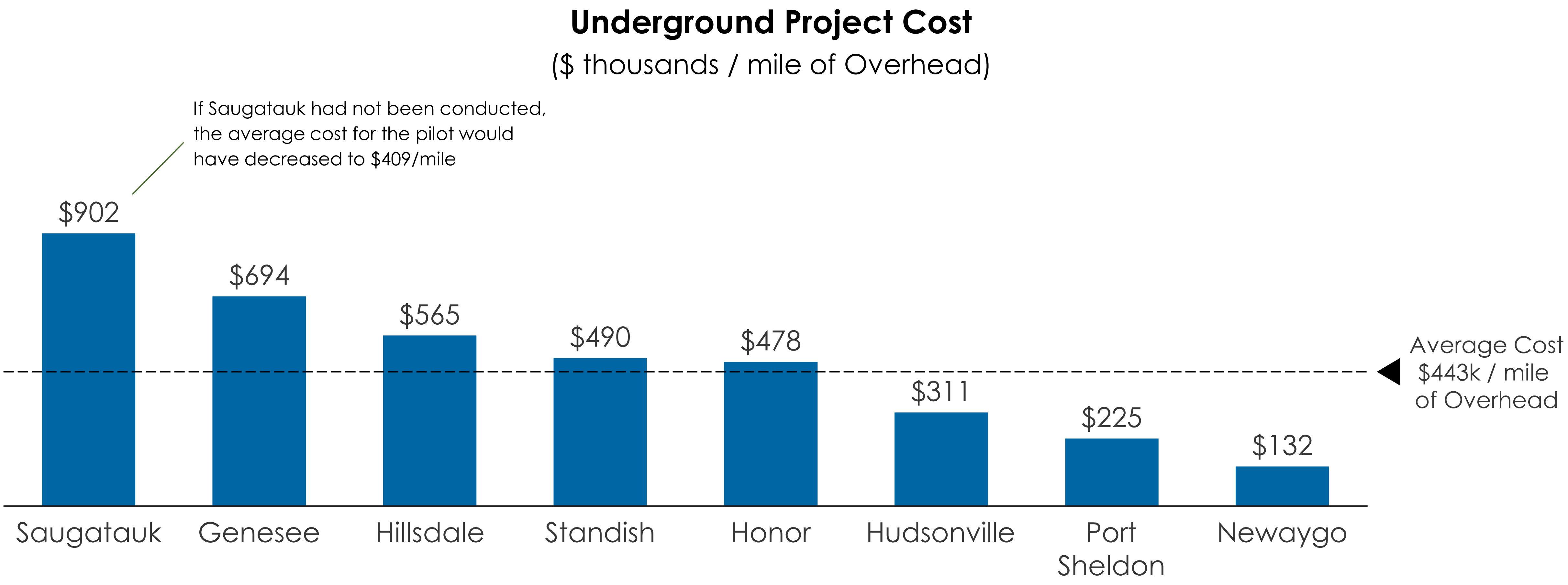
## Lessons Learned

- Need to keep momentum going on undergrounding as project planning and design needs to happen well in advance of plan year
- All projects in delayed status were due to issues in acquiring easements
- Utilizing the road right-of-way should reduce easement difficulties and vegetation removal and allow for faster and less costly construction through plowing as opposed to boring

## Customer Feedback

- Several customers expressed excitement for better reliability
- Customer alignment is needed on equipment locations, even with existing easements
- Better understanding of forestry activities is needed for undergrounding construction

# The Company experienced a large range of project costs with an average pilot cost of approximately $443k / mile of overhead converted




Average cost based on underground conductor installed was $422k/mile, or $398k/mile excluding the costliest project, lower than the $626k/mile cost the Company first expected the process to cost in the early half of the decade[1]

1. U-21122 filed in 2021 had an expected cost of undergrounding averaging $626k for Rural Feeder

# The conditions present at the undergrounding locations affected the project costs

## High End Conversion Cost

Saugatuck at $902k per Overhead Mile

Almost 100% bore
Narrow right of way
High customer density
Busy road with popular local park

## Low End Conversion Cost

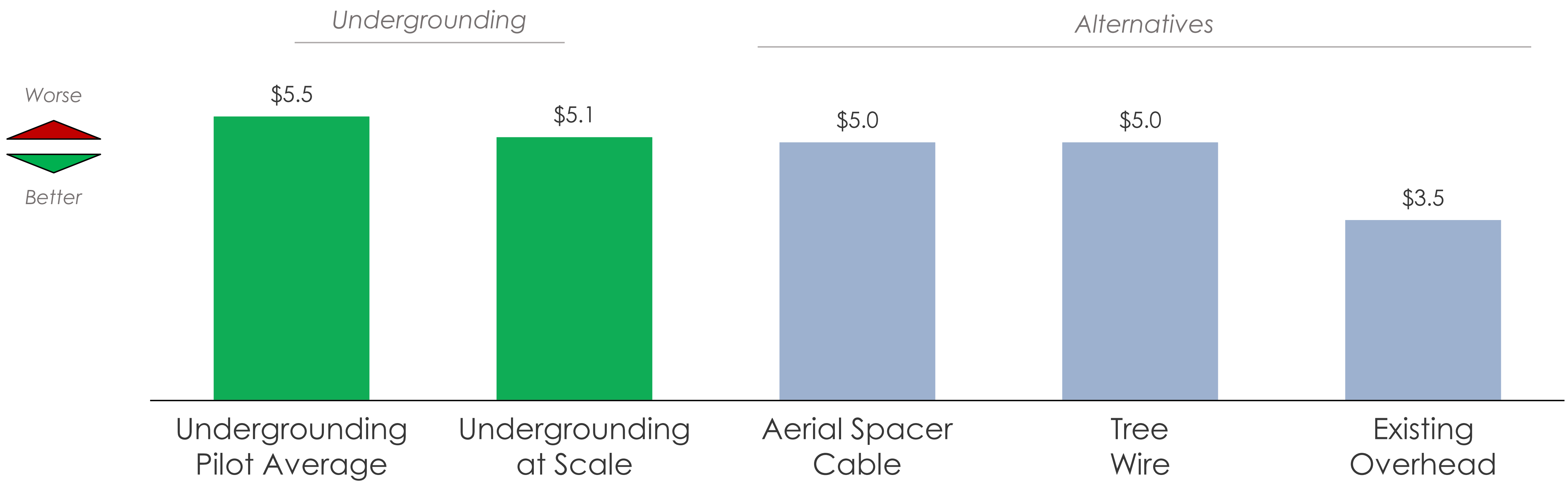
Newaygo at $132k per Overhead Mile

100% plowing, no boring
Rural with good right of way
Lower customer density
Away from busy roads

# When programmatically converting overhead to underground, avoid high-cost areas to yield a comparable cost to customers

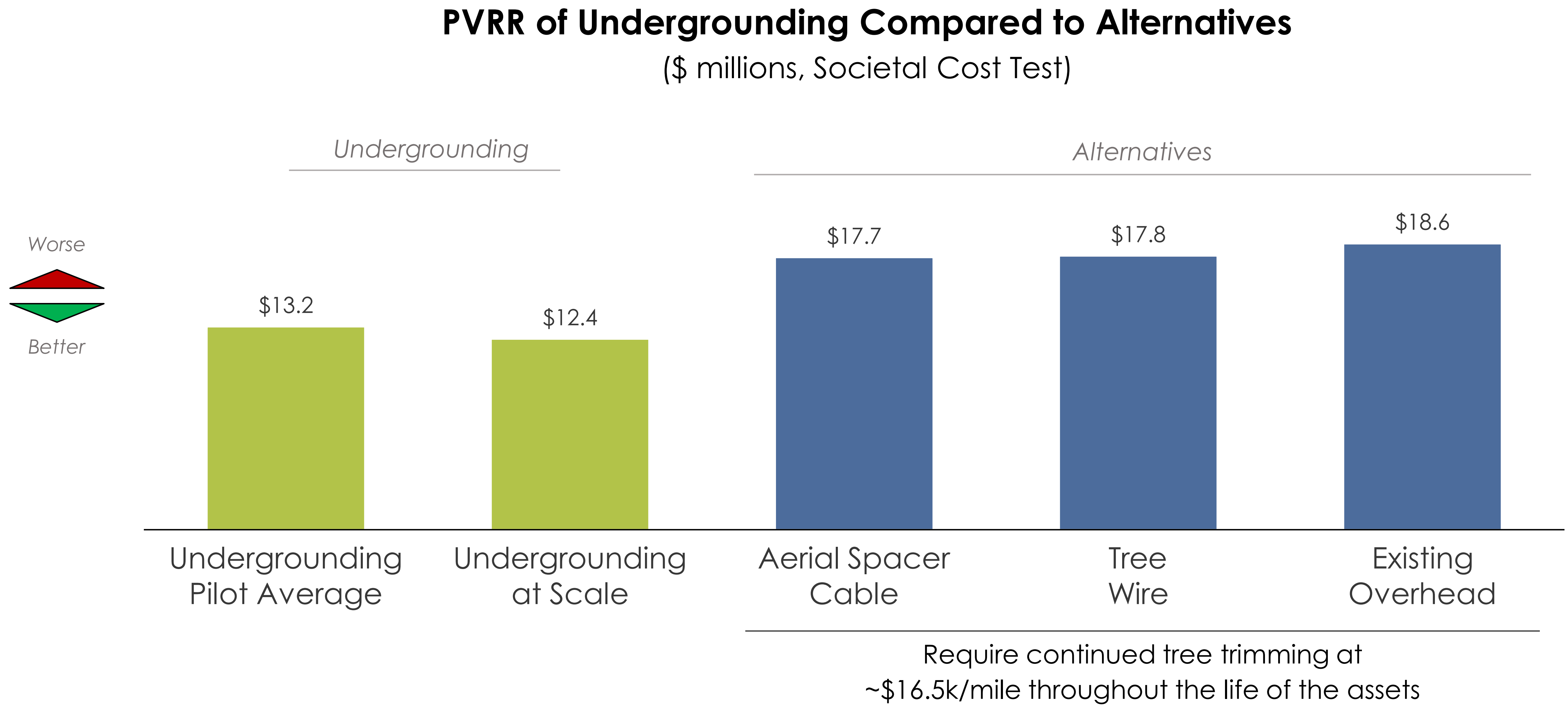
**PVRR of Undergrounding Compared to Alternatives**

($ millions, Utility Cost Test)

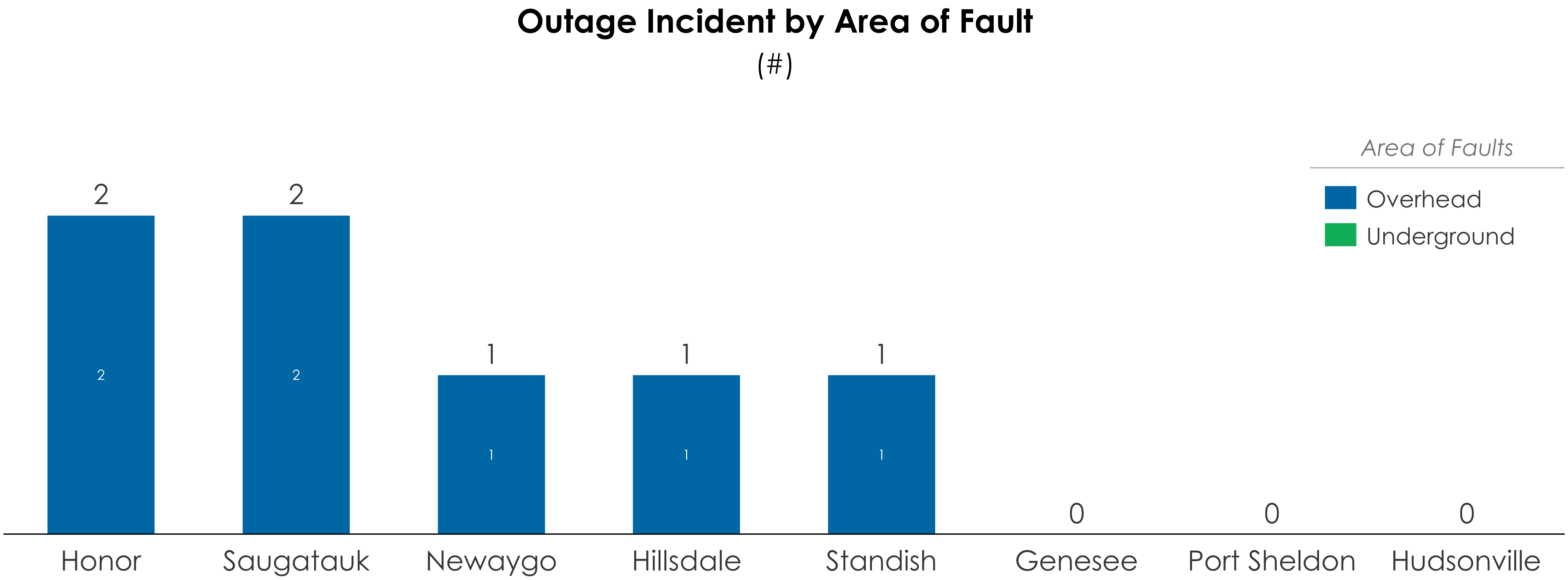



Require continued tree trimming at ~$16.5k/mile throughout the life of the assets

# Undergrounding provides better value to customers when utilizing an alternate valuation methodology to consider the societal costs of outages



# Since the completion of the pilot, customers have experienced outages but they are due to faults on the overhead system powering their feeders




Customers experience outages because the undergrounded segments of the system are still fed by an overhead system and exposed to severe weather and trees

ALPENA POWER COMPANY

# Undergrounding in Michigan

# Utility Perspective & Efforts Underway

## September 17, 2025

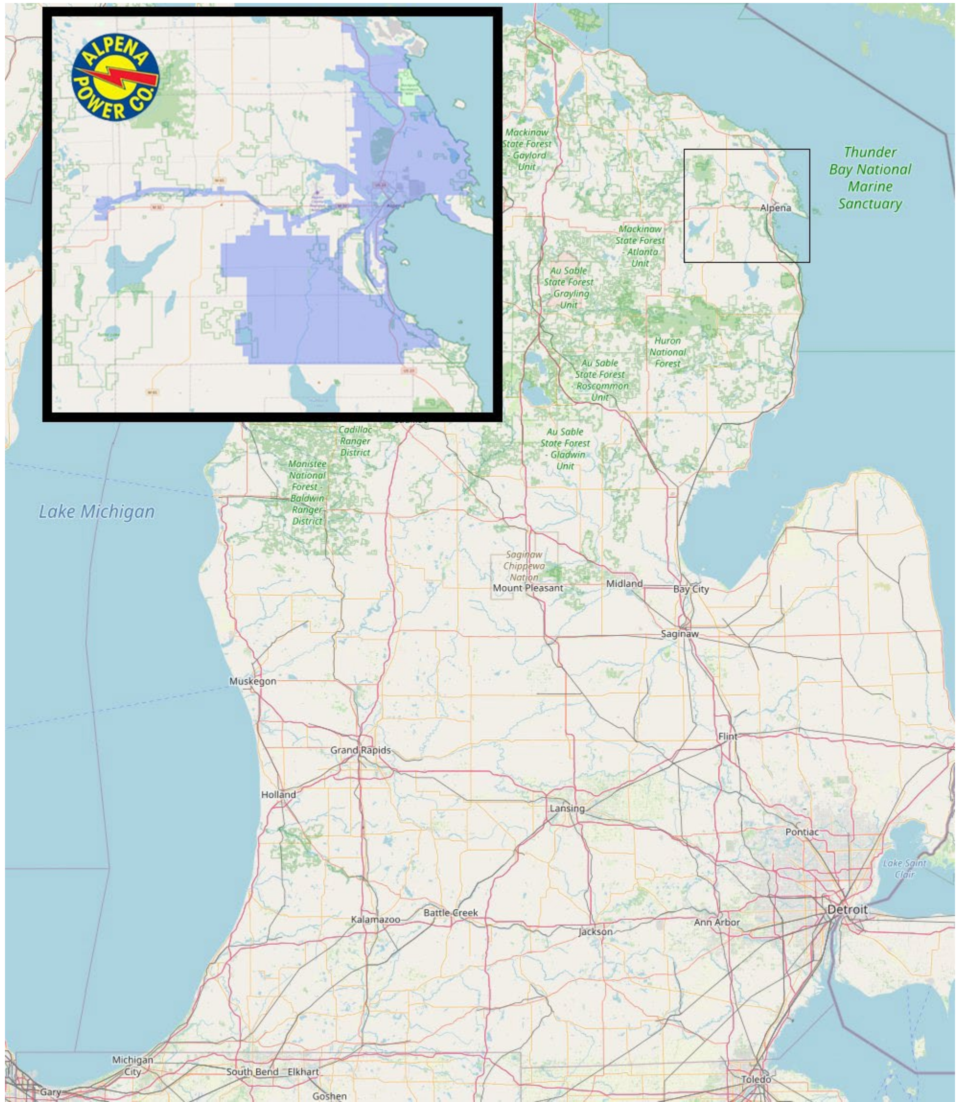
ALPENA POWER COMPANY

# Company Overview

- Serve approximately 16,750 customers in NE lower MI
- Service territory includes portions of Alpena, Alcona, Montmorency and Presque Isle counties
- Territory includes approximately 61 miles of Lake Huron shoreline and 250 square miles
- 656 Miles of Overhead Primary Line
- 75 Miles of Underground Primary Line
- 33 Full Time Employees

ALPENA POWER COMPANY

# Service Territory



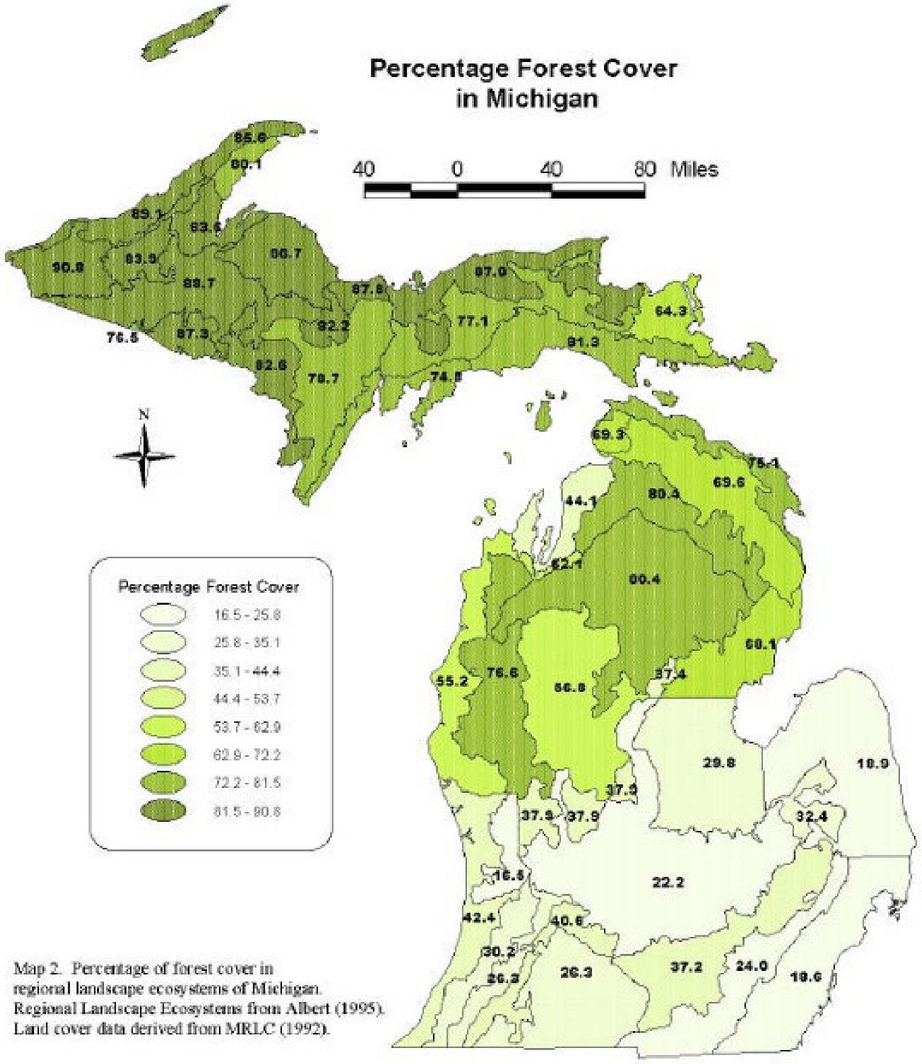
**ALPENA POWER COMPANY**

# Service Territory Challenges – Wetlands [1]


[1] https://www.michigan.gov/egle/maps-data/wetlands-map-viewer

**ALPENA POWER COMPANY**

# Service Territory Challenges – Forest Cover [2]




Map 2. Percentage of forest cover in regional landscape ecosystems of Michigan. Regional Landscape Ecosystems from Albert (1995). Land cover data derived from MRLC (1992).

[2] https://www.michigan.gov/- /media/Project/Websites/dnr/Documents/FRD/SFMP/13overview.pdf?rev=44d9b8f272cb439ca62540b650ba 5ba9

ALPENA POWER COMPANY

# Reliability Challenges

- Repetitive outage issues in rural areas with low customer density
- Results in non-compliance with reliability standards for some customers
- Majority of outage causes are tree related
- Wet, rocky terrain leads to shallow tree root bases subject to uprooting
- Many trees causing outages come from outside the right-of-way

ALPENA POWER COMPANY

# Undergrounding Projects – Bloom Road Circuit

- Rural circuit serving about 330 customers
- Over 36 miles of primary, most of which was overhead construction prior to 2011
- Over 12 miles of Lake Huron shoreline
- Heavily wooded wetland with rocky soils
- Customers experienced significant outage minutes due to repetitive outages
- Full easement tree clearing, ground to sky did not have significant impact on outages
- Solution selected to address repetitive outages – targeted undergrounding

ALPENA POWER COMPANY

# Undergrounding Projects – Bloom Road Circuit

- From 2011 to 2023 converted 6.5 miles of overhead primary to primary underground
- 7 separate projects to address targeted areas causing large amount of tree related outages
- Focus was undergrounding of primary but also engaged customers in undergrounding of service drops
- Challenges
  - Soil Conditions, some areas with bedrock at or near the surface
  - Right-of-way access
  - Customer density

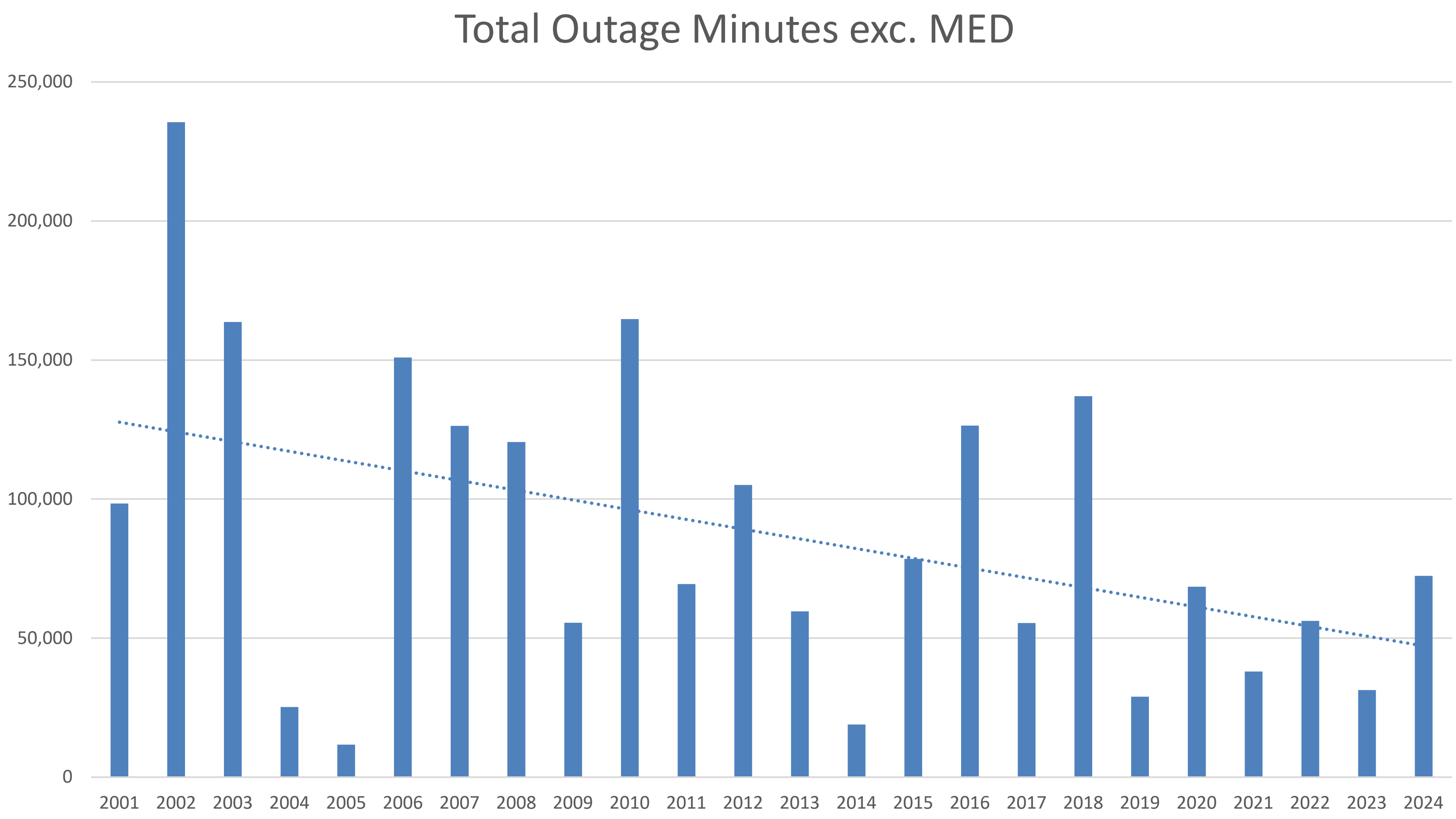
ALPENA POWER COMPANY

# Undergrounding Projects – Bloom Road Circuit

| Year | Conversion Distance (miles) | Total Cost | Cost/Foot |
|---|---|---|---|
| 2011 | 1.09 | $40,627 | $7.09 |
| 2012 | 2.39 | $178,187 | $14.13 |
| 2012 | 0.38 | $60,164 | $30.04 |
| 2013 | 0.66 | $56,048 | $15.98 |
| 2015 | 0.93 | $132,408 | $26.91 |
| 2021 | 0.40 | $59,329 | $28.33 |
| 2023 | 0.57 | $87,889 | $29.07 |
| **TOTAL** | **6.42** | **$614,655** | **$18.14** |

ALPENA POWER COMPANY

# Undergrounding Projects – Bloom Road Circuit



ALPENA POWER COMPANY

# Undergrounding Projects – Path Forward

- Targeted undergrounding has proved to be valuable tool to address repetitive outages
- Project cost largely dependent on soil conditions
- Better data drives better decisions
  - Outage reporting based on IEEE standards
  - More detailed outage cause data
  - Investigating reporting outage cause location

# Lessons Along the Road to Transmission Deployment

Josh Rogers, Policy Specialist at the Great Plains Institute

GREAT PLAINS INSTITUTE | Better Energy. Better World.

**Maine transmission line is stalled despite court victories**

By Benjamin Storrow | 04/27/2023 06:38 AM EDT

Legal fights and permitting problems have delayed a project that is supposed to help New England lower its emissions. It might mark a national trend.

StopPATH WV

**Law will help wealthy Louisiana landowner in dispute with power line builder**

**Save Maryland Farms and Families**

Stop the Transmission Lines: MD Residents Will Pay the Social & Financial Cost of Infrastructure to Serve Data Centers

DEPT. OF ENERGY

# THE HOLDOUTS IN THE QUEST FOR A BETTER POWER GRID

*Farmers in Missouri are opposing the Grain Belt Express, a transmission line that will connect wind farms in Kansas with cities in the East.*

## Legal Challenges Continue for SunZia Transmission Line

Southern Arizona tribes and San Pedro Valley residents continue their legal challenges to halt construction of the largest renewable energy project in U.S. history.

**Conservation groups sue to stop a transmission line from crossing a Mississippi River refuge**

102-mile line linking WI, IA projected to cost more than half a billion dollars

Associated Press


FC Stop Transource Stages Peaceful Protest,
FP Objecting to High-Voltage Power Line

**Environmentalists continue fight against planned power line crossing the Mississippi River**

Power companies say the transmission project would improve reliability and hook more clean energy to the electricity grid.

**Now You Know: Our push to stop new high-voltage electric lines**

Ryan Nawrocki and Kathy Szeliga Mar 19, 2025 0

**High Voltage, Higher Stakes: Residents Protest Dominion Energy's Power Expansion**

*Residents of the Loudoun Valley community fight against Dominion Energy's proposal to build power lines on the campuses of Rosa Lee Carter and Rock Ridge High School.*

**A New York power line divided environmentalists. Here's what it says about the larger climate fight.**

States waited too long to decarbonize, and now they have to make tough choices.


NORTH DAKOTA | Brief

**Landowners, local governments lose power struggle over power lines**

**Tribes, environmental groups ask US court to block $10B energy transmission project in Arizona**

**Concerns grow over proposed power lines**

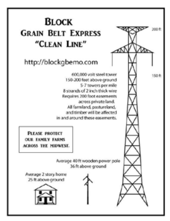
By Betty Williamson and Ron Warnick Eastern New Mexico News Feb 21, 2025

**An Epic Battle Over 1 Mile of Land in Wisconsin Is Tearing Environmentalists Apart**

*Conservationists and green energy developers square off, with big consequences for the climate.*


**A Power Line Debate Pits Environmental Allies Against Each Other in the Upper Midwest**

The transmission line project on the Iowa-Wisconsin border has been halted by the latest in a series of legal challenges.





**Residents, Parents Protest Transmission Lines on School Grounds**

**State appeals court tosses proposal for new transmission line in central Illinois**

Advocates say the controversial project is necessary to meet renewable energy needs

**Montana transmission lines draw opposition from all sides**

**Battle Lines: Fighting the Power**

**Landowners Concerned About LCRA's Hill Country CREZ Lines**

**Eastern Oregon residents oppose energy transmission line project: 'Absolute disaster for ecosystem'**

The Boardman-to-Hemingway line could move enough clean electricity to power 150,000 homes, but opponents say the environmental tradeoffs aren't worth it.

**Angry Carroll County residents plan to fight proposed transmission line project**

**Maine Gov. Mills, 2 Environmental Groups Back Controversial $1 Billion Transmission Project**


**Need a power line? That'll be $3B and 18 years.**

By ARIANNA SKIBELL | 06/21/2023 05:59 PM EDT

**Stop R-Project powerline from traversing Sandhills**

News | Feb 16, 2024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# Why does local opposition matter?

1. Transmission capacity needs to increase by 2-5 times (~75,000 miles by 2035)
2. Maintaining a rapid pace of development for a decade requires a **SOCIAL LICENSE** to build
3. Absent local support, developers are facing
    1. Costly lawsuits and delays
    2. Protest
    3. Legislative action

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# Lessons Along the Road to Transmission Deployment

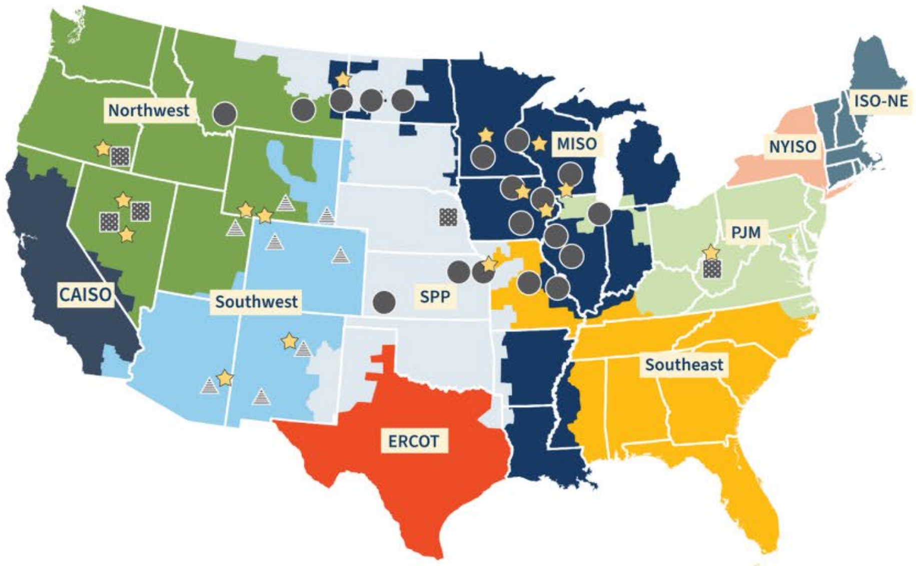



Figure 1. Geographic scope of GPI's grassroots research

- In-person interviewee
- Virtual interviewee
- Prior in-person research
- Transmission projects studied

Note: Multi-color regions on the map represent transmission planning regions.

Sources: Figure by Aime Bita, Great Plains Institute, and Esther Ramsay, Horizon Climate Group, based on data from Joshua Rogers, Great Plains Institute, and transmission planning regions by Elizabeth Abramson, Horizon Climate Group, and Aparna Narang, Clean Grid Initiative, 2025, adapted from Federal Energy Regulatory Commission (FERC) Order 1000 Regions shapefile, December 2024.

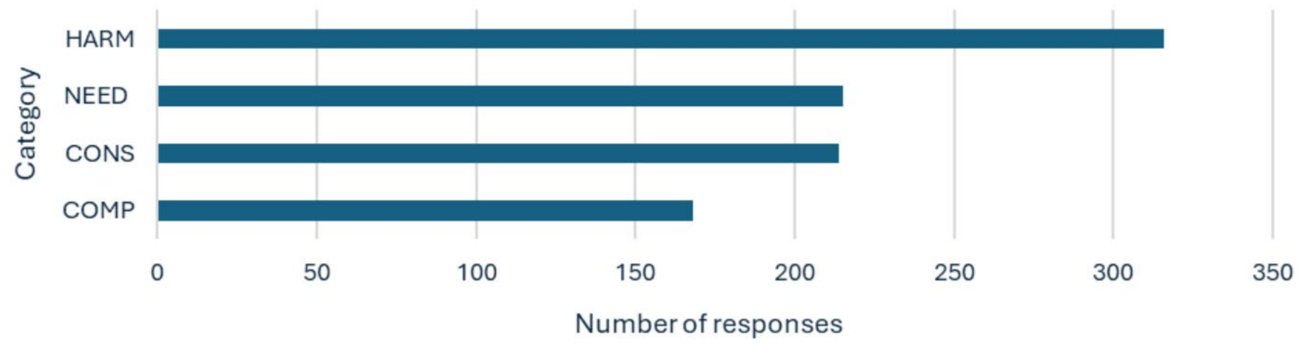
- 150 Interviews
- 5 public meetings
- 6 months on the road
- 13 states in-person
- 15 HVTLs
- 37 distinct drivers
- 910 responses



Source: MISO, MTEP Futures White Paper, April 2020.
https://cdn.misoenergy.org/20200427%20MTEP%20Futures%20Item%2002b%20Futures%20White%20Paper443656.pdf


# How to understand opposition

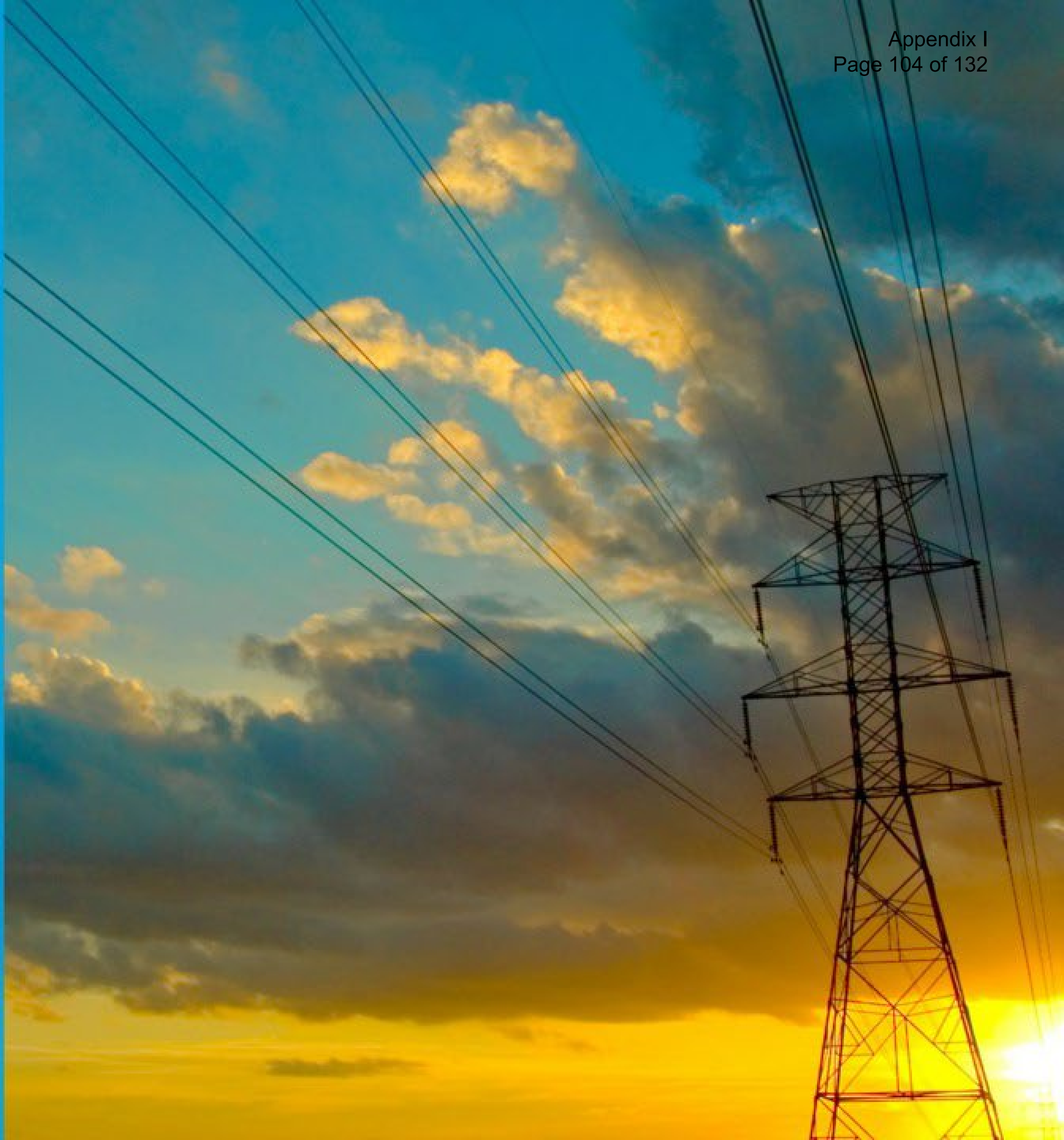
Figure 2. Opposition framework: Interview responses




1. How will this negatively impact my life?
2. Why is this project even needed?
3. How will I be consulted on this project?
4. How will I be compensated for any potential harms caused by this project?

# Undergrounding

1. **Significantly reduces perceived harm**
   - Transportation Corridors
   - Cultural & Aesthetic
   - Property Values
   - Safety*
2. Similar issues around need
   - Fear of novelty
   - Costs
3. Similar issues around consultation
4. Similar issues around compensation



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# Transportation Corridors

- **Most popular form of transmission development**
  - National opponents of transmission advocate this
  - Reduces impact on private property/Greenfields
  - Site control
- **Uncommon**
  - Increased uncertainty
  - Legal complexity: easement access


# Cultural & Aesthetic

- **Cultural and aesthetic concerns drive ideological opposition to above ground high-voltage transmission**
  - Sense of place/community
  - Landowner motivations
- **Undergrounding dramatically reduces cultural & aesthetic harms**
  - No visual impact
  - Reduced land use
  - Reduced noise pollution

# Property Values

- **Overhead**
  - Concerns: eye-sore, EMFs, & safety
  - Typically 0–10% depreciation in value
  - Some studies indicate depreciation can reach 17—45% for scenic areas
- **Underground**
  - Buring overhead lines can increase value by 5-20%
  - New lines have little to no negative effect on residential values

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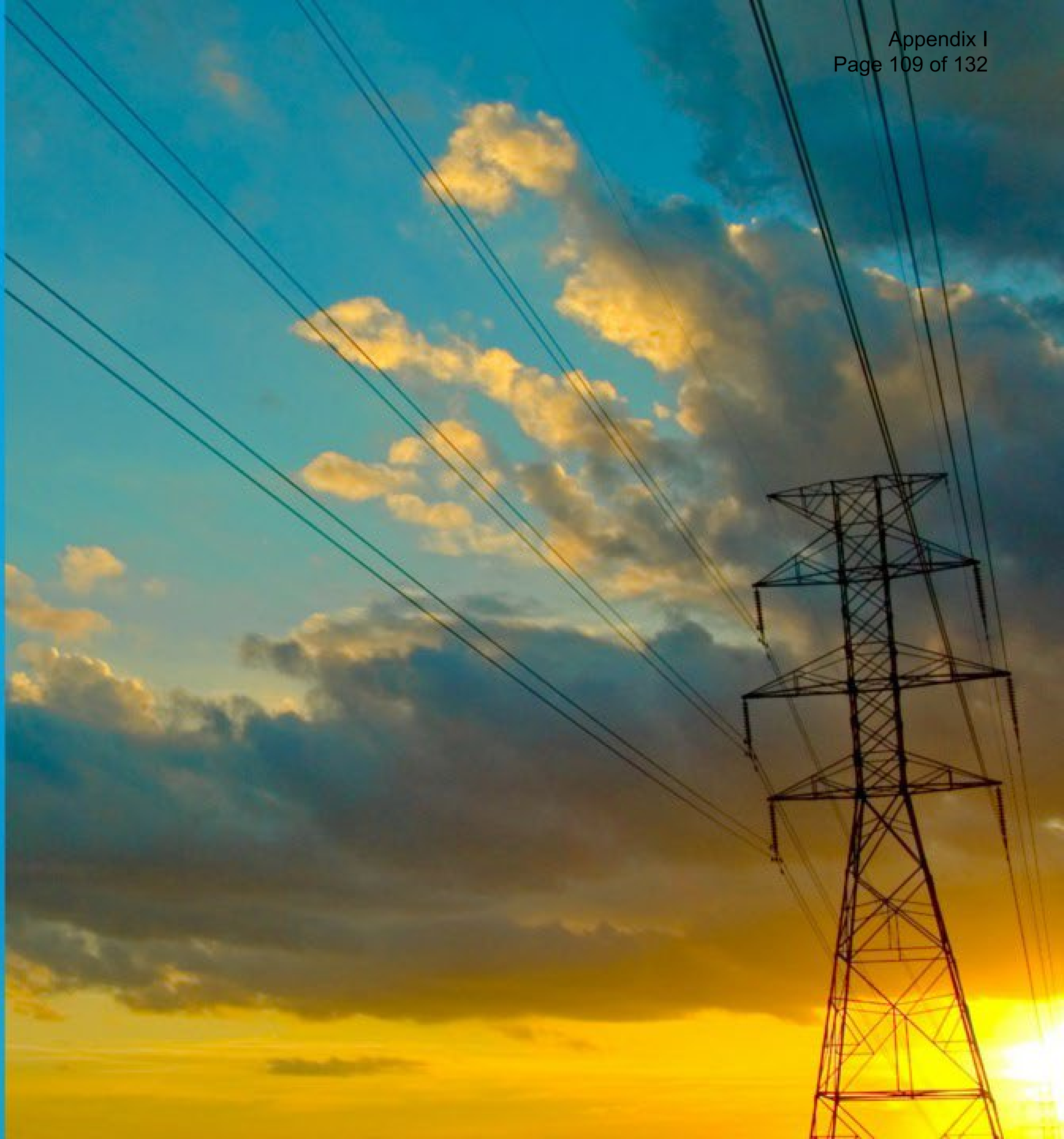
# Safety

- **Electromagnetic fields**
  - Uncertainty over whether this is a safety hazard
  - Overhead: present, can reach up to
  - Underground: metallic sheath + soil shields EMFs
- **Fire**
  - Overhead: wildfires
  - Underground: low risk
- **Repair**
  - Overhead: more frequent, but easier
  - Underground: less frequent, but more difficult

# Costs

**Underground**

- Uncertain cost estimates (we don’t build these often)
- High upfront capital (2-10 times, depending on the study)
- High repair costs
- High replacement costs
    - Potentially lower lifetime



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# THANK YOU

**Josh Rogers**
jrogers@gpisd.net

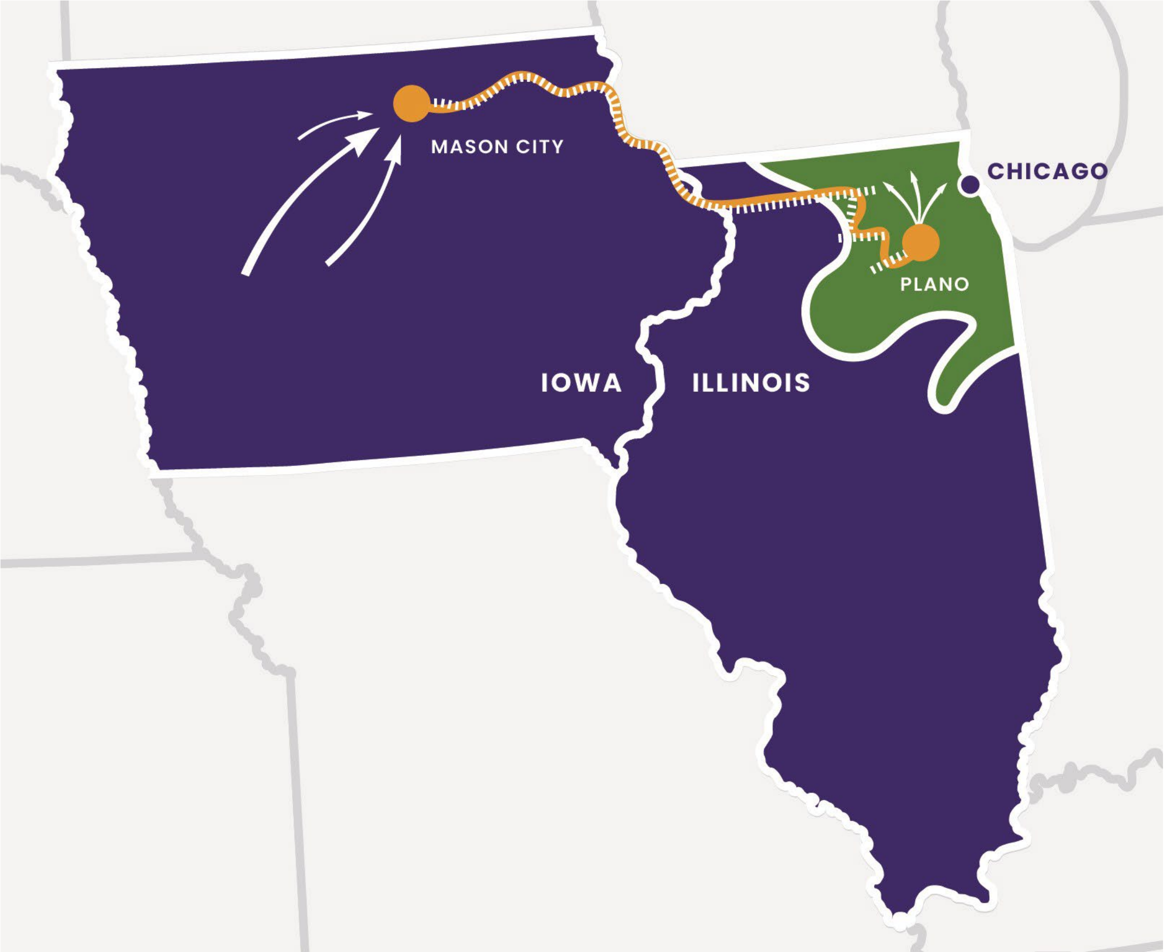
# Undergrounding Transmission:

## Permitting and Economics in the Grid Reliability and Resilience Context

Raj V. Rajan, PhD, PE [VP of Project Development, SOO Green HVDC Link ProjectCo LLC]

MPSC Undergrounding Workshop [17 September 2025]

SOO Green HVDC LINK

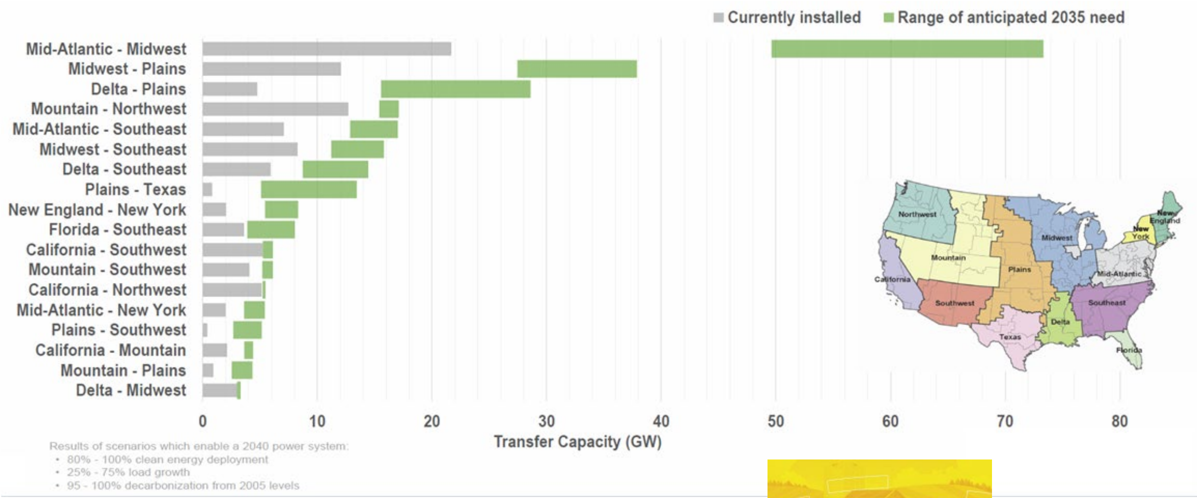



SOO Green HVDC LINK

Location

# Project

- Data from six capacity expansion studies analyzed, to identify future regional and interregional transmission needs.
- Biggest inter-regional 2035 Tx needs gap: Midwest <-> Mid-Atlantic (28-52 GW)





Driver

Project

Source: Draft National Transmission Needs Study, Dr. Adria Brooks, DOE/GDO [April 2023 @MIDGRID35 meeting]

SOO Green
HVDC LINK

Overview

# Project

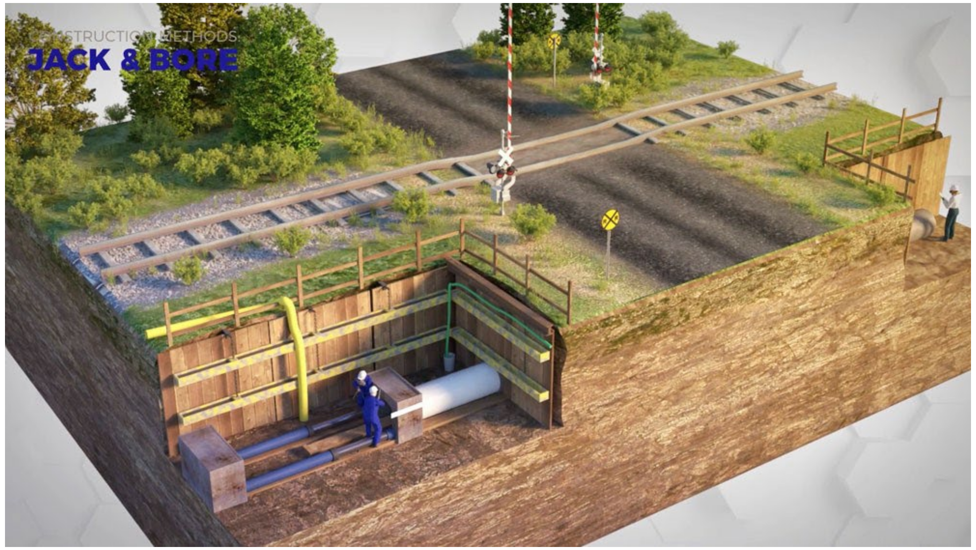
- Inter-State and Inter-RTO
- Underground Installation
- Transportation ROW Co-located
- In-Conduit Installation
- HVDC Transmission
- Symmetric Bipole configuration


SOO Green
HVDC LINK

Specifics

# Project

- Insulated and Shielded Cables
- 350+ miles point to point
- 525 kV Voltage Class
- 2100 MW Nameplate Capacity
- 13+ TWh/yr transmitted
- MMC VSC Converters




SOO Green
HVDC LINK

Development & Implementation Team

# The Project

CIP
COPENHAGEN INFRASTRUCTURE PARTNERS

energyRe

ppl
PPL Electric Utilities

SIEMENS energy

Mortenson

JINGOLI POWER

PRYSMIAN
CABLES & SYSTEMS

CPKC

CN

OmniTRAX

BNSF RAILWAY

wsp

POWER ENGINEERS

HATCH

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HVDC LINK

Development Phase Permits

# Permitting

## Federal Water Quality
Clean Water Act (Section 404)
Ambient Water Quality Permit

## Electric Franchise
Permit To Construct and Operate
Transmission Lines in Rural Iowa

## IA Environmental
Clean Water Act (Section 401)
Water Quality Certification,
Antidegradation and Outstanding State Waters,
Floodplain Development

## Federal Navigable Waters
Rivers and Harbors Act (Section 10)
Permit for construction of any structure
in, over, or under navigable waters

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Utility Installation Permits

## Federal Civil Works
Rivers and Harbors Act Section 14
Codified under 33 USC 408 (Section 408)
Permit to Alter Federal Civil Works

## Municipal Franchises
Permits To Construct and Operate
Transmission Lines in IA Municipalities

## IL Environmental
Clean Water Act (Section 401)
Water Quality Certification,
Public Water Permit,
Floodway Permit)

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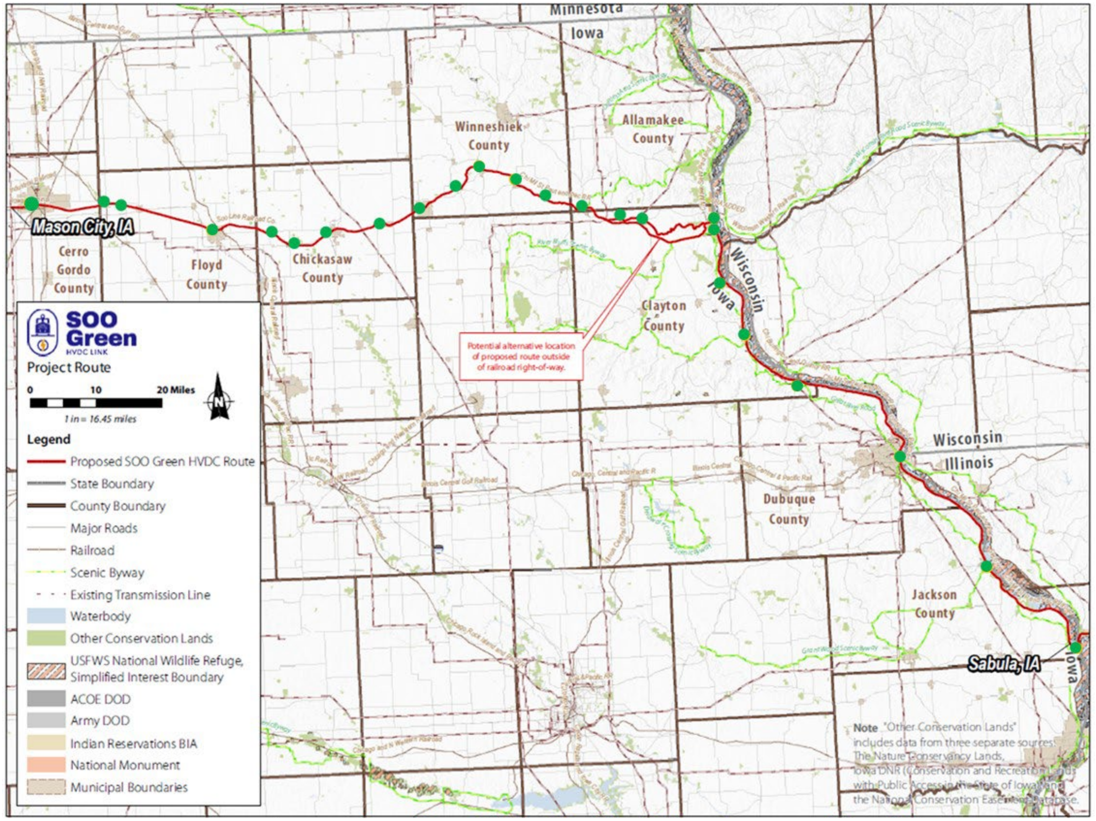
Iowa Utilities Commission

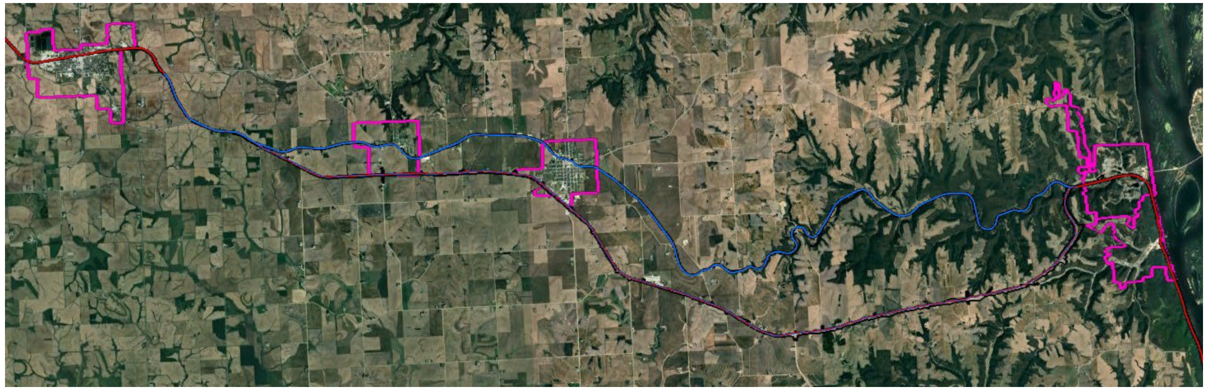



Municipal Franchise Agreement Approved & Fully Executed

State and Local Franchises

# Permitting

IOWA DOT



Illinois Department of Transportation

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State DOT Utility Installation Permits

# Permitting

Environmental Reviews

# Permitting

**Lead Federal Agency**
(Waters of the United States Jurisdiction)
National Environmenental Protection Act (NEPA) documentation

**Biological Resources**
Endangered Species Act (Section 7)
Federal Agency Consultation

**Biological Resources**
Environmental Review for Natural Resources
Listed endangered or threatened species

IOWA DEPARTMENT OF CULTURAL AFFAIRS
STATE HISTORICAL SOCIETY OF IOWA

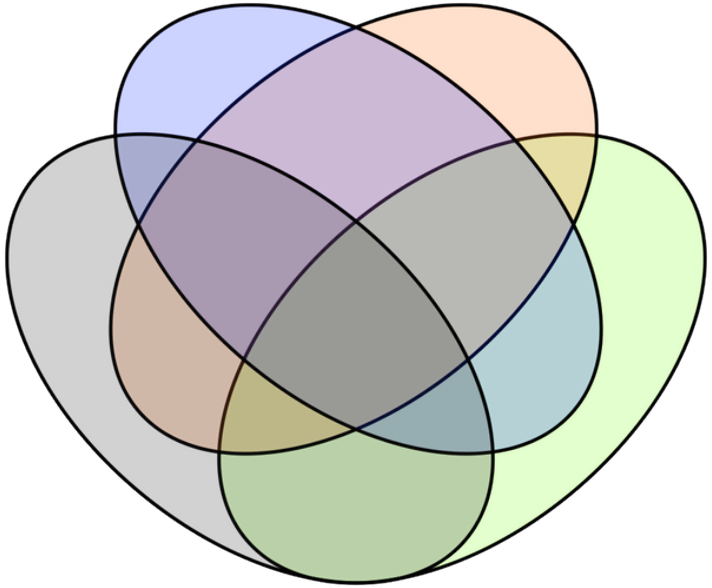
**IA Cultural Resources**
National Historic Preservation Act (Section 106)
IA SHPO Consultation

**IL Cultural Resources**
National Historic Preservation Act (Section 106)
Illinois State Agency Historic Resources Preservation Act (Section 707)
IHPA Consultation

**IL Natural Resource Reviews**
Illinois Endangered Species Protection Act
Illinois Natural Areas Preservation Act
Interagency Wetland Policy Act

Project to be submitted to and evaluated in Ecological Compliance Assessment Tool

- Financial Capital
- Human Capital
- Social Capital
- Natural Capital



Sustainable Multi Capital Accounting

# Economics

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- Fixed and Variable Costs
- Spread in Wholesale Electric Prices +
- Spread in REC Values +
- Spread in Capacity Markets +
- Value of Ancillary Services (?)

