IEc

The Benefits, Costs, and Economic Impacts of Undergrounding New York's Electric Grid

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INDUSTRIAL ECONOMICS, INCORPORATED

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and

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Chapter 1 | Introduction and Summary

Motivated by recent power outages caused by major storms, New York State Assembly Bill 2330-A, enacted in December 2021, directs the New York State Public Service Commission ("Commission") to study the feasibility and costs of burying (or "undergrounding") all or most of the State's electric, telephone, and internet transmission lines and to deliver a report of its findings to the Governor and State Legislature. The legislature subsequently enacted amendments authorizing the NYS Department of Public Service (DPS) to undertake the study, with the assistance of the New York State Energy Research and Development Authority (NYSERDA). NYSERDA contracted with Industrial Economics, Incorporated (IEc) to assist with the analysis.

This report presents IEc's findings, which are based in part on an analytic framework developed by Dr. Peter Larsen and informed by a broad review of existing literature and utility data.[1] The report summarizes the results of the analysis of the benefits and costs of burying the power lines owned and operated by New York's six investor-owned utilities and PSEG-LI,[2] which make up the majority of the state's electric power transmission and distribution network.[3] The analysis examines the impact of undergrounding on the susceptibility of the electric grid to interruptions in service, the economic benefits of reduced outages, the effect of undergrounding on utilities' capital and operating costs, and other related benefits and costs. It considers benefits and costs from a social welfare perspective, separate from rate impacts. Additionally, it estimates the effect of undergrounding on demand for labor in New York State, as the legislation requires. It also discusses the benefits and costs of undergrounding telecommunication lines but, due to data constraints, does not attempt to estimate the potential magnitude of these impacts.

Key Findings

The analysis indicates that the cost of undergrounding the electric power transmission and distribution lines owned by the utilities would substantially exceed the associated benefits. It estimates the present value of the net loss in social welfare at approximately $261 billion (2023 dollars). This result is consistent across utilities—no individual utility service area would be expected to experience a net social benefit. The degree to which costs outweigh benefits varies by utility service area, with the greatest net loss in New York's less densely populated upstate areas, where the costs of burying many miles of line would yield improved reliability of service for far fewer customers.

The potential impacts of the additional costs of undergrounding on residential electricity bills also varies greatly by utility. In the near term (by 2025), increases in total bills are estimated to range from less than two percent for Con Edison customers to nearly 50 percent for NYSEG customers. By 2055, increases in total bills are estimated to range from approximately 11 percent for Con Edison customers to nearly 200 percent for customers served by National Grid. In dollar terms, the analysis indicates that the costs associated with undergrounding would add $16 per month to the average Con Edison customer's bill in 2055, raising it from $148 per month (as estimated under the "status quo" scenario, without additional undergrounding) to $164 per month. In contrast, the analysis suggests that the costs associated with undergrounding would nearly triple the monthly bill of

[1] Dr. Larsen served as an independent consultant to IEc on this analysis. He is currently Staff Scientist/Leader of the Electricity Markets and Policy Department at the Lawrence Berkeley National Laboratory and a Research Fellow at the University of Montana's Bureau of Business and Economic Research.

[2] For ease of exposition, the six investor-owned utilities and PSEG-LI are collectively referred to as "the utilities" in this report.

[3] Although the language of the bill refers only to transmission lines, the scope of this analysis includes the impacts of undergrounding both transmission and distribution lines. This is consistent with the state agencies' understanding of the legislation's intent.

National Grid's average customer in 2055, raising it from $220 per month to $654 per month. The net cost to National Grid customers would be approximately $434 per month, or more than $5,200 per year.

From an economic perspective, undergrounding is likely to make more sense in the state's more densely populated areas, where the ratio of customers to line-miles – and thus benefits to costs – is generally higher. It is also likely to make more sense in areas that are susceptible to interruptions in service due to extreme weather events, particularly high-wind events such as hurricanes or tropical storms, to which overhead lines are especially vulnerable.

Analytical Limitations

This analysis is subject to several important limitations. Notably, it does not analyze the costs of undergrounding at a high degree of geographic specificity; this may obscure instances in which the costs of undergrounding could vary substantially from the average estimates provided by the utilities. Utility-specific data on transmission and distribution line segments, average costs, and other data are used to account for important differences in costs and benefits between utility service areas, but expanding this analysis to incorporate more detailed information—*e.g.*, costs differentiated by how land is developed, terrain, or other considerations; socioeconomic and/or demographic characteristics of affected customers; and more specific location information on power lines buried—would provide more detailed insights.

An additional limitation is that the analysis considers only the costs and benefits of undergrounding the transmission and distribution networks owned and operated by the seven utilities noted above; it does not consider the benefits and costs of undergrounding transmission and/or distribution lines owned by the New York Power Authority (NYPA), municipal utilities, or rural electric cooperatives. It is likely, however, that the benefits and costs of undergrounding these lines would be similar to those of the seven utilities analyzed—*i.e.*, that the costs of undergrounding these lines would outweigh the benefits.

It is also important to note that this analysis is based on the current configuration of New York's electric grid. It does not consider the potential expansion or contraction of the grid over time, nor does it consider potential changes in the voltage of transmission lines serving the state. Additionally, the analysis of health and safety costs to utility workers is based on the current workforce of each utility, which may change over time and/or increase in size to support undergrounding. Health and safety impacts to persons not employed by the utilities are also not considered. Similarly, the analysis of benefits is based on conditions reflecting the current state of New York's electric grid. The analysis of improved reliability benefits does not consider potential changes in the number of customers served, average annual electricity consumption, distribution of customers by sector, or other factors that affect the benefits of improved reliability. Notably, it does not account for the effect of efforts to reduce greenhouse gas emissions on the extent to which New Yorkers may in the future turn to electricity to power their vehicles or heat and cool their homes, schools, and businesses. This may lead us to understate the benefits of avoiding future interruptions in service. Similarly, the analysis of aesthetic benefits is based on current lengths and voltages of transmission lines and on current property values, without modeling any potential future changes. In addition, the methodology used to calculate aesthetic benefits does not account for where lines are located relative to single family residential properties, nor the proportion of each utility's service area that contains single family residential properties. These factors may offset each other to some degree, but it is not possible to determine whether there is a directional effect on the estimation of aesthetic benefits.

Report Organization

The remainder of this report is organized as follows:

- Chapter 2 provides background information relevant to the analysis of benefits and costs;
- Chapter 3 details the methodology employed in the benefit-cost analysis, and the results of this analysis;

- Chapter 4 presents an analysis of the impact of undergrounding on the demand for labor in New York State, focusing on the direct impacts of an undergrounding initiative on labor requirements;
- Chapter 5 assesses the sensitivity of the benefit-cost analysis to uncertainty in key parameters; and
- Chapter 6 presents an estimate of the potential impacts of undergrounding on residential electricity bills.

Chapter 2 | Overview of New York's Transmission and Distribution System

Electric Transmission and Distribution System

New York State's electric grid is owned and maintained by multiple utilities and authorities.[4] There are seven utilities that, in combination, provide electric power service to most of the state's customers. Six of these utilities are regulated by the Public Service Commission (PSC), which is responsible for overseeing the electric distribution systems of the state's investor-owned utilities. These utilities are (1) Central Hudson Gas & Electric, Inc., (2) Consolidated Edison of New York, Inc. (Con Edison), (3) National Grid, Inc. (doing business as Niagara Mohawk Power Company), (4) New York State Electric and Gas Corporation (NYSEG), (5) Orange & Rockland Utilities, Inc., and (6) Rochester Gas & Electric Company (RGE).

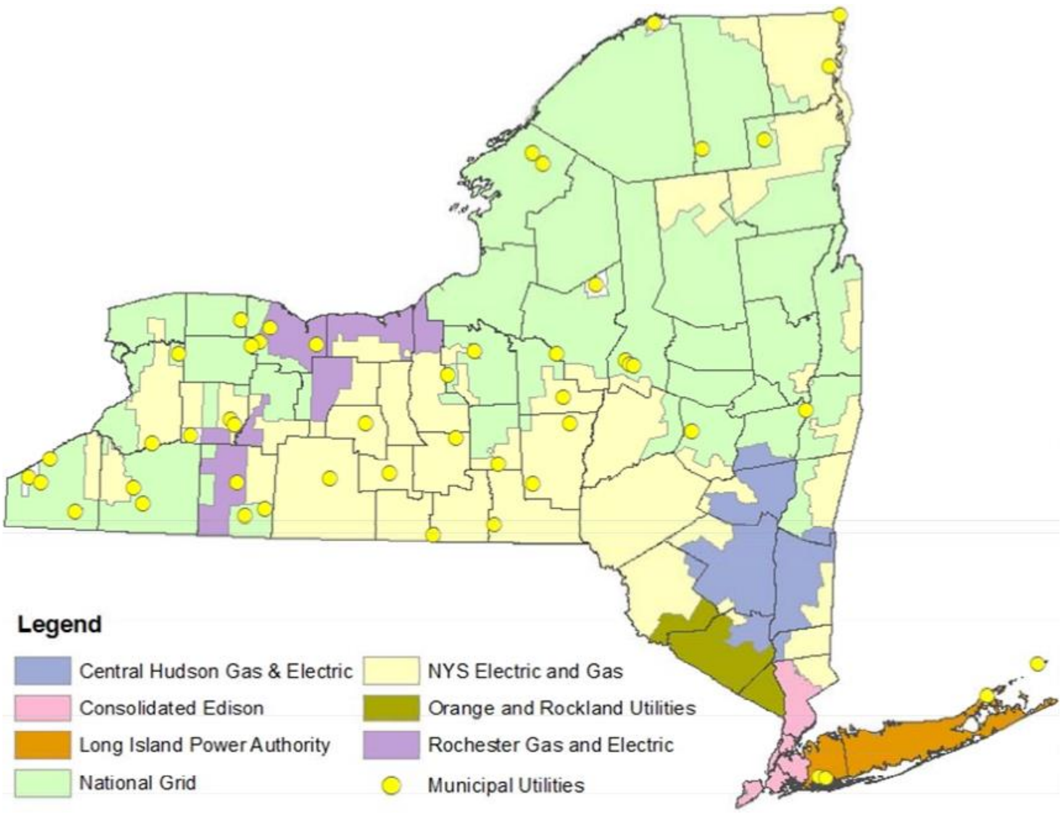
There are also two New York power authorities that are not regulated by the PSC: the Long Island Power Authority (LIPA) and the New York Power Authority (NYPA). LIPA currently contracts with PSEG Long Island (PSEG-LI), a subsidiary of Public Service Enterprise Group, Inc. (PSEG), to manage LIPA's electric system.[5] NYPA generates and delivers power to load-serving entities as well as municipal, industrial, and business customers. NYPA does not itself own any local distribution lines; therefore, any electricity that NYPA generates and sells to customers is distributed through a local utility's distribution infrastructure.

Additionally, there are 49 municipal utilities in New York (many of which are regulated by the PSC because they do not solely receive power from NYPA) and four rural electric cooperatives (which receive power from NYPA and are not regulated by the PSC). Figure 1 illustrates the territories within New York State each utility serves. As the figure indicates, the seven utilities that are the focus of this analysis are responsible for providing service to most of the state.

[4] New York State Energy Planning Board. (2012). "New York State Energy Plan: New York State Transmission and Distribution Systems Reliability Study and Report," p. 9.

[5] Long Island Power Authority, "About LIPA," accessed on April 25, 2023. Available at: https://www.lipower.org/about-us/.

Figure 1. New York Electric Grid[6]

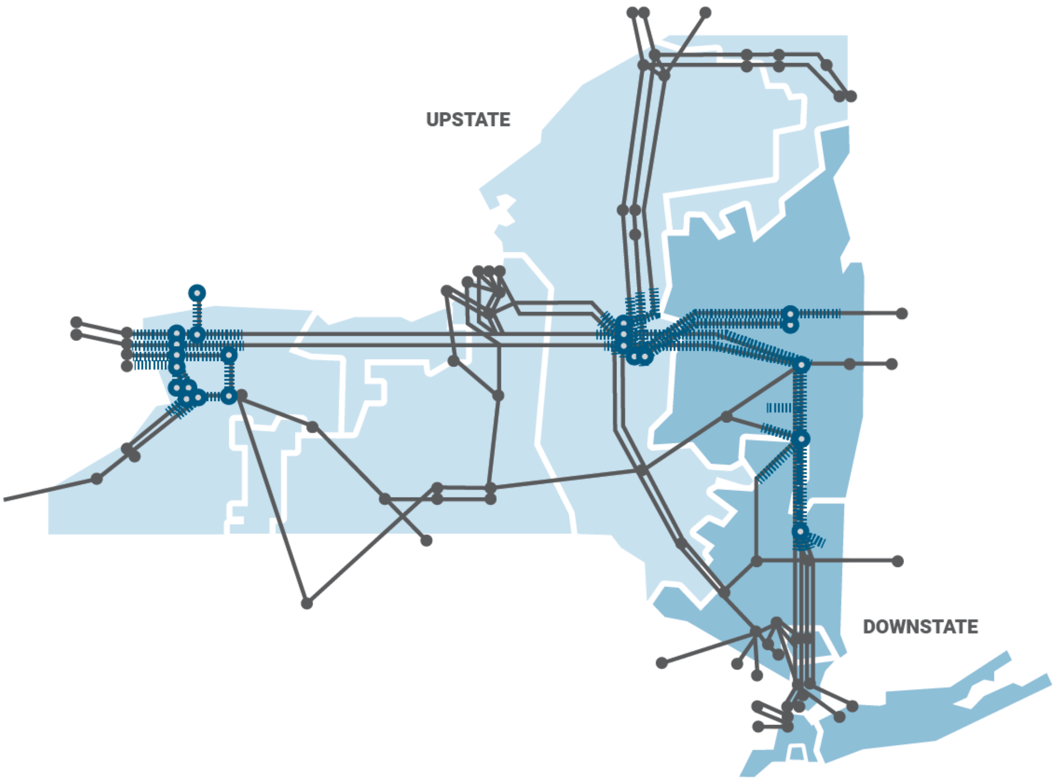


The New York transmission system is made up of about 18,000 miles of transmission lines.[7] Overhead transmission lines account for most of New York's transmission system, totaling approximately 16,000 miles (*i.e.*, nearly 90 percent of the transmission grid). A large proportion of the State's overhead lines (81 percent) is owned by National Grid or NYSEG, the utilities with the largest service areas. Underground transmission lines in New York total approximately 1,700 miles. Figure 2 depicts the New York transmission system.

[6] New York State Energy Planning Board. (2012). "New York State Energy Plan: New York State Transmission and Distribution Systems Reliability Study and Report," p. 10.

[7] Data on miles of lines were provided in response to an information request developed by IEc, in conjunction with DPS and NYSERDA; DPS then distributed the information request and relayed responses to IEc. See Table 1.

Figure 2. New York Transmission System[8]



Utilities distribute electricity to end users through radial or network distribution systems.[9] Radial distribution systems are primarily overhead systems consisting of multiple primary circuits extending radially from a substation connected to the bulk power transmission system. If a circuit fails, customers on that circuit will lose electric service. Network distribution systems are typically underground and found in high-load density metropolitan areas, such as New York City; these systems consist of parallel lower voltage feeder cables, network transformers, and protective relays. If a primary circuit or a network transformer fails, protective devices will automatically operate to isolate the failed component. Network systems are also more reliable than radial systems by design, since radial systems are subject to interruptions caused by tree contact, accidents, and lightning.

As of 2023 the New York Independent System Operator (NYISO) reported that electric generating units in New York provide approximately 37,178 megawatts of available summer capacity and 39,783 megawatts of available winter capacity.[10] Available summer capacity refers to the amount of output generating equipment can supply at the time of summer peak demand, usually from June 1 through September 30, as opposed to winter capacity,

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[8] New York ISO. (2019). "NY Poised to Make Largest Grid Investment in 30 Years." Available at: https://www.nyiso.com/-/ny-poised-to-make-largest-grid-investment-in-30-years.

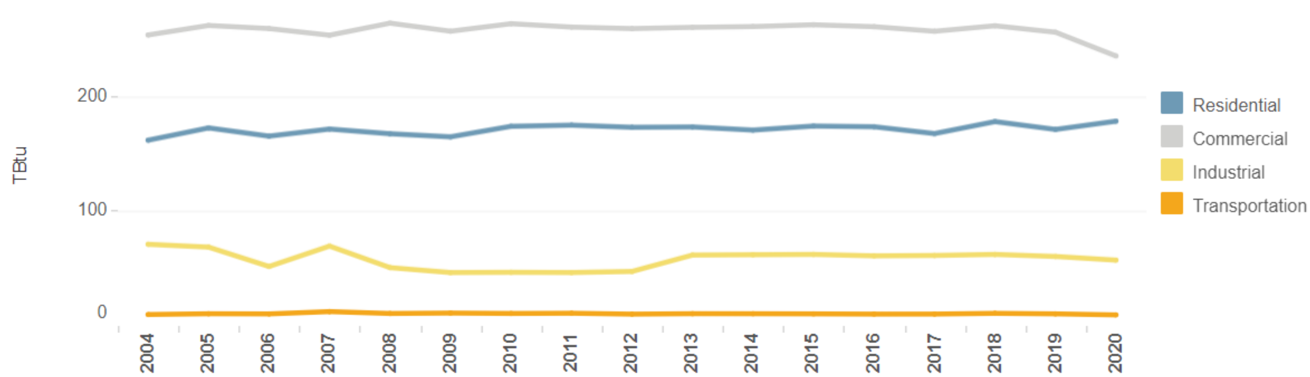
[9] The discussion here is based on New York State Energy Planning Board. (2012). "New York State Energy Plan: New York State Transmission and Distribution Systems Reliability Study and Report," p. 14.

[10] New York ISO. (2023). "2023 Load and Capacity Data Report: Gold Book." Available at: https://www.nyiso.com/documents/20142/2226333/2023-Gold-Book-Public.pdf.

which is the amount of output generators can supply from December 1 through February 28.[11] As of 2021, natural gas, nuclear power, and hydroelectric generators provide more than 90 percent of New York State's electricity net generation.[12]

Utilities are responsible for operating and maintaining their respective electric service distribution systems and for meeting load demands (*i.e.*, the amount of electric power delivered or required at any specific point or points on a system, originating at the consumer.)[13] NYISO also manages load demands through the Special Case Resource Program and the Emergency Demand Response Program. These programs allow NYISO to call on installed demand response providers to reduce load when necessary. Figure 3 illustrates historical electricity demand for New York State by sector. As of 2020 the commercial sector accounted for 49 percent of electricity demand in New York State, followed by the residential sector (37 percent), the industrial sector (12 percent), and the transportation sector (2 percent). In recent years, electricity demand from residential customers has increased slightly, while demand from the commercial sector has fallen. Demand from the industrial and transportation sectors has remained relatively constant.

Figure 3. New York State Electricity Sales to Ultimate Customers by Sector[14]



[11] U.S. EIA, "Net Summer Capacity," accessed on April 27, 2023. Available at: https://www.eia.gov/tools/glossary/index.php?id=net%20summer%20capacity#:~:text=Skip%20to%20page%20content.&text=Net%20summer%20capacity%3A%20The%20maximum,June%201%20through%20September%2030.); U.S. EIA, "Net Winter Capacity," accessed on April 27, 2023. Available at: https://www.eia.gov/tools/glossary/index.php?id=Net%20winter%20capacity#:~:text=Skip%20to%20page%20content.&text=Net%20winter%20capacity%3A%20The%20maximum,December%201%20through%20February%2028).

[12] U.S. EIA. (2022). "New York Profile Analysis," accessed on April 27, 2023. Available at: https://www.eia.gov/state/analysis.php?sid=NY.

[13] The discussion here is based on New York State Energy Planning Board. (2012). "New York State Energy Plan: New York State Transmission and Distribution Systems Reliability Study and Report."

[14] NYSERDA, Patterns and Trends – New York State Energy Profile, accessed on June 2, 2023. Available at: https://www.nyserda.ny.gov/About/Publications/Energy-Analysis-Reports-and-Studies/Patterns-and-Trends.

Reliability

Bulk electric system reliability consists of two primary elements: resource adequacy and transmission operating reliability.[15] Resource adequacy is determined by the capacity of system resources and the ability of those resources to meet demand when and where they are needed. Resource adequacy issues can lead to voltage reductions, public appeals (where regulatory authorities ask consumers to voluntarily reduce their electricity consumption[16]), and rotating feeder outages. Transmission operating reliability depends on the ability to transmit electricity while withstanding various contingencies (*e.g.*, unexpected outages of power generation facilities). Failures of the transmission system can lead to overloads, cascading outages, instability, system separations, and blackouts over widespread areas. These failures can occur without warning and are rarely anticipated. The New York State Reliability Council (NYSRC), NYISO, and New York State transmission-owning utilities conduct reliability and resource planning studies to address these issues. NYISO also collects outage information for all generating units.

The PSC oversees the operations of the distribution systems across New York and monitors the investor-owned utilities to ensure that they are operating in accordance with PSC and statutory requirements.[17] The PSC is also responsible for ensuring that utilities provide safe and adequate electric service. Utilities must collect and submit information on electric service interruptions to the PSC on a monthly basis. This information allows the PSC to calculate two primary performance metrics specific to reliability: the System Average Interruption Frequency Index (SAIFI) and the Customer Average Interruption Duration Index (CAIDI). SAIFI is the total number of annual interruptions for an average customer. CAIDI is the average length of time that a typical customer is without power, or the average interruption duration time.[18] While undergrounding existing lines may reduce the number of interruptions per customer, outages that occur on underground distribution and transmission networks typically take longer to restore and could increase the length of time a typical customer is without electricity.

Interruption Risk

Severe weather is the leading cause of power interruptions in the United States.[19] Regardless of the cause, power interruptions inconvenience residential customers and disrupt local businesses and supply chains.[20] The duration of major power interruptions is increasing.[21] In 2021, U.S. electricity customers experienced, on average, just

[15] The discussion here is largely based on New York State Energy Planning Board. (2012). "New York State Energy Plan: New York State Transmission and Distribution Systems Reliability Study and Report."

[16] Entergy, "Understanding Load Shed," accessed on April 27, 2023. Available at: https://www.entergynewsroom.com/storm-center/restoration/loadshed/.

[17] The discussion here is largely based on New York State Energy Planning Board. (2012). "New York State Energy Plan: New York State Transmission and Distribution Systems Reliability Study and Report."

[18] Sullivan, M., Collins, M. T., Schellenberg, J., & Larsen, P. H. (2018). *Estimating Power System Interruption Costs: A Guidebook for Electric Utilities.* Nexant, Inc. & Lawrence Berkeley National Laboratory.

[19] Executive Office of the President. (2013). "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages," p. 4.

[20] Feng, Kairui, MinOuyang, and Lin, Ning. (2022). "Tropical Cyclone-Blackout-Heatwave Compound Hazard Resilience in a Changing Climate."

