Cause No. 45894

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a CENTERPOINT ENERGY INDIANA SOUTH
(CEI SOUTH)

DIRECT TESTIMONY
OF
JASON D. DE STIGTER
DIRECTOR, UTILITY INVESTMENT PLANNING,1898 & CO.

ON

ELECTRIC TDSIC PLAN

SPONSORING PETITIONER'S EXHIBIT NO. 3,
ATTACHMENTS JDD-1 THROUGH JDD-2

DIRECT TESTIMONY OF JASON D. DE STIGTER

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jason De Stigter, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("Petitioner", "CEI South", or "Company").

Q. WHAT IS YOUR ROLE WITH RESPECT TO PETITIONER CEI SOUTH?

A. I am employed by 1898 & Co. as a Director and lead the Utility Investment Planning team as part of 1898 & Co.'s Energy and Utilities Consulting Practice. 1898 & Co. was established as the consulting and technology consulting division of Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") in 2019. 1898 & Co. is a nationwide network of nearly 400 consulting professionals serving the Manufacturing & Industrial, Oil & Gas, Power Generation, Transmission & Distribution ("T&D"), Transportation, and Water industries.

Burns & McDonnell has been in business since 1898, serving multiple industries, including the electric power industry. Burns & McDonnell is a family of companies made up of more than 10,000 engineers, architects, construction professionals, scientists, consultants, and entrepreneurs with more than 40 offices across the country and throughout the world.

Q. BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND CERTIFICATIONS.

A. I received a Bachelor of Science degree in Engineering and a Bachelor's in Business Administration from Dordt College, now called Dordt University. I am a registered Professional Engineer in the State of Kansas.

Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND DUTIES AT 1898 & CO.

A. I am a professional engineer with 15 years of experience providing consulting services to electric utilities. Through my work at 1898 & Co. and Burns & McDonnell, I have extensive experience in asset management, capital planning and optimization, risk and resilience assessments and analysis, asset failure analysis, and business case development for utility clients. I have been involved in numerous studies modeling risk for utility industry clients. These studies have included risk and economic analysis engagements for several multi-billion-dollar capital projects and large utility systems. In my role as a Director, I have worked on and overseen risk and resilience analysis consulting studies on a variety of electric power transmission and distribution assets, including developing complex and innovative risk and resilience analysis models. My primary responsibilities are business development and project delivery within the Utility Consulting Practice with a focus on developing risk and resilience-based business cases for large capital projects/programs.

Prior to joining 1898 & Co. and Burns & McDonnell, I served as a Principal Consultant at Black & Veatch inside their Asset Management Practice, and, in that capacity, also performed risk and resilience studies.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE INDIANA UTILITY REGULATORY COMMISSION ("COMMISSION")?

A. Yes, I provided written, rebuttal, and oral testimony on behalf of Indianapolis Power & Light, now AES Indiana, before the Commission. Additionally, a list of my prior testimony is included in my resume, provided as <u>Petitioner's Exhibit No. 3</u>, **Attachment JDD-1**.

Q. ARE YOU SPONSORING ANY ATTACHMENTS IN SUPPORT OF YOUR TESTIMONY?

A. Yes. I am sponsoring the following attachments in this proceeding:

- <u>Petitioner's Exhibit No. 3</u>, **Attachment JDD-1**: Jason De Stigter Resume; and
- <u>Petitioner's Exhibit No. 3</u>, **Attachment JDD-2:** CEI South's TDSIC Investment Identification & Business Case Supplemental Attachment

Q. WERE THESE ATTACHMENTS PREPARED OR ASSEMBLED BY YOU OR UNDER YOUR DIRECTION OR SUPERVISION?

A. Yes, they were.

Q. PLEASE DESCRIBE YOUR INVOLVEMENT IN THE PREPARATION OF CEI SOUTH'S TDSIC PLAN AND BUSINESS CASE DEVELOPMENT.

A. CEI South engaged 1898 & Co. to assist in developing, evaluating, and assessing the 2024 – 2028 TDSIC Plan ("Plan"). In that capacity, I served as the 1898 & Co. project director, working directly with CEI South's Team in the Plan development and justification.

Specifically, I was responsible for the overall 1898 engagement and involved in the development of the business case assessment.

II. EXECUTIVE SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to 1) outline the approach employed by CEI South and 1898 & Co. to develop the Plan (Section III of this testimony) and 2) to summarize the results (Section IV of this testimony) and methodology used by 1898 & Co. to identify, prioritize, and justify the Plan's investments. Through my testimony, I will describe 1898 & Co.'s approach to guide CEI South through development of the Plan and the Plan's business case showing that the Plan development and justification are intrinsically linked together. Specifically, I will describe CEI South's investment objectives for the Plan and their alignment to TDSIC Purposes. Further, I will describe the business case value framework and how it is the "measuring stick" for how each investment, program, and the Plan meet both CEI South's Plan Objectives and TDSIC Purposes. I will outline which investments are identified and evaluated using the quantified and qualitative benefits approaches. I will describe the two main approaches utilized to estimate quantified incremental benefits from the Plan, the data that served as the foundation for the evaluation, and how quantified benefits were estimated. I will also describe the results of the business case assessment performed for each investment program. Finally, I will provide my conclusions.

Q. PLEASE DESCRIBE THE EVALUATION 1898 & CO. CONDUCTED FOR CEI SOUTH.

A. 1898 & Co. employed an objective-driven decision making approach as the foundation for developing the 2024 – 2028 TDSIC Plan. The purpose of the objective-driven decision making approach is to identify and align investments to CEI South's Plan Objectives (Deliver Service Safely, Maintain Reliability & Resiliency, Manage Asset Lifecycles, and Modernize the Grid) and TDSIC Purposes (Safety, Reliability, Economic Development, Modernization). As part of this approach, 1898 & Co. developed a business case value framework to measure an investment against achieving the Plan Objectives.

CEI South and 1898 & Co. identified the following 7 investment programs that align to CEI South Plan Objectives and TDSIC Purposes.

(1) Transmission Line Rebuild
(2) Substation Rebuild
(3) Distribution 12kV Circuit Rebuild
(4) Distribution Underground Rebuild
(5) Distribution Automation.
(6) Wood Pole Replacements
(7) Substation Physical Security

The business case value framework includes both quantitative and qualitative value drivers for each investment. Each of the value drivers is directly linked to one of the CEI South Plan Objectives and indirectly to one or more TDSIC Purposes. For the quantitative evaluation, 1898 & Co. utilized a risk and resiliency-based planning approach to provide a business case for each investment. The evaluation leverages 1898 & Co.'s AssetLens Analytics Engine (also referred to as the "Risk Model"), an asset investment planning tool to evaluate the life-cycle benefits of replacing T&D infrastructure and deploying smart devices across the distribution system.

The business case evaluation employs a data-driven, bottoms-up methodology utilizing robust and sophisticated analytics to calculate the risk and resiliency benefit of investments in terms of:

- Avoided Reactive and Restoration Costs – the quantified measure for the "Manage Asset Life-Cycles" CEI South objective
- Avoided Customer Outages
  - Customer Minutes Interrupted ("CMI")
  - Monetization of avoided CMI using the Department of Energy ("DOE") Interruption Cost Estimator ("ICE") Calculator – the quantified measure for the "Maintain Reliability & Resiliency" CEI South Objective.

The quantitative business case assessment was performed across the entire CEI South T&D system. 1898 & Co. and CEI South prioritized the investments into the Plan to provide the most value to customers after accounting for CEI South execution constraints, as further discussed below. For the investments identified using this quantitative approach, the business case also included qualitative factors as additional benefit streams.

Approximately 81.2 percent of the Plan investment level was developed using this approach.

CEI South also identified investments based on other system needs. These investments were identified by CEI South planning, engineering, field operations, and maintenance teams ("CEI South System Stakeholders"). The business case for these investments is based on their alignment to CEI South Plan Objectives and TDSIC Purposes. Approximately 18.8 percent of the Plan was developed using this approach. Many of these investments are needed to manage safety risks and to continue to deliver electric service.

The evaluation also incorporated detailed Class 2 cost estimates for the first two years and Class 4 estimates for years three through five of the Plan. Additionally, the evaluation included potential substitution projects ("PSPs") for Plan flexibility.

Table JDD-1, included in the next question, shows the seven investment programs that are part of the Plan. The table includes the approach used to identify investments for each program and the corresponding business case approach to evaluate the alignment to CEI South's Plan Objectives.

Q. PLEASE PROVIDE AN OVERVIEW OF THE PLAN BUSINESS CASE.

A. Table JDD-1 provides an overview of the business case for each of the seven investment programs and the Plan. The table shows the Plan produces quantified benefits of approximately $681.3 million with a Plan investment level of $404.6 million in 2023 dollars ($454 million in nominal terms). The Plan has a quantified benefit in excess of cost for a benefit cost ratio of 1.7. Additionally, for the 5 programs that included a quantitative business case, the table shows that benefits are in excess of cost for each program. Further, for each individual investment for which a quantitative benefit was measured, the quantified incremental benefit exceeds the cost. The table also shows that many of the investments have additional qualitative benefits. For the qualitative evaluated investments identified by CEI South System Stakeholders, the main benefit drivers are safety and delivering service, which both align to CEI South Plan Objectives and TDSIC Purposes. Petitioner's Exhibit No. 3, **Attachment JDD-2** (Section 3.0) includes the business case results for each investment within each program. The attachment includes both the quantitative business case results and descriptions for each qualitative benefit driver.

Table JDD-1: CEI South TDSIC Plan Business Case Summary

Program Investment Identification Approach	**Business Case Approach**		**Quantified PV Benefit (2023) $Millions**	**Plan Investment (2023) $Millions**	**Plan Investment (Nominal) $Millions**	**Benefit Cost Ratio**
	Quantitative	**Qualitative**				
Transmission Line Rebuild						
Risk and Resiliency Analytics[1]	■	■	$142.6	$106.9	$121.0	1.3
CEI South System Stakeholders		■	N/A	$6.0	$6.2	N/A
Transmission Line Rebuild Total			**$142.6**	**$112.8**	**$127.2**	**1.3**
Substation Rebuild						
Risk and Resiliency Analytics[1]	■	■	$94.5	$79.3	$90.1	1.2
CEI South System Stakeholders		■	N/A	$12.9	$13.4	N/A
Substation Rebuild Total			**$94.5**	**$92.3**	**$103.5**	**1.0**
Distribution 12kV Circuit Rebuild						
Risk and Resiliency Analytics[1]	■	■	$336.2	$81.6	$92.1	4.1
CEI South System Stakeholders		■	N/A	$6.3	$6.7	N/A
Distribution 12kV Circuit Rebuild Total			**$336.2**	**$87.8**	**$98.8**	**3.8**
Distribution Automation						
Risk and Resiliency Analytics[2]	■	■	$37.0	$17.2	$19.6	2.2
CEI South System Stakeholders			N/A	N/A	N/A	N/A
Distribution Automation Total			**$37.0**	**$17.2**	**$19.6**	**2.2**
Distribution Underground Rebuild						
Risk and Resiliency Analytics[1]	■	■	$71.1	$40.9	$45.9	1.7
CEI South System Stakeholders			N/A	N/A	N/A	N/A
Distribution Underground Rebuild Total			**$71.1**	**$40.9**	**$45.9**	**1.7**
Wood Pole Replacement						
Risk and Resiliency Analytics			N/A	N/A	N/A	N/A
CEI South System Stakeholders		■	N/A	$40.7	$45.0	N/A
Wood Pole Replacement Total			**N/A**	**$40.7**	**$45.0**	**N/A**
Substation Physical Security						
Risk and Resiliency Analytics			N/A	N/A	N/A	N/A
CEI South System Stakeholders		■	N/A	$12.9	$14.0	N/A
Substation Physical Security Total			**N/A**	**$12.9**	**$14.0**	**N/A**
Plan Total			**$681.3**	**$404.6**	**$454.0**	**1.7**

[1] Equipment Failure Risk and Resiliency Quantitative Business Case Approach

[2] Outage Mitigation Risk and Resiliency Quantitative Business Case Approach

Q. WHAT WILL YOUR TESTIMONY CONCLUDE REGARDING CEI SOUTH TDSIC PLAN AND BUSINESS CASE EVALUATION?

A. My testimony will make two main conclusions:

1. The approach to developing the Plan provides confidence that the Plan investments will provide value to CEI South's customers and other grid stakeholders. The Plan was developed utilizing a strategic to tactical process directly aligning strategic objectives (CEI South Plan Objectives) and TDSIC Purposes to investments. Additionally, the approach to identifying investments and justifying them is customer-centric, asset- centric, data-driven, rooted in failure modeling, comprehensive, and granular.

2. The business case for the Plan is robust from several perspectives. First, the Plan as a whole has quantified incremental benefits in excess of eligible investment improvements. Secondly, all projects evaluated using the risk and resiliency project identification process have quantified incremental benefits in excess of cost. Additionally, these projects have non-quantified benefits that enhance the overall business case. Investments identified by CEI South System Stakeholders all have significant alignment to CEI South Plan Objectives and TDSIC Purposes.

III. INVESTMENT PLAN DEVELOPMENT APPROACH

Q. WHAT APPROACH DID CEI SOUTH EMPLOY TO DEVELOP THE PLAN?

A. 1898 & Co. guided CEI South through a strategic to tactical aligned process to develop the Plan with CEI South employing an objective-driven decision making approach as the foundation for developing the Plan. The strategic to tactical aligned process included:

1. Establishing overarching CEI South and system objectives for the Plan.

2. Defining investment programs to achieve those objectives.

3. Developing a value framework to measure each potential investment's ability to achieve the objectives.

4. Identifying the 'universe' of investment opportunities within each program and 'grade' them against the value framework.

5. Prioritize and refine investment opportunities into an actionable investment plan.

This approach improves 'line-of-sight' between the strategic and tactical providing confidence investments will produce desired outcomes and value to the CEI South customers.

Q. WHAT ARE CEI SOUTH'S PLAN OBJECTIVES AND WHAT INVESTMENTS HAVE BEEN IDENTIFIED TO ACHIEVE THOSE OBJECTIVES FOR THE TDSIC PLAN (STEPS 1 AND 2 FROM ABOVE)?

A. Figure JDD-1 shows the results of the first two components of the objective-driven decision making approach. The figure outlines CEI South's Objectives and investment programs for the Plan.

Figure JDD-1: CEI South TDSIC Plan Overview

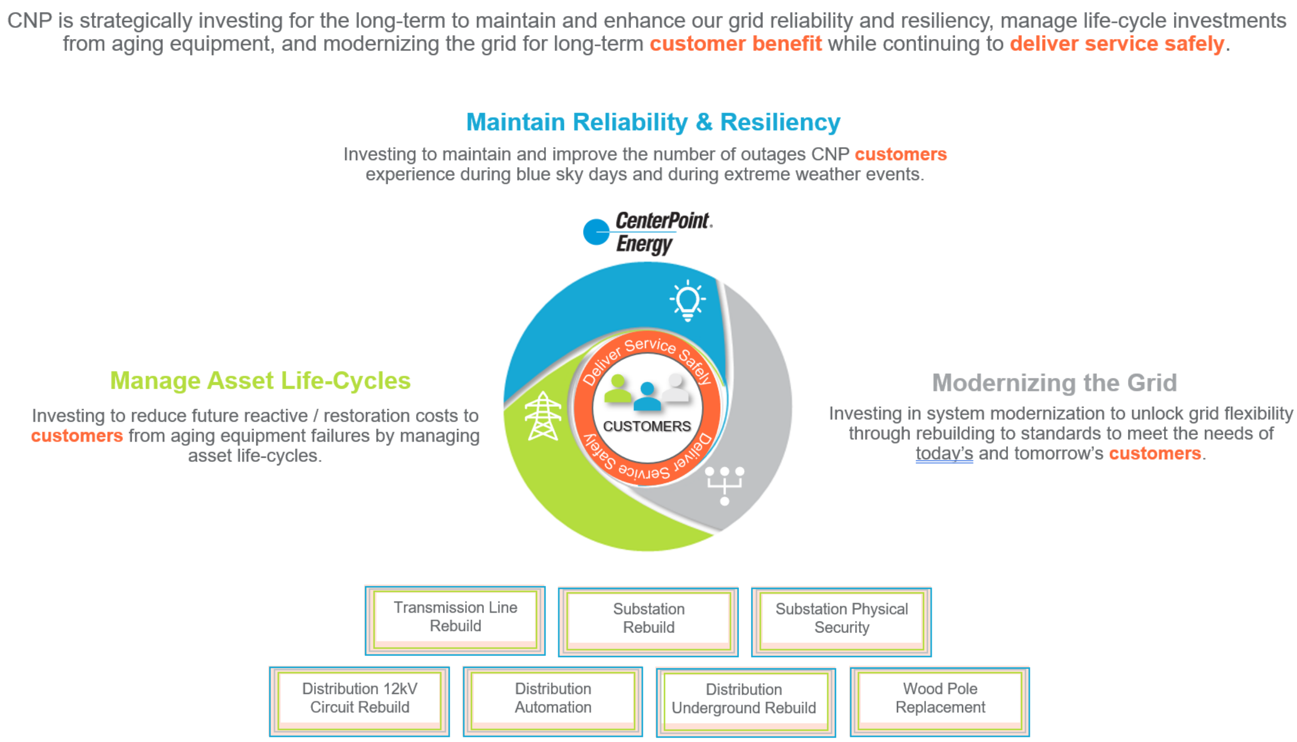


Figure JDD-1 outlines several key elements of CEI South's TDSIC Plan. First, the customer is the central focus of the Plan, represented as the center of the circle. Second, radiating away from the customer are the four main customer-centric objectives for the Plan.

1. **Deliver Service Safely** – Continuing to make investments that deliver electric service safely to all customers. Figure JDD-1 depicts delivering service safely as

a circle around the customer and touching each of the other three objectives. This depiction is meant to represent that safety is linked through all activities and a top priority for CEI South. In other words, nearly all investments will include a component of improving safety and delivering quality service. However, there are some investments that are done with the sole purpose of safety and delivering electric service, for example, wood pole replacements, capacity expansions, and capacitor upgrade projects.

2. **Maintain Reliability & Resiliency** – Investing to maintain and improve the number of outages CEI South customers experience during blue sky days and during extreme weather events. Grid outages cause more impact to customers than ever, especially for longer events. Historically, grid outages were viewed as inconveniences, but now they can cause real economic harm for residential customers, cause extreme stress for families, and place the most vulnerable of society at risk. In developing the investment activities, the evaluation establishes the relationship between equipment and customers, including customer type. The evaluation also considers the range of failure types, including both blue-sky and grey-sky (major storms) event types.

3. **Manage Asset Life-Cycle** – Investing to reduce future reactive / restoration costs to customers from aging equipment failures by managing asset life cycles. Reactively replacing failed equipment is often more costly than proactively replacing equipment in a planned approach. As more and more equipment exceed their average expected lives, the life-cycle cost can be higher than replacing all the equipment at the same time with planning and construction efficiencies. This approach also minimizes the risks of rework. In direct alignment to this objective, 1898 & Co.'s evaluation included an assessment of CEI South's assets using a risk and resiliency value-based approach. The approach aligns to CEI South's asset risk model utilized for CEI South's initial 7-year TDSIC Plan approved in Cause No. 44910 in September 2017 (the "44910 TDSIC Plan").

4. **Modernizing the Grid** – Investing in system modernization to unlock grid flexibility through rebuilding to standards to meet the needs of today's and tomorrow's customers. Grid flexibility will be critical to both serve customers and manage life-cycle costs. CEI South's TDSIC Plan includes an investment approach that enables and prioritizes rebuilding to design standards, thus modernizing the grid.

While there are some investments directly aligned to this objective, the Plan meets this objective by how project scopes are identified.

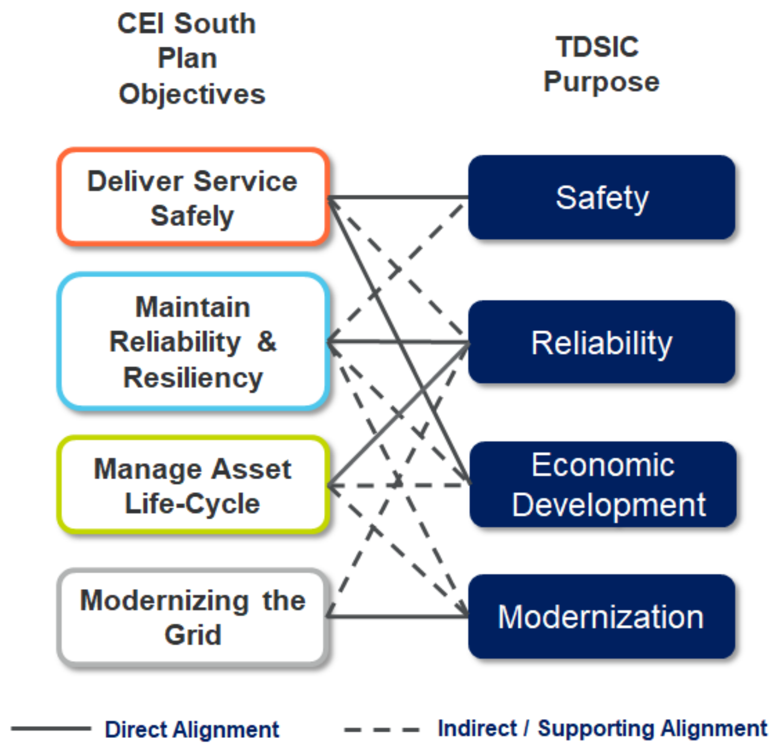
The third key element in Figure JDD-1 are the seven investment programs at the bottom. The programs include investments that align with CEI South's pursuit of the four customer-centric objectives. The programs were developed based on several factors: known issues on the system, investment alignment to objectives, engineering and construction approaches, and communicating with both internal and external investment plan stakeholders.

The fourth key element in Figure JDD-1 is the overall summary statement of the TDSIC Plan at the top of the figure. Investments were organized and selected based on their alignment to the objectives. Next, the data-centric approach, discussed in more detail later in this testimony, provides an objective methodology for the identification and selection of targeted investments in the grid. Furthermore, the assessment evaluates nearly all of CEI South's T&D infrastructure providing a comprehensive evaluation; and performs a business case for all potential projects selecting investments that provide the most value for customers.

Q. HOW DO THE CEI SOUTH OBJECTIVES ALIGN TO TDSIC PURPOSES?

A. Figure JDD-2 shows significant direct and indirect/supporting alignment between CEI South TDSIC Plan Objectives and TDSIC Purposes. In fact, for three of the four categories there is direct one to one alignment. The main difference is the inclusion of managing asset life-cycles within CEI South Plan Objectives, while not overtly included in the TDSIC Purpose categories it aligns with the overall purpose of the TDSIC statute. In summary, the CEI South Plan Objectives are a rephrasing of the TDSIC Purpose plus the inclusion of the managing asset life-cycles. Solid lines show direct alignment and linkage, while dotted lines show indirect or supporting alignment between CEI South Plan Objectives and TDSIC Purpose categories.

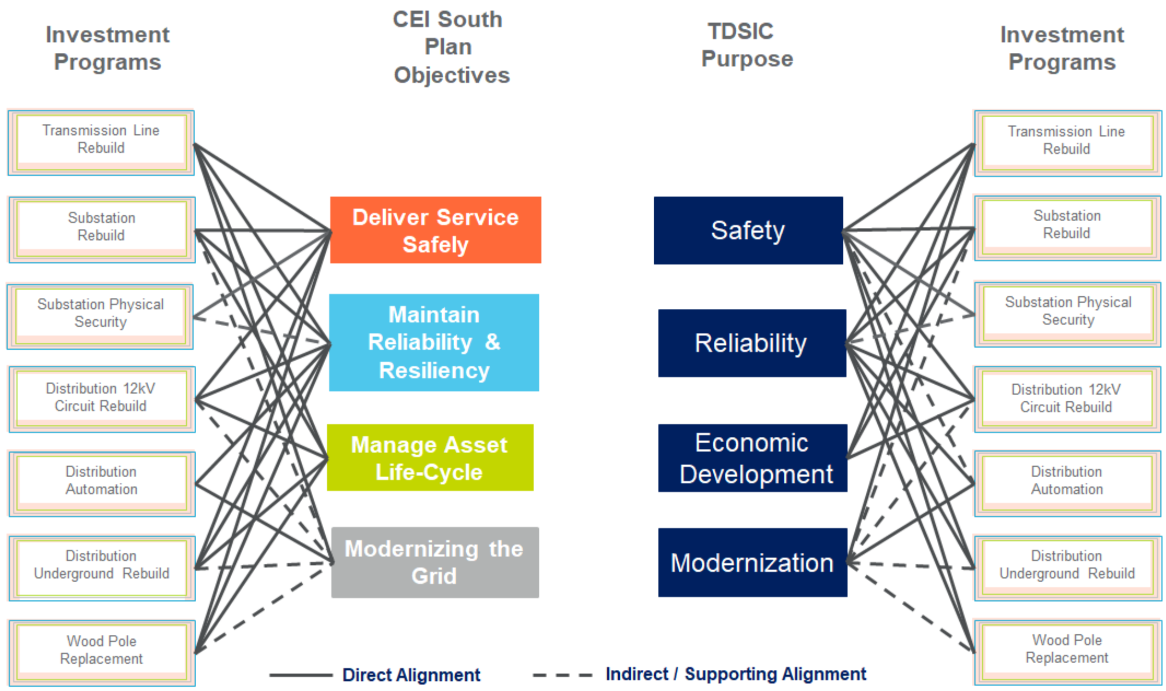
Figure JDD-2: CEI South Objectives & TDSIC Purpose Alignment



Q. FIGURE JDD-1 SHOWS THE CEI SOUTH OBJECTIVES AND INVESTMENT PROGRAMS, HOW DO EACH OF THE INVESTMENT PROGRAMS ALIGN TO EACH OF THE CEI SOUTH OBJECTIVES AS WELL AS TDSIC PURPOSES?

A. Figure JDD-3 includes the alignment or linkage between each of CEI South's Plan Objectives and the Plan investment programs. The figure also includes TDSIC Purpose categories (which align to the overall purpose of the TDSIC statute) and their alignment to each investment program. The main conclusion from this figure is that each investment program has significant alignment to several CEI South Plan Objectives and several TDSIC Purposes categories. Solid lines show direct alignment and linkage, while dotted lines show indirect or supporting alignment between CEI South Plan Objectives, TDSIC Purpose categories, and investment programs. I provide additional alignment tables for quantitative and qualitative evaluated investments later in my testimony.