Financial Capital

# Economics

SOO Green
HVDC LINK

# Economics

## Human Capital- Qualitative Considerations

- Health Benefits from Reduced Emissions
- Commitment to Organized Labor [LiUNA, Operating Engineers, IBEW]
- Commitment to Workforce Development [Community Colleges and Local/Regional Economic Development Authorities]
- Train to Hire Programs Prioritizing Local Hiring from Disadvantaged segments of Community [Hire 360 in IL and Competitive Edge in IA]


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By displacing electricity generated by fossil fuel power plants, SOO Green will lower emission of greenhouse gases and other harmful pollutants, reducing damage caused by climate change, reducing healthcare costs, and saving lives.

Human Capital- Quantified Impacts

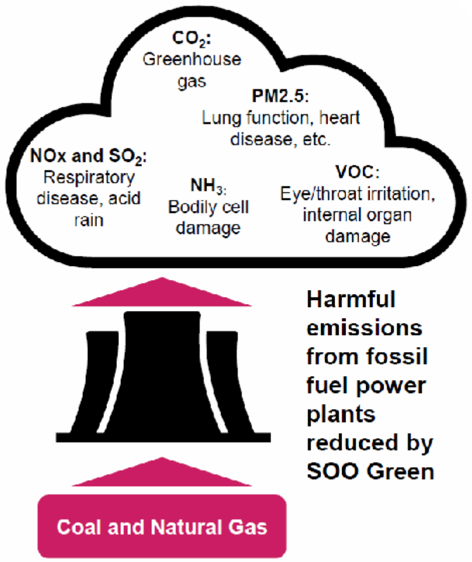
# Economics

**$9.8Bn**

Avoided Social Costs of GHG Emissions In Illinois

**$9.7Bn**

Illinois' Health Benefits, mainly in disadvantaged communities

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Source: PA Consulting [Feb 2023]

- Not relying on eminent domain authority for site control
- Economic Development [Jobs, Earnings, GDP] at Scale
- Grid Benefits from Reliability Enhancement
- Community Development Projects along project corridor
- State-of-the art Technology Transfer from Overseas w/ focus on Onshoring Manufacturing

**$4Bn**
Private Sector Investment to Boost Grid Resiliency

**$1Bn**
Avoided Daily Costs of Major Grid Interruption

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Social Capital Summary

# Economics

Source: PA Consulting [Feb 2023]

Social Capital- Economic Development

# Economics

- Upstream Generation Impacts
- In-Stream Construction/Operation Impacts
- Downstream Economic Impacts

**New Generation Construction + Component Manuf.**
$9.9 Bn+ GDP output

**New Generation Operations**
$15 Bn+ GDP output

**Tx Construction**
$4.9 Bn+ GDP output

**30-yr Tx Ops**
$5.7 Bn+ GDP output

**New Component Manufacturing**
$560 MM+ state output

**New Downstream Industrial Activities**
$26 Bn state output

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Source: Strategic Economic Research, Dr. David Loomis [Feb 2023]

# Key Takeaways from IPA Study:

- A significant portion of the energy delivered by SOO Green would contribute to generation and resource adequacy
- project would benefit ratepayers by impacting wholesale energy costs, lowering those costs for Illinois ratepayers by $5.85 billion over 20 yrs

**0.01%**

Estimated LOLE reduced from 0.1% in ComEd Territory with SOO Green

**96%**

ELCC for SOO Green in 2030 based on generation profiles submitted by the project

**92%**

ELCC for SOO Green in 2040 based on generation profiles submitted by the project

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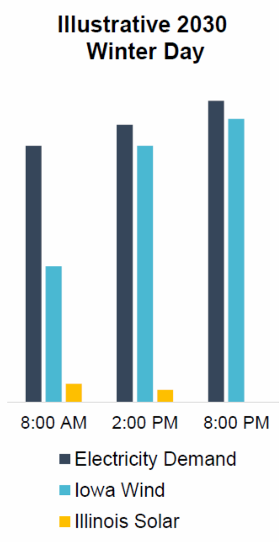
Social Capital- Grid Benefits (Reliability)

## Economics

Executive Summary, Illinois Power Agency 2024 Policy Study [March 1, 2024]

# SOO Green's generation resource diversity will contribute to additional system reliability, as Illinois shifts towards a winter peaking demand, and step in to fill unserved demand in the instance of low-probability high-impact events.

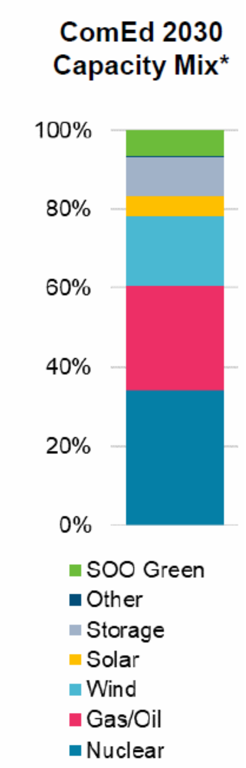



**190GWh**

Avoided Unserved Demand from Potential Summer 2030 Outage Scenario Without SOO Green

**$6Bn**

Value of Unserved Demand in Summer 2030 Generation Outage Scenario Without SOO Green

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## Social Capital- Grid Benefits (Resilience)

# Economics

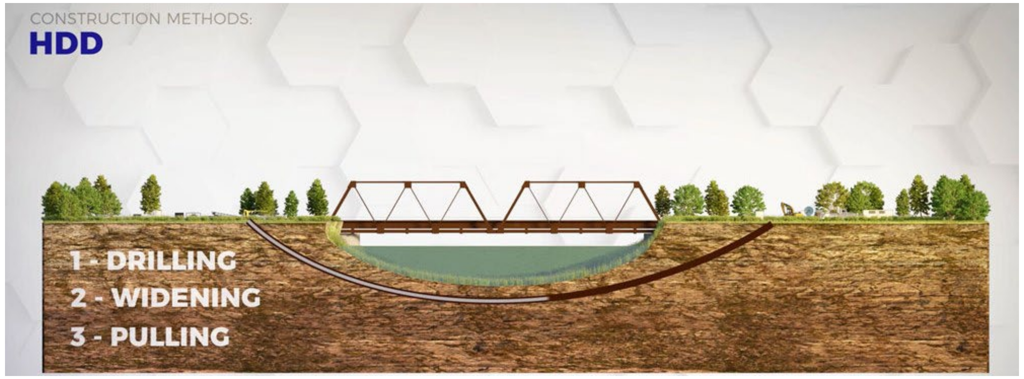
*Illinois Decarbonization Study: Climate and Equitable Jobs Act and Net Zero by 2050, Prepared for Commonwealth Edison (ComEd) by Energy and Environmental Economics, Inc. (E3), December 2022

Source: PA Consulting [Feb 2023]

Natural Capital

# Economics

- Delivers energy over long distances with low line loss
- Narrow Permanent Impact Corridor - Limited Environmental Impacts
- Extreme Weather Resilience through in-conduit Underground Installation
- Limiting Environmental Impacts to only construction and not during operations
- Low-impact Construction Methods in environmentally sensitive areas




SOO Green HVDC LINK

# Thank You!

RRajan@SOOGreen.com

# Next Steps

**Day 2 – Solutions for the Future**

- Friday, September 19th from 12:00-5:00 pm Eastern
- Topics: BCA, valuation, alternatives, community engagement, peer utility perspective, and resilience metrics

- Recordings and Presentations Posted to Event Pages

- Staff Report With Recommendations After Workshops

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# PowerPoint Template Instructions

# Day 2: Undergrounding Technical Workshop

Solutions for the Future

September 19, 2025

MPSC
MICHIGAN PUBLIC SERVICE COMMISSION

# Introduction – U-21388

**Late-March 2025**

**May 21, 2025**

**Public Forum**
Town hall in Gaylord where undergrounding emerged as a key theme

**June 12, 2025**

**Order**
Staff to 1) conduct undergrounding workshop and 2) issue report with recommendations

**Sept. 2025**

**Workshops**
Staff lead workshops on September 17 and 19

**Oct. 31, 2025**

**Staff Report**
Staff to file a report with recommended next steps

Note: Staff explored undergrounding in U-15279 (2007) and issued a report indicating that the reliability benefits of undergrounding are uncertain and did not compare favorably to the costs.

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# Agenda

| Solutions for the Future | | |
|---|---|---|
| 12:00-12:05 | Welcome & Introduction | MPSC |
| 12:05-1:00 | Valuing Investments in Reliability: A Case Study of Undergrounding | Pete Larsen, Lawrence Berkeley National Laboratory |
| 1:00-1:45 | Targeted Undergrounding Benefit-Cost Analysis in Michigan | Luke Dennin, MPSC |
| 1:45-2:30 | How to Manage Risk on a Budget | Eric Borden, Synapse Energy Economics |
| 2:30-2:45 | Break | |
| 2:45-3:15 | Policy Solutions to Support Undergrounding | Eric Dennis, Citizens Research Council of Michigan |
| 3:15-4:00 | System Modernization & Reliability Project in Wisconsin: Peer Utility Perspective | Steven Herbel, Wisconsin Public Service |
| 4:00-4:55 | Resilience Metrics & Valuation for Electric Grid Decision-Making | Shikhar Pandey, GridCo |
| 4:55-5:00 | Closing | MPSC |

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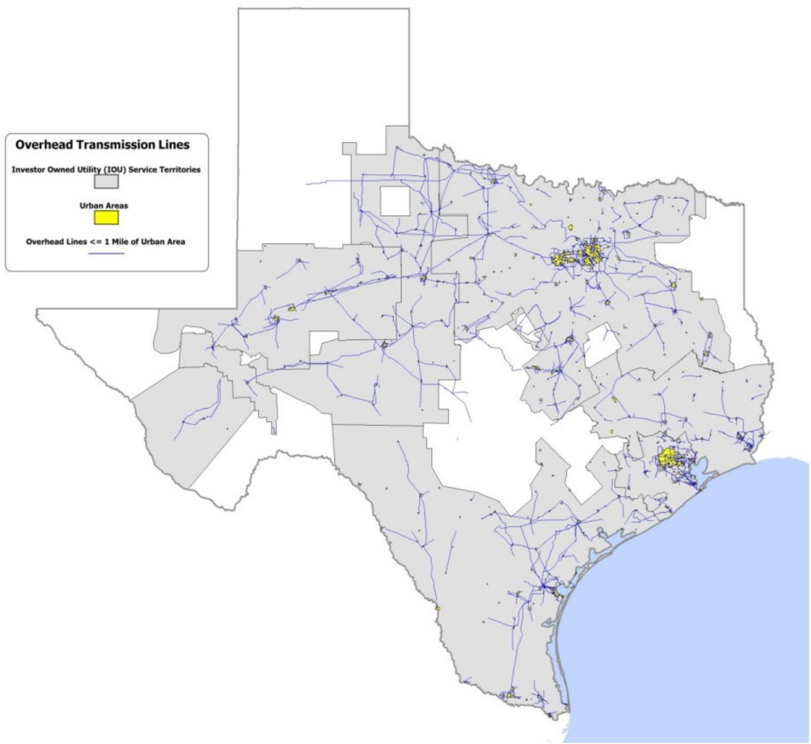
MICHIGAN PUBLIC SERVICE COMMISSION

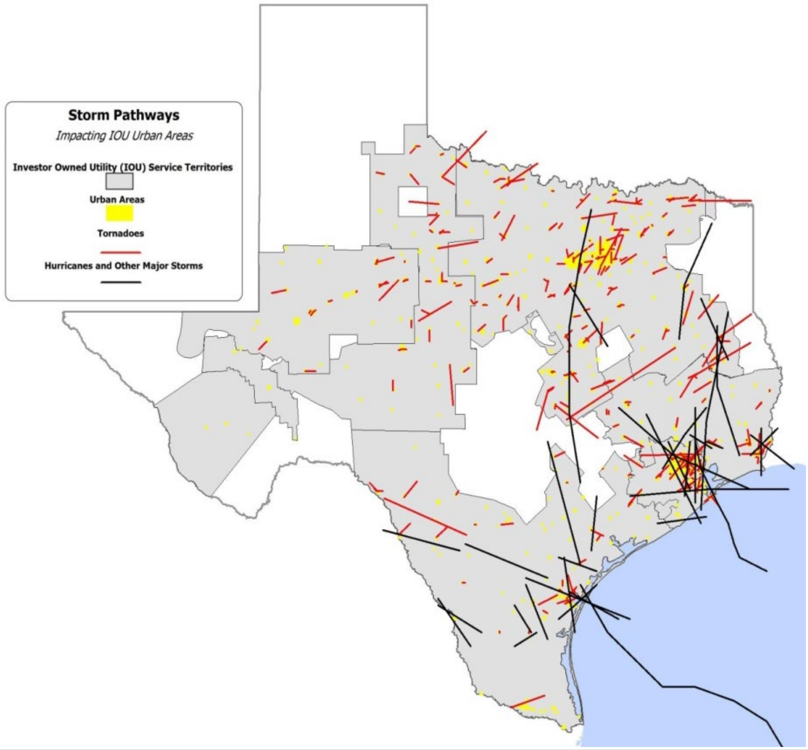
# Housekeeping

- Meeting is Recorded
- Workshop Format
  - Questions and discussion at the end of presentations
  - Raise hand feature through Teams in the order received (primary)
  - Questions in the chat (secondary)
  - Presenters may follow up with questions not answered
- Please Mute Unless You Are Speaking

MPSC
MICHIGAN PUBLIC SERVICE COMMISSION

# Valuing Investments in Reliability: A Case Study of Undergrounding




***Peter Larsen***

**September 19, 2025 ■ MPSC Undergrounding Technical Workshop**

# Examples of information needed to value grid investments

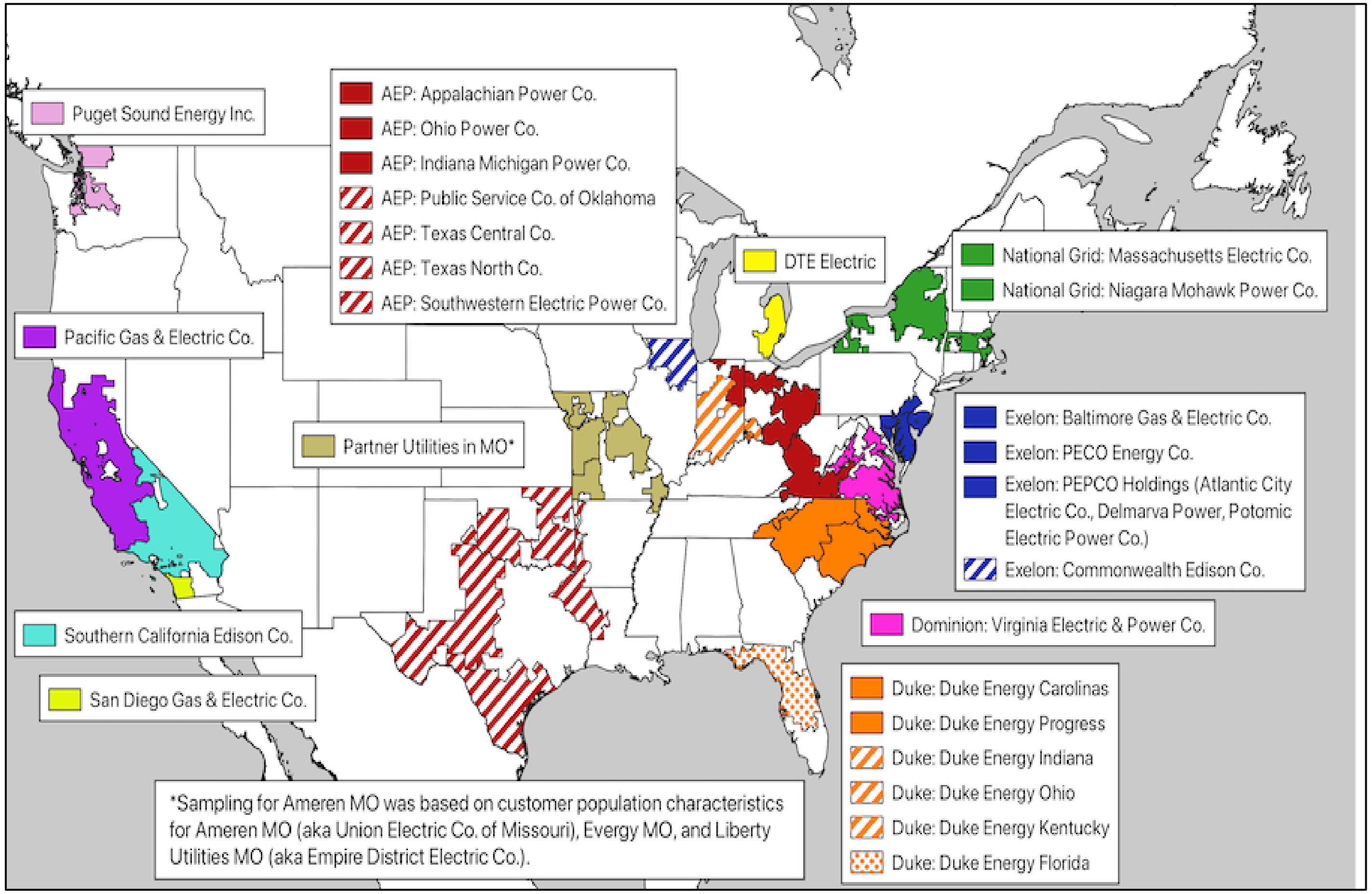
| Cost | Benefits: Non-monetized | Benefits: Monetized | Other |
|---|---|---|---|
| • Capital/installation<br>• Annual operations and maintenance | • Avoided pollution<br>• Avoided health/safety risk<br>• Avoided damage to utility infrastructure<br>• Reduction in frequency and/or duration of power interruptions<br>• Avoided impacts to national security | • Avoided morbidity and mortality costs<br>• Avoided capital and O&M costs to utility<br>• **Avoided interruption costs to customers (e.g., ICE Calculator)**<br>• Avoided "spillover" effects to regional economy<br>• Avoided aesthetic costs (if applicable) | • Real discount rate (or weighted average cost of capital)<br>• Lifespan of strategy<br>• Local, state, and federal incentives and rebates<br>• Frequency and duration of power interruptions before and after investment<br>• Detailed information about customers impacted |

# Interruption Cost Estimate (ICE) Calculator



- Provide a basis for discussing utility reliability investments, *including undergrounding*, with regulators
- Assess the economic impact of past power outages

# ICE Calculator update happening in phases

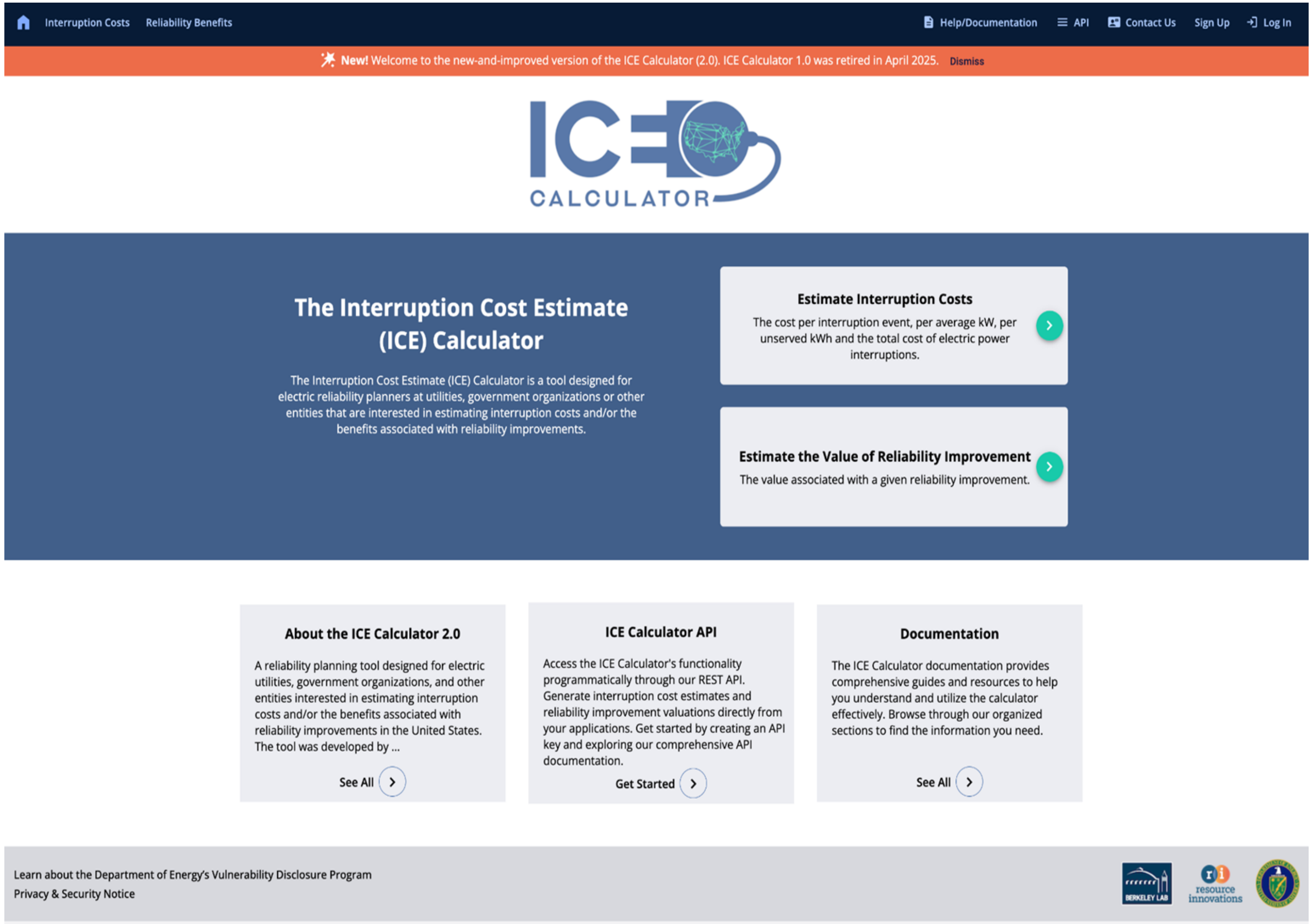



**Phase 3**

- We received support from DOE to partner with NRECA to survey select rural cooperatives across the U.S.
- One utility in the West
- Recruiting ongoing

# ICE Calculator 2.0 Website: https://icecalculator.com/





# Background on undergrounding research



- Interest in undergrounding was a result of Berkeley Lab research into factors that impact long-term reliability of U.S. power system…

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## Distribution-level electricity reliability: Temporal trends using statistical analysis

Joseph H. Eto*, Kristina H. LaCommare, Peter Larsen, Annika Todd, Emily Fisher

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H I G H L I G H T S

- We assess trends in electricity reliability based on the information reported by the electric utilities.
- We use rigorous statistical techniques to account for utility-specific differences.
- We find modest declines in reliability analyzing interruption duration and frequency experienced by utility customers.
- Installation or upgrade of an OMS is correlated to an increase in reported duration of power interruptions.
- We find reliance in IEEE Standard 1366 is correlated with higher reported reliability.

A R T I C L E I N F O

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A B S T R A C T

This paper helps to address the lack of comprehensive, national-scale information on the reliability of the U.S. electric power system by assessing trends in U.S. electricity reliability based on the information reported by the electric utilities on power interruptions experienced by their customers. The research analyzes up to 10 years of electricity reliability information collected from 155 U.S. electric utilities, which together account for roughly 50% of total U.S. electricity sales. We find that reported annual average duration and annual average frequency of power interruptions have been increasing over time at a rate of approximately 2% annually. We find that, independent of this trend, installation or upgrade of an automated outage management system is correlated with an increase in the reported annual average duration of power interruptions. We also find that reliance on IEEE Standard 1366-2003 is correlated with higher reported reliability compared to reported reliability not using the IEEE standard. However, we caution that we cannot attribute reliance on the IEEE standard as having caused or led to higher reported reliability because we could not separate the effect of reliance on the IEEE standard from other utility-specific factors that may be correlated with reliance on the IEEE standard.

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### 1. Introduction

Since the 1960s, the U.S. electric power system has experienced a major electricity blackout about once every 10 years. Each has been a vivid reminder of the importance society places on the continuous availability of electricity and has led to calls for changes to enhance reliability. At the root of these calls are judgments about what reliability is worth and how much should be paid to ensure it.

In principle, information on the actual reliability of the electric power system and how proposed changes would affect reliability ought to help to inform these judgments. The use of this type of information in local decision making, for example between an investor-owned utility and its state public utilities commission, is common. Yet, comprehensive, national-scale information on the reliability of the U.S. electric power system is lacking.

This paper helps to address this information gap by assessing trends in U.S. electricity reliability based on information reported by electric utilities on power interruptions experienced by their customers. The focus of prior published investigations of U.S. electric power system reliability has been primarily on the reliability of the bulk power system. Yet, interruptions originating on the bulk power system represent only a small fraction of the number of power interruptions experienced by electricity consumers, as indicated in Hines et al. (2009) and Eto and LaCommare (2008). The vast majority of interruptions experienced by electricity consumers are caused by events affecting primarily the electric distribution system. Both Hines et al. (2009) and Eto and LaCommare (2008) report evidence that suggests that interruptions originating within and limited to portions of

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## Recent trends in power system reliability and implications for evaluating future investments in resiliency

CrossMark

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A R T I C L E I N F O

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A B S T R A C T

This study examines the relationship between annual changes in electricity reliability reported by a large cross-section of U.S. electricity distribution utilities over a period of 13 years and a broad set of potential explanatory variables, including weather and utility characteristics. We find statistically significant correlations between the average number of power interruptions experienced annually and above average wind speeds, precipitation, lightning strikes, and a measure of population density: customers per line mile. We also find significant relationships between the average number of minutes of power interruptions experienced and above average wind speeds, precipitation, cooling degree-days, and one strategy used to mitigate the impacts of severe weather: the amount of underground transmission and distribution line miles. Perhaps most importantly, we find a significant time trend of increasing annual average number of minutes of power interruptions over time—especially when interruptions associated with extreme weather are included. The research method described in this analysis can provide a basis for future efforts to project long-term trends in reliability and the associated benefits of strategies to improve grid resiliency to severe weather—both in the U.S. and abroad.



### 1. Introduction

In the U.S. and abroad, recent catastrophic weather events; existing and prospective government energy and environmental policies; and growing investments in smart grid technologies have drawn renewed attention to ensure the reliability of the electric power system [6,42]. Over the past 15 years, the most well-publicized efforts to assess trends in electric power system reliability have focused only on a subset of all power interruption events [3,8] —namely, the very largest events, which trigger immediate emergency reporting to federal agencies and industry regulators. Anecdotally, these events are believed to represent no more than 10% of the power interruptions experienced annually by electricity consumers. Moreover, a review of these emergency reports has identified shortcomings in relying upon these data as accurate sources for assessing trends, even for the reliability events they target [16].

Recent work has begun to address these limitations by examining trends in reliability data collected annually by electricity distribution companies [13,14]. In principle, all power interruptions experienced by electricity customers, regardless of size, are recorded by the distribution utility. Moreover, distribution utilities have a long history of recording this information, often in response to mandates from state public utility commissions [12]. Thus, studies that rely on reliability data collected by distribution utilities can, in principle, provide a more complete basis upon which to assess trends or changes in reliability over time.

Eto et al. [13,14] was one of the first known studies to apply econometric methods to account for utility-specific differences among electricity reliability reports. This study found that the annual average amount of time and frequency customers are without power had been increasing from 2000 to 2009. In other words, reported reliability was getting worse. However, the Eto et al. [13,14] paper was not able to identify statistically significant factors that were correlated with these trends. The authors suggested that "future studies should examine correlations with more disaggregated measures of weather variability (e.g., lightning strikes and severe storms), other utility characteristics (e.g., the number of rural versus urban customers, the extent to which distribution lines are overhead versus underground), and utility spending on transmission and distribution maintenance and upgrades, including advanced ("smart grid") technologies" [13,14].

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# Background (cont.)

- Despite the high costs attributed to power outages, there has been **little or no research to quantify both the benefits and costs of improving electric utility reliability/resilience**—especially within the context of decisions to underground T&D lines (e.g., EEI 2013; Nooij 2011; Brown 2009; Navrud et al. 2008)

- Brown (2009) found that the costs—in general—of undergrounding Texas electric utility transmission and distribution (T&D) infrastructure were "far in excess of the quantifiable storm benefits"

- **Policies specifically targeting urban areas for undergrounding are cost-effective if a number of key criteria are met…**

# Analysis framework: Texas IOUs

- Study perspective:
  - Individuals who care about maximizing private benefits

- Key stakeholders with standing:
  - Investor-owned utilities (IOUs), ratepayers, and all residents within service territory

- Policy alternatives:

  (1) Status quo (i.e., maintain existing underground and overhead line share)

  (2) Underground all T&D lines (i.e., underground when existing overhead lines reach end of useful lifespan)

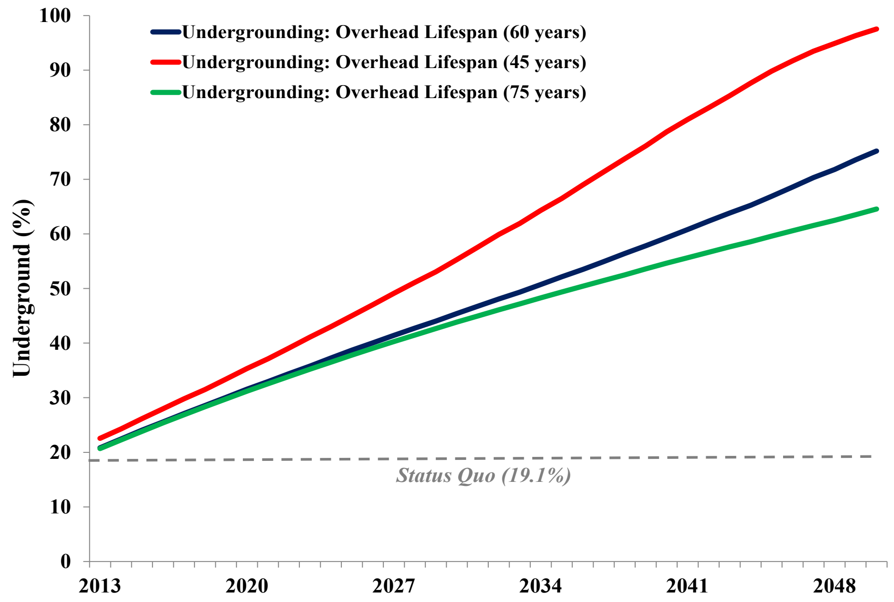
- Why Texas?

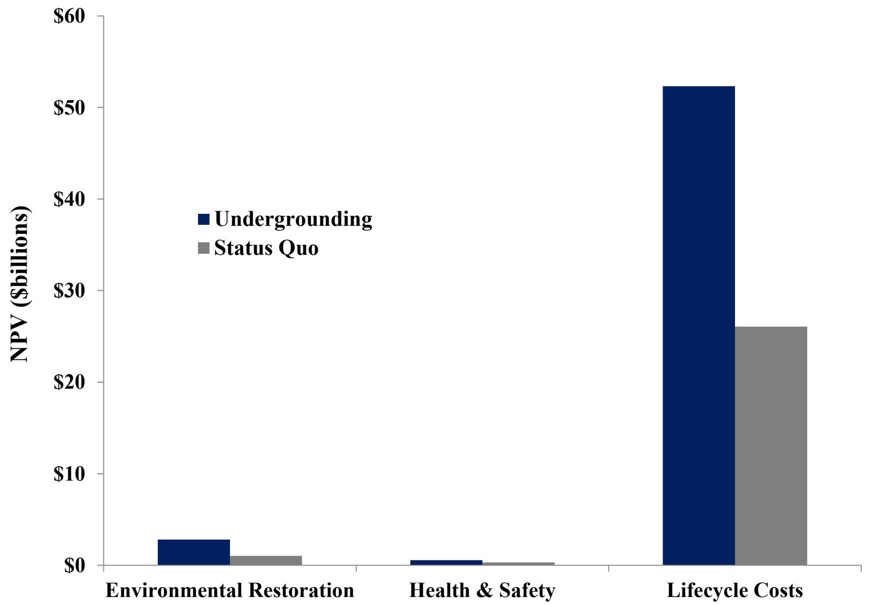
  -Texas IOU service territories were selected due to (1) previous study evaluating costs and (some) benefits of undergrounding; (2) ready access to useful assumptions; and (3) public utility commission showing interest in undergrounding major portions of electrical grid

# Analysis framework: Texas IOUs (cont.)

| *Key Stakeholders* | Undergrounding Mandate | |
|---|---|---|
| | **Selected Costs** | **Selected Benefits** |
| IOUs | • Increased worker fatalities and accidents* | |
| Utility ratepayers | • Higher installation cost of underground lines*****<br>• Additional administrative, siting, and permitting costs associated with undergrounding*<br>• Increased ecosystem restoration/right-of-way costs** | • Lower operations and maintenance costs for undergrounding* |
| All residents within service area | | • Avoided societal costs due to less frequent power outages***<br>• Avoided aesthetic costs** |

# Estimated costs

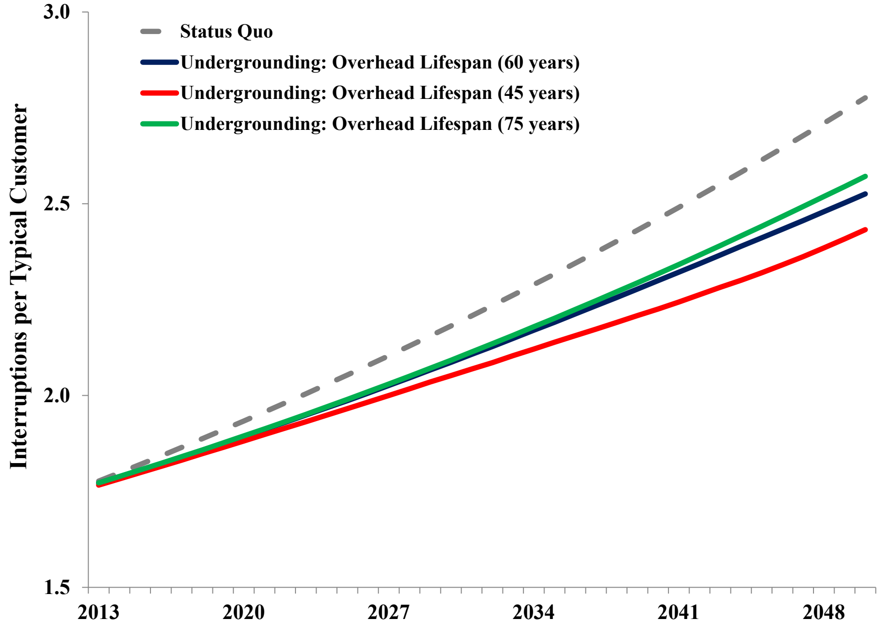


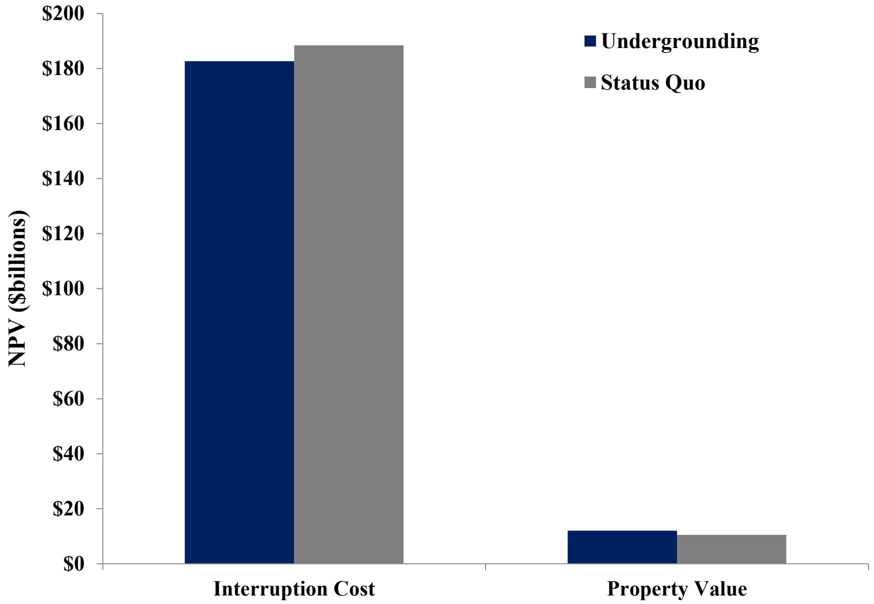




- NPV of undergrounding and status quo costs ($2012)

# Estimated benefits





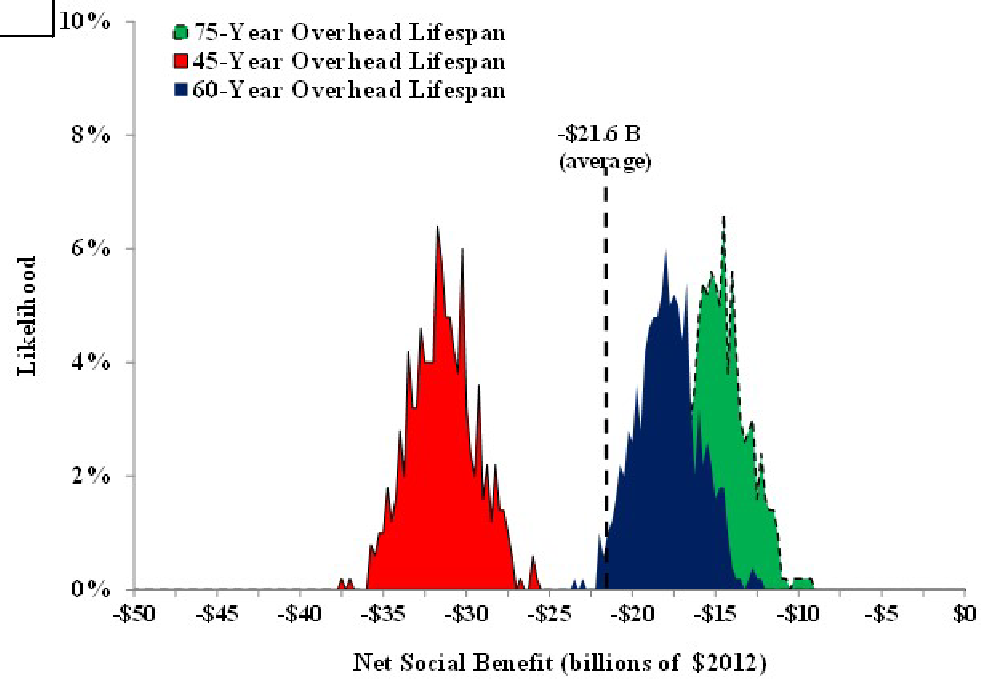

- NPV of undergrounding and status quo benefits/avoided costs ($2012)
- ICE Calculator 1.0 was used to estimate avoided interruption costs

# Net social loss

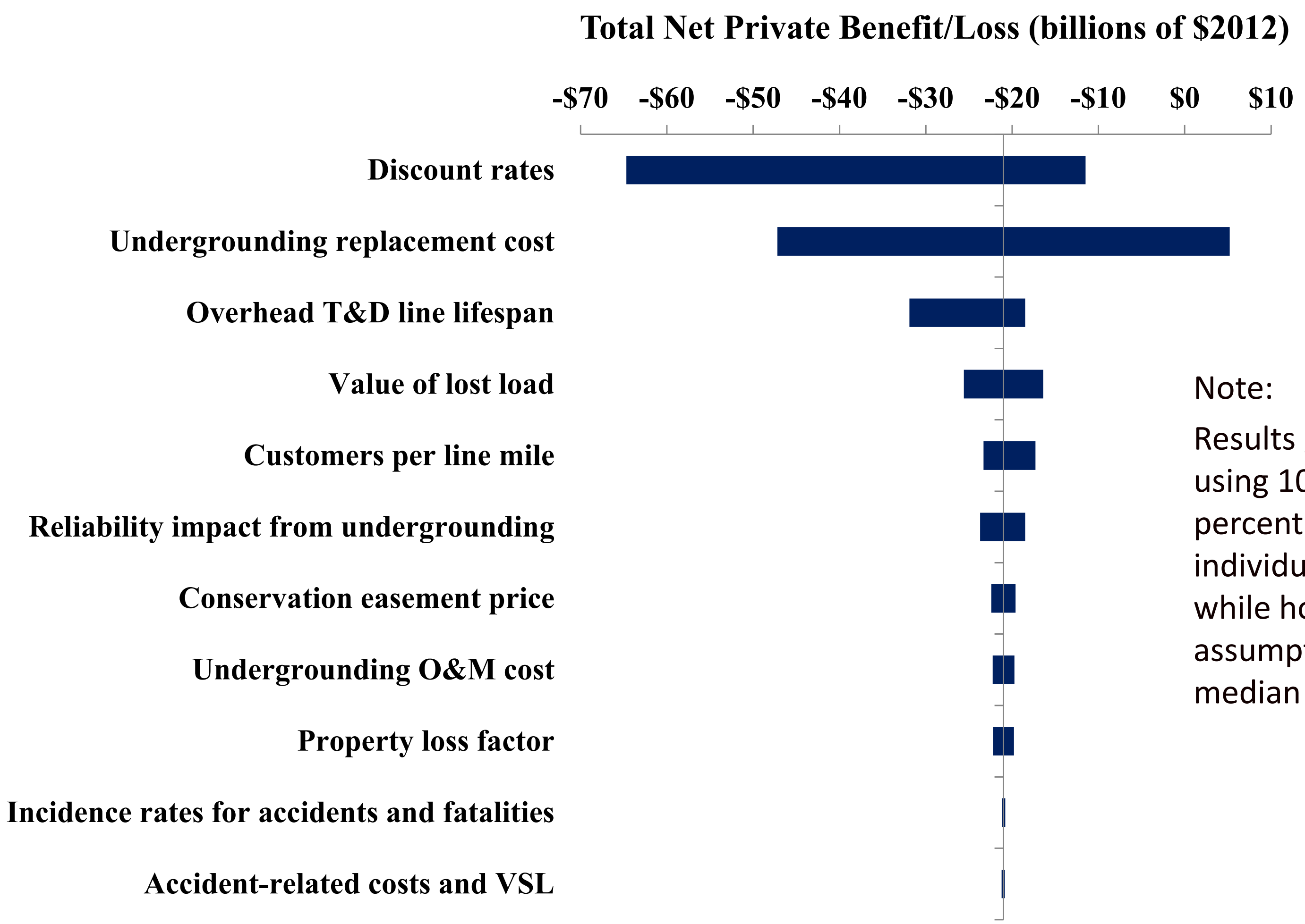
| Impact Category | Undergrounding | Status Quo | Net Cost ($billions) |
|---|---|---|---|
| Environmental restoration | $2.8 | $1.0 | $1.8 |
| Health & safety | $0.56 | $0.31 | $0.2 |
| Lifecycle costs | $52.3 | $26.1 | $26.3 |
| Total net costs (Undergrounding) | | | $28.3 |
| **Impact Category** | **Undergrounding** | **Status Quo** | **Net Benefit ($billions)** |
| Interruption cost | $182.7 | $188.4 | $5.8 |
| Avoided aesthetic costs | $12.1 | $10.6 | $1.5 |
| Total net benefits (Undergrounding) | | | $7.3 |
| **Net Social Benefit (Undergrounding)** | | | |
| **Net social benefit (billions of $2012)** | | | **-$21.0** |
| **Benefit-cost ratio** | | | **0.3** |

**Additional lifecycle costs associated with undergrounding dominate cost-benefit results**

Varying all key assumptions simultaneously led to **consistent net social losses**



# Sensitivity analysis

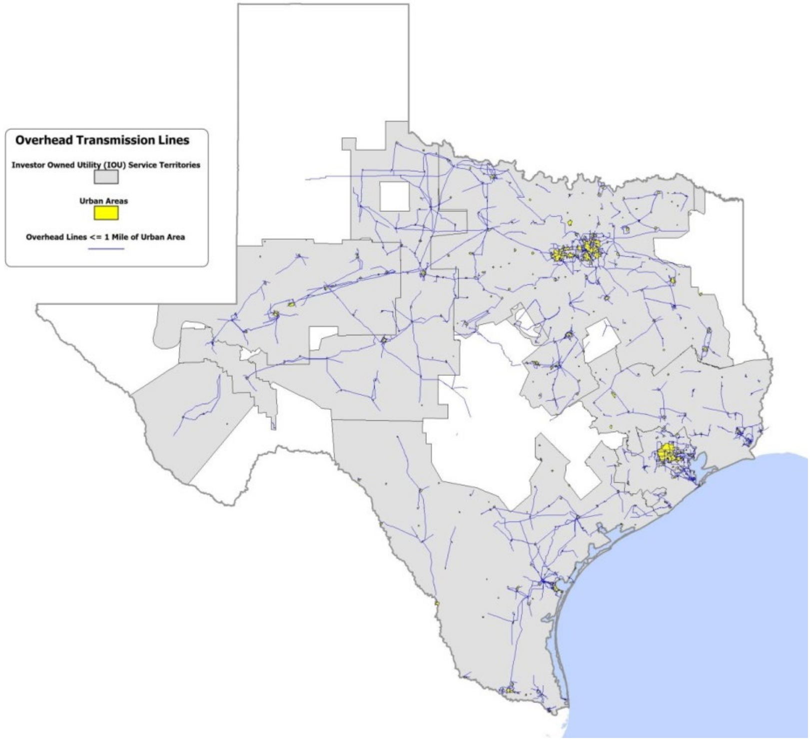


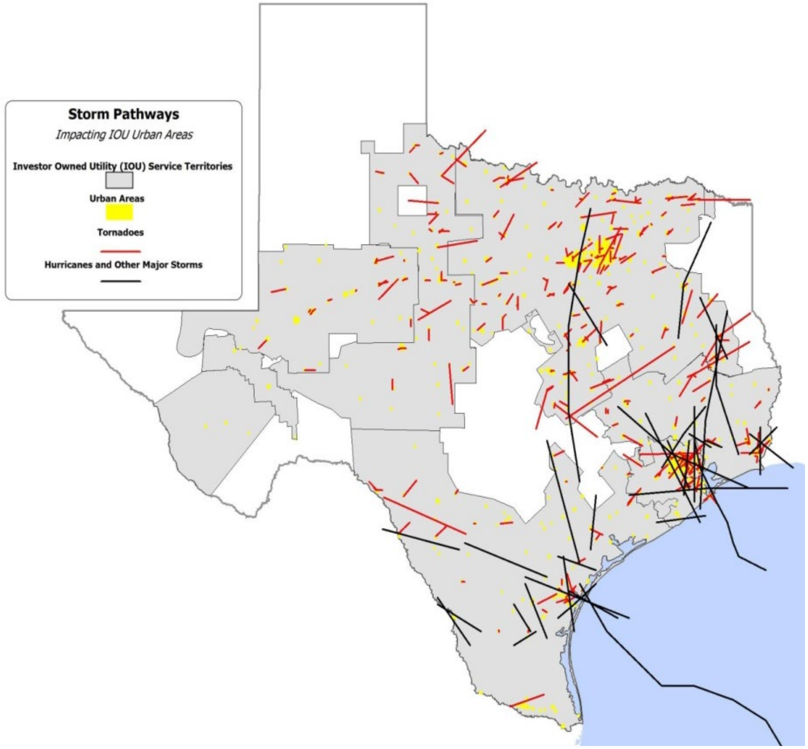

Note:

Results generated by using 10th (90th) percentile value for individual assumption while holding all other assumptions constant at median value.

# Possibility of net benefits

- Based on the initial configuration of this model, the **Texas public utility commission <u>should not</u> consider broadly mandating undergrounding when overhead T&D lines have reached the end of their useful life**

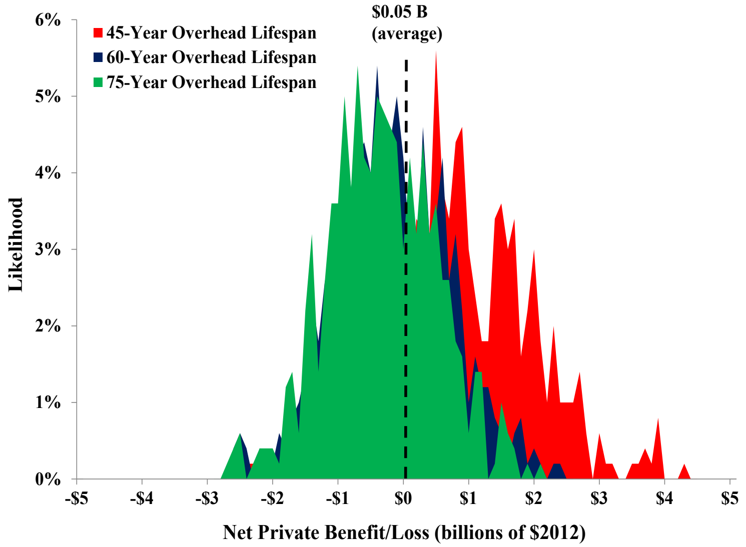


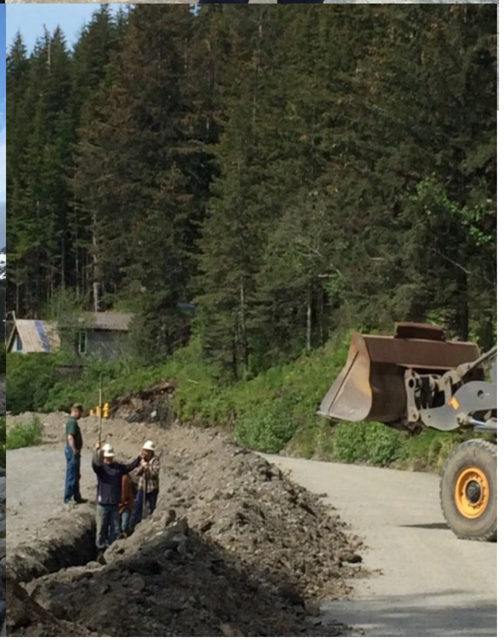
# Possibility of net benefits (cont.)

Texas policymakers should consider requiring that all T&D lines be undergrounded in places where:

- **there are a large number of customers per line mile** (e.g., greater than 40 customers per T&D line mile)
- **there is an expected vulnerability to frequent and intense storms**
- **there is the potential for underground T&D line installation economies-of-scale** (e.g., ~2% decrease in annual installation costs expected per year)
- **overhead line utility easements (i.e., rights-of-way) are larger than underground line utility easements**



# (Under)ground-truthing: Cordova, Alaska



# Analysis framework: Cordova case

- Study perspective:
  - CEO who cares about maximizing private benefits

- Key stakeholders with standing:
  - Cordova Electric Cooperative, ratepayers, and all residents within service territory

- Policy alternatives:

  (1) 1978 status quo (i.e., maintain existing underground and overhead line share)

  (2) Underground all T&D lines (i.e., underground when existing overhead lines reach end of useful lifespan)

- Why Cordova?
  - Cordova selected due to (1) community recently completing undergrounding initiative; (2) CEO showing great interest in this analysis and willingness to provide assumptions; (3) fishing industry extremely sensitive to power interruptions; and (4) extreme weather conditions.