[21] U.S. EIA, "U.S. Electricity Customers Averaged Seven Hours of Power Interruptions in 2021." (2022). Accessed at: https://www.eia.gov/todayinenergy/detail.php?id=54639#:~:text=U.S.%20electricity%20customers%20averaged%20seven%20hours%20of%20power%20interruptions%20in%202021&text=On%20average%2C%20U.S.%20electricity%20customers,hour%20less%20than%20in%202020.

over seven hours of electric power interruptions.[22] Power interruptions are also costly, though estimates of the magnitude of these costs vary substantially; a 2013 report by the Executive Office of the President estimated that weather-related interruptions from 2003 to 2012 cost the U.S. an inflation-adjusted annual average of $18 billion to $33 billion.[23] A 2018 study by the United States Department of Energy estimated that power interruptions cost American businesses around $150 billion per year.[24]

Over the past few decades, New York's electric system has been susceptible to major weather events, including Hurricane Irene in 2011, Hurricane Sandy and Nor'easter Athena in 2012, and Tropical Storm Isaias in 2020.[25] These major storm events led to many widespread interruptions, often affecting multiple utilities' networks. After Hurricane Sandy and Nor'easter Athena in the fall of 2012, Con Edison reported that 1.2 million customers experienced interruptions lasting, on average, nearly 94 hours.[26] In 2009, the Edison Electric Institute (EEI) found that 95 percent of power interruption events in New York were caused by hurricanes or tropical storms, summer storms, and winter storms.[27] Localized power interruptions, which affect a few buildings or blocks at a time, also coincide with extreme heat events, thunderstorms, and high winds.[28]

In general, moving electric power lines underground is likely to reduce exposure to weather conditions, thereby reducing the frequency of outages.[29] Undergrounding—especially via a network system, rather than radial system—is also likely to keep more utility customers in service when outages do occur, since underground system failures are typically less widespread than overhead line failures.[30]

Telecommunications System

New York's telecommunications system is made up of many interconnected networks that use wired and wireless technologies to provide voice, texting, video, and data services which play a crucial role in connecting people and businesses. In New York State, multiple agencies are involved in the regulation of telecommunications, including the Federal Communications Commission (FCC) and the New York PSC. The FCC regulates interstate and long-distance telephone service, cellular service, and Internet-based

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22 U.S. EIA, "U.S. Electricity Customers Averaged Seven Hours of Power Interruptions in 2021." (2022). Accessed at: https://www.eia.gov/todayinenergy/detail.php?id=54639#:~:text=U.S.%20electricity%20customers%20averaged%20seven%20hours%20of%20power%20interruptions%20in%202021&text=On%20average%2C%20U.S.%20electricity%20customers,hour%20less%20than%20in%202020.

23 Executive Office of the President. (2013). "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages," p. 3.

24 U.S. Department of Energy. (2018). "Department of Energy Report Explores U.S. Advanced Small Modular Reactors to Boost Grid Resiliency."

25 Office of Long-Term Planning and Sustainability. (2013). "Utilization of Underground and Overhead Power Lines in the City of New York." Available at: https://www.nyc.gov/html/planyc2030/downloads/pdf/power_lines_study_2013.pdf; National Weather Service, "New York Significant Weather Events Archive," accessed on April 27, 2023. Available at: https://www.weather.gov/okx/stormevents.

26 Office of Long-Term Planning and Sustainability, *op cit.*

27 Edison Electric Institute. (2009)."Out of Sight, Out of Mind Revisited, An Updated Study on the Undergrounding of Overhead Power Lines."

28 Dominianni, C., Lane, K., Johnson, S., Ito, K., Matte, T. (2018) "Health Impacts of Citywide and Localized Power Outages in New York City." Journal of Urban Health; Office of Long-Term Planning and Sustainability. (2013). "Utilization of Underground and Overhead Power Lines in the City of New York." Available at: https://www.nyc.gov/html/planyc2030/downloads/pdf/power_lines_study_2013.pdf, p. 9.

29 An exception might be areas prone to flooding, which can contribute to the interruptions experienced during extreme weather events.

30 Hall, Kenneth L., "Out of Sight, Out of Mind: An Updated Study on the Undergrounding of Overhead Power Lines." Prepared for Edison Electric Institute. January 2013, p. 25; Office of Long-Term Planning and Sustainability. (2013). "Utilization of Underground and Overhead Power Lines in the City of New York." Available at: https://www.nyc.gov/html/planyc2030/downloads/pdf/power_lines_study_2013.pdf, p. 15; New York State Energy Planning Board. (2012). "New York State Energy Plan: New York State Transmission and Distribution Systems Reliability Study and Report," p. 14.

telecommunications. The FCC also establishes national telecommunications standards and helps promote best practices for resiliency.[31] The PSC regulates local telephone and cable television services and oversees the operation of telephone corporations and cable companies in New York State, including infrastructure and facilities located in the public right-of-way on utility poles or within underground conduit.

Unlike the electric power system, the telecommunications system in New York is made up of hundreds of interconnected telecommunications service providers, some of whom provide service over their own facilities and some who rely on other telecommunications providers to carry all or parts of their service. Over the last 30 years the New York telecommunications system has evolved from separate copper-based telephone and coaxial-cable television networks operating in exclusively designated service territories and under tight regulatory oversight, to fiber-based and wireless networks capable of offering competitive telephone, texting, video, and high-speed Internet services in all areas of the state. The regulatory environment for telecommunications providers has evolved as competition among them has increased, with the rates charged in today's market determined largely by market forces rather than state oversight.

Like the electric power system, telecommunications systems use networks of cables to deliver telephone and cellular service, cable television services, and Internet services to customers around the state. The telecommunications system is comprised of four main components: critical facilities (*e.g.*, central switching offices, head-ends), cabling, outside-plant equipment (*e.g.*, remote switching offices, cable hubs, cell sites), and equipment located at the end-user office or home.[32] Critical facilities are larger distribution and switching centers that provide connectivity across all major services. Cabling provides the connections from the critical facilities to end-users; cables are either strung overhead via utility poles or run underground through a conduit. Outside-plant equipment helps connect the cables to the larger telecommunications network. Lastly, equipment in homes, offices, and other buildings such as electronic multiplexers or terminals distribute the signal transmitted via cabling from critical facilities to the customer.

Telecommunications system infrastructure is also vulnerable to storm events, including wind damage to aerial cables and poles and flooding.[33] Various components of the system rely on electric power. For instance, some wireless services rely on batteries charged by the electric system to power cell sites; cable and internet services in homes also use commercial electric power provided by the customer. Past storm events have caused significant telecommunications interruptions. During Hurricane Sandy, telephone, wireless, cable, and internet services experienced widespread and long-duration outages, following patterns similar to those the state's electric utilities experienced.[34] Burying telecommunication lines along with electric power lines may reduce outage risks, particularly those due to wind, downed poles, and tree damage .[35]

[31] The City of New York. (2013). "A Stronger, More Resilient New York," p. 164.

[32] Discussion here based on The City of New York. (2013). "A Stronger, More Resilient New York."

[33] *Ibid*.

[34] *Ibid*., p. 166.

[35] Massachusetts Department of Energy Resources. (2014). "Feasibility Study for Undergrounding Electric Distribution Lines in Massachusetts," p.7; McNair, B. and Abelson, P. (2010). "Estimating the Value of Undergrounding Electricity and Telecommunications Networks." The Australian Economic Review, 43, no. 4, 376-88.

Chapter 3 | Benefit-Cost Analysis

Overview of Methodology

Overview

Undergrounding electric power lines involves numerous stakeholders, including utilities, ratepayers, developers, and society at large. This analysis estimates the benefits and costs of fully undergrounding the electric transmission and distribution lines owned by the utilities.[36] Specifically, we compare total benefits and costs under a scenario in which all electric transmission and distribution lines are moved underground over time (referred to as the "UG" scenario) against a baseline scenario in which the placement of electric transmission and distribution lines does not change (referred to as the status quo, or "SQ," scenario). Comparing conditions under these two scenarios provides an estimate of the *incremental* (or net) social benefit of undergrounding relative to the status quo.

The benefit-cost framework employed in this analysis is adapted from one developed by Dr. Peter Larsen, who is currently Staff Scientist/Leader of the Electricity Markets and Policy Department at Lawrence Berkeley National Laboratory.[37] It incorporates data provided by the utilities, including data on individual line segment characteristics (*e.g.*, length, age, lifespan, and voltage), information on capital and operations and maintenance costs, counts of employees and customers, and other information. It also draws upon data from independent research to characterize benefits and costs, including historical reliability indices, costs of short-duration outages, and other benefit and cost parameters.

The benefit-cost model is developed in R—an open-source programming language with a specialized emphasis on statistical computing. Leveraging the computational power afforded by R enables the benefit-cost model to consider replacement decisions on the level of individual line segments, integrate data from multiple sources, and compute additional modeling parameters as needed. Starting from an initial data set of line segment characteristics in 2023 (including type, placement, length, age, and lifespan), the model extends this single-year cross sectional data into the future. In future years, line segments age, incur operations and maintenance costs, and are eventually replaced, at which point capital costs are also incurred. The temporal dimension of the analysis is set so that, in the UG scenario, all electric power lines are moved underground based on the methodology and modeling parameters employed. This analysis, which is conducted for individual line segments, is summarized to the utility level, annually, to allow for straightforward calculations of the costs and benefits of undergrounding (*e.g.*, by computing additional statistics, benefits, or costs that are incurred at the utility level).

As noted in the previous chapter, telecommunications lines may also be placed underground. However, data on the benefits and costs of undergrounding telecommunications lines are not available at a level of detail sufficient to incorporate telecommunications into the benefit-cost analysis framework. A discussion of the potential magnitude of the benefits and costs of undergrounding telecommunications lines is provided at the end of this chapter.

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[36] This analysis examines net benefits and costs in the aggregate, without estimating distributional effects or providing an accounting-level perspective of benefits, costs, or cash flows.

[37] Larsen, P. H. (2016). A method to estimate the costs and benefits of undergrounding electricity transmission and distribution lines. *Energy Economics, 60,* 47-61.; Larsen, P. H., Lawson, M., LaCommare, K. H., & Eto, J. H. (2020). Severe Weather, utility spending, and the long-term reliability of the U.S. power system. *Energy, 198*.

Components of Analysis

The benefit-cost model considers five key impact categories:

- Lifecycle costs (*i.e.*, capital and operations and maintenance expenditures),
- Economic benefits of improved reliability (*i.e.*, the value of improved reliability due to undergrounding),
- Aesthetic benefits associated with moving high-voltage transmission lines underground,
- Environmental costs, and
- Health and safety costs.

For each impact category, the model estimates the difference in magnitude between the status quo and undergrounding scenario. The net benefit of undergrounding is equal to the marginal difference in benefits minus the marginal difference in costs between scenarios. Each of these impact categories is discussed in greater detail in the following sections of this chapter, including the data relied upon and modeling framework used.

All impacts are estimated in monetary terms in 2023 dollars; costs and benefits in future years are then discounted into present value terms using a real discount rate of 4.78 percent.[38] The discount rate reflects the time value of money—*i.e.*, that a given quantity of money is worth more at present than the same quantity would be at a future date, due to opportunities to use that money in other ways in the interim period or a societal preference for immediate utility over future utility. The discount rate is *real* in that it does not *also* adjust for inflation, as all impacts are estimated in constant 2023 dollars, and therefore reflects the time value of money without consideration of inflationary effects on nominal dollar values. Costs and benefits in each year (y) are discounted to their present value by multiplying them by a $DiscountFactor$, calculated as

$$DiscountFactor = \frac{1}{(1+r)^{y-2023}}$$

where the discount rate (r) is equal to 4.78 percent, y is the year in question, and 2023 is the initial year in the analysis.

Sensitivity Analysis

In addition to presenting the primary results of the benefit-cost analysis, the sensitivity of the analysis to uncertainty in key model parameters is evaluated. This sensitivity analysis is conducted via a Monte Carlo framework, in which the main undergrounding analysis (*i.e.*, total benefits and costs under the status quo and undergrounding scenario, and the incremental net social benefit of undergrounding) is run repeatedly while varying certain model parameters. This simulation estimates the range of net benefits if multiple parameters vary simultaneously and independently, reflecting uncertainty around these parameters. The methodology and results of the sensitivity analysis are described in greater detail in Chapter 5.

Network Data

The benefit-cost model is, at its foundation, based on key characteristics of existing transmission and distribution lines, including the length, age, placement, and lifespan of these lines. These data were provided by each utility, specific to their transmission and distribution networks. Additionally, the analysis relies upon utility data related to other analytical parameters, including estimates of the unit cost ($/mile) of replacing and maintaining overhead and underground transmission and distribution lines. These data were provided in

[38] NYSERDA. (2023). "Nominal and Real Discount Rate (NRDR)."

response to an information request developed by IEc, in conjunction with DPS and NYSERDA; DPS then distributed the information request and relayed responses to IEc.[39] Given the uncertainty in changes in the electric power network and customer base over the period of time analyzed, the analysis holds the value of several key parameters constant, including the lengths of transmission and distribution lines required, the number of customers served, and annual electricity demand. While holding these parameters constant may understate some costs and/or omit some benefits, these effects are likely to be small relative to the overall magnitude of the costs and benefits estimated.

Table 1 provides a high-level overview of the network data provided, including the total length of transmission and distribution lines, by type and placement, and the percent of lines underground as of 2023, both by utility and across all seven utilities. As shown, Con Edison's network is already nearly two-thirds underground, and substantial portions of the networks operated by RGE and PSEG-LI are also underground. In contrast, less than 8 percent of NYSEG's network is currently underground, and Central Hudson, National Grid, and Orange and Rockland have almost no underground lines.

[39] New York Department of Public Service. (2022). "Data Requests for Study of Undergrounding Electric Transmission and Distribution Lines. Undergrounding Study Pursuant to 2022 Sess. Law News of N.Y. Ch. 7." Request Nos. DPS-01, DPS-02, DPS-03, DPS-04, DPS-05, DPS-06, and DPS-07.

Table 1. Electric Transmission and Distribution Network Characteristics

Category	Central Hudson	Con Edison	National Grid	NYSEG	Orange and Rockland	RGE	PSEG-LI	Total
Line miles by type and placement								
Overhead transmission	558	393	8,649	4,485	363	708	991	16,147
Underground transmission	15	682	233	63	12	307	424	1,737
Overhead distribution	8,713	3,895	44,412	30,554	5,870	5,931	8,979	108,353
Underground distribution	64	7,405	184	2,945	0	2,238	4,922	17,758
Total	**9,350**	**12,375**	**53,478**	**38,047**	**6,245**	**9,184**	**15,316**	**143,996**
Percent of line miles underground								
Transmission	2.6%	63.5%	2.6%	1.4%	3.2%	30.3%	30.0%	9.7%
Distribution	0.7%	65.5%	0.4%	8.8%	0%	27.4%	35.4%	14.1%
Overall	**0.8%**	**65.4%**	**0.8%**	**7.9%**	**0.2%**	**27.7%**	**34.9%**	**13.5%**

Figure 4 provides a graphical depiction of the age of each utility's distribution network, with age (in years) on the horizontal axis and length of line (in miles) on the vertical axis. The distribution of line miles by age varies somewhat across utilities. Central Hudson, NYSEG, RGE, and especially National Grid show densely clustered distributions around a single line age (approximately 40 to 50 years old). In contrast, Orange and Rockland's network shows a more normal distribution, with greater lengths of line in the center of its distribution (around 50 years old) and lesser lengths at the extremes. PSEG-LI's network is relatively evenly distributed by age, while the distribution for Con Edison is bimodal, with a high concentration of lines that are approximately 25 years old (primarily underground lines) and a somewhat lower concentration of lines around 100 years old (primarily overhead lines).

Figure 4. Distribution Line Ages, by Utility

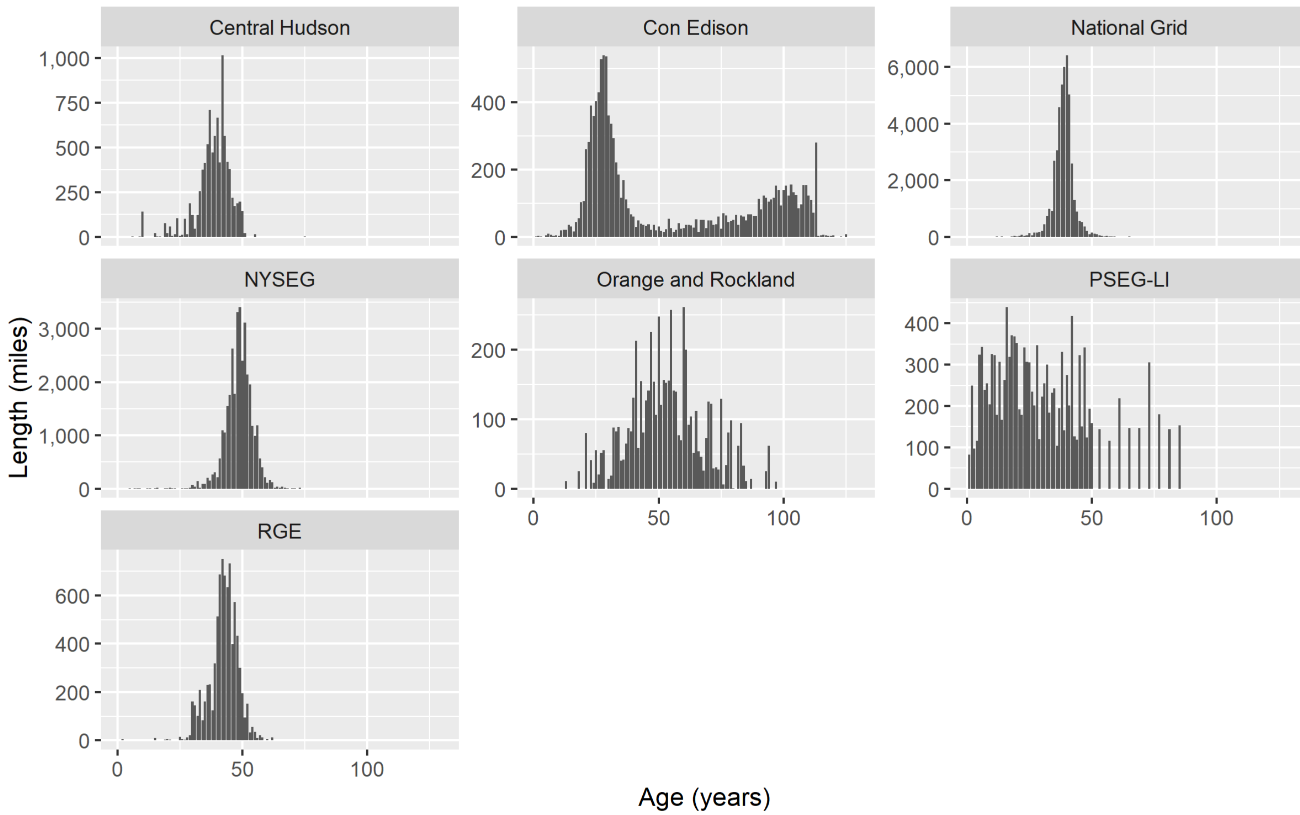
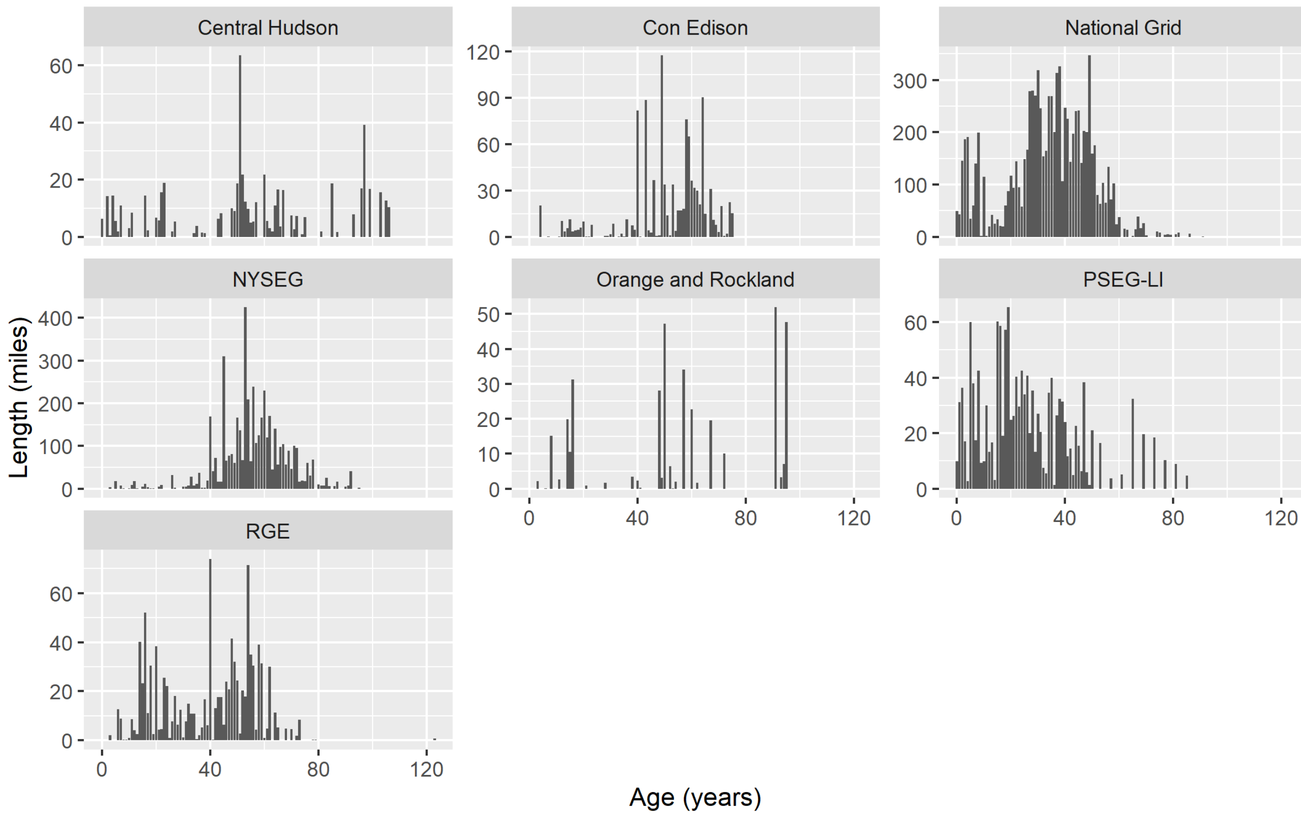


Figure 5 provides the same graphical depiction for each utility's transmission network. Unlike distribution lines, transmission line ages are more evenly distributed for all utilities.

Figure 5. Transmission Line Ages, by Utility



The age distribution of electric power lines, along with their expected lifespans, provides a basis for projecting the length of line due to be replaced in future years. Utilities with a more uniform distribution of line ages—for example, PSEG-LI—would, in the absence of any constraint on replacement decisions, face relatively steady demand for line replacement. In contrast, utilities with more densely clustered distributions of line ages—*e.g.*, National Grid, with one cluster, or Con Edison, with two clusters—would face uneven demands, with periods of intense replacement activity whenever a large percentage of lines reach the end of their useful life. As discussed below, these considerations have important implications for construction of the status quo and undergrounding scenarios, particularly the estimated timing of line replacement costs.

Lifecycle Cost Modeling

Estimating lifecycle costs involves two key steps: first, specifying when line segments are assumed to be replaced, and second, estimating the costs associated with replacement (when applicable) and ongoing operations and maintenance (O&M). As described above, this analysis constructs a dataset of individual line segments as a starting point, with information on line length, type, current placement (overhead or underground), age (as of 2023), expected lifespan, and voltage. This dataset is then used to model replacement decisions and associated costs over the analysis period.