Figure JDD-3: Investment Alignment to CEI South Objectives & TDSIC Purpose



Q. **WHAT VALUE FRAMEWORK WAS EMPLOYED TO MEASURE EACH POTENTIAL INVESTMENT'S ABILITY TO ACHIEVE THESE OBJECTIVES (STEP 3 FROM THE PROCESS ABOVE)?**

A. 1898 & Co. and CEI South adopted the following high-level value framework approach to identify, prioritize, and justify investments:

- Utilize a data and analytics centric approach with quantified business case results for the Maintain Reliability & Resiliency and Manage Asset Lifecycles objectives to identify and prioritize initial potential investments. The approach leverages 1898 & Co. AssetLens Analytics Engine, an asset investment planning tool to evaluate the life-cycle benefits of replacing T&D infrastructure and deploying smart devices across the distribution system. The analytics engine both identifies investments and performs the business case for the investment based on the underlying asset and outage data. Projects are initially prioritized based on their business case results, specifically their benefit to cost ratio ("BCR").
- Enhance the quantified business case results with non-quantified factors, safety being the main factor. This makes the quantified business case conservative since it does not overtly include these other factors. These value streams should not be

ignored, in fact in a few cases they could be the main driver for investment need. All investments that were developed utilizing the data and analytics centric approach have quantified business cases where benefits are in excess of costs. The non-quantified factors such as safety and grid modernization only enhance this business justification for the investments.

- Incorporate non-specific equipment-based investments identified by CEI South's system stakeholders (field operations, system operations, planning, and engineering). This includes a wood pole inspection program where assets will be identified after inspections, capacitor upgrades, physical security, and capacity-based projects. These projects are evaluated on a system requirements basis based on their direct alignment to CEI South Plan Objectives and TDSIC Purposes.

The quantified benefits assessment (bullet one from above) utilized a risk and resiliency-based planning approach to estimate the customer benefits for each potential grid investment. The benefits assessment employs a data-driven, asset centric, bottoms-up methodology utilizing robust and sophisticated analytics to calculate the risk and resiliency benefit of projects in terms of:

- Avoided Reactive and Restoration Costs – the quantified measure for the "Manage Asset Life-Cycles" CEI South objective.
- Avoided Customer Outages
  - Customer Minutes Interrupted ("CMI").
  - Monetization of avoided CMI (reviewed in more detail below) – the quantified measure for the "Maintain Reliability & Resiliency" CEI South Objective.

This quantitative approach provides a business case evaluation that is customer-centric. To evaluate the benefits of the potential TDSIC investments, 1898 & Co. utilized two main approaches described in more detail further below in my testimony:

1. Equipment Failure Risk & Resiliency
2. Outage Mitigation Risk & Resiliency

Equipment failure risk and resiliency investment activities primarily focus on aged or poor condition assets and known problematic equipment types. These factors are indicative of assets that have higher risks of failure in the future. The Equipment Failure Risk &

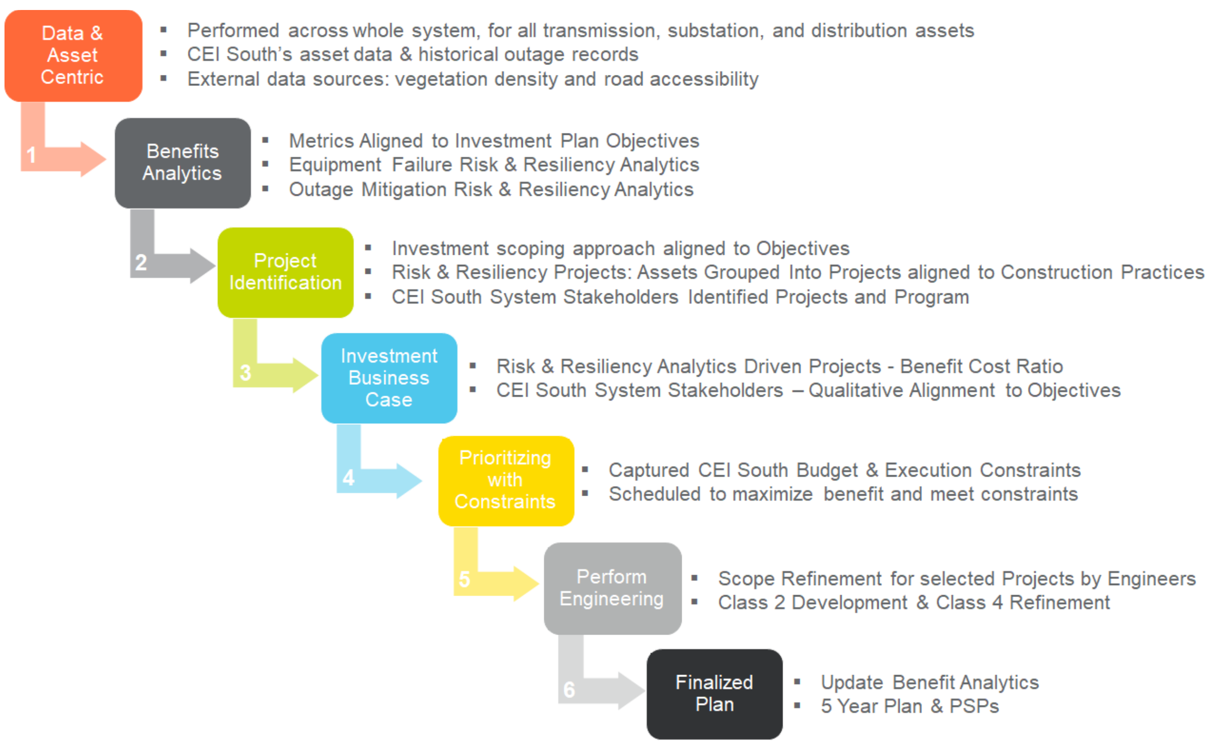
Resiliency approach estimates benefits for asset replacement investments. This approach utilizes a risk-based methodology in alignment to CEI South's 44910 TDSIC Plan filing to calculate the future reactive and restoration costs and customer outages.

Distribution automation investment activities to mitigate outages are primarily focused on decreasing customer outages to support the requirements of the modern customer. The Outage Mitigation Risk & Resiliency approach estimates benefits by re-calculating the historical outage records assuming the investments had been in place. The evaluation provides confidence that selected investments produce present value benefits more than cost.

Q. PLEASE DESCRIBE THE INVESTMENT IDENTIFICATION AND PLAN DEVELOPMENT PROCESS.

A. Figure JDD-4 provides an overview of the Plan development process executed by CEI South and 1898 & Co. The figure shows the 'line-of-sight' from CEI South data to the Plan.

Figure JDD-4: CEI South TDSIC Plan Development Process Overview



As Figure JDD-4 denotes, the process started with CEI South's asset and historical outage data as well as the use of external data sources (Step 1). That data was utilized within

1898 & Co. risk and resiliency analytics to estimate the customer-centric quantified benefits at the asset level (Step 2). The benefit analytics estimate the life-cycle risk-weighted Net Present Value ("NPV") of replacing all the core assets within CEI South's electric T&D system.

Utilizing the asset level quantified benefit analytics, assets were grouped together into potential projects (Step 3). Generally, the asset grouping into initial projects was performed from a customer-centric perspective (protection zones described in more detail below) taking into account construction practices. Additionally, the grouping was performed to enable rebuilding of the grid to meet the Modernizing the Grid objective, specifically enabling CEI South to rebuild the grid to engineering and equipment standards. CEI South planners and engineers also identified investments for consideration within the Plan. It should be noted that most, 81.2 percent, of the Plan was developed using the data and analytics-based approach. 5.8 percent of the Plan is based on system capacity and power quality needs identified by CEI South planners and engineers, 3.1 percent of the Plan is for the substation physical security and the remaining 9.9 percent of the Plan is for the wood pole inspection program.

Step 4 of the process includes performing the business case for each investment. For the risk and resiliency analytics driven projects, the quantified business case is based on the sum of the benefits for each asset (Step 2) within each project (Step 3). This produces a life-cycle risk-weighted NPV benefit for each project. The quantified business case also included converting this value to a simple BCR. The business case for the risk and resiliency analytics driven projects are enhanced by the non-quantified factors such as safety. The business case for the CEI South System Stakeholder driven projects was based on their alignment to CEI South Plan Objectives and TDSIC Purposes as outlined above. 1898 & Co. and CEI South included select CEI South System Stakeholder driven projects with business justification using this framework.

1898 & Co. and CEI South prioritized the projects based on their business case results, integrating the prioritization and justification together. The prioritization also considered execution constraints including equipment availability, crew and labor constraints, outage coordination, ease of constructability, additional execution efficiencies between programs (Distribution 12kV Circuit Rebuild and Distribution Automation specifically), and other factors. This approach is important to help manage various procurement, execution, and staffing risks to produce a more actionable TDSIC Plan.

CEI South and 1898 & Co. also identified Potential Substitution Projects ("PSPs") from the risk and resiliency analytics project identification approach. Theses PSPs each had quantified benefits in excess of cost. Given the uncertain nature of project execution and unknown challenges, the PSPs provide CEI South needed execution flexibility as realities outside of CEI South's control cause changes to the execution of the TDSIC Plan. One example is supply chain issues with power transformers that may cause a delay in substation projects.

Following the analytics driven equipment selection, 1898 & Co. and CEI South refined the initial project scope based on reviews by CEI South system planners and engineers. The reviews include augmenting the data records with engineers or operators experience, additional desktop evaluation, and visual inspection in the case of some projects. CEI South and its partners also performed engineering on each of the projects and developed Class 2 cost estimates for years 1 and 2 of the Plan and Class 4 cost estimates for years 3 through 5 of the Plan and the PSP projects. CEI South provided 1898 & Co. with the updated cost estimates for each project.

As a last step to finalize the Plan, 1898 & Co. incorporated the scope refinements and Class 2 and Class 4 cost estimates for each project into the risk and resiliency analytics and re-performed the business case. The final Plan includes 5 years of investment with specific projects and their business case. The finalized Plan also includes a list of PSPs for execution flexibility.

Q. YOU HAVE MENTIONED THAT THE BENEFIT APPROACH EMPLOYS A DATA-DRIVEN METHODOLOGY. PLEASE DESCRIBE WHAT CORE DATA SETS ARE UTILIZED IN THE ENGINE AND HOW THEY ARE USED IN THE BENEFIT CALCULATION?

A. The risk and resilience-based approach and methodology is data driven. CEI South's data systems include a connectivity model that allows for the linkage of many foundational data sets - the Geographical Information System ("GIS"), the Substation Asset Register, the Outage Management System ("OMS"), and Customer Information. The AssetLens Analytics Engine transforms the data sets into the needed data model to perform the risk and resiliency analytics using this connectivity. The following includes the core data sets utilized within the approach.

GIS – The GIS provides the list of assets in CEI South's distribution and transmission circuit system, their attributes (type, manufacturer, age), and how they are connected to each other, both physically and electrically. Significant for the distribution circuit business case evaluation is the relationship between assets and customers. The connectivity model provides the relationship between assets and their upstream protection device. If an asset fails, the upstream protection device operates, locking out downstream customers. With this connectivity, the AssetLens Analytics Engine links distribution asset failures to customer impacts.

Substation Asset Register – These databases are the companion source to the GIS for the substation assets. CEI South provided detailed asset register tables for power transformers, breakers, relays, and other ancillary assets. The tables include equipment type, high-level position within the substation, age, and other attributes. 1898 & Co. leveraged this information to establish additional connectivity within the asset base. Three specific connectivity relationships were developed. The first is establishing the link between the GIS protection devices and the breakers from the substation asset register so that accurate customer outage impacts could be established. The second was the relationship between the distribution breakers and the power transformers, this connectivity allows the AssetLens Analytics Engine to connect customers to the power transformer inside the substation. The third is the relationship between relays and breaker protection. Since the upgrades impact the other, establishing this relationship is critical to link customer impact and investment to benefit.

OMS – OMS includes detailed outage information by cause code for each protection device over the last 17 years, with detailed outage step information for the last 5 years. The data include causes, duration, Customers Interrupted ("CI"), CMI, and location for approximately 17,800 outage events (last 5 years only). The AssetLens Analytics Engine utilized this information to understand the historical outages across the system, including Major Event Days ("MED"), vegetation, lightning, and storm-based outages. The Outage Mitigation Risk & Resiliency benefits approach utilizes this data set.

Customer Data – CEI South provided customer count and type information with database relationships to the GIS and OMS. This data allowed the AssetLens Analytic Engine to directly link the number and type of customers impacted to each protection device. Types of customers include residential, small commercial and industrial ("Small C&I"), and large commercial and industrial ("Large C&I"). This customer information is used for both benefit approaches as it is foundational for the customer-centric business case evaluation. Petitioner's Exhibit No. 3, **Attachment JDD-2** (Section 1.0) includes additional details on the count and type of customers for each circuit, protection zone, and substation.

Equipment Condition Data – Equipment condition data was provided for a wide range of asset types and in many forms depending on the assets being evaluated. The condition data included test results, operator reports, and outage data. For the substation transformers, DGA analysis was provided. For structures, inspection reports and operations reports provide condition information. The condition of the conductor for each protection zone was derived by utilizing the outage management system. Transmission operations provided reports on circuit condition. The asset condition is used to create an effective age that better reflects the condition of the asset.

Vegetation Density Algorithm – The level of vegetation density around overhead infrastructure can have a significant impact on the expected lives of the infrastructure, specifically poles. 1898 & Co. utilized satellite tree canopy data to estimate the percentage of vegetation for each span of overhead conductor on the system. The vegetation density is used to categorize different expected lives and failure types for the overhead infrastructure. Poles that are in high vegetation areas are subject to more life-cycle stresses over their lifecycle than poles in low vegetation areas. The life-cycle stresses impact the expected life and increases the likelihood that poles or pole tops may fail.

Accessibility – The accessibility of an asset has an impact on the duration of the outage and the cost to restore that part of the system. Rear lot structures take much longer to restore and cost more to restore than front lot structures. To take differences in accessibility into account, the risk and resiliency analytics model performs a geospatial analysis of each structure against a data set of roads. Structures within a certain distance of the road were designated as having roadside access; others were designated as in the deep right-of-way ("ROW"). This designation was used to estimate additional cost adders to restore infrastructure after it fails. It was also incorporated into the estimation of project costs. Approximately 76 percent of the structures have road access while 24 percent are in the deep right-of-way.

Q. PLEASE DESCRIBE THE APPROACH TO ESTIMATE EQUIPMENT FAILURE RISK & RESILIENCY BENEFITS.

A. The Equipment Failure Risk & Resiliency modeling approach calculates the benefits of replacing existing infrastructure. Table JDD-1, above, indicates which programs utilized this approach to identify and justify investments. The approach forecasts the probability-weighted consequence of failure for a range of failure types. The failure types are based on how assets fail over their lifecycle, including inspection-based failures. Consequences are estimated for a range of factors but fall into two main categories. The first category is reactive or restoration costs. The second category is customer-based outages. This category is the monetization of customer outages in the event of an asset failure.

Additionally, the approach calculates each asset's lifecycle reactive costs and customer outage costs for two scenarios. The first is a Status Quo scenario where the asset is not replaced; the second is the Investment scenario in which the asset is replaced with the current equipment standard. The benefit of replacing infrastructure is the difference between the two scenarios. Additional details regarding the approach are found in Petitioner's Exhibit No. 3, **Attachment JDD-2** (Section 2.0).

Q. WHAT ASSETS WERE EVALUATED USING THIS APPROACH AND HOW WERE THEY ORGANIZED INTO PROJECTS?

A. Table JDD-2 provides a summary of the circuit assets evaluated using the Equipment Risk & Resiliency approach. As I noted above, these asset counts are from CEI South's GIS.

Table JDD-2: Circuit Asset Summary

Asset Type	Units	Value
Transmission Line Segments	**Count**	**285**
Poles / Structures	Count	12,569
Conductor Length	Miles	1,014
Distribution Circuits	**Count**	**190**
Primary Poles	Count	78,900
OH Primary	Miles	2,943
UG Primary	Miles	1,292
Line Transformers	Count	50,566
Downtown Network Transformers	Count	35

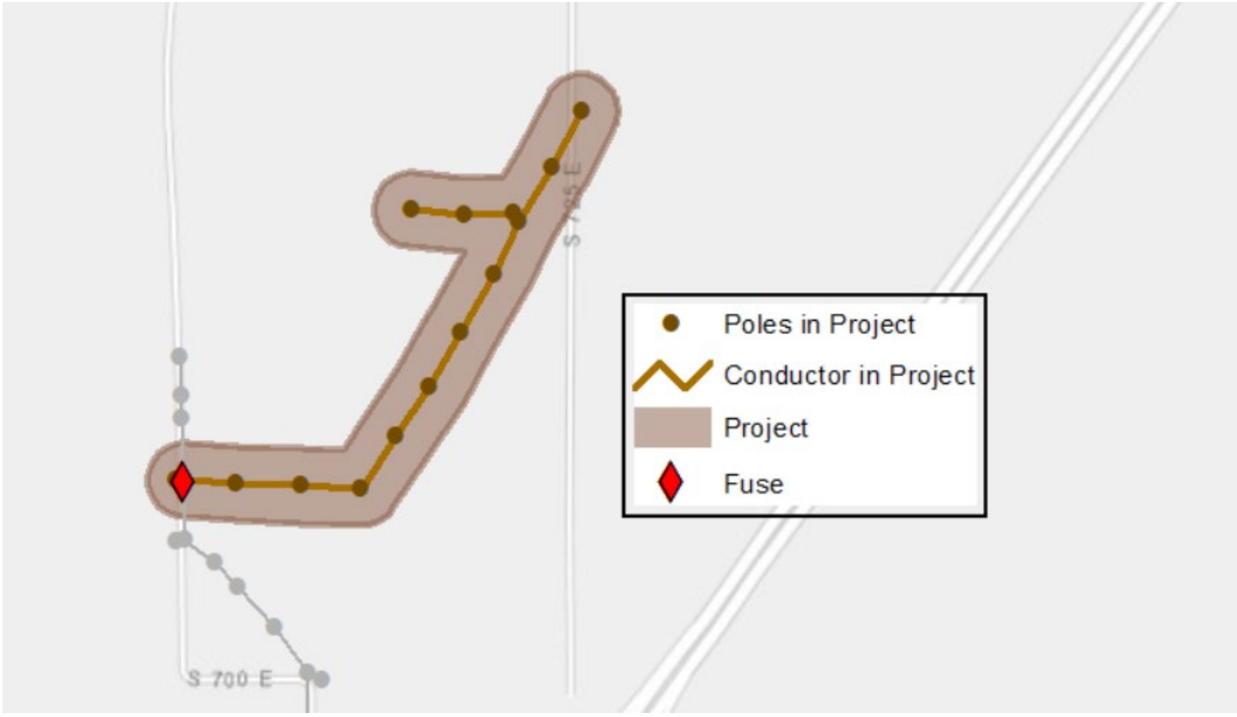
Table JDD-3 includes a summary of the substation assets evaluated using the Equipment Risk & Resiliency benefits approach. These asset counts are from the substation asset register outlined above.

Table JDD-3: Substation Asset Summary

Asset Type	Units	Count
Substations	**count**	**109**
Power Transformers	count	157
Breakers	count	610
Relays	count	2,808
Battery/Chargers	count	121
Capacitor Banks	count	23
Circuit Switcher	count	67
Fuses	count	46
GPS Clocks	count	55
Lightning Arrestors	count	702
Potential Transformers	count	860
Remote Terminal Units	count	84
Station Service Voltage Transformers	count	62
Switches	count	753
Voltage Regulators	count	412

1898 & Co. utilized the connectivity within CEI South's GIS to link each distribution voltage asset up to a lateral (fuse protection device) or feeder (breaker or recloser protection device). This linkage of assets to protection zones provides a granular evaluation of the distribution system that allows projects to be created to target only portions of a circuit for investment. The relationship between assets and projects is illustrated in the geospatial figure, Figure JDD-5, for a distribution project.

Figure JDD-5: Distribution Circuit Asset Grouping



For transmission circuits, assets were grouped at the line segment level. For substations, assets were grouped together at the substation level to identify potential projects.

Through this approach, 1898 & Co. was able to use the asset level information from Table JDD-2 and Table JDD-3 and convert it to the project level summaries in Table JDD-4. It is important to note that each asset in Table JDD-2 and the assets included in substation projects from Table JDD-3 is tied to one of the projects listed in Table JDD-4, which provides a data-driven and bottom-up analysis.

Table JDD-4: Benefit Analytics Potential Projects Evaluated

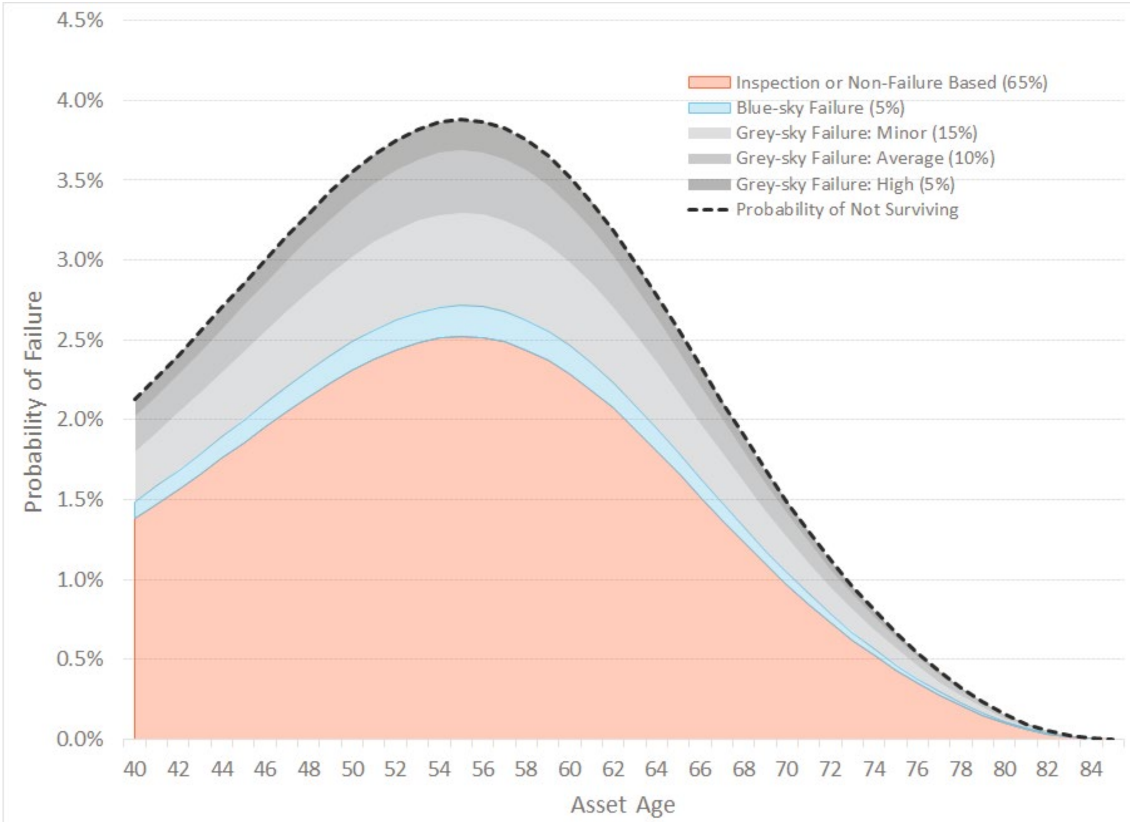
No.	Program	Evaluated Project Count
Equipment Failure Risk & Resiliency Analytics		
1	Transmission Line Rebuild	285
2	Substation Rebuild	109
3	Distribution 12kV Circuit Rebuild	7,679
4	Distribution Underground Rebuild	7,760
Outage Failure Risk & Resiliency Analytics		
5	Distribution Automation	175
	Total	**16,008**

Q. HOW WAS THE ANNUAL PROBABILITY OF FAILURE FOR EACH FAILURE TYPE ESTIMATED?

A. The evaluation leverages the use of end-of-life curves, also known as Survivor Curves, to forecast an asset's expected remaining life and the probability of not surviving each year. Survivor curves, or End-of-Life curves, approximate the probability of an asset not surviving over time. Within utilities, depreciation studies utilize property accounting records to designate Iowa Survivor Curves for asset types to establish rates.

Based on 1898 & Co.'s collection of asset class expected lives, and referencing CEI South's depreciation study, each asset class was assigned an Iowa Survivor Curve inside the AssetLens Analytics Engine. The curves create a unique probability density function for each asset based on its condition-based age. The area under each curve is equal to 100 percent. The annual probabilities of not surviving are divided up into several failure types mirroring the range of failure events for assets. 1898 & Co.'s AssetLens Analytics Engine includes a library of failure types for all major asset types in electric T&D systems. Failure types are based on how assets fail over their lifecycle and include the range of consequence types from minor consequence events to extreme consequence events. Figure JDD-6 shows annual probabilities of failure for five different failure types for an example condition based 40-year-old wood pole.

Figure JDD-6: Failure Types and Probability of Failure for 40-Year-Old Wood Pole



Q. WHAT CONSEQUENCE FACTORS WERE INCLUDED IN THE EVALUATION?

A. Consequences are estimated for a range of factors but fall into two main categories. The first category is reactive or restoration costs. These are costs to the utility and eventually to the customer to restore the system in the event of a failure. The second category is customer-based outages. This category is the monetization of customer outages in the event of an asset failure. For each failure type, the risk framework library inside of the AssetLens Analytics Engine includes a range of consequence types based on expected impact should the asset fail. Table JDD-5 shows the range of consequence types evaluated and the asset classes that they apply to. The framework puts a monetary value on each of these consequence factors as described below.