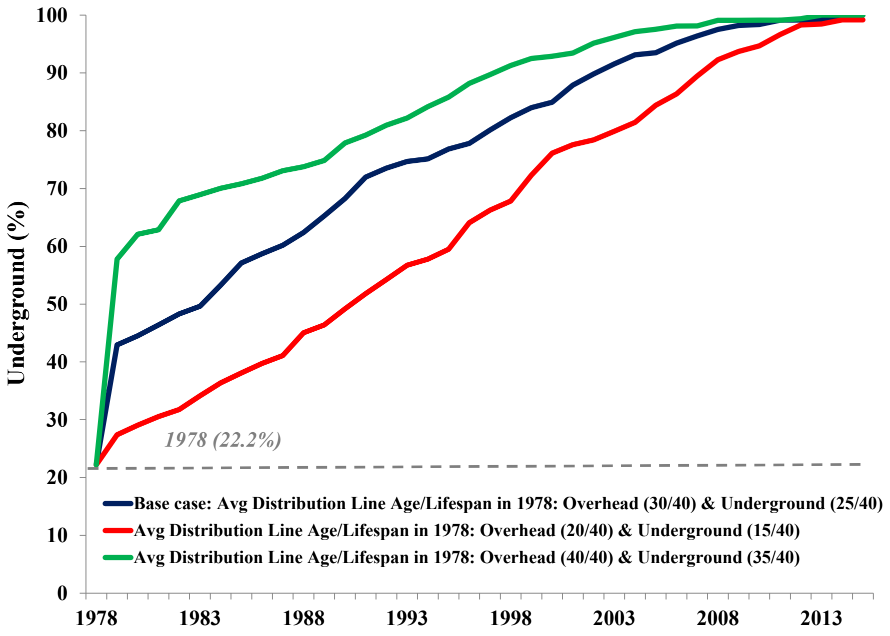
# Analysis framework: Cordova case (cont.)

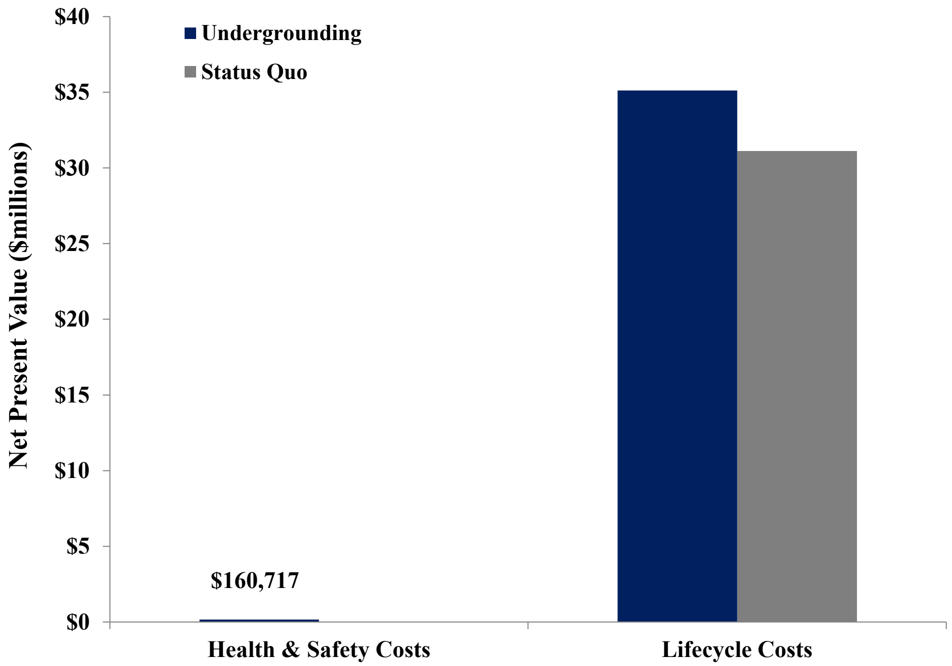


| *Key Stakeholders* | 1978 Decision to Underground 100% of Distribution System | |
|---|---|---|
| | **Selected Costs** | **Selected Benefits** |
| Cordova Electric Cooperative | • Increased chance of worker accidents* | |
| Cordova ratepayers | • Additional administrative, siting, and permitting costs associated with undergrounding*<br>• Increased capital costs for undergrounding*** | • Lower operations and maintenance costs for undergrounding*<br>• Decreased ecosystem restoration/right-of-way costs* |
| All residents/businesses within service area | | • Avoided societal costs due to less frequent power outages*****<br>• Avoided aesthetic costs***<br>• Decreased chance of community fatalities and accidents[NA] |

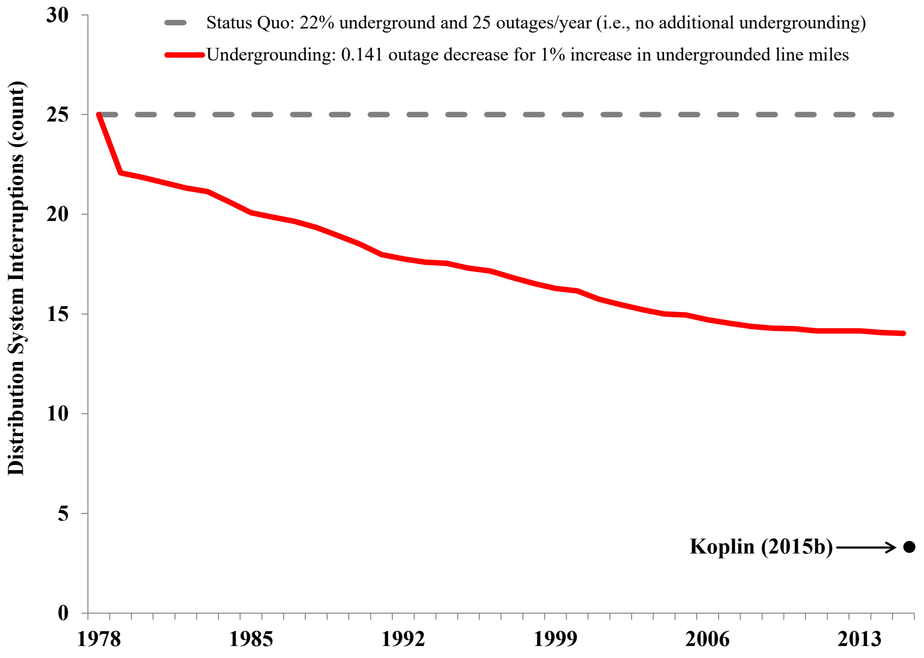
# Estimated costs



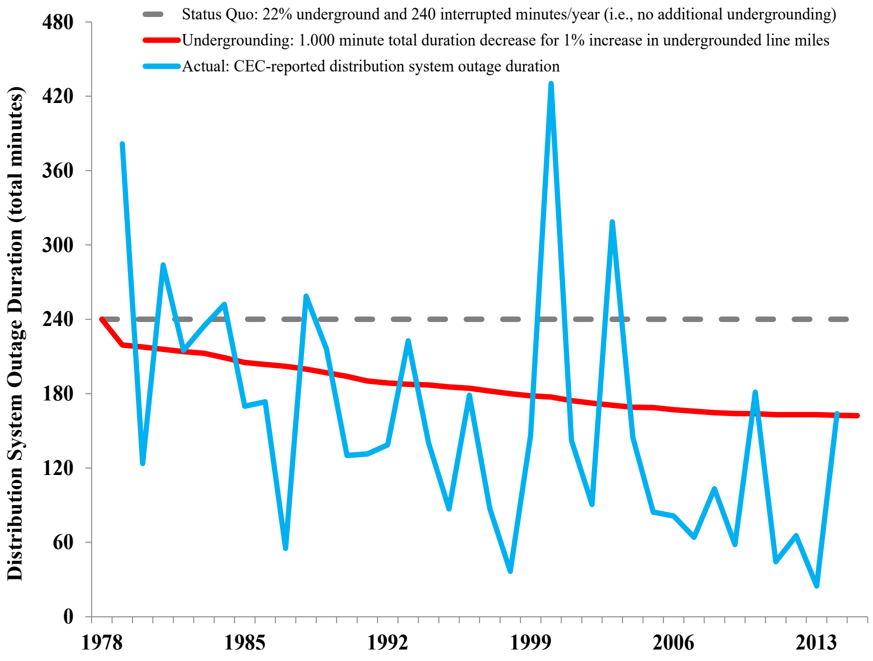


# Estimated benefits




## *Interruption minutes*

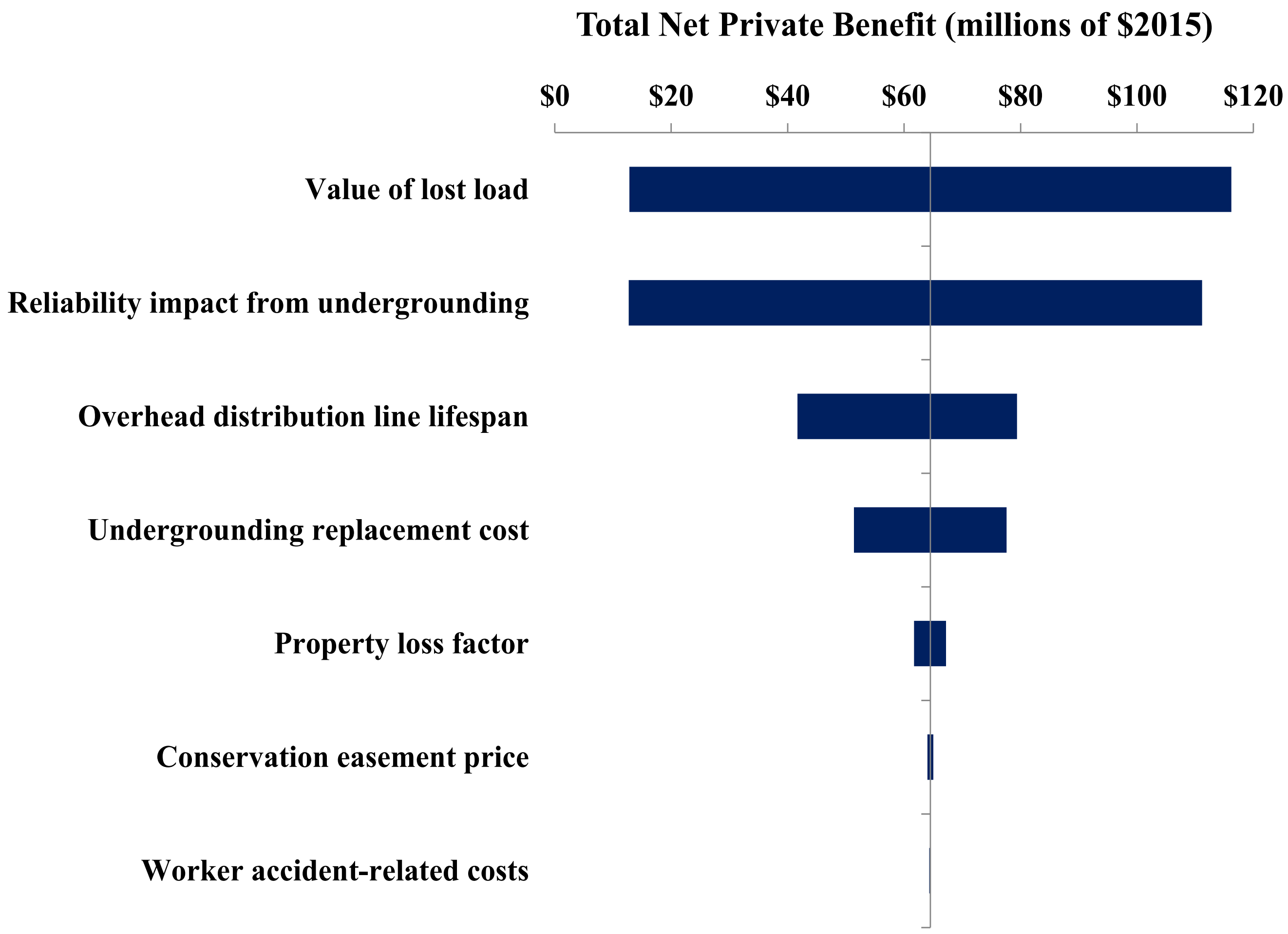


# Net social benefit



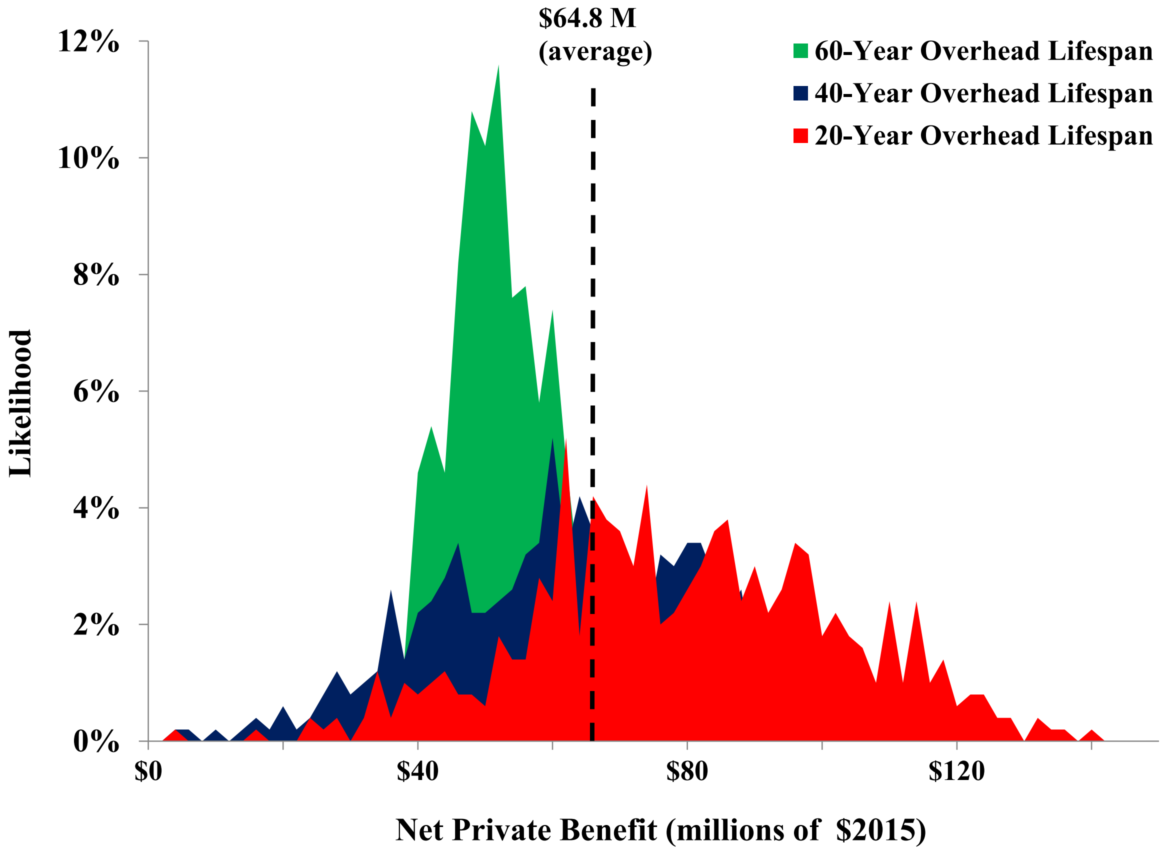
| Impact Category | 100% Underground | Status Quo | Net Cost ($millions) |
|---|---|---|---|
| Health & safety costs | $0.2 | $0 | $0.2 |
| Lifecycle costs | $35.3 | $31.1 | $4.1 |
| Total net costs (Undergrounding) | | | $4.3 |
| **Impact Category** | **100% Underground** | **Status Quo** | **Net Avoided Costs ($millions)** |
| Interruption costs | $130.1 | $194.7 | $64.6 |
| Aesthetic costs | $27.9 | $24.4 | $3.5 |
| Enviro. restoration costs | $2.4 | $3.1 | $0.6 |
| Total net benefits (Undergrounding) | | | $68.7 |
| **Net Social Benefit (Undergrounding)** | | | |
| **Net social benefit (millions of $2015)** | | | **$64.5** |
| **Benefit-cost ratio** | | | **16.1** |

# Sensitivity analysis



# Sensitivity analysis (cont.)



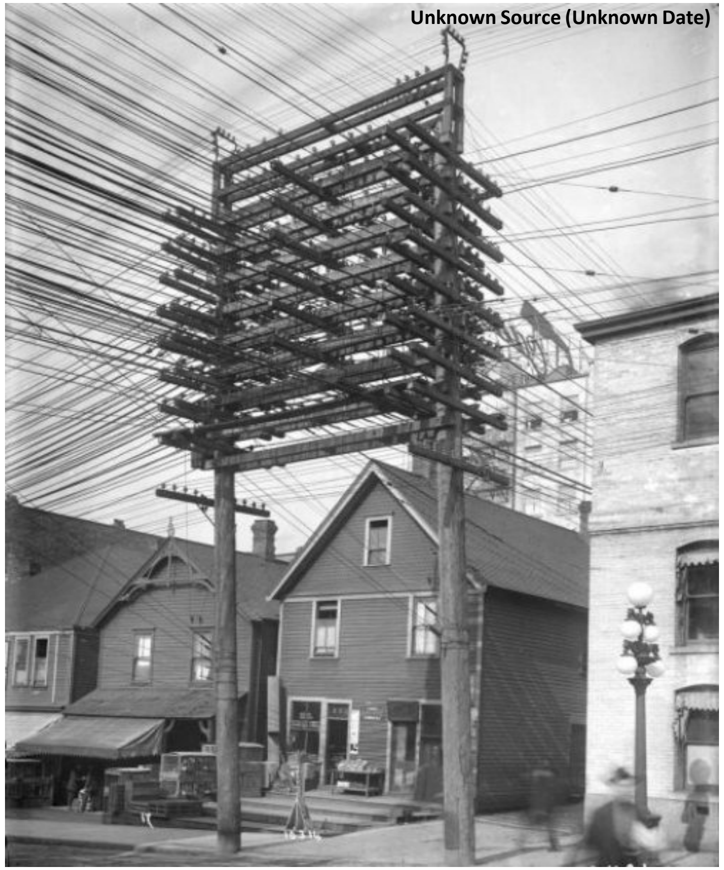


# Overall conclusion



- Generally **assumed that the costs of undergrounding transmission and distribution lines far exceed the benefits** from avoided outages
- Undergrounding power system infrastructure can improve reliability and that comprehensive benefits of this strategy can, in some cases, exceed the all-in costs
- **Cost-effectiveness depends on (1) the age/lifespan of existing overhead infrastructure; (2) whether economies of scale can be achieved; (3) the vulnerability of locations to increasingly severe and frequent storms; and (4) the number of customers per line mile.**
- **Analysis framework could be adapted to evaluate economics of other strategies to improve grid resiliency and reliability** (e.g., grid hardening activities)

# Thank you

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# Appendix



# Estimating lifecycle costs



**Step 1**
- Collect information on the total line mileage, lifespan, capital, and operations and maintenance (O&M) costs of T&D infrastructure that is currently overhead and underground for IOUs operating in Texas

**Step 2**
- Randomly determine the age and length of existing overhead and underground line circuits; project growth in T&D line miles to 2050

**Step 3**
- Replace lines at end of useful life; calculate the net present capital and O&M costs of T&D lines through 2050 for the status quo and undergrounding mandate

**Step 4**
- Subtract status quo lifecycle costs from undergrounding lifecycle costs

# Estimating benefits from less frequent outages

**Step 1**

- Apply econometric model (*i.e., LBNL 2015 reliability trends report*) to estimate the total number of Texas IOU outages—under the status quo—from now until 2050

**Step 2**

- Estimate the total number of outages—for the undergrounding alternative—by gradually removing the effect of weather on this same econometric model as the share of undergrounded line miles increases each year

**Step 3**

- Assign a dollar value for the total number of annual customer outages for both alternatives using information from Sullivan et al. (2015) (*i.e., ICE Calculator*)

**Step 4**

- Discount all costs back to the base year; subtract the outage-related costs for the undergrounding alternative from the outage costs for the status quo

# Estimating avoided aesthetic costs

**Step 1**

- Estimate number of residential, commercial and industrial, and other properties within an "overhead transmission viewing corridor" which is decreasing in size over time

**Step 2**

- Multiply number of affected properties against the real estate value for each property class and lost property value associated with overhead high-voltage transmission lines (e.g., 12.5%)

**Step 3**

- Discount the stream of avoided aesthetic costs back to the present using discount rate (e.g., 10%)

# Ecosystem-related restoration costs

**Step 1**
- Estimate the number of acres affected by T&D line growth in the future (using development corridor width and total line miles)—for both alternatives

**Step 2**
- For both alternatives, multiply total T&D line development corridor acreage against a conservation easement price (e.g., $3,000/acre)

**Step 3**
- Discount the stream of ecosystem restoration costs back to the present using discount rate

**Step 4**
- Subtract status quo restoration costs from undergrounding restoration costs

# Conversion-related morbidity and mortality costs

**Step 1**
- Collect information on total number of IOU employees; utility sector accident rates and costs from relevant injuries; utility sector fatality rates and the value of statistical life (VSL)

**Step 2**
- For status quo, multiply fatality and non-fatality incidence rates by VSL and accident costs, respectively, and number of IOU employees

**Step 3**
- For undergrounding alternative, increase fatal and non-fatal incidence rates proportionally as share of underground line miles increases each year; multiply increased fatality and non-fatality incidence rates by VSL and accident costs, respectively, and number of IOU employees

**Step 4**
- For both alternatives, discount all costs back to base year; subtract status quo morbidity/mortality costs from undergrounding morbidity/mortality costs

# Key assumptions: Texas IOUs



| | | Range | | | Impact Category | | | | |
|---|---|---|---|---|---|---|---|---|---|
| # | Sensitivity/ scenario analysis | Minimum value (10th %) | Base case value (50th %) | Maximum value (90th %) | Lifecycle assessment (cost) | Avoided outages (benefit) | Aesthetics (benefit) | Health and safety (cost) | Ecosystem restoration (cost) |
| 1 | Alternative replacement cost of undergrounding T&D lines ($ per mile) | $71,400 (dist.) $336,000 (trans.) | $357,000 (dist.) $1,680,000 (trans.) | $642,600 (dist.) $3,024,000 (trans.) | * | * | | | |
| 2 | Alternative values of lost load for each customer class ($ per event) | $0.5 (residential) $87 (other) $1,843.4 (C&I) | $2.7 (residential) $435 (other) $9,217 (C&I) | $4.9 (residential) $783 (other) $16,590.6 (C&I) | | * | | | |
| 3 | Alternative discount rates (%) | 2% | 10% | 18% | * | * | * | * | * |
| 4 | Alternative aesthetic-related property loss factors (% of property value) | 2.5% | 12.5% | 22.5% | | | * | | |
| 5 | Alternative incidence rates for accidents and fatalities (per 100,000 employees) | 420 (non-fatal) 3 (fatal) | 2,100 (non-fatal) 15 (fatal) | 3,780 (non-fatal) 27 (fatal) | | | | * | |
| 6 | Alternative accident costs and VSL ($ per accident/$ per life) | $26,131.6 $1,380,000 (VSL) | $130,658 $6,900,000 (VSL) | $235,184.4 $12,420,000 (VSL) | | | | * | |
| 7 | Alternative conservation easement prices ($/acre) | $600 | $3,000 | $5,400 | | | | | * |
| 8 | Alternative lifespan assumptions for overhead T&D infrastructure (years) | 45 | 60 | 75 | * | * | * | * | * |
| 9 | Share of underground line miles impact on reliability | -0.0002 | -0.001 | -0.0018 | | * | | | |
| 10 | Number of customers per line mile | 15 | 75.0 | 135 | | * | | | |
| 11 | Annual O&M cost expressed as % of replacement cost: underground T&D lines | 1% (trans.) 0.1% (dist.) | 5% (trans.) 0.5% (dist.) | 9% (trans.) 0.9% (dist.) | * | | | | |

# Key assumptions: Cordova Electric Coop.

***For the base case, it is assumed that half of all distribution-related reductions in the frequency and total minutes customers were without power are a result of the Cordova's decision to underground lines…***

| | | Range | | | Impact Category | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **#** | **Sensitivity/ scenario analysis** | **Minimum value (10th %)** | **Base case value (50th %)** | **Maximum value (90th %)** | **Lifecycle assessment (cost)** | **Avoided outages (benefit)** | **Aesthetics (benefit)** | **Worker safety (cost)** | **Ecosystem restoration (benefit)** |
| 1 | 1978 replacement cost of undergrounding dist. lines ($2015 per mile) | $60,814 | $304,070 | $547,326 | * | | | | |
| 2 | Alternative values of lost load for each customer class ($ per event) | -80% below base case values | See Figures 40–42 | +80% above base case values | | * | | | |
| 3 | Alternative aesthetic-related property loss factors (% of property value) | 2.5% | 12.5% | 22.5% | | | * | | |
| 4 | Alternative conservation easement prices ($/acre) | $1,091.2 | $5,456 | $9,820.8 | | | | | * |
| 5 | Alternative lifespan assumptions for overhead dist. infrastructure (years) | 20 | 40 | 60 | * | * | * | * | * |
| 6 | Outage duration and frequency change due to undergrounding activities | 25 outages/240 minutes (1978); 22.8 outages/224.3 minutes (2015) | 25 outages/240 minutes (1978); 14 outages/161.5 minutes (2015) | 25 outages/240 minutes (1978); 5.2 outages/98.7 minutes (2015) | | * | | | |
| 7 | Workers compensation direct and indirect cost ($/accident) | $32,143.4 | $160,717 | $289,290.6 | | | | * | |

# Targeted Undergrounding Benefit-Cost Analysis in Michigan

MPSC Case U-21388:
Undergrounding Workshop

**Luke Dennin, Ph.D.**

U.S. Department of Energy Fellow
Michigan Public Service Commission

September 19, 2025

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# Does strategic undergrounding make sense?

- **Conventional wisdom suggests that undergrounding is cost prohibitive**
- **However, the electricity sector is shifting**
  1. Extreme weather is increasing in frequency and intensity
  2. Electrification is growing
- **Previous work suggests undergrounding may be cost effective in specific circumstances (Larsen, 2016)**
- **This work conducts circuit-level benefit-cost analysis (BCA) of overhead-to-underground conversions across Consumers Energy's (CE's) service territory, evaluating a targeted approach**

# Agenda for the Talk

1. **Notes on BCA and this study's research design**
2. **Reliability projections and improvements from undergrounding**
3. **Average outcome and value stream review**
4. **Detailed findings**
   - Circuit-level outcomes
   - Uncertainty analysis
   - Portfolio analysis
5. **Conclusions**

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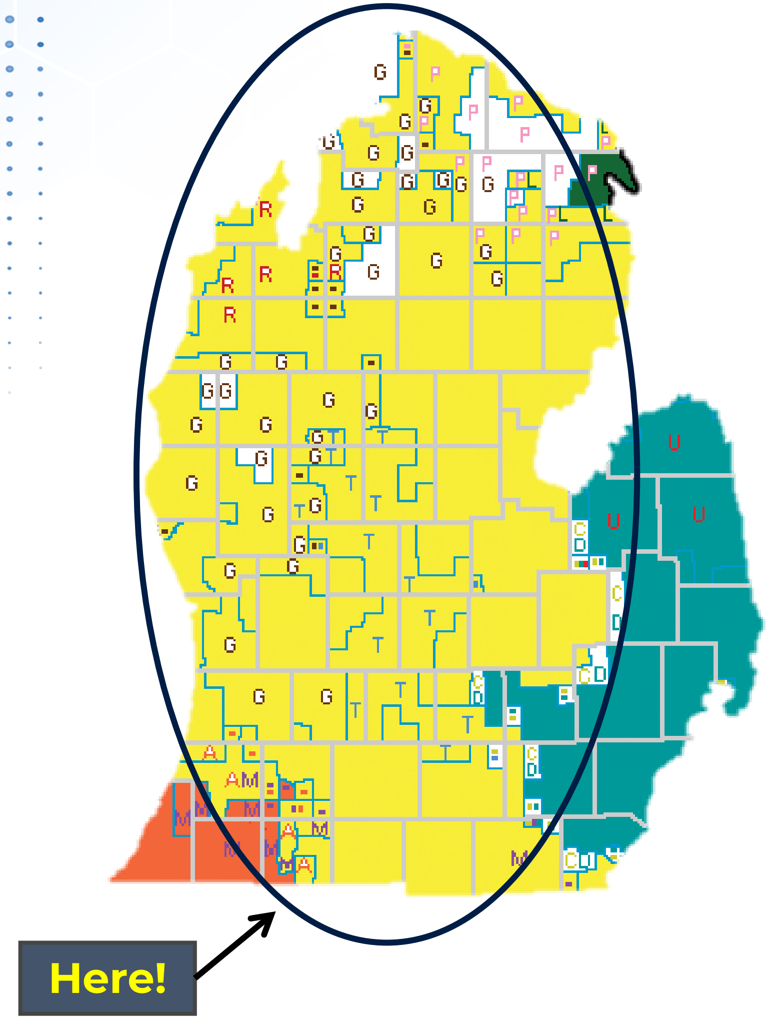
# 1. Notes on BCA and this study's research design

# BCA is a decision-making framework that quantitatively weighs pros and cons


1. **BCA provides an "apples-to-apples" comparison by transforming impacts into comparable units being $**
2. **Attributing $ values to project components is difficult and uncertain**
3. **Anything not explicitly included is implicitly given a zero $ value**
4. **BCA is one of several decision-making considerations**
   - We may choose not move forward with a project yielding net benefits
   - We may choose to move forward with a project yielding net costs
   - Other considerations: Affordability, equity, risk aversion, decision-maker preferences

# Notes on this study's research and analysis design




## Component Selection

- One-mile single-phase lateral projects
- Undergrounding vs. rebuilding overhead
- Circuit-level impact assessment

## Utility Data + External Data

- Utility system characteristics and costs
- Extreme weather projections
- Economic information, trends, and models

## Systematic Approach to Uncertainty

- Monte Carlo simulations
- Sensitivity analysis

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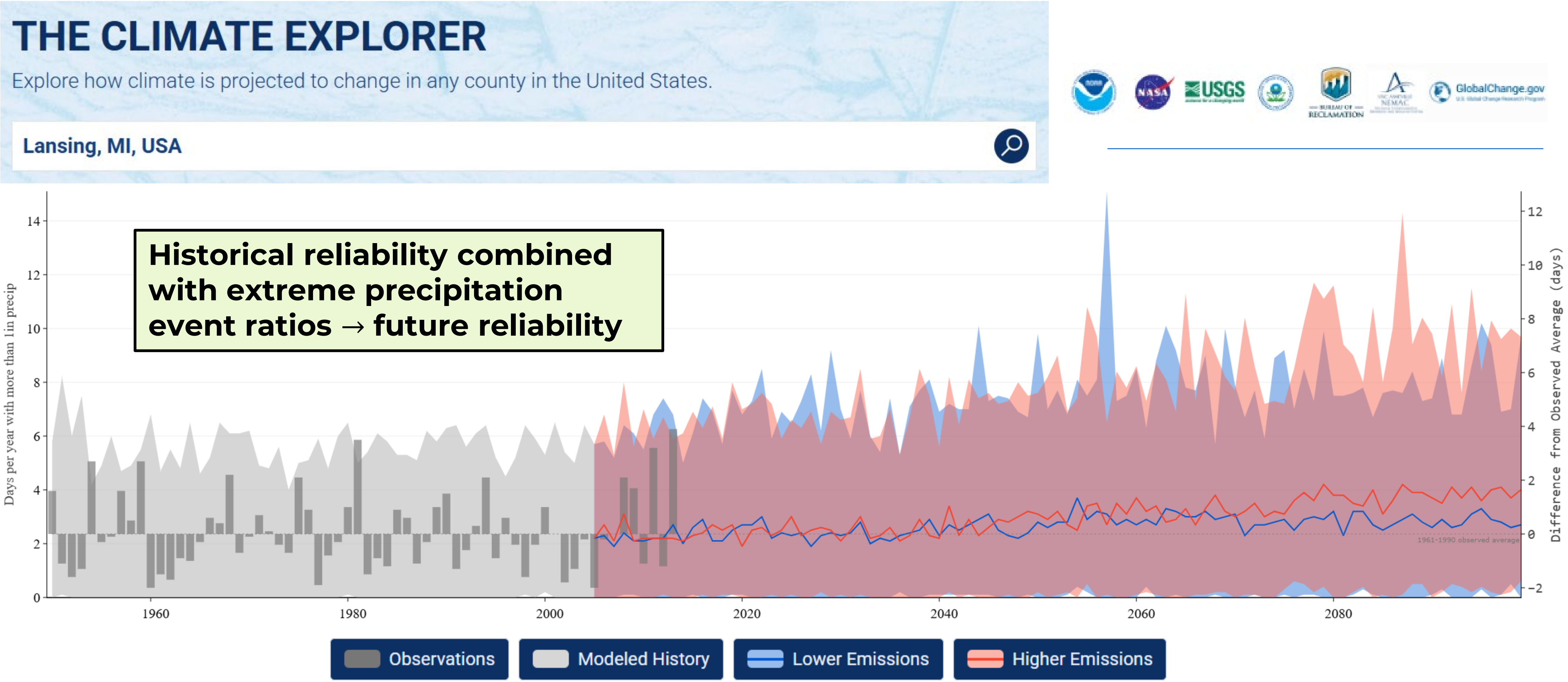
# 2. Reliability projections and improvements from undergrounding

# Extreme weather projections from NOAA's Climate Explorer guide future reliability metric estimates



# What are the reliability improvements from undergrounding under different outage conditions?

- **Approach:** Regression analysis of reliability metrics vs. underground line share.
- **Data:** >1,900 circuits, 5 years, 3 outage conditions + an all-condition model:
  - Blue Sky: <1% of customers out
  - Gray Sky: <10% of customers out
  - Catastrophic: >10% of customers out
- **Objective:** Assess effect of undergrounding on SAIFI and SAIDI, controlling for other variables (e.g., tree density, customer counts).

| Condition | SAIFI | SAIDI |
|---|---|---|
| All Condition | -4.87E-03*** | -8.02E-03*** |
| Blue Sky | -2.48E-03* | -5.61E-04 |
| Gray Sky | -6.51E-03** | -9.24E-03*** |
| Catastrophic | -7.36-03** | -8.51E-03*** |

***Note:*** *** $p < 0.01$; ** $p < 0.05$; * $p < 0.10$; ‘ ’ $p \geq 0.10$

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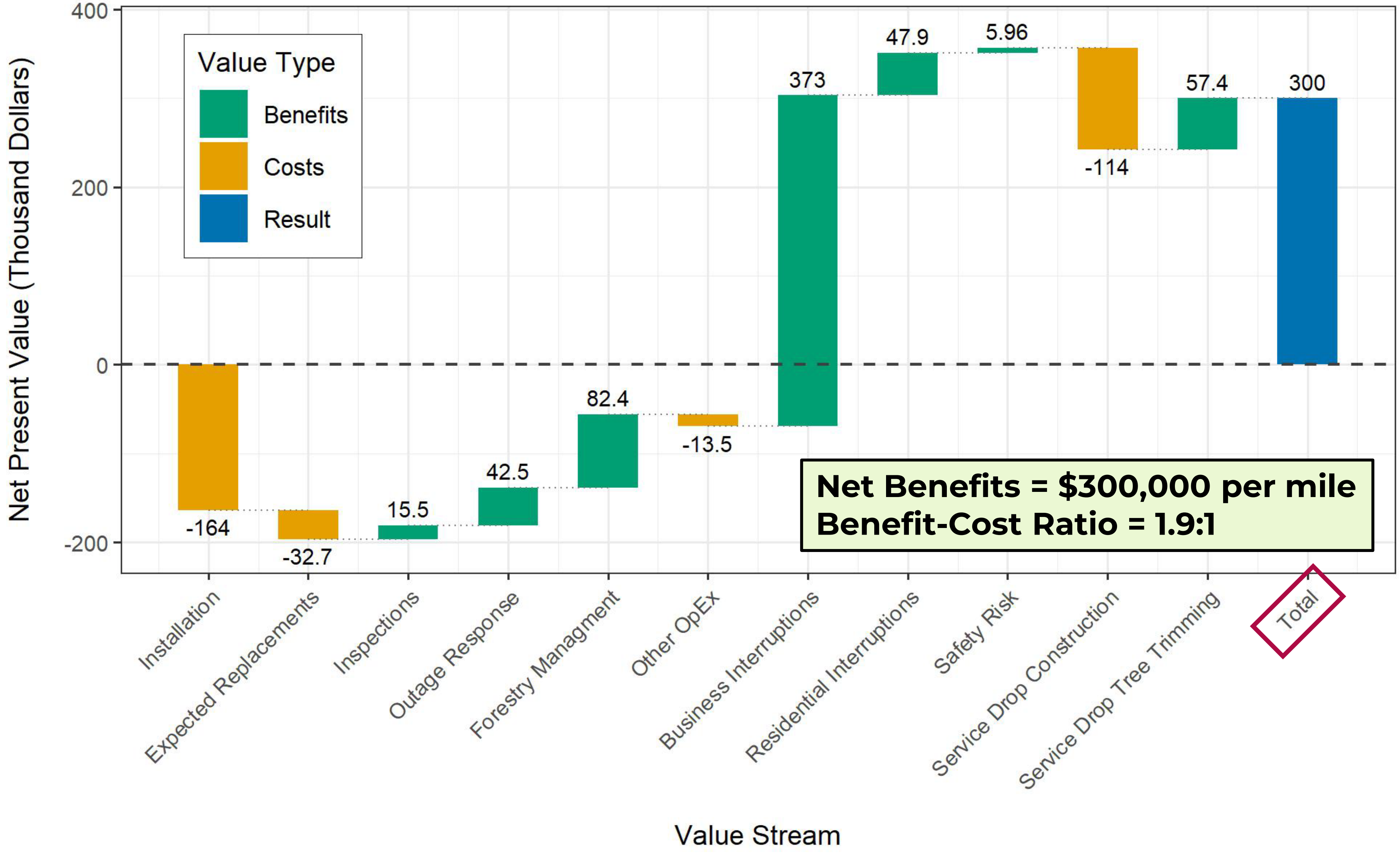
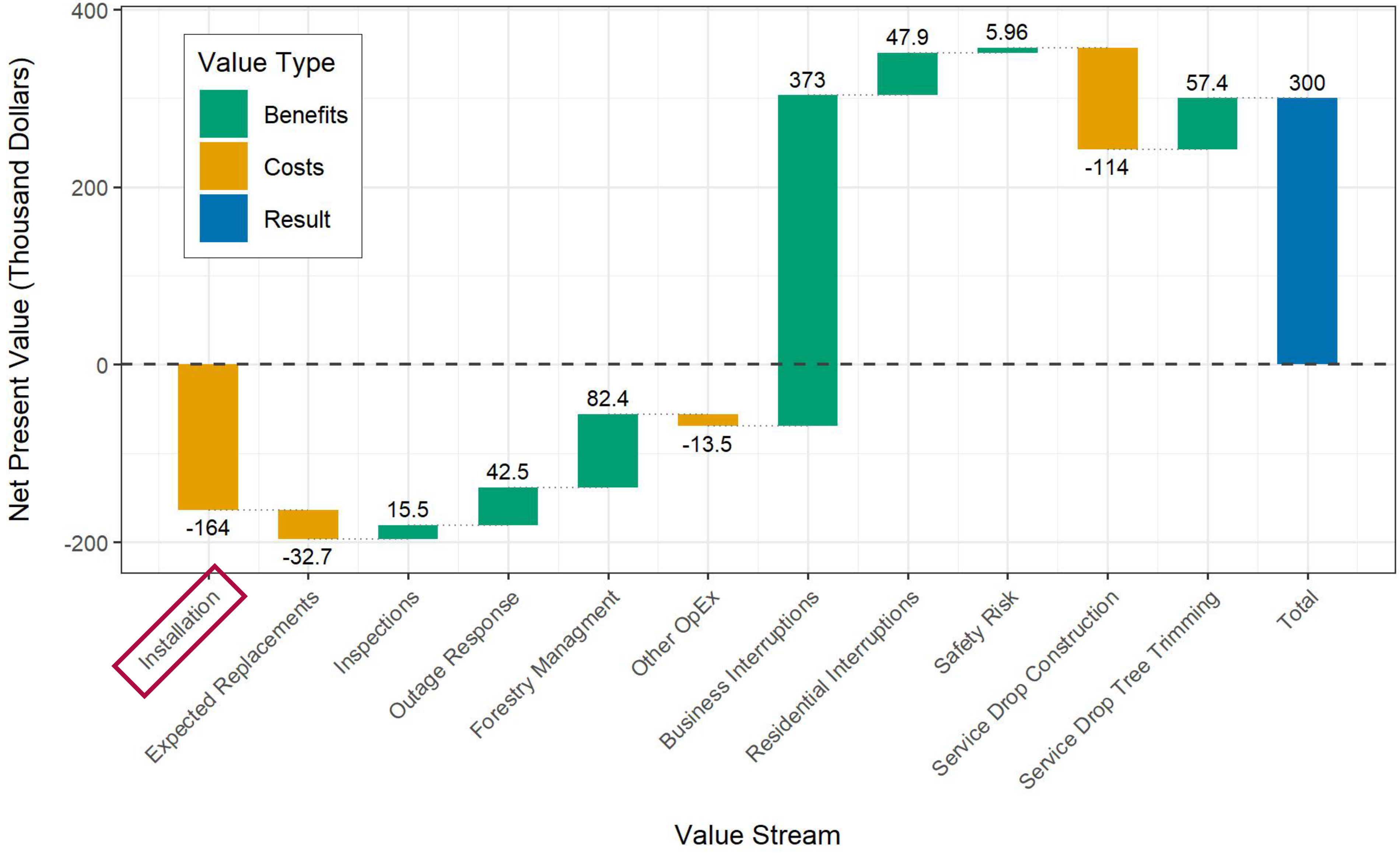
# 3. Average outcome and value stream review


Value Type
Benefits
Costs
Result
Net Present Value (Thousand Dollars)
400
200
0
-200
-164
-32.7
15.5
42.5
82.4
-13.5
373
47.9
5.96
-114
57.4
300
Net Benefits = $300,000 per mile
Benefit-Cost Ratio = 1.9:1
Installation
Expected Replacements
Inspections
Outage Response
Forestry Managment
Other OpEx
Business Interruptions
Residential Interruptions
Safety Risk
Service Drop Construction
Service Drop Tree Trimming
Total
Value Stream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Total
Value Stream

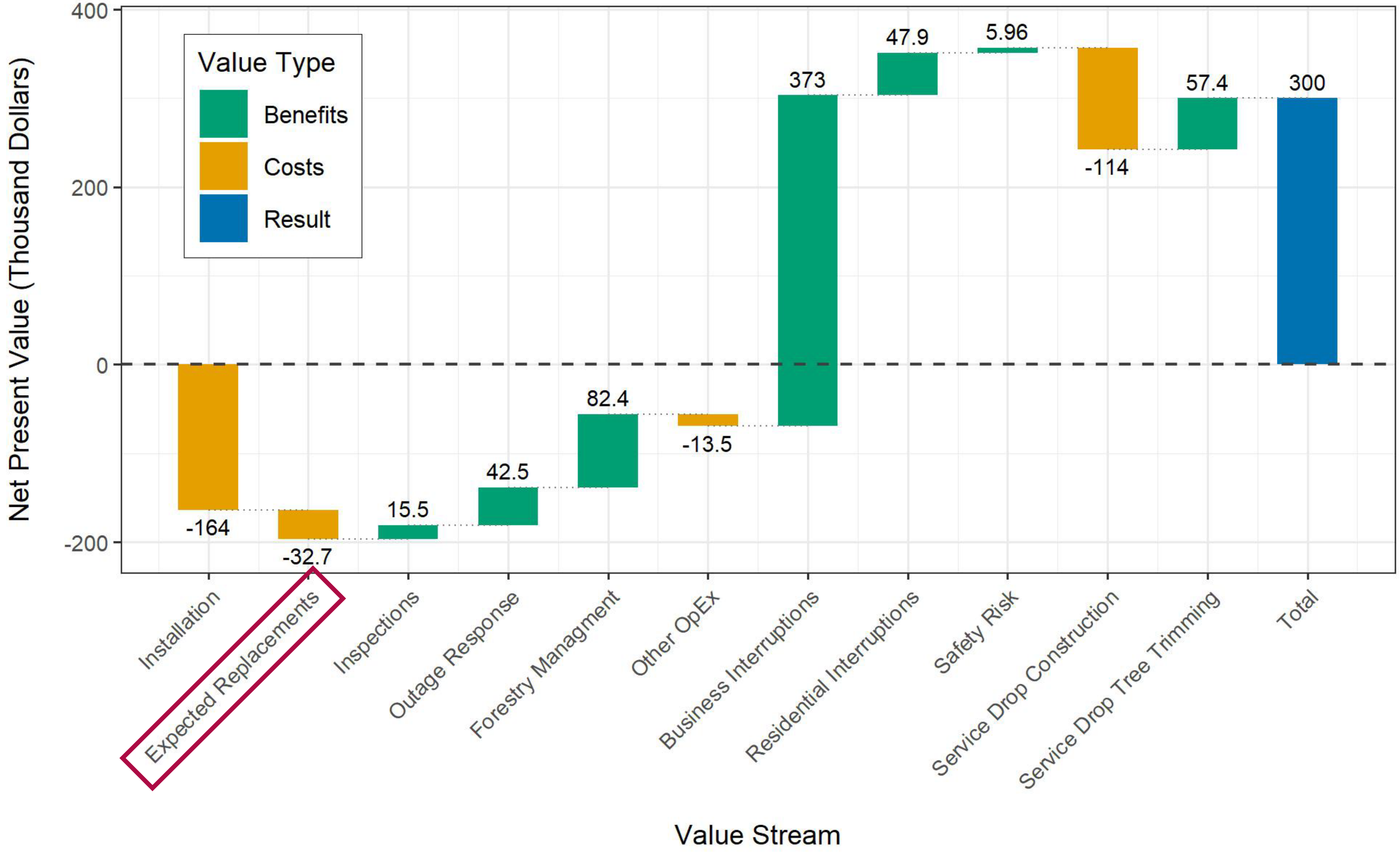
# Installation costs are informed by EPRI's Undergrounding Cost Study and Industry Scan

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

***Underground conversions are about 2.5x as expensive as overhead

| Project Scope | Area Type | Installation CapEx (Thousand $ per Mile) | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Overhead | Underground New Build | | | Underground Conversion | | |
| | | | Estimate | Difference vs. OH | | Estimate | Difference vs. OH | |
| Services Excluded | Urban | 131 | 275 | +144 | 2.10x | 329 | +198 | 2.51x |
| | Suburban | 103 | 208 | +105 | 2.02x | 250 | +147 | 2.43x |
| | Rural | 83.9 | 180 | +96.5 | 2.15x | 216 | +133 | 2.58x |
| Services Included | Urban | 214 | 449 | 235 | 2.10x | 539 | +325 | 2.51x |
| | Suburban | 168 | 341 | 172 | 2.02x | 409 | +240 | 2.43x |
| | Rural | 137 | 295 | 158 | 2.15x | 354 | +217 | 2.58x |

Link

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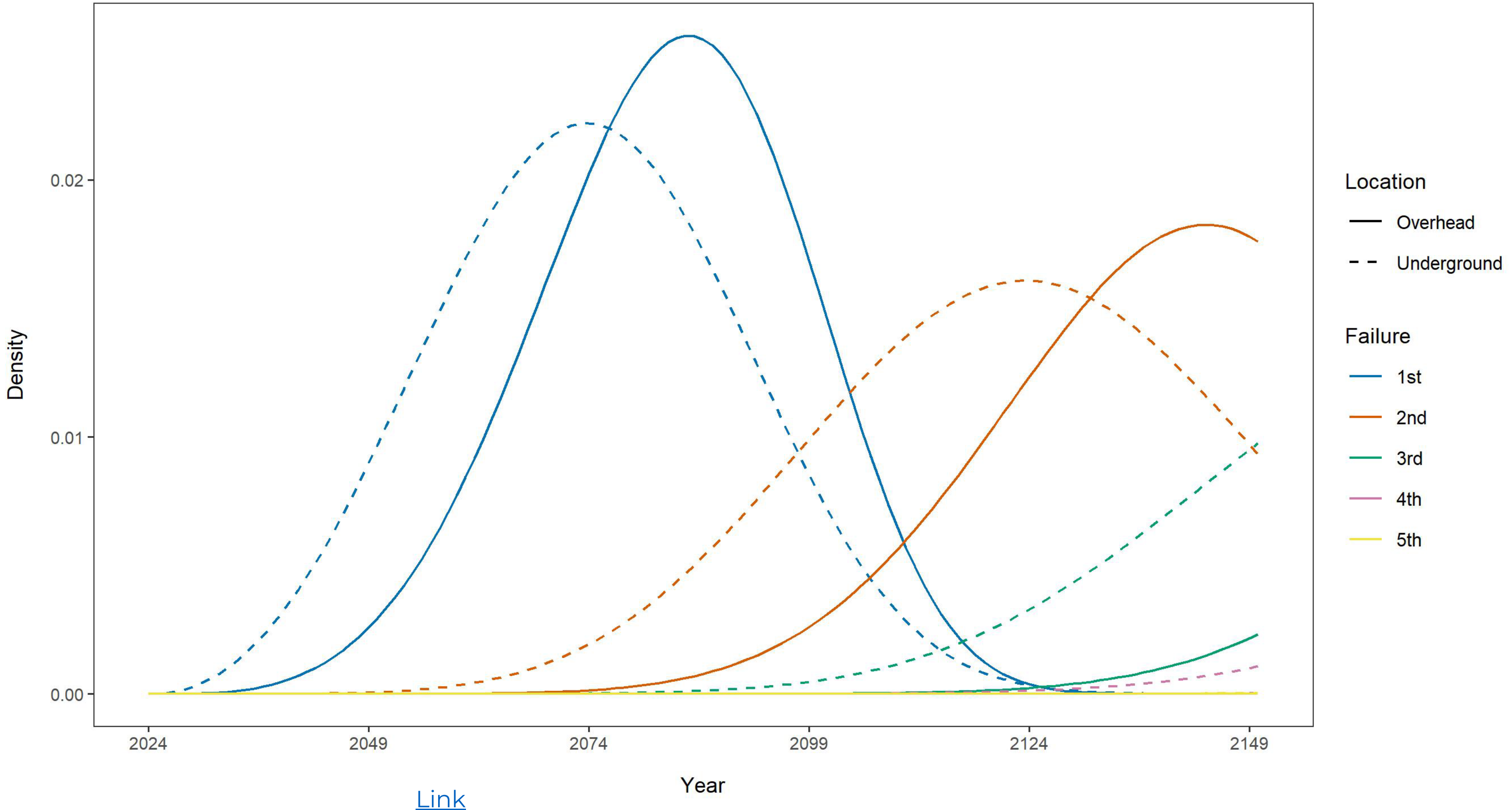
# Failure probabilities are informed by 1898 & Co.'s undergrounding BCA for DTE Electric

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*****Underground is expected to fail earlier than overhead**
- Modeled via expected values of successive failures

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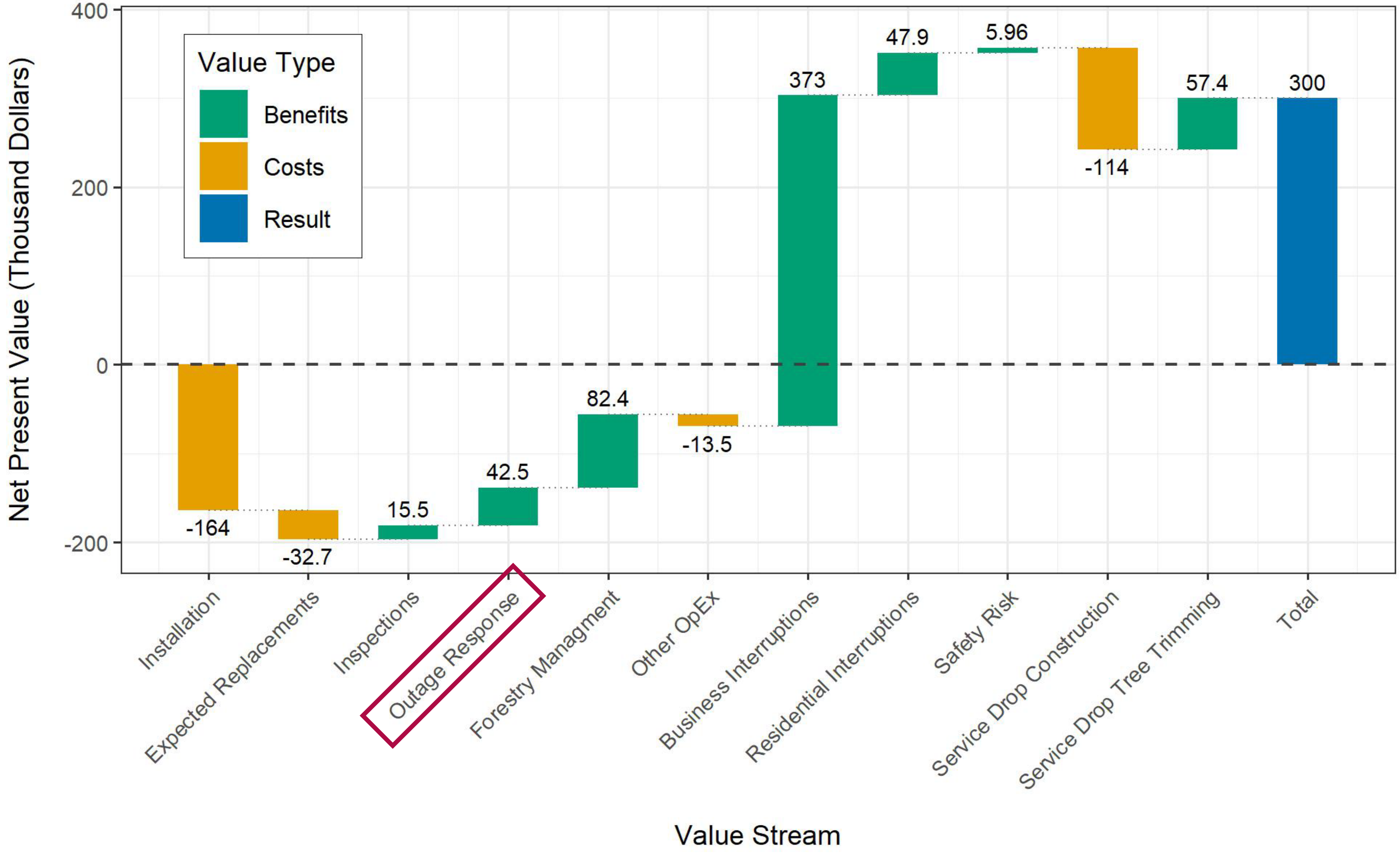
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Residential Interruptions
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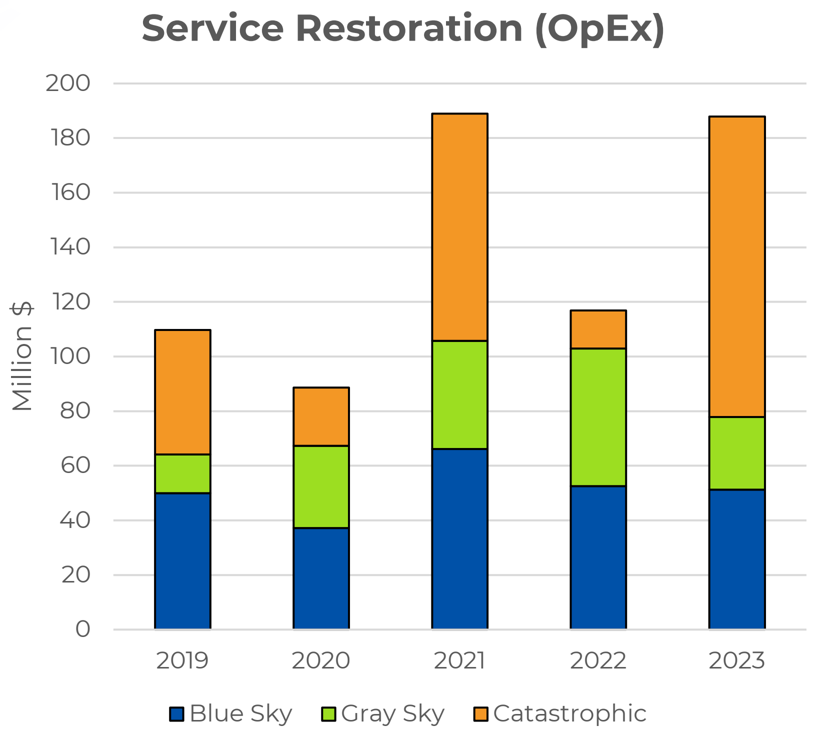
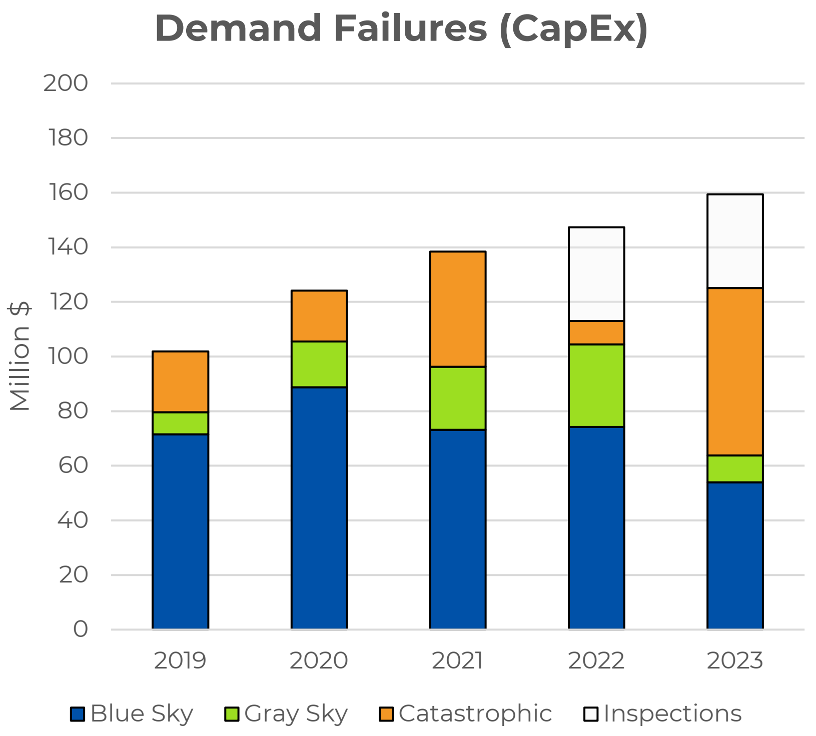
Service Drop Construction
Service Drop Tree Trimming
Total
Value Stream