Replacement Decision

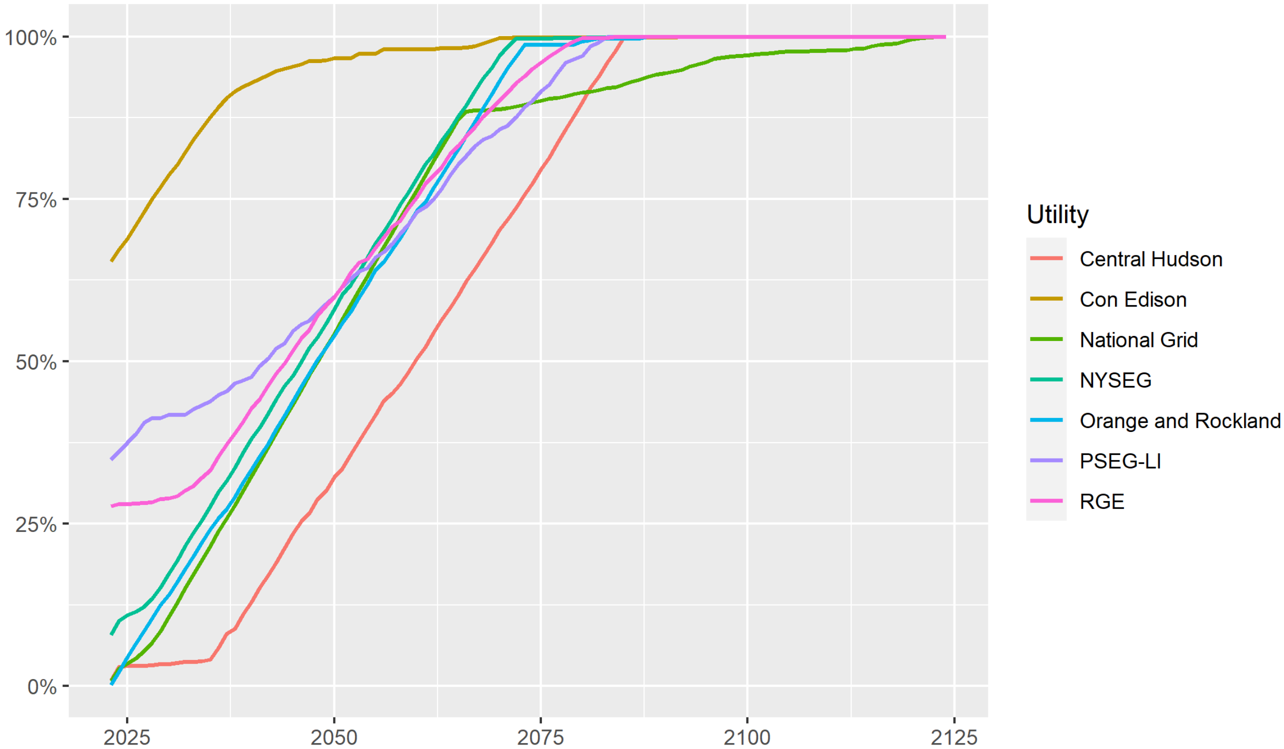
To model the replacement decision, the age of each individual line segment is evaluated over time, and a determination is made as to whether each line segment needs to be replaced given its age and expected lifespan. Expected lifespans differ by line type, placement, and voltage, ranging from 40 to 100 years for transmission lines and from 40 to 80 years for distribution lines. The distribution of line ages as of 2023 and the expected lifespans of those lines indicates that a large percentage of lines are due to be replaced in a relatively short period of time, raising concerns about the feasibility of adhering to a replacement schedule based strictly on the age of each line segment. The analysis therefore imposes a constraint on the percentage of each utility's transmission and distribution network that can be replaced in a single year. This constraint—set at 2.25 percent of the total length of the utility's network—allows each utility to replace its lines over the course of the analysis, but at a more realistic rate. The replacement decision is summarized by the following steps:

1. Increase the age of all line segments with each successive year.
2. Determine which line segments are due to be replaced in a given year ($Age = Lifespan$).
3. Prioritize replacement by line age, then by line length.
4. Calculate the cumulative length of lines in need of replacement, as a percentage of overall network length.
5. Flag the line segments identified by the prior steps that are cumulatively beneath a 2.25 percent threshold of total network length for replacement; model these segments as undergoing replacement.
6. For line segments that are replaced, reset line age to 0; in the undergrounding scenario, change line placement from overhead to underground.

As discussed in the following section, the analysis estimates the capital costs associated with line replacement on an annual basis, based on the length and placement of each segment to be replaced. If more than 2.25 percent of a utility's network, by length, is due for replacement, line segments not identified for replacement based on the prioritization in step 3 above will remain; these lines then become eligible for replacement in the subsequent year(s).

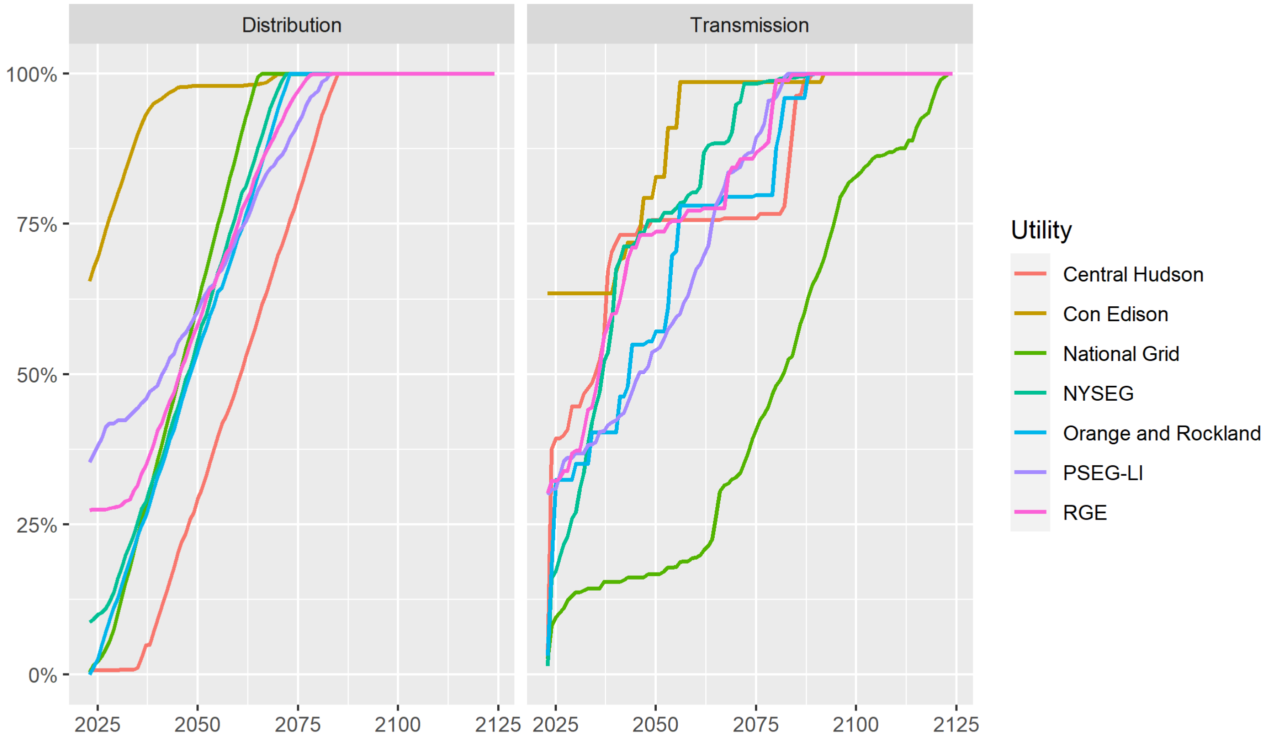
In the undergrounding scenario, lines are moved underground at a consistent rate for most utilities as lines reach the end of their useful lifespan, as shown in Figure 6. Utilities with a more balanced distribution of line ages (Con Edison and PSEG-LI) and with less of their overall network to move underground (*i.e.*, those starting with a higher share of lines already underground) exhibit a more gradual progression towards a fully underground network.

Figure 6. Percent of Distribution and Transmission Line Miles Underground, by Year and Utility



As shown in Figure 7, our modeling of line replacement decisions leads to conversion of overhead to underground lines at a more consistent rate for distribution lines than transmission lines. The conversion of transmission lines from overhead to underground is projected to occur more gradually and sporadically, consistent with the longer expected life of the lines in the transmission network.

Figure 7. Percent of Line Miles Underground, by Year, Utility, and Line Type



As shown in Table 2, under the UG scenario, our modeling of replacement decisions results in all utilities except National Grid having fully underground transmission and distribution networks by 2092. Due to the expected lifespan estimates for its high-voltage transmission lines and the current age of those lines, the analysis estimates that National Grid's network would not be fully underground until 2123. The threshold of 90 percent of electric power lines placed underground is projected to be met earlier – no later than 2081 for any of the seven utilities, and as early as 2037 for Con Edison.

Table 2. Undergrounding Milestones under the UG Scenario

Utility	50 Percent Underground	75 Percent Underground	90 Percent Underground	100 Percent Underground
Central Hudson	2060	2073	2081	2089
Con Edison	2023	2029	2037	2092
National Grid	2049	2060	2075	2123
NYSEG	2047	2059	2067	2090
Orange and Rockland	2048	2062	2069	2090
PSEG-LI	2042	2063	2074	2083
RGE	2045	2060	2070	2088

Costs

A critical component of this benefit-cost analysis is the total capital and O&M costs associated with the utilities' transmission and distribution networks, in both the status quo and undergrounding scenarios. Each year, all line segments incur O&M costs. Capital costs are incurred only in years when line segments are replaced. Capital costs are further divided into replacement costs (*i.e.*, capital costs for replacing lines without changing their placement) and new construction costs (*i.e.*, those incurred for converting from overhead to underground lines).

O&M Costs

The analysis estimates O&M costs for each line segment in every year of the analysis, as shown in the equation below:

$$OpEx_s^{Scenario} = \sum_{y=2024}^{2123} OMCostPerMile_{utp} \times Length_s \times \alpha_{sy} \times DiscountFactor$$

where:

- $OpEx_s^{Scenario}$ represents total O&M expenditures, in present value terms, incurred for a specific line segment (s), in a specified scenario ($Scenario$), over the entire analysis period;
- $OMCostPerMile_{utp}$ represents the per-mile O&M costs for line segments of a specified type (t) and placement (p), by utility (u), corresponding to the type, placement, and ownership of the line segment in question;
- $Length_s$ indicates the length of the individual line segment (s); and
- α represents a scaling factor used to increase O&M costs based on the age of the line (described below).

Per-mile O&M cost estimates were provided by the utilities in response to DPS' information request. These costs vary by utility, line type (transmission vs. distribution) and line placement (overhead vs. underground). In cases where a utility did not provide a cost estimate for a specific line type and placement, the average cost for lines of that type and placement, based on the responses provided by all other utilities, serves as the cost estimate.

As shown in Table 3, annual O&M costs per mile range from $900 to $36,000 for distribution lines and $4,000 to $100,000 for transmission lines, depending on line placement.

Table 3. Range of Utility-Provided O&M Costs per Mile

Line Type and Placement	Minimum O&M Cost per Mile	Maximum O&M Cost per Mile
Overhead Transmission	$4,000	$37,000
Underground Transmission	$4,000	$100,000
Overhead Distribution	$1,700	$22,000
Underground Distribution	$900	$36,000

As an adjustment to the cost estimates provided by the utilities, O&M costs also increase over time based on the age of the line, as described in the following formula:[40]

$$\alpha_{sy} = (7\% * (Age_s)^{0.6}) + 1$$

where:

- α_{sy} is the O&M age scaling factor, by line segment (s) and year (y); and
- Age_s is the age of the line segment.

This adjustment increases the O&M costs assigned to each line segment by a base value of 7 percent per year of the line's age. The line age is raised to the power of 0.6 to dampen this increase over time, resulting in an approximate doubling of O&M costs by the time a line reaches 85 years of age.[41]

O&M expenditures are summed across line segments to provide total O&M expenditures for each utility (u), by scenario:

$$OpEx_u^{Scenario} = \sum_s OpEx_s^{Scenario}$$

Capital Costs

In contrast to O&M costs, capital costs are only incurred in years when a line segment is replaced, as shown in the following formula:

[40] This approach is consistent with the methodology employed by Larsen, P. H. (2016). A method to estimate the costs and benefits of undergrounding electricity transmission and distribution lines. *Energy Economics*, *60*, 47-61.

[41] $1 + (0.07 * 85^{0.6}) = 2.00635$.

$$CapEx_s^{Scenario} = \begin{cases} \sum_{y=2024}^{2123} CapitalCostPerMile_{utp} \times Length_s \times DiscountFactor, & if\ (Repl_{sy} = True) \\ 0, & if\ (Repl_{sy} = False) \end{cases}$$

where:

- $CapEx_s^{Scenario}$ represents the total capital expenditures, in present value terms, incurred for a specific line segment (s), in a specified scenario ($Scenario$), over the entire analysis period;
- $CapitalCostPerMile_{utp}$ represents the per-mile capital costs for line segments of a specified type (t) and placement (p), by utility (u), corresponding to the type, placement, and ownership of the line segment in question (s);
- $Length_s$ indicates the length of the individual line segment (s); and
- $Repl_{sy}$ is a logical (True/False) variable indicating whether the line segment is replaced in a given year (y), based on the replacement decision methodology discussed in the preceding section.

Utilities provided capital cost estimates for both new construction and for replacement. As with O&M costs, capital costs per mile vary substantially across line types and placements, and by utility. As shown in Table 4, capital expenditures on transmission lines range from $930,000 to $32 million per mile, and from $120,000 to $7.2 million on distribution lines.[42]

Table 4. Range of Utility-Provided Capital Costs per Mile

Line Type and Placement	Minimum Capital Cost per Mile – New Construction	Maximum Capital Cost per Mile – New Construction	Minimum Capital Cost per Mile – Replacement	Maximum Capital Cost per Mile – Replacement
Overhead Transmission	$1,300,000	$11,000,000	$930,000	$7,300,000
Underground Transmission	$7,200,000	$32,000,000	$3,600,000	$23,700,000
Overhead Distribution	$120,000	$3,600,000	$430,000	$3,600,000
Underground Distribution	$4,000,000	$7,200,000	$3,600,000	$7,300,000

Capital expenditures are summed across line segments to provide total capital expenditures for each utility (u), by scenario:

$$CapEx_u^{Scenario} = \sum_s CapEx_s^{Scenario}$$

Finally, O&M and capital expenditures by utility are summed to estimate total lifecycle costs for each utility (u) in both scenarios:

[42] These cost estimates do not encompass all capital expenditures associated with undergrounding. For example, they do not reflect the costs of removing existing overhead infrastructure or converting the service entrances at each customer's property to an underground connection.

$$LifecycleCost_u^{Scenario} = OpEx_u^{Scenario} + CapEx_u^{Scenario}$$

Value of Improved Reliability

Method Overview

By reducing exposure to severe weather, undergrounding electric utility infrastructure is expected to reduce the frequency of power interruptions, as well as the costs attributable to those interruptions. To estimate the avoided interruption costs in the undergrounding (UG) scenario relative to the status quo (SQ) scenario, this analysis:

1. Projects the impact of undergrounding on the reliability of each utility's service over time, as measured by standard indices of service reliability.
2. Enters the projected reliability index values into the U.S. Department of Energy's Interruption Cost Estimate (ICE) Calculator, which generates interruption cost estimates for each scenario.
3. Calculates the value of improved reliability by subtracting the net present value (NPV) of projected interruption costs in the UG scenario from the NPV of projected interruption costs in the SQ scenario.

Reliability Modeling

The analysis relies on three standard metrics to characterize the reliability of electric utility service: the System Average Interruption Duration Index (SAIDI); the System Average Interruption Frequency Index (SAIFI); and the Customer Average Interruption Duration Index (CAIDI). SAIDI is the total annual duration of interruptions for an average customer; SAIFI is the number of annual interruptions for an average customer; and CAIDI is the length of time that a typical customer's interruption lasts, or the average interruption restoration time.[43] Historical data on SAIDI, SAIFI, and CAIDI from NY DPS Reliability Reports from 2007 to 2021 are used to establish a baseline from which future reliability index values can be estimated. Consistent with the purposes of this analysis, we rely on indices that include interruptions during "major storm events."[44] Figure 8 presents historical trends in SAIDI over time for each utility; Figure 9 presents trends in SAIFI; and Figure 10 presents trends in CAIDI.

[43] Sullivan, M., Collins, M. T., Schellenberg, J., & Larsen, P. H. (2018). *Estimating Power System Interruption Costs: A Guidebook for Electric Utilities.* Nexant, Inc. & Lawrence Berkeley National Laboratory.

[44] State of New York Department of Public Service. (2012). *2011 Electric Reliability Performance Report.*; State of New York Department of Public Service. (2017). *2016 Electric Reliability Performance Report.*; State of New York Department of Public Service. (2022). *2021 Electric Reliability Performance Report.*

Figure 8. Historical SAIDI, by Utility, 2007-2021, Including Major Storm Events

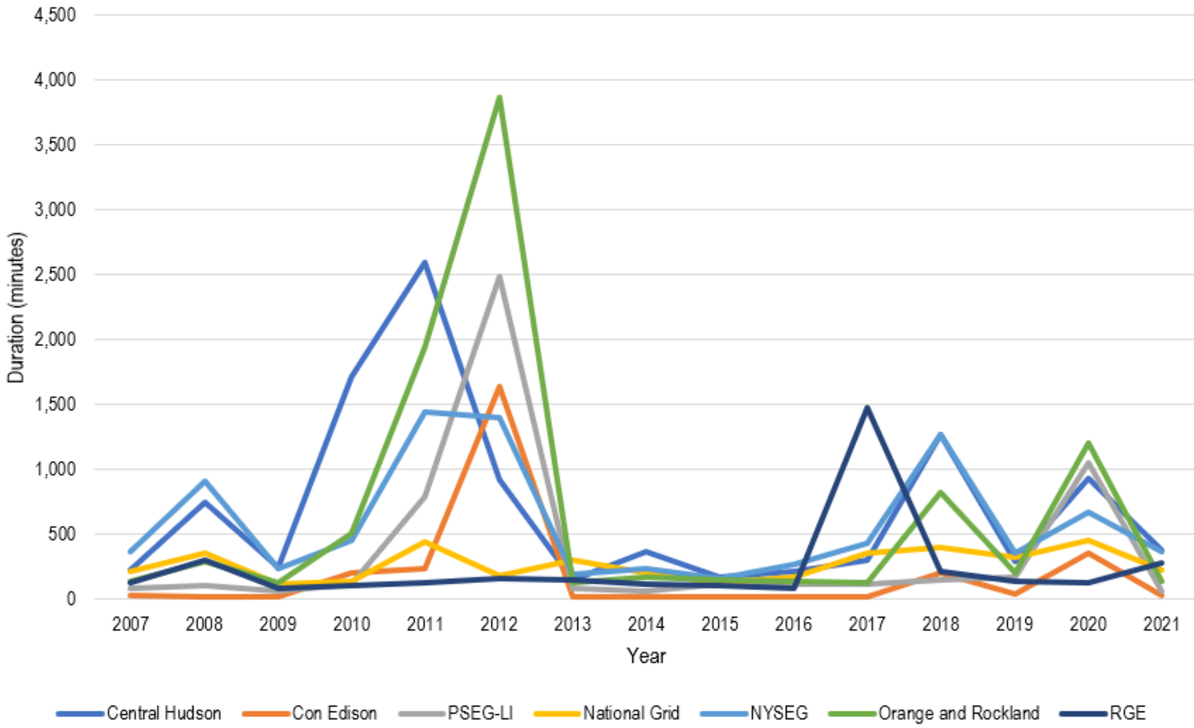


Figure 9. Historical SAIFI, by Utility, 2007-2021, Including Major Storm Events

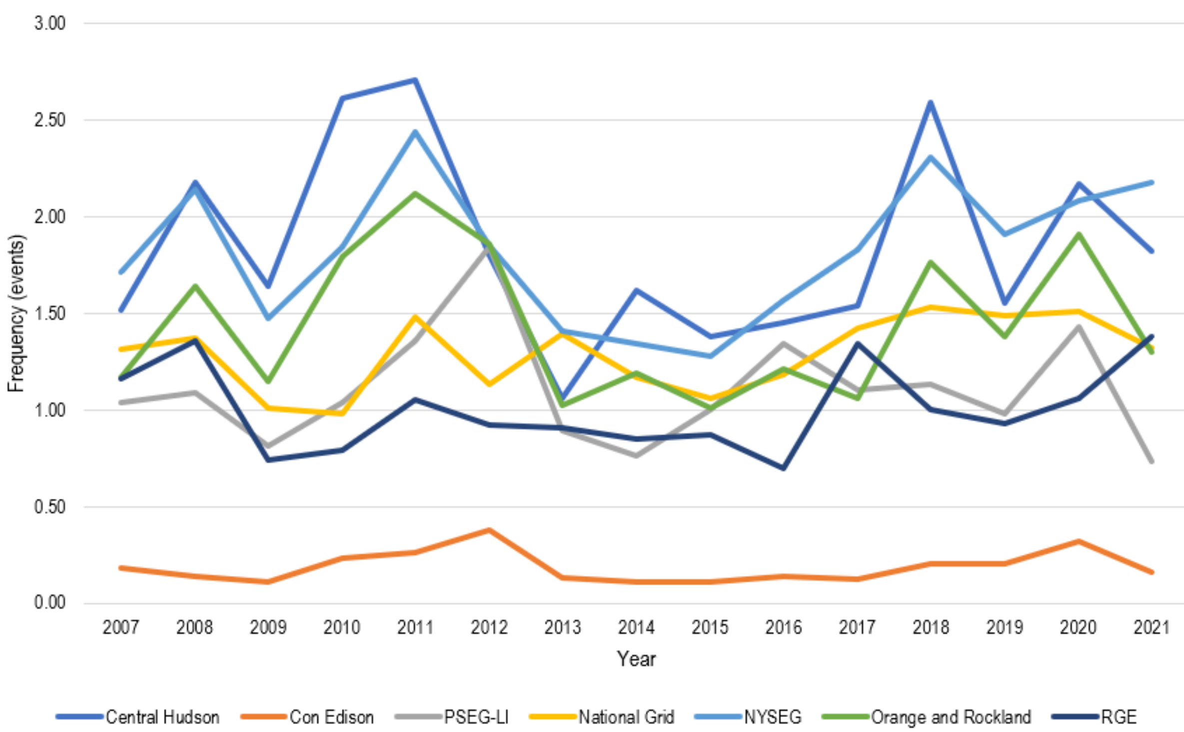
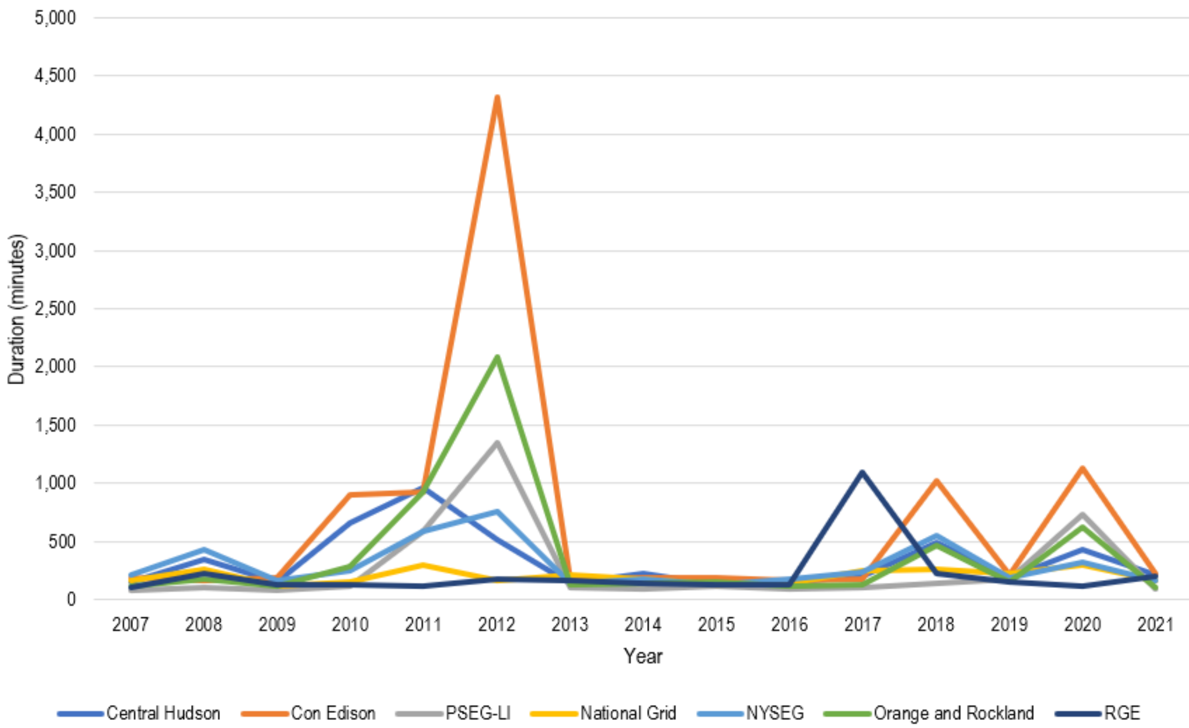


Figure 10. Historical CAIDI, by Utility, 2007-2021, Including Major Storm Events



This analysis calculates averages of historical SAIFI and CAIDI values for each utility from 2007 to 2021, then recalculates SAIDI using those averaged values. To project reliability over time in the UG scenario, SAIFI is multiplied by a factor estimating the effect of undergrounding on reliability, derived from a regression analysis by Larsen et al. (2020) that estimated the relationship between reliability metrics and the share of line miles underground, among other explanatory variables.[45] The preferred regression model ("Model D") in Larsen et al. (2020) indicates that a percentage point increase in the share of lines underground is associated with a 0.426 percent *reduction* in SAIFI (including major storm events).[46]

To apply this relationship to historical SAIFI averages for each utility, the analysis translates the difference in the percentage of transmission and distribution lines underground each year relative to the percentage underground in the initial year (2023) into a multiplicative scaling factor to generate projected future SAIFI values. The equation below outlines this process:

$$SAIFI_{uy} = \left(1 + \left(\left(Percent\ UG_{uy} - Percent\ UG_{uy_0}\right) \times UG\ Coefficient_{SAIFI} \times 100\right)\right) \times SAIFI_{uy_0}$$

[45] Larsen, P. H., Lawson, M., LaCommare, K. H., & Eto, J. H. (2020). Severe Weather, utility spending, and the long-term reliability of the U.S. power system. *Energy*, *198*.