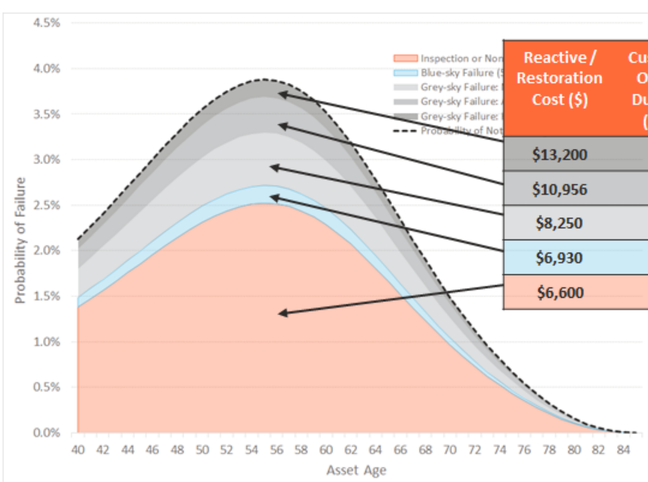
Table JDD-5: Consequence Types and Asset Classes

Consequence	Avoided Cost Type	Circuit Assets	Substation Assets
Customer Outages	Customer Outage	☐	☐
Equipment Failure Costs	Reactive	☐	☐
End of Life O&M	Reactive		☐
Mobile Substation	Reactive		☐
Oil Spill Remediation	Reactive		☐
Collateral Damage	Reactive		☐
Re-replacement Costs	Reactive	☐	☐

Q. PLEASE DESCRIBE HOW THE STATUS QUO SCENARIO IS ESTIMATED?

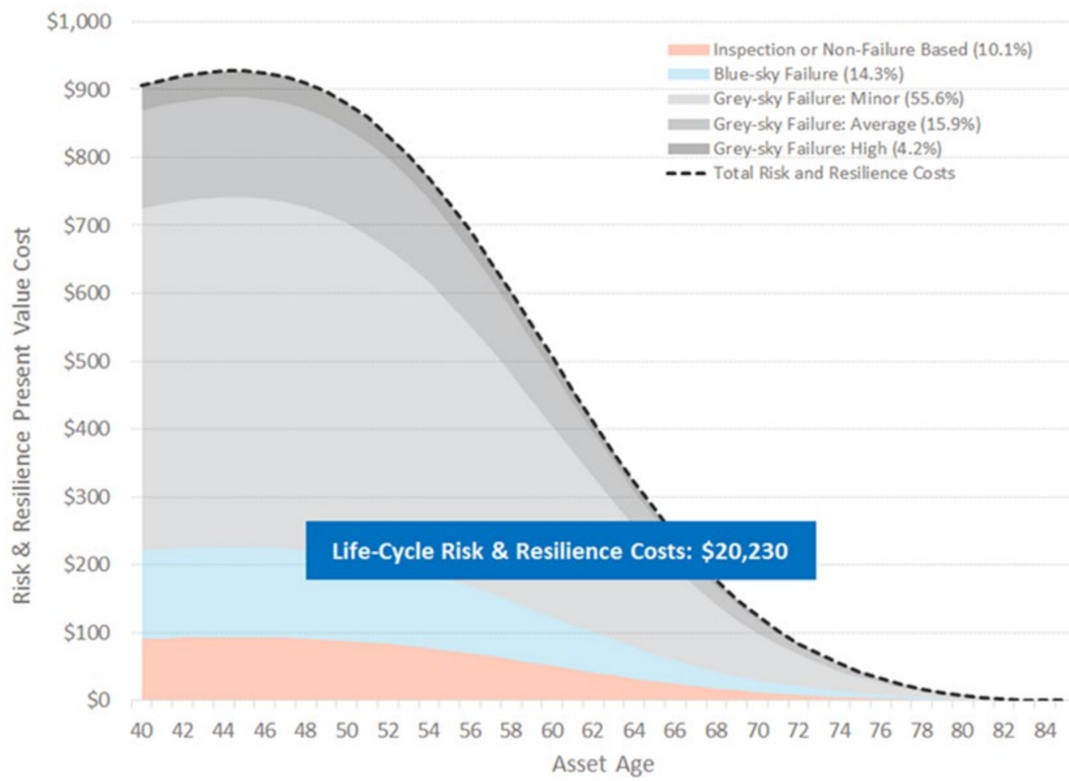
A. The Status Quo scenario assumes the asset is not replaced and could incur risk costs over time. To calculate the Status Quo Risk & Resiliency costs over time, each of the probability of failures for each failure type is multiplied by each consequence of failure costs for each failure type. Figure JDD-7 depicts this approach for the 40-year-old wood pole example on a backbone with approximately 400 customers. The figure shows the number of residential, small C&I, and large C&I customers for this example. Figure JDD-8 shows the resulting risk and resiliency cost profile by multiplying the annual failure type probabilities by the consequence costs from Figure JDD-7 while factoring in the escalation and discount rate.

Figure JDD-7: Status Quo Risk & Resiliency Calculation 40-Year-Old Wood Pole



Reactive / Restoration Cost ($)	Customer Outage Duration (Min)	Residential (358) Outage Costs ($)	Small C&I (48) Outage Costs ($)	Large C&I (1) Outage Costs ($)	All Customer (407) Outage Costs ($)
$13,200	720	$10,310	$399,080	$38,090	$447,480
$10,956	360	$5,620	$165,460	$18,100	$189,170
$8,250	300	$4,900	$130,140	$14,810	$149,860
$6,930	240	$4,230	$98,960	$11,810	$115,000
$6,600	0	$0	$0	$0	$0

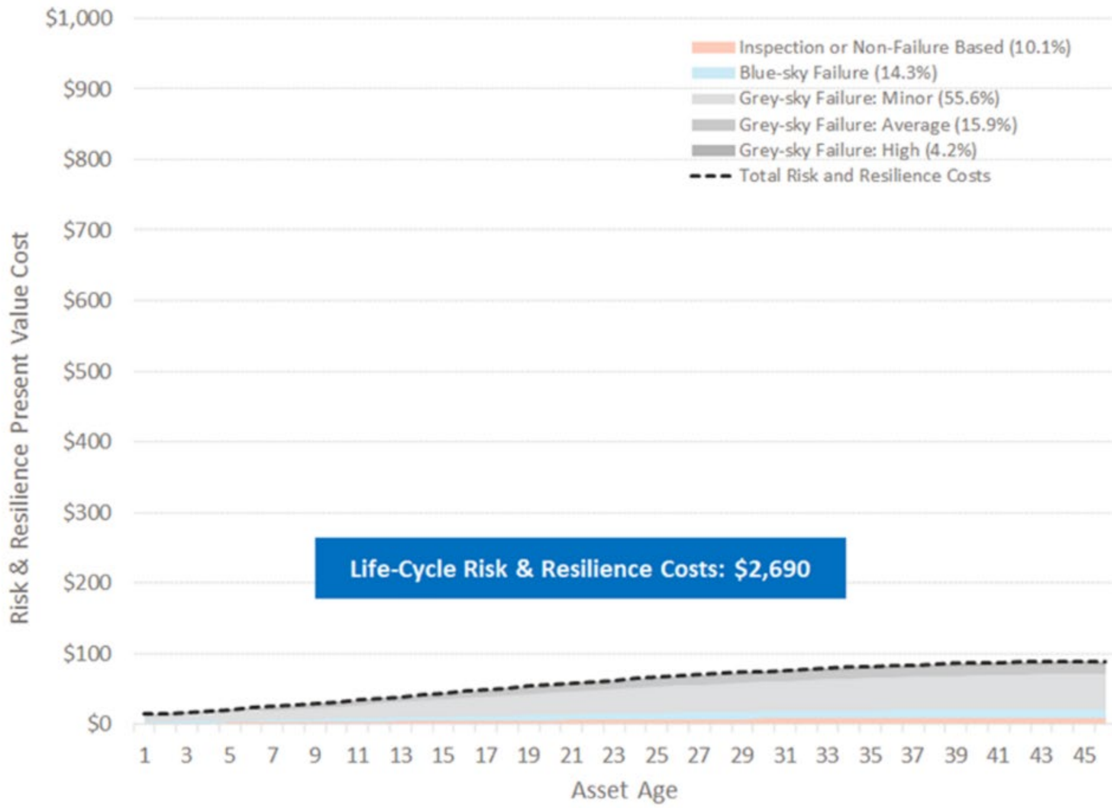
Figure JDD-8: Status Quo Risk & Resiliency Reactive Costs Profile - 40-Year-Old Wood Pole



Q. PLEASE DESCRIBE HOW THE INVESTMENT SCENARIO WAS ESTIMATED.

A. The Investment scenario assumes the asset is replaced and factors in the residual risk and resiliency costs over time. By replacing the asset, the failure probabilities decrease since the asset is now 0 years old. In some cases, the failure types change with the replacement, such as oil circuit breakers that are replaced with gas breakers. The calculation is the same as the Status Quo Risk & Resiliency costs over time, each of the probability of failures for each failure type is multiplied by each consequence of failure costs for each failure type. Figure JDD-9 depicts this approach for the replacement of the 40-year-old wood pole example on a backbone with approximately 400 customers.

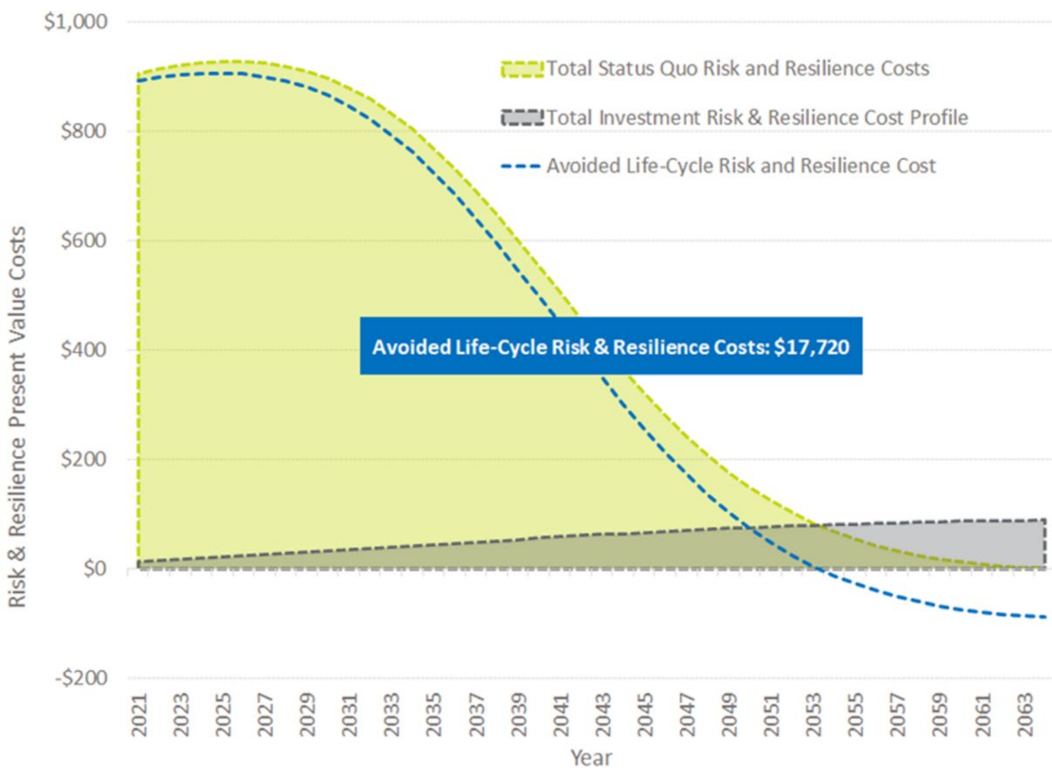
Figure JDD-9: Investment Risk & Resiliency Reactive Costs Profile - 0-Year-Old Wood Pole



Q. PLEASE DESCRIBE HOW THE AVOIDED COSTS WERE ESTIMATED?

A. The avoided risk and resiliency costs are the annual difference between the Status Quo and Investment scenario results. Figure JDD-10 shows the annual avoided costs for replacement of the 40-year-old wood pole example. The profile shows 33 years of positive avoided costs with the remaining negative. The approach allows for modeling of residual risk. If younger assets are replaced, the switchover from positive to negative occurs earlier and decreases the avoided costs. This approach is used for all the assets outlined in Table JDD-2 and Table JDD-3 above and broken down for each of the consequence factors shown in Table JDD-5 above.

Figure JDD-10: Avoided Risk & Resiliency Cost Benefit



Q. PLEASE DESCRIBE THE APPROACH TO ESTIMATE OUTAGE MITIGATION RISK & RESILIENCY BENEFITS.

A. The Outage Mitigation Risk & Resiliency modeling approach calculates the benefits for investments aimed at decreasing customer outages. This approach was utilized to estimate benefits for the Distribution Automation investments as indicated in Table JDD-1 above. The approach leverages the last 5 years of CEI South's 17-year historical outage records to capture outage trends while providing a more accurate view of the current system. The last 5-years of data included detailed outage steps needed for the evaluation. Each outage, approximately 17,800 unique events, is re-calculated, assuming the distribution automation investments had been in place. This calculation produces the avoided CI and CMI for the investment. The DOE's ICE calculator monetizes the avoided outages by factoring in customer types and durations. The life-cycle risk-weighted present value of avoided customer outages is calculated by adjusting for inflation and discount rate over the life cycle of the investment. Additional details regarding the approach to estimate the benefits associated with mitigating customer outages by employing distribution automation are found in Petitioner's Exhibit No. 3, **Attachment JDD-2** (Section 2.0).

Q. WHY WERE AVOIDED CUSTOMER OUTAGES MONETIZED?

A. The availability of electric energy is one of the cornerstones of a community's economic well-being and quality of life. This is why electric outages are so disruptive to the members of a community when they occur. It is not just people's home, but also where they work, where they buy groceries, the daycare and school for their kids, the care facility for a parent, and all other facilities that are part of society's daily lives. When these facilities are unable to continue normal operations, the lives of many are disrupted, often with financial consequences for both the facilities and their customers. The level of disruption will grow as society becomes more dependent on electrical power with work from home programs and electrification initiatives. Without monetization of outages, the appropriate investments cannot be prioritized to address outage management and ensure a community's long-term economic well-being and quality of life.

Q. WHAT APPROACH WAS USED TO MONETIZE OUTAGES?

A. To monetize the cost of an outage, the benefits approach utilizes the DOE ICE Calculator. The ICE Calculator is a widely used electric reliability planning tool developed by Freeman, Sullivan & Co. and Lawrence Berkeley National Laboratory. This tool is designed for electric reliability planners at utilities, government organizations, or other entities interested in interruption costs and/or the benefits associated with reliability improvements in the United States. The ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy.

The calculator includes the estimated average interruption costs for residential, small C&I, and large C&I customers for a range of durations. The average interruption cost by category captures the full spectrum of end users (some with no impact and others with substantial impact) with one representative value per customer category that is appropriate for system wide business case development. The calculator was extrapolated for the longer outage durations for storm-based outages. The ICE Calculator is used for both the Equipment Failure Risk & Resiliency Modeling Approach and Outage Mitigation Risk & Resiliency Modeling Approach.

Q. YOU MENTIONED THAT THE QUANTIFIED BENEFITS METHODOLOGY EMPLOYED A DISCOUNTED CASH FLOW METHODOLOGY, WHAT ASSUMPTIONS ARE USED IN THE CALCULATION?

A. The discounted cash flow calculations were done over a 50-year time horizon for the Equipment Failure Risk & Resiliency based approach, the expected useful life for the infrastructure. 20 years was assumed for the Outage Mitigation Risk and Resiliency evaluated investments, the expected useful life for distribution automation devices. The evaluation assumed 4 percent for short term capital cost escalation and 2 percent for long term cost escalation. 6 percent was assumed for the discount rate.

IV. BUSINESS CASE RESULTS

Q. PLEASE PROVIDE AN OVERVIEW OF THE PLAN BUSINESS CASE.

A. The overview of the business case is provided in the Executive Summary section above and shown in Table JDD-1.

Q. WHAT ARE THE BUSINESS CASE RESULTS FOR EACH INVESTMENT IDENTIFIED USING THE RISK & RESILIENCY ANALYTICS APPROACH?

A. Approximately 81.2 percent of the Plan investment was identified utilizing the Risk & Resiliency analytics approach. Figure JDD-11 shows the quantified business case results for each project, ranked from highest BCR to lowest. The figure includes nearly 270 individual investments. As the figure shows, each risk & resiliency identified project has a quantified business case with benefits in excess of cost, BCR greater than 1. For all risk & resiliency analytics defined projects, the figure shows the total investment of $325.8 million (2023 dollars) produces life cycle PV of benefits of $681.3 million. In aggregate, all risk & resiliency analytics defined projects have a positive quantified business case with a total NPV of $355.5 million for customers and a benefit cost ratio of 2.1 As the figure shows, each program has benefits in excess of costs.

Figure JDD-11: Risk & Resiliency Identified Projects Quantified Business Case

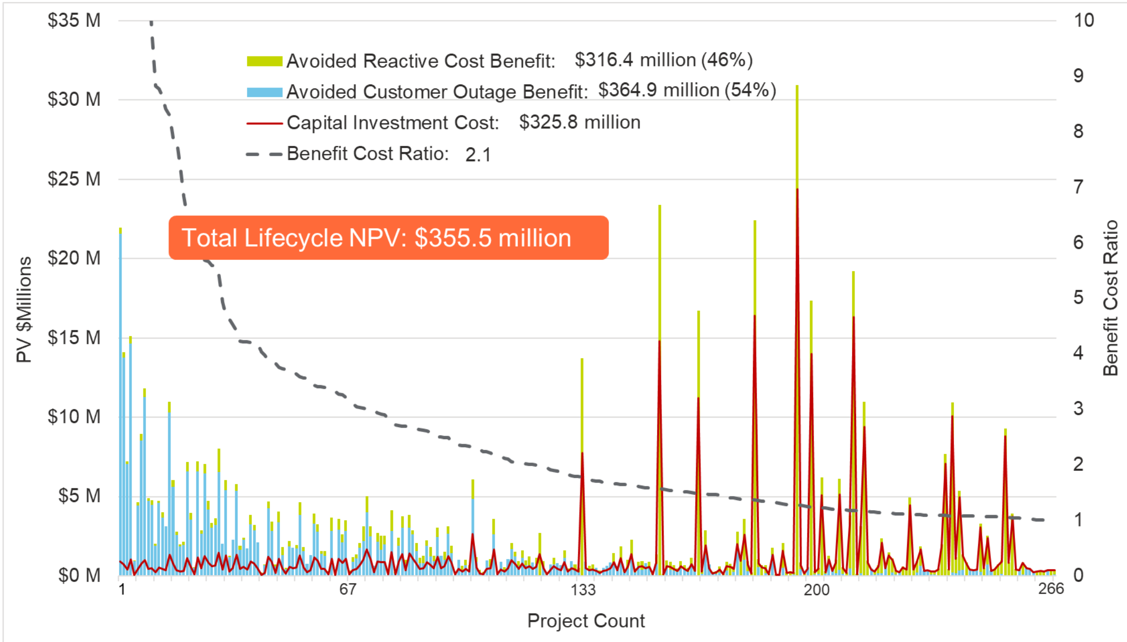


Figure JDD-12 organizes all the individual investments from Figure JDD-11 into their respective program and provides the summary quantified business case. The 'stair-step' figure layers the benefit and costs of the program investments of each benefit category to the previous starting from the life cycle NPV. It should be noted that the portfolio summary results from both figures are the same.

Figure JDD-12: Risk & Resiliency Identified Investments Quantified Business Case Summary

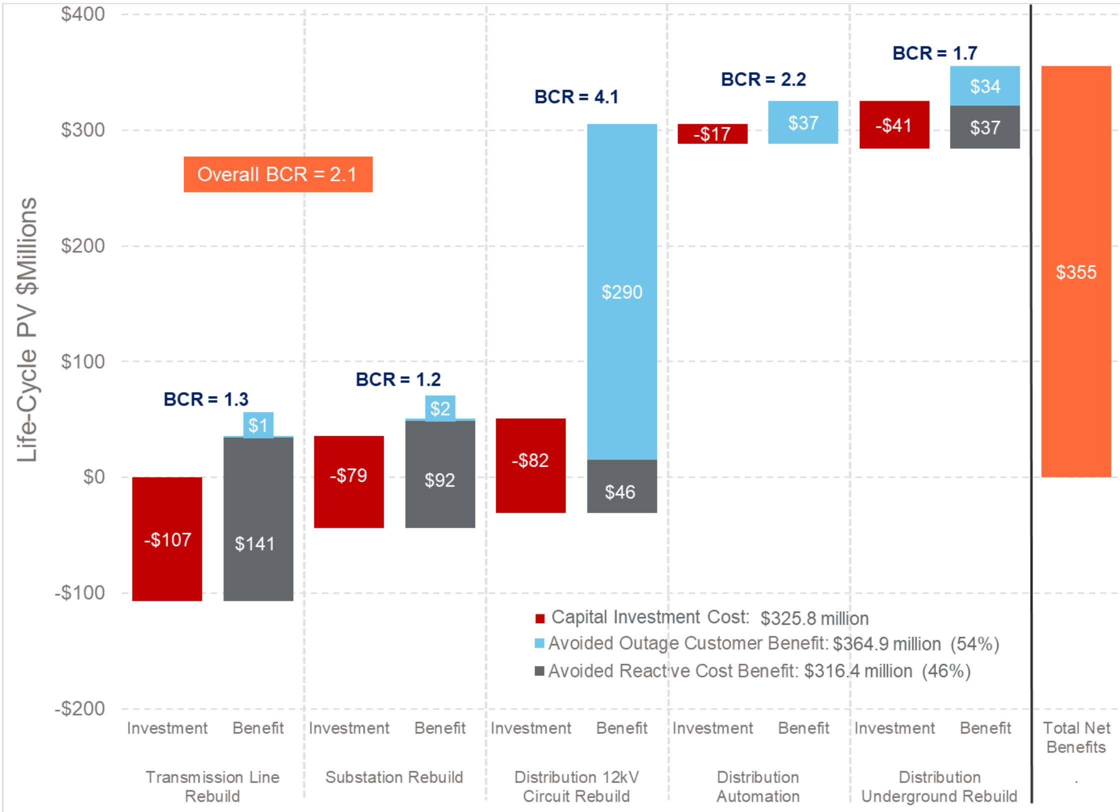


Table JDD-6 shows the alignment to CEI South Plan Objectives for each of the risk & resiliency identified investments by program. As the table notes, there are quantitative and qualitative benefits for each of the investments. The previous figures show the quantitative business case results provide benefits in excess of cost. However, each of the investments also includes benefits streams not quantified as the table shows. These additional benefits streams enhance the overall business case for these investments. It should be noted that most of the programs indirectly improve safety for the general public and CEI South employees. Additionally, Transmission Line Rebuilds and Distribution Automation directly provide benefits to modernize the grid for the future. Additional details at the individual investment level and program for the quantitative and qualitative business case results are included in Petitioner's Exhibit No. 3, **Attachment JDD-2** (Section 3.0).

Table JDD-6: Risk & Resiliency Identified Investment Qualitative Benefit Drivers

TDSIC Program	CEI South Plan Objective			
	Deliver Service Safely	Maintain Reliability and Resiliency	Manage Asset Life-Cycle	Modernizing the Grid
Transmission Line Rebuild	■	□	□	■
Substation Rebuild	■	□	□	□
Distribution 12kV Circuit Rebuild	■	□	□	□
Distribution Automation		□		■
Distribution Underground Rebuild	■	□	□	□
Wood Pole Replacements	N/A	N/A	N/A	N/A
Substation Physical Security	N/A	N/A	N/A	N/A

□ Quantified Direct Alignment ■ Non-quantified Direct Alignment
□ Indirect / Supporting Alignment

Q. WHAT ARE THE BUSINESS CASE RESULTS FOR THE INVESTMENTS IDENTIFIED BY CEI SOUTH SYSTEM STAKEHOLDERS?

A. As noted above, the business case framework for these investments is based on their alignment to the CEI South Plan Objectives, and by extension the TDSIC Purposes given the two are tightly aligned. Approximately 18.8 percent, $85.5 million, of the Plan was identified by CEI South System Stakeholders (planning, engineering, field operations, and maintenance). Table JDD-7 provides a summary of the business case results for each program, specifically showing the direct and indirect/supporting alignment to each of the CEI South Plan Objectives.

Table JDD-7: CEI South Identified Investments Qualitative Benefit Drivers

TDSIC Program	Plan Investment Nominal $Millions	CEI South Plan Objective			
		Deliver Service Safely	Maintain Reliability and Resiliency	Manage Asset Life-Cycle	Modernizing the Grid
Transmission Line Rebuild	$6.2	■	□		□
Substation Rebuild	$13.4	■	□		□
Distribution 12kV Circuit Rebuild	$6.7	■	□		□
Distribution Automation		N/A	N/A	N/A	N/A
Distribution Underground Rebuild		N/A	N/A	N/A	N/A
Wood Pole Replacements	$45.0	■	■	■	□
Substation Physical Security	$14.0	■	□		

■ Non-quantified Direct Alignment □ Indirect / Supporting Alignment

The largest program from these identified investments is the wood pole replacement program with over half of the $85.3 million investment. This program improves safety, reliability and resiliency, and manages long-term costs by replacing poles with known defects based on inspections. Poles with known defects are at elevated risk of failing.

Substation Physical Security is the second largest investment program, approximately 16.4 percent of the total, identified by CEI South System Stakeholders. Intentional vandalism toward substations equipment has seen an increase recently. These events can cause significant disruption to serving customers and can be costly to restore. The investments in this program will provide additional monitoring, specifically cameras, to help mitigate these events.

The remaining investment of $26.3 million for transmission line rebuild, substation rebuild, and distribution 12kV circuit rebuild are mainly to mitigate against system capacity constraints and improve power quality. This accounts for approximately 30.8 percent of the investment identified by CEI South System Stakeholders. In terms of the total Plan, these projects account for approximately 5.8 percent of the total Plan investment. If capacity constraints are not mitigated, there is risk of overloading equipment causing it to burn or not being able to utilize switching schemes to minimize disruptions to customers.

Additional details at the individual investment level and program for the qualitative business case results are included Petitioner's Exhibit No. 3, **Attachment JDD-2** (Section 3.0).

Q. PLEASE PROVIDE AN OVERVIEW OF CEI SOUTH'S TDSIC PLAN AND PROGRAMS?

A. Table JDD-8 shows the Plan investment profile. The investment capital costs are in nominal dollars, the dollars of that day. The Plan is approximately $454 million in nominal terms over the 2024-to-2028-time horizon.