# Outage response is modeled using historical spend from two programs and reliability metric projections




**$ per customer minute interrupted (CMI) & $ per customer interruption (CI)**

1. Unit costs per program (2) and outage condition (3)
2. Compute costs with future reliability data for both UG and OH scenarios
3. Average between CMI approach and CI approach

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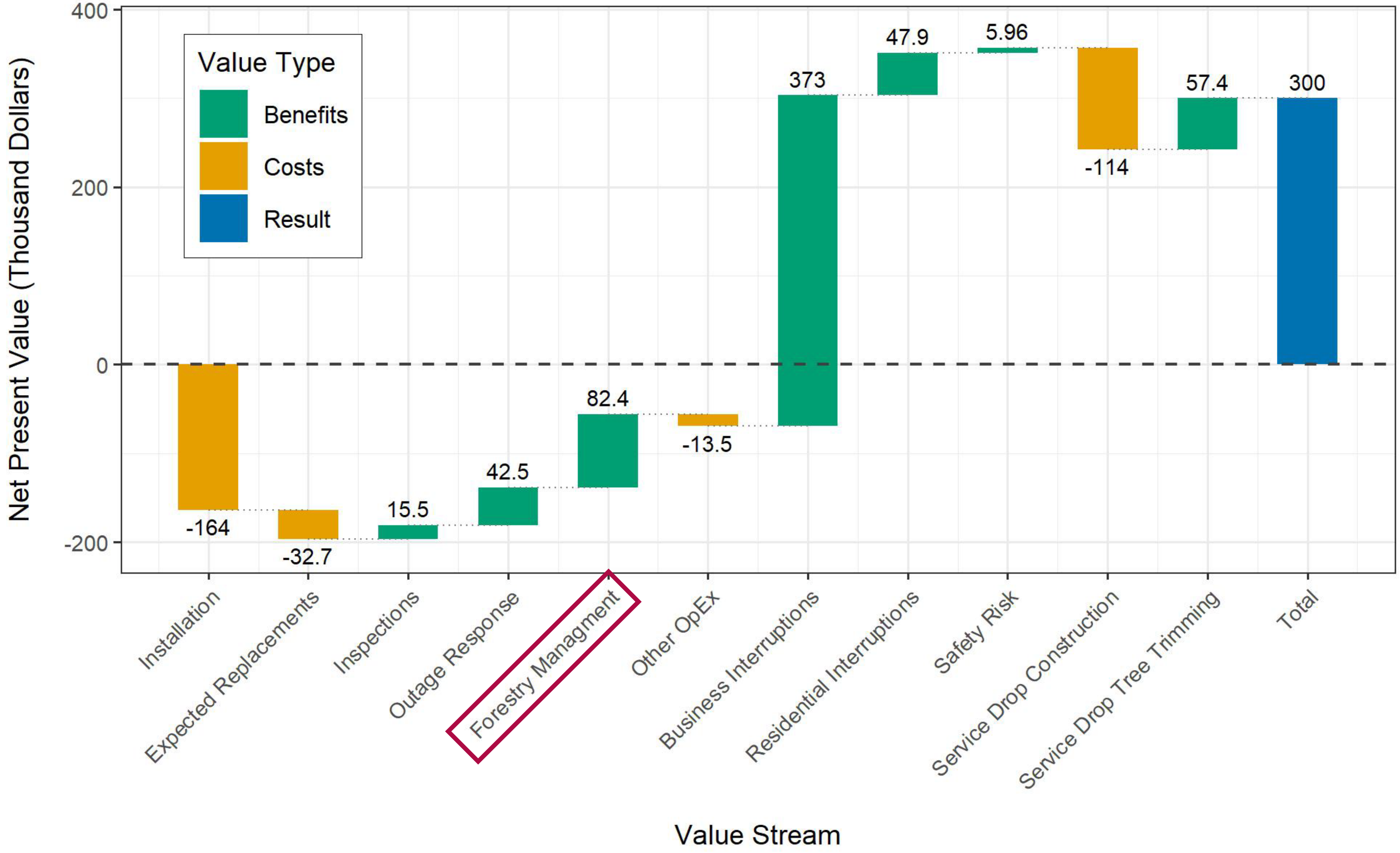
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# Undergrounding avoids forestry management costs aligning with the 5-year effective cycle goal

| Area Type | Infrastructure Location | Full System | | 5-Year Effective Cycle | | Unit Costs | |
|---|---|---|---|---|---|---|---|
| | | Overhead Miles | Trees | Annual Miles Trimmed | Annual Trees Trimmed | Per Mile | Per Tree |
| Urban | Backlot | 1,881 | 178,399 | 375 | 35,107 | $23,825 | $222 |
| | Frontlot | 10,305 | 884,878 | 2,071 | 176,119 | $14,267 | $133 |
| Rural | Backlot | 7,451 | 830,129 | 1,578 | 175,498 | $18,974 | $177 |
| | Frontlot | 31,908 | 3,663,067 | 6,840 | 782,537 | $14,267 | $133 |
| Total | | 51,545 | 5,556,473 | 10,864 | 1,169,261 | $15,280 | $142 |

**$ per mile & per tree**

1. Unit costs per area type (2) and infrastructure location (2)
2. Compute costs per effective (i.e., annualized using voltage cycles) mile and effective tree
3. Average between mile approach and tree approach

**** Also, consider reliability benefits of the new 5-year effective cycle*

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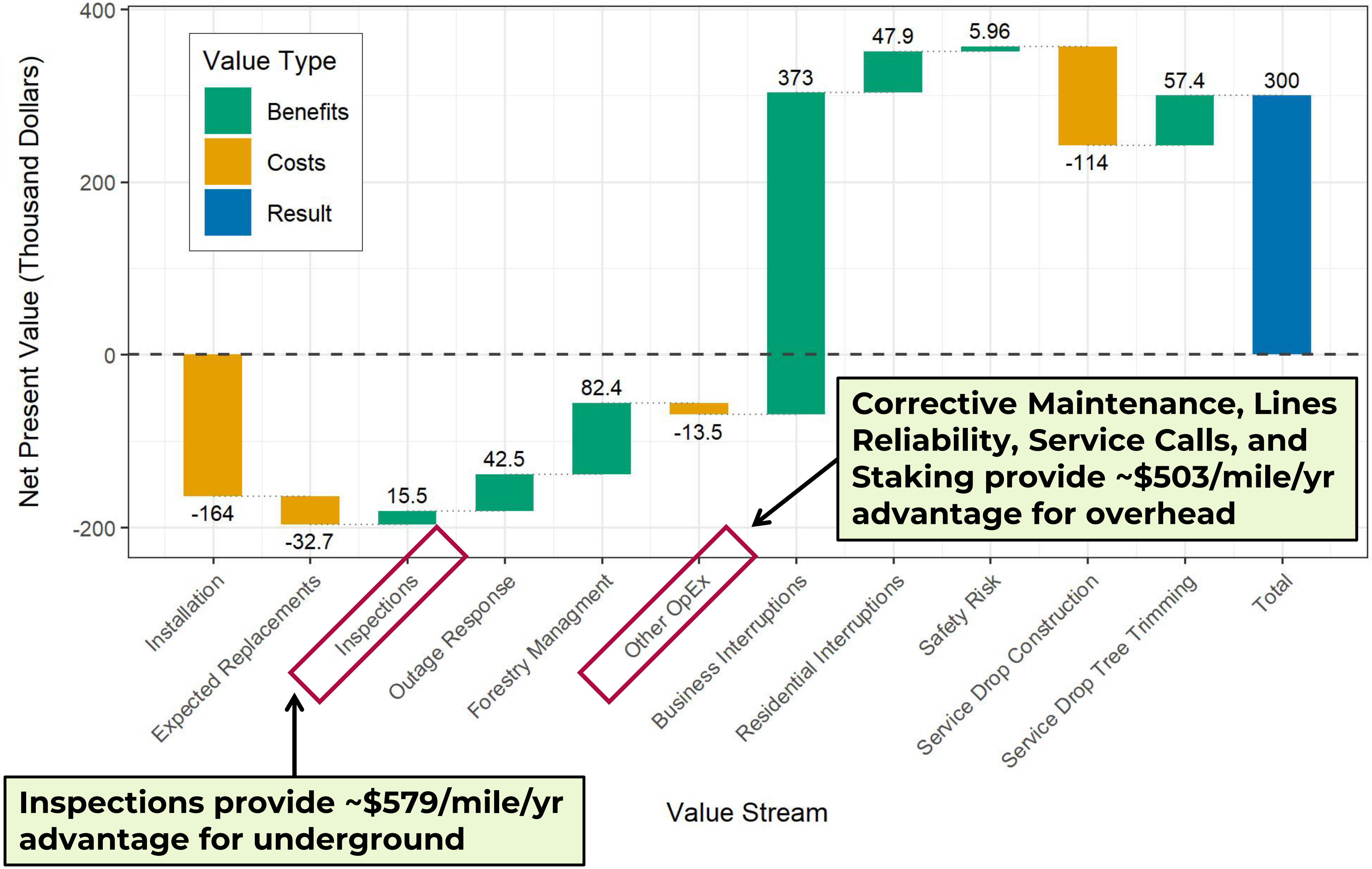
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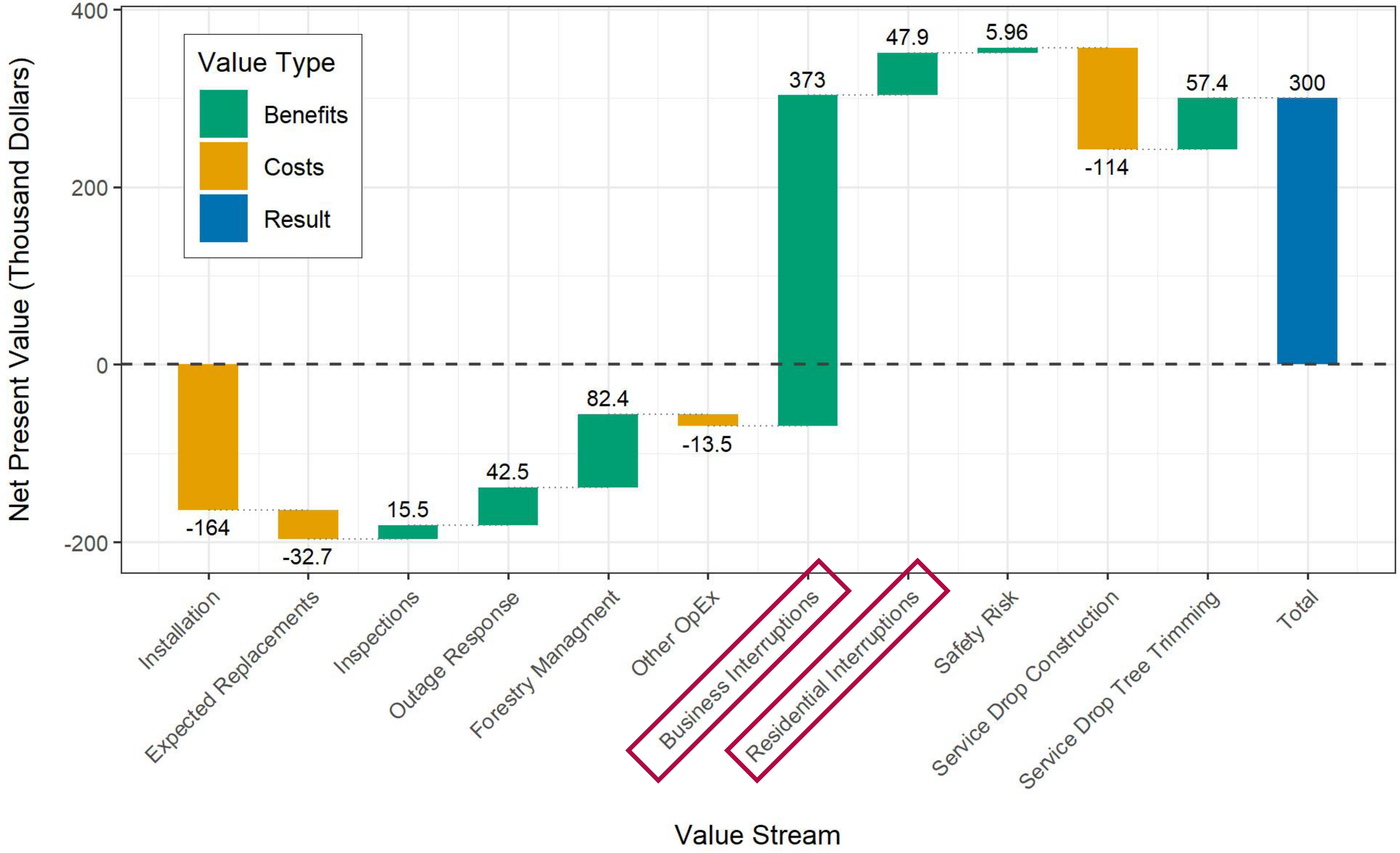
Residential Interruptions
Safety Risk
Service Drop Construction
Service Drop Tree Trimming
Total
Value Stream
Corrective Maintenance, Lines Reliability, Service Calls, and Staking provide ~$503/mile/yr advantage for overhead
Inspections provide ~$579/mile/yr advantage for underground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Value Stream

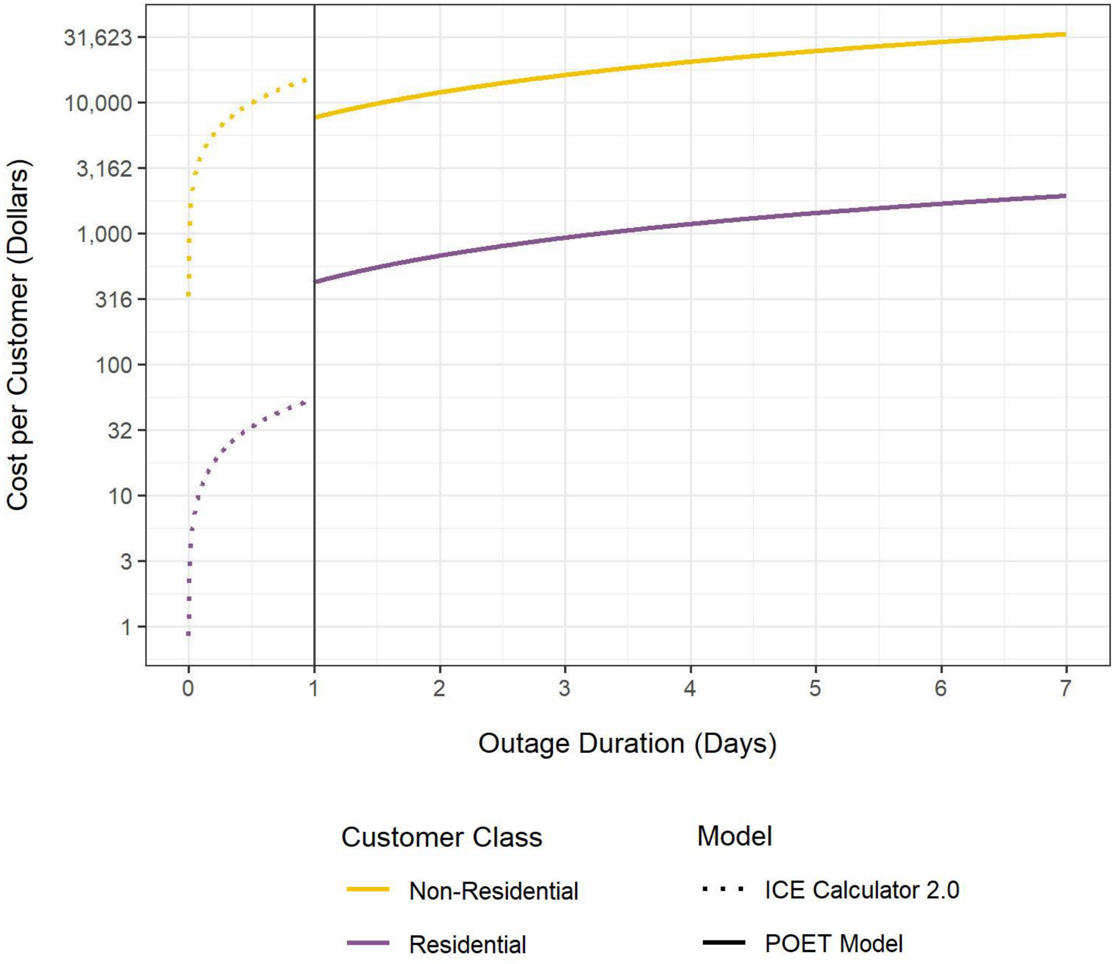
# Interruption costs are modeled using valuation tools and reliability metric projections

Link

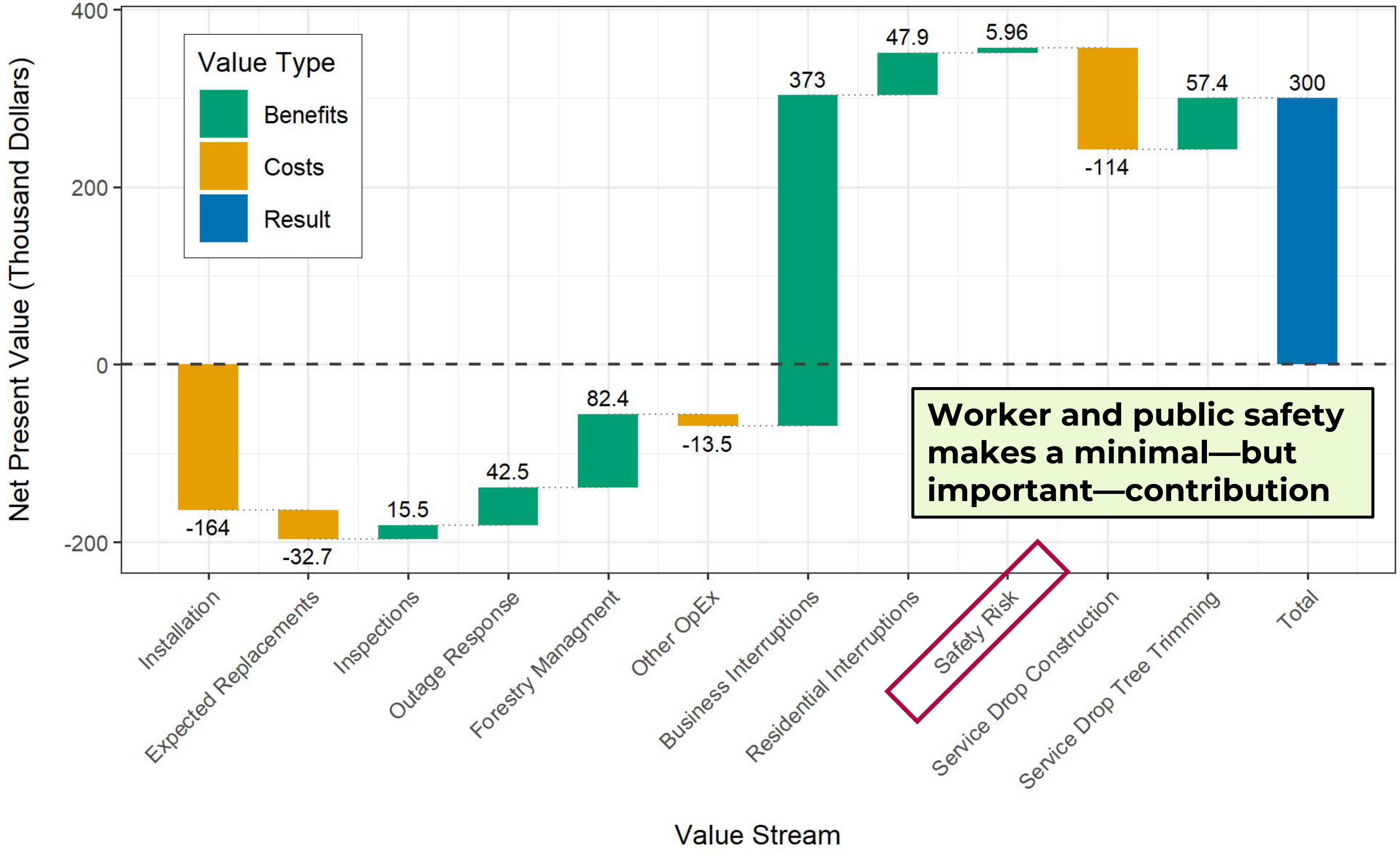
- **Reliability** context; short-duration, minimally inconvenient events
- Michigan-specific estimates
- Applicable through 24 hours

Link

- **Resilience** context; widespread long-duration events
- Prototype characterizes ComEd in Illinois—adapted here for Michigan
- Applicable past 24 hours




Larsen et al. (2025) and Larsen et al. (2024)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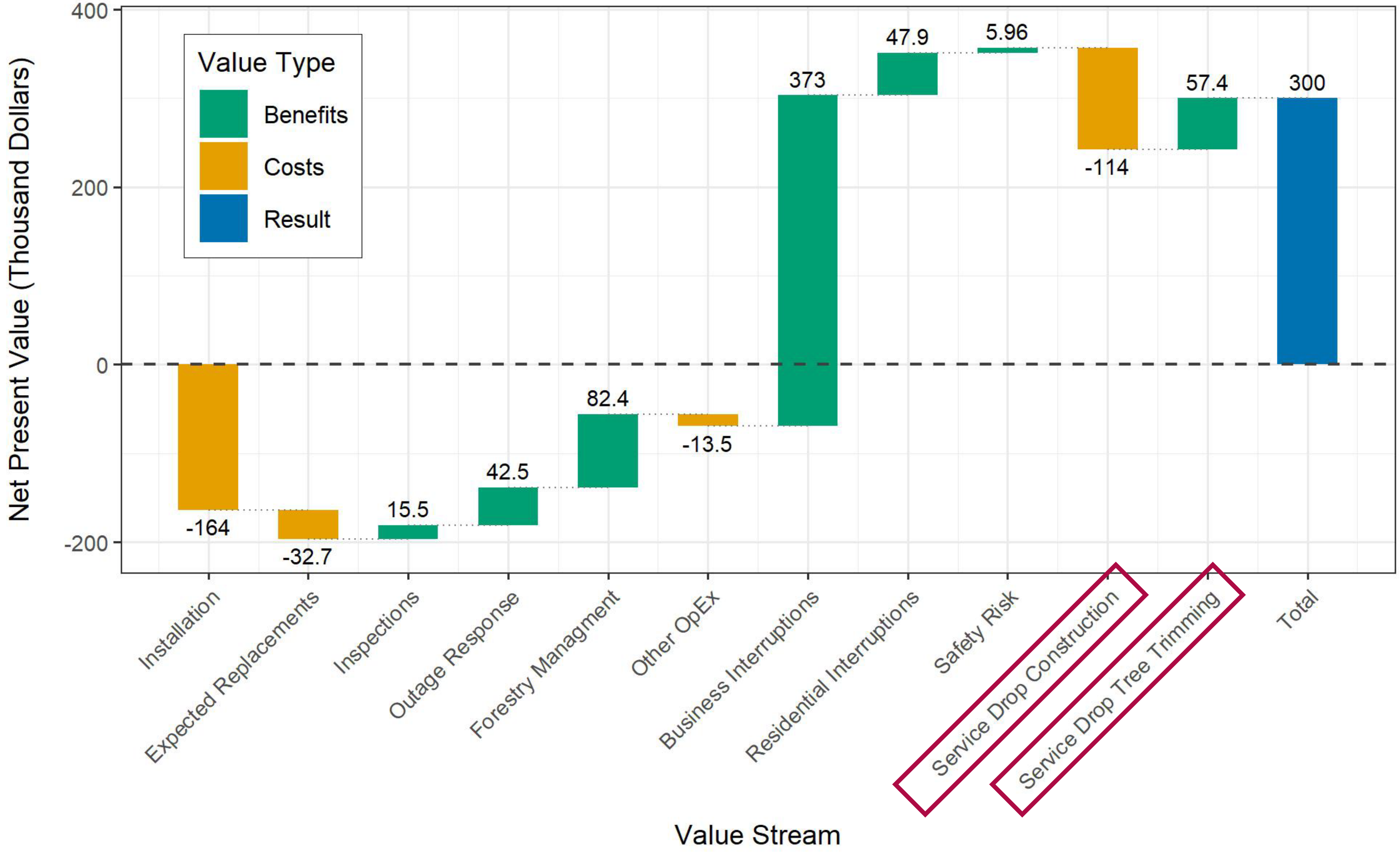
-114
57.4
300
Worker and public safety makes a minimal—but important—contribution
Installation
Expected Replacements
Inspections
Outage Response
Forestry Managment
Other OpEx
Business Interruptions
Residential Interruptions
Safety Risk
Service Drop Construction
Service Drop Tree Trimming
Total
Value Stream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# Service drops are a unique value stream because they can be optional and subject to cost sharing

- At a ~$2,100 per customer premium (Tripolitis et al., 2015), undergrounding services increases total installation costs by more than 50% for the average circuit
- Installing riser polls is an option to avoid these costs
- Cost sharing may shift this from a utility expense to a customer expense
- Importantly, associated benefits are entirely customer specific

- Tree trimming savings (~$300 every 6 years) go to customers, not the utility

# Two tests: Primary Societal Cost Test (SCT) and secondary Utility Cost Test (UCT)

## Primary SCT

- Installation
- Expected Replacements
- Inspections
- Outage Response
- Forestry Management
- Other OpEx
- Business Interruptions
- Residential Interruptions
- Safety Risk
- Service Drop Construction
- Service Drop Tree Trimming

**Net Benefits = $300,000 per mile**
**Benefit-Cost Ratio = 1.9:1**

## Secondary UCT

- Installation
- Expected Replacements
- Inspections
- Outage Response
- Forestry Management
- Other OpEx
- Business Interruptions
- Residential Interruptions
- Safety Risk
- Service Drop Construction
- Service Drop Tree Trimming

**Net Benefits = -$69,300 per mile**
**Benefit-Cost Ratio = 0.7:1**

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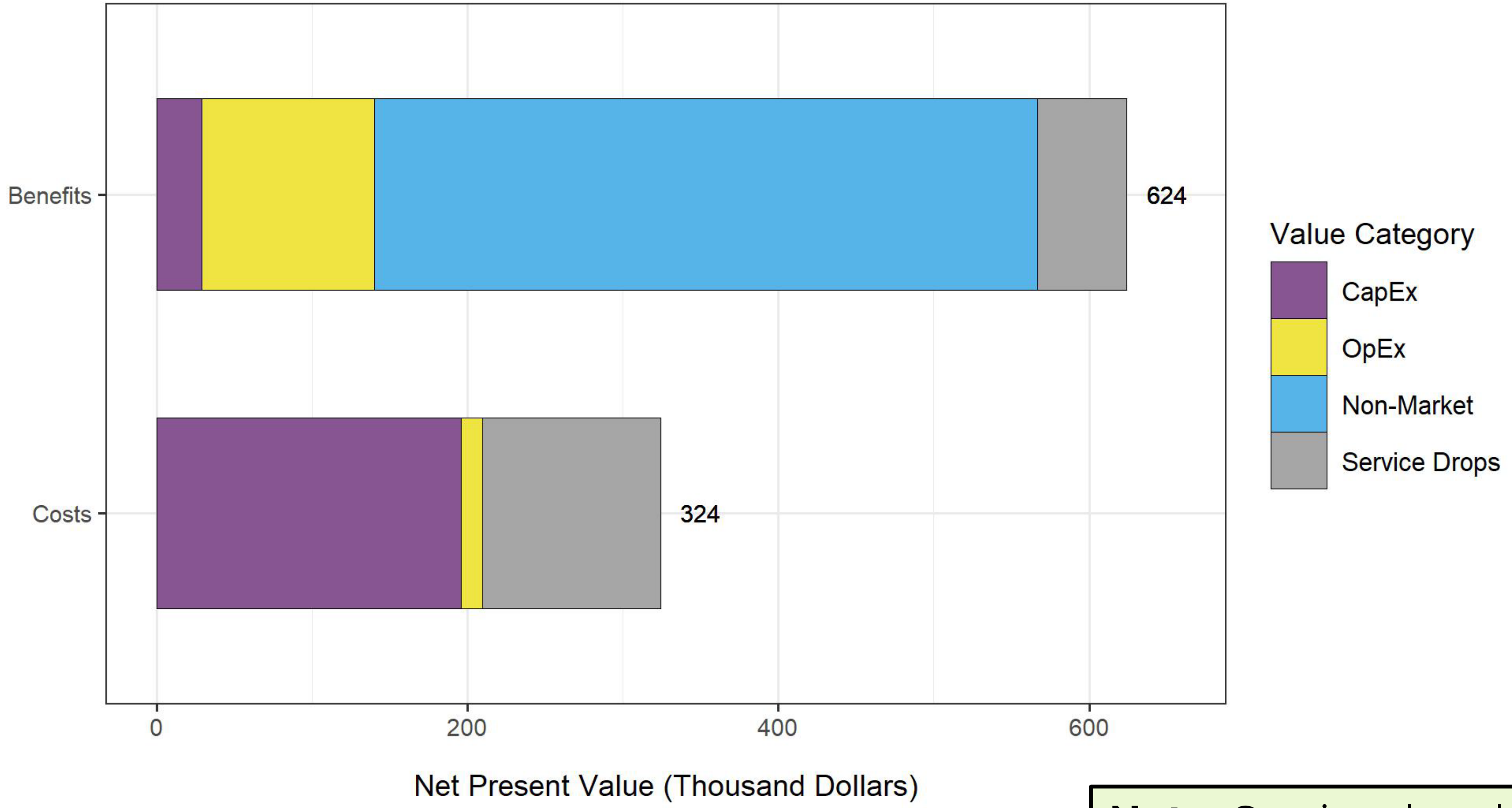
# 4. Detailed findings

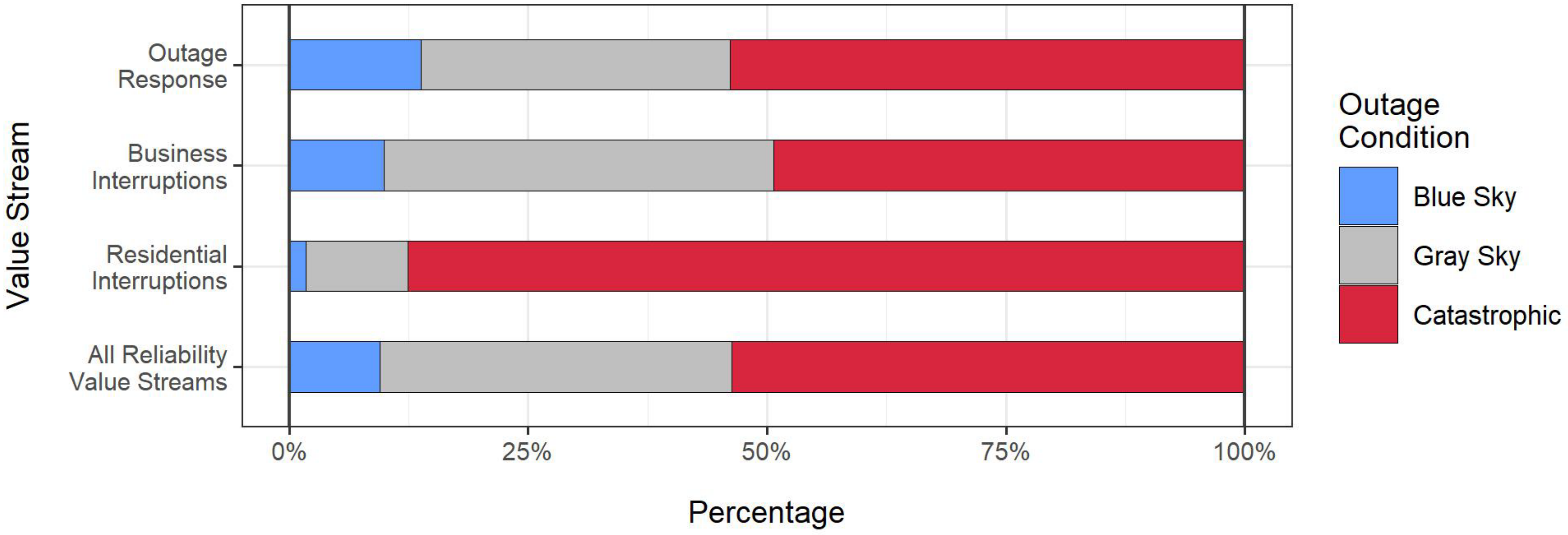
# Benefits are primarily non-market values and OpEx while costs are primarily CapEx



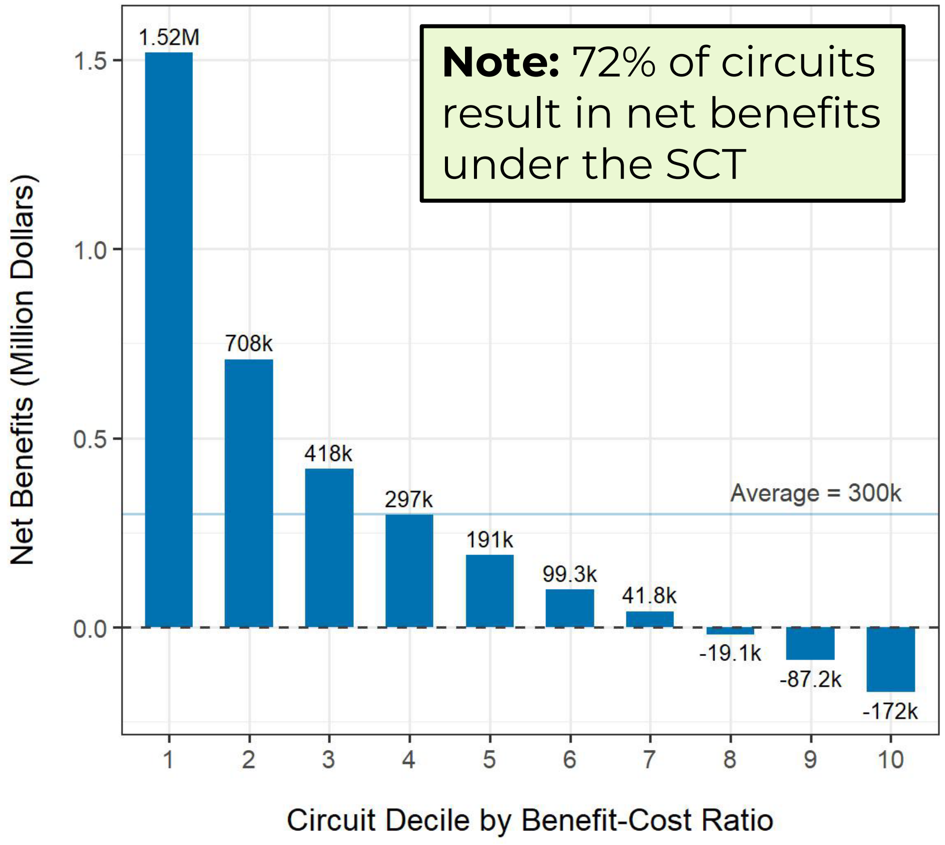

**Note:** Service drop benefits are tree trimming (OpEx) while service drop costs are construction (CapEx)

# Benefits are dominated by reliability and resilience improvements during storms

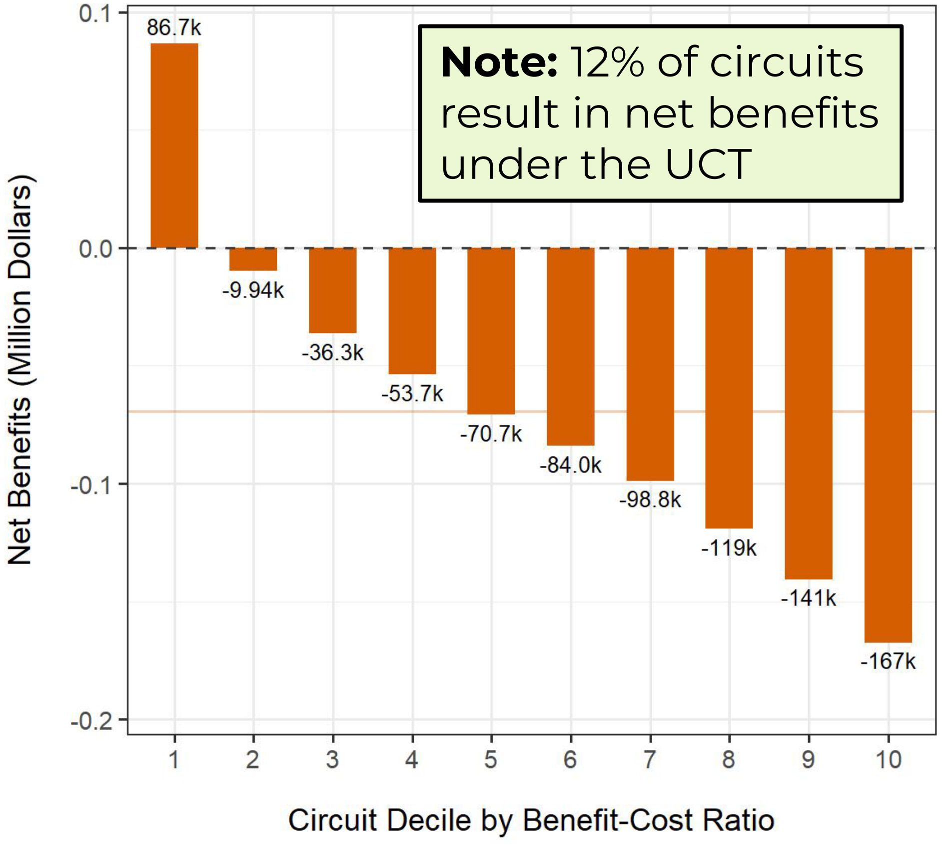
**Note:** 74% of benefits are tied to reliability and resilience improvements



# The 10% most SCT cost-effective circuits yield net benefits of over $1.5 million per mile

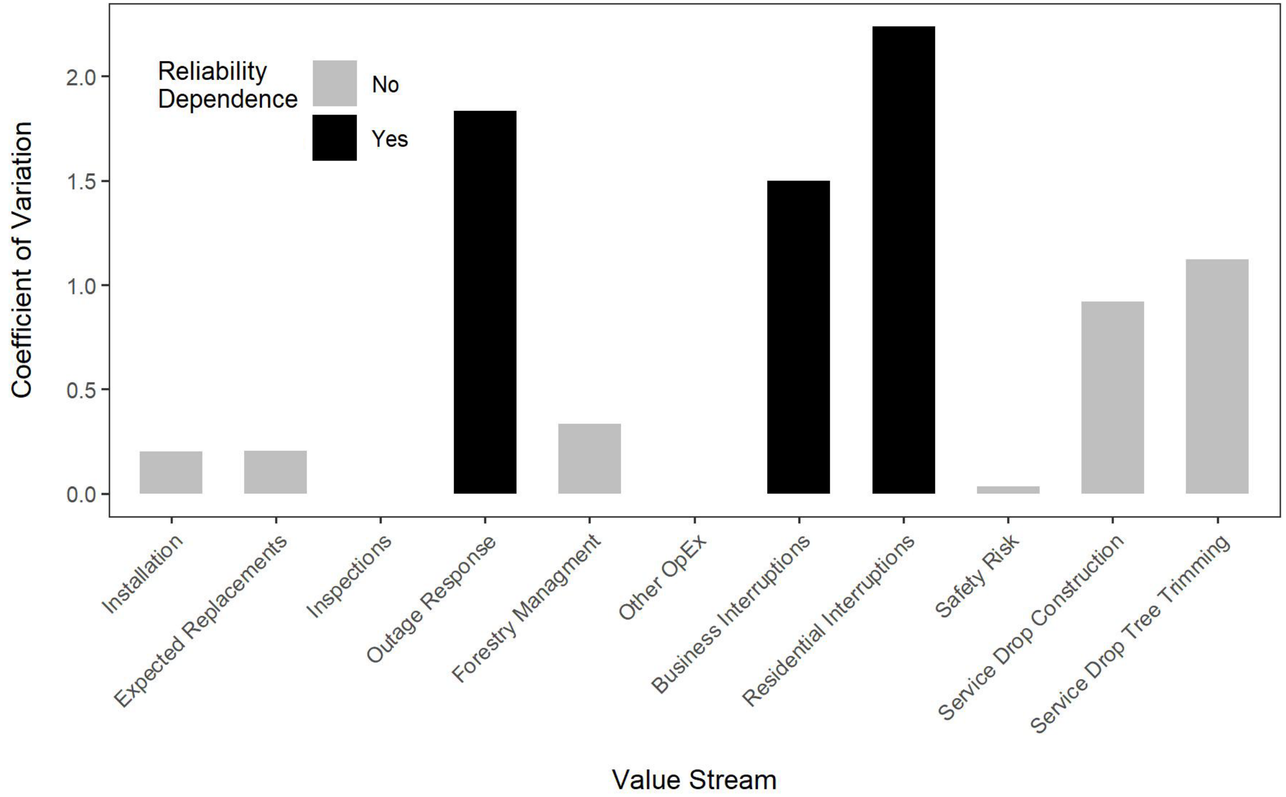



**Primary SCT**



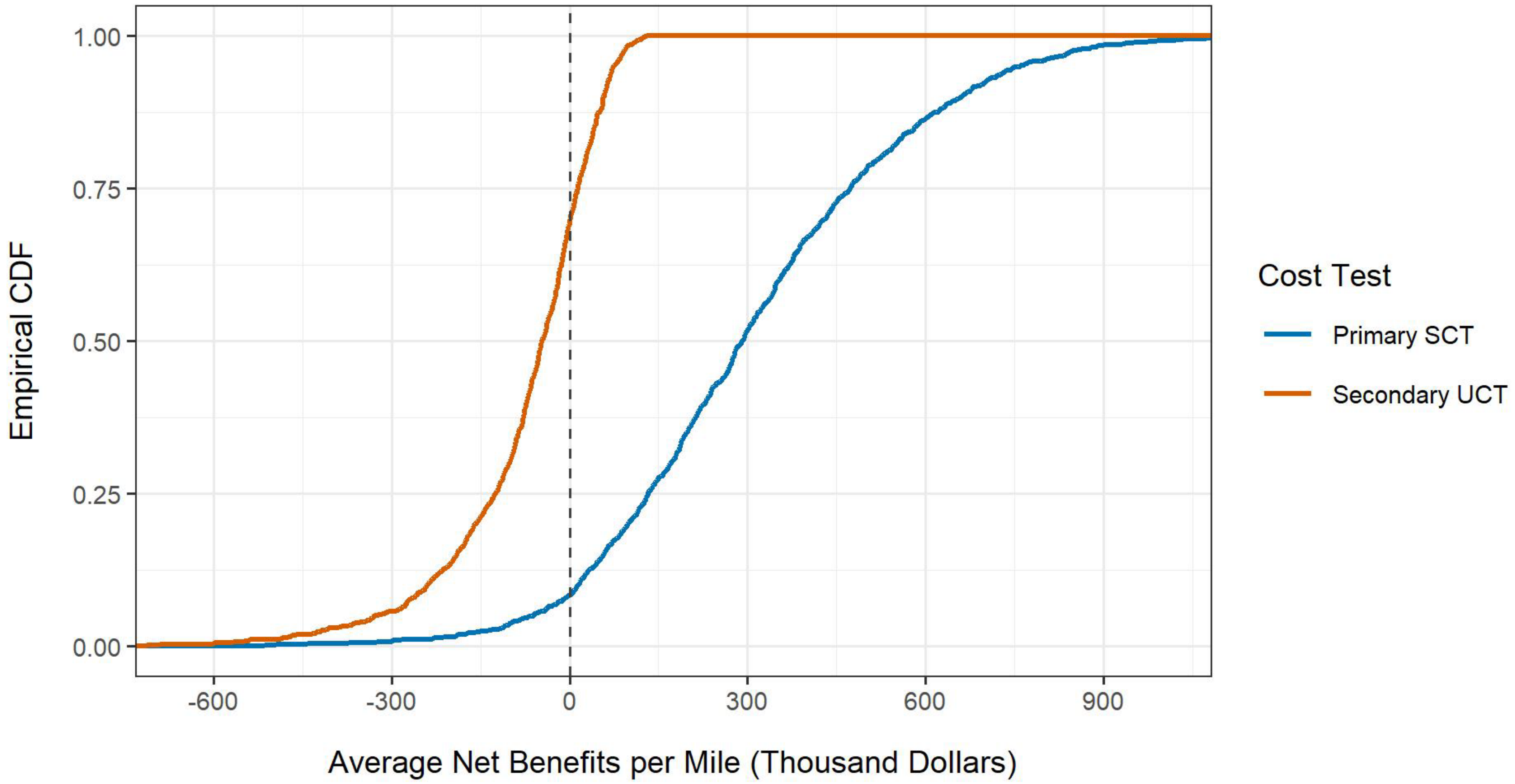

**Secondary UCT**

# Circuit variation is dominated by the reliability value streams, particularly business interruptions



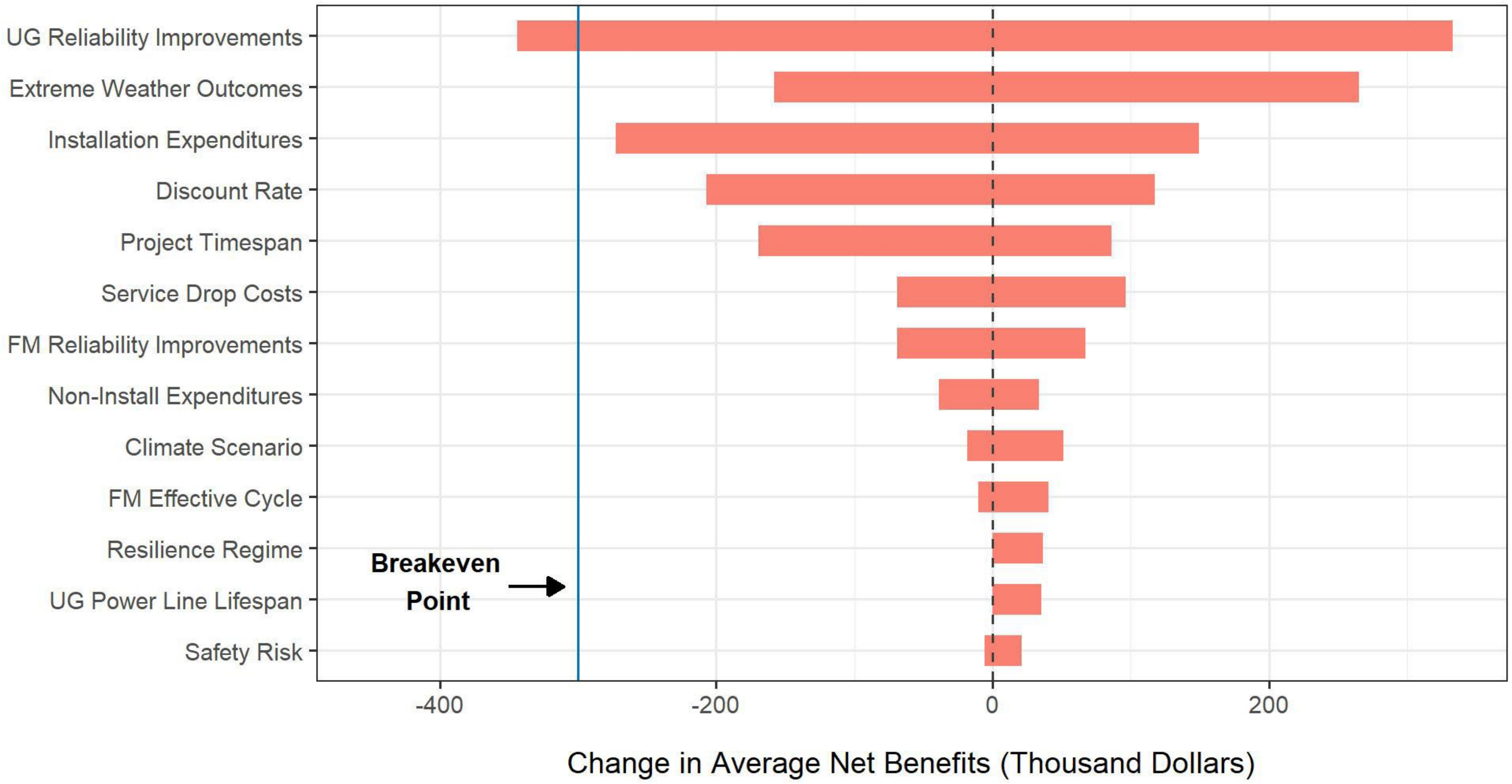

- Customer density explains another 15% of variation
- No other variable explains more than 2% of variation

# Average net benefits per mile are positive in 92% of uncertainty simulations under the primary SCT




**Note:** Average net benefits per mile are positive in 31% of uncertainty simulations under the secondary UCT

# Results are most sensitive to reliability gains, extreme weather outcomes, and installation costs



# Selecting projects optimally yields a major advantage for cost-effectiveness

| | 35-Mile Portfolio (35 Unique Circuits) | Benefits (Million $) | Costs (Million $) | Net Benefits Total (Million $) | Net Benefits Per Mile (Thousand $) | Benefit-Cost Ratio |
|---|---|---|---|---|---|---|
| 1 | **Highest BCR: SCT** | 111 (13.3) | 13.2 (6.98) | 98.3 (6.33) | 2,810 (181) | 8.45 (1.91) |
| 2 | **Highest BCR: UCT** | 115 (16.2) | 17.4 (7.54) | 97.5 (8.64) | 2,790 (247) | 6.61 (2.15) |
| 3 | **Random** | 19.0 (4.94) | 10.0 (7.06) | 8.98 (-2.12) | 256 (-60.7) | 1.89 (0.70) |
| 4 | **Highest Storm SAIFI** | 80.5 (11.6) | 10.8 (6.59) | 69.7 (5.05) | 1,990 (144) | 7.47 (1.77) |
| 5 | **Highest Customer Density** | 81.4 (11.8) | 26.7 (8.81) | 54.8 (2.97) | 1,560 (85.0) | 3.05 (1.34) |

**Key Takeaways:**

- Choosing projects based on modeled outcomes can yields net benefits 10x those of a random portfolio
- Sacrificing some SCT net benefits to maximize UCT net benefits still yields strong outcomes
- Prioritizing based on historical storm SAIFI is the strongest proxy variable approach, but net benefits are still 29% lower than when optimizing via modeled outcomes

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# 5. Conclusions

# So, does strategic undergrounding make sense? This study's results suggest it does

- Converting overhead lines to underground is economically viable for the CE service territory, with average **net benefits of $300,000 per mile and a BCR of 1.9**
- The most cost-effective projects are found in areas with high storm-related outages and dense customer bases, with the **top 10% of circuits yielding net benefits of $1.5 million per mile and a BCR of 5.3**
  - A targeted 35-mile portfolio could achieve net benefits of $98 million at a BCR of 8.5
- While this study suggests undergrounding is a sound strategy, its **cost-effectiveness is highly dependent on context**, and the framework used here should consider unique conditions if adapted by other utilities
- There are several **limitations**, including the model's circuit-level resolution, its simplification of infrastructure age, and its inability to quantify all potential benefits and costs, like **aesthetic benefits and wildfire risk reduction**

# Thank you! Questions?

**Luke R. Dennin, Ph.D.**

**U.S. Department of Energy Fellow (Energy Innovator Fellowship)**

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Synapse
Energy Economics, Inc.

# How to Manage Risk on a Budget

***Tools and frameworks for addressing safety, affordability, and equity***

- Founded in 1996 by CEO Bruce Biewald
- Leader for public interest and government clients in providing rigorous analysis of the electric power and natural gas sectors
- Staff of 40+ includes experts in energy, economic, and environmental topics

- ➢ Overall framework for how to address affordability in the context of safety investments

- ➢ Risk in context
  - Example: Minnesota state and utility wildfire risk in context

- ➢ Examining options to address risk in cost-efficient manner for wildfire expenditures in California
  - Example 1: Southern California Edison
  - Example 2: San Diego Gas and Electric

Three key elements:

1) Robust benefit-cost analysis (BCA) based on granular risk modeling. Inputs and outputs can be utilized to a) *prioritize investment* from highest to lowest risk areas/infrastructure, and b) *assess tradeoffs,* if any, between safety and affordability.

2) Recognition that ratepayers have finite resources. The goal should be to achieve the maximum amount of risk reduction for each ratepayer dollar spent, ideally within an overall budget constraint that also considers other priorities and expenditures.
   - This can be done by evaluating risk in context and all options to address risk (e.g. undergrounding vs. alternatives) to examine benefits and costs.
   - The examples to follow from Minnesota and California provide illustrations of this.