[46] The regression coefficient estimated by Larsen et al. is -0.00426. The log-linear specification of the Larsen et al. model implies that a 1 percentage point increase in the percent of lines underground results in a 0.426 percent reduction in SAIFI (*i.e.*, -0.00426 × 100 = -0.426).

where:

- $SAIFI_{uy}$ is SAIFI for a utility (u) in a given analysis year (y);
- $SAIFI_{uy_0}$ is SAIFI for the utility in the initial analysis year (y_0);
- $Percent\ UG_{uy}$ is the percentage of lines underground for the utility in the given year;
- $Percent\ UG_{uy_0}$ is the percentage of lines underground for the utility in the initial year; and
- $UG\ Coefficient_{SAIFI}$ is the effect of undergrounding on SAIFI, -0.00426.

Scaling SAIFI in this way maintains the historical average reliability indices for all years in the SQ scenario, as the percentage of lines underground remains constant. For the UG scenario, each percentage point increase in the percentage of lines underground is translated into a proportional improvement in SAIFI according to the econometric relationship estimated by Larsen et al. (2020).

While undergrounding is expected to reduce the frequency of interruptions over time, as indicated by the Larsen et al. (2020) study, it is anticipated that with an increase in the share of undergrounded lines, average interruption restoration times may increase, due primarily to the greater difficulty of accessing underground lines. As a result, it may take longer to repair a defective underground line than an overhead line. This implies an increase in CAIDI as the percentage of undergrounded lines increases. The economic and electric power system literature, however, does not explicitly examine the degree to which CAIDI increases with undergrounding.[47] In the absence of empirical data on the marginal change in CAIDI associated with changes in the undergrounding of lines, this analysis examines changes in CAIDI under three scenarios designed to specify upper bound, central, and lower bound values. The main results presented in this analysis are based on the scenario using central values for CAIDI.

Upper Bound Values for CAIDI

The first CAIDI scenario specifies upper bound values for CAIDI, resulting in the lowest reliability benefits from undergrounding. Under this scenario, the analysis assumes a proportional increase in CAIDI equal to the lowest proportional increase that results in at least one utility other than Con Edison achieving a SAIDI value equal to its historical average when its entire transmission and distribution network is undergrounded.[48] Changes in Con Edison's reliability indices in this scenario are modeled independently. A scenario in which the scaling factor for all utilities is based on the increase in CAIDI that would yield a SAIDI value equal to Con Edison's historical average is presented as the central scenario.

As an initial step in specifying the upper bound CAIDI values, the analysis first estimates the value of SAIFI with all utility lines undergrounded, based on the following equation:

$$SAIFI_u^{FullUG} = \left(1 + \left(\left(100\% - Percent\ UG_{uy_0}\right) \times UG\ Coefficient_{SAIFI} \times 100\right)\right) \times SAIFI_{uy_0}$$

$SAIFI_u^{FullUG}$ refers to the projected value of SAIFI with fully undergrounded lines for each utility, and hence the initial percentage of underground lines ($Percent\ UG_{y_0}$) is subtracted from 100%. For example, based on

[47] Larsen et al. (2020) also examined the impact of underground line miles on SAIDI and found a negative, but statistically insignificant relationship between these two variables.

[48] Con Edison is excluded from this calculation because, in contrast to the other utilities, approximately two-thirds of its network is already underground. Undergrounding the rest would yield only modest improvements in Con Edison's overall SAIFI value, and thus only modest improvements in SAIDI. By extension, relatively small increases in CAIDI would return Con Edison's SAIDI value to its historical average. Excluding Con Edison from the calculation allows us to explore the implication of higher CAIDI values for utilities that currently depend more heavily on overhead transmission and distribution.

PSEG-LI's historical average SAIFI of 1.10 and the $UG\ Coefficient_{SAIFI}$ of -0.00426, this equation yields a $SAIFI^{FullUnderground}$ of 0.7969—*i.e.*, a 27.73 percent decrease from the historical average.

The analysis then divides the historical average value of SAIDI for each utility by the projected SAIFI value when all lines are underground (as described above) to calculate the value of CAIDI that would result in no change from the utility's historical SAIDI value:

$$CAIDI_u^{Max} = \frac{SAIDI_{y_0}}{SAIFI^{FullUG}}$$

Again using PSEG-LI as an example, based on a $SAIFI^{FullUnderground}$ of 0.7969, the maximum value of CAIDI is 362.20—1.38 times the actual historical value of 261.76. In comparison, Con Edison's historical average SAIFI is 0.186, and its projected SAIFI with a fully-underground network is estimated to be 0.1585—*i.e.*, a 14.76 percent decrease from its historical average. Con Edison's maximum value of CAIDI (holding SAIDI constant) is 793.39—1.17 times the actual historical value of 675.44.

After performing this calculation for each utility, the minimum ratio of the maximum CAIDI values ($CAIDI_u^{Max}$) and the initial historical average CAIDI values across utilities *except Con Edison* is used as a scaling factor to project growth in all utilities' CAIDI as lines are moved underground. As noted above, this scaling factor is calculated separately for Con Edison:

$$CAIDI^{ScalingFactor} = \begin{cases} \min\limits_{u}\left(\dfrac{CAIDI_u^{Max}}{CAIDI_{u\,y_0}}\right) \forall\ u \neq Con\ Edison \\ \dfrac{CAIDI^{Max}}{CAIDI_{y_0}}\ if\ u = Con\ Edison \end{cases}$$

This scaling factor—1.38 for all utilities except Con Edison, and 1.17 for Con Edison—is applied to the utilities' initial CAIDI values to estimate the CAIDI values with all lines underground:

$$CAIDI_u^{FullUG} = CAIDI_{uy_0} \times CAIDI^{ScalingFactor}$$

where:

- $CAIDI_{u\,y_0}$ is CAIDI for a utility in the initial analysis year;
- $CAIDI^{ScalingFactor}$ is the minimum CAIDI ratio across all utilities, used for scaling; equal to 1.38 for all utilities except Con Edison, and 1.17 for Con Edison; and
- $CAIDI_u^{FullUG}$ is the CAIDI value for each utility when all lines are underground.

To model the proportional increase in CAIDI relative to SAIFI as both are projected forward, a scaling factor is calculated by dividing the difference between the CAIDI value with fully underground networks and the initial CAIDI value by the difference between the fully undergrounded SAIFI value and the initial SAIFI value, for each utility:

$$CAIDIperSAIFI_u = \frac{CAIDI_u^{FullUG} - CAIDI_{uy_0}}{SAIFI_u^{FullUG} - SAIFI_{uy_0}}$$

Once these scaling factors are obtained, SAIFI is projected forward using the equations outlined above to capture the change in reliability over time as utility lines are undergrounded. CAIDI values in each year are scaled proportionally according to the derived scaling factor ($CAIDIperSAIFI_u$):

$$CAIDI_{uy} = CAIDI_{uy_0} + \left(\left(SAIFI_{uy} - SAIFI_{uy_0}\right) \times CAIDIperSAIFI_u\right)$$

The analysis then recalculates SAIDI each year based on the projected CAIDI and SAIFI values:

$$SAIDI_{uy} = CAIDI_{uy} \times SAIFI_{uy}$$

Figure 11 presents the projected values of SAIFI for each utility over the analysis period based on this methodology; Figure 12 presents the projected values of CAIDI; and Figure 13 presents the projected values of SAIDI.

Figure 11. Projected SAIFI by Utility

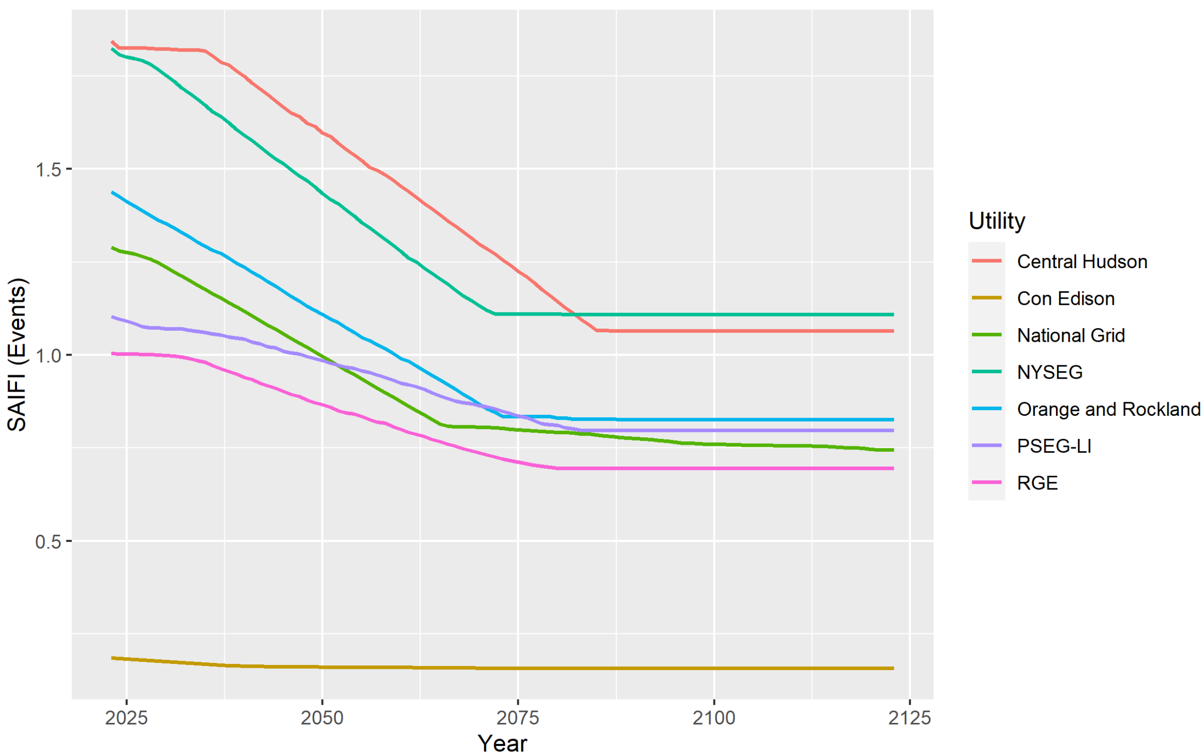


Figure 12. Projected CAIDI by Utility using Upper Bound Values for CAIDI

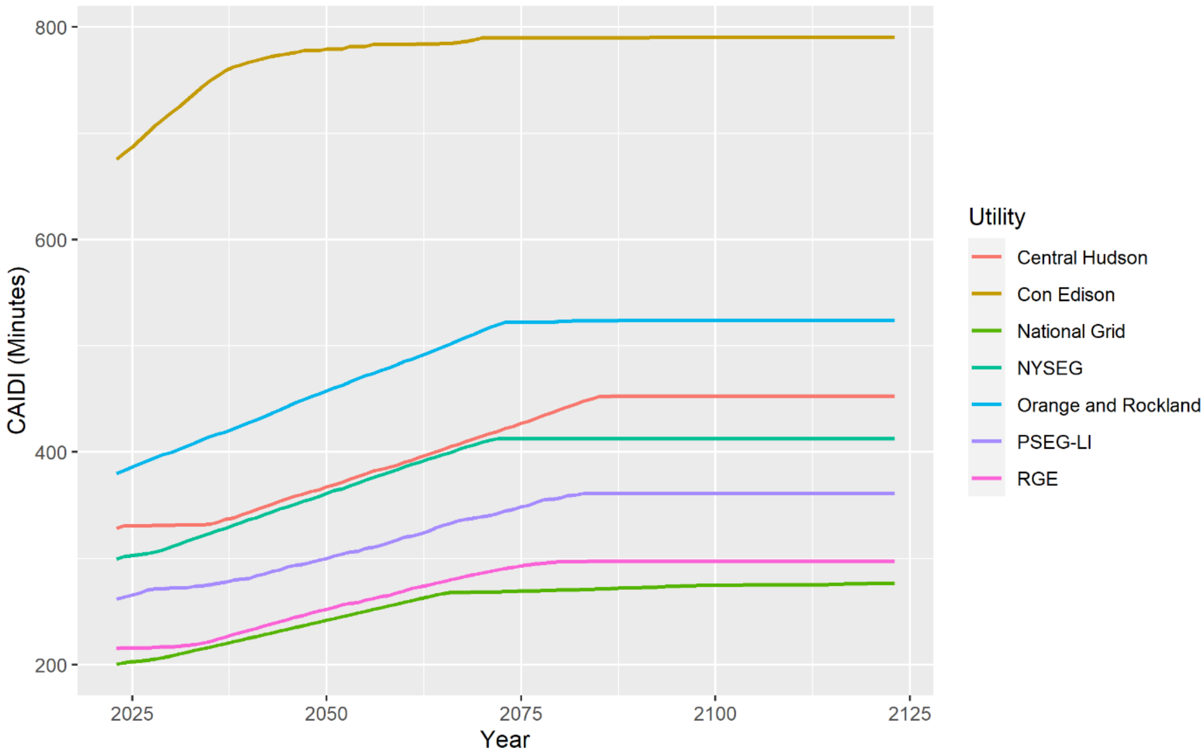
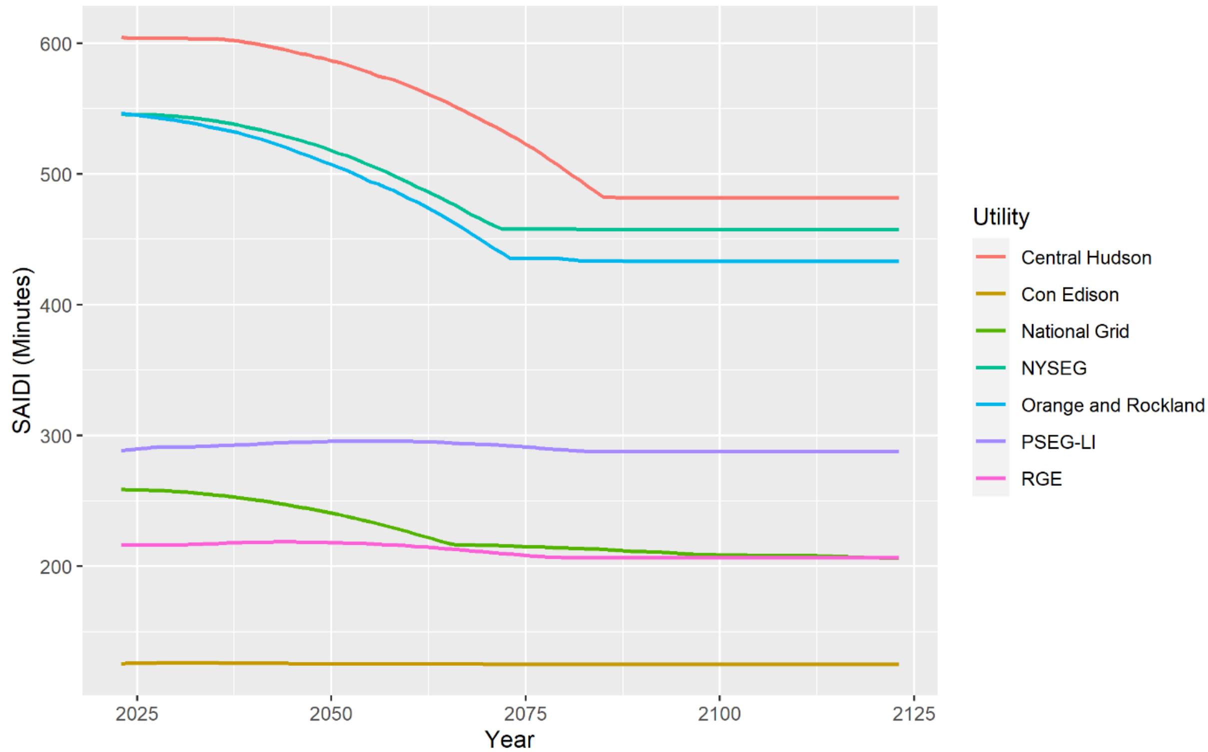


Figure 13. Projected SAIDI by Utility using Upper Bound Values for CAIDI



Central Values for CAIDI

The second CAIDI scenario specifies central values for CAIDI, resulting in reliability benefits from undergrounding between the upper and lower bounds. This scenario follows the same methodology as employed for the upper bound scenario described above, but also includes Con Edison's reliability indices in the calculation of $CAIDI^{ScalingFactor}$ applied to all utilities. As noted above, Con Edison's historical average SAIFI is 0.186, and its projected SAIFI with a fully-underground network, $SAIFI^{FullUnderground}$, is estimated to be 0.1585—*i.e.*, a 14.76 percent decrease from its historical average. Con Edison's maximum value of CAIDI (holding SAIDI constant) is 793.39—1.17 times the actual historical value of 675.44.

In the central scenario, this value of 1.17 is used as the $CAIDI^{ScalingFactor}$ upon which the change in CAIDI associated with changes in SAIFI is modeled for all utilities (rather than the scaling factor of 1.38, based on PSEG-LI). This scenario results in a more moderate increase in CAIDI as electric power lines are moved underground, as shown in Figure 14. Figure 15 shows utility-specific estimates of SAIDI that reflect these CAIDI values and the estimated SAIFI values for each utility.