Table JDD-8: CEI South TDSIC Plan Profile by Program (Nominal $Millions)

Program	2024	2025	2026	2027	2028	Total
Risk & Resiliency Analytics Defined Projects						
Transmission Line Rebuild	$17.1	$25.5	$27.5	$19.2	$31.7	$121.0
Substation Rebuild	$7.8	$19.9	$21.2	$23.6	$17.6	$90.1
Distribution 12kV Circuit Rebuild	$14.4	$18.3	$17.1	$24.8	$17.5	$92.1
Distribution Underground Rebuild	$9.1	$9.7	$9.0	$9.3	$8.8	$45.9
Distribution Automation	$2.7	$2.2	$3.9	$4.7	$6.0	$19.6
Sub-Total	**$51.1**	**$75.7**	**$78.7**	**$81.6**	**$81.6**	**$368.7**
CEI South System Stakeholders Defined Projects						
Transmission Line Rebuild	$6.2					$6.2
Substation Rebuild	$13.4					$13.4
Distribution 12kV Circuit Rebuild	$5.3	$0.3	$0.3	$0.4	$0.4	$6.7
Wood Pole Replacement	$12.0	$12.0	$9.0	$6.0	$6.0	$45.0
Substation Physical Security	$5.3	$5.8	$0.9	$1.0	$1.0	$14.0
Sub-Total	**$42.2**	**$18.1**	**$10.2**	**$7.4**	**$7.4**	**$85.3**
Total	**$93.3**	**$93.8**	**$88.9**	**$89.0**	**$89.0**	**$454.0**

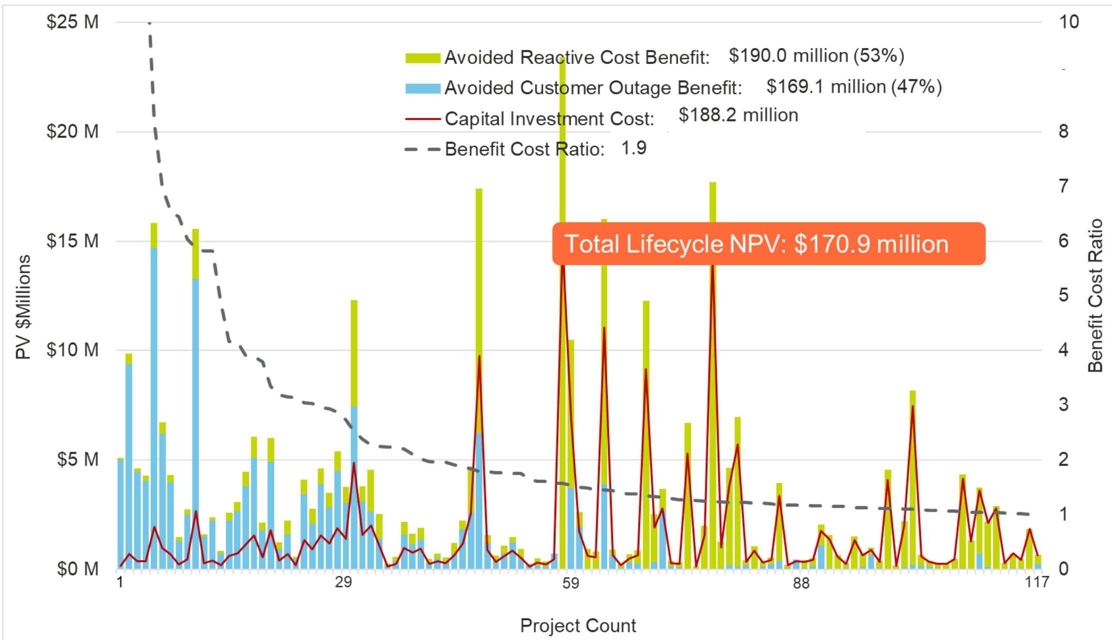
Transmission Line Rebuild is the largest individual program accounting for approximately 28.0 percent of the investment level. Substation Rebuilds account for approximately 22.8 percent of the investment level for the Plan. The distribution circuit focused investment (Distribution 12kV Circuit Rebuild, Distribution Underground Rebuild, and Distribution Automation) account for approximately 36.2 percent of the Plan. Wood Pole Replacements due to inspections account for approximately 9.9 percent of the Plan. Substation Physical Security accounts for approximately 3.1 percent of the Plan.

Q. WHAT ARE THE QUANTIFIED BUSINESS CASE RESULTS FOR THE POTENTIAL SUBSTITUTION PROJECTS (PSPs)?

A. PSPs are alternative investment projects that can serve as replacements. The goal of the Plan is to invest in the grid assets and provide value to the customer. The 5-year Plan is targeted to be executed during the 2024 – 2028 TDSIC time frame. However, should circumstances prevent full execution of the five-year Plan, it would provide the best system benefit to substitute a PSP investment in contrast to having those investment funds go unallocated. To this end, a list of PSP investments has been developed. For each category, these projects represent a similar selection and benefits assessment.

Figure JDD-13 shows the business case results for the PSP investments. As the figure shows, the total potential investment of $188.2 million produces life cycle PV of benefits of $359.1 ($190.0 + 169.1) million for a benefit cost ratio of 1.9. From an aggregate perspective, the investment category has a positive business case. The reactive cost benefits alone cover approximately 53 percent of the total investment. As the figure shows, all projects have quantified benefits in excess of cost (all BCRs are greater than or equal to 1).

Figure JDD-13: PSPs Quantified Project Business Case



V. CONCLUSIONS

Q. WHAT CONCLUSIONS CAN BE MADE FROM THE BUSINESS CASE RESULTS?

A. The following include the conclusions of the TDSIC Plan business case.

- The TDSIC Plan has a robust business case from several perspectives.
  - From the portfolio level, the quantified benefits are in excess of the Plan's investment level producing a benefit cost ratio of 1.7. For only the investments identified using the risk & resiliency analytics approach, the quantitative analysis produces a life cycle NPV of $355 million and benefit cost ratio of 2.1.
  - From a program perspective, all five programs evaluated with the risk & resiliency benefit analytics have quantified benefits in excess of costs.
  - At the individual project level all investments with quantifiable benefits have quantified benefits in excess of cost.

- □ The business case also includes alignment to CEI South Plan Objectives and TDSIC Purposes that were not quantified. These qualitative factors should not be ignored or dismissed, specifically for safety mitigation. They are a key part of the overall business case.
- □ The quantified business case is conservative, it does not include benefit streams for safety risk mitigation or the other CEI South objectives.

- ■ The business case results are customer-centric. The quantified benefits were done from the customer's perspective calculating the avoided reactive costs and avoided customer outages. All quantified business case results included both of these metrics.
- ■ The investment identification and business case analysis are transparent showing the 'line of sight' from CEI South data to the TDSIC Plan.

Q. WHY IS THIS APPROACH TO INVESTMENT PLANNING, IDENTIFICATION, AND JUSTIFICATION VALUABLE?

A. The development of the TDSIC Plan using the objective-driven decision making approach with the strategic to tactical aligned process provides confidence investments were identified that provide the most value to CEI South customers. The process and business case approach provides confidence for the following reasons:

- ■ **Customer and Asset-Centric:** The risk & resiliency analytics are foundationally customer and asset-centric in how they organized with the alignment of assets to protection devices and protection devices to customer information (number, type, and priority). This enables the value framework to directly link investments in aging equipment (TDSIC purpose) to customer benefit (investment prudency)
- ■ **Data as the Foundation**: The risk & resiliency-based planning approach is foundationally data centric. The model utilizes CEI South's GIS, OMS, CIS, distribution circuit models, critical customer information, and condition information. It also utilizes satellite tree canopy data and road layers. The data centric approach minimizes subjectivity in developing the TDSIC Plan.
- ■ **Drives Consistency**: The models calculate the benefits consistently for nearly all investments. The model carefully normalizes for more accurate benefits comparison between asset types. For example, the model can compare a substation rebuild to a distribution automation project. This is a significant

achievement allowing the assessment to accurately compare a wide range of investment types.

- **Captures the range of failure types**: The model is based on the range of failure types that impact assets capturing the high probability low consequence impact through the low probability and high consequence events.
- **Comprehensive:** The approach is comprehensive and evaluates nearly all of the assets on CEI South's T&D systems. By considering and evaluating those systems on a consistent basis, the results of the Plan provide confidence that portions of CEI South's grid assets are not overlooked for potential customer benefit.
- **Granular**: The granularity at the asset and project levels allows CEI South to invest in portions of the system that provide the most value to customers from both a restoration cost reduction and avoided CMI perspective. For example, a circuit may have 10 laterals that come off a feeder, and the age and reliability investment model may determine that only 3 out of the 10 should be rebuilt. Without this granularity, a suboptimal or inefficient level of investment could occur. The adopted approach provides confidence that the overall Plan is investing in parts of the system that provide the most value for customers.
- **Provides balance and confidence:** The process utilizes a data and analytics-based approach to identify initial investments balanced by review and refinement from system planners and engineers. This balanced approach provides more robust and actionable project scopes and investment plan while also having foundations in an objective methodology. This provides confidence in the final TDSIC Plan.
- **Business Case Foundations & Prudency**: The outputs of the models are the life-cycle risk-weighted NPV of each project as well as the simple BCR. This allows regulatory stakeholders to evaluate projects on a value framework they understand, benefits and costs. The business case approach also incorporates other factors when quantified benefits are not in excess of cost. Additionally, for qualitative based investments, the business case approach is linked directly to CEI South objectives. This approach drives enhanced prudency.

Q. DOES THIS CONCLUDE YOUR PREPARED VERIFIED DIRECT TESTIMONY?

A. Yes.

Cause No. 45894

VERIFICATION

I affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

Jason D. De Stigter
Director, 1898 & Co.

22 May 2023
Date

1898 & Co.

Jason De Stigter, PE

Director - Utility Investment Planning

Jason leads the Utility Investment Planning business line at 1898 & Co., part of Burns & McDonnell. In this role, Jason is responsible for business development, marketing, staff training and development, solution and product development, and overall project delivery within the business line. The Utility Investment Planning business line supports electric utilities in developing long-term investment plans and portfolios to meet one or all of the following objectives: 1) aging infrastructure, 2) reliability, 3) resilience or system hardening, and 4) electrification and distributed energy resources (DERs). The business line owns solutions and tools around each of offerings to produce data-driven decisions. Jason is the main architect and solution developer of the data-driven analytic solutions for each of the four offerings inside 1898 & Co.'s AssetLens Analytics Engine.

Jason has 15 years of extensive experience in performing business case evaluation on a variety of project types helping utility clients with difficult investment decisions. Jason also has a deep financial and economic analysis background and specializes in business case evaluation and risk assessment and management for utility client. Jason has extensive experience modeling risk for utility industry clients. His modeling experience includes developing complex and innovative risk analysis models using industry leading risk analysis software tools employing Monte Carlo simulation, decision trees, and Optimization algorithms. His experience includes performing risk and economic analysis engagements for several multi-billion-dollar capital projects and large utility systems for aging infrastructure, system resilience, reliability and distribution automation, and electrification. Jason also serves as expert witness for many of these engagements supporting the full regulatory process.

Education

B.S. / Engineering

B.A. / Business Administration

Registrations

- Professional Engineer (KS)

6 years with 1898 & Co.

15 years of experience

Visit my LinkedIn profile.

1898 & Co.

TESTIMONY/REGULATORY FILING EXPERIENCE

Utility Company	Regulatory Agency	Docket No. | Year	Subject
Baltimore Gas & Electric	Maryland Public Service Commission	9692 | 2023 1898 Technical Report (137-276) *Testimony not provided, case is still pending	2024 – 2026 Mutli-Year Plan (MYP): Resilience Investment Plan
Entergy Louisiana	Louisiana Public Service Commission	U-36625 | 2022 Direct Testimony Filing/Sponsoring Report Case is still pending	2023-2033 Storm Resiliency Plan
Tampa Electric Company (TEC)	Florida Public Service Commission	20220048-EI | 2022 Direct Testimony (412-485) Filing/Sponsoring Report (141-222) Oral Testimony Provided	2022 – 2031 Storm Protection Plan (SPP)
Oklahoma Gas and Electric Company (OG&E)	Oklahoma Corporation Commission	202100164 | 2022 Direct Testimony (1-45) Filing/Sponsoring Report (46-181) Rebuttal Testimony Not in Public Domain	Grid Enhancement Business Case for 2020 & 2021 Investment
Tampa Electric Company (TEC)	Florida Public Service Commission	20200067-EI | 2020 Direct Testimony (549-623) Filing/Sponsoring Report (100-180) Rebuttal Testimony (72-105)	2020 – 2029 Storm Protection Plan (SPP)
Indianapolis Power & Light Company (now AES Indiana)	Indiana Utility Regulatory Commission	45264 | 2019 Direct Testimony Filing/Sponsoring Report Rebuttal Testimony Oral Testimony Provided	Indianapolis Power & Light Company Transmission Distribution Storage System Improvement Charge (TDSIC) Plan

Additionally, Jason testified in front of the State of Alaska Senate and House Resource committees on project economics and challenges of the AKLNG project.

PROJECT EXPERIENCE

10 Year Storm Resiliency Plan / Entergy Louisiana

Louisiana / 2022-Current

Project director for developing and providing justification for Entergy Louisiana's 2024-2033 10-year Storm Resiliency Plan for its transmission and distribution system to mitigate the impact of major events. The project utilized 1898 & Co.'s Storm Resilience Model to develop and prioritize projects on a cost benefit perspective. The model employed data-driven analyses and robust algorithms to calculate the resilience benefit of over 150,000 storm hardening projects in terms of the range of reduced restoration costs and customer minutes interrupted (CMI). The Storm Resilience Model organized the system into 50 mile by 50 mile system sections and models 49 storm events against each section and estimates which parts of the system will fail in each storm event. The model evaluates each project before and after hardening for both an overhead hardening and underground conversion. The model further utilizes Stochastic Model to simulate storm events and calculate resilience benefits. Finally, the model performs budget optimization to identify ideal investment levels and prioritize projects. The 1898 & Co. resilience benefit assessment report and Jason written testimony were included in the filing. Jason is supporting the regulatory process to include responding to data requests and interrogatories.

Resiliency Multi-Year Plan / Baltimore Gas & Electric

Maryland/ 2022-Current

Project director for developing distribution resiliency portfolio of overhead hardening and underground conversions for Baltimore Gas & Electric. Jason is leading the effort to identify and justify investments for the 2024 through 2026 time horizon. The project utilized 1898 & Co.'s Resilience Investment Model to develop and prioritize projects on a cost benefit perspective. The model employed data-driven analyses and robust algorithms to calculate the resilience benefit hardening projects and alternatives in terms of the range of reduced restoration costs and customer minutes interrupted (CMI). The output of the analysis included three years of specific distribution investments in overhead hardening and underground conversions and the benefits for those projects. 1898 & Co. provided a technical report that was included as an exhibit to BGE's witness. 1898 & Co. is currently supporting the discovery process, the case is still pending.

Distribution Automation Plan Development / Confidential Client

Midwest / 2022-Current

Project director for developing and providing justification for a distribution automation circuit configuration investment portfolio for a Midwest Investor-Owned Utility. The evaluation utilized 1898 & Co.'s reliability and distribution automation analytics model inside our AssetLens Analytics Engine, an asset investment planning tool to evaluate the life-cycle benefits of replacing Transmission and Distribution (T&D) infrastructure and deploying smart devices across the distribution system. The analytics model estimates the expected benefit of deploying distribution automation to every circuits factoring in scheme effectiveness due to tie-line constraints and conductor capacity. The business case monetized the outage improvement and estimated the project cost to include new reclosers, associated communications upgrades, new tie lines, and conductor upgrades. Jason will serve as the expert witness and sponsor the technical report. The case is expected to be filed in May 2023.

Long-term Portfolio Development / Confidential Client

Midwest / 2022-Current

Project director for developing the portfolio of investment projects for a Midwest Investor Owned Utility. Jason is leading the effort to identify and justify investments in transmission, substation, and distribution systems over the next 5 years. The evaluation leveraged 1898 & Co.'s AssetLens Analytics Engine, an asset investment planning tool to evaluate the life-cycle benefits of replacing Transmission and Distribution (T&D) infrastructure and deploying smart devices across the distribution system. The analysis leveraged utility datasets (GIS, OMS, distribution circuit models, asset management systems, condition records, customer counts and profiles) inside the engine's aging infrastructure and reliability analytics. The project included data cleansing, organizing, linking, and transformation and configuration of the holistic risk framework across poles, conductor spans, line transformers, breakers, power transformers, relays, and other assets classes. Jason will serve as the expert witness and sponsor the technical report.

Grid Investment Plan Benefits Assessment / Confidential IOU

Midwest / 2022 - Current

Project director for development of the benefits assessment for a $2.6 billion grid investment plan. The plan includes investments in distribution circuit upgrades, distribution automation, substation rebuilds, capacity rebuilds, and low voltage conversions to improve reliability and resilience, manage long-term costs, modernize for the future, and decrease risk. The engagement include mapping investments to the underlying asset infrastructure, calculating the benefits using the AssetLens Analytics Engine analytics models, and developing the business case for over 6,000 different investment activities across 6 programs. The analysis and results are formalized within a technical report that will be submitted within the public record.

Grid Enhancement Investment Plan Benefits Assessment / Oklahoma Gas & Electric

Oklahoma / 2021-2022

Project director for development of the benefits assessment for OG&E's 2020 and 2021 Grid Enhancement Plan. The plan includes investments in distribution circuit upgrades, distribution automation, and substation rebuilds totaling nearly $250 million. Jason organized the business case framework including the linkage of investments to benefits approaches and calculating the life-cycle benefits in terms of decreased customer outages and avoided restoration costs. Jason also served as the expert witness for the benefits assessment and has provided direct testimony sponsoring the technical report, supported interrogatories and data requests, and provided rebuttal testimony. OG&E settled the case in June 2022.

2022-2031 Storm Protection Plan Resilience Assessment / Tampa Electric Company

Florida / 2021-2022

Project director for supporting the development of TEC's 2022-2031 10-year Storm Protection Plans for its transmission and distribution system in accordance with Florida Statute 366.96. This project is an update to the original 2020-2029 10-Yr Storm Protection Plan. The project utilized 1898 & Co.'s Storm Resilience Model to develop and prioritize projects on a cost benefit perspective. The model employed data-driven analyses and robust algorithms to calculate the resilience benefit of over 20,000 storm hardening projects in terms of the range of reduced restoration costs and customer minutes interrupted (CMI). The Storm Resilience Model models nearly 100 storm events and estimates which parts of the system will fail in each storm event. The model evaluates each project before and after hardening. The model further utilizes Stochastic Model to simulate storm events and calculate resilience benefits. Finally, the model performs budget optimization to identify ideal investment levels and prioritize projects. The 1898 & Co. resilience benefit assessment report and Jason written testimony were included in the filing. Jason supported the regulatory process to include responding to data requests and interrogatories. Jason testified in hearings in Tallahassee in early August 2022. The commission approved nearly all of TEC investment plan.

Long-term Portfolio Development / Public Service New Mexico

New Mexico / 2021-Current

Project director for developing the portfolio of investment projects for Public Service New Mexico (PNM). Jason led the effort to identify and justify investments in PNM's transmission, substation, and distribution systems over the next 20 years. The evaluation leveraged 1898 & Co.'s AssetLens Analytics Engine, an asset investment planning tool to evaluate the life-cycle benefits of replacing Transmission and Distribution (T&D) infrastructure and deploying smart devices across the distribution system. The analysis leveraged PNM datasets (GIS, OMS, distribution circuit models, asset management systems, condition records, customer counts and profiles) inside the engine's aging infrastructure and reliability analytics. The project included data cleansing, organizing, linking, and transformation and configuration of the holistic risk framework across poles, conductor spans, line transformers, breakers, power transformers, relays, and other assets classes. The evaluation organized all PNM's assets into over 20,000 projects. The risk framework allowed for the calculation of benefit in financial terms across each of the 20,000 projects from, specifically the mitigated reactive and restoration costs and the monetization of customer outages. Finally, the project included budget optimization to identify the point of diminishing returns to provide valuable management insights into the level of needed investment in the system over the next 20 years. The overall investment level is confidential. PNM is currently executing the projects that resulted from the evaluation and moving their overall investment levels to manage system risk.

2020-2029 Storm Protection Plan Resilience Assessment / Tampa Electric Company

Florida / 2019-2020

Project director for supporting the development of TEC's 2020-2029 10-year Storm Protection Plans for its transmission and distribution system in accordance with Florida Statute 366.96. The projects utilized 1898 & Co.'s Storm Resilience Model to develop and prioritize projects on a cost benefit perspective. The model employed data-driven analyses and robust algorithms to calculate the resilience benefit of over 20,000 storm hardening projects in terms of the range of reduced restoration costs and customer minutes interrupted (CMI). The Storm Resilience Model models nearly 100 storm events and estimates which parts of the system will fail in each storm event. The model evaluates each project before and after hardening. The model further utilizes Stochastic Model to simulate storm events and calculate resilience benefits. Finally, the model performs budget optimization to identify ideal investment levels and prioritize projects. Tampa Electric Company $1.5 billion 10-year plan was approved in September 2020. The 1898 & Co. resilience benefit assessment report and Jason written testimony were included in the filing. Jason supported the regulatory process to include responding to data requests and interrogatories. He also provided rebuttal testimony. Tampa Electric settled with the interveners.

Grid Investment Business Case / Confidential IOU

Southeast / 2021

Project director for development of a business case for all grid investment planned projects over the next 10 years. Business case evaluated both mitigated life-cycle reactive and restoration costs and monetization of customer outages. Investments included traditional rebuilds for reliability and resilience purposes, distribution automation, communications, and deployment of new technologies. The business case was used for internal executive management approvals.

Distribution Investment Plan Development with AssetLens / Evergy

Missouri and Kansas / 2019-Current

Project director for configuration and implementation of AssetLens for Evergy's distribution system across multiple states and jurisdictions. AssetLens is an asset investment planning software developed by 1898 & Co. to 1) automate project identification in T&D systems using typical utility data set and 2) provide business justification for all projects in life-cycle NPV benefit terms. The software ingests a range of datasets to include GIS, OMS, distribution circuit models, asset management systems, condition records, customer counts and profiles and performs the necessary cleansing, transformation, and linking. Jason led the effort to configure the risk framework analytics that estimate the risk adjusted life-cycle costs and customer impact for all T&D asset classes including poles, pole tops, primary conductor spans, primary underground sections, secondary cable, line transformers, manholes, conduit, splices in manholes, network assets and more. The analytics employ a risk-based methodology across a range of failure types (various probabilities and consequences) to calculate the annual risk costs for a Status Quo and Investment scenario. Life-cycle risk costs include a range of reactive and restoration costs and the monetization of customer outages. The evaluation organized assets into over 100,000 potential projects and scheduled investments to maximize benefit given budget, schedule, and other technical constraints. The overall investment level is confidential. AssetLens visualizes the project plan geospatially providing specific assets for replacement with the business case results for each project. Evergy's distribution engineering teams has been using AssetLens to develop work orders and executive the project plan. It was also used to support their regulatory filing to the Missouri commission.

Distribution Automation Plan Development / Confidential IOU

Central Midwest / 2021-Current

Project director for development of a distribution automation investment plan for the next 5 years. The project involved using GIS and outage records to circuits that would provide the most benefit from the deployment of reclosers. The effort included estimating the number of devices for each circuit and placement of devices for the first few years of the plan. The business case results include the estimated decrease in customer outages and monetization of the outages for an investment business case. The utility is currently developing work orders for 2022 projects.

Overhead and Underground Business Case Development / Confidential IOU

Upper Midwest / 2021-Current

Project director for development of a business case comparing overhead rebuilds to a new modern standards or undergrounding. The business case was performed from a life-cycle cost perspective and impact to customers over a range of events to include extreme weather. The business case evaluated a range of areas of the system to include urban, rural, and suburban. The result of the evaluation may be used for responding to regulators requests.

Long-term Investment Plan Development / Confidential IOU

Midwest / 2021

Project director for identification and justification of distribution circuit and substation investments for a long-term investment plan. The evaluation utilized the AssetLens Analytics Engine to evaluate a range of investment options across the grid, establish 'ideal' investment levels, and provide direction to the 'ideal' split of investment across the system. The utility utilized the study to help develop their long-term investment plan for executive management approval and regulatory strategy.

Distribution Automation Business Case Pilot / Confidential IOU

Midwest / 2021

Project director for a pilot study on distribution automation project identification and justification. The evaluation performed 8760 modeling to understand system overloading constraints to performing automated load transfer schemes. The constraints analysis was utilized in the business case assessment to understand the percentage of time the scheme could operate and provide benefits to customers and if there was a business case to make other grid investments to unlock potential overloading constraints.

Distribution Reliability Investment Plan Development with AssetLens / Confidential IOU

Midwest / 2020-Current

Project director for development of a 10-year distribution investment plan focused on improving overall system reliability and delivery of AssetLens. The data and analytics-based planning approach included the cleansing, organizing, transformation, and linking of GIS, OMS, distribution circuit models, customer data, and condition information. The planning analytics included evaluation of the benefits and costs of rebuilding each protection zone, over 40,000, across they system. Benefit profiles included the mitigated reactive and restoration costs and decreased customer outages monetized using the DOE ICE Calculator. The project also included budget optimization to identify the long-term need for investment. The overall investment level is confidential. The client's distribution engineering team is currently utilizing the AssetLens solution to build work orders from the projects identified. The client is also moving toward the more 'ideal' long-term investment levels to manage system risk.

Long Term Electric Transmission and Distribution Capital Plan / Indianapolis Power & Light

Indiana / 2017-2019

Project manager for developing IPL's asset risk model. The asset risk model includes transmission circuit, substation, and distribution circuit assets. The asset risk model was used to identify and prioritize asset replacements for nearly $750 million of the $1.2 billion filing. Jason developed an innovative approach for modeling distribution circuit risk down to the span level. For the risk model, Jason developed an integrated and holistic probability and consequence of failure framework to evaluate any asset consistently. The approach has allowed IPL to prioritize investment across transmission and distribution and substations and circuits. The analysis included using Burns & McDonnell's proprietary capital optimization algorithm to group assets into projects and prioritize projects to maximize risk reduction benefit. Burns & McDonnell prepared two reports that are part of IPL's public record filing. Jason also provided written (direct and rebuttal) and oral testimony. The entire plan (100%) was approved in February of 2020.

Grid Modernization Engineering Study / Entergy

Louisiana/Mississippi/Arkansas/Texas / 2016–2019

Entergy is embarking on a new approach to electric distribution planning, design and engineering to meet the future needs of its customers. The new approach includes developing modernize electric distribution equipment, engineering and design, and construction standards to drive value throughout the supply chain from material purchasing, inventory, system design, and construction. Additionally, the grid modernization approach leverages a modern holistic distribution asset and capital planning process with associated tools (DNV GL's Synergy) to facilitate efficient and robust performance and risk assessment of Entergy's electric distribution system. The approach identifies the portfolio of issues facing a family or cluster of distribution feeders and then develops the ideal portfolio of projects to address to improve feeder performance, cost, and risk.

Project manager for the business case evaluation and capital project prioritization aspects of Grid Modernization Engineering Study for Entergy. For the portfolio of projects, Jason developed a robust business case methodology that calculates risk reduction benefits, reliability improvement, and operational efficiency (i.e. fewer truck rolls) to justify each capital investment.

Entergy intends to use the results of the engineering study to propose a list of grid modernization project to consider for regulatory approval and funding. Additionally, these projects and the holistic planning approach will be the first step in an evolutionary change to build Entergy's grid of the future, ready for the next generation of consumers and system performance.