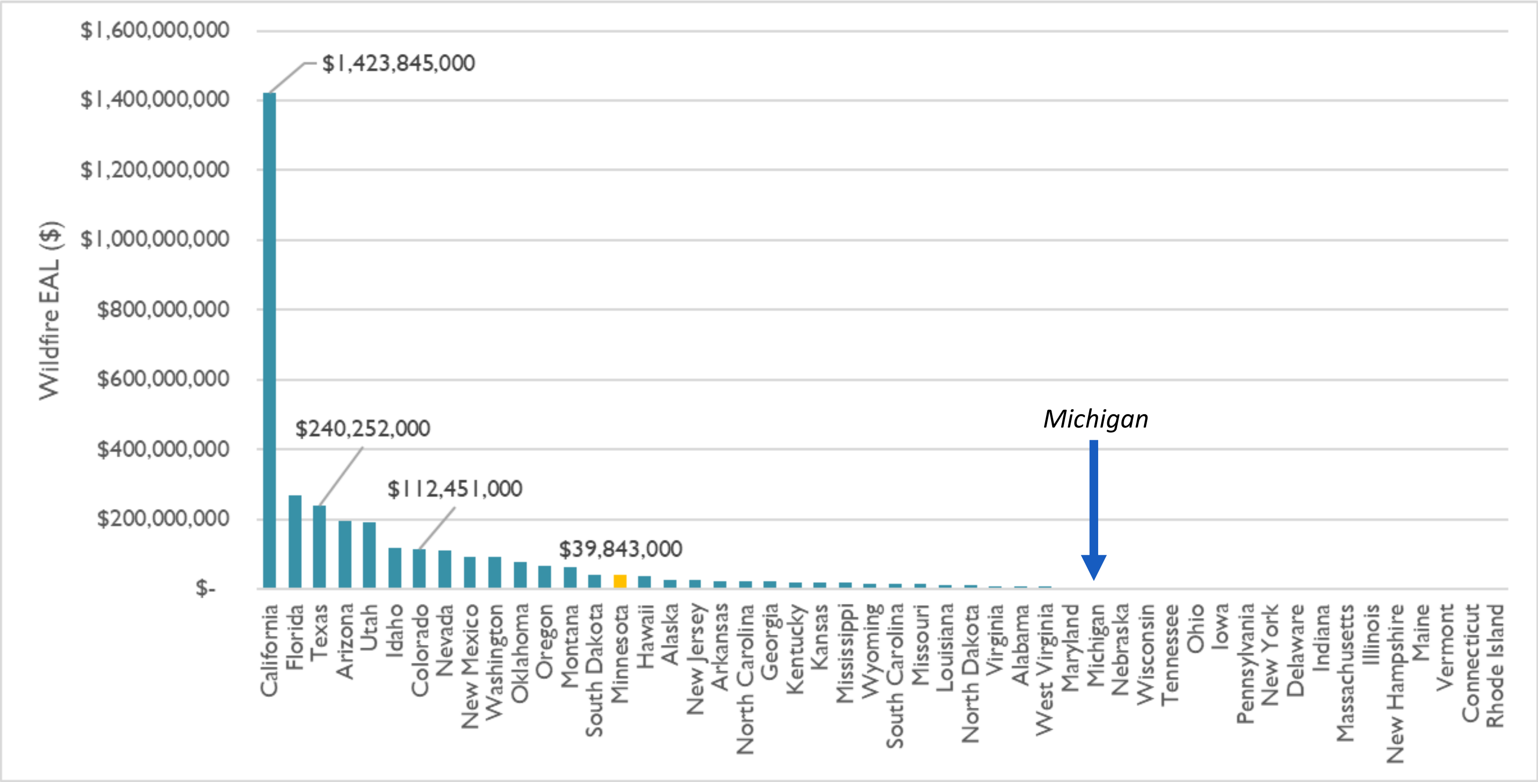
3) Equity issues should be considered and/or incorporated into the BCA. For example, vulnerable communities may not be adequately represented in a typical BCA.

# Putting Risk in Context to Maximize Benefits and Minimize Costs

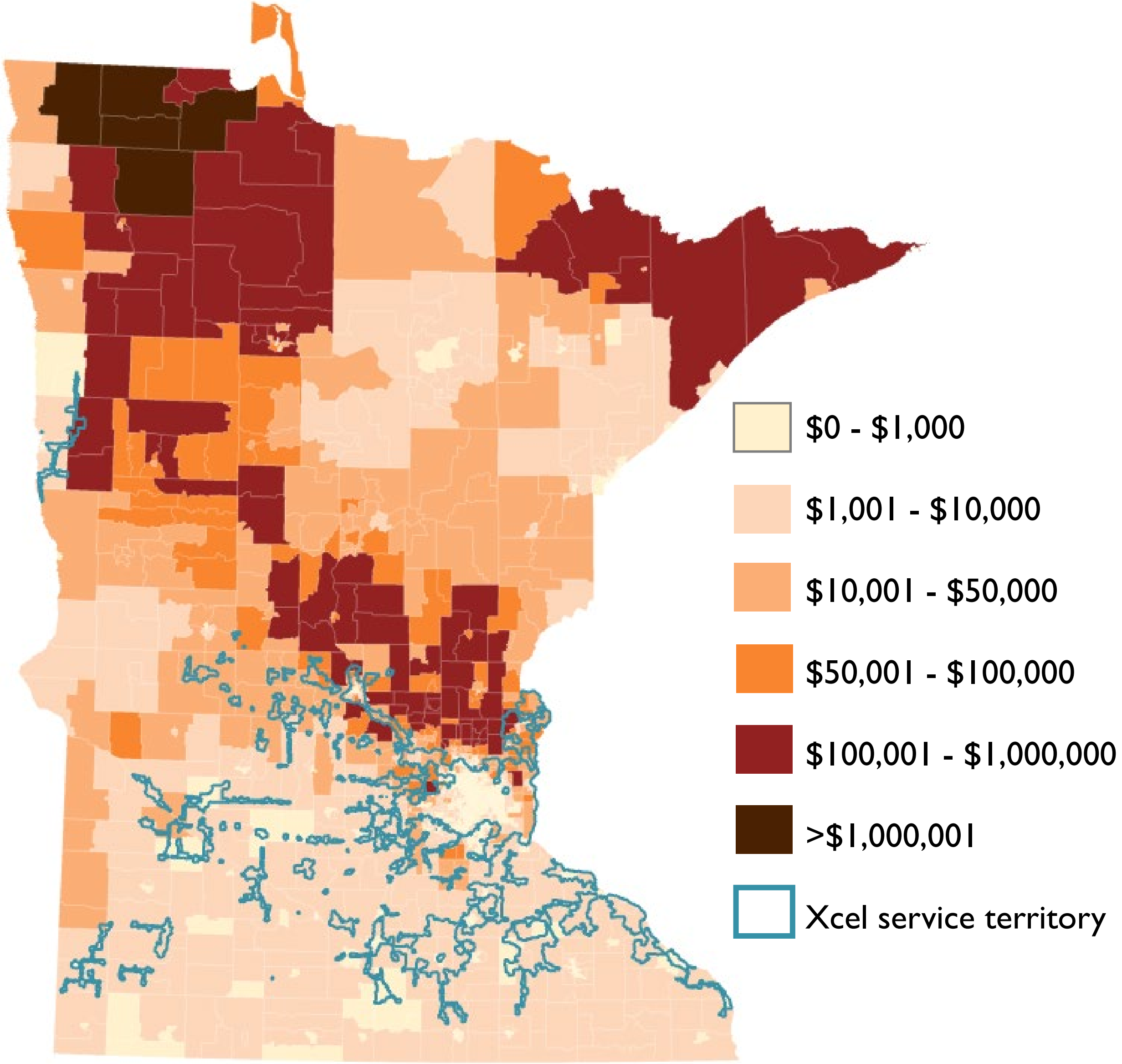
# Wildfire risk in Minnesota compared to other states

*Wildfire Risk by State ($ 2022)*



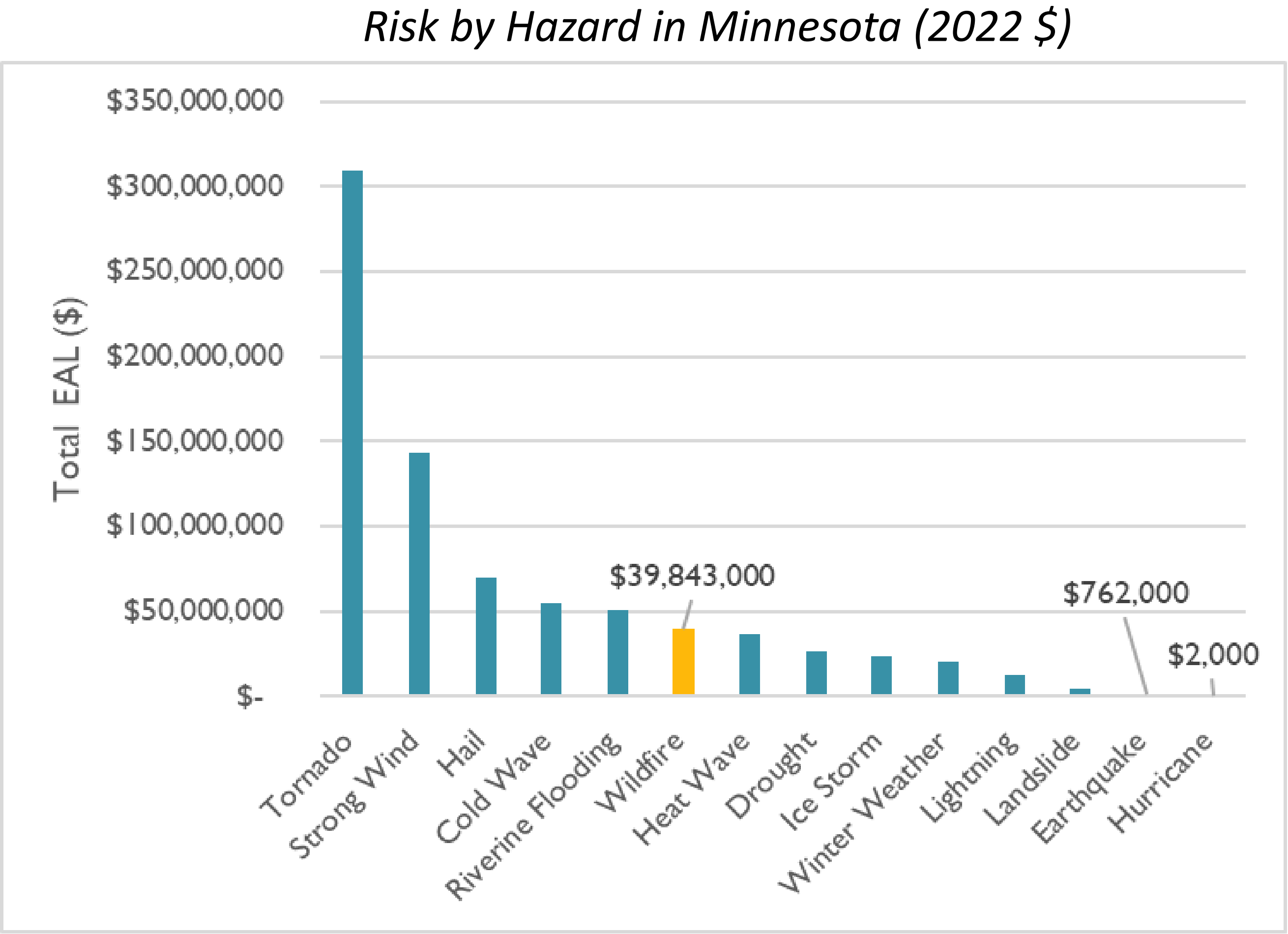

*Data Resources | National Risk Index*

***State and societal risks should be addressed holistically***



# Wildfire risk in Minnesota compared to other risks

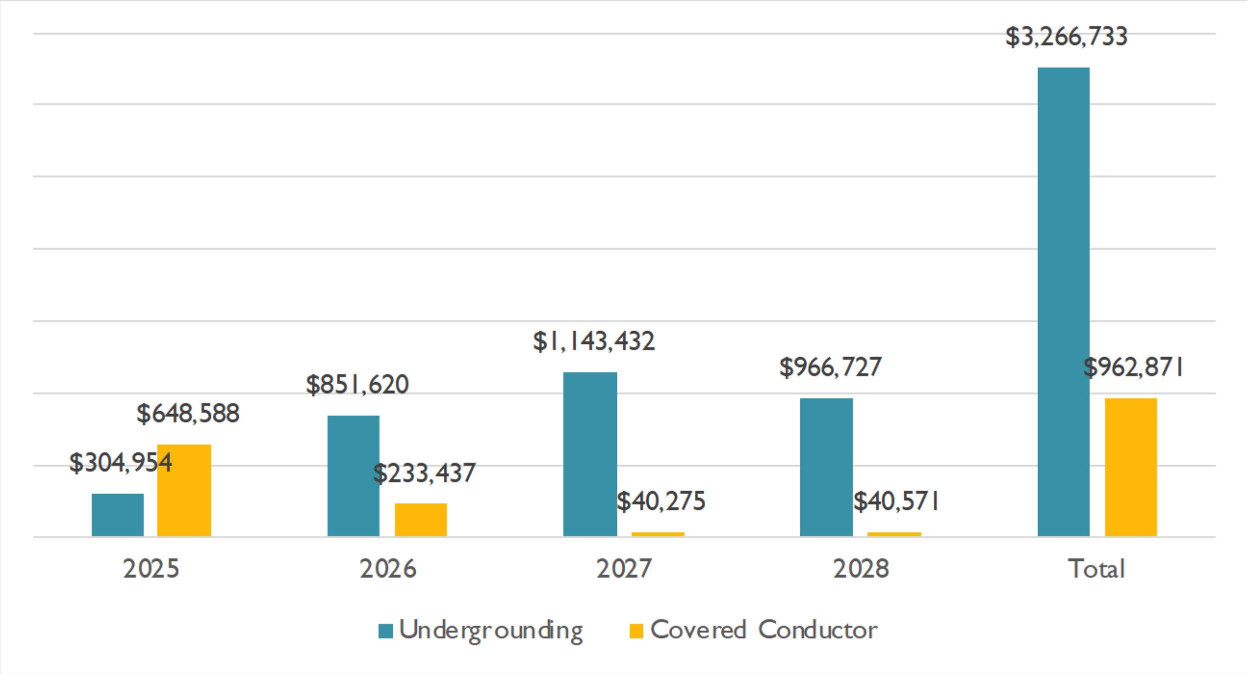


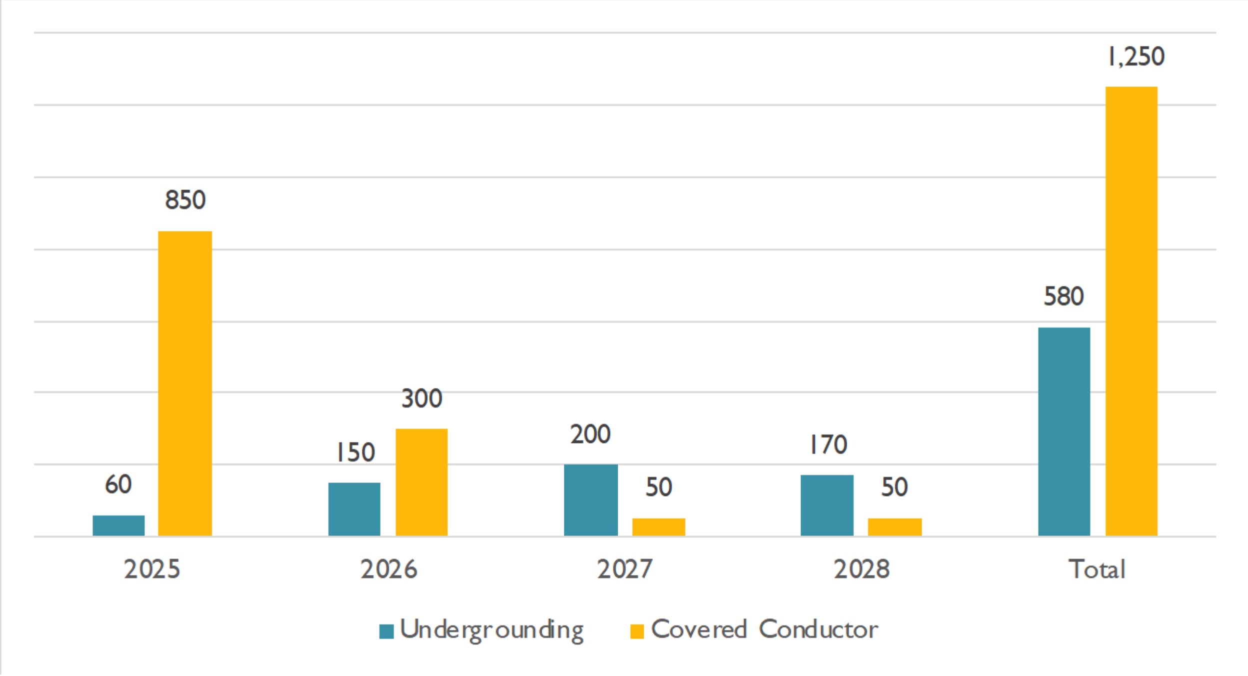

*Data Resources | National Risk Index*

# Undergrounding and Affordability in California

*SCE Forecast Grid Hardening Costs ($ Thousands)*

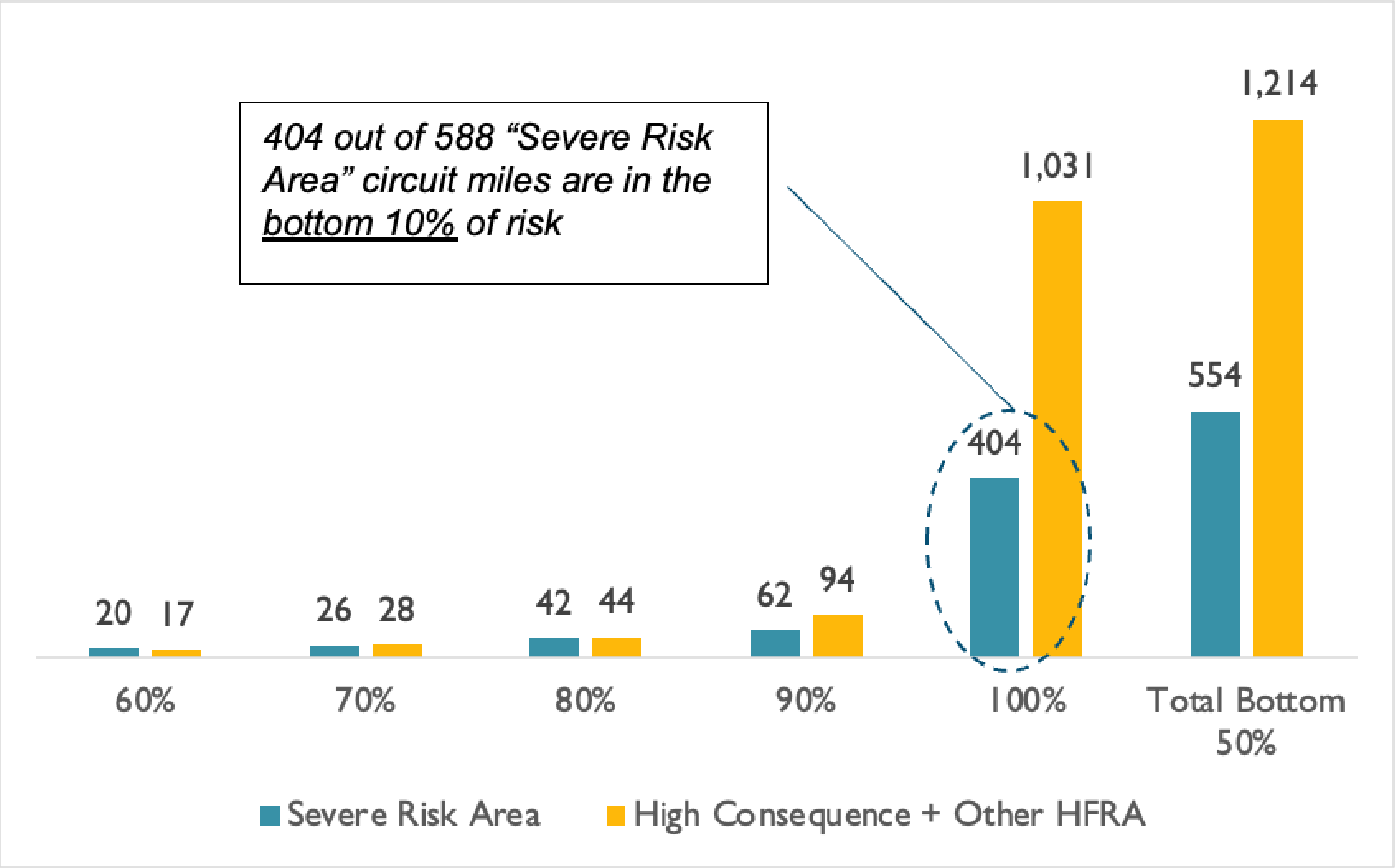



- SCE proposed to underground overhead miles in "Severe Risk Areas" (SCE's term).
- These criteria were qualitative – we found most or all of them were already captured in SCE's quantitative risk modeling or did not necessarily lead to the conclusion that undergrounding is always the best alternative.

- The x-axis shows circuit miles which according to SCE's risk model results, are in the bottom 50 percent of risk in its service territory when ranked from highest to lowest risk

*Circuit Miles in Bottom 50 Percent of Risk*



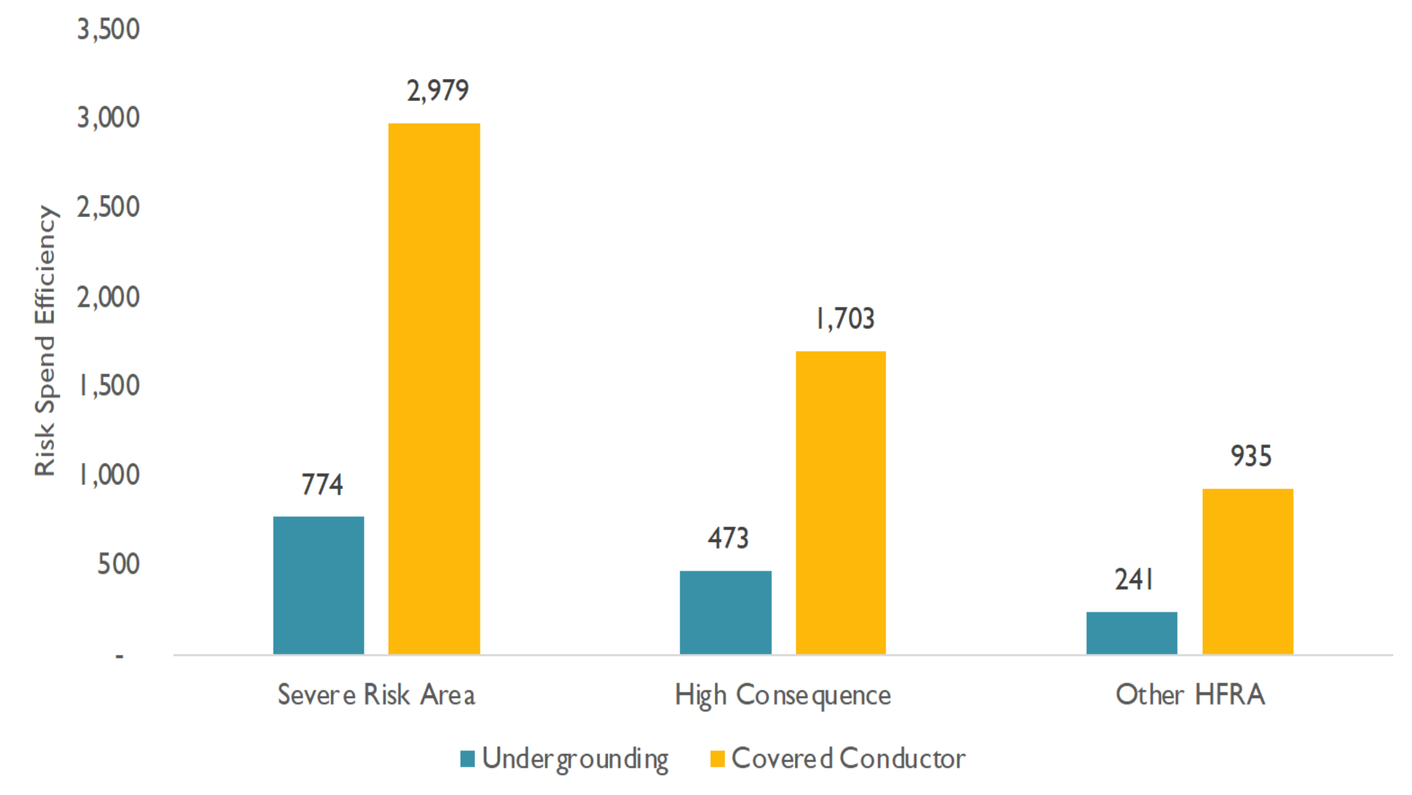
## *Billions of ratepayer dollars spent on covered conductor, plus line settings to shut off power, reduced risk by nearly 75 percent before the rate case*

*Wildfire Risk Remaining After Grid Hardening and Fast Curve Settings (2018-2024)*

- Covered conductor is significantly more cost-effective than undergrounding, meaning each dollar of expenditures achieves more risk reduction relative to undergrounding.

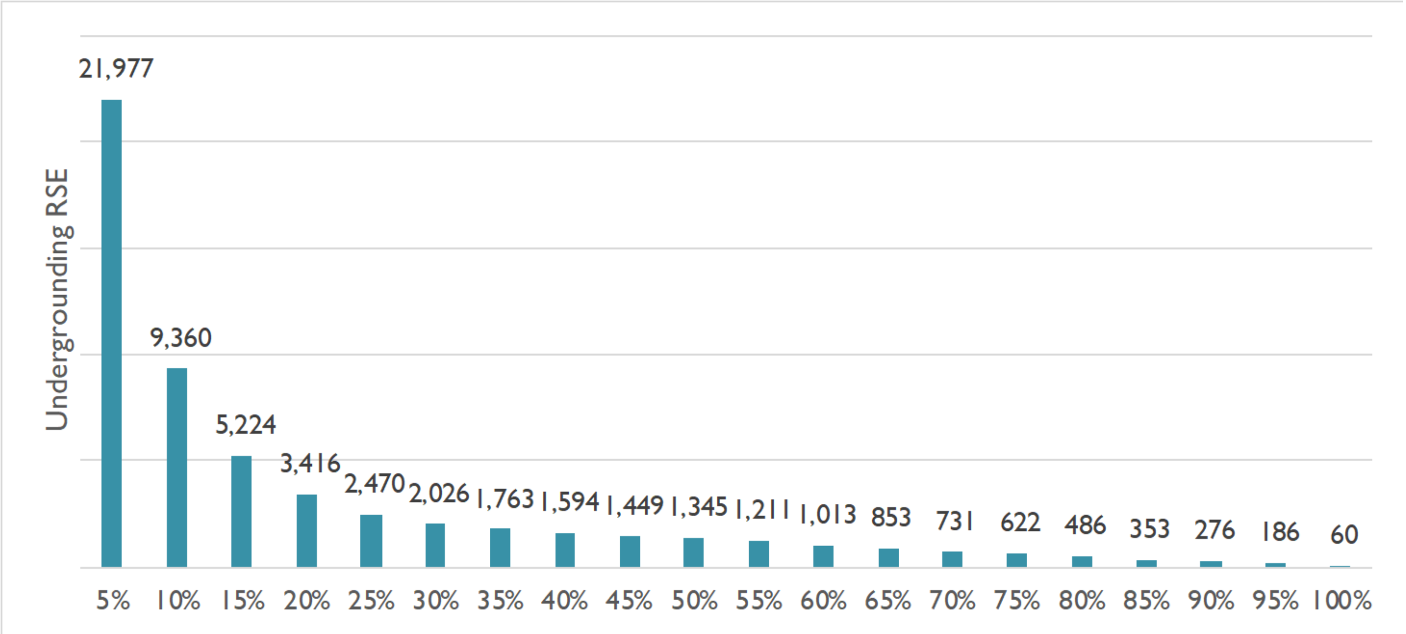
- However, undergrounding provides higher absolute benefits (risk reduction) when comparing alternatives for the same project.

*Cost-effectiveness of Undergrounding vs. Covered Conductor*



## *Undergrounding cost-effectiveness has diminishing returns as projects address lower-risk areas*

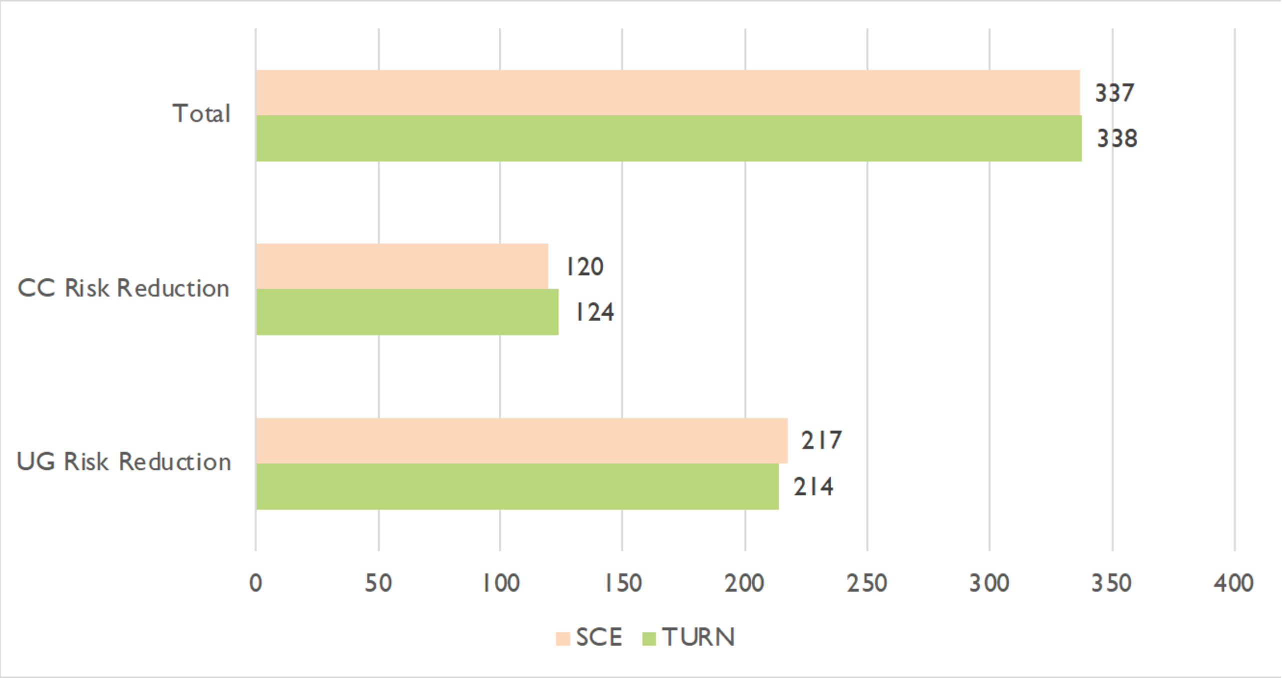
*Cost-effectiveness of Undergrounding*



- We proposed significantly less undergrounding than SCE (177 vs. 580 miles) but more miles of covered conductor (1,651 vs. 1,250).
- By focusing on only the highest risk circuits, we dramatically reduce risk.
- The risk reduction of these proposals is equal, and would save ratepayers **$2 billion**.

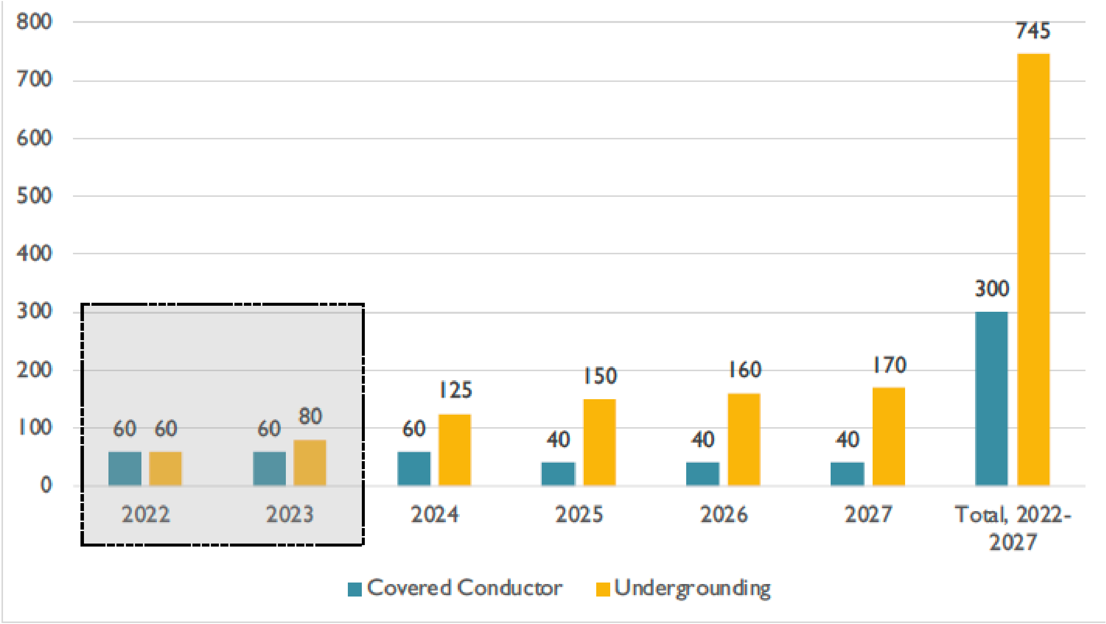
*Mileage and Costs of Grid Hardening ($ thousands)*

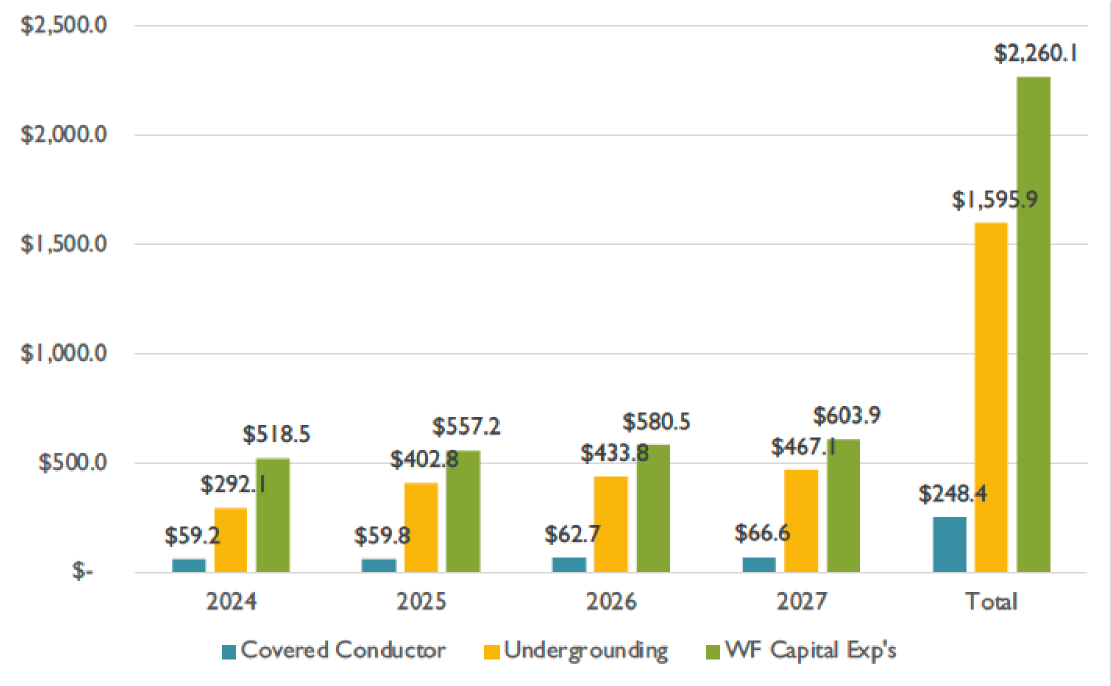



| | Undergrounding | | | | |
|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | Total / Weighted Average |
| TURN Miles | 44 | 44 | 44 | 44 | 177 |
| SCE Miles | 60 | 150 | 200 | 170 | 580 |
| *Unit Cost* | *$ 5,083* | *$ 5,677* | *$ 5,717* | *$ 5,687* | *$ 5,632* |
| | | | | | |
| TURN Budget | $ 224,903 | $ 251,227 | $ 252,984 | $ 251,633 | $ 980,746 |
| SCE Budget | $ 304,954 | $ 851,620 | $ 1,143,432 | $ 966,727 | $ 3,266,733 |
| **TURN-SCE** | **$ (80,051)** | **$ (600,392)** | **$ (890,448)** | **$ (715,095)** | **$ (2,285,986)** |

| | Covered Conductor | | | | |
|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | Total / Weighted Average |
| TURN Miles | 413 | 413 | 413 | 413 | 1,651 |
| SCE Miles | 850 | 300 | 50 | 50 | 1,250 |
| *Unit Cost* | *$ 763* | *$ 778* | *$ 805* | *$ 812* | *$ 770* |
| | | | | | |
| TURN Budget | $ 314,921 | $ 320,902 | $ 332,373 | $ 335,247 | $ 1,303,442 |
| SCE Budget | $ 648,666 | $ 233,289 | $ 40,271 | $ 40,620 | $ 962,845 |
| **TURN-SCE** | **$ (333,745)** | **$ 87,613** | **$ 292,101** | **$ 294,627** | **$ 340,597** |

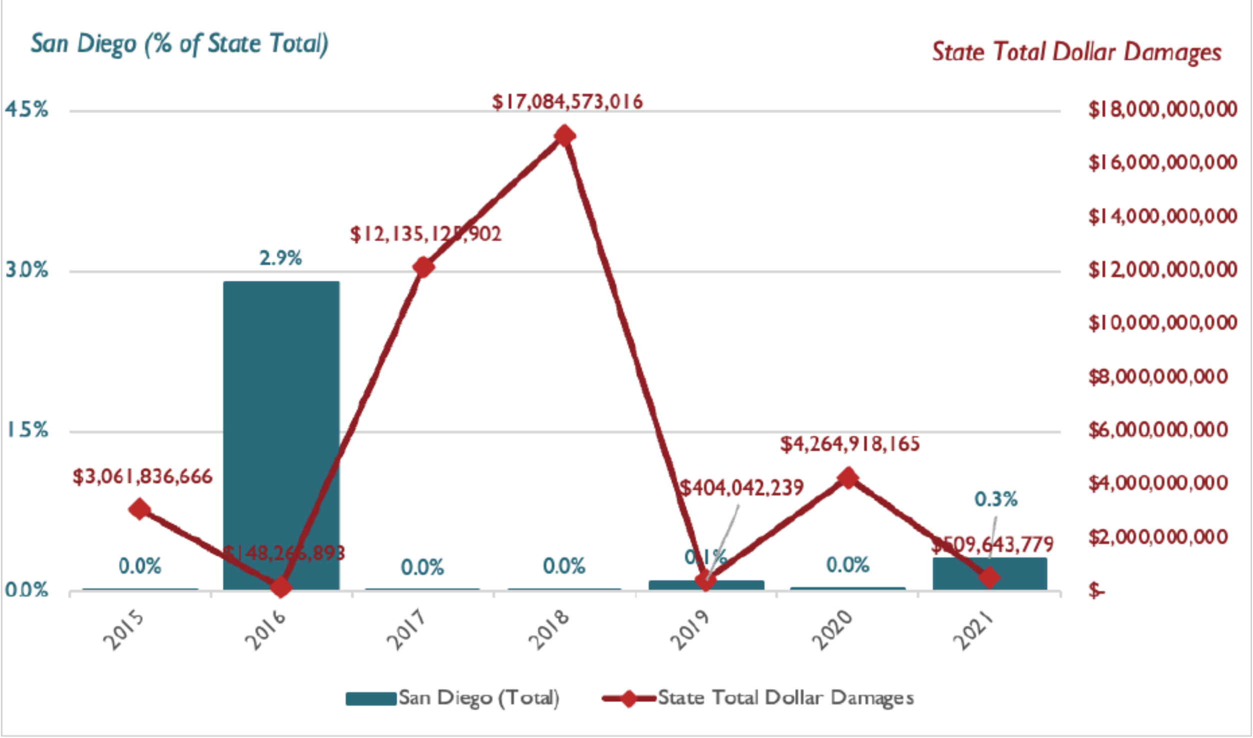
*Covered Conductor vs. Undergrounding Miles*



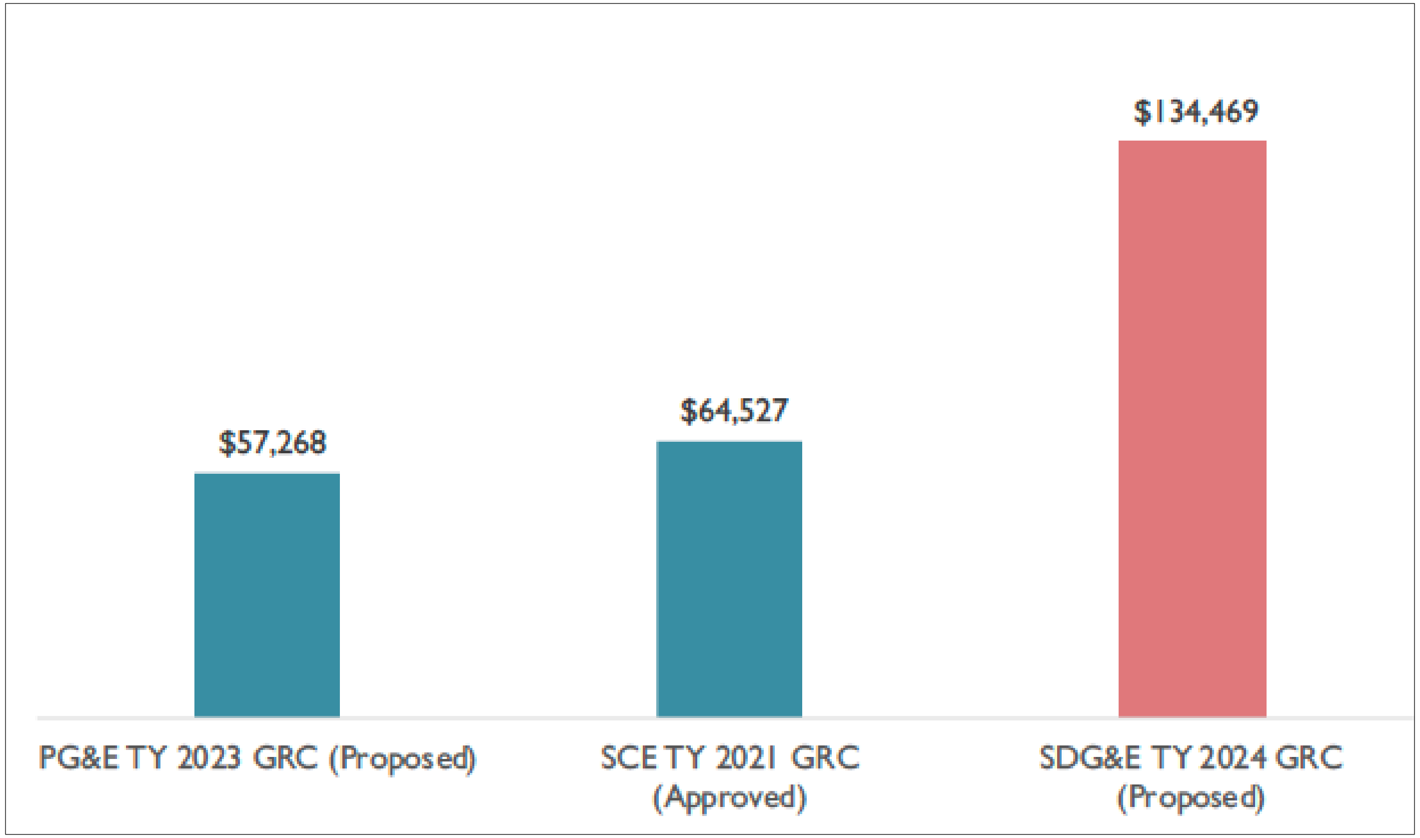



## Using San Diego County as a proxy, unadjusted for utility-specific risk, San Diego accounted for a maximum of 3.3% of acres burned in CA and 2.9% of damages from 2015-2021

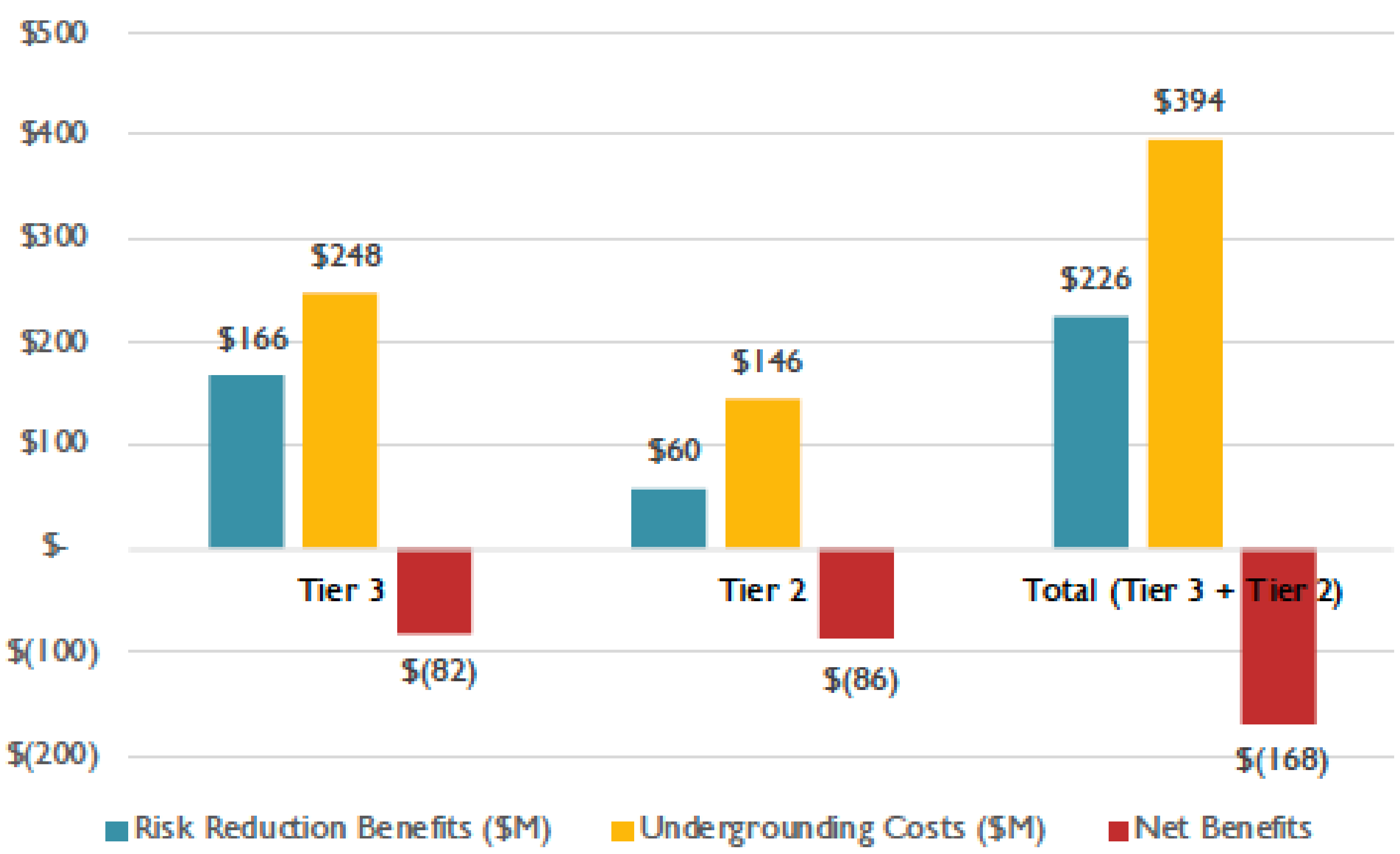
*San Diego County, Percentage of Acres Burned 2015-2021*

*Average Annual Undergrounding and Covered Conductor Cost per HFTD Overhead Mile ($2021)*



*Undergrounding Risk Reduction versus Costs*



- We proposed 465 less undergrounding miles and 260 more covered conductor miles than SDG&E.
- This achieves 78% of the risk reduction benefits for 35 percent of the costs.
- With Public Safety Power Shutoffs (PSPS), wildfire risk is reduced to near-zero, but this worsens reliability.
    - Undergrounding is by far the least cost-effective way to mitigate PSPS risk.
- Our proposal was adopted by the CPUC.

- Equity starts with affordability due to the regressive nature of energy costs.
- Equity also considers disparate impacts on vulnerable populations.
  - The costs for undergrounding projects are socialized across all customers, but undergrounding for reliability inherently benefits a small subset of these customers.
  - For example, is we use Value of Lost Load (VOLL) as the basis for reliability benefits, predominately commercial and industrial customers may be targeted for these projects. Similarly, if wealthy households tend to use more energy, the analysis may indicate solutions that benefit these households while not adequately considering impacts on vulnerable populations.
    - This issue can be addressed directly in the BCA or qualitatively outside of the BCA.

**Reliability example: weighting and "tranches" to help prioritize vulnerable populations**

- Extreme: Public Safety Partners; Provides Emergency Services
- Significant: Life Support customers or Medical Baseline customers who are low income
- Elevated: All other Medical Baseline, all other critical customer designations
- Regular: Regular customer

| Line No. | Tranche | Exposure (%) | Safety Risk Value ($M) | Reliability Risk Value ($M) | Financial Risk Value ($M) | Aggregated Risk Value ($M) | Risk (%) |
|---|---|---|---|---|---|---|---|
| 1 | Regular | 77% | 19.4 | 1,577.0 | 25.9 | 1,622.4 | 44% |
| 2 | Elevated | 18% | 12.2 | 990.0 | 16.3 | 1,018.5 | 28% |
| 3 | Significant | 5% | 9.1 | 736.9 | 12.1 | 758.1 | 21% |
| 4 | Extreme | 0% | 3.1 | 248.7 | 4.1 | 255.8 | 7% |
| 5 | Total | 100% | 43.8 | 3,552.6 | 58.3 | 3,654.7 | 100% |

Source: PG&E 2024 RAMP filing, online: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/2024-ramp-application-pge051524.pdf.

# Questions?

- Federal Emergency Management Agency (FEMA), 2025. Data Resources. Available at Data Resources | National Risk Index.
- **California Public Utilities Commission (A.23-05-010):** Direct Testimony of Eric Borden addressing Southern California Edison's Test Year 2025 General Rate Case Wildfire Grid Hardening Investments. On behalf of the Utility Reform Network. February 29, 2024.
- **California Public Utilities Commission (A.22-05-016):** Prepared Testimony Addressing San Diego Gas and Electric's Test Year 2024 Wildfire Mitigation Hardening Measures and Related Wildfire Risk Modeling Issues for The Utility Reform Network. March 27, 2023.
- PG&E 2024 RAMP filing, online: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/2024-ramp-application-pge051524.pdf.

# Undergrounding Technical Conference| September 19, 2025

*Michigan Public Service Commission*

CITIZENS RESEARCH COUNCIL OF MICHIGAN

## Potential to Improve Grid Resilience through Policy Solutions that Enable Undergrounding Power Lines

CITIZENS RESEARCH COUNCIL OF MICHIGAN

- Founded 1916
- Statewide, non-partisan, private not-for-profit
- Promotes sound policy for state and local governments through factual research – accurate, independent, and objective
- Relies on charitable donations from foundations, businesses, and individuals

## Eric Paul Dennis, PE

- BSE, Civil Engineering, Michigan State University, 2006
- MSE, Environmental Engineering, University of Michigan, 2010
- MS, Urban and Regional Planning, University of Michigan, 2012
- Michigan-licensed PE since 2012
- Joined CRC in January 2022 as Research Associate of Infrastructure Policy

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QUALITY OF LIFE

# Michigan power outages: Thousands could remain without service for days

by Janelle D. James
February 23, 2023

- *Winter storm dumps heavy ice in lower Michigan and at least 5 inches of snow in upper Michigan*
- *More than 700,000 people are without power,*
- *Power is expected to be restored for most by Sunday*

mLIVE Michigan

NEWS

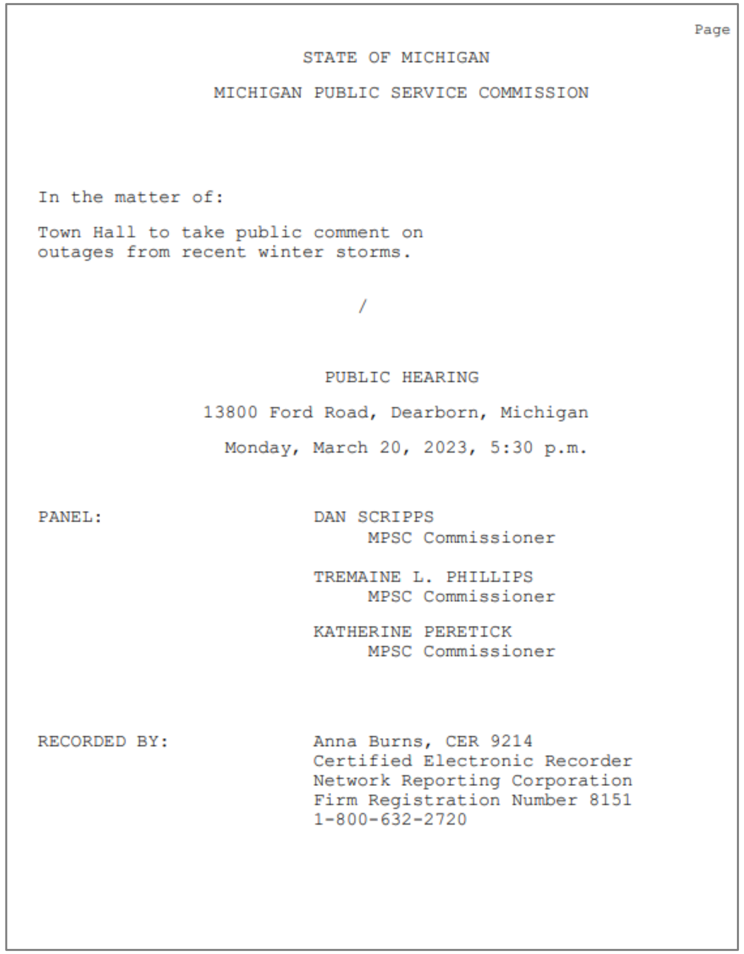
# 'Catastrophic' damage: Thousands of miles of powerlines smothered in ice after Northern Michigan storm

Updated: Apr. 01, 2025, 1:59 p.m. | Published: Apr. 01, 2025, 1:22 p.m.

More than 40,000 GLE customers are without power today. Consumers Energy reports more than 90,000 without power; however, some of that is in southern Michigan where there was a devastating wind storm over the weekend.

## "There is no such thing as a 'natural disaster.'"

# 2023 Public Comments:


Page

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of:

Town Hall to take public comment on
outages from recent winter storms.

/

PUBLIC HEARING

13800 Ford Road, Dearborn, Michigan

Monday, March 20, 2023, 5:30 p.m.

PANEL: DAN SCRIPPS
MPSC Commissioner

TREMAINE L. PHILLIPS
MPSC Commissioner

KATHERINE PERETICK
MPSC Commissioner

RECORDED BY: Anna Burns, CER 9214
Certified Electronic Recorder
Network Reporting Corporation
Firm Registration Number 8151
1-800-632-2720

"They've torn up my street. They've taken out all the trees. … They're redoing the street, and yet they are not burying the power lines.

One of the complaints is that it's all the infrastructure they have to work around. It's all torn up! They replaced the water lines. They're replacing the sidewalk today.

*Why in the heck are they not out there burying the power lines?"*

*~ Onsted (Lenawee Co.) resident and home care nurse*

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RESEARCH DETROIT BUREAU PODCAST BLOG EVENTS ABOUT CONTACT

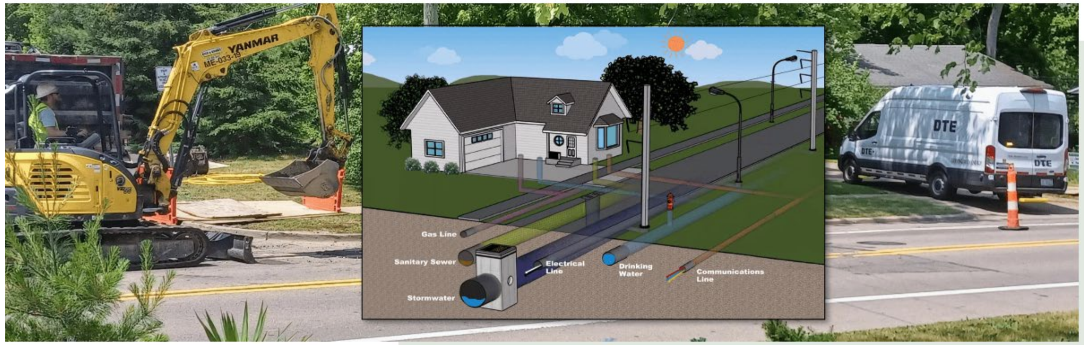
MARCH 29, 2023

# Undergrounding Electrical Lines is an Option to Prevent Power Outages, but State Policy is Needed to Better Enable the Practice

- Stand-alone projects to underground lines cost 3-10 times as much as updating or ‘hardening’ projects.
- Additional costs would be passed on to ratepayers, or taxpayers if done at direction of government.
- No formal framework to underground utilities within ‘dig-once’ projects.
- Socioeconomic costs imposed by power outages are not typically considered in benefit:cost analyses guiding investments.
- MPSC regulatory authority is limited.