Figure 14. Projected CAIDI by Utility using Central Values for CAIDI

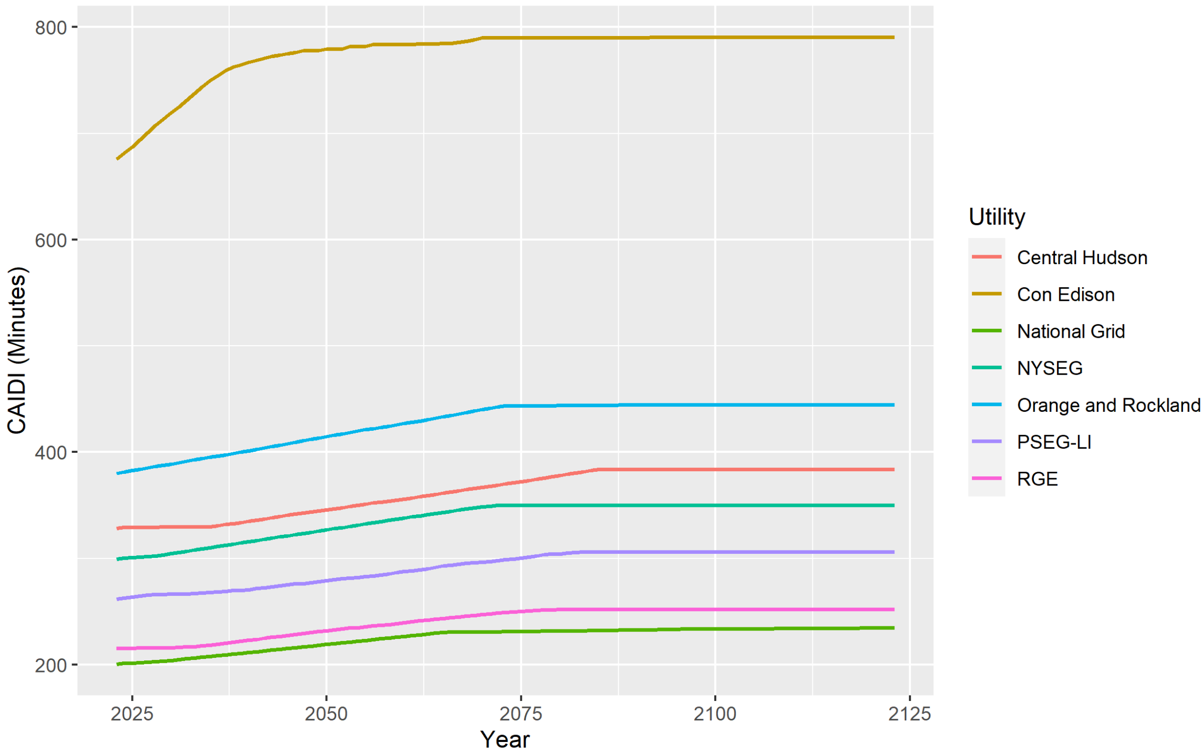
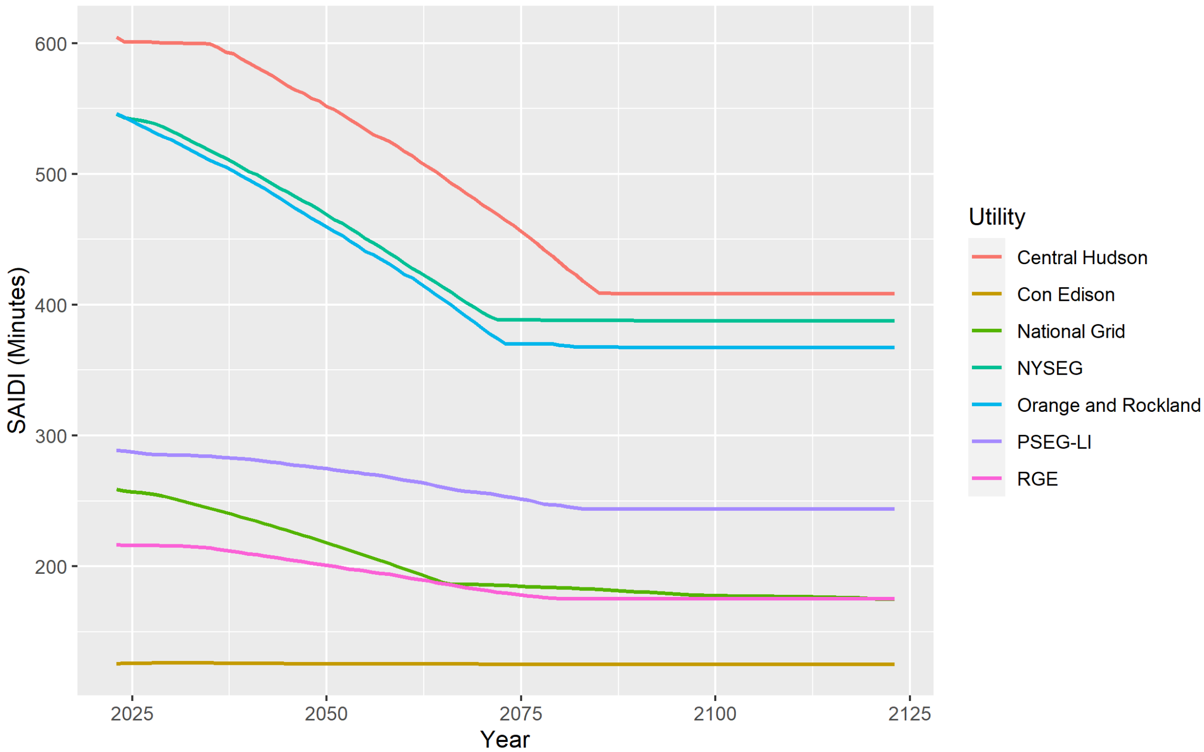


Figure 15. Projected SAIDI by Utility using Central Values for CAIDI



Lower Bound Values for CAIDI

The upper bound and central CAIDI approaches outlined above are likely to result in lower estimates of reliability benefits, given that they envision an increase in CAIDI as lines are moved underground. Thus, as an alternative to the upper bound CAIDI values, this analysis also includes a scenario under which CAIDI is held constant at the historical average for each utility. While this could lead to overestimation of reliability benefits, this approach provides an upper bound limit on these benefits that will be useful for the purposes of interpreting the results of this study. Figure 16 presents projected values of CAIDI for each utility over the analysis period under the lower bound values for CAIDI. Figure 17 presents the projected values of SAIDI under the same assumption.

Figure 16. Projected CAIDI by Utility using Lower Bound Values for CAIDI

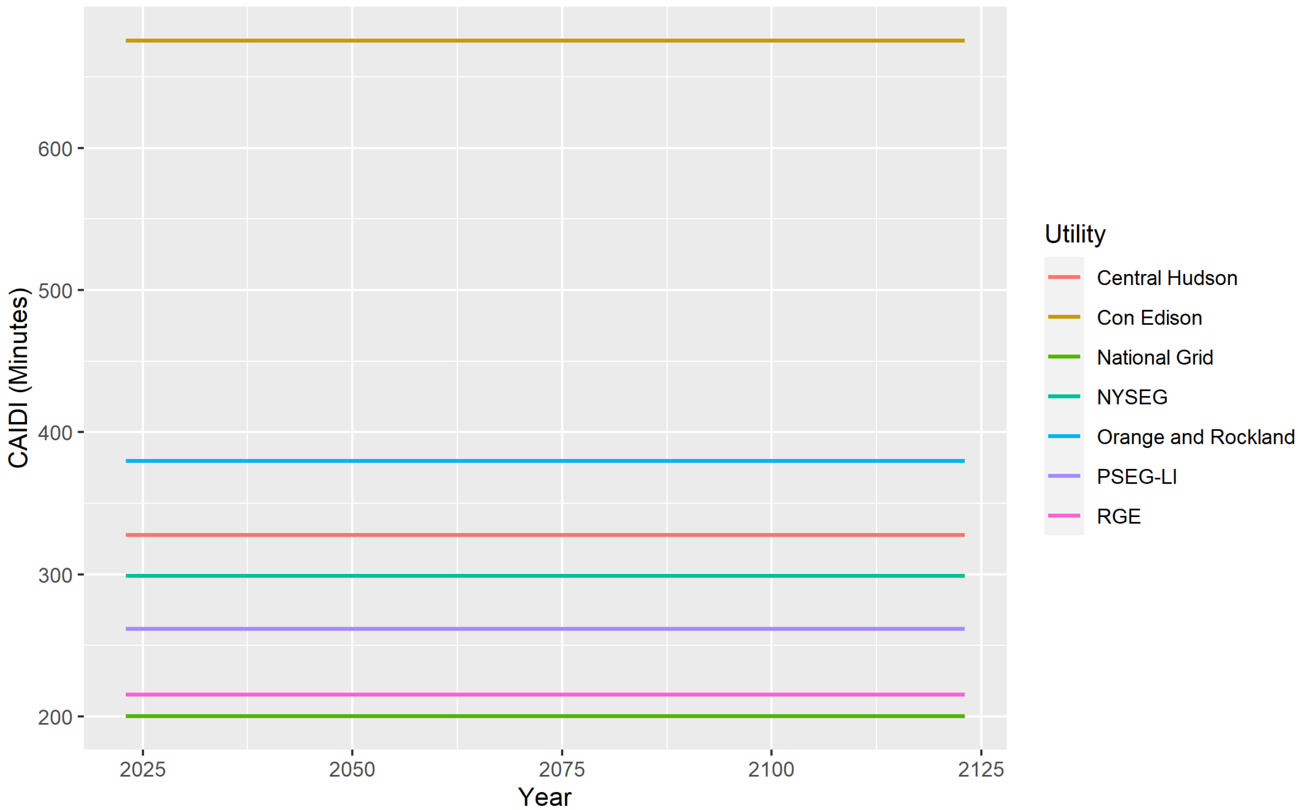
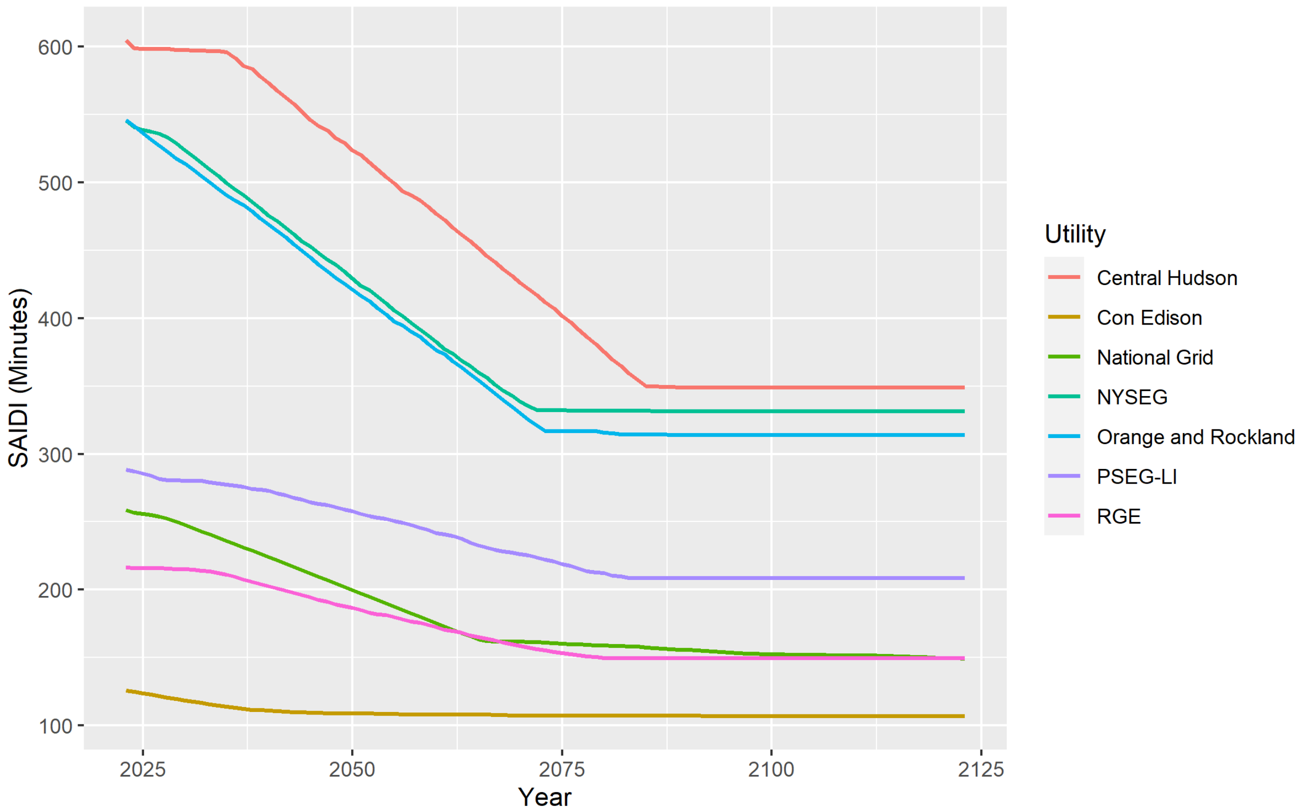


Figure 17. Projected SAIDI by Utility using Lower Bound Values for CAIDI



Implementation of ICE Calculator

Estimating the benefit of improved reliability from undergrounding electric utility lines requires determining the cost of interruptions to utility customers (*i.e.*, value of lost load) under the status quo (SQ) and undergrounding (UG) scenarios. These costs are estimated using the Interruption Cost Estimate (ICE) calculator, a tool maintained by Lawrence Berkeley National Laboratory for use in estimating interruption costs and reliability improvement benefits.[49] This analysis implements the ICE Calculator framework directly within the benefit-cost model, using projected reliability indices and utility-provided customer data to estimate short-duration (*i.e.*, less than 24 hours) interruption costs in both scenarios.[50] These costs are compared between the two scenarios to determine the interruption costs avoided (*i.e.*, value of improved reliability) due to undergrounding.

Customer interruption cost functions in the ICE Calculator are estimated using a two-part regression model based on data from 34 existing customer interruption cost studies and regional data (including annual power usage, household income, and GDP per commercial/industrial kilowatt-hour consumption). Drawing on these

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[49] U.S. Department of Energy, Lawrence Berkeley National Laboratory, & Resource Innovations, Inc. (formerly Nexant, Inc.). *Interruption Cost Estimate (ICE) Calculator*. ICE Calculator. https://icecalculator.com/home.

[50] The framework used to calculate the value of improved reliability with the ICE Calculator is based on interruptions lasting less than 24 hours. See Sullivan, M. J., Schellenberg, J., & Blundell, M. (2015). *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory & Resource Innovations, Inc.

regional parameters, the ICE Calculator estimates interruption costs within a region based on a limited set of user inputs: reliability index values and the number of affected customers, by class (residential, small commercial and industrial (C&I), and medium/large C&I).[51]

To determine the total cost of interruptions for a given year, the cost per event for each customer class, as estimated with the ICE Calculator, is multiplied by the frequency of interruptions for the average customer annually (SAIFI) and the number of customers for each customer class. Total interruption costs are then discounted over time and summed to estimate the present value of interruption costs, by utility and scenario:

$$OutageCost_u^{Scenario} = \sum_{y=2024}^{2123} \left(\sum_c CostPerEvent_{ucy} \times SAIFI_{uy} \times Customers_{uc} \right) \times DiscountFactor$$

Environmental Costs

Utility line corridors can disturb ecosystems and the services they provide. The extent of the disturbance varies from case to case, but in general, the installation process for underground infrastructure is likely to increase the environmental disturbance area in comparison to traditional overhead line replacement.[52] To account for this difference, the analysis of power line installation and replacement costs in both the status quo and undergrounding scenarios includes an estimate of ecosystem restoration costs. In the absence of a specific measure for the economic value of ecosystem restoration costs, the analysis draws upon data reflecting society's willingness to pay for the protection of nature or environmental quality through the purchase of conservation easements (CEs).[53] The value of CEs for comparable land to that which is disturbed by utility infrastructure projects approximates the cost of environmental restoration after replacement and/or conversion projects.

To estimate ecosystem restoration costs, the analysis calculates the land area impacted by line replacements in each year, multiplies this area by an appropriate CE price, and discounts these costs to present value. For each year, environmental costs are calculated as total line miles for each utility line placement type multiplied by the relevant line type's ecosystem footprint corridor width (converted from square miles to acres) and the per-acre CE price ($EasementValue$). The analysis sums these costs across all years and discounts to present value terms.

The following equation describes this process:

$$EnvCost_u^{Scenario} = \sum_{y=2024}^{2123} \sum_p Length_{upy} \times \left(\frac{EcoCorridor_p \times 640}{5280} \right) \times EasementValue \times DiscountFactor$$

where:

[51] Additional details on the calculations used in the ICE Calculator are provided in Appendix I.

[52] Public Service Commission of Wisconsin. (2013). *Environmental Impacts of Transmission Lines*.

[53] These assumptions are consistent with those employed by Larsen (2016) in his prior work on estimating the benefits and costs of undergrounding. (Larsen, P. H. (2016). A method to estimate the costs and benefits of undergrounding electricity transmission and distribution lines. *Energy Economics*, *60*, 47-61.)

- $EnvCost_u^{Scenario}$ is the present value of the environmental cost for each utility (u) in either the status quo or undergrounding scenario, summed across all years (y) from the initial year of the analysis to the final year;
- $Length_{upy} \times \left(\frac{EcoCorridor_p \times 640}{5280}\right)$ represents the area, in acres, affected by line replacement in a year, consisting of the following components:
    - $Length_{upy}$ is the total length, in miles, of overhead or underground lines (as indicated by line placement, p) for each utility, u, replaced in each year, y;
    - $EcoCorridor_p$ is the ecosystem footprint corridor width, in feet, for overhead or underground lines (as indicated by line placement, p);
    - $\frac{640}{5280}$ is a conversion factor to calculate the resulting area in acres; and
- $EasementValue$ is a per-acre conservation easement price, used as an estimate of environmental restoration costs.

The length of line replaced in each year, by placement, is derived from the undergrounding modeling framework, drawing on data provided in utilities' responses to the information request. The analysis assumes an ecosystem footprint corridor width for overhead transmission and distribution lines of 60 feet in total (30 feet on either side of the electric power line), and for underground transmission and distribution lines a width of 120 feet in total.[54] In the absence of geospatial location data for individual line segments, these costs are estimated for all line segments, whether in urban or undeveloped areas. Therefore, these costs represent a conservative, upper bound estimate of environmental restoration costs.

The value of a CE is calculated as the weighted average purchase price per acre across three CE programs in New York State—approximately $2,407 per acre, as shown in Table 5.[55]

[54] These assumptions are consistent with those employed by Peter Larsen in his prior work on estimating the benefits and costs of undergrounding. (Larsen, P. H. (2016). A method to estimate the costs and benefits of undergrounding electricity transmission and distribution lines. *Energy Economics*, *60*, 47-61.)

[55] National Academies of Sciences, Engineering, and Medicine, Division on Earth and Life Studies, Water Science and Technology Board, & Committee to Review the New York City Watershed Protection Program. (2020). 7: Land Protection and Management Programs. In *Review of the New York City Watershed Protection Program*, pp. 201-222. National Academies Press.

Table 5. Estimated Conservation Easement Price

Program	Total Acreage	Purchase Price (USD 2019)
NYC Conservation Easements	25,933	$72,236,000
Watershed Agricultural Council Farm CE	27,895	$41,149,000
Watershed Agricultural Council Forest CE	2,982	$2,886,000
Total	**56,810**	**$116,271,000**
Weighted Average Price per Acre (2019 USD)		**$2,046.66**
Weighted Average Price per Acre (2023 USD)*		**$2,406.58**

* Inflated to 2023 dollars using U.S. Bureau of Labor Statistics consumer price index.[56]

Aesthetic Benefits

An ancillary benefit of burying electric power lines is improvement to the aesthetics of areas served by those lines. Most people are likely to consider electric power lines to have a negative effect on the visual appeal of an area, especially when the overhead infrastructure is large, crosses natural landscapes of special visual significance, and/or affects views of or from a private property.[57] The aesthetic benefits of moving electric power lines underground likely include benefits to property owners and to the general public, who may have a preference for improved aesthetics of landscapes beyond their private property. The literature estimating the magnitude of aesthetic benefits to the public, however, is limited. Given this limitation, the analysis considers only aesthetic impacts to private property owners.

Hedonic price studies (*i.e.*, studies that seek to estimate the contribution of specific characteristics to the overall value of a good) have empirically demonstrated that the presence of high-voltage transmission lines negatively impacts residential property values. The infrastructure for these lines – which typically includes tall metal towers and a relatively wide right of way – can have a substantial visual impact. While it is likely that the presence of lower-voltage transmission and distribution lines may also negatively impact property values, the current body of literature does not provide a reliable estimate of these lines' aesthetic impact. Therefore, our analysis does not quantify the aesthetic benefits of undergrounding distribution lines or lower-voltage transmission lines. It only quantifies the benefits of undergrounding high-voltage transmission lines, defined as transmission lines with voltages greater than or equal to 100 kV.

Method

Aesthetic impacts are calculated in each year based on the length of high-voltage transmission lines converted from overhead to underground, the number and value of properties estimated to experience improved aesthetics

[56] U.S. Bureau of Labor Statistics. (2023). Consumer Price Index for All Urban Consumers (CPI-U) [Data set]. https://data.bls.gov/PDQWeb/cu

[57] See, *e.g.*, Public Service Commission of Wisconsin. *Environmental Impacts of Transmission Lines*, p. 6. Available at https://psc.wi.gov/Documents/Brochures/Enviromental%20Impacts%20TL.pdf.

due to these underground conversions, and the estimated aesthetic impact. The following equation summarizes this methodology:

$$AestheticBenfit_u^{UG} = \sum_{y=2024}^{2123} \left(\frac{UnHVTL_{uy} \times AesCorr}{ServiceArea_u}\right) \times Prop_u \times PropValue_u \times AesImpact_u \times DiscountFactor$$

where:

- $\left(\frac{UnHVTL_{uy} \times AesCorr}{ServiceArea_u}\right)$ represents the percentage of a utility's service area expected to experience improved aesthetics in a given year, based on
  - The number of miles of high-voltage transmission lines moved underground within utility u's service area in year y, $UnHVTL_{uy}$,
  - The width of the area, in miles, around the high voltage transmission line expected to experience improved aesthetics, $AesCorr$, and
  - The utility's total service area in square miles, $ServiceArea_u$;
- The total number of residential properties within the utility's service area, $Prop_u$;
- The average value of these properties, $PropValue_u$; and
- The aesthetic impact of undergrounding on properties in the utility's service area, $AesImpact_u$.

This methodology—based on applying land area-based proportions to all properties within the overall area–does not account for the specific location of transmission lines relative to single-family residential properties. As such, a large portion of the service area, especially in more rural areas, may be unaffected by undergrounding. To the extent the $ServiceArea_u$ component of the equation above reflects areas that do not contain residential properties, the aesthetic benefits calculated may be understated. Similarly, attributing aesthetic benefits to the undergrounding of lines that are far removed from any single-family residential properties may result in an overstatement in aesthetic benefits (*i.e.*, not all land within $AesCorr$ is residential property). These uncertainties may offset each other to some degree, but it is not possible to determine whether there is a directional effect on the estimation of aesthetic benefits.

This stream of benefits is discounted to present value terms using a discount factor. This same calculation is performed for each utility using utility-specific values for the number of high-voltage transmission lines moved underground, the number of properties affected, the average value of those properties, and the average impact of undergrounding high-voltage transmission lines on housing values within the utility's service area. The following sections describe the derivation of the average property values, the number of properties potentially affected, and the aesthetic impact factor in greater detail.

Calculation of Aesthetic Impact Factor and Aesthetic Impact Area

Economic studies of the effect of high-voltage transmission lines on property values have found impacts ranging from 2 percent to 20 percent of total property values. These studies have been conducted in a variety of settings with varied conditions, including examining the sales of homes within view of transmission lines,[58] the sale duration of properties near power lines,[59] and the proximity and visibility of pylons from a residence.[60] Of these studies, a 2002 publication by Des Rosiers provides a reasonable midpoint estimate of the aesthetic impact of

[58] Des Rosiers, F. (2002). "Power Lines, Visual Encumbrance, and House Values." *Journal of Real Estate Research,* 23, no. 3.

[59] The Public Service Commission of Wisconsin. (2013). "Environmental Impacts of Transmission Lines."

[60] Sims and Dent. (2005). "High-voltage Overhead Power Lines and Property Values: A Residential Study in the UK." *Urban Studies,* 42, no. 4, 665-694.

high-voltage transmission lines on property values. Des Rosiers found that the direct view of a transmission system pylon or conductors negatively impacts single-family home prices depending on the property's distance from the transmission line, with an average aesthetic impact factor of 12.5 percent.[61] As a starting point for the analysis, it is assumed that, consistent with Des Rosiers' finding, the aesthetic impact of overhead high-voltage transmission lines on single-family home values is 12.5 percent (*i.e.*, burying high voltage transmission lines increases the value of single-family homes within a certain distance of these lines by 12.5 percent).

Given that not all properties affected by the undergrounding of high-voltage transmission lines in New York are single family homes, this base aesthetic impact factor is scaled to reflect the composition of homes in each utility's service area. Drawing on data on the number of housing units, by type, within each utility's service area, the percentage of housing units that are single-family homes is calculated; the base aesthetic impact factor is then multiplied by this percentage to obtain a utility-specific aesthetic impact factor. A summary of these calculations is shown in Table 6.

Table 6. Scaled Aesthetic Impact Factor

Utility	Base Aesthetic Impact Factor	Percent of Housing Units that are Single Family	Scaled Aesthetic Impact Factor
Central Hudson	12.5%	67%	8.4%
Con Edison	12.5%	21%	2.7%
National Grid	12.5%	64%	8.0%
NYSEG	12.5%	75%	9.4%
Orange and Rockland	12.5%	66%	8.3%
PSEG-LI	12.5%	80%	10.0%
RGE	12.5%	72%	9.0%

Source: NYSERDA Building Efficiency and Electrification Model (BEEM).