69 kV Wood Pole Replacement Program Evaluation / Salt River Project (SRP)

Phoenix, Arizona / 2017–2018

Project manager for evaluation of the 'ideal' level of 69 kV wood pole replacement SRP should execute each year. The effort includes development of an asset risk model, including risk framework, and various replacement strategies that maximize risk reduction while also maintaining overall budget levels. The final outcome will include the risk mitigated for the whole portfolio over 30 years for a range of budget levels to identify an 'ideal' overall investment rate.

PRIOR EXPERIENCE

Capital and Operations & Maintenance (O&M) Budget Prioritization / Tulsa Metropolitan Utility Authority (TMUA) Utility Enterprise Initiative

Tulsa, Oklahoma / 2013-2016

Project manager for the Capital Prioritization and Optimization task of TMUA's Asset Management implementation initiative, Utility Enterprise Initiative. He used a 'Project Prioritization and Optimization' solution for several water and wastewater projects as part annual cycle phased approach (executed three of four phases). Jason was responsible for leading workshops with engineering and maintenance staff, developing business case approaches for each water/wastewater project, performing Monte Carlo and optimization simulations, and developing strategies for the Utility's capital improvement plan (CIP) during a period of tight budget constraints to minimize rate increases. TMUA was working toward codifying the process and tool into their own annual budget and rates process. As such, Jason was responsible for developing users guide documentation and holding training on the process and tool for TMUA.

2017 Executive Asset Management Plan Alternatives Evaluation / Washington Suburban Sanitation Commission (WSSC)

Laurel, Maryland / 2015

Project manager for alternatives evaluation to support WSSC in the development of their 2017 Enterprise Asset Management Plan Business Case. Effort included developing forecasted 30-year capital plans optimizing on level of service, risk and cost. WSSC utilized the results of the evaluation to develop long term forecasts of capital improvements for communication to decision make Capital Prioritization Pilot Project / Salt River Project (SRP)

Project Prioritization / Salt River Project

Arizona / 2013-2014

Subject matter expert for this pilot study for SRP to prioritize and optimize several electrical generation, transmission and distribution planned investments. Allowed SRP management the opportunity to further develop and improve upon their current budget processes and to consider adopting the solution enterprise-wide. Jason's responsibilities included developing business case approaches for several of the pilot study projects and supporting workshops.

Long Term Electric Transmission and Distribution Capital Plan / Duke Energy

Indiana / 2014-2015

Subject matter expert and manager for development of a risk-based electric T&D capital plan that included Duke's long-term electric transmission and distribution (T&D) investments. This work provided evidence of how Duke's investments in its system provided risk reduction benefits and focused spending on high risk assets. As a capital prioritization and risk subject matter expert, he also developed capital plan profiles and resulting risk reduction solutions which were key to showing the value of the 7-year capital plan.

Long Term Electric Transmission and Distribution Capital Plan / Northern Indiana Public Service Company (NIPSCO)

Indiana / 2013-2014

Subject matter expert for development of a long-term $1 billion plus capital plan for NIPSCO's electric T&D infrastructure. A system risk model was developed to analyze and score asset risk across the T&D system for NIPSCO. The model highlighted the risk reduction benefits achieved through NIPSCO's long-term asset replacement program, which is focused on addressing high-risk assets that are nearing the end of their useful life.

Capital Prioritization System Master Plan / Hetch Hetchy Water and Power

California / 2009, 2011, 2012

Primary consultant for this system master plan, developing the analysis and prioritization of recommended capital and O&M projects for the Hetch Hetchy power, transmission and civil asset system. The process utilized a risk-based approach to economically schedule investments to maximize risk reduction given a certain budget constraint. The Hetch Hetchy Reservoir system lies within the scenic Yosemite National Park and provides electricity and water storage for the San Francisco Public Utility Commission.

Capital Project Prioritization with Risk Assessment / Colorado Springs Utilities

Colorado Springs, Colorado / 2008

Primary analyst on an innovative capital project prioritization process for Colorado Springs Utilities' Raw Water System. The engagement applied the Strategic Value Creation process to quantify the physical and financial parameters of capital and O&M projects identified for the utility's raw water system. A wide variety of projects and risk were then prioritized to develop the system capital improvement plan while considering utility risk tolerance, budget constraints and other planning criteria. Monte Carlo simulations were used to quantify the physical and financial parameters of each individual project, and the projects are evaluated and ranked using a consistent and transparent approach.

Jason was responsible for performing the Monte Carlo analysis, understanding the risks of each CAPITAL and O&M project, and prioritizing the projects to reduce the overall risk to the client.

Alaska Liquefied Natural Gas (AKLNG) Economic and Risk Analysis / State of Alaska Departments of Natural Resources and Revenue

Alaska / 2013-2016

Project manager responsible for economic and risk analysis for the AKLNG project on behalf of the State. In this role, Jason developed analysis to explore various project questions and negotiating position to better understand the perspective of each project sponsor and the best position for the State. He routinely developed materials to present to the commissioners of the departments or Natural Resources and Revenue, the State of Alaska legislature, negotiating teams, and the governor's office. On a few occasions, Jason has testified to the state of Alaska legislature of the economics and risks associated with the AKLNG project.

Deep Tunnel Sewerage System (DTSS) Phase 2 Resiliency Assessment / Singapore Public Utilities Board (PUB)

Singapore / 2014-2015

Subject matter expert for an alternative's resiliency assessment of several deep tunnel sewerage systems alternatives for Singapore PUB. In his role for this engagement, Jason created an innovated approach to evaluating the resiliency of several tunneling alternatives including total risk weighted level of service and cost over the asset's life cycle. The assessment identified several key risks impacting each alternative then quantifying the likelihood and the level of service and cost impacts of each risk. Employing Monte Carlo simulation, the risk cost and discount to level of service scores were calculated to develop a range of potential benefit cost ratios for each alternative. Singapore PUB utilized the process and results to identify a preferred alternative and move forward with key design decisions.

Kirkwood Penstock Risk Evaluation / Hetch Hetchy Water and Power

California / 2014

Project manager for a risk assessment of HHWP's critical Kirkwood Penstock which over 80% of San Francisco Bay's water supply moves through. The risk assessment following guidelines set out by the United States Bureau of Reclamation including a failure modes and effects analysis applying a qualitative scoring-based approach to evaluate the likelihood and consequence of failure for each failure mode. HHWP utilized the results of the evaluation to prioritize investment needs to ensure reliability of this critical asset.

Business Case Evaluation and Risk Analysis / Hampton Roads Sanitation District (HRSD, Wastewater Utility)

Virginia / 2011-2012

Business case evaluation and lead risk consultant for this long-term evaluation of the business case and associated risk of alternative wastewater system master plans. Working with Hampton Roads' senior management team, Jason evaluated the economics and risk of alternative strategic long-term wastewater system expansion plans related to biosolids management, which involved hundreds of millions of dollars in capital and O&M expenditures. This developed a long-term strategy that is now being used to optimize short- and long-term implementation plans for HRSD's wastewater system.

Conveyance Alternative Risk Assessment / Metropolitan Water District

California / 2010

Primary consultant for this engagement which analyzed several water conveyance options for the California State Department of Water Resources. This analysis was focused on capital cost and schedule risk of different multi-billion-dollar canal and tunnel conveyance alternatives. Jason was the risk specialist for the Environmental team for the risk assessment workshop. Utility decision-makers utilized the results to more fully understand the risk inherent in each alternative to decide on a preferred alternative.

Integrated Water Power Plant Economic and Regulatory Assessment / Public Authority for Electricity and Water of Oman

Oman, Middle East / 2009-2010

Primary analyst for the economic and regulatory (tariff) modeling of a new, highly efficient integrated water & power plant. Jason's responsibilities included performing economic and tariff modeling of several different desalination and power plant alternatives and presenting final results to the Chairman of the Public Authority for Electricity and Water of Oman.

AGIA Economic and Risk Modeling / State of Alaska Department of Natural Resources (DNR)

Alaska / 2009-2010

Primary analyst for this economic and risk modeling assignment for the State of Alaska DNR. Analysis included modeling and evaluation of different natural gas pipeline project risk factors, as well as risk mitigation measures the state has within its control. The results of the analysis assisted the State of Alaska in negotiations with other pipeline stakeholders.

Black & Veatch's Energy Market Perspective Emissions Modeling

Overland Park, Kansas / 2012-2013

As part of Black & Veatch's annual release of its Energy Market Perspective, Jason developed a fundamental economic model to calculate emissions prices based on the EPA's Cross State Air Pollution Rule.

Commercial Modeling and Analysis / Alaska Gasline Development Corporation (AGDC)

Anchorage, Alaska / 2010-2011

Lead consultant for ongoing commercial and tariff modeling for AGDC's analysis of in-state pipeline alternatives. This modeling included sensitivity and scenario analysis, midstream tariff modeling, and stakeholder cash flow analysis.

Black & Veatch's Energy Market Perspective

Overland Park, Kansas / 2009-2011

The Energy Market Perspective developed by Black & Veatch uses an integrated market modeling approach to develop price forecasts for energy and natural gas prices. The modeling team, which included Jason, developed forecasts for CO2 taxes, energy demand and peak demand, generation retirements, generation expansion, renewables buildout and transmission expansion. Using these forecasts, the integrated market model used an interactive process of a production cost model for electric prices and a fundamental market model for natural gas prices.

Jason's principal responsibilities included developing forecasts, running and understanding the production cost model for a large region in the United States, and drawing conclusions for the region. The main forecasts Jason developed included energy and peak demand, generation retirements, generation expansion, and transmission expansion. Furthermore, Jason was responsible for developing the final report for the regional perspective.

Alaska Gasline Inducement Act (AGIA) Net Present Value (NPV) and Risk Analysis / State of Alaska Departments of Natural Resources and Revenue

Alaska / 2007-2008

In 2007, the state of Alaska passed the Alaska Gasline Inducement Act (AGIA). This act created a framework for the State to issue a license to build a 1,400 mile pipeline to transport natural gas from the North Slope of Alaska to either the North American market or elsewhere.

Uncertainty for a project of this size (over $30 billion) is understandably significant. In order to quantify this significant uncertainty, risk analysis was performed explicitly with the NPV model to evaluate the level of project risk to the various stakeholders due to various assumptions such as commodity prices, capital cost escalation, project schedule uncertainty, and reserve risk.

Jason performed economic, risk and financial analysis for several different stakeholders for the proposed projects and several sensitivities and alternative scenarios. Jason's main responsibilities included model development/creation, Monte Carlo risk modeling, and understanding risk for each stakeholder. He also performed financial analysis, data validation, and report and presentation support.

Socioeconomic Analysis, Riverbend Unit 3 and Fermi Unit 3 Nuclear Licensing Project / Entergy and Detroit Edison

Louisiana and Michigan / 2007-2008

Senior analyst served as an economist for a detailed socioeconomic analysis associated with the construction and operating license application (COLA) process for Entergy and Detroit Edison. He was responsible for developing population distributions; population projections; demographic characteristics to include age, sex, race and income; transient population distributions; and community characteristics for the surrounding area. Jason was also responsible for writing and reviewing significant portions of the COLA

Market and Economic Analysis / Termobarranquilla

Colombia, South America / 2007-2008

As a senior analyst, Jason provided market analysis, economic analysis and a discounted cash flow model to evaluate the worth of the Termobarranquilla power plant after an energy market restructuring in Colombia. He was responsible for developing an energy market model, economic dispatch model, discounted cash flow model and writing the report.

Taylor Energy Center Need for Power Application / Various Clients

Florida / 2006

Jason performed production costing, economic analysis and other support to facilitate the completion and filing of the Taylor Energy Center (TEC) Need for Power Application (NFP). The NFP provided a determination of the most cost-effective capacity addition to satisfy forecasted capacity requirements for the four separate utilities participating in the project while maintaining consistency with the Florida Public Service Commission statutory requirements. The analysis considered self-build and purchase-power alternatives.

Portfolio of Wind Farms and Coal Fired Plants / Sembcorp Industries Pte Ltd.

China / 2011

Lead consultant to Sembcorp Industries Pte (buy-side), in support of their potential acquisition of an equity position in a Chinese investment company (confidential). This engagement required due diligence site visits and technical and commercial review of a wind portfolio and coal fired generation plant in Shanxi Province, Hebei Province, and Inner Mongolia Autonomous.

Water and Wastewater Utility Independent Engineer's Report / Confidential Client

2011

Primary consultant assisted and prepared an independent engineer's report for a confidential client seeking to divest its portfolio of water and wastewater utilities. The report provided an overview of the systems, the major sources of supplies, rates, and environmental and regulatory issues. Major facilities were evaluated to document the condition of specific utilities. A final report was prepared and delivered to the client for use in its divestment proceedings.

Combined Cycle Due Diligence / Confidential Client

California / 2011

Jason was involved with the technical due diligence of 1,000 megawatt (MW) combined-cycle power plant in the state of California. Jason was responsible for reviewing maintenance and performance reports on plant equipment and safety along with O&M and energy management agreements. Jason also developed the corresponding report sections that summarized the results of the analysis.

Engineer's Report / Philadelphia Gas Works (PGW)

Philadelphia, Pennsylvania / 2010-2011

Lead consultant on the engineer's reports developed for PGW's last two revenue bond issues for $165 million and $150 million, respectively. Proceeds from the bond issues funded needed capital improvements to PGW's distribution system and LNG facilities. The engineer's report summarized the findings of a study of PGW's facilities, management, operations, gas supply, rates and marketing, and customer service, and assessed the financial feasibility of the bond issue.

E.ON US Portfolio Due Diligence, Various Coal, Gas and Hydroelectric Power Plants / E.ON

Kentucky, United States / 2010

Jason performed technical due diligence for the potential sales of approximately 9,500 MW coal, gas and hydroelectric generating assets in the state of Kentucky. Jason was responsible for reviewing maintenance and performance reports on plant equipment and safety along with O&M and energy management agreements. Jason also developed the corresponding report sections that summarized the results of the analysis.

Technical Due Diligence / Con Edison Development, Inc.

2007

Jason performed a technical due diligence assessment of certain power generation facilities in the northeast United States. He was responsible for developing power plant performance sections of the assessment and reviewing O&M, power purchase, maintenance, gas supply, oil supply, electrical interconnection and water supply agreements.

PUBLICATIONS AND PRESENTATIONS

- *Asset Management: A Framework for Maximized Value*, published and featured in Burns & McDonnel's quarterly BenchMark article in 2020. (Video and quoted)
- How IPL Created an Optimized Capital Plan to manage risk across the entire T&D system, published and presented at the 2020 DistribuTECH conference. (Co-Author)
- How IPL solved the challenges of modeling linear assets in their asset risk model by leveraging GIS, published and presented at the 2020 DistribuTECH conference. (Co-Author)
- Capital Planning for Grid Modernization, Building the Grid of Tomorrow, 2018 EUCI course presenter. (Co-presenter)
- *Changing the Way the Grid's Future is Planned*, published Burns & McDonnell white paper in 2017. (Co-Author)
- Monetizing Risk Helps Tulsa Optimize Capital Investments, published in the July 2016 Journal American Water Works Associate (JAWWA). (Co-Author)
- Monte Carlo Simulations Take The Chance Out Of Investment Decisions, published in the April 2016 Breaking Energy. (Co-Author)
- Monetizing Risk – Capital Investment Prioritization and Optimization for Tulsa Metropolitan Utility Authority, published at the 2016 Utility Management Conference. (Co-Author)
- Priorities: Getting the Most From Your Capital Improvement Plan, published in the May 2015 Florida Water Resources Journal. (Author)
- Monetizing Risk – A Capital Investment Prioritization and Optimization Model, presented and published at the 2015 Texas Water Conference. (Co-Author/Presenter)
- How to Get More Reliability Bang from Your Capital Spending Buck, presented and published at the 2014 Florida Water Resources Conference. (Co-Author/Presenter)
- Triple Bottom Line and Monte Carlo Simulation: Business Case Evaluation Methodologies and Testing Sensitivities: Understanding Economic Models and Uncertainty in Results, presented at the 2013 WEFTEC conference workshop titled "WERF Barriers to Biogas Workshop: Learn to Use the Right Economic Methodologies to Evaluate Cost-Saving Projects". (Presenter)
- The Challenge of Regulatory Compliance and Multiple Facility Upgrades – A Progressive System Approach, presented and published at the 2012 WEFTEC conference proceedings. (Co-Author)
- Asset Management and Maintenance Strategies – Balancing Costs and Risk, poster presentation and published at Hydrovision 2011 conference. (Co-Author)

CEIS Pet.'s Ex. No 2, Attachment JDD-2

CEI South

CEI South TDSIC Investment Identification & Business Case Supplemental Attachment

5/16/2023

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1.0 CUSTOMER & INFRASTRUCTURE LINKAGE

CEI South provided customer count and type information with database relationships to the GIS and OMS. Using connectivity from the distribution circuit to the breaker, the customer relationship to the substation was also established. This data allowed the AssetLens Analytic Engine to directly link the number and type of customers impacted to each protection device and substation to assign the appropriate customer consequence to each asset failure type. Types of customers include residential, small commercial and industrial (Small C&I), and large commercial and industrial (Large C&I). This customer information is used for both incremental benefit approaches as it is foundational for the customer-centric business case evaluation. The following figures show the customer counts for the following sub-systems.

- Transmission Line Segments (with distribution underbuild)
- Substation
- Distribution Backbone Protection Zones
- Distribution Lateral Protection Zones

The figures show the customer counts from highest to lowest.

Figure 1-1: Customers by Transmission Line Segment

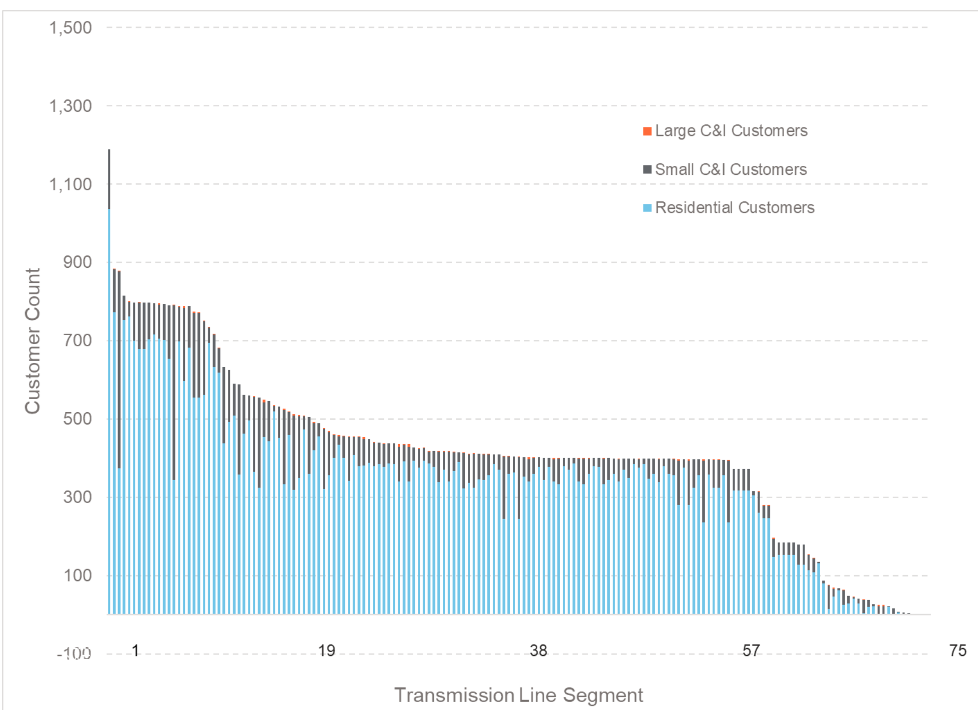


Figure 1-2: Customers by Substation

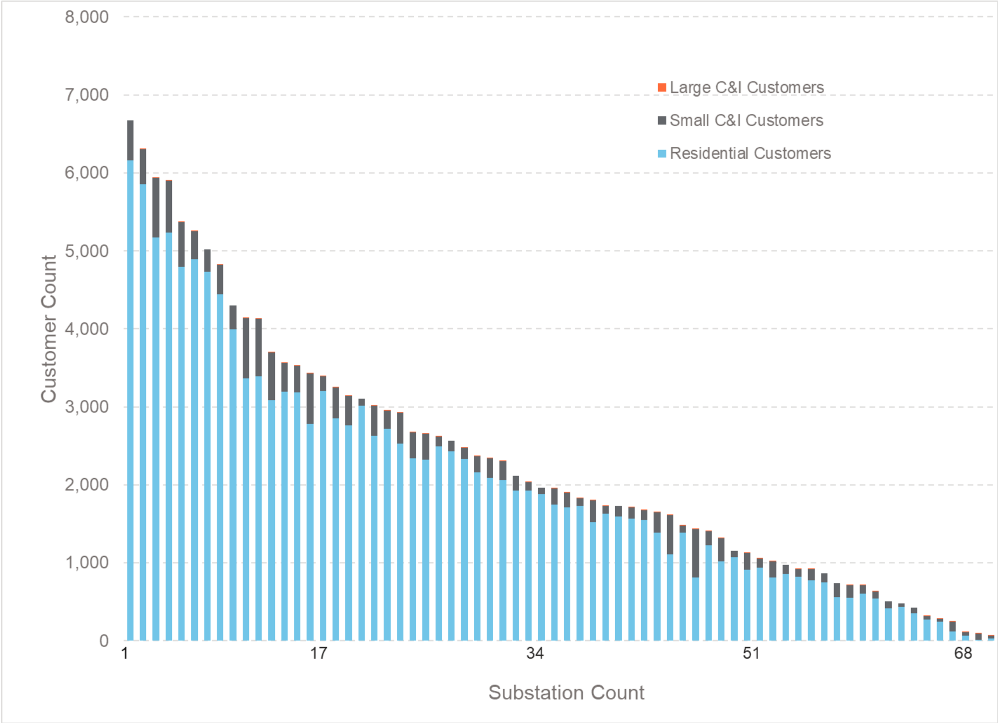


Figure 1-3: Customers by Distribution Backbone Protection Device

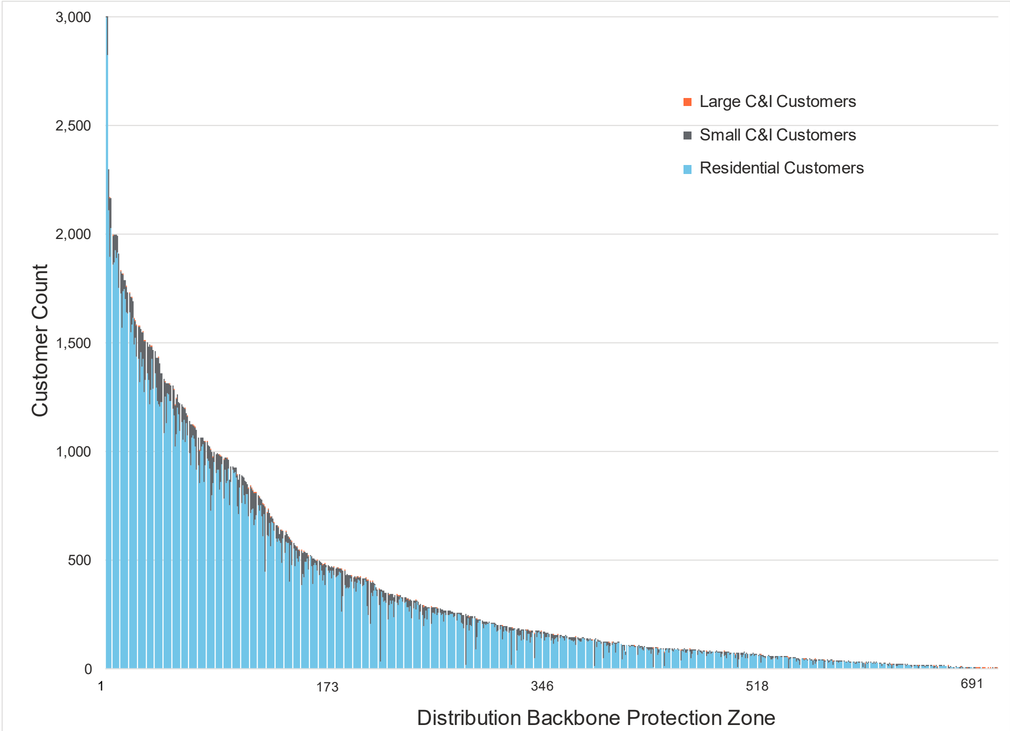
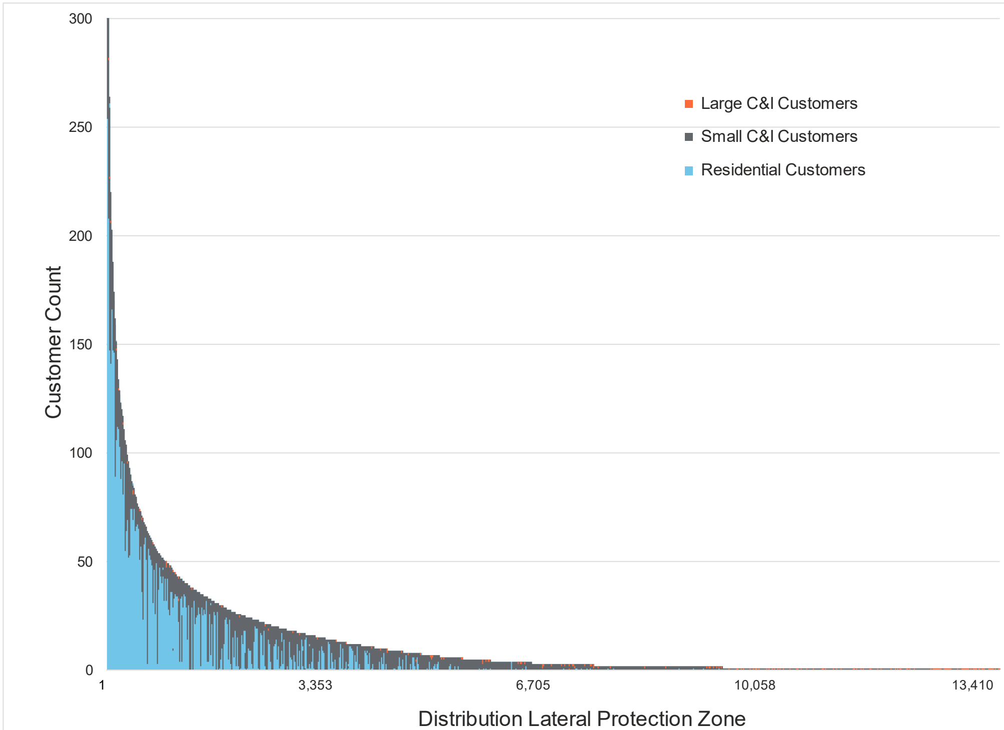


Figure 1-4: Customers by Distribution Lateral Protection Device



2.0 QUANTIFIED BENEFITS MODELING APPROACH

The quantified risk-based benefits assessment for the TDSIC Plan projects includes two main approaches:

1. Equipment Failure Risk & Resiliency
2. Outage Mitigation Risk & Resiliency

Each approach calculates the incremental benefits by comparing a status quo case to an investment case such that the incremental benefit can be compared to the incremental cost. These two approaches match the type of investment activities for TDSIC types of investment. Additionally, they produce business case metrics that map CEI South's objectives: Maintain Reliability & Resiliency and Managing Asset Life-Cycles. Further, both approaches are rooted in a bottom up, data driven, asset centric, business case evaluation that produces a benefit cost ratio for each evaluated project.