“My street is all torn up! They’re redoing the street. They’ve taken out all the trees. They replaced the water lines. They’re replacing the sidewalk today.

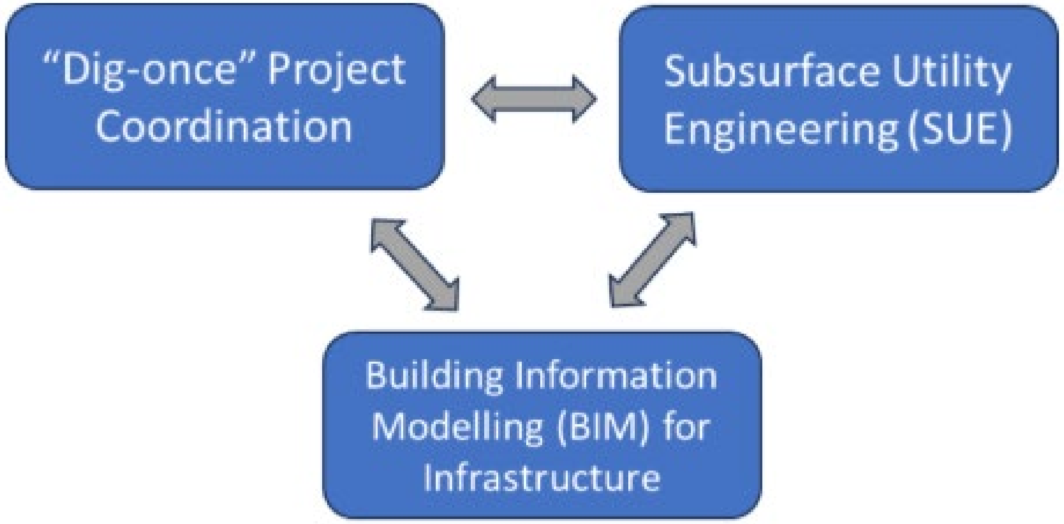
*Why in the heck are they not out there burying the power lines?”*




JUNE 21, 2023

# Legislative Direction is Needed to Facilitate Infrastructure Coordination

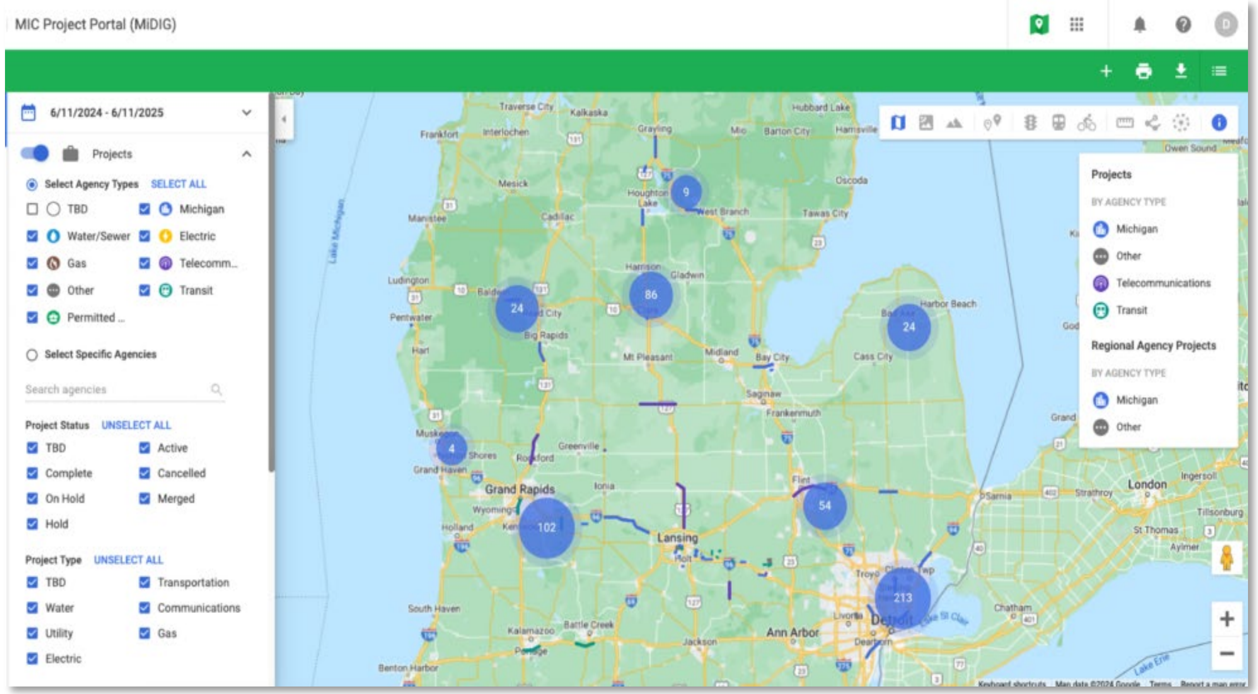
- Infrastructure management in Michigan is largely uncoordinated between various infrastructure owners who must share common right-of-ways. This imposes cost inefficiencies for all agencies, which are passed-on to the public as taxpayers and utility ratepayers.
- The cost burden of all types of infrastructure could be reduced if the various agencies were to pool resources for multi-agency construction projects, share quality data on the location of their assets, and adopt a shared long-term vision for right-of-way management.
- Michigan should pursue statutory options that will enable and support infrastructure owners and operators to more efficiently coordinate towards common objectives in the public interest.



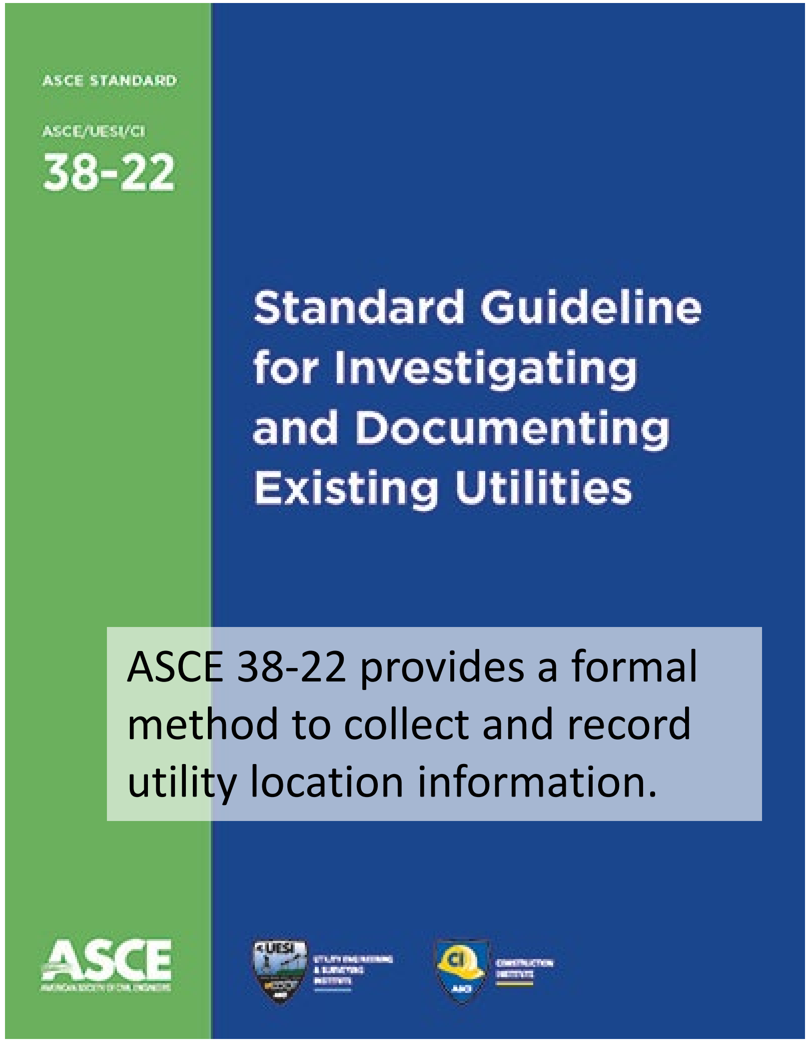
# Dig-once Legislation (Near-term)

- Rationalize existing dig-once initiatives across the state to **avoid duplicative efforts** and encourage participation. … ✓(?)
- **Establish a regulatory role for state-level infrastructure coordination** and management of the dig-once platform. Provide the infrastructure coordinator with sufficient resources and authority to identify dig-once projects that are not proposed through voluntary efforts, adjudicate disagreements between ROW users, and allocate funding as appropriate.
- Provide **dedicated dig-once project funding** to public agencies and utilities to enable compliance with participation requirements. (The benefits of dig-once coordination will accrue to the general public, Thus the costs of coordination should not be borne solely by project budgets.)
- Provide the infrastructure coordinator with **enforcement mechanisms** to ensure earnest participation in the program from all required entities.
- Recognize that while short-term benefits are achievable through a dedicated dig-once platform, the long-term vision should better enable life-cycle management of all infrastructure. **Task State Infrastructure Coordinator with evolving the platform**.

Michigan Infrastructure Council



# Subsurface Utility Engineering (SUE)

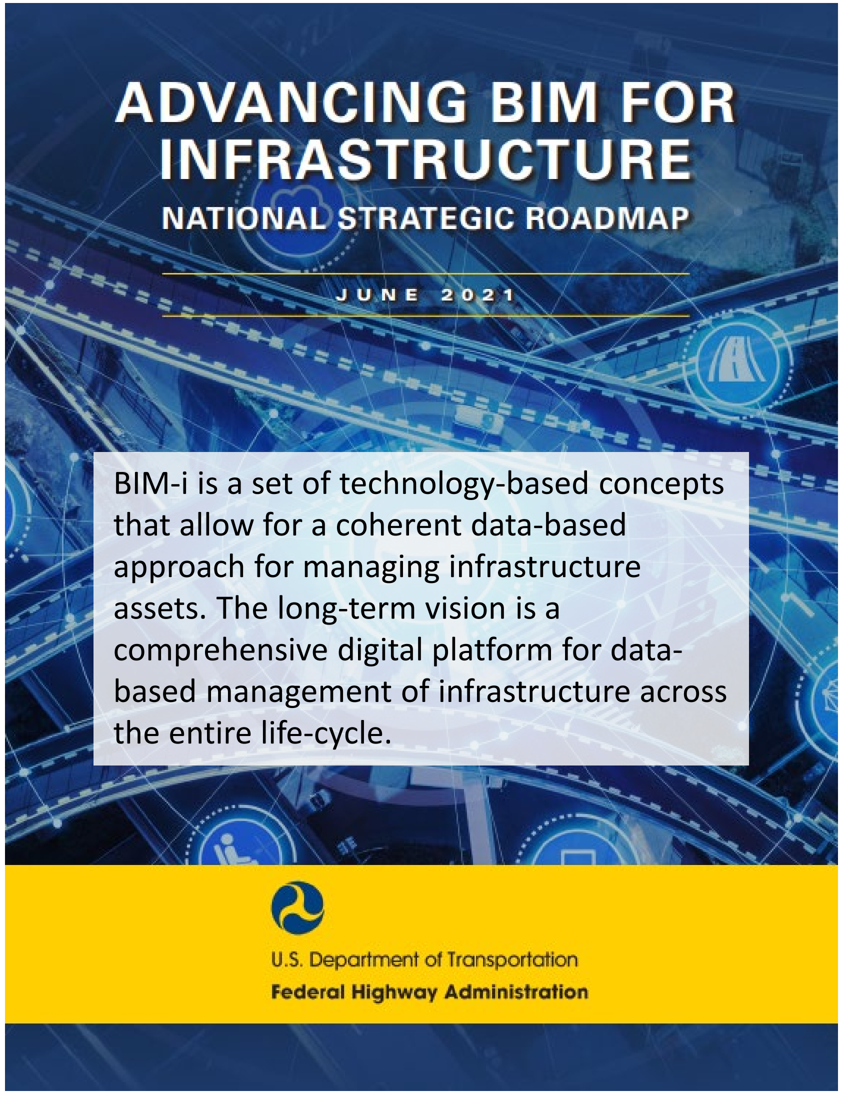



ASCE 38-22 provides a formal method to collect and record utility location information.

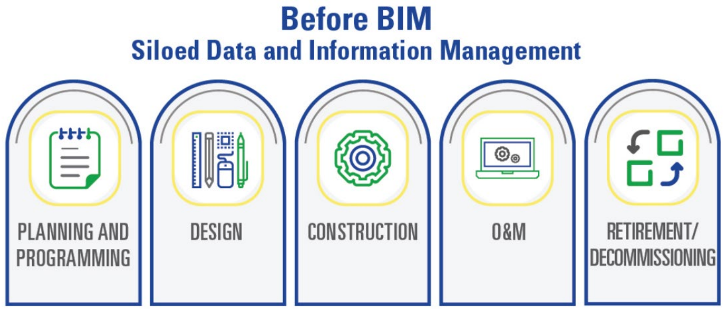

## SUE Legislation (Medium-term)

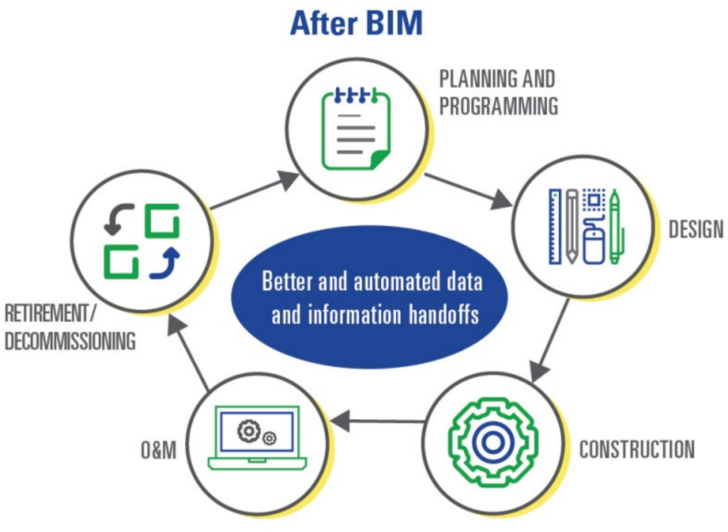
- **Require the use** of ASCE 38-22-complaint SUE for all public projects that meet certain requirements (e.g., a project cost threshold).
- **Establish a statewide platform** for SUE document sharing.
- **Provide a funding mechanism** to subsidize SUE efforts, along with regulatory authority to distribute funds and ensure compliance of deliverables.

# Building Information Modelling for Infrastructure (BIM-i)




BIM-i is a set of technology-based concepts that allow for a coherent data-based approach for managing infrastructure assets. The long-term vision is a comprehensive digital platform for data-based management of infrastructure across the entire life-cycle.




*O&M: Operations and Maintenance, which includes Asset Management*

## BIM-i Legislation (Long-term)

**Initial legislative efforts must be unobtrusive and deliberate.** Specifically, the legislature should establish a statement of principles that Michigan wishes to pursue a statewide BIM for infrastructure strategy and create a commission or working group to study the issue and report back with recommendations. Ideally this would be coordinated through a new State Office of Infrastructure Coordination.

**Long-term goal is to establish a shared vision for infrastructure design and life-cycle management within the public right-of-way.**

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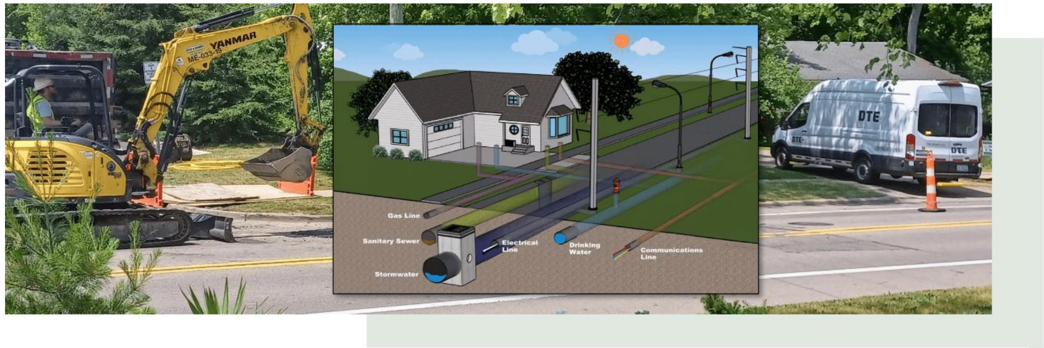
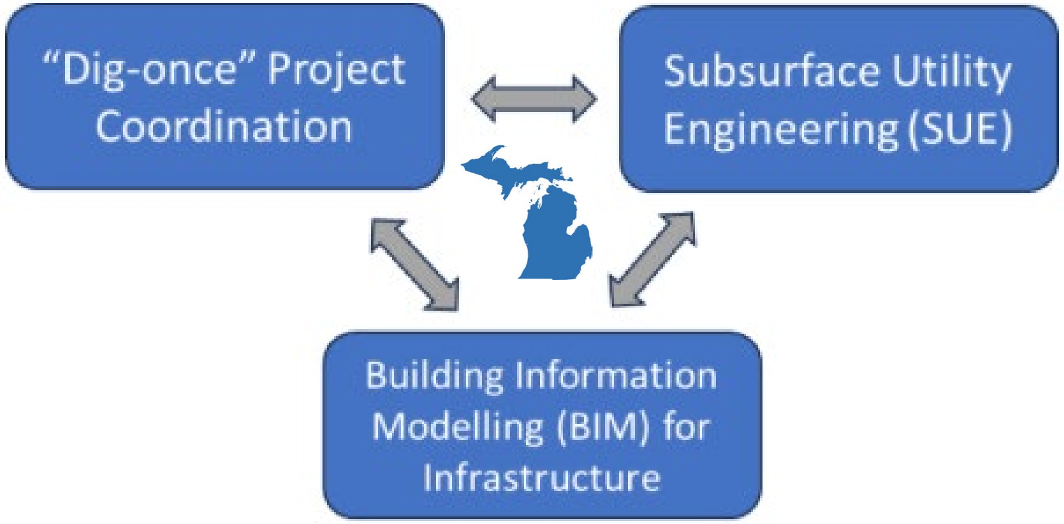



JUNE 21, 2023

# Legislative Direction is Needed to Facilitate Infrastructure Coordination

Short-term:
*Shared Resources*

Medium-term:
*Shared Data*




Long-term:
*Shared Vision*

# Possibilities for Progress without Legislation

MPSC has some limited ability to encourage undergrounding when it makes sense.

- Review Benefit:Cost Analyses
  - Consider benefits of risk mitigation of catastrophic outages, including socioeconomic factors
  - Update underground/overhead reliability data, life-cycle costs
  - Update climate assumptions, including tree growth rates due to longer growing season and establishment of rapidly-growing invasive species
  - Reconsider "aesthetic benefits" (2007 report)
- "Nudge" utilities to cooperate with local governments with dig-once projects.
  - Share data on depreciated costs of existing facilities, expected service life, circuit priority
  - Revise Mich Admin Code Rule 460 to allow for undergrounding during replacement of circuits
  - Establish undergrounding fund for cost-sharing (?)

"The Commission should consider amending [Rule 460.517] so that it allows burying…where overhead distribution and service lines are due for replacement. We are very rational actors in Farmington. We just want the opportunity to understand the cost-benefit of burial when the time comes."

~ *Joe LaRussa, Mayor of Farmington*

"My street is all torn up! They're redoing the street. They've taken out all the trees. They replaced the water lines. They're replacing the sidewalk today.

*Why in the heck are they not out there burying the power lines?"*

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CITIZENS RESEARCH COUNCIL OF MICHIGAN

# System Modernization & Reliability Project

Steven Herbel – Wisconsin Public Service

# Agenda

- Background on the Project
  - The Problem
  - The Goals
- Execution of the Project
  - Strategy
  - Problems
  - Solutions
- Completion of the Project
  - Reliability Results
  - Lessons Learned

# Background for SMRP

# Background for SMRP

- Wisconsin Public Service (WPS)
  - 453,000 electric customers
  - 18 Wisconsin Counties (11,000 sq miles)
- The Problem
  - 71% of the service area is medium to high-density forest
  - Need for reliability improvement when compared to industry benchmarks and other Midwest utilities
  - Challenge to maintain vegetation clearances and deal with hazard trees
  - Aging overhead lines

# Background for SMRP

- Additional Background
  - Project began in 2014
  - Almost half of customers surveyed indicated they valued and were willing to pay for improvements through increased electric rates
  - Advancements in underground cable installation and testing techniques

# Background for SMRP

- The Goals
  - Install 1000 miles of underground to replace overhead lines
    - Additional 1000 miles was added as Phase 2 of project
  - Deploy distribution automation (DA) equipment on 400 miles of existing three-phase mainline
  - Improve reliability (reduced SAIDI)
    - "Improved performance at a reasonable cost"
  - Reduce O&M expenses

# Distribution Automation

# Execution of the Project

- Project work started two years before construction
- Extensive coordination with:
  - U.S. Army Corps of Engineers
  - State Historic Preservation Office
  - Wisconsin Department of Natural Resources
  - U.S. Fish and Wildlife Service
  - U.S. Forest Service

# Execution of the Project

- Environmental inspectors were employed and dedicated to the project
  - Meet with crews, monitor, and inspect
- Techniques included plowing, boring and open cutting
- Used partial-discharge testing techniques to verify the quality of materials and workmanship
  - Terminations and splices identified as high risk areas
- Contacted over 50,000 landowners

# Execution of the Project

- Issues
  - High impact mainlines are expensive to rebuild underground
  - High voltage concerns on distribution system due to the amount of underground cable installed
  - Easement refusals or unable to contact with landowners

# Execution of the Project

- Solutions
  - Distribution Automation was an alternative to burying 3 phase mainline overhead lines
  - Inductors were installed as needed as part of the project
  - Mail hard copies to customers well in advance and follow up with duplicate mailings
  - Willing to cancel a project if significant issues with customer cooperation
    - Sometimes walking away from a project got cooperation in a future year

# Completion of the Project

- Reliability Data
  - SMRP project area contribution to total system SAIDI
  - SAIDI numbers are calculated on a utility-wide basis, inclusive of the entire WPS customer base

| | Year of Installation | | | | | |
|---|---|---|---|---|---|---|
| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
| Pre-SMRP average SAIDI (minutes) | 22.84 | 21.09 | 21.67 | 22.83 | 18.61 | 23.02 |
| Post-SMRP average annual SAIDI (minutes) | 0.49 | 0.36 | 0.43 | 0.59 | 0.46 | 0.12 |
| Improvement (minutes) | 22.35 | 20.72 | 21.24 | 22.24 | 18.15 | 22.90 |
| Improvement (%) | 98% | 98% | 98% | 97% | 97% | 99% |

# Completion of the Project

- Lessons Learned
  - "Improved performance at a reasonable cost" left behind some big reliability concerns
  - Distribution Automation does not prevent any outages, only reduces the impact at times
  - Project selection left behind some overhead in what is now mostly underground areas

GridCo Partners

# Resilience Metrics & Valuation for Electric Grid Decision-Making

Presented by | Shikhar Pandey

September 19, 2025

Need For Resilience

IEEE Resilience Metrics

System Resilience

Operational Resilience

Case Studies

PNNL–GridCo: Valuing Resiliency

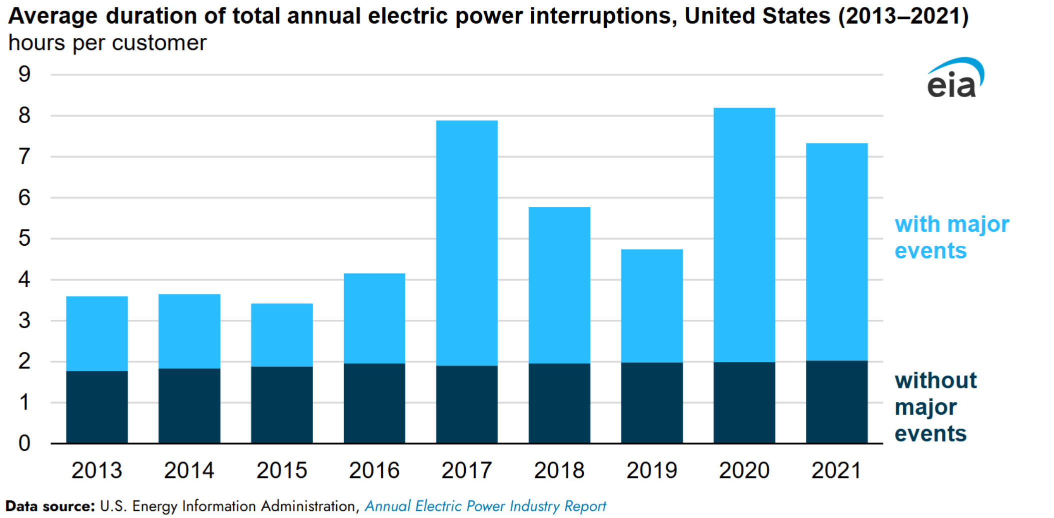
# Need for Resilience

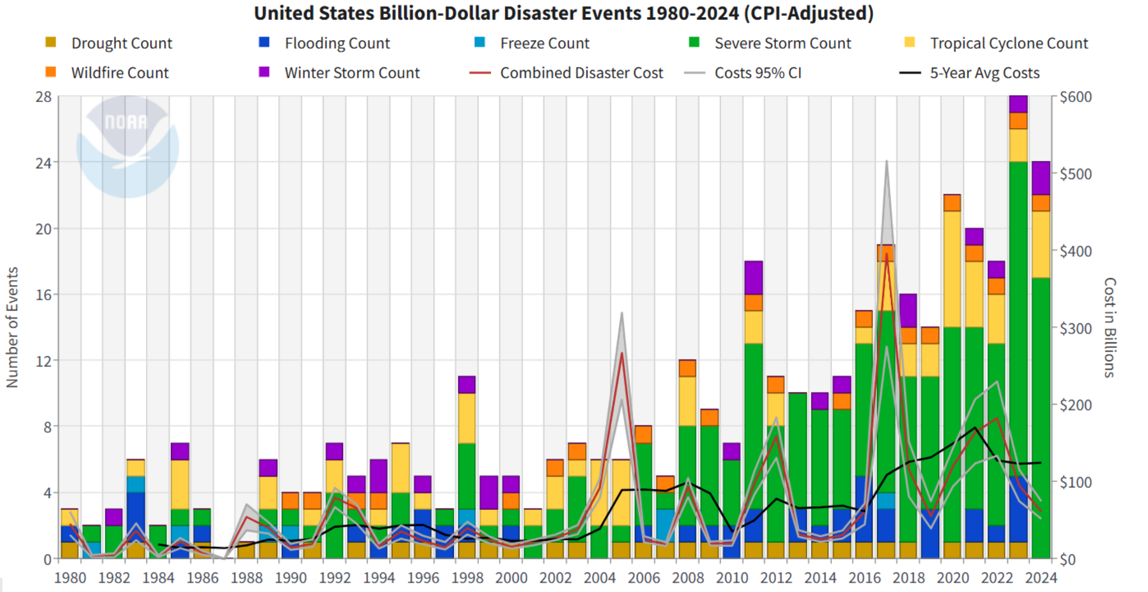
## Increasing Weather Events and Damage

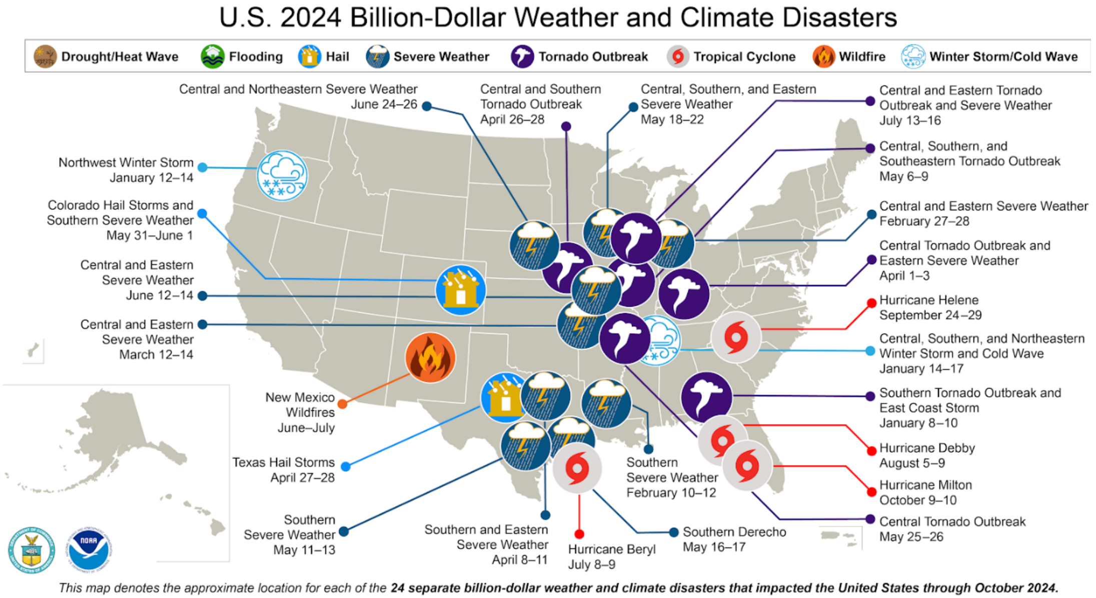
________ over the past two decades.”[1]

____ were due to weather.”[2]

_____ over two decades”[4]




[1] U.S. Is Facing More Power Outages Due To Extreme Weather | TIME   [2] Surging Weather-related Power Outages | Climate Central
[3] U.S. electricity customers averaged seven hours of power interruptions in 2021 (EIA)
[4] Billion-Dollar Weather and Climate Disasters | National Centers for Environmental Information (NCEI)

# Storm Events – Increasing Expectations

**Increased focus on Storm Events – No longer an Infrequent Outlier**

**Customer Expectations**
- Resilient System
- Estimated Time of Restoration
- Affordability

**Regulatory Requirements**
- Stringent Metrics
- Performance Based Rate Making
- Storm Reporting

**Industry Expectations**
- Reliability Metrics
- **'New' Resiliency Metrics**
- **Distribution Resiliency Guide**

GridCo Partners

# IEEE Resiliency Metric

# What is Resiliency?

*FERC has proposed* that resilience means the ***"ability to withstand and reduce the magnitude and/or duration of disruptive events,*** which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."

Credit: Utility Dive Feb 2, 2018, by Kate Konschnik and Brian Murray

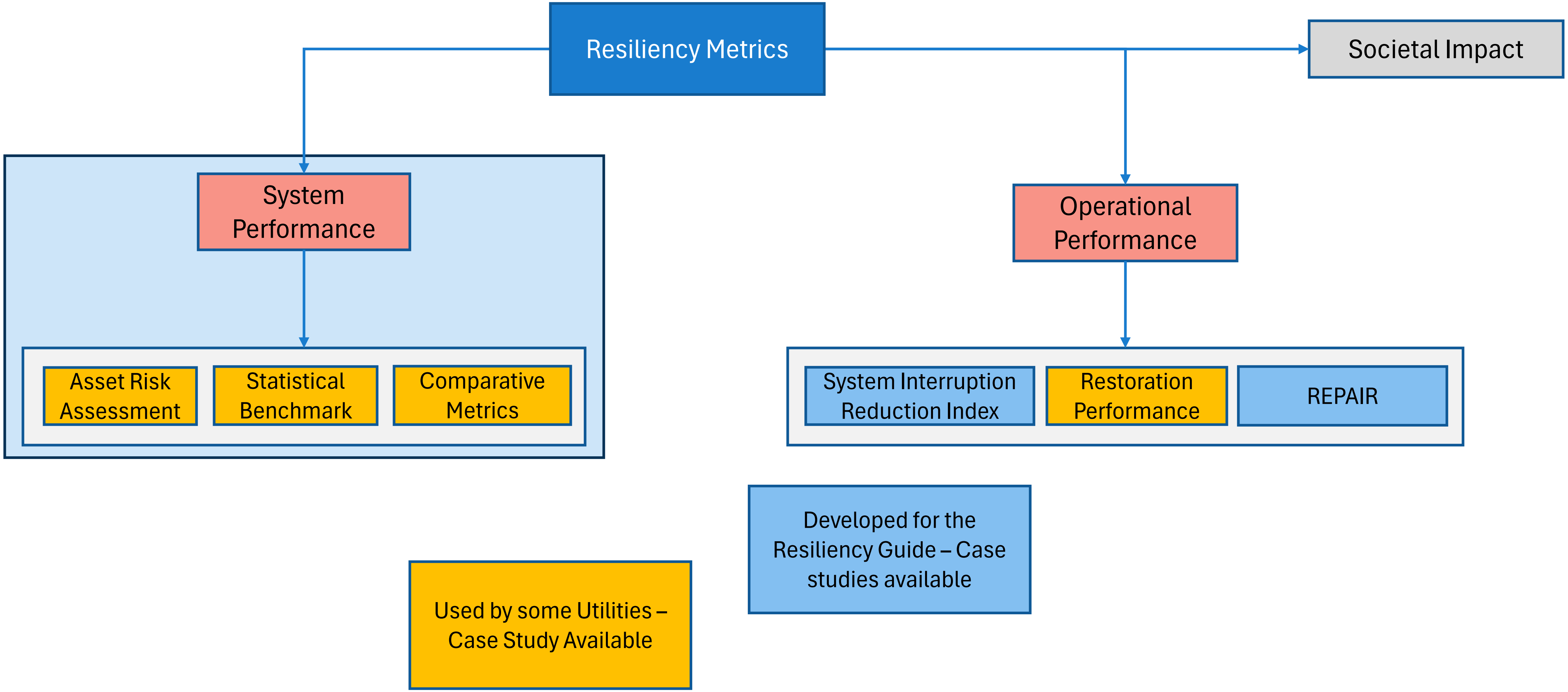
# Proposed IEEE Definition

*The capability of electric power* ***distribution*** *systems to* ***deliver*** *electric energy to end-use customers by* ***avoiding interruptions and/or recovering this capability*** *following exposure to* ***naturally occurring high impact low frequency events.***

**IEEE Distribution Resiliency Focus**

Out of scope: BES, Cyber/Physical Security, Operational Events

Primary Focus: Extreme Weather Events, Natural Phenomenon




These metrics are designed by the IEEE Distribution Resiliency Taskforce. They are currently in draft and will be refined.

# Assets Risk Assessment

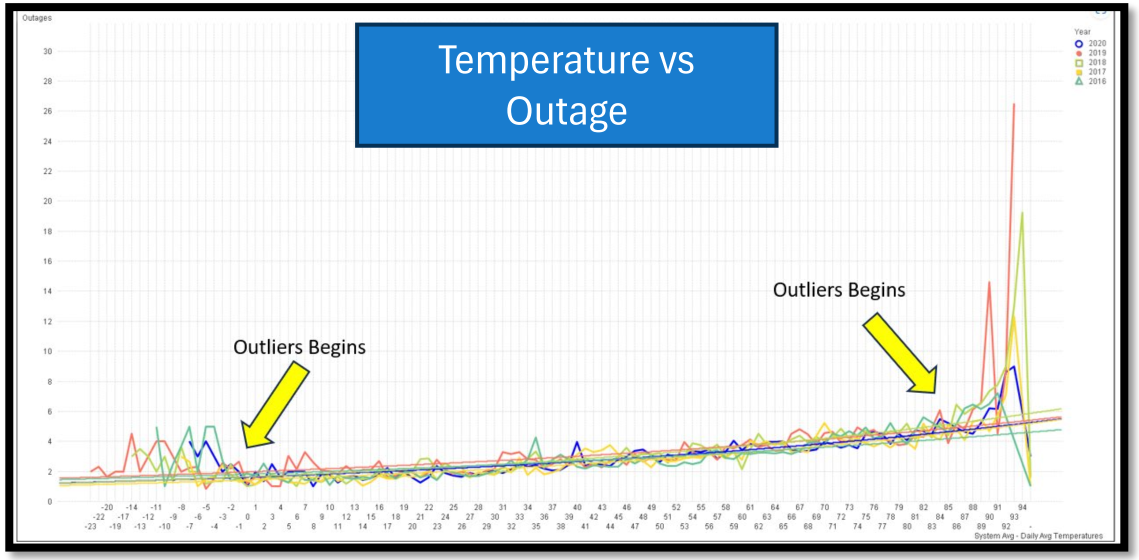
| Description | Temperature, Heat and Humidity | Flooding | Wind and Ice | Wildfire |
|---|---|---|---|---|
| **Exposed Assets-At-Risk Properties** | Thermal rating reduction, Accelerated asset degradation | Water-related equipment sensitivity, Corrosion, Soil Weakening | Wind and Ice Loading Tolerance, Vegetation Proximity | Fire-related equipment damage, Smoke on conductors, Soot accumulation over insulators, damaged insulators exhibiting high leakage currents, Vegetation Proximity |

2. **Asset-Risk Assessment Metric**: Utilizes two matrices:
   - **Exposure Properties to Risk Matrix**: Identifies asset properties affected by climate change
   - **Assets-to-Exposure Matrix**: Prioritizes asset strengthening based on risk levels (medium, high, low) against climate change variables

| Equipment vs Threat | Temperature, Heat and Humidity | Flooding | Wind and Ice | Wildfire |
|---|---|---|---|---|
| Substation | High Risk | High Risk | Low Risk | Low Risk |
| Overhead Equipment | Medium Risk | Low Risk | High Risk | High Risk |
| Underground Equipment | High Risk | Medium Risk | Low Risk | Low Risk |

# Statistical Benchmark: Outages on Gray Sky days

- This benchmark tracks the system performance (of outages) during gray sky days




**Yellow**

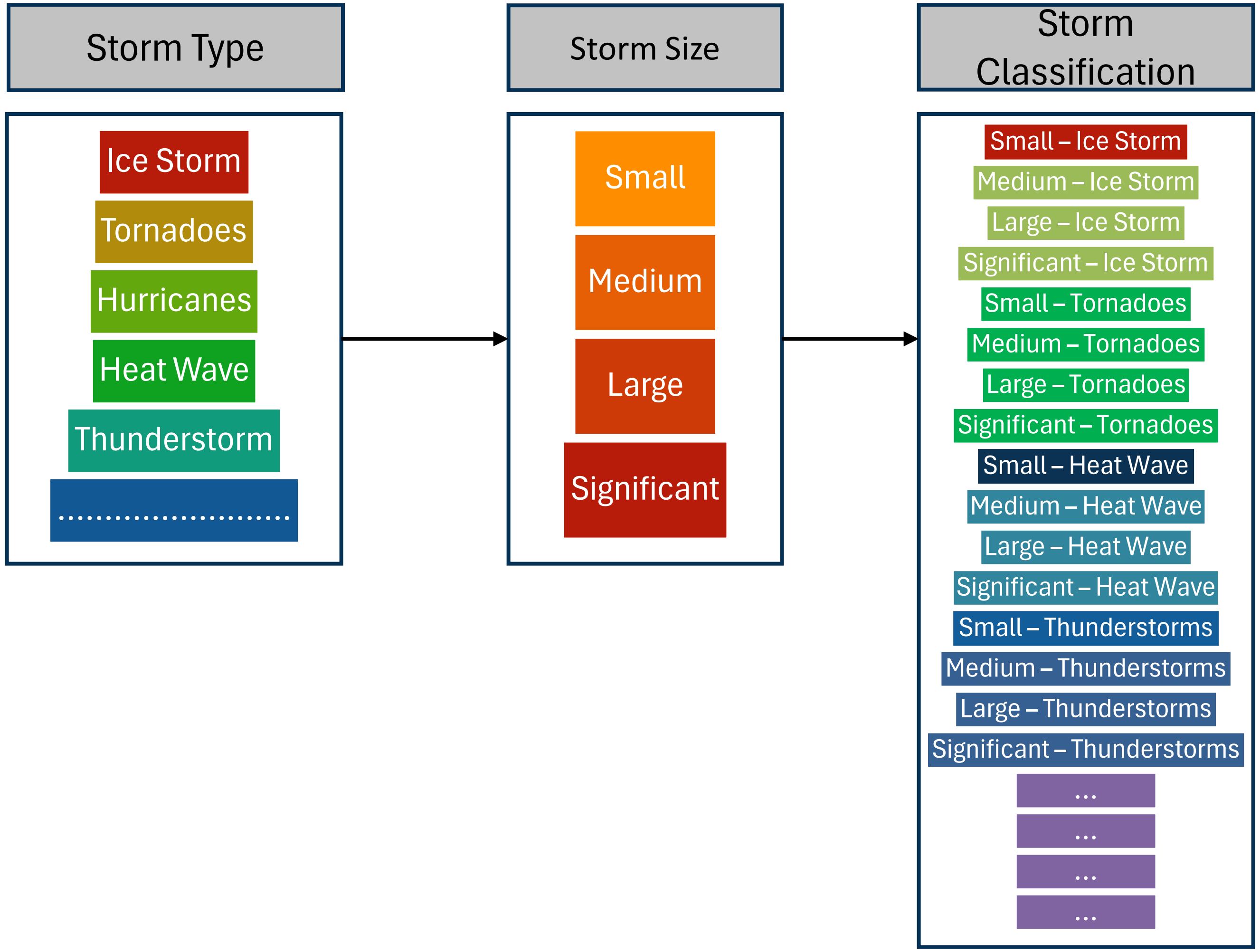
- **Average temperature** between 80 and 85 degrees
- **Average temperature** between 0 and -5 degrees
- **Average sustained wind speed** between 25 and 30 MPH
- **Average of one-hour wind gust** between 25 MPH and 30 MPH
- **Average rainfall** between 0.75" and 1"
- **Lightning stroke count** between 3,000 and 6,000

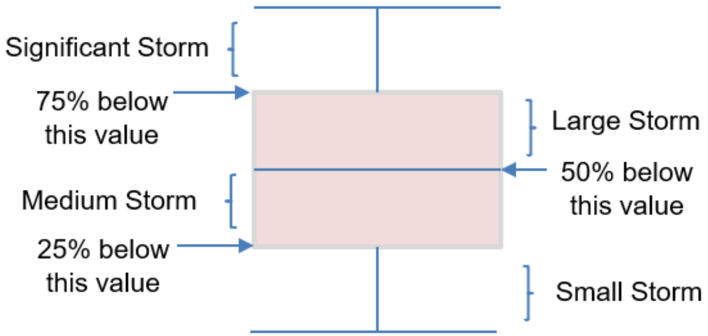
**Orange**

- **Average temperature** between 85 and 90 degrees
- **Average temperature** between -5 and -10 degrees
- **Average sustained wind speed** between 30 and 35 MPH
- **Average of one-hour wind gust** between 30 MPH and 35 MPH
- **Average rainfall** between 1" and 1.25"
- **Lightning stroke count** between 6,000 and 10,000

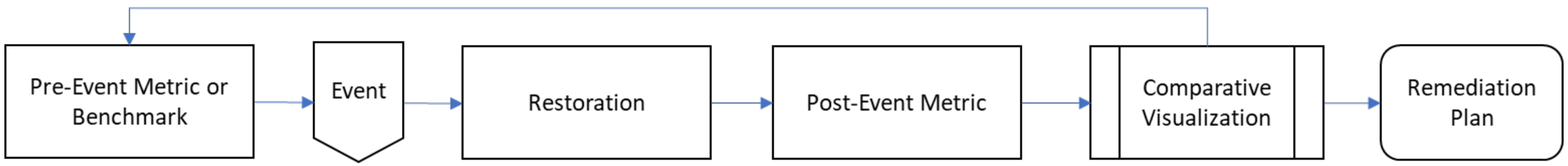
**Red**

- **Average temperature** greater than 90 degrees
- **Average temperature** less than -10 degrees
- **Average sustained wind speed** >= 35 MPH
- **Average of one-hour wind gust** >= 30 MPH
- **Average rainfall** greater than 1.25"
- **Lightning stroke count** greater than 10,000




It is Important to classify different storm categories to apply the metrics on.




| Metric | Attributes | Historical Benchmark | Current Event Records | Performance Assessment |
|---|---|---|---|---|
| Storm Strength Comparison | Wind Speed | 70 mph | 80 mph | Increased wind speed, correlates with longer outages |
| | Precipitation | 2 inches | 3 inches | Higher precipitation, potential cause for disruptions |
| Flood Comparison – Substations/Underground Equipment | Substation Outages due to Flood | 5 incidents | 3 incidents | Improved resilience, fewer outages |
| | Underground Equipment Outages due to Flood | 10 incidents | 12 incidents | Slight increase, review flood mitigation strategies |
| Square Miles Impacted/Customer Density | Square Miles Impacted | 50 sq miles | 60 sq miles | Larger area impacted, reassess preparedness |
| | Customer Density | 1,000 customers/sq mile | 1,200 customers/sq mile | Higher density, more significant impact |
| Pole Damage Comparison | Pole Damage Incidents | 15 incidents | 20 incidents | Increased incidents, consider reinforcement strategies |
| Equipment Damage Comparisons | Equipment Damage Incidents | 30 incidents | 52 incidents | Increased incidents, proactive maintenance strategy |
| Construction Person Hours to Restore Hardened vs. Non-Hardened | Construction Person Hours - Hardened | 500 hours | 450 hours | Improved efficiency, hardening measures effective |
| | Construction Person Hours - Non-Hardened | 1,200 hours | 1,400 hours | Increased time, need for further hardening measures |
| Smart Grid Performance | Smart Grid - Interruptions Avoided | 300 incidents | 350 incidents | Improvement, smart grid enhancing resilience |
| Equipment Comparison (Substation /Distribution) | Hardened Substation (Outages) | 80,000 | 60,000 | Improved performance, effective hardening measures |
| | Non-Hardened Substation (Outages) | 86,667 | 125,333 | Increased, monitor for further hardening |
| | Hardened Distribution (Outages) | 106,667 | 155,333 | Big increase, analysis needed |
| | Non-Hardened Distribution (Outages) | 126,667 | 185,333 | Increased vulnerability, consider reinforcement |
| Restoration Comparison to Prior Events | Restoration - 24 hrs | 60% restored | 55% restored | Slight delay, assess resource allocation |
| | Restoration - 48 hrs | 85% restored | 80% restored | Similar delay, possible need for more resources |
| | Restoration - 72 hrs | 95% restored | 92% restored | Minor delay, review efficiency |
| | Total Restoration Days | 5 days | 5.5 days | Slight increase, investigate specific challenges |

# Example on Comparative Metrics Application

$$\text{X-Parameter Performance Ratio (X-PR)} = \frac{\text{Incidents Avoided}}{\text{Incidents Avoided} + \text{Sustained Incidents}}$$

$$\text{Historical Pole Damage metric} = \frac{(200 - 40)}{(200 - 40) + (40)} \quad \mathbf{= 0.8}$$

- Event 1 affects 25% of the poles  Event 2 affects 5% of the poles.

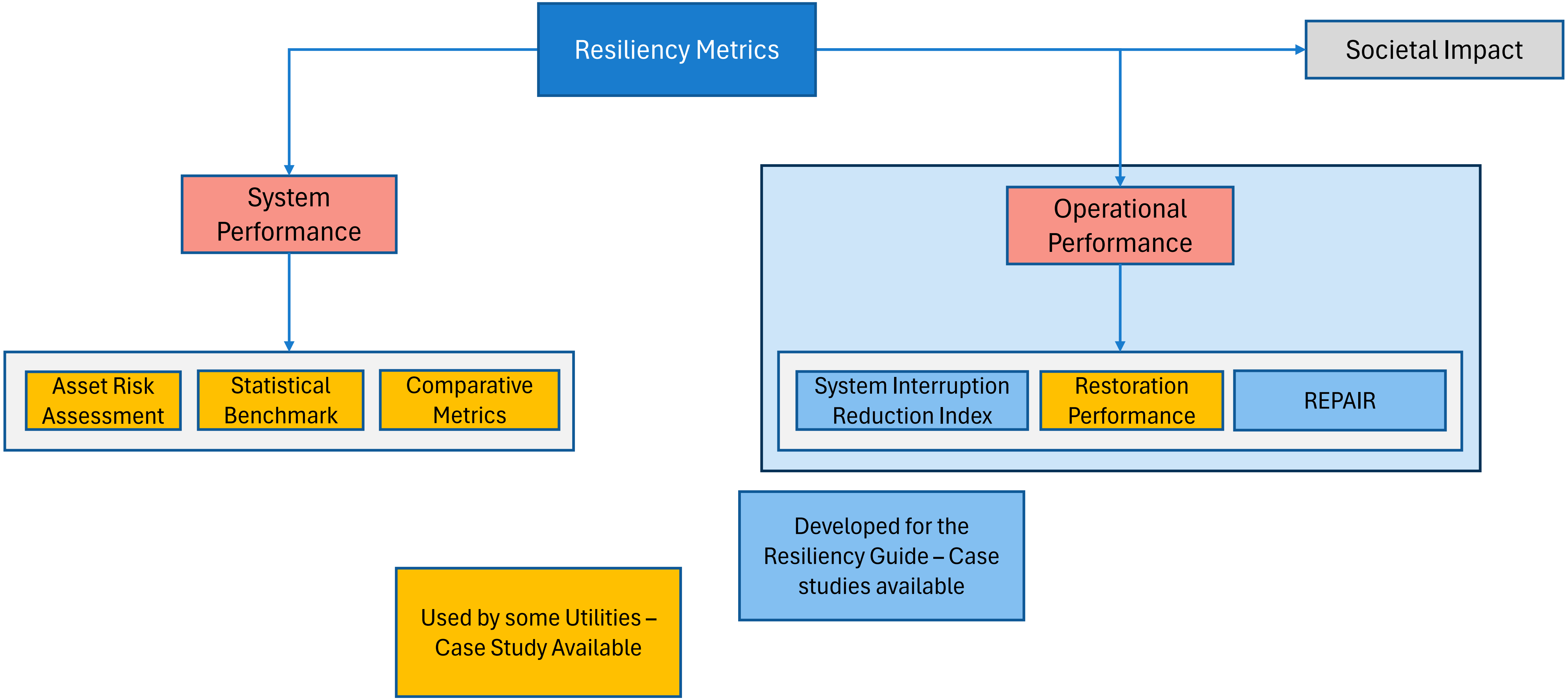
$$\text{Event 1 Pole Damage Metric} = \frac{(200 - 50)}{(200 - 50) + (50)} \quad \mathbf{= 0.75}$$

$$\text{Event 1 Pole Damage Ratio} = \frac{(0.75)}{(0.8)} \quad \mathbf{= 0.94}$$

$$\text{Event 2 Pole Damage Metric} = \frac{(200 - 10)}{(200 - 10) + (10)} \quad \mathbf{= 0.95}$$

$$\text{Event 2 Pole Damage Ratio} = \frac{(0.95)}{(0.8)} \quad \mathbf{= 1.19}$$

Ratio less than unity indicates system performance less favorable than historical; whereas the event ratio greater than unity indicates performance favorable than historical benchmark.




These metrics are designed by the IEEE Distribution Resiliency Taskforce. They are currently in draft and will be refined.

$$\text{SIRI} = \frac{\text{Avoided Sustained Customer Interruption (CI) by Automation/Hardening}}{\text{Avoided Sustained CI by Automation/Hardening + Sustained CI}}$$

| Aspect | Key Points |
|---|---|
| Perfect Resilience Scenario | Automation Performance **Ratio of 1** signifies perfect resilience, ensuring uninterrupted service and high customer satisfaction. |
| Factors Influencing the Ratio | **Automation Mechanisms:** Impact on outage prevention.<br>**Sustained Outages**: Causes like equipment failure or external disruptions. |
| Real-World Implications | **Case Studies**: Successful automation in outage prevention.<br>**Challenges**: Areas where automation needs improvement. |
| Trends Over Time | **Historical Analysis**: Trends in Automation Performance Ratio and automation strategies.<br>**Continuous Improvement**: Informing ongoing efforts. |
| Comparisons with Other Metrics | **Comprehensive Resilience**: Alignment with other metrics.<br>**Interconnected Nature**: Holistic understanding of grid resilience. |
| Operational Considerations | **Response Times**: Speed of detection, decision-making, and execution.<br>**Adaptability**: Handling different disturbances. |
| Scalability and Adaptability | **Scalability Challenges**: For larger grid systems.<br>**Technological Advances**: Enhancing automation systems. |
| Practical Applications | **Decision-Making Support**: Helps in prioritizing investments.<br>**Customer Impact**: Improved service reliability through outage prevention. |

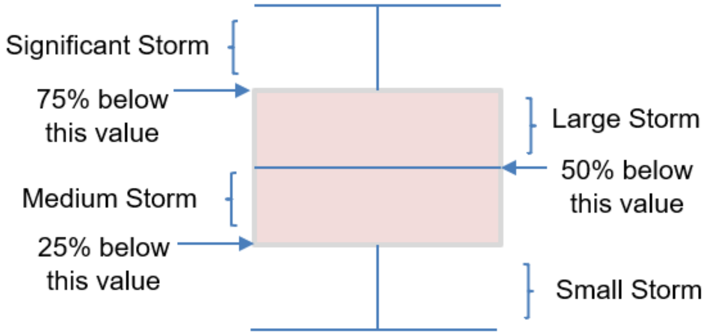
# Restoration Performance

**Calculation:**

1) For each storm in a calendar year, calculate the ratio of customers without power for more than 12 hours and total customer interruptions (CI) including customers automatically restored (ACI) through smart switch operations (DA devices), community energy storage, and microgrids (does not include substation reclosing events – measured in %)

$$\text{Storm Event: } X = \frac{\sum \text{Customers Without Power for More than Z hours}}{\text{Avoided Sustained CI by Automation /Hardening + Sustained CI}}$$

2) Based on number of interruptions (storm outages), categorize each storm event significant, large, medium, or small



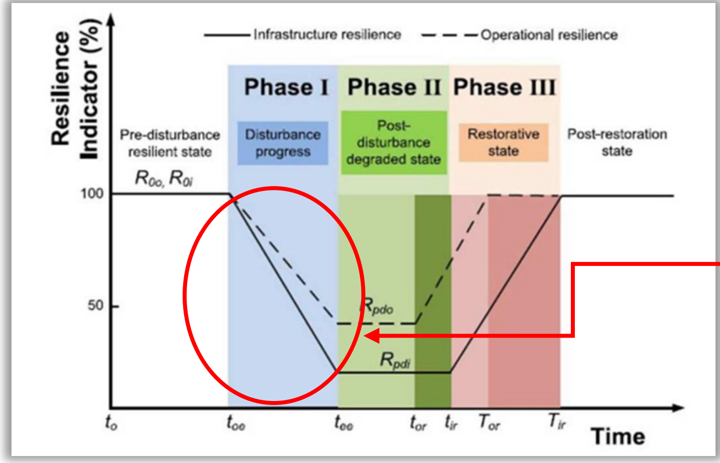

3) Determine if X is greater than or equal to the threshold value (Y) for the category

4) X<Y, storm met expectations. If X>=Y, storm did not meet expectations

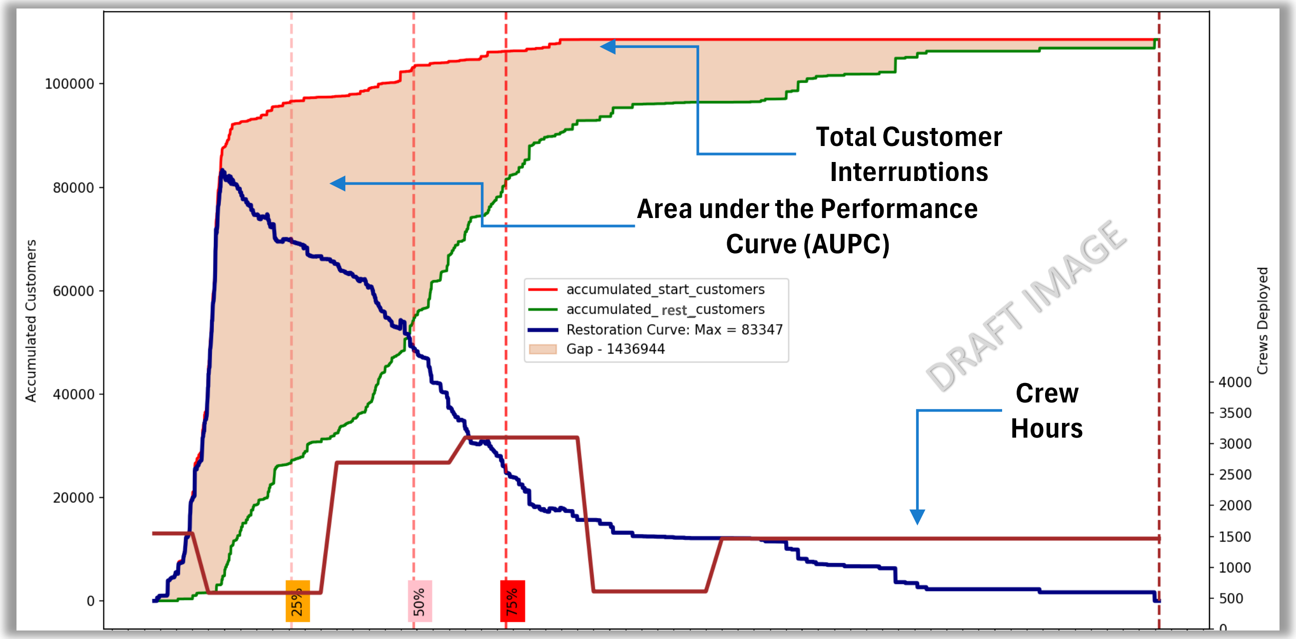
Threshold "Y" is calculated based on data analytics of small, medium, large, and significant size storm with 5 year moving average data. Details are explained in IEEE distribution resiliency guide.