Studies of the aesthetic impacts of high-voltage transmission lines vary in their conclusions on the distance over which these impacts are incurred, ranging from 200 feet to 450 feet.[62] As a conservative assumption, the width of the area expected to experience aesthetic benefits due to moving high-voltage transmission lines underground is assumed to be 150 feet on either side, or 300 feet in total.[63]

Calculation of Housing Values and Housing Units

To estimate the aesthetic impact of underground lines in New York by utility, the analysis relies on residential property values from Zillow and housing unit data from the United States Census Bureau (Census). Zillow—a tech real-estate marketplace company—publishes data on the value of a typical property, by county, based on

[61] Des Rosiers, F. (2002). "Power Lines, Visual Encumbrance, and House Values." *Journal of Real Estate Research,* 23, no. 3.

[62] Jackson, Thomas and Pitts, Jennifer. (2010). "The Effects of Electric Transmission Lines on Property Values: A Literature Review." *Journal of Real Estate Literature*: Volume 18, Number 2, p. 248.

[63] For each mile of high-voltage transmission line converted from overhead to underground, this assumption implies that 0.0568 square miles experience improved aesthetic benefits (*i.e.*, $1\ mile \times \frac{300\ feet}{5280\ feet\ per\ mile} = 0.0568$ square miles).

the distribution of housing values in that region; this metric is known as the Zillow Home Value Index (ZHVI).[64] The ZHVI measures monthly changes in property-level Zestimates[65] (Zillow's estimate of a home's market value) across housing types; it also reflects the typical home value and market changes across a given region.[66] This analysis uses the smoothed, seasonally adjusted ZHVI for homes in the 35th to 65th percentile of house values by county in New York State.

The analysis employs Census data on housing units in conjunction with the Zillow property values to estimate the total aesthetic benefit of underground lines.[67] To calculate average property values by utility, the analysis first calculates the number of housing units by utility, based on county-level estimates of housing units and a GIS analysis of utility service areas by county. Each county's housing units are apportioned to the utilities serving that county according to the share of the county's land area served by that utility. The weighted average property value for the utility's overall service area is then calculated by weighting the average property value by county by the proportion of all housing units served by each utility within each county. Table 7 presents the resulting estimates of average property values and number of housing units by utility.

Table 7. Average Property Value and Housing Units by Utility

Utility	Average Property Value	Number of Housing Units
Central Hudson	$402,211	271,686
Con Edison	$947,861	3,844,165
National Grid	$234,974	1,602,351
NYSEG	$307,942	1,162,628
Orange and Rockland	$517,994	230,398
PSEG-LI	$957,495	1,120,026
RGE	$216,411	299,809

Con Edison's service area is unique in that it has a far greater number of housing units than other service areas, as well as the second-highest average property value. However, many of these housing units are concentrated in densely populated portions of the service area which are served by a transmission and distribution network that is already at least partially, if not fully, underground. If the methodology described above were to be applied using the number of properties and average property value shown above, it would overstate aesthetic benefits in the Con Edison service area, as it would estimate aesthetic benefits for areas where lines are already

[64] Larsen, P. H. (2016). A method to estimate the costs and benefits of undergrounding electricity transmission and distribution lines. Energy Economics, 60, 47-61.

[65] "What is a Zestimate?" Zillow, accessed on April 21, 2023. Available at: https://www.zillow.com/z/zestimate/.

[66] Olsen, Skylar, "Zillow Home Value Index Methodology, 2023 Revision: What's Changed?" Zillow, accessed on April 21, 2023. Available at: https://www.zillow.com/research/methodology-neural-zhvi-32128/.; "Housing Data," Zillow, accessed on April 21, 2023. Available at: https://www.zillow.com/research/data/.

[67] Because the aesthetic impact factor is scaled by the proportion of single-family homes in each utility's service area, this factor can be applied to all housing units regardless of type.

underground. Therefore, for Con Edison only, the number of properties and average property value are adjusted to reflect the portions of the service area served by existing overhead lines.

As shown in Table 8, in the counties primarily served by Con Edison, between 0 percent and 72 percent of lines are overhead. These percentages are applied to the number of housing units in each county to estimate the number of housing units that would likely be affected by undergrounding. The weighted average property value across the Con Edison service area is then recalculated based on the revised number of housing units. Similarly, the total Con Edison service area likely to be affected by undergrounding ($ServiceArea_u$ for Con Edison in the equation above) is scaled on a proportional basis, using the proportions in Table 8.

Table 8. Percentage of Overhead Lines in Con Edison Service Area, by County[68]

County	Overhead Percent
Bronx	20%
Kings (Brooklyn)	12%
New York (Manhattan)	0%
Queens	22%
Richmond (Staten Island)	72%
Westchester	70%
Total	**28%**

Source: Office of Long-Term Planning and Sustainability. Office of the Mayor. City of New York. “Utilization of Underground and Overhead Power Lines in the City of New York.” December 2013. Accessed at https://www.nyc.gov/html/planyc2030/downloads/pdf/power_lines_study_2013.pdf, p. 38.

The revised number of housing units and average property values used in the calculation of aesthetic benefits are shown in Table 9. Compared to the initial estimate, the potential effect of undergrounding on properties in the Con Edison service area is substantially reduced, largely due to the removal from the analysis of a large number of high-value properties in New York, Kings, and Queens counties.

[68] Based on the network data provided by Con Edison, 34.5 percent of distribution line miles are overhead, as are 0 percent of low-voltage transmission lines and 38 percent of high-voltage transmission lines. As these data do not differentiate by county, the data presented in Table 8 are used for this apportionment.

Table 9. Adjusted Average Property Value and Housing Units by Utility

Utility	Average Property Value	Number of Housing Units
Central Hudson	$402,211	271,686
Con Edison	$774,000	743,330
National Grid	$234,974	1,602,351
NYSEG	$307,942	1,162,628
Orange and Rockland	$517,994	230,398
PSEG-LI	$957,495	1,120,026
RGE	$216,411	299,809

Health and Safety Costs

Replacing overhead infrastructure with underground infrastructure is likely to affect the health and safety risks utility operational staff are exposed to while performing necessary construction and replacement field work.[69] To quantify these costs for each utility, the analysis estimates the number of employees that experience non-fatal and fatal injuries each year, based on U.S. Bureau of Labor Statistics (BLS) data on non-fatal and fatal incidence rates for electric utility workers. The number of non-fatal injuries and workplace mortalities are then multiplied by the average cost of non-fatal injuries and the value per statistical life (VSL), respectively.[70]

In response to DPS' information request, utilities provided estimates of the total number of direct and contract employees. Table 10 presents the number of direct, contract, and total employees, by utility, as reported in their responses.

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[69] Hall, K. L. (2013). *Out of Sight, Out of Mind 2012: An Updated Study on the Undergrounding Of Overhead Power Lines.*; Larsen, P. H. (2016). A method to estimate the costs and benefits of undergrounding electricity transmission and distribution lines. *Energy Economics*, *60*, 47-61.

[70] This approach is consistent with the approach employed by Larsen. (Larsen, P. H. (2016). A method to estimate the costs and benefits of undergrounding electricity transmission and distribution lines. *Energy Economics*, *60*, 47-61.)

Table 10. Employment by Utility

Utility	Direct Employment	Contract Employment	Total Employment
Central Hudson	1,132	360	**1,492**
Con Edison	12,933	4,569	**17,502**
Orange and Rockland	1,140	708	**1,848**
National Grid	4,050	161	**4,211**
NYSEG*	2,071	748	**2,819**
RG&E*	790	329	**1,119**
PSEG-LI	2,497	250	**2,747**

* NYSEG and RG&E provided separate estimates for electric operations contractors and additional supporting contractors. Contract employment values above combine these estimates (NYSEG: 546 electric ops. + 202 supporting = 748 contractors; RG&E: 233 electric ops. + 96 supporting = 329 contractors).

These employment data are used to estimate non-fatal injury costs and fatality-related economic losses in each scenario with the following equations:

$$NonFatalCost_u^{Scenario} = \sum_{y=2024}^{2123} \Psi_{uy} \times NFIR \times \left(\frac{Employees_u}{100}\right) \times InjuryCost \times DiscountFactor$$

$$FatalCost_u^{Scenario} = \sum_{y=2024}^{2123} \Psi_{uy} \times FIR \times \left(\frac{Employees_u}{100{,}000}\right) \times VSL \times DiscountFactor$$

where:

- $NonFatalCost_u^{Scenario}$ and $FatalCost_u^{Scenario}$ denote the present value of non-fatal and fatal injury costs, by utility (u);
- $NFIR$ and FIR refer to annual incidence rates for non-fatal and fatal injuries, respectively;
- $Employees_u$ represents the number of direct and contract workers employed, by utility (u);
- $InjuryCost$ refers to the cost of non-fatal injuries;
- VSL denotes the value of a statistical life; and
- Ψ_{uy} represents a factor used to scale incidence rates of non-fatal and fatal accidents based on the proportion of line miles which are underground.

The annual incidence rate of non-fatal injuries, $NFIR$, is estimated as 1.4 accidents per 100 workers, based on data published by the U.S. Bureau of Labor Statistics (BLS). [71] The annual incidence rate of fatal injuries, FIR, is estimated as 5.5 fatalities per 100,000 workers, also based on BLS data.[72]

The total direct and indirect cost of utility-related injury, $InjuryCost$, is estimated as $332,257 per electric shock accident, based on data published by the Occupational Safety and Health Administration.[73] The value of a statistical life, VSL, is derived by adjusting the base value of $7.4 million (in 2006 USD) recommended by the U.S. Environmental Protection Agency (EPA) for inflation and changes in real income, using the methodology outlined for the U.S. Department of Health and Human Services (HHS).[74] This process generates a VSL estimate of approximately $11.5 million for 2023, growing annually under an income elasticity of 0.4 as real income increases at a projected rate of 0.8% each year.[75] This methodology is consistent with the methodology outlined in the Integration Analysis Technical Supplement published for the New York State Climate Action Council Scoping Plan in 2022.[76]

The health and safety scaling factor, Ψ_{uy}, represents the estimated increase in fatality and injury rates associated with an increase in the proportion of transmission and distribution lines placed underground.[77] This scaling factor is calculated based on the percent of transmission and distribution line miles underground, for each utility in each year, as specified in the following equation:

$$\Psi_{uy} = 1 + \frac{(Percent\ Underground_{uy} - Percent\ Underground_{uy_0})}{2}$$

In the status quo scenario, this scaling factor remains at a value of 1, while in the undergrounding scenario, this factor increases fatality and injury incidence rates proportionally to the increase in the percentage of underground lines ($Percent\ Underground_{uy}$) each year relative to the initial year

71 United States Bureau of Labor Statistics (BLS). (2020). Incidence Rates of Nonfatal Occupational Injuries and Illnesses by Industry and Case Types, 2020.

72 United States Bureau of Labor Statistics (BLS). (2020). Fatal injury rates by state of incident and industry, all ownerships, 2020.

73 OSHA. (2022). OSHA's Safety Pays Program: Estimated Costs of Occupational Injuries and Illnesses and Estimated Impact and a Company's Profitability Worksheet.

74 U.S. EPA. (2023). *Mortality Risk Valuation.* Environmental Economics; Office of the Assistant Secretary for Planning and Evaluation (ASPE). (2021, June 29). *Appendix D: Updating Value per Statistical Life (VSL) Estimates for Inflation and Changes in Real Income*

75 United States Department of Health and Human Services. Office of the Assistant Secretary for Planning and Evaluation (ASPE). (2021). *Appendix D: Updating Value per Statistical Life (VSL) Estimates for Inflation and Changes in Real Income*; U.S. EPA. (2021). *User's Manual for the Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA)*; U.S. EPA. (2022). *COBRA Questions and Answers.* CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool: COBRA.

76 Energy and Environmental Economics (E3) & Abt Associates. (2022). Appendix G: Integration Analysis Technical Supplement New York State Climate Action Council Scoping Plan; U.S. EPA. (2021). *User's Manual for the Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA)*; U.S. EPA. (2022). *COBRA Questions and Answers.*CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool: COBRA.

77 Larsen, P. H. (2016). A method to estimate the costs and benefits of undergrounding electricity transmission and distribution lines. *Energy Economics*, *60*, 47-61.

($Percent\ Underground_{uy_0}$), up to a maximum increase of 1.5—*i.e.*, at most, incidence rates when all lines are underground are 1.5 times their initial values.[78]

Calculation of Net Benefits

The analysis calculates the overall net benefit of undergrounding electrical transmission and distribution lines in New York State as the marginal difference in benefits minus the marginal difference in costs between the status quo (SQ) and undergrounding (UG) scenarios. First, the net present value (NPV) of each component of the benefit-cost analysis is calculated for both the UG scenario and the SQ scenario, using the previously specified discount factor. Next, the marginal difference between these scenarios is calculated. Finally, the sum of marginal costs is subtracted from the sum of marginal benefits to yield the overall net benefit of undergrounding. This calculation is performed for each utility separately, then aggregated across utilities to estimate the net change in social welfare for the state as a whole.

The increase in costs attributable to undergrounding electric transmission and distribution lines is calculated by subtracting the NPVs of lifecycle, environmental, and health and safety costs for each utility (u) in the SQ scenario from the corresponding NPVs in the UG scenario, as summarized in the following equations:

$$LifecycleCost_u^{Net} = LifecycleCost_u^{UG} - LifecycleCost_u^{SQ}$$

$$EnvCost_u^{Net} = EnvCost_u^{UG} - EnvCost_u^{SQ}$$

$$HealthSafetyCost_u^{Net} = (NonFatalCost_u^{UG} + FatalCost_u^{UG}) - \left(NonFatalCost_u^{SQ} + FatalCost_u^{SQ}\right)$$

The calculation of the net benefits of undergrounding differs slightly from the calculation of costs. The net aesthetic benefit of undergrounding is conceptually calculated in the same manner, but because this aesthetic impact is only incurred when high voltage transmission lines are moved underground, there is no aesthetic benefit in the SQ scenario. Thus, net aesthetic benefits are equal to aesthetic benefits in the UG scenario:

$$AestheticBenefit_u^{Net} = AestheticBenefit_u^{UG}$$

The net benefit of improved reliability is calculated in the same manner as costs, with a slight difference: because outage costs are higher in the SQ scenario than the UG scenario, the *benefit* of avoiding these higher costs is expressed as the cost of outages in the SQ scenario minus the cost of outages in the UG scenario (*i.e.*, the order of subtraction is inverted compared to the calculation of net costs), as in the following formula:

$$ImprovedReliability_u^{Net} = OutageCost_u^{SQ} - OutageCost_u^{UG}$$

To calculate the overall net benefit of undergrounding for each utility, the marginal costs of undergrounding are subtracted from the marginal benefits, as shown in the following equation:

$$NetBenefit_u = MarginalBenefits_u - MarginalCosts_u$$

where

$$MarginalBenefits_u = ImprovedReliability_u^{Net} + AestheticBenefit_u^{Net}$$

[78] The minimum and maximum percentages of miles underground are 0 percent and 100 percent, respectively. Thus, the maximum value of this scaling factor is $\Psi_y^{Max} = 1 + \frac{100\%-0\%}{2} = 1 + \frac{1}{2} = 1.5$.

and

$$MarginalCosts_u = LifecycleCost_u^{Net} + EnvCost_u^{Net} + HealthSafetyCost_u^{Net}$$

The net social benefit of undergrounding at a statewide level is estimated by summing utility-specific net benefits:

$$NetBenefit^{NYS} = \sum_u NetBenefit_u$$

Results

The results of the benefit-cost analysis are presented in Table 11. As shown, the net social benefit of undergrounding is negative on a statewide level, at a net social loss of approximately $261 billion. Similarly, the net social benefit of undergrounding is negative for each utility to varying degrees of magnitude. Due to its lengthy network, and because it provided the highest capital and O&M costs, especially for underground transmission and distribution lines, the net welfare loss for National Grid's service area is projected to be far greater than the other utilities'—a net social welfare loss of approximately $143 billion. To a lesser extent, NYSEG's service area, which also has a lengthy network, is also estimated to experience a large net loss in social welfare due to undergrounding—approximately $72 billion. The other utility service areas are also expected to experience net social welfare losses, albeit to a lesser extent. These losses range from $13 billion (Con Edison) to $6.4 billion (PSEG-LI).

Lifecycle (*i.e.*, capital and O&M) costs represent nearly all of the costs estimated under the benefit-cost analysis—between 98 and 99.7 percent of all costs across service areas. For nearly all service areas, the value of improved reliability represents a similarly large share of total benefits—between 85.7 and 98.8 percent of benefits for all but two areas. In the Con Edison and PSEG-LI service areas, aesthetic benefits are also a large component of total benefits. This result is driven by two factors. First, both areas currently have a higher-than-average share of underground lines, which leads to a comparatively smaller improvement in reliability compared to the historical baseline over the period of the analysis. Second, these utilities both serve densely populated areas with high property values, which leads to higher-than-average aesthetic benefits related to the undergrounding of high-voltage transmission lines.

Table 11. Results of Benefit-Cost Analysis (Present Value in Millions, 2023 Dollars)[79]

Category	Central Hudson	Con Edison	National Grid	NYSEG	Orange and Rockland	PSEG-LI	RGE	Total
Lifecycle Cost	$10,234	$12,756	$144,362	$73,092	$8,241	$7,310	$10,388	**$266,384**
Environmental Cost	$38	$48	$361	$235	$43	$57	$35	**$817**
Health and Safety Cost	$20	$216	$85	$55	$40	$30	$13	**$458**
Total Cost	**$10,292**	**$13,020**	**$144,808**	**$73,382**	**$8,324**	**$7,398**	**$10,436**	**$267,660**
Improved Reliability	$934	$183	$1,583	$1,122	$1,555	$581	$103	**$6,062**
Aesthetic Benefit	$36	$331	$20	$158	$28	$423	$16	**$1,012**
Total Benefit	**$970**	**$514**	**$1,603**	**$1,280**	**$1,584**	**$1,004**	**$119**	**$7,074**
Net Benefit	**-$9,321**	**-$12,506**	**-$143,205**	**-$72,103**	**-$6,740**	**-$6,394**	**-$10,317**	**-$260,586**

Note: Figures presented in this table are based on the central method for modeling reliability as a function of undergrounding.

Under the scenarios for modeling changes in CAIDI described above, the results of the benefit-cost analysis are equal for all components of the benefit-cost analysis except the value of improved reliability. As shown in Table 12, the lower bound assumption of changes in CAIDI over time (*i.e.*, assuming no detrimental effect of undergrounding on CAIDI) has a comparatively minimal effect on the conclusions of the benefit-cost analysis—while the value of improved reliability nearly doubles from $6 billion to $12 billion, the effect on net social benefits is relatively minimal, at an increase of approximately 2.3 percent across all utility service areas. Under the upper bound assumption of changes in CAIDI (*i.e.*, assuming a *more* detrimental effect of undergrounding on CAIDI), the impact on reliability is estimated to be a net *loss* for the customers of two utilities: PSEG-LI and RGE. For these utilities, the increase in the average interruption restoration time (as measured by increases in CAIDI) due to undergrounding outweighs the reduction in interruption frequency (measured by SAIFI). This result suggests that the potential benefits of undergrounding on reliability are sensitive to the interaction between these two factors—where improvements in the frequency of interruptions are comparatively less impactful than the increase in restoration time for interruptions that do occur, undergrounding may in fact provide no reliability benefits.

[79] For information on the calculations employed to estimate interruption costs and a more detailed understanding of the effect of changes in SAIFI and CAIDI on those costs, see Appendix I.

Table 12. Comparison of Net Benefit under Upper and Lower Bound CAIDI Assumptions (Present Value in Millions, 2023 Dollars)

Category	Central Hudson	Con Edison	National Grid	NYSEG	Orange and Rockland	PSEG-LI	RGE	Total
Upper Bound CAIDI								
Improved Reliability	$267	$183	$716	$178	$462	-$458	-$3	**$1,345**
Net Benefit	**-$9,989**	**-$12,506**	**-$144,073**	**-$73,046**	**-$7,833**	**-$7,433**	**-$10,423**	**-$265,302**
Central CAIDI								
Improved Reliability	$934	$183	$1,583	$1,122	$1,555	$581	$103	**$6,062**
Net Benefit	**-$9,321**	**-$12,506**	**-$143,205**	**-$72,103**	**-$6,740**	**-$6,394**	**-$10,317**	**-$260,586**
Lower Bound CAIDI								
Improved Reliability	$1,455	$2,494	$2,246	$1,847	$2,431	$1,383	$183	**$12,040**
Net Benefit	**-$8,800**	**-$10,195**	**-$142,542**	**-$71,378**	**-$5,864**	**-$5,592**	**-$10,236**	**-$254,608**

Telecommunications

Like the electric power transmission and distribution system, telecommunications systems use a network of cables to deliver telephone, cable, and internet services to customers. Unlike electric power systems, however, telecommunications networks overlap each other. In addition, system providers operate in a mostly competitive environment and are subject to varying degrees of regulatory oversight; thus, data on infrastructure costs and outage statistics are not required to be reported uniformly and are generally not publicly available. This lack of data likely explains why the costs and benefits of burying telecommunications networks has not been studied in great detail in publicly available literature.

Because aerial telecommunications lines often share the same infrastructure as electric power lines, it is possible for the undergrounding of these cables to be paired with the undergrounding of electric utility cables. This pairing would be a necessity if the poles used to support electrical lines are partially or fully owned by telecommunication companies that choose to remove them.[80] Telecommunication and cable lines may be directly buried alongside electric power lines, sharing the costs of direct burial, or co-located in a "multi-utility

[80] Troy, J. (2014). *Feasibility Study for Undergrounding Electric Distribution Lines in Massachusetts.* Massachusetts Department of Energy Resources.

tunnel" (an underground passage carrying both electric and telecommunication lines, potentially among other utility services).[81]

In addition to the lack of uniform infrastructure cost data among the various telecommunications sectors or modes (i.e., telephone, cable television, Internet service providers or ISPs, cellular), tracking the reliability of the telecommunications system and costs attributable to outages is complicated because the resiliency of each sector differs depending on the type of storm or emergency event, as well as its reliance on commercial power. For instance, legacy copper-based telephone networks are designed to withstand commercial power loss, even at the customer premise, but they are susceptible to water inundation even in an aerial deployment and are highly vulnerable to flooding. Fiber-based telephone and data networks are generally passive (i.e., no power is required in the outside plant) and not at risk due to rain and flooding, but they do require that commercial power or generated power be provided by the customer in normal operating conditions and during storms and electric outages. Coaxial hybrid fiber-copper networks (i.e., those used in cable TV networks) are generally more resilient to rain and flooding than copper networks, but they too require customer-provided power. Likewise, their outside plant equipment relies on commercial power in normal operating conditions and batteries or power generation during power outages. Cellular telecommunications networks similarly rely on batteries or power generation during power outages, but they also rely on continuous operation of their backhaul copper or fiber system or that of an underlying carrier. Moreover, because restoration of telecommunications networks following storms lags that of electric restoration, it is often impossible to determine whether storm-related outages are due to damaged aerial facilities or commercial power loss. That said, improved electric utility reliability can generally be expected to improve the reliability of all telecommunications sectors dependent on uninterrupted commercial power.