Equipment failure risk and resiliency investment activities primarily focus on aged or poor condition assets and known problematic equipment types. These factors are indicative of assets that have higher risks of failure in the future. The Equipment Failure Risk & Resiliency approach estimates benefits for asset replacement investments. This approach utilizes a risk-based methodology in alignment to CEI South original TDSIC filing to calculate the future reactive and restoration costs and customer outages.

Distribution automation investment activities to mitigate outages are primarily focused on decreasing customer outages to support the requirements of the modern customer. The Outage Mitigation Risk & Resiliency approach estimates benefits by re-calculating the historical outage records assuming the investments had been in place. The evaluation provides confidence that selected investments produce present value benefits more than cost.

2.1 Equipment Failure Risk & Resiliency Modeling Approach

The Equipment Failure Risk & Resiliency modeling approach calculates the benefits of replacing existing infrastructure. It utilizes a risk and resiliency-based planning approach to forecast the probability-weighted consequence of failure for a range of failure types. The failure types are based on how assets fail over their lifecycle, including inspection-based failures. Consequences are estimated for a range of factors but fall into two main categories. The first category is reactive or restoration costs. The second category is customer-based outages. This category is the monetization of customer outages in the event of an asset failure based on the DOE ICE calculator.

Additionally, the approach calculates each asset's lifecycle reactive costs and customer outage costs for two scenarios. The first is a Status Quo scenario where the asset is not proactively replaced; the second is the Investment scenario in which the asset is upgraded to the current equipment standard. The benefit of replacing infrastructure is the difference between the two scenarios, the avoided risk and resiliency life-cycle costs.

The following sub-sections outline the approach in further detail. The section uses an example 40-year-old wood pole on the backbone to show the incremental benefit calculations.

2.1.1 Probability of Surviving

Many of the asset classes included within the Plan are typically replaced before failure-causing outages. This replacement is because the consequence of failure typically exceeds utilities' desired risk tolerance levels. For this reason, utilities actively inspect the assets, perform testing, and even collect real-time condition information. When assets exceed a pre-established condition tolerance, they are proactively replaced. While there are historical equipment failures, the number of failures is insufficient to enable a statistical analysis to calculate reliable historical failure rates. In the absence of historical failure rates, Survivor curves, or End-of-Life curves, approximate the probability of an asset not surviving over time.

Based on workshops with CEI South's planning and engineering teams, review of CEI South's depreciation study, and leveraging 1898 & Co.'s collection of the asset expected lives, each asset class was assigned an Iowa Survivor Curve inside the AssetLens Analytics Engine. Figure 2-1 shows an example End-of-Life (Iowa Survivor Curve) for wood poles. Wood poles are expected to have an average service life of between 45 and 65 years with average service lives of 45 years for high vegetation areas and up to 65 years for no vegetation areas. Figure 2-2 shows the approach to calculate the annual probability of not surviving for a 40-year-old wood pole asset.

Figure 2-1: Example Survivor Curve for Wood Poles

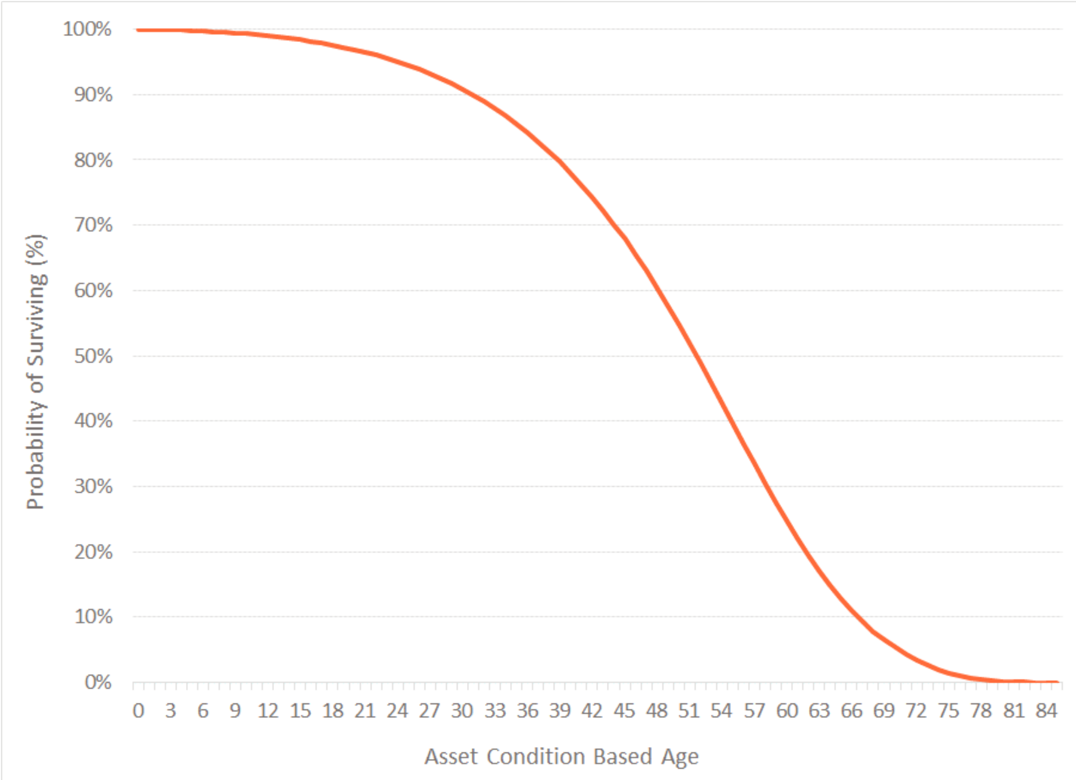
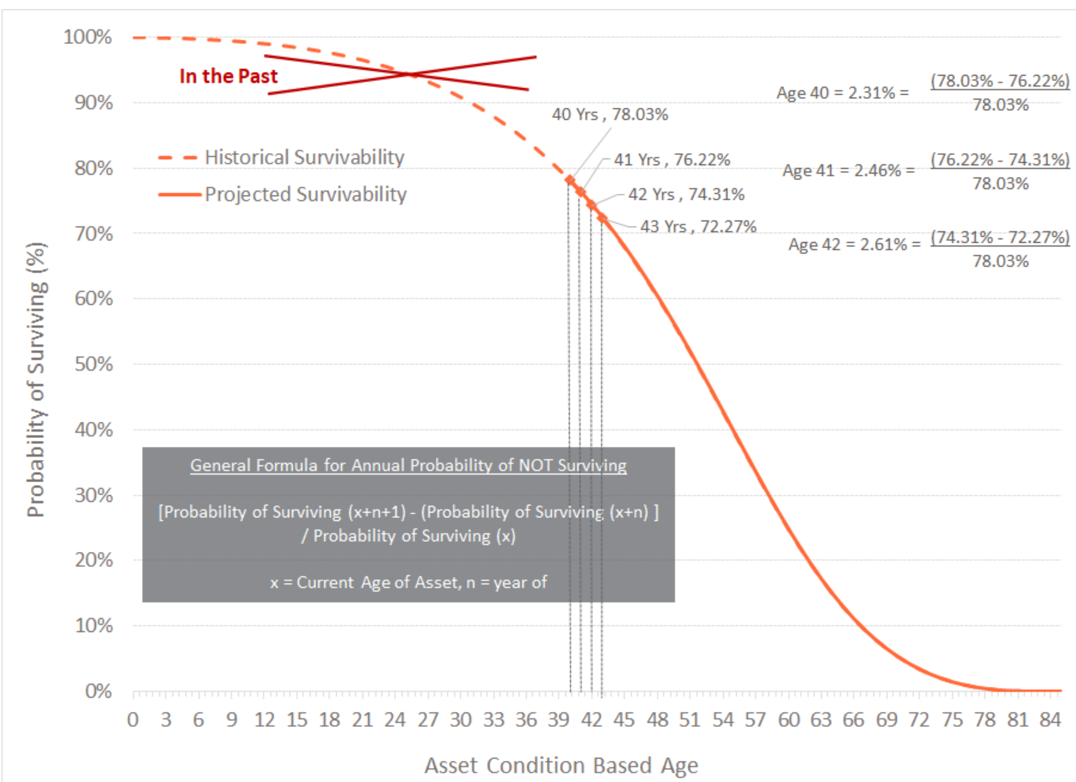


Figure 2-2: Annual Probability of Not Surviving Example – 40-Year-Old Wood Pole



The survivor curves allow for the calculation of the annual probability of not surviving over time. This curve produces a probability density function where the total probability is 100 percent. The curves are leveraged to forecast the probability of not surviving based on an asset's condition-based age. Figure 2-3 shows the annual probability of not surviving for a range of wood pole ages based on the mathematical approach shown in Figure 2-2. The figure shows that as assets get older the 100 percent probability of not surviving is distributed over fewer years.

Figure 2-3: Survivor Curves to Annual Probability of Not Surviving Profiles for Wood Poles

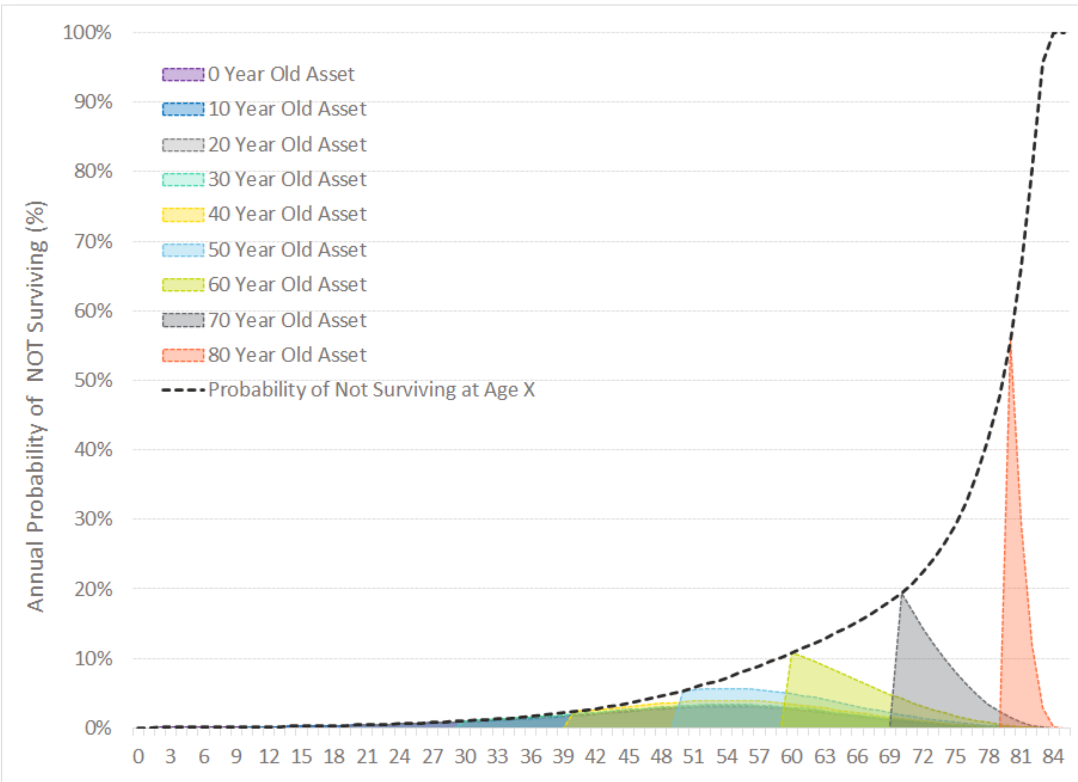


Figure 2-3 also shows the probability of not surviving at each age (Probability of Not Surviving at Age X). It is important to note that this representation of the Survivor curve produces a "Bath-tub" curve for wood poles. Each asset class survivor curve is a different representation of failure rate profiles as assets age. The AssetLens Analytics Engine calculates the probability of not surviving for each asset included in the evaluation.

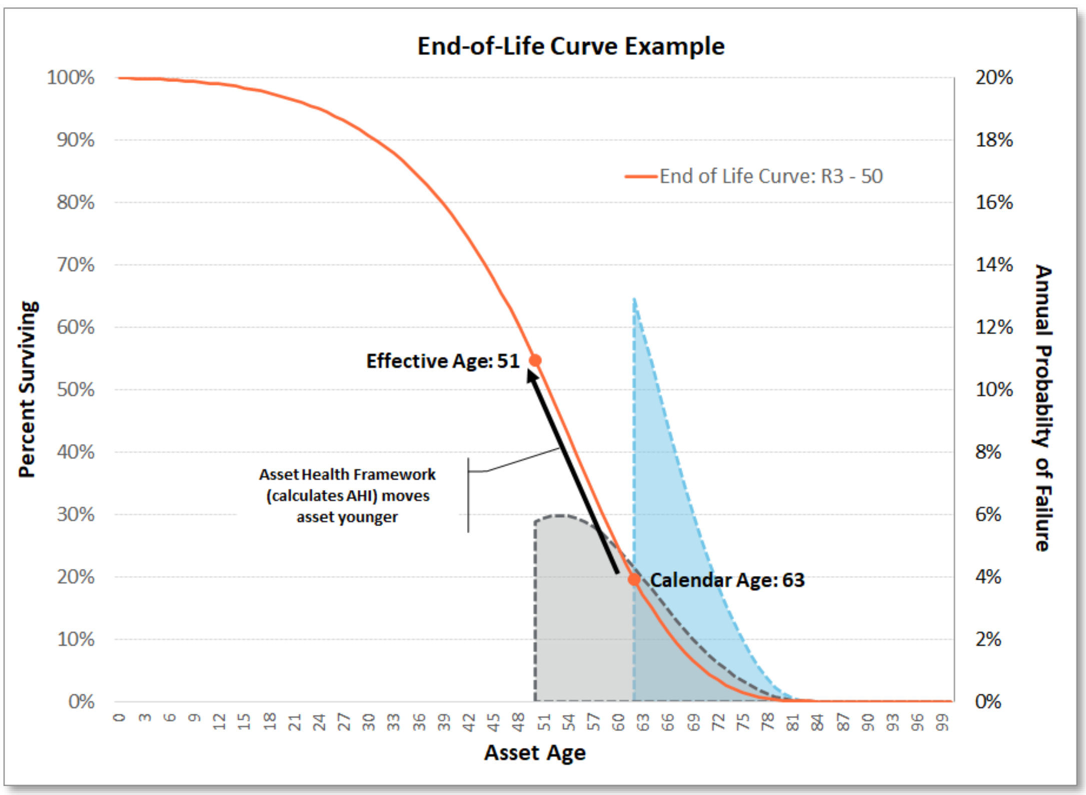
2.1.2 Condition-Based Age

The approach also includes estimating the condition-based or "effective" age for all assets where condition information is available. The AssetLens Analytics Engine includes asset health frameworks to estimate the condition-based age for equipment. The evaluation incorporated asset health frameworks for:

- Power Transformers – DGA
- Distribution Poles – Groundline inspections
- Conductor –Historical outage records and expected splice count per span for each protection zone.
- Network Transformers – Operational reports
- Transmission Structures - Transmission line condition reports

Figure 2-4 provides an example of the impact to an assets end-of-life curve based on condition information.

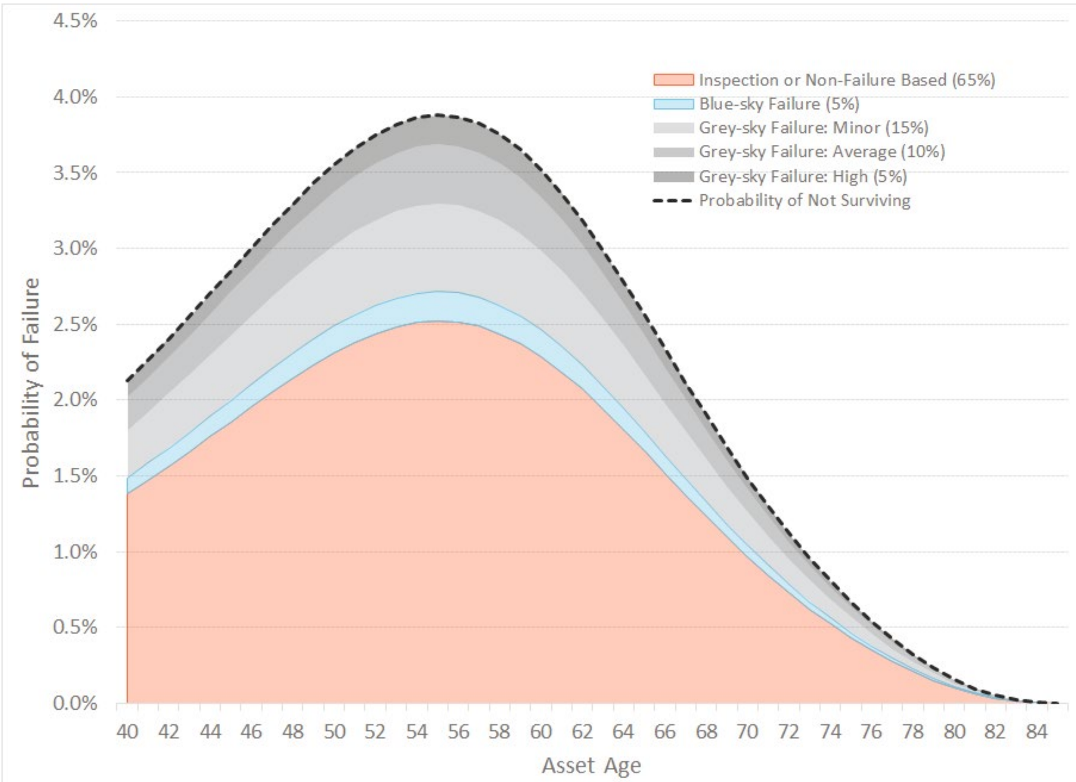
Figure 2-4: Estimating Condition or 'Effective' Asset Age



2.1.3 Failure Types and Probability of Failure

The previous section, Section 2.1.1, described the approach to forecast an assets annual probability of not surviving over time. Assets fail to survive a year for many wide-ranging reasons. For example, a wood pole may be replaced due to failed inspection or after a major storm event. 1898 & Co. has developed a library of failure type profiles for T&D infrastructure assets. That library is codified within the AssetLens Analytics Engine, a proprietary and confidential software developed by 1898 & Co. Figure 2-5 shows the probability of failure profile for each failure type for the example 40-year-old wood pole.

Figure 2-5: Failure Types and Probability of Failure for 40-Year-Old Wood Pole



For wood poles, the most common expected failure type is an inspection-based failure where the pole is inspected by the utility and determined not to meet minimum engineering standards. As the figure shows, this failure type is expected to occur 65 percent of the time.

2.1.4 Consequence of Failure

For each failure type, the risk framework library inside of the AssetLens Analytics Engine includes a range of consequence types based on expected impact should the asset fail. Table 2-1 shows the range of consequence types evaluated and the asset classes that they apply to. The framework puts a monetary value on each of these consequence factors.

Table 2-1: Consequence Types and Asset Class

Consequence	Avoided Cost Type	Circuit Assets	Substation Assets
Customer Outages	Customer Outage	□	□
Equipment Failure Costs	Reactive	□	□
End of Life O&M	Reactive		□
Mobile Substation	Reactive		□
Oil Spill Remediation	Reactive		□
Collateral Damage	Reactive		□
Re-replacement Costs	Reactive	□	□

2.1.4.1 Customer Outage Impact

One of the main consequences of failure across all asset classes is the impact to customers. When assets fail, the protection schemes activate to protect the system against fault currents. The protective interventions cause customers outages for the time it takes to restore the system. The relationship between assets and customers was established for all circuit and substation assets. The customer totals assume the distribution automation investment is in place for applicable circuits. This is done to avoid double counting customer benefit and to reflect the customer impact more accurately.

For each asset and failure type, the expected duration of the outage was estimated based on typical restoration times. For example, the expected duration to replace a wood pole during a blue-sky type of event is approximately 4.5 to 6 hours since crews are likely readily available. The duration of a major grey sky event can be much longer since crews are constrained and access can be challenging, especially for rear-lot infrastructure. The duration to replace a wood pole during a grey-sky event is estimated at 8.5 hours for poles with street access and 10 hours for poles without street access. This mirrors typical restoration approaches for utilities to restore upstream protection first, then move downstream to restore as many customers as possible. With this granular level of modeling, the approach balances the higher number of customers impacted on mainline feeders with shorter durations and the lower number of customers impacted on minor laterals with much longer durations.

Based on the expected duration of each failure type and expected customers impacted (residential, small C&I, or Large C&I) for each asset, the approach calculates the risk-weighted customer minutes interrupted (CMI) for each asset. This risk-weighted CMI is monetized using the DOE ICE Calculator to estimate each asset's risk-weighted monetized CMI over time.

2.1.4.2 Equipment Failure Costs

When assets fail before being proactively replaced, it creates an urgency to minimize the impact to the customer. The level of urgency is generally proportional to the failure types outlined in Figure 2-6. This urgency results in a level of effort that is not without cost. These additional costs are captured under the category of equipment failure costs. The magnitudes of these costs are different depending on the failure type. Crews are generally available during "blue sky" (non-storm) failure types, but capital efficiencies are lost as the mobilization is generally for only one asset. During the various "grey sky" (storms/medium severity), overtime is generally authorized to restore electric power as soon as possible. During a major "grey sky" failure (major storm/catastrophic failures), crews from neighboring utilities are often utilized to minimize the impact to the customer. However, these costs can be significant. For these types of events, it is not uncommon for the cost of replacement to be two to three times higher than if replaced proactively.

Equipment Failure costs were estimated for all asset categories and all failure types. Combined with the annual probabilities for each failure type, these values are used to calculate the failure cost profiles for all assets.

2.1.4.3 End-of-Life Operations and Maintenance (O&M) Costs

As assets age, the investment required to keep an asset performing at the required specification increases. As assets age, seals can degrade, connections loosen, recalibration is needed, leaks occur. These are just a few examples of issues that require additional O&M investment compared to newer assets without these issues. The level of O&M investment required to keep an asset performing to the required specification can vary from minor to significant.

Additionally, it is challenging to identify when an asset has entered this exact period. The risk and resiliency modeling approach probabilistically models these costs over the near end-of-life period for each asset class. End-of-life O&M costs were factored into various substation asset categories by probabilistically assigning end-of-life O&M costs. These end-of-life costs are then incorporated in the estimation of benefit cost ratios for the various substation investments.

2.1.4.4 Oil Spill Remediation

Oil is a vital fluid for the functioning of specific substation equipment assets. This includes power transformers and older design standard oil circuit breakers. The current equipment standard for circuit breaker insulation is SF6 or vacuum, depending on voltage sizes. While rare, these assets can fail with consequences that include significant oil leaks or oil spattering over a sizeable area. This risk increases as assets age. Should an asset fail where oil is not contained, the oil spills must be addressed through remediation. The higher the asset capacity rating, the larger the potential remediation costs (i.e., more oil for insulation purposes).

Oil spill remediation costs were probabilistically factored into the analysis for substation assets where this risk applies. These costs are then incorporated in the estimation of benefit cost ratios for the various substation investments. For oil circuit breakers, the approach assumed replacement with an SF6 or vacuum circuit breaker depending on voltage size, eliminating oil remediation risk altogether. In the case of oil circuit breakers, the risk and resiliency benefit are two-fold. Firstly, decreasing the condition-based age for the asset, secondly decreasing the oil spill risk.

2.1.4.5 Collateral Damage

Substations are an area of high energy transfer, this high energy in combination with an asset failure can result in a catastrophic failure that may result in fire or explosion, especially with arcing. The fire or explosion is generally not contained to the asset that failed. The result is collateral damage to other assets within the substation and in very rare circumstances property outside the substation boundaries. These collateral damage costs can vary significantly from thousands to millions. As assets age (power transformers and breakers especially), the probability of this type of failure increases. While statistically rare, these high to extreme costs are factored into the analysis for substation assets.

2.1.4.6 Re-replacement Costs

Either through special circumstances, acquisitions, or strategies to minimize acquisition costs, non-standard equipment is often present in all electric utilities. While most assets adhere to the utility's standard, non-standard equipment should be treated differently than standard equipment.

When these non-standard assets fail, replacement to standard equipment may not occur for several reasons. Firstly, replacing standard equipment may require engineering that cannot be completed when restoring customer service is urgent. Secondly, given the urgency to restore customers, crews replace failed equipment with whatever equipment is most readily available which may not be standard. This practice is typical for electric utilities worldwide. The result is often a mismatch between newly reactively replaced assets and the long-term system requirements.

In some cases, this can only be permanently remedied with re-replacement of the relatively new asset with the standard equipment. For example, oil circuit breakers that fail often get replaced with a spare oil circuit breaker to restore customers as soon as possible. Replacement to the current standard requires engineering. Changing to the current standard to mitigate the environmental risk requires the re-replacement of a relatively young asset.

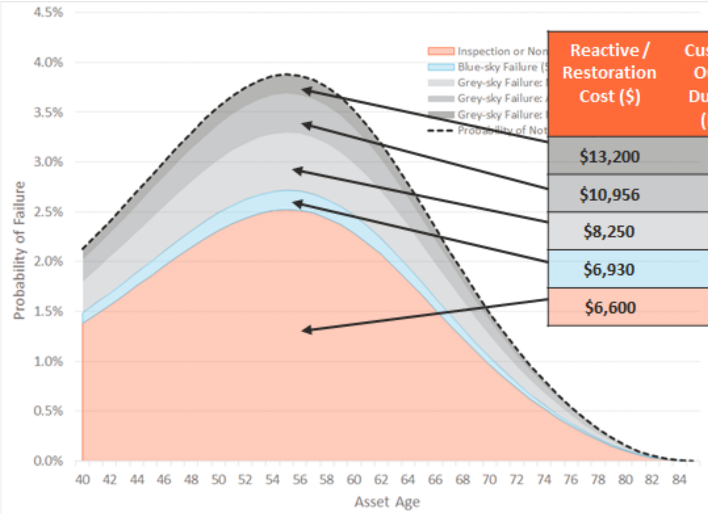
These costs are factored into the analysis for non-standard substation assets where this risk applies. Some assets have a higher probability than others of being replaced with non-standard assets requiring re-replacement later. A proactive investment approach allows CEI South to perform the necessary planning and engineering to replace the infrastructure to equipment standards. It should be noted that equipment standards are established to meet future customer electrical usage needs, provide the necessary protection to operate the grid reliability and safely, and balance long-term costs with procurement purchasing power, inventory management, and asset operations and maintenance.