# REPAIR Metric

- **Semi-Controllable** – better human performance, lower CI.
- But for severe events where all outages happen at the head end of the chart, there will be significant lag in start of restoration by crews




If Customer Interruptions is the resilience indicator in this figure, then the operational resilience is enabled by restoration efforts, both automated and by crew work



# Sample Calculations for 9 Storms

- Wide range – compression required – Use Log scale

- REPAIR = $\log\left(\frac{\text{Crew Hours}}{\text{Outages}} \times \frac{\text{AUPC}}{\text{CI}}\right)$

  + Area Index Resiliency (AIR)

- Insights:
  - Lower crew
  - Lower max customer interruptions
  - Lower AUPC

| Outages (n) | Crew Hours | RE | AUPC | CI | AIR | REPAIR |
|---|---|---|---|---|---|---|
| 1,536 | 142,172 | 1.97 | 1,135,907 | 176,929 | 0.81 | 2.77 |
| 1,126 | 49,549 | 1.64 | 370,417 | 107,578 | 0.54 | 2.18 |
| 1,267 | 42,399 | 1.53 | 282,653 | 128,132 | 0.34 | 1.87 |
| 216 | 31,866 | 2.17 | 31,786 | 28,724 | 0.04 | 2.21 |
| 2,588 | 118,405 | 1.66 | 2,221,044 | 208,613 | 1.03 | 2.69 |
| 850 | 75,411 | 1.95 | 753,380 | 88,923 | 0.93 | 2.88 |
| 457 | 30,250 | 1.82 | 91,268 | 49,497 | 0.27 | 2.09 |
| 347 | 30,816 | 1.95 | 80,027 | 38,053 | 0.32 | 2.27 |
| 1,129 | 49,443 | 1.64 | 576,270 | 111,156 | 0.72 | 2.36 |

| | |
|---|---|
| **Average** | **2.37** |
| Standard Deviation | 0.32 |
| Range | 2.05 -2.69 |

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# Case Studies

Storm 1 and 2 are comparable in nature

Storm 1 was hit in a lower DA Penetration area

ACI is lower for Storm 2

Storm 2 hit at 8 PM vs Storm 1 was at 5 PM

$$X = \frac{\sum \text{Customers Without Power for More than Z hours}}{\text{Avoided Sustained CI by Automation /Hardening + Sustained CI}}$$

$$SIRI = \frac{\text{Avoided Sustained Customer Interruption (CI) by Automation/Hardening}}{\text{Avoided Sustained CI by Automation/Hardening + Sustained CI}}$$

| Description | Storm 1 | Storm 2 | Storm 3 |
|---|---|---|---|
| Start Storm Date Time | 6/26/20 16:53 | 6/20/21 20:18 | 9/7/21 13:02 |
| End Storm Date Time | 6/27/20 18:51 | 6/21/21 17:34 | 9/8/21 6:13 |
| Sustained Outage Count | 575 | 527 | 420 |
| Sustained Cust Inter | 57,504 | 53,156 | 40,946 |
| Max Outage (Hours) | 75.7 | 93.1 | 39.4 |
| DA ACI | 30537 | 26511 | 30372 |
| X : Restored >12Hrs (w/ ACI) | 4.18% | 8.01% | 3.67% |
| SIRI | 35% | 33% | 43% |
| Restored ≤12Hrs | 93.60% | 88.00% | 93.60% |
| Major Causes | HAIL, LIGHTNING, RAIN, WIND | RAIN, TORNADO, WIND | HAIL, LIGHTNING, RAIN, WIND |

## Sequential vs. Multiple Storm Waves

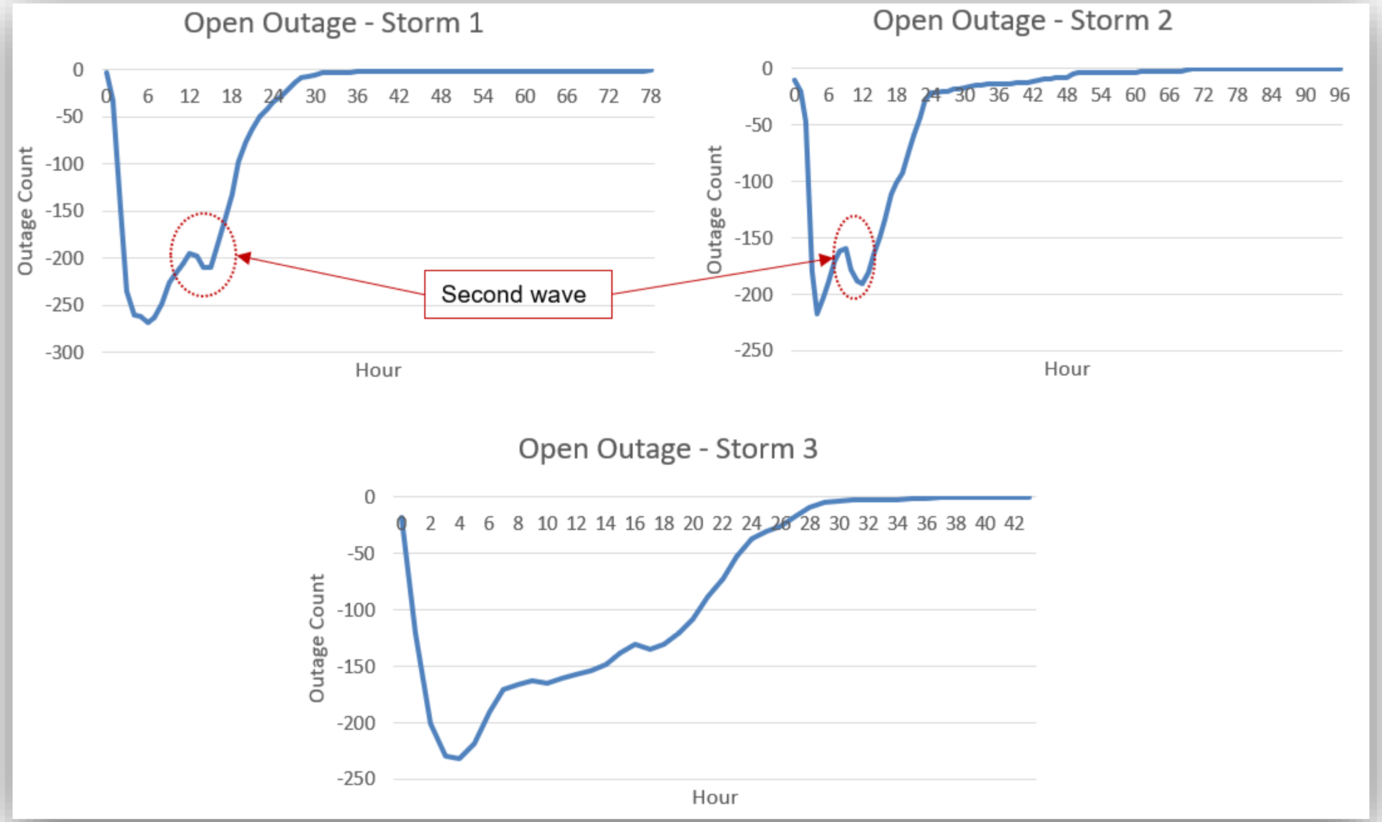
- Surge in outages after 10 hours, indicating a second wave of storm, not just initial tripping/fuse events

## Impact on Restoration Planning

- Multiple storm waves disrupt restoration, complicating crew deployment and resource management during recovery

## Timing and Automation Matter

- Faster deployment in the first 12 hours and higher automation (e.g., DA devices) significantly improve performance against ComEd's resiliency targets



## What Was Done

- Utility tested IEEE's Restoration Effectiveness, which measures % of customers out >12 hours during storms.
- Applied across 5 regions using real utility data from 2018–2023.

## Storms classified by severity using IEEE 1366 TMED multipliers

- *Small*: 1.0–1.5 | *Medium*: 1.75–2.5
- *Large*: 2.75–3.5 | *Significant*: 3.75+

## Key Results

- More than 70–90% of storms across most regions in 2023 performed better than the 5-year baseline.
- Backbone device analysis (reclosers, breakers, switches) showed even better resiliency scores, especially for small/medium storms.
- High variability in performance tied to storm type and location (e.g., rural vs. urban, weather-driven vs. equipment failure).

| Date | Outages | Customers Out | >12hr Outages | % Saved via Self-Healing | X : Restored >12Hrs (w/ ACI) |
|---|---|---|---|---|---|
| Jan 7, 2023 | 88 | 10,082 | 4,638 | 0% | **46%** (very poor) |
| Apr 7, 2023 | 310 | 39,922 | 20 | 15% | **0.04%** (excellent) |

Jan 7: Transformer failure in rural area with no backfeed capability led to high outage duration.

Apr 7: Widespread storm but automation saved 7,000+ customers, leading to excellent score.

| Hurricane | Year | Grid Strategy | % Feeders Hardened | Smart Devices (Reclosers) | 50% Restored | 100% Restored | Avg. Outage |
|---|---|---|---|---|---|---|---|
| **#1** | Pre-Resiliency | None | 0% | None | 3 days | 13 days | 3.5 days |
| **#2** | Pre-Resiliency | None | 0% | None | 5 days | 18 days | 5.4 days |
| **#3** | 12 yrs later | Storm hardening + Reclosers | 27% | Moderate | **1 day** | 10 days | 2.1 days |
| **#4** | 17 yrs later | Storm hardening + More Reclosers | 58% | **Doubled** | **1 day** | **8 days** | **1.5 days** |

## Post-Hurricane #2, launched aggressive storm hardening

- Upgraded poles and feeders to high wind-load standards
- Reduced pole damage significantly (from 12,400 to 3,200)

## Installed smart grid tech (self-healing reclosers)

- Avoided 546k interruptions (Hurricane #3)
- Avoided 405k interruptions (Hurricane #4)

## Improved resource deployment and grid design

- Cut average outage duration by over 70%
- Achieved 50% restoration in 1 day, even for stronger storms

## Evaluated Gray Sky Day (GSD) metric using divisional-level analysis, not company-wide, due to varied geography and weather patterns.

## Used airport weather stations

**Yellow**

- **Average temperature** between 80 and 85 degrees
- **Average temperature** between 0 and -5 degrees
- **Average sustained wind speed** between 25 and 30 MPH
- **Average of one-hour wind gust** between 25 MPH and 30 MPH

**Orange**

- **Average temperature** between 85 and 90 degrees
- **Average temperature** between -5 and -10 degrees
- **Average sustained wind speed** between 30 and 35 MPH
- **Average of one-hour wind gust** between 30 MPH and 35 MPH

**Red**

- **Average temperature** greater than 90 degrees
- **Average temperature** less than -10 degrees
- **Average sustained wind speed** >= 35 MPH
- **Average of one-hour wind gust** >= 30 MPH

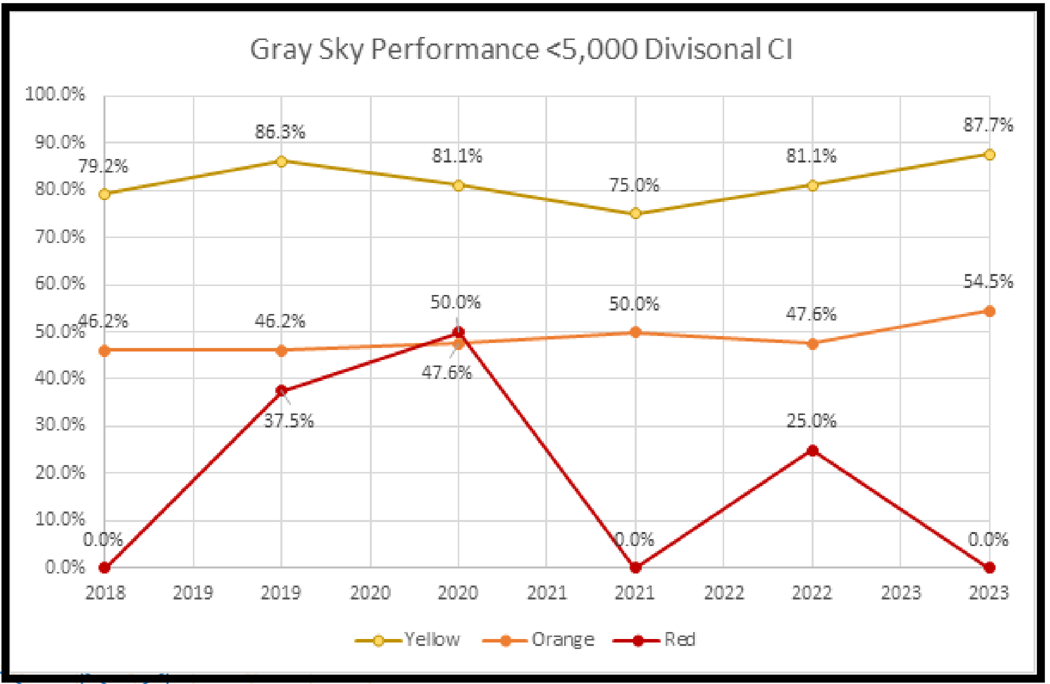
## Metric Definition

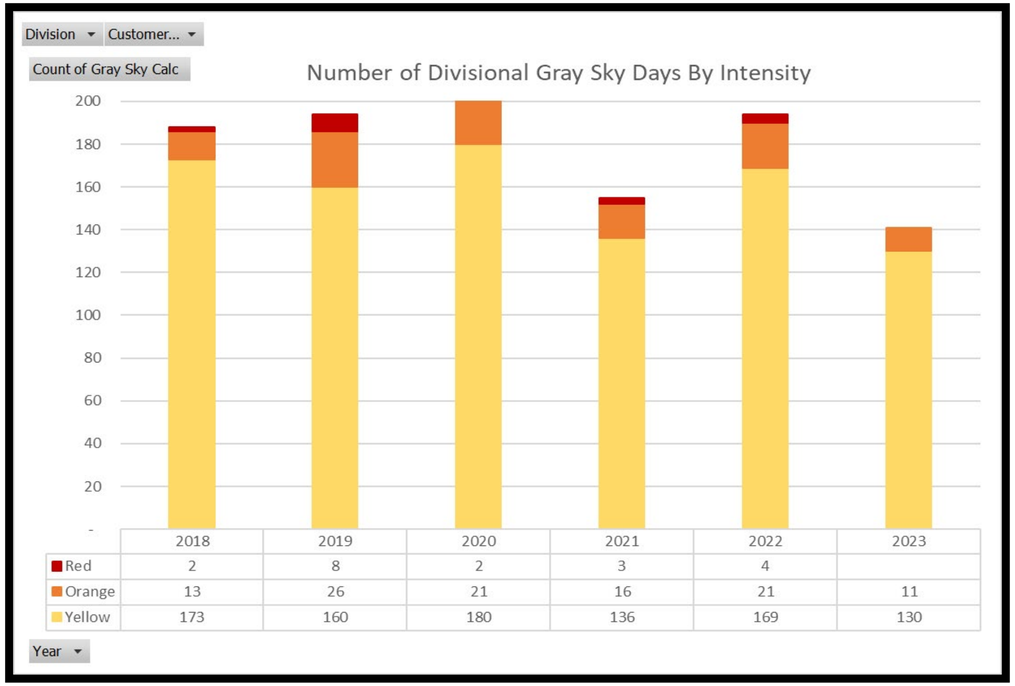
- Success = % of GSDs where <5,000 customers were interrupted
- Target value: 5,000 Customer Interruptions (CI)
  (based on 5-year average daily CI incl. major storms from 2018–2022)

| All Gray Sky Days | Yellow | Orange | Red | Grand Total |
|---|---|---|---|---|
| 2018 | 173 | 13 | 2 | 188 |
| 2019 | 160 | 26 | 8 | 194 |
| 2020 | 180 | 21 | 2 | 203 |
| 2021 | 136 | 16 | 3 | 155 |
| 2022 | 169 | 21 | 4 | 194 |
| 2023 | 130 | 11 | | 141 |
| **Total** | **948** | **108** | **19** | **1,075** |

| <5,000 CI Gray Sky Days | Yellow | Orange | Red | Grand Total |
|---|---|---|---|---|
| 2018 | 137 | 6 | | 143 |
| 2019 | 138 | 12 | 3 | 153 |
| 2020 | 146 | 10 | 1 | 157 |
| 2021 | 102 | 8 | | 110 |
| 2022 | 137 | 10 | 1 | 148 |
| 2023 | 114 | 6 | | 120 |
| **Total** | **774** | **52** | **5** | **831** |

| % | Yellow | Orange | Red | Grand Total |
|---|---|---|---|---|
| 2018 | 79.2% | 46.2% | 0.0% | 76.1% |
| 2019 | 86.3% | 46.2% | 37.5% | 78.9% |
| 2020 | 81.1% | 47.6% | 50.0% | 77.3% |
| 2021 | 75.0% | 50.0% | 0.0% | 71.0% |
| 2022 | 81.1% | 47.6% | 25.0% | 76.3% |
| 2023 | 87.7% | 54.5% | - | 85.1% |
| **Total** | **81.6%** | **48.1%** | **26.3%** | **77.3%** |



## Key Results

- 2023 performance >70% success rate across all divisions
- Year-over-year improvement since 2018 in Yellow & Orange GSDs
- Red GSDs lacked sufficient data for conclusions

## Challenges & Observations

- Limited localized weather station data (mostly from airports) reduced ability to classify more days as GSDs
- Variability in data granularity across divisions
- Results show system resiliency investments are paying off

## Next Steps

- Incorporate longer weather and outage history for better trend detection
- Enhance weather station network granularity
- Continue using this metric to guide targeted infrastructure upgrades

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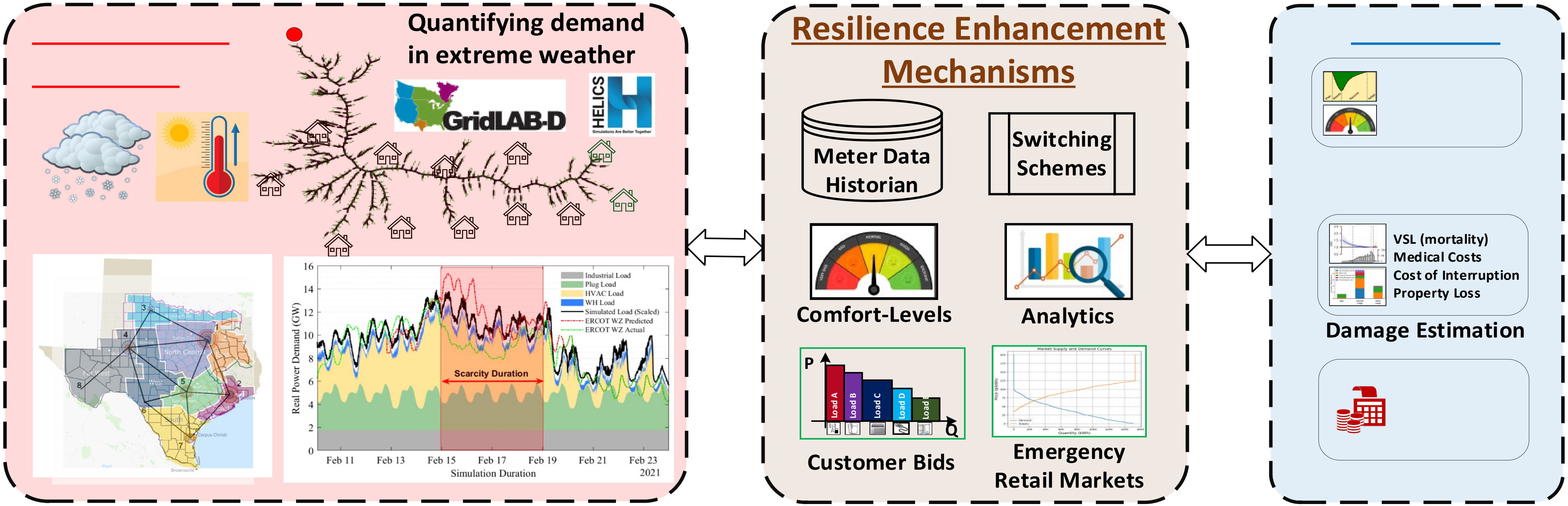
# PNNL - GridCo Resiliency Valuation

# DSO-RISE Study

DSO RISE

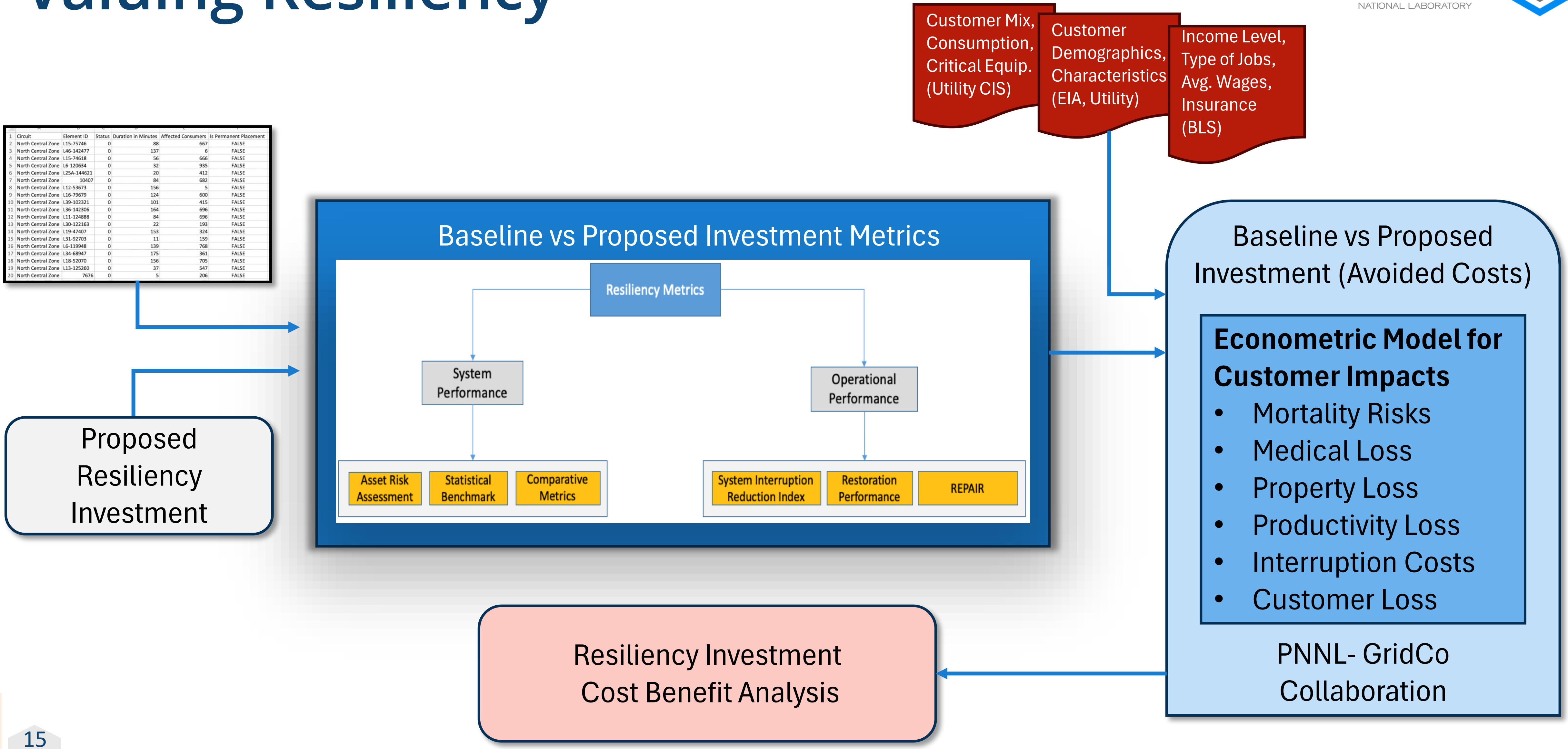



Implementation of Advanced Outage Management approaches including (1) Controlled Outages, (2) Direct Load Control, & (3) DER Coordination Mechanisms for Resilience enhancement

Developed method for calculating cost of outages including mortality risks, productivity & property damage

Determine the cost of deployment for resilience enhancement mechanisms

# Valuing Resiliency



| | Circuit | Element ID | Status | Duration in Minutes | Affected Consumers | Is Permanent Placement |
|---|---|---|---|---|---|---|
| 2 | North Central Zone | L15-75746 | 0 | 88 | 667 | FALSE |
| 3 | North Central Zone | L46-142477 | 0 | 137 | 6 | FALSE |
| 4 | North Central Zone | L15-74618 | 0 | 56 | 666 | FALSE |
| 5 | North Central Zone | L6-120634 | 0 | 32 | 935 | FALSE |
| 6 | North Central Zone | L25A-144621 | 0 | 20 | 412 | FALSE |
| 7 | North Central Zone | 10407 | 0 | 84 | 682 | FALSE |
| 8 | North Central Zone | L12-53673 | 0 | 156 | 5 | FALSE |
| 9 | North Central Zone | L16-79679 | 0 | 124 | 600 | FALSE |
| 10 | North Central Zone | L39-102321 | 0 | 101 | 415 | FALSE |
| 11 | North Central Zone | L36-142306 | 0 | 164 | 696 | FALSE |
| 12 | North Central Zone | L11-124888 | 0 | 84 | 696 | FALSE |
| 13 | North Central Zone | L30-122163 | 0 | 22 | 193 | FALSE |
| 14 | North Central Zone | L19-47407 | 0 | 153 | 324 | FALSE |
| 15 | North Central Zone | L31-92703 | 0 | 11 | 159 | FALSE |
| 16 | North Central Zone | L6-119948 | 0 | 139 | 768 | FALSE |
| 17 | North Central Zone | L34-68947 | 0 | 175 | 361 | FALSE |
| 18 | North Central Zone | L18-52070 | 0 | 156 | 705 | FALSE |
| 19 | North Central Zone | L13-125260 | 0 | 37 | 547 | FALSE |
| 20 | North Central Zone | 7676 | 0 | 5 | 206 | FALSE |

ComEd has been utilizing two metrics, restoration performance and Gray Sky day, since 2020.

These metrics have allowed ComEd to concentrate on system enhancements and improvements in resiliency.

Through the IEEE Distribution Resiliency Working Group, three other utilities have adopted the restoration performance and Gray Sky day metrics for their systems.

The final draft of the guide will be submitted for review and ballot at IEEE in 2025.

GridCo & PNNL are developing Resiliency Valuation tool to evaluate investment scenarios in rate cases.

GridCo Partners

*Navigating the Future of the **Grid***

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# Next Steps

- Recordings and Presentations Posted to Event Pages
- Staff Report With Recommendations due October 31, 2025

# PowerPoint Template Instructions

# Strategic Undergrounding: A Benefit-Cost Analysis of Targeted Electric Distribution Conversions in Michigan

Luke R. Dennin[1]

[1] Energy Innovator Fellowship, sponsored by the U.S. Department of Energy, hosted by the Michigan Public Service Commission, Lansing, MI, USA

**Abstract**

This study evaluates the economic viability of converting overhead electric distribution lines to underground in Consumers Energy's service territory in Michigan. The circuit-level benefit-cost analyses incorporate value streams focusing on reliability and resilience improvements and changes to utility system expenditures. The findings reveal that undergrounding can provide substantial net benefits, averaging approximately $300,000 per mile with a benefit-cost ratio of 1.9. While higher capital expenditures drive costs, these are offset by reduced operational and power interruption costs. Two-thirds of total benefits arise from improved reliability and resilience during storm events, avoiding outage impacts and response activities. Over 70% of circuits show net positive returns from undergrounding, though outcomes vary widely. The top 10% of circuits deliver far higher returns, with an average net benefit of $1.5 million per mile and a benefit-cost ratio of 5.3. A targeted program focusing on one-mile projects across the 35 most cost-effective circuits could produce $98 million (95% CI: $32.2M to $232M) in net benefits and achieve a benefit-cost ratio of 8.5 (95% CI: 2.9 to 24)—without incurring utility system net costs. These results suggest that undergrounding can be economically justified when implemented selectively, underscoring the value of a data-driven approach to infrastructure resilience.

## 1. Introduction

Electric power grid resilience is of paramount importance, particularly as climate change amplifies the risk of extreme weather events (Newman & Noy, 2023). While attributing specific weather events directly to climate change remains complex, a confluence of observed trends, theoretical frameworks, and numerical modeling supports the assertion that global warming contributes to an increased frequency and intensity of such events (Huber & Gulledge, 2011). Notably, evidence indicates a rising probability of high-impact, historically low-frequency storms (National Oceanic and Atmospheric Administration, 2024). This trend poses a significant challenge to Michigan's electric distribution system, where weather is the primary driver of power outages (Michigan Public Service Commission, 2025). The financial burden of these events is substantial; in 2023 alone, catastrophic storms cost Consumers Energy Company (CE) over $100 million in service restoration expenditures (Consumers Energy Company, 2024a).

At the same time, growing reliance on electricity—driven by electrification—underscores the escalating need for grid resilience. Electrification is widely recognized as a key strategy for mitigating the climate crisis, requiring both a transition to cleaner generation sources and the electrification of sectors such as transportation, buildings, industry, and agriculture (Aalto, 2021; U.S. Department of Energy, n.d.). Projections from the U.S. Energy Information Administration (EIA) anticipate national electricity consumption will rise from approximately 4.08 million GWh in 2022 to over 5.18 million GWh by 2050, a 27% increase (U.S. Energy Information Administration, 2023). As electricity becomes further embedded in daily life, ensuring uninterrupted, reliable, and resilient access is more critical than ever.

Among potential strategies for improving grid resilience, undergrounding overhead power lines stands out as the only option that fully protects against aerial hazards (Tripolitis et al., 2015). There is broad industry consensus that undergrounding improves reliability, particularly by reducing outage frequency (Hall, 2013; Larsen et al., 2020; NEI Electric Power Engineering, Inc., 2009; Shaw Consultants International, Inc., 2010; twentytwenty LLP, 2019). However, despite its benefits, especially in the face of intensifying storms, a central question remains: Do these benefits justify the substantial costs?

Previous studies have addressed this question and often concluded that undergrounding is prohibitively expensive. For instance, (Larsen, 2016) evaluated a hypothetical scenario in which all transmission and distribution lines in Texas were undergrounded at the end of their useful life. (Industrial Economics, Incorporated, 2023) adapted this analysis for New York. Both studies compared underground conversion to overhead replacement and reached similar conclusions: (1) costs significantly outweigh benefits overall; (2) reliability and resilience are the main benefits, while life-cycle expenditures drive costs; and (3) undergrounding is more viable under specific conditions, such as high customer density and elevated vulnerability to extreme weather.

This study advances the literature by conducting a novel circuit-level benefit-cost analysis (BCA) of converting overhead electric distribution lines to underground in Michigan, with a focus on reliability, resilience, and operational expenditure (OpEx) savings under increasing extreme weather impacts. Using a "marginal mile" approach—comparing undergrounding versus overhead rebuilding of a single mile across all eligible circuits—this research captures critical variation across CE's distribution system and enables a targeted undergrounding strategy. The analysis draws on a comprehensive utility-provided dataset covering roughly 2,000 circuits within CE's service territory, supplemented by operations and cost data from regulatory filings and other public sources. Reliability improvements are estimated using regression models that analyze outage frequency and duration under blue sky, gray sky, and catastrophic conditions (Michigan Public Service Commission, 2021). The analysis adapts the industry-accepted Interruption Cost Estimate (ICE) Calculator (Larsen et al., 2025; Sullivan et al., 2015) to estimate reliability-related value of lost load (VOLL), and incorporates the newly developed Power Outage Economics Tool (POET) to estimate resilience-related benefits (Larsen et al., 2024). The study also models installation, service restoration, forestry management, and component failure and replacement to estimate full system lifecycle costs. Additionally, it includes the value of avoided safety risks for workers and the public.

The primary findings are as follows. Strategically undergrounding overhead distribution lines in CE's service territory can deliver substantial net benefits. On average, undergrounding yields net benefits of approximately $300,000 (95% confidence interval [CI]: –$119,000 to $951,000) per mile, with a benefit-cost ratio (BCR) of 1.9 (95% CI: 0.78 to 6.1). While costs are primarily driven by increased capital expenditures (CapEx), benefits stem from OpEx reductions and avoided non-market impacts—especially business-related power interruptions. For the average circuit, improvements in storm-related reliability and resilience contribute over 67% of total benefits. Although 72% of circuits show positive net benefits, economic viability varies widely; circuits with higher storm outage frequency and greater customer density are the strongest candidates. The top 10% most cost-effective circuits yield an average of $1.52 million in net benefits per mile and a BCR of 5.3. A program targeting the 35 most cost-effective circuit miles is projected to deliver $98.3 million (95% CI: $32.2M to

$232M) in net benefits, with a BCR of 8.5 (95% CI: 2.9 to 24), and no net utility system costs in the base case or in 90% of uncertainty simulations. These findings suggest that undergrounding can be economically justified—and that a targeted, data-driven approach is essential to realizing its full potential.

## 2. Methods

Table 1 summarizes the key benefit and cost categories associated with undergrounding (Consumers Energy Company, 2024c; Larsen, 2016; Lawrence Berkeley National Laboratory, 2024; Tripolitis et al., 2015). This study focuses on four primary impact areas: utility expenditures, the VOLL, the value of safety risk, and customer service drops. While Table 1 includes additional relevant impacts, prior research indicates that more than 85% of total benefits stem from reliability and resilience improvements, while over 95% of costs are driven by utility capital and operating expenditures (Industrial Economics, Incorporated, 2023). Accordingly, the modeling approach prioritizes the value streams most influential for decision-making, while acknowledging that it does not capture all potential costs and benefits.

**Table 1: Benefits and costs of undergrounding compared to an overhead rebuild.**

| Impact Category | Advantages of Undergrounding | Disadvantage of Undergrounding |
|---|---|---|
| Utility Expenditures | - Lower outage response costs[A]<br>- Lower forestry management costs<br>- Lower inspection costs | - Higher installation costs<br>- Lower lifespan expectancy<br>- Higher other OpEx[B] |
| Value of Lost Load | - Fewer power interruptions: Any condition<br>- Shorter power interruptions:<br>Gray sky & catastrophic conditions | - Longer power interruptions:<br>Blue sky conditions |
| Value of Safety Risk | - Lower fatality risk<br>- Lower injury risk | - N/A |
| Customer Service Drops | - Lower tree trimming costs | - Higher installation costs<br>- Lower lifespan expectancy |
| Other Impacts[C] | - Utility revenue during would-be outages[D]<br>- Avoided customer credits[D]<br>- Lower wildfire risk<br>- Improved aesthetics<br>- Better long-run community relations after construction | - Added admin, siting, and permitting costs<br>- Increased ecosystem restoration costs<br>- Increased underground facility strike risk<br>- Disruptions during construction<br>- Worse short-run community relations during construction |

Sources: (Larsen, 2016); (Tripolitis et al., 2015); (Consumers Energy Company, 2024c); (Lawrence Berkeley National Laboratory, 2024)
Notes: A = "Outage response" includes both service restoration operating expenses (OpEx) and demand failures capital expenditures (CapEx). B = "Other OpEx" encompasses the corrective maintenance, lines reliability, service calls, and staking programs, all of which are more costly for underground line miles (Consumers Energy Company, 2024c). C = "Other Impacts" refers to effects beyond the scope of this analysis. D = These are financial transfers rather than net flows, as losses and gains are offset between parties.

This study employs two cost tests: a primary Societal Cost Test (SCT) and a secondary Utility Cost Test (UCT). The SCT includes all modeled value streams, while the UCT is limited to utility expenditure impacts that directly affect customer rates. Supplementary Note 1 provides a detailed discussion of both tests.

This section provides a concise overview of the methodologies used to quantify the SCT value streams. It also summarizes the overall modeling framework, the utility-provided dataset, and the approach to uncertainty. Additional methodological details are provided in the Supplementary Information, as referenced throughout.

### 2.1. Modeling framework

This study evaluates the circuit-level costs and benefits of undergrounding one mile of single-phase lateral distribution lines relative to rebuilding them overhead. The analysis incorporates data through 2023 and projects impacts from 2024 (year 0) to 2074 (year 50). Where historical data exhibit trends, future values are forecasted using an exponential smoothing state space model (Hyndman et al., 2008). An exception is made for storm-related power outage data, which are assumed to rise in proportion to projected increases in extreme precipitation frequency under the Representative Concentration Pathway 4.5 (RCP4.5), a moderate greenhouse gas emissions scenario (NOAA Climate Program Office, 2025). Additional methodological detail is provided in Supplementary Methods 1.

All value streams are expressed in 2023 U.S. dollars and evaluated using a net present value (NPV) framework to account for the time value of money. A social discount rate (SDR) of 3% is applied in the base case, consistent with guidance from the Michigan Public Service Commission (Michigan Public Service Commission, 2023) and supported by expert elicitation (Drupp et al., 2018).

The analysis adopts a "marginal mile" approach, assuming *ceteris paribus* conditions—i.e., holding all other components of the electric distribution system constant over the evaluated assets' lifetimes. For example, customer counts remain fixed, and system-wide upgrades or modifications are excluded. While this simplification is necessary for long-term forecasting, it constitutes a key limitation of the study. Notably, modeled reliability benefits (1) are measured relative to baseline performance and (2) scale multiplicatively with customer counts, as discussed in later sections. One exception to the *ceteris paribus* assumption is made for vegetation management: changes in tree trimming cycles are incorporated into both projected reliability outcomes and the expected improvements from undergrounding (see Supplementary Methods 2).

### 2.2. Utility-provided dataset

This study focuses on the service territory of CE, Michigan's second-largest investor-owned utility. CE serves nearly two million customers—approximately 38% of the state's population—across 60 counties in Michigan's Lower Peninsula (U.S. Energy Information Administration, 2024). As of 2024, roughly 84% of CE's distribution system is overhead, while the remaining 16% is underground.

The dataset used in this analysis (Consumers Energy Company, 2024c), described further in Supplementary Methods 3, includes detailed information for 2,390 low-voltage distribution (LVD) circuits. It encompasses more than 61,000 miles of primary conductor, categorized by circuit, voltage, phase, and overhead versus underground configuration. Additional within-circuit data provide segment-level detail for over 150,000 protective zones. This granularity allows for general classification of circuit segments into mainlines (which carry electricity from substations to feeders), feeders (which distribute electricity from mainlines to laterals), and laterals (which deliver electricity to end users). Notably, 77% of CE's underground segments are single-phase, and 92% are laterals.

Reliability data are central to several components of this analysis (Institute of Electrical and Electronics Engineers Standards Association, 2022). The System Average Interruption Frequency Index (SAIFI) measures the average number of power interruptions per customer over a given time period (t), as shown in Equation 1. The Customer Average Interruption Duration Index (CAIDI) quantifies the average duration of outages experienced by affected customers, as shown in Equation 2. These metrics can be combined to provide a broader picture of reliability via the System Average Interruption Duration Index (SAIDI), which reflects the total outage duration for the average customer, as shown in Equation 3:

$$\text{SAIFI}_t = \frac{\text{Total Number of Interruptions}_t}{\text{Total Number of Customers Served}_t} \quad \text{(Equation 1)}$$

$$\text{CAIDI}_t = \frac{\text{Total Duration of Interruptions}_t}{\text{Total Number of Interruptions}_t} \quad \text{(Equation 2)}$$

$$\text{SAIDI}_t = SAIFI_t \times CAIDI_t = \frac{\text{Total Duration of Interruptions}_t}{\text{Total Number of Customers Served}_t} \quad \text{(Equation 3)}$$

Circuit-level SAIFI and CAIDI data are available for each year from 2019 to 2023, disaggregated by outage condition: blue sky, gray sky, and catastrophic. These categories, defined by MPSC's Service Quality Rules (Michigan Public Service Commission, 2021), are as follows:

- **Blue Sky** = ≤ 1% of customers interrupted.
- **Gray Sky** = > 1% but < 10% of customers interrupted.
- **Catastrophic** = ≥ 10% of customers interrupted, or outages associated with events that trigger an official emergency declaration from local, state, or federal authorities.

Low blue sky and gray sky metrics indicate a reliable grid that performs well under typical and moderately adverse conditions. In contrast, catastrophic events involve widespread disruptions typically beyond a utility's direct control. Strong performance under these high-impact, low-frequency events signals greater grid resilience (Chiu et al., 2020; Michigan Public Service Commission, 2020). This study adopts the blue sky, gray sky, and catastrophic classification system—rather than the commonly used major event day (MED) framework (Warren et al., 2003)—for reasons outlined in Supplementary Note 2.

The CE dataset also includes customer counts by class (residential, commercial, industrial, and unknown), geographic details (county, CE headquarters, and urban or rural designation), tree density along primary conductors, and the percentage of rear-lot service connections (used to estimate backlot infrastructure mileage). These variables support the modeling of value streams in the undergrounding BCAs.

### 2.3. Reliability improvements from undergrounding

Industry consensus indicates that undergrounding power lines enhances reliability and resilience (Hall, 2013; Larsen et al., 2020; NEI Electric Power Engineering, Inc., 2009; Shaw Consultants International, Inc., 2010; twentytwenty LLP, 2019). For a detailed literature review, see Supplementary Note 3.

(Larsen et al., 2020) provided insightful guidance by employing regression analysis to examine the relationship between reliability metrics and factors such as the proportion of underground line miles. The study analyzed service territory-level data from over 80 utilities, spanning up to 16 years for some utilities, with annual temporal resolution. Their preferred SAIFI model revealed a statistically significant relationship with the share of underground line miles, indicating a 0.426% decrease in SAIFI for each one-percentage-point increase in underground proportion. Their preferred SAIDI model showed a 0.574% decrease associated with a one-percentage-point increase in underground proportion, although this effect was not statistically significant.

This study adapts the approach of (Larsen et al., 2020) with several key modifications. First, it focuses on CE's service territory at the circuit level. Second, whereas (Larsen et al., 2020) assessed and controlled for reliability changes over time, this study aggregates five years of annual data (2019 to 2023) into five-year reliability metrics. Third, it differentiates reliability data by outage condition—blue sky, gray sky, and catastrophic. Notably, although (Larsen et al., 2020) conducted supplementary analyses excluding MEDs, they did not estimate models specifically for MED conditions.

Following the methodology of (Larsen et al., 2020), I model outage-condition-specific SAIFI and SAIDI as a function of various explanatory variables, as represented in Equation 4. Equation 5 depicts the optimization process of ordinary least squares regression, where the model is constructed by minimizing the sum of squared residuals (i.e., differences between observed and predicted values):

$$\ln(y_{o,c}) = B_o X_c + \epsilon_{o,c} \quad \text{(Equation 4)}$$

$$\text{Minimize} \sum_{c=1}^{n} \left(\ln(y_{o,c}) - \widehat{\ln(y_{o,c})}\right)^2 \quad \text{(Equation 5)}$$

In these equations, $\ln(y_{o,c})$ represents the natural logarithm of the five-year (2019 to 2023) SAIFI or SAIDI by outage condition $o$ for circuit $c$. $X_c$ is a vector of circuit-level explanatory variables (regressors), which remain consistent across outage conditions. $B_o$ is a vector of coefficients, specific to each outage condition, associated with the regressors in $X_c$, and $\epsilon_{o,c}$ represents the error term. Among the regressors in $X_c$, the percentage of primary miles underground is of primary interest (see Supplementary Methods 4 for a complete list of covariates). The corresponding coefficients $\beta_o$ quantify the relationship between reliability metrics and the share of underground lines. Because these are log-level regressions, a one-unit increase in a regressor corresponds to a $100 \times \beta_o$ percent change in the dependent variable.

(Larsen et al., 2020) emphasized the importance of accounting for SAIFI's influence when modeling SAIDI, given their inherent relationship (see Equation 3). To address this, I include the residuals from the SAIFI regressions as an additional regressor in the SAIDI models. This approach allows me to control for variation in SAIFI that is not explained by the observed circuit-level variables, enabling a clearer identification of the independent association between the regressors and SAIDI. In doing so, I mitigate omitted variable bias that could otherwise arise from the close interdependence of these reliability metrics.[1]

Although CAIDI is not modeled directly and therefore does not yield its own statistical significance estimates, its relationship with undergrounding can be inferred from the results for SAIFI and SAIDI. Since CAIDI is calculated as the ratio of SAIDI to SAIFI, the natural logarithm of CAIDI is equal to the difference between the logged values of SAIDI and SAIFI. This yields the relationship $\beta_{SAIDI,o} - \beta_{SAIFI,o} = \beta_{CAIDI,o}$ (see Supplementary Methods 4 for details). While this approach does not provide

[1] Unlike Larsen et al. (2020), who used an instrumental variable approach to isolate exogenous variation in SAIFI, my method leverages regression residuals to capture unexplained variance—avoiding the need for external instruments while still addressing endogeneity concerns.

a standalone regression model for CAIDI, it offers a practical means of assessing how undergrounding is associated with changes in CAIDI without introducing additional regressions.

### 2.4. Value of lost load

The VOLL can be interpreted as either the cost incurred by customers during a power outage or the price they would be willing to pay to avoid such an outage. This subsection reviews two models—the ICE Calculator and POET—designed to estimate the VOLL under different circumstances. Generally, the ICE Calculator is more appropriate for reliability assessments, while POET is better suited for resilience evaluations. See Supplementary Methods 5 for additional details.

#### 2.4.1. Value of reliability

The ICE Calculator is a tool developed for electricity system planners at utilities, government agencies, and other organizations to estimate the costs of power interruptions and the benefits of reliability enhancements (Sullivan et al., 2015). It is specifically tailored to assess costs associated with short-term outages (up to 24 hours) in a reliability context and is not suitable for estimating the economic impacts of long-duration outages related to resilience.

The ICE Calculator is grounded in extensive surveys and studies evaluating the economic effects of power outages across different customer groups. Its primary data collection method is contingent valuation, which elicits customers' willingness to pay to avoid an outage or the compensation they would require to endure one. These surveys also capture observed losses, such as reduced productivity and spoiled goods.

This study employs ICE Calculator 2.0, an updated version that improves upon the original through standardized and coordinated survey protocols, incorporation of behavioral and technological developments (e.g., advance outage notifications, increased adoption of residential backup generation, and the rise of remote work), and a refined survey design using the one-and-one-half-bound dichotomous choice technique (Larsen et al., 2025). Because outage costs differ significantly between residential and non-residential customers, ICE Calculator 2.0 uses two separate statistical models, each calibrated to reflect the specific characteristics and economic behaviors of its respective customer class.

For this analysis, the ICE Calculator is configured to reflect Michigan-specific conditions and incorporates forecasted data for future cost estimates, where applicable. The statistical models generate outage cost estimates on a per-customer, per-event basis, as a function of outage duration (CAIDI) and other variables described in Supplementary Methods 5. Figure 1 presents the Michigan-specific models for each customer class in 2023. Total interruption costs are calculated by multiplying these per-customer, per-event estimates by the number of affected customers and the frequency of outages (SAIFI).

#### 2.4.2. Value of resilience

POET is an in-development model intended to help electricity system planners estimate the costs of widespread, long-duration (WLD) power interruptions and the benefits of resilience enhancements (Larsen et al., 2024). It employs a hybrid methodology by integrating direct customer surveys with regional economic modeling. The survey component aligns with the ICE Calculator approach, eliciting direct costs such as spoiled food, lost income, and loss of access to essential appliances (for residential customers), or lost production value and related expenses (for businesses), across 1-, 3-, and 14-day outages.[2] The regional economic modeling supplements this by capturing indirect or "spillover" effects through a computable general equilibrium framework, which models interactions across economic sectors.

This study uses prototype POET results for the Commonwealth Edison (ComEd) service territory in Illinois to estimate resilience costs for Michigan. Although these two states are distinct, they are located in similar regions and share broadly comparable populations and economies. Limitations associated with this extrapolation are discussed in Supplementary Methods 5.

Two economic metrics characterize the costs: household consumption (i.e., the subsidy required to make residential customers indifferent to the disruption) and gross domestic product (GDP; i.e., lost economic output). Importantly, POET scenarios simulate outages across entire micro-regions or the full service area, and the resulting economic effects are assessed across the entire region—not just for customers directly affected. This enables the model to capture complex regional interdependencies and the redistribution of economic activity during extended outages.

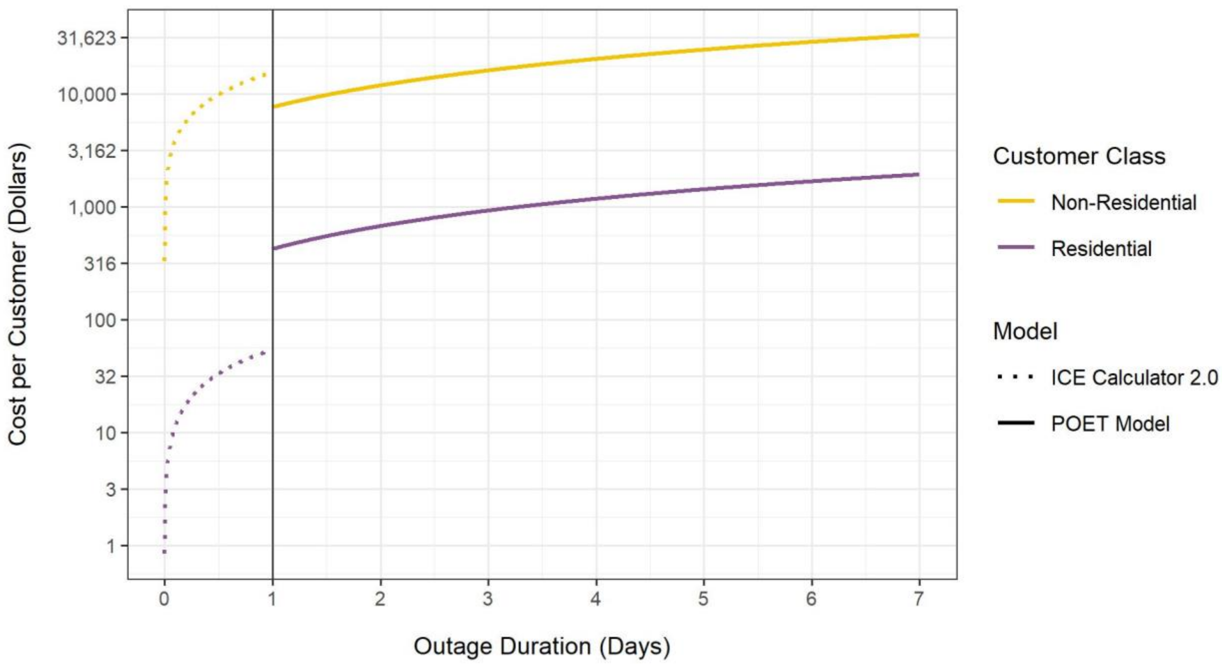


**Figure 1: Value of lost load per customer as a function of outage duration.**

Sources: Interruption Cost Estimate Calculator 2.0 (Larsen et al., 2025); Power Outage Economics Tool (Larsen et al., 2024)
Notes: Values are reported in 2023 U.S. dollars. The y-axis is log-transformed. Costs are shown separately for residential (purple) and non-residential (yellow) customers. he "reliability regime" spans outages up to 24 hours and is represented by ICE Calculator 2.0 (dashed lines). The "resilience regime" includes outages longer than 24 hours and is represented by POET (solid lines). Within the resilience regime, POET per-customer costs are applied only when they exceed the maximum value from ICE Calculator 2.0 at 24 hours. This occurs for the residential model at all durations and for the non-residential model beginning at 2.87 days.

In this study, I adapt the POET estimates from ComEd to (1) apply to Michigan and (2) yield a workable model for estimating WLD outage costs for durations exceeding one day. As described in

[2] POET's cost estimates account for "resilience tactics" by customer class, including—but not limited to—use of backup generation or temporary relocation of residences or business operations during the interruption.

Supplementary Methods 5, this involves regressing POET's household consumption and GDP impacts on outage duration, weighted by the number of directly affected customers. Figure 1 reflects the resulting Michigan-specific cost estimates for residential and non-residential customers. For this BCA, resilience costs are triggered only when CAIDI exceeds 24 hours *and* POET estimates exceed those from ICE Calculator 2.0.[3] Final VOLL estimates reflect either reliability or resilience costs—not both.

### 2.5. Value of safety risk

A significant limitation of BCA is that any impact not explicitly assigned a dollar value is implicitly treated as zero. This is particularly important when considering the monetization of safety risk, a topic that remains contentious (Simon et al., 2019). This subsection briefly outlines the methods used in this study to estimate the value of avoided fatality and injury risks associated with transitioning from overhead to the statistically safer underground power line configuration. See Supplementary Methods 6 for more details.

#### 2.5.1. Value of fatality risk

Contact with or exposure to electricity is a leading cause of workplace fatalities in the U.S., with an average of 112 deaths annually from 2014 to 2023 (Electrical Safety Foundation International, 2025). Notably, over 40% of these fatalities result from contact with overhead power lines, while less than 1% are attributed to underground lines (Cawley & Homce, 2006; Electrical Safety Foundation International, 2025). This study estimates cause-specific worker fatality rates per customer based on national figures, adjusted for CE's overhead-to-underground line mileage ratio. These rates are then scaled to CE's customer base and normalized by line mileage to yield expected fatalities per line mile.

Public fatality rates are estimated using a public-to-worker electrocution fatality ratio derived from Maryland data (Massey et al., 2018). Although incident patterns vary by state, this approach provides an empirical basis to approximate public risk relative to worker risk. To account for differences in exposure pathways, public rates are normalized by customer counts rather than line mileage: workers' risk is tied to direct contact with infrastructure, which scales with system miles, while public exposure is more closely associated with the number of customers served.

To monetize fatality risk, this study applies the value of a statistical life (VSL), a metric widely used in BCA by researchers and federal agencies (U.S. Environmental Protection Agency, 2024). Importantly, the VSL does not assign a value to life itself but rather to risk and is based on willingness-to-pay (WTP) for marginal reductions in fatality risk (Cropper et al., 2011).[4] The baseline VSL applied is $11.1 million (2023 U.S. dollars) for the year 2022 (U.S. Environmental Protection Agency, 2024). This value is adjusted annually based on projected median household income growth (U.S. Census Bureau, 2024) and an income elasticity of 0.4 (U.S. Environmental Protection Agency, 2024).

[3] As shown in Figure 1, this condition is always met for residential customers but not for business customers. For business customers, the maximum per-customer cost from ICE Calculator 2.0 (corresponding to a 24-hour outage duration) is applied until POET's per-customer cost exceeds this value.

[4] The VSL is typically calculated by scaling an individual's WTP for a small reduction in mortality risk to represent one statistical death. For example, if an individual is willing to pay $10 for a one-in-a-million reduction in fatality risk, the implied VSL is $10 million. Alternatively, if each person in a group of one million individuals is willing to pay $10 to collectively avoid one death, the aggregate WTP similarly implies a VSL of $10 million.

#### 2.5.2. Value of injury risk

Between 2011 and 2020, electricity caused an average of 1,990 workplace injuries annually in the U.S. (Electrical Safety Foundation International, 2025). Expected injury rates per line mile are estimated using the same methodology as for fatalities, assuming that the distribution of causes mirrors those observed in fatal incidents. These are interpolated via customer counts, adjusted for CE's underground line share, and scaled using a public-to-worker injury ratio assumed to be half that of fatalities—reflecting the likely effectiveness of protective equipment in reducing fatality risk more than injury risk among workers.