Like electric utilities, a significant portion of all telecommunications networks in New York is comprised of aerial infrastructure. By reducing exposure to severe weather, undergrounding copper and fiber telecommunications cable and equipment would be expected to reduce the frequency and cost of outages caused by winds, falling trees or poles, vehicle accidents, gunfire, etc. However, in cases where utility poles are used to carry both telecommunications and electric infrastructure, telecommunications cables, whether copper or fiber, are deployed below electric cables, which often act as a barrier to downed trees and fallen limbs during storms. Because they already benefit from this protection, undergrounding would likely have a lower incremental value for the reliability of telecommunications service. Additionally, storms like Hurricane Sandy, which caused severe flooding due to storm surge, had a devastating effect on underground legacy copper systems and led to prolonged outages. Thus, undergrounding copper telecommunications infrastructure in areas prone to flooding would have little or no incremental value.[82] Aerial copper telecommunications infrastructure designated to be undergrounded would first need to be repaired to prevent water inundation (for instance, by sealing and pressurizing cable sheaths carrying individual copper lines) or replaced with newer copper cables less resistant to water damage (*e.g.*, petroleum jelly filled cable) or with fiber optic cable and equipment. Upgrading copper cable to fiber would necessitate extensive upgrades to other outside plant equipment and at switching offices to accommodate the new cable technology. Telecommunications providers already deploy geographically diverse routing in the most critical segments of their networks (*i.e.*, interoffice transport and signaling) to mitigate damage to aerial plant and outages caused by storms. For these reasons, the incremental benefit to improved

[81] Bergman et al. "A Critical Review of the Sustainability of Multi-Utility Tunnels for Colocation of Subsurface Infrastructure." *Frontiers in Sustainable Cities*. Volume 4. 2022. https://www.frontiersin.org/articles/10.3389/frsc.2022.847819.

[82] State of New York Department of Public Service. (2013). "Report on Telecommunications Network Restoration Following Superstorm Sandy." Issued November 19, 2013, pg. 3 (Case13-M-0025).

service reliability by undergrounding telecommunications infrastructure is expected to be relatively minor in comparison to the benefit of improved electric utility reliability due to undergrounding.

Previous efforts to quantify the additional costs of undergrounding telecommunication lines have yielded a wide range of results. A report from the Washington, D.C. Executive Office of the Mayor estimated that the marginal cost of undergrounding communications lines is almost equivalent to the cost of undergrounding electrical lines alone – *i.e.*, undergrounding telecommunication lines in addition to electric utility lines doubles the cost of undergrounding electric lines alone.[83] In contrast, Consolidated Edison has previously estimated that undergrounding existing lines for cable television and private fiber optic companies would cost an additional 25 percent to 55 percent of the costs of undergrounding electric distribution lines alone.[84]

Breakeven Analysis

The framework used to calculate the value of improved reliability with the ICE Calculator is based on interruptions lasting less than 24 hours. Documentation for the ICE Calculator notes that for considerations involving long-duration power interruptions of 24 hours or more, the indirect, spillover effects on the greater economy must be considered.[85] Thus, the conclusion of the benefit-cost analysis—*i.e.*, that costs outweigh benefits—likely understates the benefits of avoiding long-duration interruptions.

Estimating the probability and frequency of major storm events and associated interruptions would serve as a basis for estimating these additional benefits; however, as of the time this report was developed, projections of the frequency and severity of storm events in a future subject to climate change are not readily available. In the absence of storm event projections, a breakeven analysis is developed to provide a sense of the frequency with which the economic consequences of major storm events would need to be successfully avoided for the net social benefit of undergrounding to be cost-neutral (*i.e.*, benefits equal to costs). Under this framework, the value of economic activity lost due to Tropical Storm Isaias is used as an approximation of the economic losses that would be experienced due to future major weather events. An analysis conducted by IEc in 2021 estimated that the gross state product (GSP)[86] lost due to Tropical Storm Isaias was approximately 0.040 percent of annual GSP in the counties most affected by the storm.[87] This figure provides the foundation for the breakeven analysis.

Assuming the economic impact of each major weather event avoided by undergrounding is 0.040 percent of GSP for each utility service area, the following equation describes the calculation of the frequency at which major storm events would need to occur for the net social benefit of undergrounding to be cost neutral ($Freq_u$), for a given utility (u):

$$Freq_u = \frac{\left(\frac{-1 \times NetBenefit_u}{LongDurationOutageCost_u}\right)}{100}$$

[83] Executive Office of the Mayor. (2013). *Mayor's Power Line Undergrounding Task Force: Findings and Recommendations.* Government of the District of Columbia.

[84] CHA Consulting, Inc. (2013). *Feasibility Report: Underground Electric Utilities.* Consolidated Edison Company of New York, Inc.

[85] Sullivan, M. J., Schellenberg, J., & Blundell, M. (2015). *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory & Resource Innovations, Inc.

[86] IEc's analysis measured the impact of Tropical Storm Isaias on "Value Added" from the IMPLAN regional input-output economic model, which is equivalent to gross domestic or state product.

[87] Industrial Economics, Inc. (2021b). *Estimated Impacts of the Outages Caused by Tropical Storm Isaias on New York State's Economy*.

where:

- $LongDurationOutageCost_u$ is the expected cost of a major storm event in a given utility's service area, equal to 0.040 percent of the utility service area's annual GSP;
- $NetBenefit_u$ is the net benefit of undergrounding for the utility in question (as this value is expected to be a net cost, it is multiplied by -1); and
- 100 is the number of years in the analysis.

Under this framework, the net social costs estimated in the main benefit-cost analysis would require major storm events to occur at a frequency that is highly unlikely in order for undergrounding to be cost neutral from a social welfare perspective. In the Con Edison service area, the breakeven analysis implies that if a major storm occurred approximately every 4.2 years, the additional economic impacts avoided would render undergrounding cost neutral. In the National Grid service area, however, major weather events would need to occur more than 10 times in a single year, for 100 years continuously, for the projected benefits of undergrounding to equal its costs. As shown in Table 13, the breakeven storm frequency in other service areas lies between these extremes—in some cases, less than once a year, and in others, several times in a single year. It is highly unlikely that major weather events leading to long-duration interruptions would occur at these frequencies, suggesting that the net social welfare effect of undergrounding is likely to be negative—*i.e.*, a net social cost—even when the broader economic effects of long-duration interruptions are taken into account.

Table 13. Results of Breakeven Analysis

Category	Cost of Major Storm Event ($M 2023USD)	Net Benefit ($M 2023USD)	Breakeven Point
Central Hudson	$40.7	-$9,321	2.3 major storm events per year
Con Edison	$525.6	-$12,506	Major storm event every 4.2 years
National Grid	$137.0	-$143,205	10.5 major storm events per year
NYSEG	$157.3	-$72,103	4.6 major storm events per year
Orange and Rockland	$18.5	-$6,740	3.6 major storm events per year
PSEG-LI	$135.4	-$6,394	Major storm event every 2.1 years
RGE	$30.0	-$10,317	3.4 major storm events per year

Note: The cost of a major storm event is calculated as 0.04 percent of the utility service region's annual GSP ("value added" in IMPLAN).

Chapter 4 | Labor Demand Analysis

This chapter describes the methodology used to estimate the change in demand for labor (full-time equivalent workers) associated with undergrounding the utilities' transmission and distribution networks and the results of this analysis.

Methodology

To provide insights into the magnitude of the economic development impact associated with undergrounding utilities' transmission and distribution networks, this analysis estimates the demand for in-state labor under the SQ scenario and the UG scenario, and the net effect of undergrounding on labor demand as the difference between these scenarios. These labor demand estimates include jobs associated with investments in equipment and facilities related to the construction, manufacturing, and installation of overhead and underground lines, as well as those related to the operation and maintenance of this infrastructure.

Labor demand impacts are estimated based on expenditure data from the benefit-cost model, assessment of the industry sectors in which these expenditures are likely to occur, and data on the level of in-state labor associated with expenditures in each of these sectors. The last of these steps relies upon data from IMPLAN, a regional input-output model that characterizes economic activity (*e.g.*, annual expenditures, labor income, employment, and regional supply and demand relationships) for more than 400 industry sectors. While IMPLAN is able to estimate the direct, indirect, and induced employment impacts of expenditures, this analysis focuses only on direct labor demand.[88] Below, each of these steps is discussed in greater detail.

The capital and O&M expenditures previously estimated in the benefit-cost analysis serve as the basis for our labor demand estimates. In order to translate these expenditures to labor demand, the expenditures must be allocated to the industry sectors in which they are likely to occur. We base our allocation of expenditures to industry sectors on analyses of the lifecycle costs of electric transmission lines prepared by Con Edison and the Connecticut Siting Council.[89] Specifically, we assign the capital cost components identified in this analysis to appropriate IMPLAN-defined industry sectors, as shown in Table 14 and Table 15. We assign the O&M costs associated with the operation and maintenance of transmission and distribution lines to a single IMPLAN industry (the commercial and industrial machinery and equipment repair and maintenance sector); for these costs, no further apportionment is necessary.

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[88] Indirect employment results from business-to-business purchases in the supply chain stemming from the initial industry input purchases. Induced employment stems from the household spending of employees within the businesses' supply chain. See IMPLAN. (2020). "Understanding IMPLAN: Direct, Indirect, and Induced Effects." Accessed at https://blog.implan.com/understanding-implan-effects.

[89] This analysis uses the Connecticut Siting Council's lifecycle cost estimates for overhead lines and Con Edison's lifecycle cost estimates for underground lines. CT Siting Council. (2012). "Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines"; Consolidated Edison Company of New York, Central Operations. (2002). "Petition Memo to Office of Electricity and Environment: 'Application of ConEd for Certificate of Environmental Compatibility and Public Need for the Construction and Operation of the Grasslands Project.'"

Table 14. Allocation Assumption by IMPLAN Sector for Overhead Lines

Expenditure Type	Cost Component	Percentage of Costs	Assigned IMPLAN Sector
Capital	Poles and foundations	26%	Power, distribution, and specialty transformer manufacturing
Capital	Conductor and hardware	20%	Power, distribution, and specialty transformer manufacturing
Capital	Administration and project management	11%	Electric power transmission and distribution
Capital	Site work	30.5%	Construction of new power and communication structures
Capital	Construction	3.5%	Construction of new power and communication structures
Capital	Engineering	9%	Architectural, engineering, and related services
O&M	N/A	100%	Commercial and industrial machinery and equipment repair and maintenance

Source: CT Siting Council. (2012). "Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines"

Table 15. Allocation Assumption by IMPLAN Sector for Underground Lines

Expenditure Type	Cost Component	Percentage of Costs	Assigned IMPLAN Sector
Capital	Materials and supplies (*e.g.*, cables, splices, and associated equipment)	5%	Power, distribution, and specialty transformer manufacturing
Capital	Purchased equipment (*e.g.*, transformers, circuit switches, etc.)	18%	Power, distribution, and specialty transformer manufacturing
Capital	Labor	14%	Power, distribution, and specialty transformer manufacturing
Capital	Administrative overhead	19%	Electric power transmission and distribution
Capital	Construction	42%	Construction of new power and communication structures
Capital	Other direct costs including permit fees, surveying, inspections, etc.	2%	Architectural, engineering, and related services
O&M	N/A	100%	Commercial and industrial machinery and equipment repair and maintenance

Source: Consolidated Edison Company of New York, Central Operations. (2002). "Petition Memo to Office of Electricity and Environment: 'Application of ConEd for Certificate of Environmental Compatibility and Public Need for the Construction and Operation of the Grasslands Project.'"

Expenditures in each year are multiplied by the shares shown in Table 14 and Table 15, based on expenditure type and line placement, to estimate expenditures by industry. Expenditures are further multiplied by an industry-specific "regional purchase coefficient," representing the proportion of the expenditures that is likely to be supplied by producers within the region (expenditures which are identified as wage labor are *not* multiplied by this regional purchase coefficient, as these expenditures are assumed to be related entirely to local labor).

After determining the level of in-state expenditures (or labor income) for each industry sector, the expenditures are multiplied by the ratio of employment to expenditures (or employment to labor income) from IMPLAN to convert expenditures (or labor income) into estimates of direct labor demand. These ratios are specific to each industry and utility service area. The resulting labor demand estimates, generated annually for each utility, can then be summed across utilities to provide an estimate of statewide labor demand associated with operating, maintaining, and replacing electric transmission and distribution lines in both the status quo and undergrounding scenarios.

Results

Based on the capital and O&M expenditures estimated in the benefit-cost analysis, the direct impact of operating, maintaining, and replacing electric transmission and distribution lines on statewide demand for labor varies substantially between the status quo and undergrounding scenario. As shown in Table 16, in the status quo scenario, the operation, maintenance, and replacement of electric transmission and distribution lines is estimated to require a labor force of approximately 22,000 workers per year.[90] In the undergrounding scenario, these activities are estimated to require a labor force of approximately 78,000 workers per year. Thus, the net effect of undergrounding the utilities' transmission and distribution systems is estimated to be an increase in labor requirements of approximately 56,000 workers per year (an increase of more than 250 percent). The largest effects would be realized in the transformer manufacturing and power and communication structure construction sectors, due to the greater capital expenditures associated with underground lines.

Table 16. Summary of Labor Demand Impacts

Industry Sector	Average Jobs per Year – Status Quo Scenario	Average Jobs per Year – Undergrounding Scenario	Average Jobs per Year – Net	Change in Average Jobs per Year
Capital	15,578	65,587	50,010	+321%
O&M	6,432	12,549	6,117	+95%
Total	**22,010**	**78,136**	**56,126**	**+255%**

[90] All estimates of labor force requirements are expressed on a full-time equivalent basis.

Figure 18 illustrates the variation in direct, in-state labor force requirements by industry and year in the status quo scenario. As the figure indicates, demand for labor in the commercial and industrial machinery and equipment repair and maintenance sector—the industry sector associated with O&M expenditures—is projected to remain relatively constant over time. Because capital expenditures in the benefit-cost model vary from year to year based on the replacement decision methodology, annual demand for labor in sectors related to capital expenditures varies more substantially. This is especially true of the construction of new power and communication structures and transformer manufacturing sectors. Demand for labor in the architectural, engineering, and related services and electric power transmission and distribution sectors is projected to remain relatively constant over time; as these industries constitute a smaller share of overall capital expenditures, the demand for labor in these sectors varies by a smaller amount than in others.

Figure 18. Direct Labor Demand by Cost Type – Status Quo Scenario

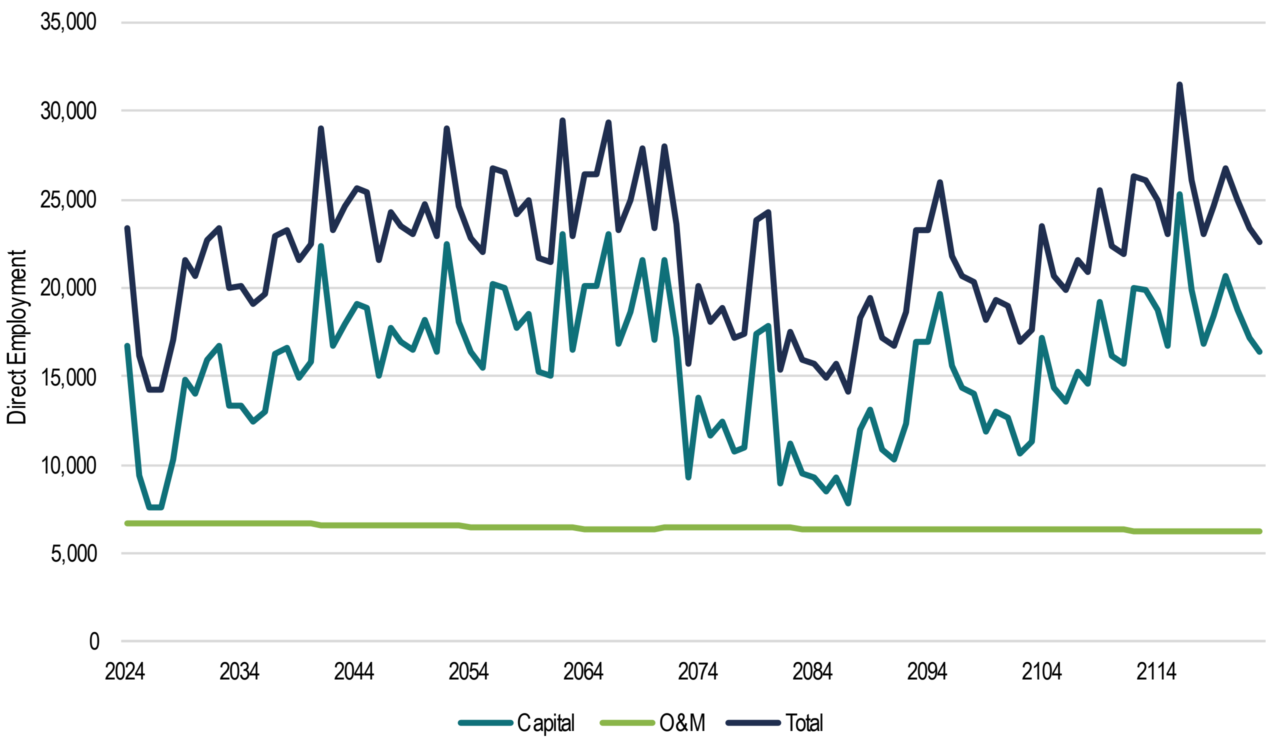


Figure 19 illustrates the variation in direct, in-state demand for labor by cost type and year in the undergrounding scenario. As in the status quo scenario, demand for labor varies substantially from year to year. In the undergrounding scenario, however, demand for labor is expected to be much higher. In the commercial and industrial machinery equipment repair and maintenance sector, the increase in labor demand reflects the higher O&M costs relative to the status quo scenario. Demand for labor in the construction of new power and communication structures sector and transformer manufacturing sector is also projected to be substantially higher, with a notable dip from around 2067 to 2090. This timing corresponds with a period in which multiple utilities are not expected to replace transmission lines, based on the ages and lifespans of transmission lines used in this analysis (see Figure 7 on page 19).

Figure 19. Direct Labor Demand by Cost Type - Undergrounding Scenario

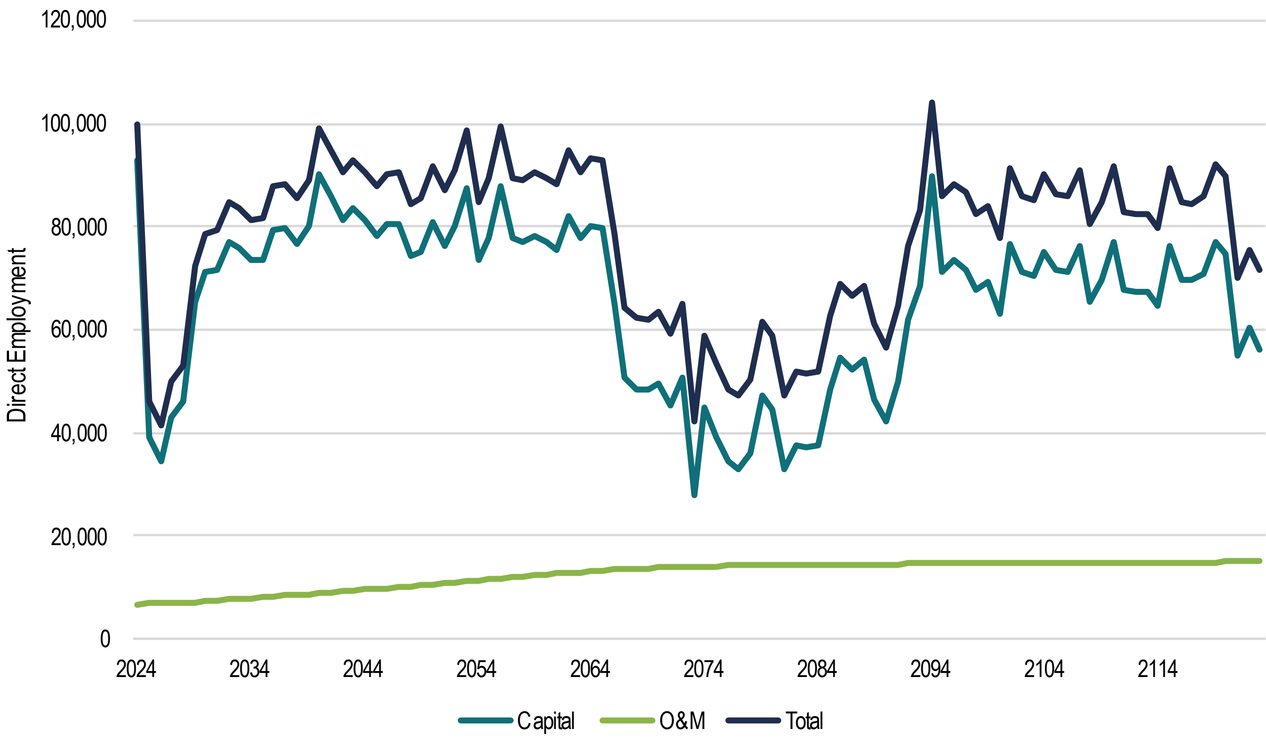
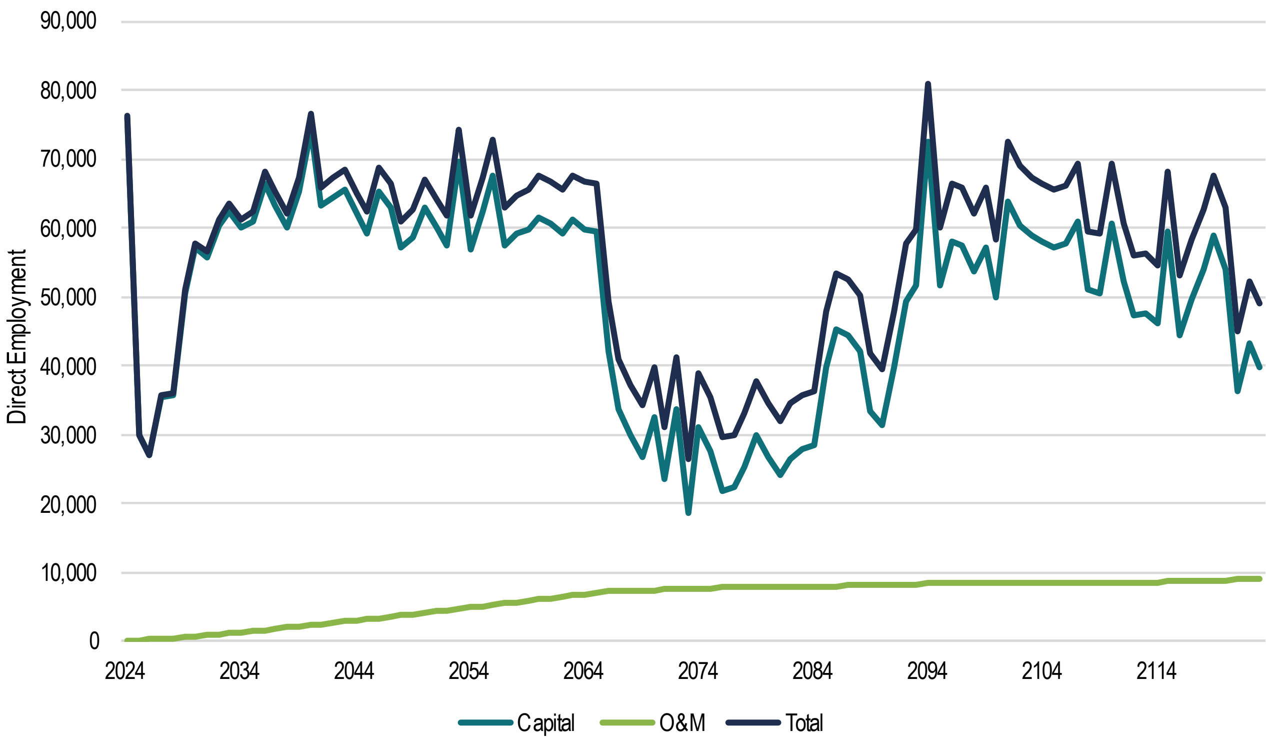


Figure 20 presents the projected change in labor requirements for the undergrounding scenario relative to the status quo. Demand for labor associated with operation and maintenance of the electric transmission and distribution network (*i.e.*, in the commercial and industrial machinery and equipment repair and maintenance sector) is projected to increase over time as lines are moved underground. Demand for labor related to transformer manufacturing and construction of power and communication structures is also projected to be substantially higher in the earlier years of the analysis, with year-to-year variation based on the timing of line replacement (especially lines requiring a higher level of capital expenditures).