2.1.5 Status Quo Risk & Resiliency Profile

As discussed above, the evaluation calculates the risk & resiliency costs profile over time for two scenarios, the Status Quo Scenario, and the Investment Scenario. The Status Quo scenario assumes the asset is not replaced and could incur risk costs over time. To calculate the Status Quo Risk & Resiliency costs over time, each of the probability of failures for each failure type is multiplied by each consequence of failure costs for each failure type. Figure 2-6 depicts this approach for the 40-year-old wood pole example on a backbone with approximately 400 customers. The figure shows the number of residential, small C&I, and large C&I customers for this example.

Figure 2-7 and Figure 2-8 show the Status Quo Risk & Resiliency Costs for reactive and restoration costs and customer outage costs, respectively. The profiles are based on multiplying the probabilities in Figure 2-6 by the consequences and applying escalation and discount rate described in the testimony. Figure 2-7 and Figure 2-8 both show the percentage of total risk and resiliency costs for each failure type. Figure 2-9 is the sum of Figure 2-7 and Figure 2-8 for each year and shows the total risk & resiliency costs for the 40-year-old wood pole.

Figure 2-6: Status Quo Risk & Resiliency Calculation 40-Year-Old Wood Pole



Reactive / Restoration Cost ($)	Customer Outage Duration (Min)	Residential (358) Outage Costs ($)	Small C&I (48) Outage Costs ($)	Large C&I (1) Outage Costs ($)	All Customer (407) Outage Costs ($)
$13,200	720	$10,310	$399,080	$38,090	$447,480
$10,956	360	$5,620	$165,460	$18,100	$189,170
$8,250	300	$4,900	$130,140	$14,810	$149,860
$6,930	240	$4,230	$98,960	$11,810	$115,000
$6,600	0	$0	$0	$0	$0

Figure 2-7: Status Quo Risk & Resiliency Reactive Costs Profile - 40-Year-Old Wood Pole

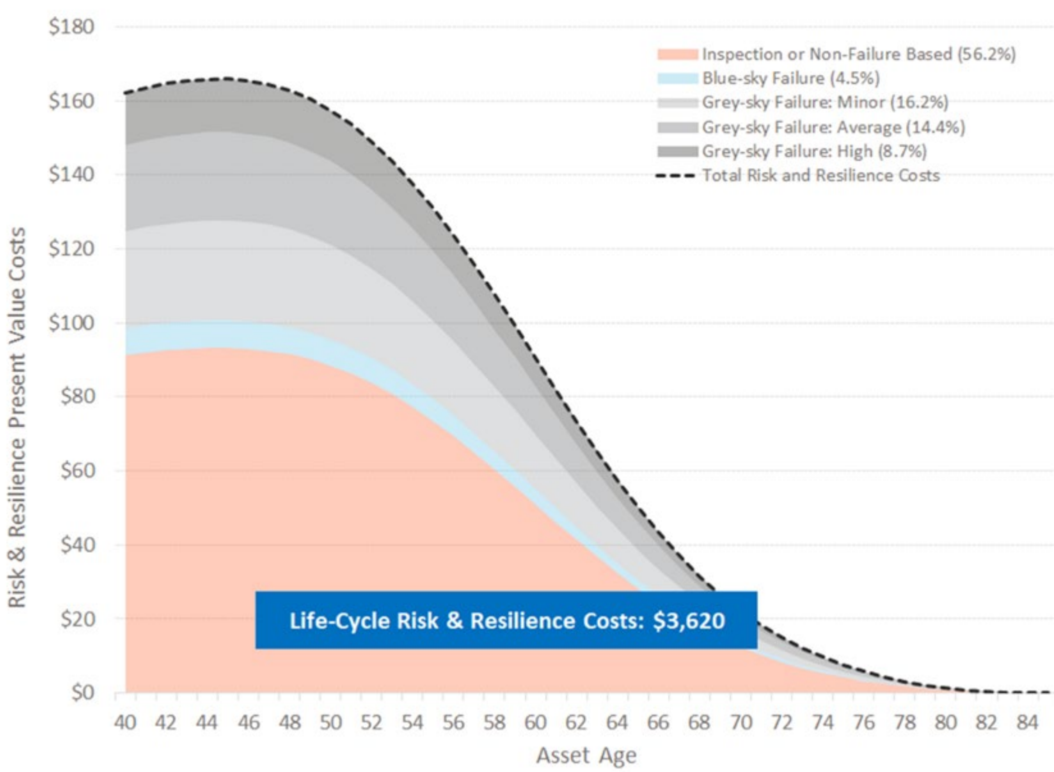


Figure 2-8: Status Quo Risk & Resiliency Customer Costs Profile - 40-Year-Old Wood Pole

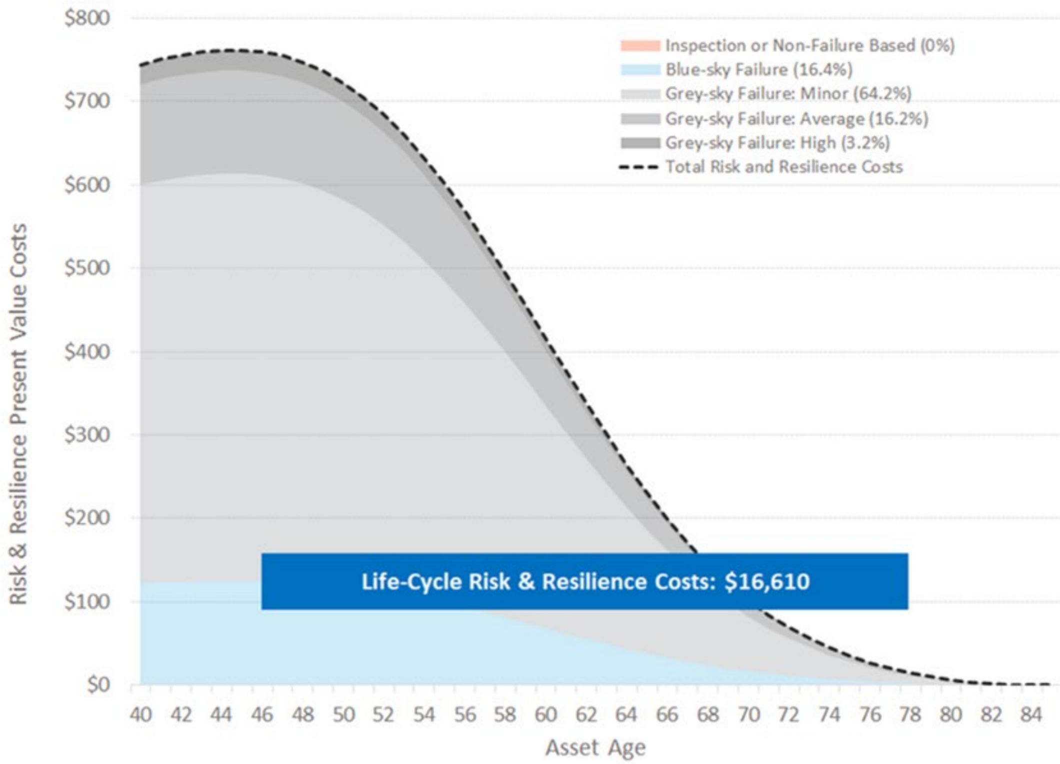
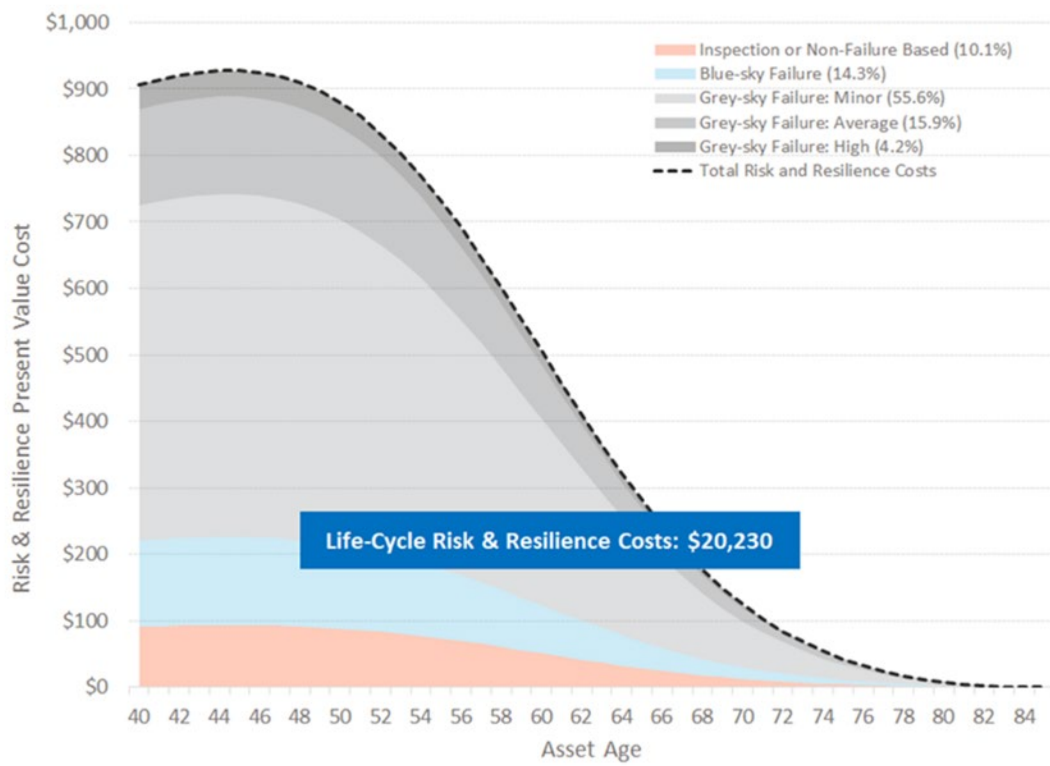


Figure 2-9: Status Quo Risk & Resiliency Costs Profile - 40-Year-Old Wood Pole



2.1.6 Avoided Risk & Resiliency Cost Benefit Calculation

The second scenario evaluated for each asset is the Investment Scenario. This scenario assumes the asset is replaced. By replacing the asset, the failure probabilities decrease since the asset is now 0 years old. In some cases, the failure types change with the replacement, such as oil circuit breakers that are replaced with gas breakers. The avoided risk and resiliency benefit for infrastructure upgrades is the difference between the Status Quo and Investment scenarios.

Figure 2-10 and Figure 2-11 shows the failure probabilities of the Status Quo and Investment scenarios for the example 40-year-old wood pole. Over the 44-year possible remaining life for the 40-year-old wood pole, there is a 100 percent probability of not surviving past that time horizon. If the wood pole is replaced there is approximately 30 percent probability of not surviving over the same 44-year time horizon. The figures also show the life-cycle probabilities for each failure type.

Figure 2-10: Status Quo Probability of Failure Profiles

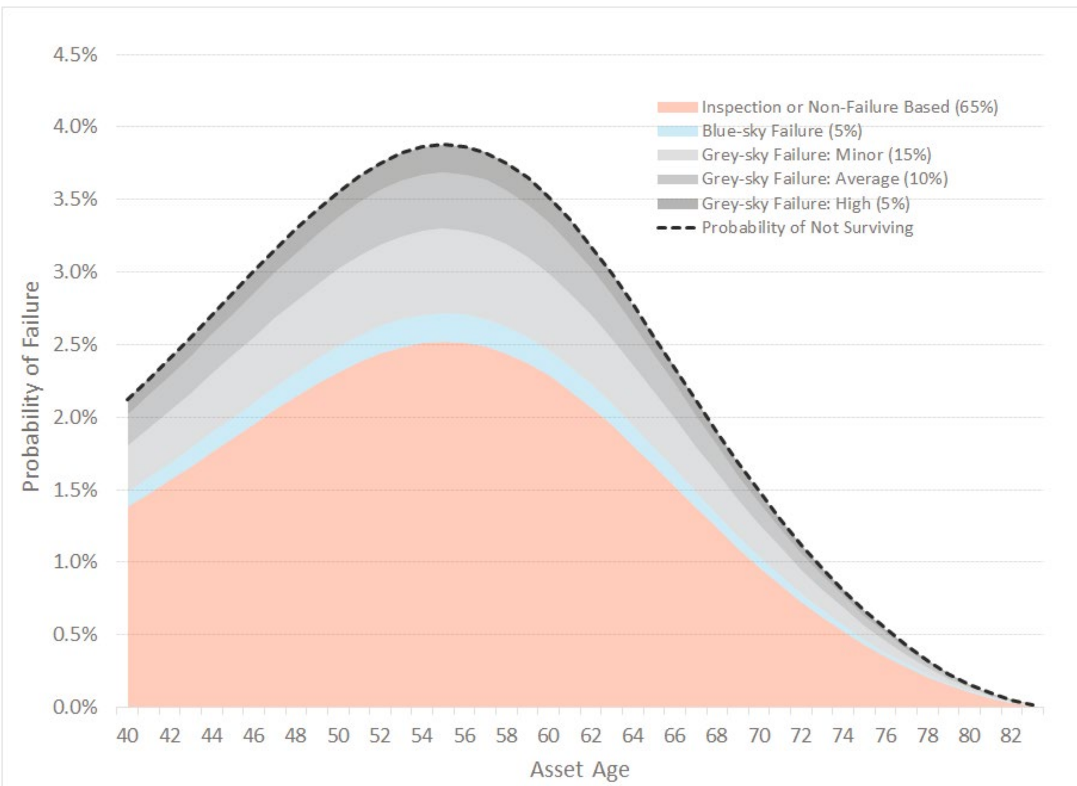


Figure 2-11: Investment Scenario Probability of Failure Profiles

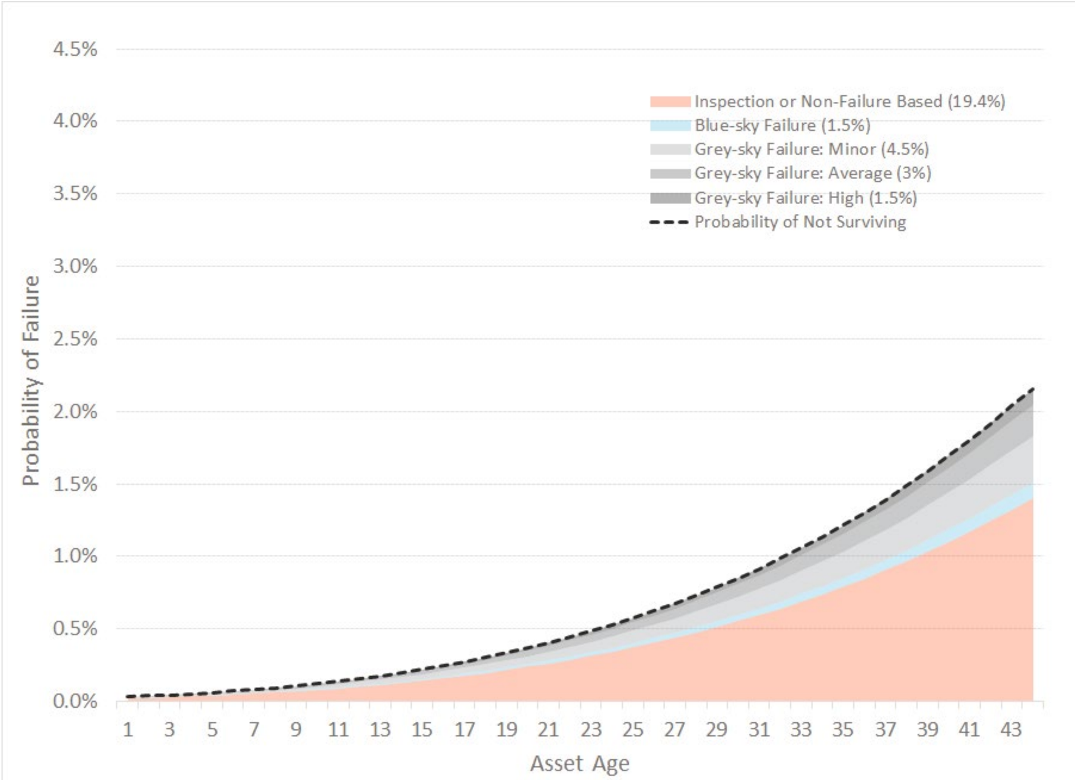


Figure 2-12 and Figure 2-13 show the companion risk and resiliency cost profiles for the Status Quo and Investment scenarios. Figure 2-14 shows the total values from Figure 2-12 and Figure 2-13 and the annual difference (Status Quo – Investment). The annual difference is the avoided annual costs for replacing the 40-year-old wood pole. In the first 33 years of the profile the avoided costs are positive with the remaining negative. The life cycle avoided cost benefit is approximately $17,720 (present value dollars) for replacing the pole. If the pole were younger the annual avoided costs would turn negative sooner and make the project less beneficial.

Figure 2-12: Status Quo Risk & Resiliency Cost Profiles

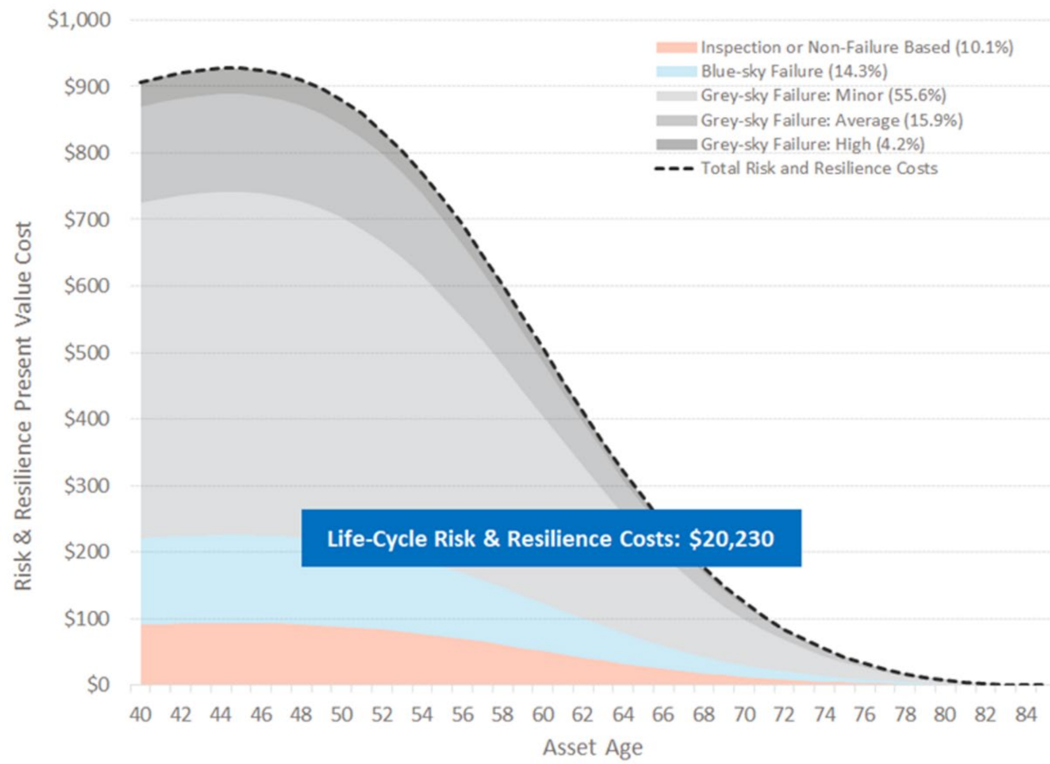


Figure 2-13: Investment Scenario Risk & Resiliency Cost Profiles

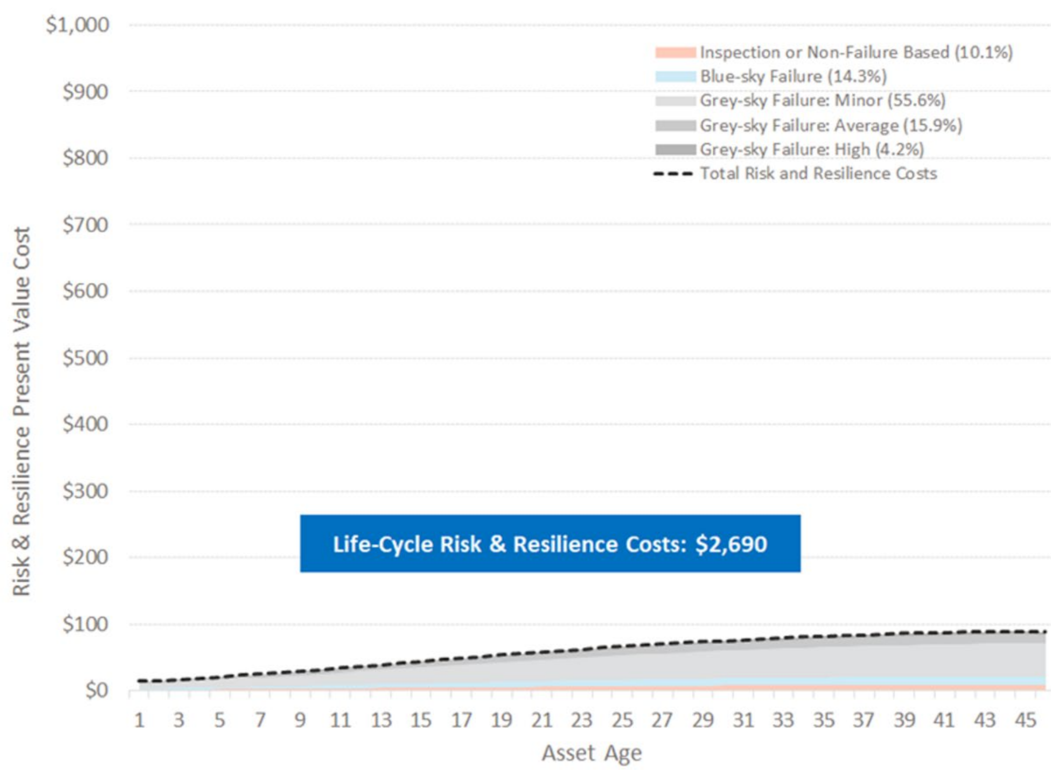
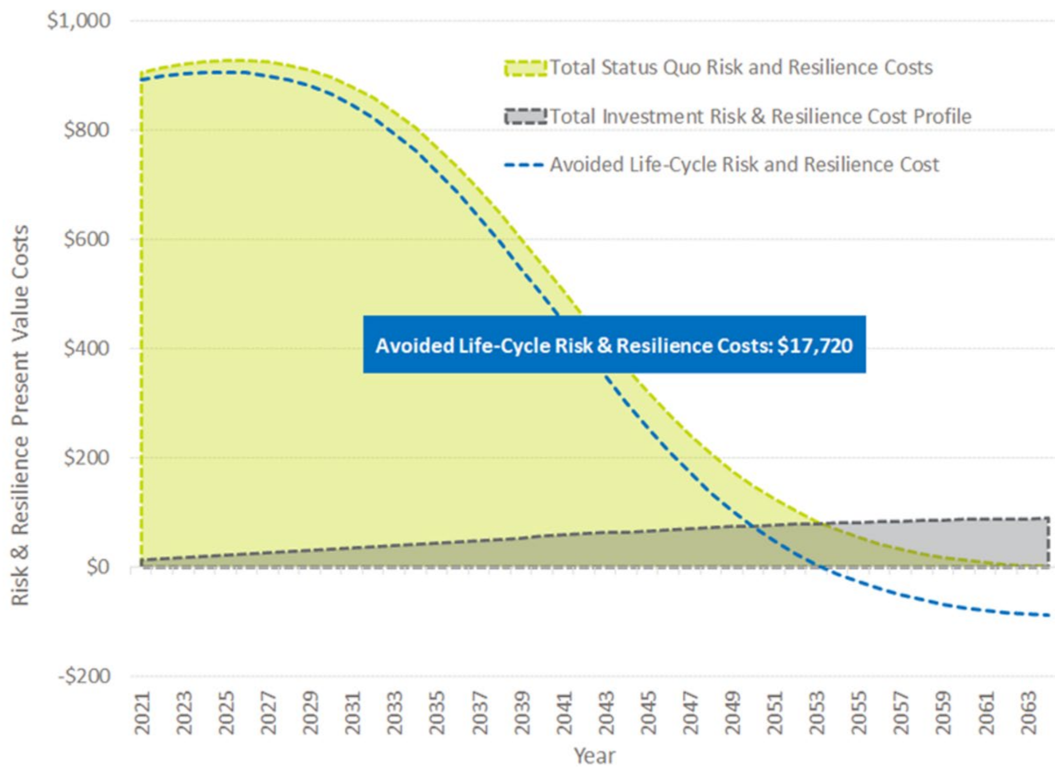


Figure 2-14: Avoided Risk & Resiliency Cost Benefit



2.1.7 Assets into Project Grouping

The Equipment Failure Risk & Resiliency analytics described above were performed for all the assets shown in testimony. For conductor, the modeling was done at the span level for overhead primary and the segment level for underground primary. Both poles and pole tops were modeled as separate asset classes for each structure. The risk framework within the AssetLens Analytics Engine was configured to model different expected lives and failure types for various types of asset cohorts within each asset class.

As discussed above, assets were grouped together at the protection zone level to describe the initial project level for distribution circuits. This provides a direct linkage between assets and customers impacted. For substation, the approach grouped assets at the substation level in alignment to CEI South's construction strategy to rebuild at a substation once within the 5-year period. For transmission circuits, assets were grouped at the line segment level.

2.2 Outage Mitigation Risk & Resiliency Benefits Assessment

The Outage Mitigation Risk & Resiliency modeling approach calculates the benefits of distribution automation investments. The approach leverages the last 5 years of CEI South's 17-year historical outage records to capture outage trends while providing a more accurate view of the current system. The last 5-years of data included detailed outage steps needed for the evaluation. Each outage is re-calculated, assuming the distribution automation investments had been in place. This calculation produces the avoided customers interrupted (CI) and customer minutes interrupted (CMI) for the investment. The DOE's ICE calculator monetizes the avoided outages by factoring in customer types and durations. The life-cycle risk-weighted present value of avoided customer outages is calculated by adjusting for inflation and discount rate over the life-cycle of the investment.