Injuries are monetized using cost estimates from the Occupational Safety and Health Administration (Occupational Safety and Health Administration, 2024), which include both direct costs (e.g., medical treatment) and indirect costs (e.g., lost productivity, administrative overhead). Worker injuries are assigned both direct and indirect costs, while public injuries are conservatively assigned only direct costs. Between 2015 and 2017, electric shock incidents incurred an average of $201,000 in direct costs and $221,000 in indirect costs per case, for a total of $422,000 per injury (2023 U.S. dollars). These values are adjusted over time for expected changes in median household income using the same income elasticity applied to the VSL.

### 2.6. Utility expenditures

CE's utility expenditures that differ substantially between overhead and underground power lines include both CapEx and OpEx. These encompass upfront installation costs as well as ongoing expenditures such as expected replacements, outage response, forestry management, and several smaller programs. This subsection outlines how these value streams are incorporated into the modeling framework; additional details are provided in Supplementary Methods 7.

#### 2.6.1. Installation costs

It is well established that installing power lines underground is significantly more expensive than overhead construction. Based on data from the Electric Power Research Institute (EPRI), undergrounding a single-phase lateral costs approximately $329,000 per mile in urban areas and $216,000 per mile in rural areas (Tripolitis et al., 2015). Notably, these costs exclude customer services, which are modeled via a separate value stream. As discussed in Supplementary Methods 7, recent pilot projects conducted by CE suggest these estimates are reasonably representative of the company's experience (Consumers Energy Company, 2025). In contrast, the EPRI data indicates that rebuilding these lines overhead costs approximately $131,000 per mile in urban areas and $83,900 per mile in rural areas. Thus, undergrounding is just over 2.5 times more expensive than overhead reconstruction (see Supplementary Table 1 for a cost summary). This study focuses on single-phase laterals—the components of the system that are generally the most affordable to underground and comprise the majority of CE's existing underground system (see Supplementary Table 2).

#### 2.6.2. Failure probabilities and expected replacement costs

Historically, overhead power lines have demonstrated longer service lives than underground lines, primarily due to the latter's exposure to subsurface conditions that can accelerate degradation (1898 & Co., 2024; Tripolitis et al., 2015). This results in two key disadvantages for undergrounding: (1) higher replacement costs and (2) shorter replacement cycles.

For the first point, this study assumes that the cost of replacing failed line miles is 20% lower than the initial installation cost. This assumption is based on EPRI data, which incorporates the cost premium associated with overhead-to-underground conversions relative to new underground builds (Tripolitis et al., 2015). While replacement costs may not perfectly align with those of new builds, they are likely to be substantially lower than the costs of conversions, which involve additional civil and logistical complexities. For overhead lines, the cost assumptions used in both installation and expected replacement value streams are based on new build overhead costs.

To address the second point, the BCAs apply failure probabilities that—together with replacement costs—yield expected value impacts over time. This probabilistic approach enables replacement costs to be distributed based on risk of failure rather than fixed service life assumptions. Failure probabilities are estimated using data from DTE Electric, a peer utility serving a comparable customer base along the eastern side of Michigan's Lower Peninsula (1898 & Co., 2024; U.S. Energy Information Administration, 2024).

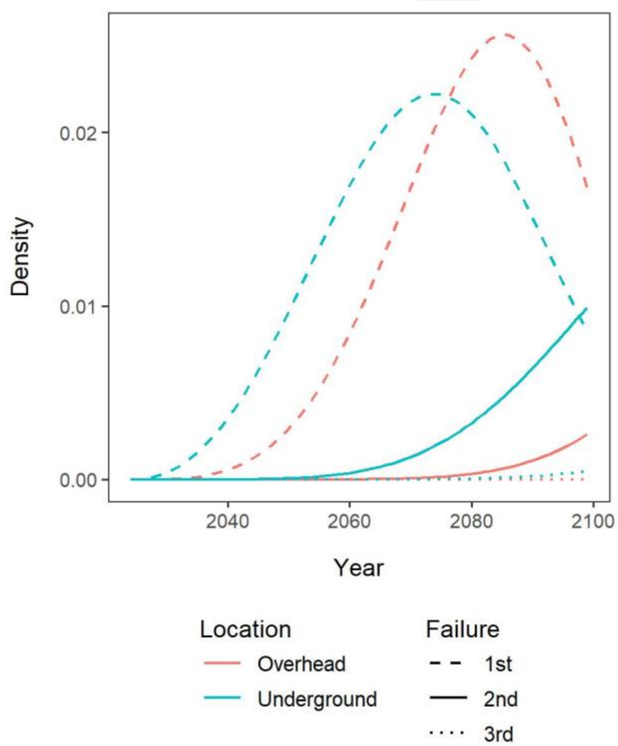


**Figure 2: Failure probabilities for newly installed overhead and underground power lines over time.**

Note: Data are probability density functions derived from Weibull survival curves, calibrated to DTE Electric's asset population (1898 & Co., 2024). Weibull parameters are as follows: shape ($\alpha$) = 4.4, scale ($\beta$) = 65 for overhead; shape ($\alpha$) = 3.2, scale ($\beta$) = 56 for underground. Successive failures are modeled using joint probabilities, which account for the requirement that a prior failure must occur before a subsequent one. Only the first three failure occurrences are shown in the figure; the analysis accounts for up to five failure occurrences (see Supplementary Figure 1). Cumulative failure probabilities by decade for each failure occurrence are provided in Supplementary Table 3.

The model also accounts for the possibility of multiple failures over time by evaluating all combinations of preceding and successive failure years. Specifically, it computes the joint probability of a failure occurring in one year followed by subsequent failures in later years, summing these probabilities across all valid sequences to determine the overall likelihood of successive failures in each year. The probability density functions (PDFs) for the first three failure occurrences are shown in

Figure 2. The analysis considers up to five failure occurrences, with the corresponding PDFs presented in Supplementary Figure 1. Cumulative failure probabilities by decade are provided in Supplementary Table 3.

#### 2.6.3. Outage response costs

CE operates two outage response programs: an OpEx service restoration program and a CapEx demand failures program. While conceptually similar, the latter involves capital-intensive activities such as replacing damaged poles, transformers, or major sections of power lines.

From 2019 to 2023, CE spent an average of $138 million per year on service restoration (Consumers Energy Company, 2024b). Although most outages occurred under blue sky and gray sky conditions, relatively infrequent catastrophic events consumed a disproportionately large share of the budget. During such events, CE quickly exhausts its in-house crews and must rely on higher-cost off-system contractors (Consumers Energy Company, 2024a). Blue sky, gray sky, and catastrophic events accounted for approximately 37%, 23%, and 40% of total restoration costs, respectively (Consumers Energy Company, 2024c).

Over the same period, CE spent an average of $134 million annually on demand failures (Consumers Energy Company, 2023, 2024c). Blue sky, gray sky, and catastrophic events accounted for roughly 64%, 13%, and 23% of these costs, respectively (Consumers Energy Company, 2024c). Two components of this value stream warrant emphasis. First, biennial overhead infrastructure inspections—initiated by CE in 2022—are included in this program (Consumers Energy Company, 2024a). CE estimates these inspections cost approximately $34.3 million per year (Consumers Energy Company, 2023). For modeling purposes, this amount is carved out of blue sky demand failures and treated as a standalone value stream: inspections.

Second, while many value streams in this analysis can be reasonably assumed to operate independently, demand failures and expected replacements are inherently linked. Expected replacement costs reflect typical wear-and-tear over time. While extreme weather clearly influences failure probabilities, quantifying that effect is highly uncertain—particularly given the origin of the data (DTE's asset populations) and the evolving landscape of extreme weather events. In essence, investments in demand failures reduce failure probabilities by replacing aging infrastructure and effectively "resetting the clock." For instance, a 30-year-old asset taken out by a catastrophic storm and replaced through demand failures should no longer be treated as a 30-year-old asset for failure probability modeling, which is a function of age (see Figure 2).

Still, because the demand failures program covers a wide range of assets, it would be an oversimplification to assume that every dollar spent directly offsets expected replacement costs. The interactions between these streams are not explicitly modeled due to the complexity and data intensity required to do so. However, to partially account for overlap between storm-driven capital work and general replacement cycles, the analysis applies a uniform 25% discount to the CapEx value attributed to avoided demand failures. This adjustment reflects the underlying overlap without necessitating asset-level tracking.

To allocate these system-level outage response expenditures to individual circuits, the analysis uses reliability data categorized by outage condition (Consumers Energy Company, 2024c). Two allocation methods are considered. The first assumes costs are proportional to customer-minutes interrupted (CMI), under the premise that longer outages incur higher expenses. The second assumes costs are proportional to customer interruptions (CI), based on the idea that each interruption triggers a relatively fixed cost regardless of duration. Circuit-level expenditures are calculated by averaging the results from both approaches.

Between 2019 and 2023, CE customers experienced approximately 1.32 billion CMI and 2.71 million CI. Blue sky events accounted for 21% of total CMI but 59% of CI; catastrophic events made up 56% of CMI and 18% of CI. Gray sky events contributed 23% to both CMI and CI. Supplementary Table 4 summarizes outage response expenditures by year; Supplementary Table 5 provides CMI and CI data; and Supplementary Table 6 reports unit costs. These unit costs are combined with reliability forecasts (and expected improvements from undergrounding) to estimate future benefits and costs.

### 2.6.4. Forestry management costs

From 2019 to 2023, CE spent an average of $82.5 million annually on forestry management (Consumers Energy Company, 2024a). This funding level supported an approximately 11-year effective vegetation management cycle—more than double CE's new target of a 5-year cycle (Consumers Energy Company, 2025). Since tree contact is a major cause of outages in CE's service territory (Michigan Public Service Commission, 2025), and vegetation management is among the most effective mitigation strategies (The Liberty Consulting Group, 2024), historical spending likely represents a lower bound for future costs, assuming no significant expansion of undergrounding.

Although unit costs may vary modestly with cycle length, they are assumed constant in this analysis. As with outage response costs, forestry management expenditures are allocated to circuits using two methods: a per-mile approach, applying a base cost of $15,300 per overhead mile, and a per-tree approach, applying a base cost of $142 per tree. These methods reflect variation in both circuit mileage and tree density. In practice, actual costs likely fall between these two estimates, as circuits with more trees are typically more expensive to maintain, though not necessarily in direct proportion. Circuit accessibility also influences unit costs: I assume overhead lines located in backlots incur a 33% cost premium in rural areas and a 67% premium in urban areas.

Vegetation management cycles vary by voltage level, which may differ both between and within circuits. For a 7-year effective cycle, CE's three primary voltage classes—4.8 kV, 7.2 kV, and 14.4 kV—correspond to nominal trimming cycles of 9, 7, and 5 years, respectively (Consumers Energy Company, 2024a). To account for these differences, the model employs "effective mile" and "effective tree" approaches, which annualize maintenance needs based on cycle length. For example, a tree on a 7-year cycle is counted as one-seventh of an effective tree per year. This framework enables consistent, smoothed cost allocation across years, regardless of where a given year falls in the trimming cycle.

Supplementary Tables 7 and 8 detail forestry expenditures and unit costs. These values, combined with effective tree and mile estimates (based on a 5-year cycle), support projections of future forestry management costs. Reliability impacts from forestry management changes are addressed separately (see Supplementary Methods 2).

For simplicity, the model assumes no ramp-up period for the 5-year cycle. Any gaps in near-term spending are assumed to be offset by backlog reduction efforts (Consumers Energy Company, 2024a), which are not explicitly modeled in the BCA. Additionally, this module assumes that CE would underground both primary and collocated secondary lines, in line with the company's 2024 pilot projects (Consumers Energy Company, 2025) and consistent with the characterization of undergrounding costs (Tripolitis et al., 2015).

While this analysis applies circuit-level generalizations, greater precision could be achieved by evaluating specific projects. For instance, analyzing a 14.4 kV backlot segment in an urban area targeted for undergrounding could yield more refined cost estimates. However, such granular project-level analysis is beyond the scope of this study, which instead incorporates these characteristics proportionally across circuits.

#### 2.6.5. Other operation and maintenance costs

CE spends approximately $8.69 million annually on the other OpEx programs included in this study (Consumers Energy Company, 2024c). While not exhaustive, the selected programs—corrective maintenance, lines reliability, service calls, and staking—were chosen because their costs differ substantially between overhead and underground infrastructure. Although overhead lines make up 84% of the system, only about 33% of these costs are attributed to overhead assets. The remaining 67% are associated with underground infrastructure, which comprises just 16% of the system.

In this analysis, these other OpEx costs are allocated to circuits on a per-mile basis, separately for overhead and underground segments. Under the "marginal mile" framework employed here, the annual value of this cost stream is defined as the difference between underground and overhead unit costs. In the base case, these are approximately $48.9 per mile for overhead and $552 per mile for underground—resulting in an annual cost premium of just over $500 per underground mile. Supplementary Table 9 provides detailed expenditures and unit costs for each program.

### 2.7. Service drops

Service drops, which deliver electricity from the grid to individual customers, present a distinct consideration in undergrounding decisions. Practically speaking, they are optional components of undergrounding projects. While somewhat unconventional, CE could underground the LVD system while retaining overhead service drops by installing riser poles to maintain connections. Alternatively, CE could either share or fully pass along the cost of undergrounding service drops to customers. This approach is not uncommon and is justified given that service drops are entirely customer-specific and are not shared components of the broader grid. Moreover, customers—not the utility—are responsible for tree trimming around service drops and would therefore be the primary beneficiaries of any long-term savings from avoided trimming.

Another key reason to treat service drop undergrounding as discretionary is the magnitude of the cost. EPRI estimates the cost to underground a single service drop at approximately $3,500—substantially higher than the $1,400 cost to rebuild an overhead drop (Tripolitis et al., 2015). This $2,100 per-customer premium increases total installation costs by more than 50% for the average circuit. Additionally, expected failure rates contribute to lifecycle costs. For consistency, this analysis applies the same failure rate assumptions and cost estimation methodology used for the broader LVD system.

Despite the high upfront cost, undergrounding service drops can yield long-term savings for customers by eliminating the need for tree trimming. This study assumes a mean trimming cost of $300 per cycle, with cycle length aligned to the voltage class that determines the longest interval within the 5-year base case (i.e., every 5.66 years). These mean costs are further adjusted based on tree density and area type, as detailed in Supplementary Methods 8.

### 2.8. Uncertainty analysis

The methods described thus far reflect the base case analysis. However, the modeling framework and value streams used in this study rely on numerous assumptions and input parameters subject to uncertainty. To characterize the influence of these uncertainties, a Monte Carlo simulation is conducted. This approach defines plausible statistical distributions for uncertain inputs and reruns the model across many iterations. Each iteration draws from the defined distributions—either independently or conditionally, depending on inter-variable relationships—and recalculates model outcomes. The result is a probabilistic distribution of key outputs. These defined input ranges also support a sensitivity analysis, which identifies the relative influence of each variable on overall outcomes.

The full uncertainty analysis is described in Supplementary Methods 9. To illustrate the approach, the discount rate is discussed here. Although the base case uses a 3% SDR consistent with MPSC guidance, utility financial planning often uses the weighted average cost of capital (WACC), typically around 6% (ValueInvesting.io, 2025). Some scholars, meanwhile, advocate for a lower SDR, such as 2% (Drupp et al., 2018). This range—2% to 6%—defines the plausible bounds for the discount rate. A PERT distribution—a smoothed version of the triangular distribution that places greater weight on the most likely value—is used, with 3% as the central value (Pouillot & Wiener, 2024).

Many variables follow this same procedure. Others rely on empirical statistics from historical data (e.g., 2019 to 2023) to inform fitted distributions such as the normal. For regression-based inputs, bootstrapping is applied (Efron & Tibshirani, 1994). The choice of distribution and estimation method depends on the structure and characteristics of each variable. Supplementary Table 10 summarizes the inputs included in the uncertainty analysis, along with their associated distributions and parameter values. Supplementary Table 11 summarizes the sensitivity analysis.

## 3. Results and discussion

### 3.1. Reliability improvements from undergrounding

Figure 3 presents results from the reliability regression models used to estimate the effects of undergrounding in this study (see Supplementary Tables 12-19 for full model outputs). Generally consistent with (Larsen et al., 2020), the models show that each one-percentage-point increase in underground line miles is associated with a 0.487% decrease in all-condition SAIFI and a 0.802% decrease in all-condition SAIDI, both statistically significant at the $p < 0.05$ level. These imply a corresponding 0.315% reduction in all-condition CAIDI.

However, these relationships vary notably across outage conditions. Undergrounding is negatively associated with SAIFI under all conditions, with the strongest effect occurring during storm conditions (gray-sky and catastrophic events). Under blue-sky conditions, the effect on SAIFI is smaller but remains statistically significant. A similar pattern holds for SAIDI: undergrounding significantly reduces SAIDI during storm events, while the decrease under blue-sky periods is slight and not statistically significant.

These patterns directly affect CAIDI. When undergrounding reduces SAIDI more than SAIFI, CAIDI improves—as observed under storm conditions. Conversely, when SAIDI decreases less than SAIFI—as in blue-sky conditions—CAIDI worsens. This aligns with operational realities: locating and repairing underground faults typically takes longer under normal (non-storm) conditions.

Overall, the findings are consistent with expectations. Undergrounding provides the greatest reliability benefits during storm events by mitigating exposure to aerial hazards. Modest improvements under blue-sky conditions likely reflect reduced exposure to non-storm-related risks, such as vegetation or wildlife. The slight worsening of blue-sky CAIDI reflects the longer restoration times typical of underground infrastructure. Finally, the smaller CAIDI benefit during catastrophic events, compared with gray-sky conditions, may reflect outage management priorities during high-impact events—for example, utilities focusing first on overhead circuits serving larger customer counts.

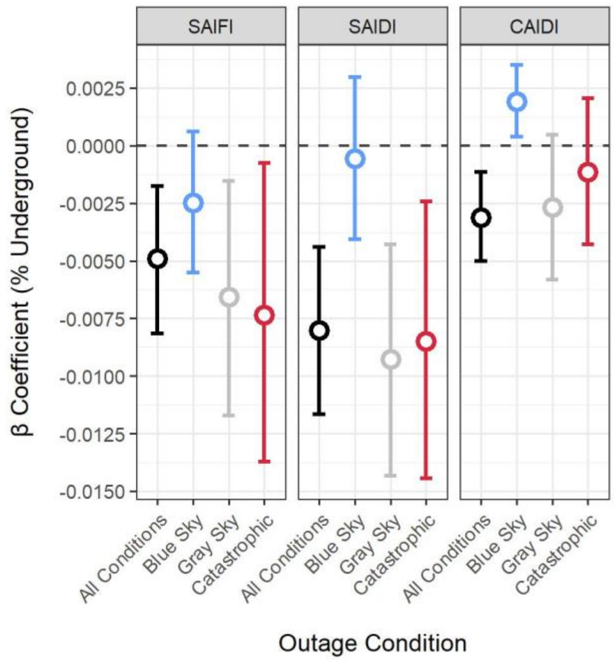


**Figure 3: Reliability improvements from undergrounding by outage condition.**

Note: Results reflect beta coefficients from regressions of circuit-level ln(5-year SAIFI) and ln(5-year SAIDI) on the percentage of circuit miles underground (see Supplementary Tables 12-19). CAIDI beta coefficients are derived from SAIFI and SAIDI coefficients (see Supplementary Methods 4). Each beta represents a $\beta \times 100$ percent change in the reliability metric associated with a one-percentage-point increase in undergrounding. Regressions are run separately by outage condition, as indicated by color. Outage categories are defined by the percentage of customers interrupted: blue sky (≤1%), gray sky (>1% and <10%), and catastrophic (≥10%). Error bars show 95% confidence intervals based on bootstrap resampling.

### 3.2. Average benefits and costs from undergrounding

While the disaggregation of CE's grid for a targeted undergrounding analysis may represent the most novel and important contribution of this work, average results remain useful for conveying baseline outcomes. Accordingly, Figure 4 presents the average "marginal mile" BCA results across circuits. Figure 4a displays the contribution of each value stream—aggregated where appropriate—to the overall BCA using a waterfall plot, where benefits (green bars) add value and costs (orange bars) subtract value, cumulatively yielding the net outcome (blue bar). These value streams comprise the primary SCT. The average result is $300,000 in net benefits, with a benefit-cost ratio (BCR) of 1.9. (Note: net benefits characterize the total value created by a project, while BCRs characterize its cost-effectiveness.) See Supplementary Figure 2 for a similar plot that further disaggregates the value streams shown in Figure 4a.

As shown in Figure 4a, installations and replacements drive most costs, while the primary benefits come from avoided interruption costs—followed by reduced forestry management and, to a lesser extent, outage response expenditures. For detailed breakdowns of benefits and costs, see Supplementary Figures 3 and 4. Figure 4b groups the value streams into four broader categories: CapEx, OpEx, non-market values, and service drops. Service drops are presented separately to reflect their optionality and customer exclusivity, as discussed previously; however, their cost components (construction) align with CapEx, and their benefits (tree trimming) align with OpEx. Figure 4b shows that the majority of costs stem from increased CapEx (61%) and service drop construction (35%), while the largest share of benefits comes from non-market values (68%), followed by avoided OpEx (18%) and service drop tree trimming (9%).

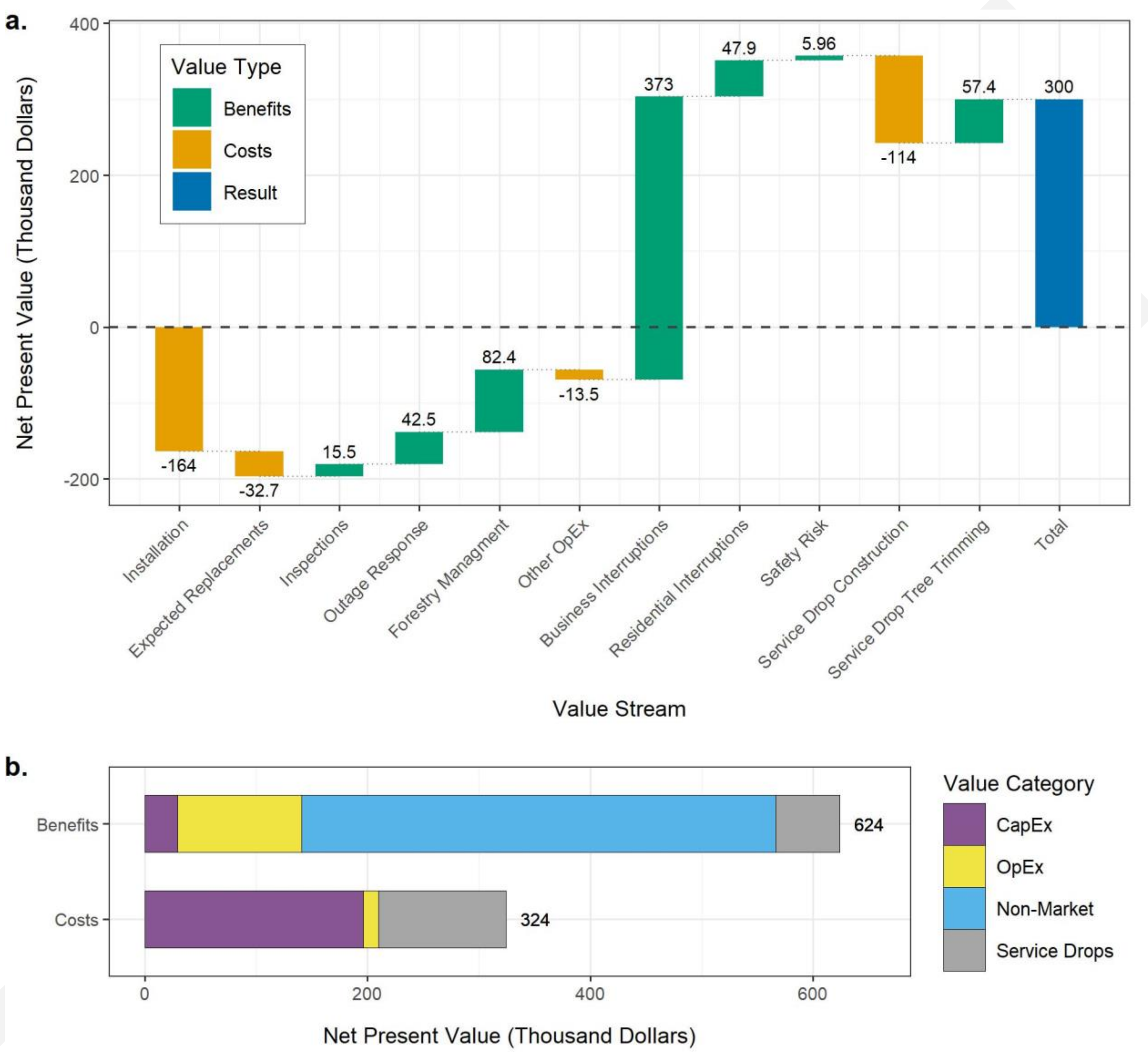


**Figure 4: Average benefits and costs from undergrounding one mile of electric distribution power lines.**

Note: Values are reported in thousands of 2023 U.S. dollars. Results reflect the average benefits and costs across circuits (n = 1,518) using the "marginal mile" approach. Net present values are calculated from 2024 (year 0) through 2074 (year 50), applying a 3% discount rate. **a.** Benefits are shown in green, costs in orange, and net benefits in blue. "Outage Response" includes service restoration and demand failures. "Other OpEx" includes the corrective maintenance, lines reliability, service calls, and staking programs. "Business/Residential Interruptions" reflect the value of lost load. "Safety Risk" captures reductions in both fatality and injury risks for workers and the public. "Service Drop Construction" accounts for initial installations and expected replacements. **b.** CapEx is shown in purple, OpEx in yellow, non-market values in light blue, and service drops in gray. CapEx includes installations, expected replacements, inspections, and demand failures. OpEx encompasses service restoration, forestry management, and other operational expenditures. Non-market values reflect business and residential interruption benefits and safety risk reductions. Service drops cover both construction (aligned with CapEx) and tree trimming (aligned with OpEx).

This breakdown corresponds to non-market benefits of $426,000 and OpEx benefits of $111,000 (or $169,000 including service drops), offset by CapEx costs of $196,000 (or $311,000 with service drops). These shifts have several implications. Undergrounding may be particularly attractive to utilities aiming to enhance reliability and resilience while expanding the rate base on which returns are earned. However, the case may be less compelling for other stakeholders. Although improvements in reliability and resilience are widely valued, undergrounding results in net costs of $69,300 under the secondary UCT—i.e., considering only value streams that directly influence customer rates and excluding non-market benefits, safety, and service drop impacts.[5] Moreover, shifting utility expenditures from OpEx to CapEx increases the cost of service on a dollar-for-dollar basis, due to regulatory returns on capital investments. This does not undercut the case for undergrounding—all assessed costs and benefits are real—but it underscores the need for complementary analyses (e.g., rate impacts and distributional effects) to fully inform decision-making.

The predominance of reliability and resilience benefits prompts a closer examination of how these gains are distributed across different outage conditions. Together, reductions in interruption costs and outage response expenditures account for 74% of total benefits. Figure 5 disaggregates these benefits by outage condition across all reliability-dependent value streams. As expected—given the reliability improvements shown in Figure 3—undergrounding yields substantial benefits by mitigating storm-related impacts and more moderate benefits under blue sky conditions. Although gray sky storms are more frequent than catastrophic events in CE's service territory (see Supplementary Table 20), the total benefits of undergrounding are greatest during catastrophic events because of their disproportionately severe impacts.

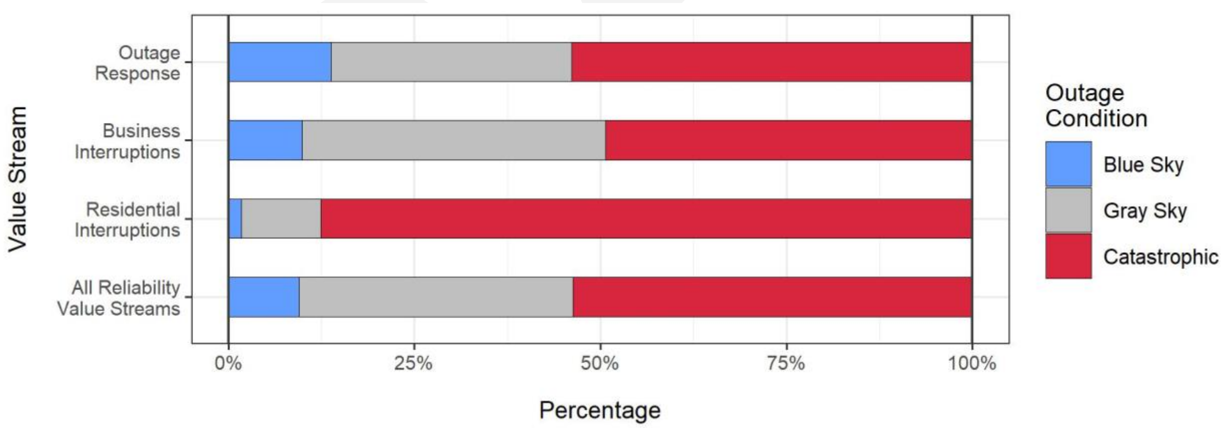


**Figure 5: Reliability and resilience benefits from undergrounding by outage condition.**

Note: Results reflect average benefits across circuits (n = 1,518) using the marginal mile approach. Net present values are calculated from 2024 (year 0) through 2074 (year 50), applying a 3% discount rate. "Outage Response" includes service restoration and demand failures. Outage categories are defined by the percentage of customers interrupted: blue sky (≤1%), gray sky (>1% and <10%), and catastrophic (≥10%). Included value streams all represent benefits and comprise 74% of the total.

[5] Although undergrounding may raise rates, some out-of-pocket costs for customers are likely to decline. Avoided tree trimming for service drops is one clear example, but customers may also save on expenses such as generator fuel, spoiled food during outages, or temporary relocation in extreme cases. These tangible costs should be considered alongside rate impacts when assessing overall value.

Residential interruption benefits, in particular, merit closer attention. About 88% of the residential interruption benefits accrue during catastrophic events—substantially more than for outage response or business interruptions. This discrepancy stems from the valuation tools used in this study: the ICE Calculator and POET. Residential outage costs increase sharply beyond 24 hours, triggering a shift to a resilience regime in which valuation transitions from ICE to POET. Since such prolonged outages occur most often during catastrophic events, undergrounding delivers especially high residential benefits in these scenarios. Notably, the forthcoming Monte Carlo analysis incorporates uncertainty around this threshold, with 50% of simulations reducing it to as little as 8 hours.

### 3.3. Benefits and costs from undergrounding by circuit

The previous section focused on average outcomes across circuits. However, these averages obscure considerable variation—some circuits are significantly better candidates for undergrounding than others. Figure 6a displays BCA results at the circuit level, grouped into percentiles ranked by descending BCR for ease of interpretation. Each percentile presents mean benefits (bars), costs (solid lines), and BCR (dashed line). Primary SCT results are represented by the full bars (gray plus green) and the light orange line, while secondary UCT results are shown as gray bars and the dark orange line. All BCR values correspond to the primary SCT.

Figure 6a underscores the value of a targeted undergrounding strategy. While 72% of circuits yield net benefits and a BCR greater than 1, the most cost-effective opportunities are concentrated in the top percentiles. These high-performing circuits deliver significantly more value per dollar spent, driven largely by higher benefits—particularly those outside the scope of the UCT. In contrast, UCT benefits and costs for both tests vary far less across circuits.

Figure 6b summarizes these findings by presenting net benefits by circuit decile, again ranked in order of decreasing BCR. The top 10% of circuits (decile 1) deliver average net benefits of $1.52 million and a BCR of 5.3. Deciles 2 and 3 also perform well, with net benefits of $708,000 and $418,000 and corresponding BCRs of 3.1 and 2.4, respectively. Together, these top three deciles—representing 456 circuits—are the most economically compelling candidates for undergrounding. In contrast, the remaining deciles exhibit average or below-average results, with deciles 8 through 10 offering limited to no economic justification for undergrounding.

From a purely efficiency-focused perspective—excluding equity or other policy goals—investment should be concentrated in the top decile(s). Notably, Supplementary Figure 5 shows that these top-performing circuits are geographically dispersed across CE's service territory, with strong candidates in both urban and rural areas. While further analysis is warranted for all projects, this provides a clear starting point for identifying high-potential circuits for targeted undergrounding.

Figure 6c expands the analysis by examining which value streams vary most across circuits, using coefficients of variation (CVs)—standard deviations divided by means—as normalized measures. Several value streams remain constant across circuits, but others vary substantially. Reliability-dependent value streams (black bars) exhibit the greatest variability, followed by service drop impacts, forestry management, and—less prominently—installation and replacement costs. While CV highlights relative variability, it does not indicate each stream's contribution to overall BCA variation; for that, absolute variation (e.g., standard deviation) is more informative (see Supplementary Figure 6). An analysis of variance (ANOVA) of the value streams indicates that business interruptions dominate circuit-level variation, accounting for nearly 85% of the total (see Supplementary Note 4).

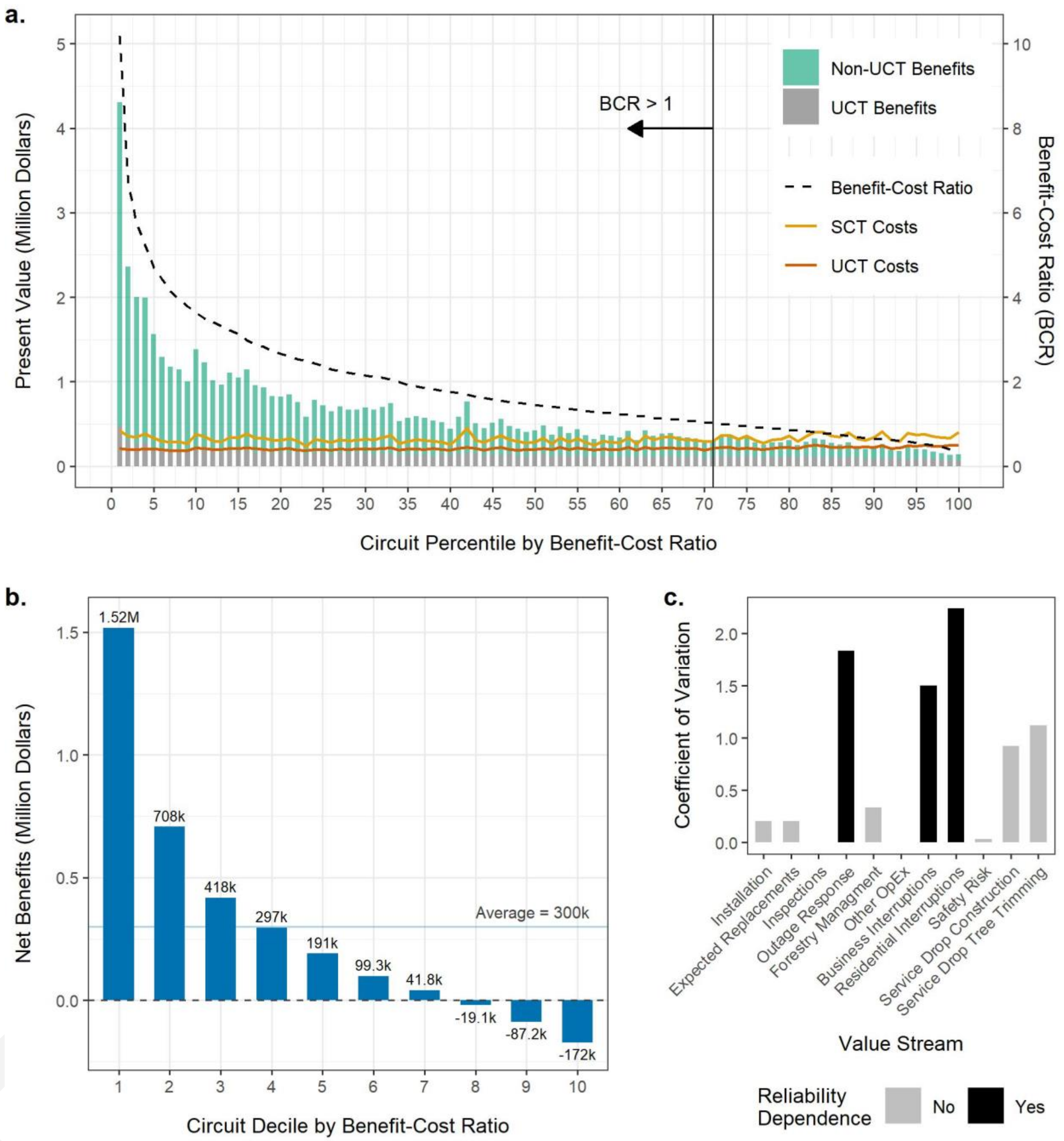


**Figure 6: Circuit-level variation in net benefits from undergrounding one mile of electric distribution power lines.**

Note: Values are reported in millions of 2023 U.S. dollars. Results reflect BCA outcomes across circuits (n = 1,518) using the "marginal mile" approach. Net present values are calculated from 2024 (year 0) through 2074 (year 50), using a 3% discount rate. **a.** Mean benefits, costs, and benefit–cost ratios (BCRs) by percentile, ordered from highest to lowest BCR. Primary societal cost test (SCT) results are shown as full (gray plus green) bars and the light orange line. Secondary utility cost test (UCT) results are shown as gray bars and the dark orange line. All BCR values reflect the primary SCT. Left-side y-axis shows present value for benefits and costs; right-side y-axis shows BCR. **b.** Mean net benefits by decile, ranked by decreasing BCR. The overall mean net benefit ($300,000) is marked for reference. All data characterize the primary SCT. **c.** Coefficient of variation (standard deviation divided by mean) of value stream outcomes across circuits. Black bars denote reliability-dependent value streams; gray bars indicate reliability-independent streams.

A second ANOVA of circuit characteristics further clarifies the drivers of this variation (see Supplementary Note 4 for details). Gray-sky and catastrophic SAIFI are the strongest individual predictors, together explaining roughly 39% of the variation in BCA outcomes. Customer density accounts for an additional 12%. These findings reinforce the central role of reliability in determining undergrounding value. No other variable explains more than 4% of the observed variation, leaving a substantial share unexplained by observable circuit characteristics. This highlights the need for detailed, circuit-specific modeling to capture the complex interactions that shape outcomes—patterns that cannot be adequately represented by simple proxies.

### 3.4. Uncertainty with net benefits from undergrounding

The preceding results reflect base-case outcomes, but it is important to emphasize that the BCAs involve substantial uncertainty. Figure 7 summarizes this uncertainty using three complementary perspectives. All panels reflect the primary SCT; see Supplementary Figure 7 for results under the secondary UCT.

Figure 7a summarizes the results of a Monte Carlo simulation using an empirical cumulative distribution function (ECDF) for average net benefits across all circuits. This curve represents the probability that average net benefits (comparable to the blue bar in Figure 4a) fall below a given value. As shown, net benefits are positive in 95% of simulations, with a 50% chance that average net benefits exceed $357,000. The 95% confidence interval ranges from –$119,000 to $951,000. While each circuit has its own ECDF, the average ECDF presented here offers a high-level summary of uncertainty across the entire system.

Figure 7b shifts the focus to individual circuits. The plot displays how many circuits achieve net benefits in a given share of simulations. The x-axis shows the percentage of simulations (out of 1,000) in which each circuit yields net benefits, while the color scale indicates the circuit's base case SCT BCR decile—mirroring the groupings used in Figure 6b. The results show that 42% of circuits achieve net benefits in at least 90% of simulations, while only 3% do so in fewer than 10%. Overall, 80% of circuits yield net benefits in more than half of simulations. These findings confirm a strong correlation between base case performance and resilience to uncertainty: circuits with a higher base case BCR (shown in green) maintain a higher likelihood of generating net benefits across varied conditions. This robust relationship suggests that prioritizing high-BCR circuits offers the dual advantage of maximizing expected returns and ensuring a high probability of success under uncertainty.

Figure 7c further explores uncertainty through a "one-at-a-time" sensitivity analysis. Each bar shows how average net benefits shift when key input categories are varied across plausible ranges, while all other inputs are held constant. As with Figure 7a, the values reflect average outcomes across all circuits. The net neutral point—where average net benefits fall to zero—is shown as a vertical line at –$300,000. Bars that cross this threshold indicate scenarios where net costs occur on average.

This analysis reveals that three variables have the greatest influence on results:

- The magnitude of reliability improvements from undergrounding (see Figure 3)
- Extreme weather impacts
- The cost differential between underground and overhead construction

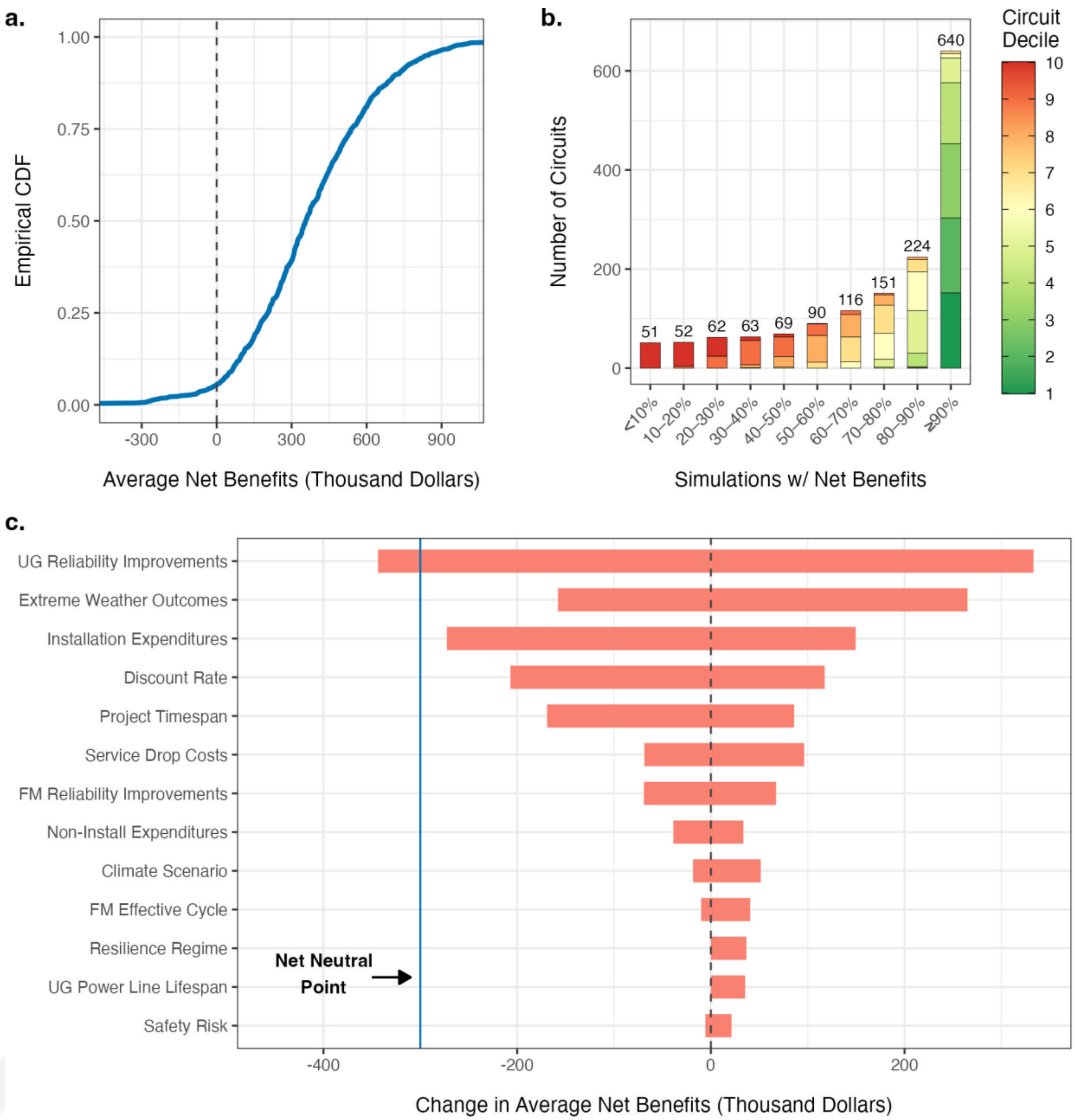


**Figure 7: Uncertainty in net benefits from undergrounding one mile of electric distribution power lines.**

Note: Values are reported in thousands of 2023 U.S. dollars. Results reflect BCA outcomes across circuits (n = 1,518) using the "marginal mile" approach. Net present values are calculated from 2024 (year 0) through 2074 (year 50), using a 3% discount rate. All data characterize the primary Societal Cost Test (SCT). See Supplementary Figure 7 for data characterizing the secondary Utility Cost Test (UCT). **a.** Empirical cumulative distribution function (ECDF) of average net benefits across 1,000 Monte Carlo simulations. **b.** Number of circuits versus the percentage of simulations (out of 1,000) in which net benefits are realized. Color scale denotes base-case SCT BCR decile (mirroring Figure 6b); greener indicates higher BCR and redder indicates lower BCR in the base case. **c.** Change in average net benefits when each of 13 input categories is varied to produce category-level lower- and upper-bound outcomes. Some categories include multiple related variables (e.g., construction and tree-trimming costs for service drops; see Supplementary Table 11). For categories with multiple variables, the combination of variable-level minima and maxima that yields the lowest or highest net benefit is applied. The blue vertical line marks the net neutral point (–$300,000), below which average net costs occur. UG = underground(ing); FM = forestry management.

Only the lower bounds of reliability improvements result in average net costs rather than net benefits. It is worth emphasizing that further research (e.g., project performance) could reduce the uncertainty surrounding this factor. Both reliability improvements and extreme weather have great potential to drive higher average net benefits; however, with the latter, the associated uncertainty is more likely to persist. Results are also substantially influenced by other factors, including but not limited to the chosen discount rate and analysis horizon as well as service drop costs (including both construction and tree trimming). For further details and discussion of this sensitivity analysis, see Supplementary Methods 9.

### 3.5. Benefit-cost analysis of a targeted undergrounding program

This final results section evaluates the benefits and costs of undergrounding ten different circuit portfolios, each comprising 35 line miles across CE's LVD system—approximately equal to the mileage proposed in CE's recent rate case (Consumers Energy Company, 2024a). To promote geographic diversity and equity, each portfolio includes one mile of undergrounding per circuit, totaling 35 distinct circuits.

The portfolios are constructed based on ten different selection criteria. Portfolios 1 and 2 target the most cost-effective circuits according to the highest BCRs under the SCT and UCT, respectively. Portfolios 3 through 7 are random samples drawn from specific BCR deciles under the SCT (see Figure 6b), while Portfolio 8 represents a fully random sample from the complete circuit population. Portfolios 9 through 11 are defined by proxy characteristics that serve as inputs to the modeling framework.

**Table 2: Benefit-cost analysis of undergrounding 35 line miles.**

| Circuit Portfolio | Selection Criteria | Benefits (Million $) | Costs (Million $) | Net Benefits | | Benefit-Cost Ratio |
|---|---|---|---|---|---|---|
| | | | | Overall (Million $) | Per Mile (Thousand $) | |
| 1 | Highest BCR: SCT | 111 (13.3) | 13.2 (6.98) | 98.3 (6.33) | 2,810 (181) | 8.45 (1.91) |
| 2 | Highest BCR: UCT | 115 (16.2) | 17.4 (7.54) | 97.5 (8.64) | 2,790 (247) | 6.61 (2.15) |
| 3 | Random: Top 10% | 50.7 (7.53) | 9.80 (6.67) | 40.9 (0.86) | 1,170 (24.6) | 5.18 (1.13) |
| 4 | Random: Top 30% | 40.8 (6.67) | 10.6 (6.75) | 30.2 (-0.08) | 863 (-2.26) | 3.86 (0.99) |
| 5 | Random: Top 50% | 40.4 (6.38) | 12.3 (7.30) | 28.1 (-0.92) | 803 (-26.3) | 3.29 (0.87) |
| 6 | Random: Bottom 50% | 10.8 (3.87) | 11.4 (7.46) | -0.65 (-3.59) | -18.5 (-103) | 0.94 (0.52) |
| 7 | Random: Bottom 10% | 6.36 (2.86) | 12.5 (8.25) | -6.17 (-5.40) | -176 (-154) | 0.51 (0.35) |
| 8 | Random | 19.0 (4.94) | 10.0 (7.06) | 8.98 (-2.12) | 256 (-60.7) | 1.89 (0.70) |
| 9 | Highest Storm SAIFI | 80.5 (11.6) | 10.8 (6.59) | 69.7 (5.05) | 1,990 (144) | 7.47 (1.77) |
| 10 | Highest Customer Density | 81.4 (11.8) | 26.7 (8.81) | 54.8 (2.97) | 1,560 (85.0) | 3.05 (1.34) |
| 11 | Highest Tree Density | 21.8 (7.10) | 11.2 (7.14) | 10.6 (-0.04) | 303 (-1.24) | 1.95 (0.99) |

Note: Values are reported in 2023 U.S. dollars. Results reflect benefit-cost analysis outcomes across 35 circuits using the "marginal mile" approach. Net present values are calculated from 2024 (year 0) through 2074 (year 50), applying a 3% discount rate. Each portfolio includes one mile of undergrounding per circuit, totaling 35 distinct circuits. Portfolios are defined according to the selection criteria listed. The first value represents results under the primary Societal Cost Test (SCT), which includes all value streams. The second value, shown in parentheses, reflects results under the secondary Utility Cost Test (UCT), which excludes interruption, safety risk, and service drop value streams.

Table 2 summarizes the benefits, costs, net benefits, and BCRs for each portfolio. Targeting the 35 most cost-effective circuits under the SCT (Portfolio 1) yields the highest net benefits—$98.3 million—with a BCR of 8.5. Monte Carlo simulations place the 95% CI for net benefits between $32.2 million and $232 million, with BCRs ranging from 2.9 to 24. The same portfolio also yields net benefits of $6.33 million and a BCR of 1.9 under the UCT, with fewer than 10% of simulations resulting in net costs to the utility. These results underscore the substantial value of targeted investment: the SCT-targeted portfolio produces more than double the net benefits of the top decile portfolio (Portfolio 3) and over ten times that of a random selection (Portfolio 8).

As expected, UCT-based targeting (Portfolio 2) yields greater net benefits and a higher BCR than SCT-based targeting when evaluated under the secondary UCT (see Table 2, values in parentheses). However, it produces lower net benefits and a smaller BCR under the primary SCT. Both targeting strategies nonetheless highlight the potential for substantial gains—under either test—when undergrounding is focused on the highest-performing circuits.

Broader targeting strategies can still deliver meaningful net benefits. Randomized selections from the top 10%, 30%, and 50% of circuits (Portfolios 3-5) yield SCT net benefits of $40.9 million, $30.2 million, and $28.1 million, respectively—though only the top 10% sample produces net benefits under the UCT. Among portfolios guided by proxy variables, prioritizing circuits with high gray-sky and catastrophic SAIFI (Portfolio 9) performs especially well, ranking third overall, followed by customer density (Portfolio 10), which ranks fourth. In contrast, prioritizing tree density (Portfolio 11) offers only marginal improvement over a fully random sample. As anticipated, portfolios targeting less cost-effective circuits (Portfolios 6 and 7) result in net losses and should be avoided. To evaluate uncertainty, Supplementary Figures 8 and 9 show the ECDFs from the Monte Carlo simulations for all portfolios listed in Table 2, illustrating the distributions of overall net benefits under the SCT and UCT, respectively.

## 4. Conclusions

This study demonstrates the economic viability of strategically converting overhead electric distribution lines to underground in CE's service territory in Michigan. On average, undergrounding one eligible mile yields $300,000 in net benefits, with a BCR of 1.9. The bulk of these benefits arise from avoided operating costs and non-market impacts—particularly storm-related business interruptions—while costs are driven primarily by capital expenditures. Although 72% of circuits generate net positive outcomes, the most promising candidates are exceptionally cost-effective: the top 10% of circuits deliver $1.52 million in net benefits per mile and a BCR of 5.3. These high-performing opportunities tend to occur in areas with both high storm-related SAIFI and dense customer bases. A portfolio targeting the most cost-effective one-mile segments across 35 unique circuits is estimated to generate $98 million in net benefits, achieving a BCR of 8.5—without imposing net costs on the utility. These findings suggest that, when implemented selectively and guided by data-driven prioritization, undergrounding can be economically justified.

The modeling developed for this research provides foundational insights into the economic potential of undergrounding CE's distribution lines and establishes a basis for future analyses. For instance, targeting circuits to maximize net benefits under the SCT until net benefits under the UCT fall to zero simulates a rate-neutral program. This strategy—entailing undergrounding 518 unique circuit-miles—is projected to yield $418 million in net benefits. Alternative grid-hardening measures, such as aerial spacer cable and tree wire, represent less expensive options than undergrounding (Consumers Energy

Company, 2024c). However, average underground-only net benefits—reflecting avoided forestry management, fewer inspections, and safety improvements less increased staking—approach $100,000 per mile. In many cases, undergrounding's premium over these alternatives may be justified on that basis alone. Recognizing that residential customers can be particularly vulnerable to rate increases, it may be more prudent to treat business interruption savings as a supplementary benefit rather than a primary rationale. When these savings are excluded, only 21% of circuits produce net benefits. Overall, these findings highlight a range of future policy analysis opportunities for distribution planning within CE's service territory. Additional detail on these high-level analyses is provided in Supplementary Note 5.

Although the modeling is tailored to CE's service territory in Michigan, the underlying framework is adaptable to other utilities with access to comparable data. While this analysis shows that targeted undergrounding is cost-effective for CE, each utility operates under unique conditions, and undergrounding may not always represent the most economical option. Territory-specific modeling remains critical to evaluate the localized costs and benefits of potential investments. This study provides a foundation for other utilities and regulators to assess the economic performance of undergrounding at a granular scale within their own jurisdictions.

This work is not without limitations, many of which are discussed in detail alongside their respective methods within the Supplementary Information. Chief among these is the model's resolution: while undergrounding occurs at the segment level, the analysis is conducted at the circuit level. The model relies on circuit-wide statistics and reliability metrics, yet the benefits of avoided interruptions accrue primarily to customers directly served by undergrounded segments. Several checks suggest this may not introduce significant bias—for instance, the proportion of business customers on single-phase laterals closely mirrors that of the overall system. Nonetheless, it remains important to acknowledge that business interruption benefits, which comprise the largest share of total benefits, may be overstated if a project primarily serves residential customers.

A related limitation is that, aside from accounting for expected replacement value, this study does not incorporate infrastructure age. Rebuilt overhead lines are likely more reliable and resilient than their prior, potentially degraded, states. However, assigning a single age to a segment is challenging, as key components—such as poles, transformers, and conductors—often vary in both age and condition. This complexity is magnified at the circuit level, where variability exists both within and across segments. While this limitation is partially mitigated by the expectation that early-life reliability gains and late-life losses may offset one another over time, the assumption is imperfect. Because the historical reliability data informing the model reflects existing asset ages, future reliability projections could be overestimated in areas where reinvestments change asset conditions, if age does indeed influence reliability. Furthermore, assuming reliability gains and losses balance out is invalid if the analysis period concludes midway through an asset's expected lifespan.

A final limitation worth highlighting is the inherent incompleteness of BCA. Not all relevant benefits and costs can be captured quantitatively. One salient example is the rising risk of wildfire activity in the U.S., to which overhead power lines are a significant contributor. Wildfires impose substantial societal costs through both direct physical damage (Thomas et al., 2017) and smoke-related health impacts (Dennin et al., 2025). Undergrounding distribution lines can meaningfully mitigate this risk (Lawrence Berkeley National Laboratory, 2024). On the cost side, the analysis does not explicitly account for evolving macroeconomic and geopolitical factors that could influence infrastructure costs. Because the model compares undergrounding to rebuilding overhead lines, shared cost changes—such as broad increases in material prices—are partially captured. However, undergrounding is more capital- and material-intensive and relies on components that may be more susceptible to global supply chain disruptions. As a result, it may be disproportionately exposed to these risks, potentially reducing its relative economic attractiveness.

Despite these limitations, this study offers compelling evidence that strategically targeted undergrounding projects can yield substantial benefits. It arrives at a pivotal moment for the U.S. electric grid, as decision-makers face high-stakes choices about how best to modernize infrastructure for a more reliable and resilient future. These decisions will shape long-term outcomes, particularly as extreme weather events become more frequent and society's dependence on electricity continues to grow. In this context, robust, data-driven analysis is essential to ensure that every investment delivers meaningful and cost-effective value. The time for proactive, evidence-based energy planning is now.

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