Figure 20. Direct Labor Demand by Industry Sector - Net



Chapter 5 | Sensitivity Analysis and Other Considerations

Sensitivity Analysis

Sensitivity analyses—*i.e.*, evaluating how the results of a model vary based on changes in certain inputs—are used to evaluate the range of potential results in the face of uncertainty. As is the case with any large-scale economic model, the benefit-cost model employed in this analysis is subject to a variety of uncertainties. Chief among these, based on the range of estimates provided by the utilities in response to DPS' information request and the subsequent effect on the calculation of costs—and therefore net social welfare—are the per-mile capital and O&M cost estimates associated with replacing and maintaining electric power lines. While other parameters also have an impact on the analysis, their effects are relatively minimal in comparison. Due to the overwhelming effect of costs on the net social welfare calculation, this sensitivity analysis focuses on the range of net social welfare outcomes when considering uncertainty regarding capital and O&M costs.

The sensitivity analysis employs a "Monte Carlo" model to evaluate the implications of changes in analytic inputs. A Monte Carlo model uses repeated random sampling to ascertain the range of possible outcomes under uncertainty—*i.e.*, it is a simulation-based approach to evaluating model sensitivity. Compared to a scenario-based sensitivity analysis (*e.g.*, modeling a low, medium, and high case), Monte Carlo models are able to effectively evaluate a wide range of scenarios by randomly determining the value of multiple parameters simultaneously.[91]

In the base benefit-cost analysis, capital and O&M costs were applied to each utility's network based on the responses provided by that utility (*e.g.*, the modeled costs for Central Hudson's network were based on Central Hudson's costs estimates). In the Monte Carlo analysis, capital and O&M costs are assumed to be equal across utilities. The unit costs used in the benefit-cost model are randomly sampled from uniform distributions[92] based on the range of costs in the utilities' responses (see Table 3 on page 21 and Table 4 on page 22). The Monte Carlo model is run 500 times, each time drawing a randomly determined set of costs from these ranges, and conducting the benefit-cost analysis using these costs.

The results of the Monte Carlo sensitivity analysis are presented in Figure 21. As shown, the range of potential net social welfare results is negative across all 500 simulations. The average net social benefit of -$231 billion is slightly greater (*i.e.*, less of a loss) than the net social benefit estimated in the main benefit-cost analysis (-$261 billion). These results do not include consideration of the breakeven analysis, which may posit a more plausible breakeven point for at least some Monte Carlo simulation results that still estimate a net social cost.

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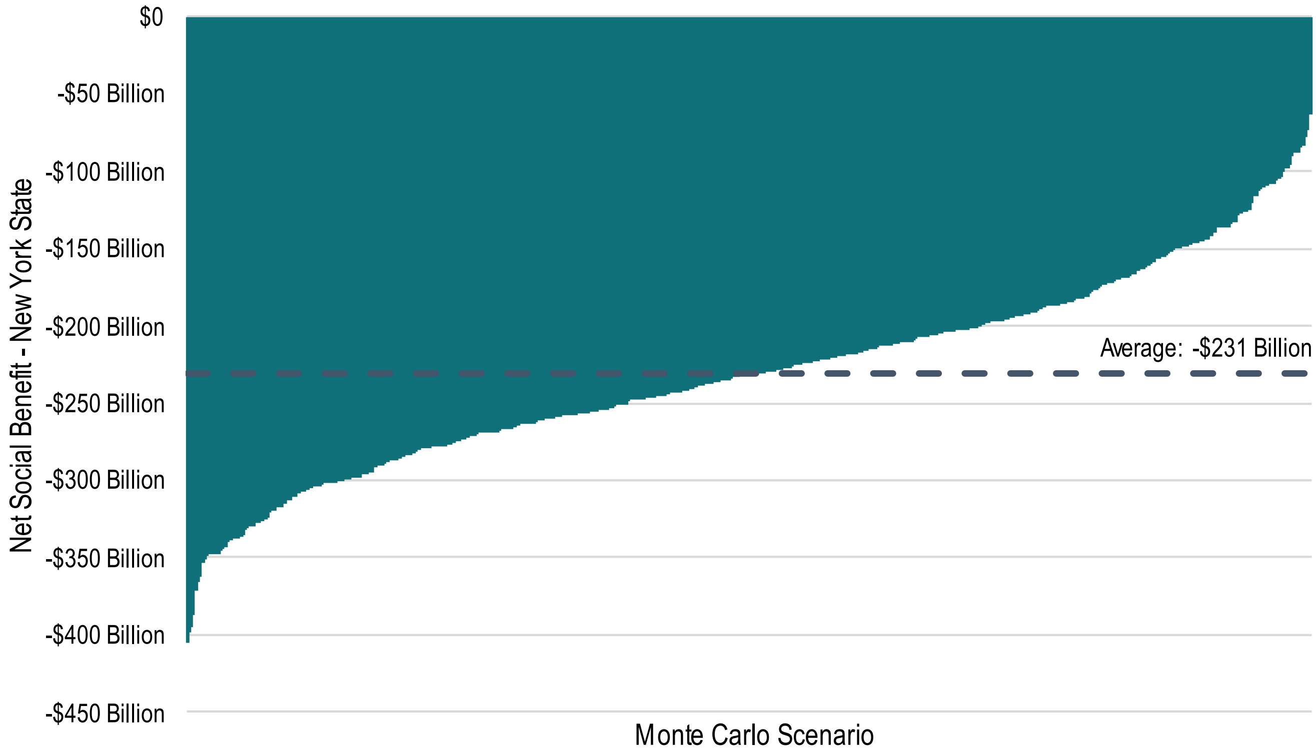
[91] In other words, rather than a "low" scenario in which all parameters being tested assume a low value, and a "high" scenario in which all parameters assume a high value, a Monte Carlo analysis will, over repeated simulations, evaluate cases in which all parameters are low, various combinations of parameters are low or high, and all parameters are high.

[92] With a uniform distribution, each value within the defined range is equally likely to be selected in each Monte Carlo simulation.

Figure 21. Net Social Benefit Results under Monte Carlo Sensitivity Analysis



This sensitivity analysis shows that the overall result of the analysis—*i.e.*, that undergrounding the utilities' electric power lines represents a net social cost to the state—is unlikely due to uncertainty around capital and O&M costs. In other words, the fact that these costs are a key factor in yielding a negative net benefit is not due to uncertainty or variation in the utilities' estimates of these costs, but rather the sheer magnitude of the difference in costs compared to expected benefits.

Chapter 6 | Residential Electricity Bill Impact Analysis

In addition to the benefit-cost analysis, this analysis assesses the potential impact of undergrounding the utilities' electric transmission and distribution lines on residential customers' monthly bills. Under the undergrounding scenario, utilities would incur additional costs—beyond those they would incur in the status quo scenario—to bury transmission and distribution lines; these costs would then be passed on to customers in their electricity bills. With the support of DPS, this analysis uses the expenditures estimated in the benefit-cost analysis to estimate impacts on customers' electricity bills.

The analysis of rate impacts is conducted on a utility-by-utility basis. It considers six of the seven utilities examined in the benefit-cost assessment; differences in the underlying revenue requirement model for PSEG-LI prohibited analysis of potential impacts on PSEG-LI's customers. The analysis follows a standard set of steps for each utility. First, the difference in O&M costs over time and between scenarios is calculated. Second, a similar exercise is performed with respect to capital expenditures to calculate the rate base; this calculation includes not only estimates of incremental capital expenditures, but also retirement costs and depreciation expenses. As with O&M expenditures, the capital expenditures used in these calculations are drawn from the lifecycle cost component of the benefit-cost analysis. These calculations are performed for each placement and line type combination (*i.e.*, overhead distribution, underground distribution, overhead transmission, and underground transmission—in this analysis, referred to as "investment categories"). Third, the incremental O&M and capital costs are used as the basis for calculating the total incremental revenue requirement associated with undergrounding—*i.e.*, the additional amount the utilities must collect from customers to pay the additional costs of undergrounding. Finally, the cost impact to average residential customer electricity bills is estimated. These steps are explained in greater detail below:

1. **Calculate incremental O&M costs due to undergrounding**, a component of the total incremental revenue requirement associated with undergrounding:
    a. For both the undergrounding and status quo scenarios, estimate incremental O&M expenditures for a given year as the difference between the O&M expenditures estimated for that year (in the lifecycle cost component of the benefit-cost analysis) and O&M expenditures in the initial analysis year (2023).
    b. Calculate the difference in incremental annual O&M expenditures between the undergrounding and status quo scenarios.
2. **Calculate change in rate base due to undergrounding**, a component of the total incremental revenue requirement:
    a. Track *new expenditures* and *retirements* in each year. New expenditures are drawn from annual capital expenditures, as estimated in the lifecycle cost component of the benefit-cost model. These capital expenditures are assumed to have an average service life of 65 years, after which they are retired, at a cost of removal (net salvage rate) of 80 percent of the original capital expenditure.
    b. For each year, estimate the *average plant in service* as the average of the plant in service at the start of the year and the plant in service at the end of the year. *Start-of-year plant in service* was calculated as total capital expenditures at the end of the previous year, while *end-of-year plant in service* is calculated as *start-of-year plant in service* plus new capital expenditures in that year, less retirements in that year. New capital expenditures are based on the lifecycle costs modeled in the benefit-cost analysis, while retirements are assumed to occur in the 65th year, based on an assumed average service life of 65 years.

c. Calculate *incremental depreciation expenses* as the *composite depreciation rate* of 2.77 percent[93] multiplied by the *average plant in service*.
d. Calculate the *cost of removal* as the cost of removal rate (80 percent) multiplied by retirements in each year.
e. Calculate the current year reserve as the prior year reserve, plus depreciation expenses, minus net salvage expenses (total retirements minus cost of removal).
f. Calculate the *rate base* by subtracting the *current year reserve* (step e) from the *average plant in service* (step b).
g. Calculate the *incremental revenue requirement* associated with the *rate base* by multiplying the *rate base* by the pre-tax rate of return (10 percent[94]).

3. **Calculate total incremental revenue requirement** to inform the expected increase in customer bills:
   a. Add the *incremental O&M expenses, depreciation expenses,* and *return on rate base* calculated in prior steps to estimate the *incremental revenue requirement* in each year. This calculation is performed separately for all investment categories under both the status quo and undergrounding scenarios.
   b. Calculate the difference in the *incremental revenue requirement* between the status quo and underground scenarios, by investment category and in total.
   c. Calculate the *difference in delivery revenues and total revenues* by dividing *(i)* the change in the incremental revenue requirement from status quo and undergrounding scenarios by *(ii)* present delivery revenues and total revenues.
4. **Estimate the cost impact to average residential customer electricity bills** by applying the incremental revenue requirement to existing billing information:
   a. Obtain New York Public Service Commission-approved distribution and transmission overhead and underground allocation factors from Embedded Cost of Service (ECOS) studies. Using these factors, allocate costs by investment category to residential classes under both the status quo and undergrounding scenarios.
   b. Calculate average monthly bills for each utility using base delivery, total revenue, and customer counts.
   c. Calculate future monthly bills by adding the incremental revenue requirement to the present total and base delivery revenues, divided by the average number of annual residential bills.
   d. Calculate the difference in average monthly total bills and average monthly delivery bills as the average bill in the undergrounding scenario minus the average bill in the status quo scenario, for each year.

Table 17 presents the average increase in residential customers' total monthly bills at 10-year intervals, from 2025 through 2055. Table 18 presents similar information, but focuses on the average increase in monthly delivery charges (i.e., the component of the monthly bill that reflects the cost of delivering electricity to each customer). As the table shows, potential impacts to customers in all service areas are smaller in earlier years, as undergrounding efforts are still in their initial stages, and increase over time as the difference in total expenditures between the undergrounding and status quo scenarios increases. Nevertheless, in service areas where costs are higher and customer densities are lower, the impact on the average customer's bill could quickly

[93] The composite depreciation rate is calculated as $\frac{100\%-80\%}{65}$, based on the cost of removal rate of 80 percent and average service life of 65 years.

[94] 10 percent was used as a conservative estimate, as bill impacts estimated in this analysis do not include property taxes, as well as other factors not included in the estimated incremental revenue requirement.

become substantial. —For example, the analysis indicates that NYSEG's residential customers could face an average increase of nearly 50 percent in their monthly bills by 2025.

Table 17. Average Increase in Total Monthly Bill Relative to 2023

Year	Central Hudson	Con Edison	National Grid	NYSEG	Orange and Rockland	RGE
2025	20%	1.4%	27%	48%	23%	3.3%
2035	22%	10%	121%	140%	77%	32%
2045	113%	11%	172%	168%	103%	70%
2055	171%	11%	197%	168%	116%	71%

Table 18. Average Increase in Monthly Delivery Charge Relative to 2023

Year	Central Hudson	Con Edison	National Grid	NYSEG	Orange and Rockland	RGE
2025	35%	2.4%	50%	91%	40%	5.9%
2035	39%	15%	187%	187%	114%	49%
2045	184%	17%	241%	203%	142%	87%
2055	270%	16%	264%	194%	156%	84%

By 2055, the magnitude of the estimated rate impacts varies substantially by service area. Customers served by Con Edison, where many lines are already underground and the density of customers per line mile is higher, are projected to experience relatively minor impacts, with increases in total bills of approximately 11 percent (with a slightly higher increase in delivery charges of around 16 percent). In contrast, customers served by National Grid and NYSEG are projected to experience far greater impacts, due both to the higher costs associated with undergrounding electric transmission and distribution lines in those service areas and the low density of customers. National Grid customers could see their total electricity bills increase by nearly 200 percent (*i.e.*, triple in cost), and delivery charges increase by an even greater amount (264 percent).

Because the analysis of residential bill impacts draws upon expenditures estimated in the benefit-cost analysis, it is subject to many of the same limitations. Importantly, these impacts are based on expenditures estimated according to the methodology described in Chapter 3, which assumes lines are replaced when they reach the end of their stated lifespan, rather than according to a planned replacement schedule. The variance in expenditures across years as modeled is therefore higher than it would be in practice.

Appendix I | ICE Calculator

This appendix provides additional details on the ICE Calculator framework for estimating interruption costs.

Customer interruption cost functions in the ICE Calculator are estimated via a two-part regression: (1) a probit model predicts the probability of a given customer reporting a positive value rather than a value of zero for an interruption scenario based on independent variables capturing customer and interruption characteristics, and (2) a generalized linear model (GLM) is then used to relate interruption costs for customers who report positive costs to the same set of independent variables.[95] Based on data from 34 existing customer interruption cost studies, the ICE Calculator estimates interruption costs based on a limited set of inputs: reliability index values, the affected geographical area (which determines the value of geographically-specific parameters), and the number of affected residential, small commercial and industrial (C&I), and medium/large C&I customers. The ICE Calculator draws on regionally specific data to determine the following customer characteristics:

- Annual power usage in megawatt-hours (MWh) by customer class
- Median household income (HHI) for residential customers
- Percentages of small and medium/large C&I customers in construction and manufacturing
- Medium/large C&I gross domestic product (GDP) per kilowatt-hour (KWh)
- Percentage of power interruptions occurring at certain times-of-day or times-of-year
- Percentage of C&I customers with backup generation **or** power conditioning vs. backup generation ***and*** power conditioning

These reliability and customer characteristic inputs are used in the probit and GLM models to obtain the cost per interruption event for each customer class. The cost per event is multiplied by the annual interruption frequency for an average customer (SAIFI) and the number of customers in each respective class to produce an estimate of total sustained interruption costs, which are then combined across all customer classes into an overall interruption cost.

The following formula outlines the general structure of the probit and GLM regression models used in the ICE Calculator:

$$
\begin{aligned}
&CustomerClass^{ModelType}\\
&\quad = (CAIDI_y \times \beta_{CAIDI}) + (\mathrm{CAIDI}_y^2 \times \beta_{CAIDI^2}) + (\ln MWh \times \beta_{\ln MWh})\\
&\quad + \left(\ln MWh \times \mathrm{CAIDI}_y\right) \times \beta_{\ln MWh*CAIDI}\big) + \left((\ln MWh \times \mathrm{CAIDI}_y^2) \times \beta_{\ln MWh*CAIDI^2}\right)\\
&\quad + (HHI \times \beta_{HHI}) + (Summer \times \beta_{Summer}) + (Morning \times \beta_{Morning})\\
&\quad + (Afternoon \times \beta_{Afternoon}) + (Evening \times \beta_{Evening}) + (BackupOrPC \times \beta_{BackupOrPc})\\
&\quad + (BackupAndPC \times \beta_{BackupAndPc}) + (Construction \times \beta_{Construction})\\
&\quad + (Manufacturing \times \beta_{Manufacturing}) + (GDPperKWh \times \beta_{GDPperKWh}) + (Constant)
\end{aligned}
$$

For residential, small C&I, and medium/large C&I customer classes ($CustomerClass$), the structures of the probit and GLM regressions ($ModelType$) remain consistent, while the coefficients change depending on the econometric relationships between the model outputs and the independent variables for each customer type. $CAIDI_y$ and $CAIDI_y^2$ represent the value of CAIDI and the squared value of CAIDI in a given analysis year; $\ln MWh$ is the natural logarithm of power consumption; HHI is median household income; $Summer$ is the

[95] Sullivan, M. J., Schellenberg, J., & Blundell, M. (2015). *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory & Resource Innovations, Inc.

percentage of power interruptions that occur in the summer months; $Morning$, $Afternoon$, and $Evening$ are the percentages of interruptions that occur during each respective time of day; $BackupOrPC$ is the percentage of C&I customers with backup *or* power conditioning; $BackupAndPC$ is the percentage of C&I customers with backup *and* power conditioning; $Construction$ and $Manufacturing$ are the percentages of C&I customers in construction and manufacturing industries, respectively; $GDPperKWh$ is the medium/large C&I GDP per KWh; and $Constant$ represents the regression constant. While each coefficient (β) varies by customer class and model type, some independent variables differ by customer class, and others are constant across customer classes.

Table 19 lists the coefficients corresponding to each input variable in the above formula structure.

Table 19. Two-Part Regression Model Coefficients

Coefficient	Probit Regression Model – Residential Customers	GLM Regression Model – Residential Customers	Probit Regression Model – Small C&I Customers	GLM Regression Model – Small C&I Customers	Probit Regression Model – Medium/Large C&I Customers	GLM Regression Model – Medium/Large C&I Customers
CAIDI	0.001741483	0.0024405574	0.003361845	0.0041896885	0.0050624017	0.005003441
$CAIDI^2$	-0.000000673518	-0.000000947403	-0.00000178266	-0.00000215548	-0.00000268858	-0.00000291223
ln(MWh)	0.1297018404	0.2620475632	0.1235906127	0.0693833984	0.1184490626	0.4894602452
ln(MWh) * CAIDI	0	0	0	0	-0.0003182716	-0.0001269611
ln(MWh) * $CAIDI^2$	0	0	0	0	0.000000148095	0.000000107105
HHI	0.000000233991	0.00000165284	0	0	0	0
Summer	0.2239800629	0.2372353235	0.2147365799	-0.3835529067	0.3802666224	0.032149664
Morning	0	0	0.5367478573	-0.0571366526	0	0
Afternoon	-0.2551161036	-0.2905392114	0.6640246944	-0.0316658109	0	0
Evening	-0.0827135927	-0.0964909259	0	0	0	0
Backup or Power Conditioning	0	0	0.0819139252	0.3078731978	0	0
Backup and Power Conditioning	0	0	0.2715194145	0.5377311661	0	0
Construction	0	0	0.2613991976	0.785810068	0	0
Manufacturing	0	0	0.1755496488	0.5874655886	0.2031416757	0.818313885
GDP per KWh	0	0	0	0	0.024341215	0.0733090872
Constant	-0.0528423763	1.298643681	-1.332246157	7.000248624	-1.082217291	4.915990498

The values of CAIDI input into these equations vary across the modeled years depending on projected SAIFI values, as described above. Annual customer power consumption in MWh for each customer class (c) for each utility (u) is calculated from data reported by the utilities in their responses to DPS' information request by converting KWh consumption by customer class into MWh consumption, then dividing by the number of customers.

Median household income values for residential customers (in 2019 USD) are obtained from New York-specific household income data implemented in the IEc NYSERDA ORB model;[96] these household incomes are adjusted to 2013 dollars using U.S. Bureau of Labor Statistics Consumer Price Index data to align with the dollar year of the ICE Calculator's inputs.[97] The remaining input values are calculated from ICE Calculator data for New York, by customer class, as listed in Table 20.

Table 20. ICE Calculator New York State Inputs

Coefficient	Residential	Small C&I	Medium / Large C&I
Percentage of Outages in Summer	33.33%	33.33%	33.33%
Percentage of Outages in Morning	25%	25%	25%
Percentage of Outages in Afternoon	20.83%	20.83%	20.83%
Percentage of Outages in Evening	20.83%	20.83%	20.83%
Percentage with Backup *or* Power Conditioning	0%	26.2%	37.2%
Percentage with Backup *and* Power Conditioning	0%	3.4%	0.084
Percentage in Construction Industry	0%	9.86%	2.15%
Percentage in Manufacturing Industry	0%	3.53%	12.71%
GDP per KWh (2013 USD)	$15.0184	$15.0184	$15.0184

Once the probit and GLM values for each customer class are generated using these inputs and formulas, the predicted probabilities from the probit models are multiplied by the estimated interruption costs from the GLM models to calculate costs per interruption for each utility by customer class:

$$CostPerEvent_{ucy} = \left(\phi\left(Probit_{ucy}\right) \times e^{GLM_{ucy}}\right) * \frac{CPI_{2023}}{CPI_{2013}}$$

[96] Industrial Economics, Inc. (2021a). *Documentation of the NY-Outage Resiliency Benefits (NY-ORB) Model 1.0: A Modeling Tool for Evaluating the Future Costs of Power Outages in New York State.*

[97] U.S. Bureau of Labor Statistics. (2023). Consumer Price Index for All Urban Consumers (CPI-U) [Data set]. https://data.bls.gov/PDQWeb/cu.

The cost per interruption event ($CostPerEvent$) for each customer type is estimated as the standard normal cumulative distribution function (ϕ) of the probit model output ($Probit$) multiplied by the inverse of the natural-logarithmic GLM model output (GLM)—*i.e.*, the predicted probability of a customer reporting an interruption multiplied by the estimated interruption costs. As the ICE Calculator's parameter values and input data are in 2013 dollars, the resulting cost estimate is then inflated to 2023 dollars using the ratio of BLS-reported CPI in 2023 relative to 2013 ($\frac{CPI_{2023}}{CPI_{2013}}$).

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