The data-driven approach provides a high level of precision in mapping benefits to investment activities. This precision provides robustness and confidence to the benefits assessment. The following sub-sections outline the Outage Mitigation Risk & Resiliency benefit calculation approach in further detail.

2.2.1 Outage Management System Data and Customer Types

As discussed above, the Outage Mitigation Risk & Resiliency benefit approach is data-centric. CEI South provided 1898 & Co. with historical outage records. Regulated utilities are required to document customers' outages for NERC reporting. This record-keeping is typically done within the Outage Management System (OMS), an Enterprise IT/OT (Information Technology/Operational Technology) software system designed for utilities to record outages.

The outage data is derived from two sources: PowerOn (2000-2018) and the current OMS (2018-2022). The analysis utilizes only the previous 5 years of outage records to better reflect CEI South's current system and evaluate benefits more accurately. The data used spans 1,870 days and includes approximately 17,800 unique events. Altogether, over 800,000 customer interruptions (CI) led to 573 million customer minutes interrupted (CMI) over the 5-year period.

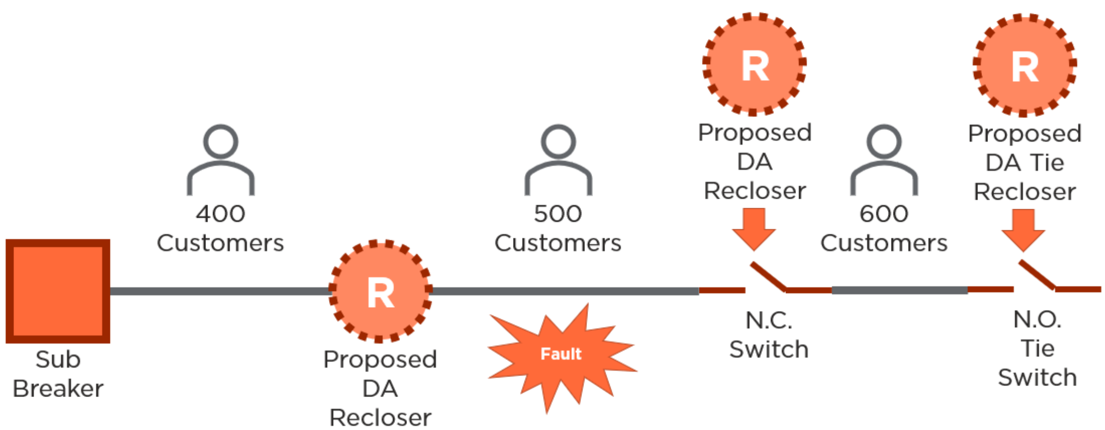
As noted above, CEI South provided customer type information with connectivity to the GIS and OMS. Using this connectivity, 1898 & Co. linked the type and number of customers impacted to each of the outages in the OMS. This data allows for the monetization of outages using the DOE ICE calculator.

2.2.2 Mitigated Outage Calculations

The Outage Risk & Resiliency benefit assessment is based on re-calculating the historical outage records assuming the investments had been in place. Additionally, the assessment estimates the decrease in truck rolls for outages that would be fully mitigated. This section outlines the general approach to re-calculating the outage records.

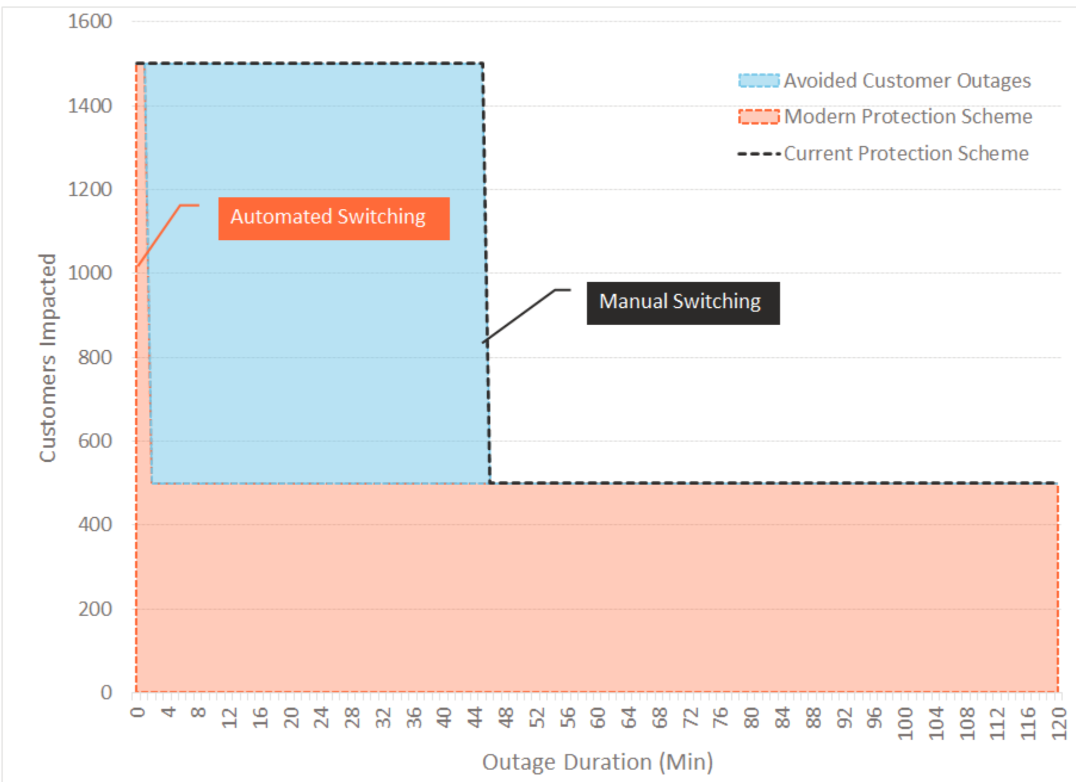
For backbone distribution circuit outages, the current protection schema includes a substation protection device and/or a mid-point recloser. The modern backbone protection schema includes additional sectionalization to each circuit creating sectionalization pods of less than 400 customers on average. With this sectionalization and ability to transfer load to adjacent circuits the number of customers impacted for a distribution mainline outage can be significantly reduced. For the modern schema a backbone outage would lock-out customers for less than a minute (typically) and then isolate the customer pod nearest that faulted section of the grid and transfer the remaining downstream customer pods to another circuit. Figure 2-15 provides a simplified diagram of the concept. There are 2 sections for the current protection schema: Breaker-to-Switch, and Switch-to-Tie. The new protection schema includes three sectionalization pods with the ability to transfer load to the adjacent circuit.

Figure 2-15: Simplified Circuit for DA Outage



Based on the mapping of new devices to the outage management system, 1898 & Co. recalculated the impact of mainline outages assuming the new customer count in each sectionalization pod and transferring customers not within the fault pod to the adjacent circuit. Figure 2-16 shows an example outage profile for a mainline outage in the before and after state. It should be noted that the original number of customers impacted, and the duration of the entire outage is the same. The difference is in the ability to restore customers through automated load transfer switching rather than manual backfeeding. The example is for a 2-hour outage with 1,500 customers initially without power. The ability to perform automated load transfer switching decreases the overall customer minutes interrupted by approximately 41.3 percent in this example. It should be noted that from a system performance reporting perspective to NERC, the improvement is higher given that only outages longer than 5 minutes are officially reported. This means the initial outage before switching would not be reported.

Figure 2-16: Mainline Outage Profile before and after DA Investment



2.2.3 Normalization, Monetization, and Life-Cycle Benefits Calculation

The mitigated outage improvement was monetized using the DOE ICE Calculator and customer profile for each outage. It was then normalized and annualized to a single year, averaging any significant year-to-year discrepancies between outage types, outage causes, and circuits. Applying escalation, discount rate, and expected useful life for the investments, 20 years, the life-cycle benefit was calculated for each outage event and rolled up to the circuit level.

3.0 PROGRAM & PROJECT BUSINESS CASE EVALUATION

The business case for each program and project is based on their alignment to CEI South Plan Objectives and TDSIC Investment Purposes. Most of the plan, 81.2 percent, includes a quantified business case using the risk & resiliency analytics described in Section 2.0 above. This approach directly quantifies the Maintain Reliability & Resiliency and Manage Asset Life-Cycles objectives.

Safety was not overtly quantified in the evaluation, but the results below show direct alignment to where and how program investments will decrease safety risk.

For delivering service and economic development the plan includes capacity and power quality investments. These investments account for approximately 5.8 percent of the plan. The substation physical security program accounts for approximately 3.1 percent of the plan. The remaining 9.9 percent of the plan is allocated to the wood pole inspection program.

The business case results for each program in the following sub-sections are first presented from an overview perspective. The overview includes overall TDSIC investment level, the number of projects in the plan, the business case results for the investments evaluated using the benefit analytics, and the programs alignment to the CEI South Plan Objectives and TDSIC Purposes. Secondly, for each CEI South objective or TDSIC purpose, the business case includes additional details for directly aligned investments. Specifically, it includes the program and individual project quantified business case results with commentary associated with the applicable objective / criteria. For non-quantified direct alignment benefit drivers, the business case describes how the investment will achieve the CEI South Plan Objective and TDSIC Purpose.

3.1 Transmission Line Rebuild

3.1.1 Overview

Figure 3-1 provides an overview of the Transmission Line Rebuild program business case.

Figure 3-1: Transmission Line Rebuilds Business Case Overview

Investment Identification	Nominal Cost (millions)	Project Count
Risk & Resiliency Analytics	$121.0*	10
System stakeholders	$6.2	1
Total	**$127.2**	**11**

Analytics Benefit (PV Millions)
$142.6
Analytics BCR
1.3

Investment Identification	CenterPoint Objectives / TDISC Criteria				
	Safety	Delivering Service	Maintain Reliability	Manage Asset Life-Cycle	Modernizing the Grid
Risk & Resiliency Analytics	□		□	□	□
System stakeholders		□	□		□

□ Quantified Direct Alignment □Non-quantified Direct Alignment □Indirect Alignment
*Present value cost is $106.9 Million

3.1.2 Background & Project Identification

CEI South owns, operates and maintains approximately 1,000 miles of transmission miles throughout the service territory, which are classified as lines and associated assets at the 69 kV, 138 kV, and 345 kV voltage levels. Transmission assets are a vital category of the greater bulk electric system, as these assets move electricity from power generation plants to substations, where power is then stepped down to feed distribution circuits. Given the critical nature of transmission, it is designed such that no single failure causes a significant disruption. However, if proactive replacements of transmission assets are not made, the entire population will continue to age, which increases the likelihood of operational failures even with the designed redundancy. The operational integrity of transmission lines is vital to maintaining safe and reliable power delivery to CEI South's customer base.

The Transmission Line Rebuild Program includes projects with differing combinations of the below scopes of work:

- Wood-to-steel pole conversions
- Reconductoring to large conductors
- Optical Ground Wire (OPGW) installation

The projects were defined at the transmission line segment level considering age, BCR, condition, and if lines comply with CEI South's current standards.

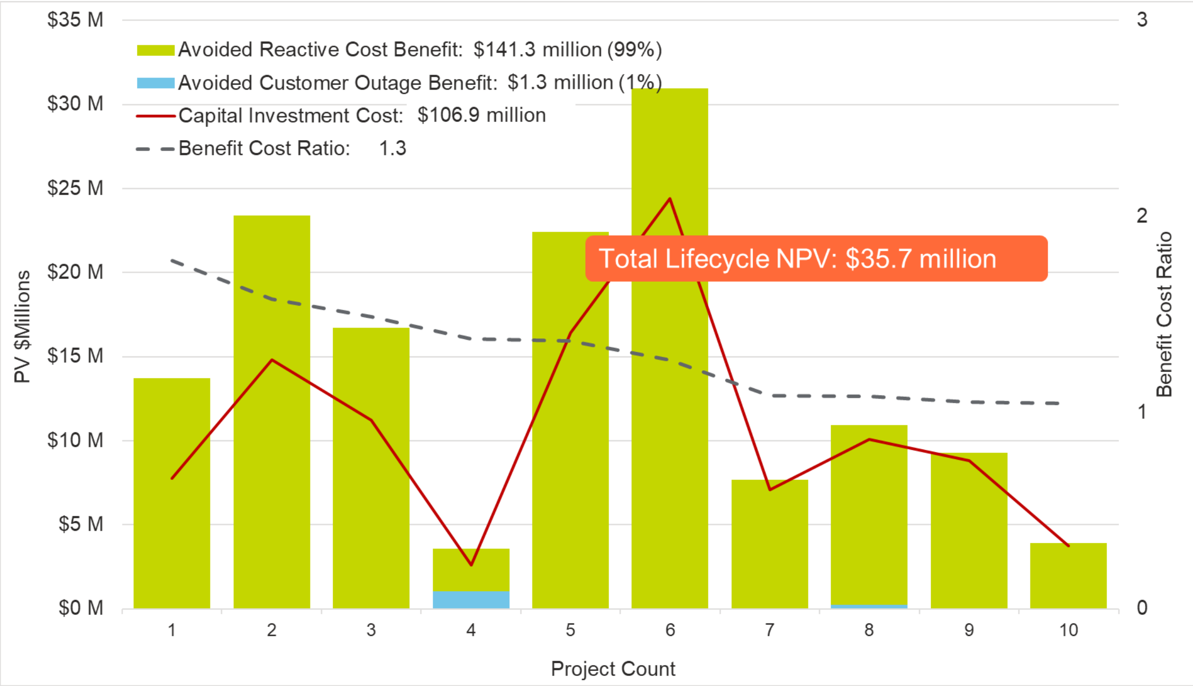
3.1.3 Business Case: Risk & Resiliency Analytics Based Projects

Maintain Reliability & Resiliency and Managing Asset Life-Cycles: Replacement of aging infrastructure reduces the risk of failure and more importantly the risk of catastrophic failure. By proactively addressing the aged and dated transmission assets, CEI South will stay ahead of reactive restoration costs that would be incurred during reactive replacements while managing lifecycle costs by building to a modernized standard. By building to the current standard, CEI South is "future-proofing" their TDSIC investment. Should capacity requirements increase on the rebuilt transmission lines, the lines and structures should be capable of accommodating the required changes since they have been built to an appropriate standard; therefore, reducing the risk of rebuilding selected transmission assets in the upcoming years.

Figure 3-2 shows the quantified business case results for Transmission Line Rebuild investments. The red line shows the estimated cost for each line segment with a total estimated investment of $106.9 million dollars. The bars on the chart show the benefits by line segment. The green bar shows the avoided reactive and restoration costs, the measurement for the manage asset life-cycle objective, while the blue bar shows the benefit of avoided customer outages, the measurement for the maintain reliability and resiliency objective. The approach to calculate both of these is described in Section 2.0. The grey dotted line shows the benefit-cost ratio for each transmission project ranked from highest to lowest. The remaining figures in this section show similar figures.

The figure shows the total investment of $106.9 million dollars produces life cycle PV of benefits of $142.6 million ($141.3 + $1.3). Approximately 99 percent of the benefits are from avoided reactive costs and 1 percent from avoided customer outages. The risk & resiliency identified investments in aggregate have a positive quantified business case with a total NPV of $35.7 million for customers and a benefit cost ratio of 1.3 The reactive cost benefits alone are in excess of the overall investment. As the figure shows, all projects have quantified benefits in excess of cost (all BCRs are greater than or equal to 1).

Figure 3-2: Transmission Line Rebuild Project Business Case



Safety: By upgrading the existing wood pole structures to monopole steel pole structures, CEI South will realize higher safety and reliability, as steel poles are stronger and more durable than wood poles, with a longer expected life. Transmission lines are typically located in their own right-of-way (ROW), but these lines may still be in close proximity to the general public. Minimizing the risk of transmission lines failing reduces the risk to the general public who live around these lines.

Modernizing the Grid: Projects that include reconductoring the lines allow for more electricity to be carried by each transmission line, increasing the area that each power line can serve without creating a new transmission line footprint. Increasing line capacity is an efficient use of existing transmission line ROWs. Lastly, the installation of OPGW introduces modern communication methods, which are essential for operating the increasingly intelligent and connected power system. OPGW wire creates accessible and efficient communication pathways essential for today's microprocessor-based relays, which communicate and operate in fractions of seconds. These relays provide a variety of protections to transmission lines and substations, such as isolating sections of line that are experiencing faults or overcurrent events (which could lead to lines arcing or even conductor failure).

3.1.4 CEI South System Stakeholders Based Project

Delivering Service: CEI South system planners identified the need to increase capacity on a transmission line with distribution underbuild to continue to serve customers. This project includes capacity relief of a distribution circuit, but is classified under this program because of the higher voltage of the circuits impacted.

3.2 Substation Rebuild

3.2.1 Overview

Figure 3-3 provides an overview of the Substation Rebuild program business case.

Figure 3-3: Substation Rebuild Business Case Overview

Investment Identification	Nominal Cost (millions)	Project Count
Risk & Resiliency Analytics	$90.1*	20
System Stakeholders	$13.4	3
Total	**$103.5**	**23**

Analytics Benefit (PV Millions)
$94.5
Analytics BCR
1.2

Investment Identification	CenterPoint Objectives / TDISC Criteria				
	Safety	Delivering Service	Maintain Reliability	Manage Asset Life-Cycle	Modernizing the Grid
Risk & Resiliency Analytics	☐		☐	☐	☐
System Stakeholders		☐			☐

☐ Quantified Direct Alignment ☐Non-quantified Direct Alignment ☐Indirect Alignment
*Present value cost is $79.3 Million

3.2.2 Background & Project Identification

CEI South owns, operates, and maintains over 100 substations throughout the service territory. Substations are critical to the operation of any power system, as vital protection devices (breakers, switches, relays, etc.) and power transformers (which step power up and down to operational voltage levels) are found in substations. Without the protective devices found in substations, the power grid would have very few points of isolating faults. For instance, substation breakers isolate differing feeders from one another; therefore, if one feeder has a tree that falls into the line, the substation breaker may operate, isolating the fault caused by the tree. This protects the fault from also traveling to the substation transformer, adjacent feeder, and adjacent transmission line. Substation transformers are similarly critical, as they step power up and down from transmission operating voltages to distribution operating levels. Without substation transformers, the power delivered to homes would be too high of a voltage level to operate modern technology. If proactive replacements of substation assets are not made, the entire population of assets will continue to age, which increases the likelihood of operational failures. The operational integrity of substation assets is vital to maintaining safe and reliable power delivery to CEI South's customer base.

The Substation Rebuild Program includes projects which replace targeted substation assets with new, updated assets that meet the current design standards.

3.2.2.1 Risk & Resiliency Analytics Based Projects

For Risk & Resiliency Analytics Based Projects, 1898 & Co provided a ranked list of targeted substations with a positive business case. CEI South reviewed this list and walked down the substations to identify projects by grouping the targeted substation assets together and confirming age assumptions. Projects were organized as comprehensive rebuilds to lessen outage requirements in the next five years. For example, if a transformer in a substation was identified as needing replacement due to condition, the associated protection devices were reviewed for appropriateness and added to the scope as necessary to provide a safe and reliable protection scheme. As part of the comprehensive scope definition, all assets included in the substation asset register were candidates for the project scope.

3.2.2.2 CEI South System Stakeholders Based Projects

For CEI South System Stakeholders based projects, CEI South system planners identified the need to increase capacity to several substations due to specific load growth in specific areas of the system increasing.

3.2.3 Business Case: Risk & Resiliency Analytics Based Projects

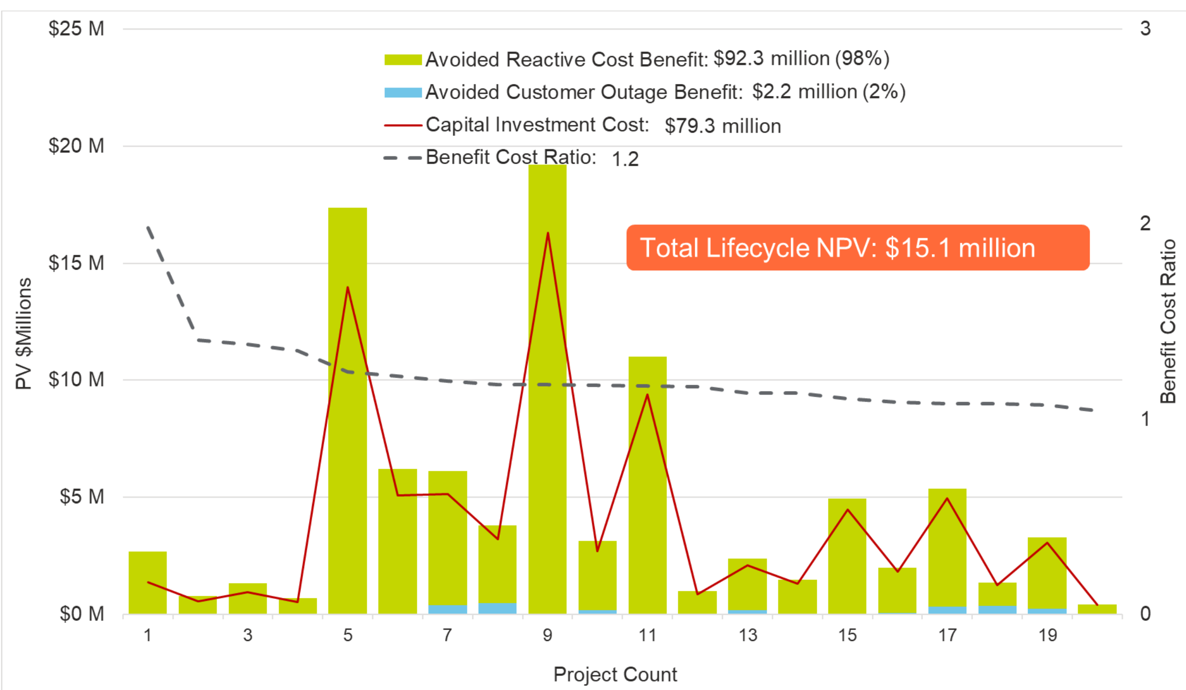
Maintain Reliability & Resiliency: Replacement of aging infrastructure reduces the risk of failure and more importantly the risk of catastrophic failure.

Manage Asset Lifecycles: By proactively addressing the aged and dated substation assets, CEI South is staying ahead of reactive restoration costs, which would be incurred during reactive replacements, while also managing lifecycle costs through building to the current design standard. By building to the current design standard, CEI South is "future-proofing" their TDSIC investment. Should capacity requirements increase on the rebuilt substation, the assts should be adequate since they have been built to an appropriate standard; therefore, reducing risk of needing to rebuild TDSIC assets in the upcoming years.

The comprehensive nature of the substation project scope creates economies of scale in engineering, labor, and outage requirements, which saves CEI South and ultimately CEI South's customers money. This also provides a more reliable substation to deliver electrical power to the customer with less interruptions.

Figure 3-2 shows the investment of $79.3 million dollars produces life cycle PV of benefits of $94.5 million. Approximately 98 percent of the benefits are from avoided reactive costs (manage asset life-cycle objective) and 2 percent from avoided customer outages (maintain reliability & resiliency objective). The risk & resiliency identified investments in aggregate have a positive quantified business case with a total NPV of $15.1 million for customers and a benefit cost ratio of 1.2 The reactive cost benefits alone are in excess of the overall investment. As the figure shows, all projects have quantified benefits in excess of cost (all BCRs are greater than or equal to 1).

Figure 3-4: Substation Rebuild Project Business Case



Safety: By upgrading the existing substation equipment, CEI South will achieve a higher level of safety, as substations are generally one of the most dangerous areas for linemen due to the small area in which electrical equipment is situated. Good standards, and equipment technologies provide safer options in substations. Replacing at-risk, aged equipment increases reliability, since the risk of failure is inherently decreased.

3.2.4 CEI South System Stakeholders Based Project

Delivering Service: CEI South system planners identified the need to increase capacity to a few substations due to specific load growth in specific areas of the system increasing. These projects will relieve existing, overburdened substation transformers by adding additional equipment to address the increased capacity requirement. These projects were not evaluated with the risk and resiliency analytics but were evaluated using electrical system planning models and confirmed to be an appropriate investment to address load concerns.

Increasing substation capacity directly serves the customer's expectation of reliable, available power where needed. By increasing a substation's ability to serve customer's, the grid can perform better during times of stress (overload circuits, or outage events in substations), and CEI South can meet a customer's load growth adequately and efficiently.

3.3 Distribution 12kV Circuit Rebuild

3.3.1 Overview

Figure 3-5 provides an overview of the Distribution 12kV Circuit Rebuild program business case.

Figure 3-5: Distribution 12kV Circuit Rebuild Overview

Investment Identification	Nominal Cost (millions)	Project Count
Risk & Resiliency Analytics	$92.1*	113
System Stakeholders	$6.7	31
Total	**$98.8**	**144**

Analytics Benefit (PV Millions)
$336.2
Analytics BCR
4.1

Investment Identification	CenterPoint Objectives / TDISC Criteria				
	Safety	Delivering Service	Maintain Reliability	Manage Asset Life-Cycle	Modernizing the Grid
Risk & Resiliency Analytics	☐		☐	☐	☐
System Stakeholders		☐			☐

☐ Quantified Direct Alignment ☐Non-quantified Direct Alignment ☐Indirect Alignment
*Present value cost is $81.6 Million

3.3.2 Background & Project Identification

CEI South owns, operates and maintains over 4,000 miles of 12 kV distribution lines, over 50,000 line transformers, and over 75,000 distribution poles. Distribution assets are a vital category of CEI South's grid system, as these assets move electricity from substations to customers.

The Distribution 12 kV Circuit Rebuild Program includes projects with differing combinations of the below scopes of work:

- Wood Pole Upgrades
- Reconductoring to larger conductors
- Line Transformers, Pole Hardware, Surge Arrestors, etc.

3.3.2.1 Risk & Resiliency Analytics Based Projects

Business cases were developed by 1898 & Co. for all potential distribution 12 kV circuit rebuilds. The potential projects were ranked by BCR and the BCR was a major consideration in the selection of projects. Project execution, service area, project complexity were other factors considered. CEI South identified projects by grouping the distribution asset classes together by protection zone, and collectively assessing age and if the assets met the current applicable equipment standards. Projects were organized as comprehensive rebuilds, such that if poles or lines in the protection zone required upgrading due to age or standards, the associated line transformers, fuses, hardware, etc. were included in the upgrade. By prioritizing at the protection zone, CEI South creates an economy of scale in engineering, labor and outage necessity, which saves the CEI South and ultimately CEI South's customer based money, and time without power.

3.3.2.2 CEI South System Stakeholders Based Project

CEI South identified projects to add circuits to better balance load. Additional projects were identified to address power factor concerns through the installation of capacitor banks on specific circuits where the current power factor is below the limit of generally accepted utility practices.

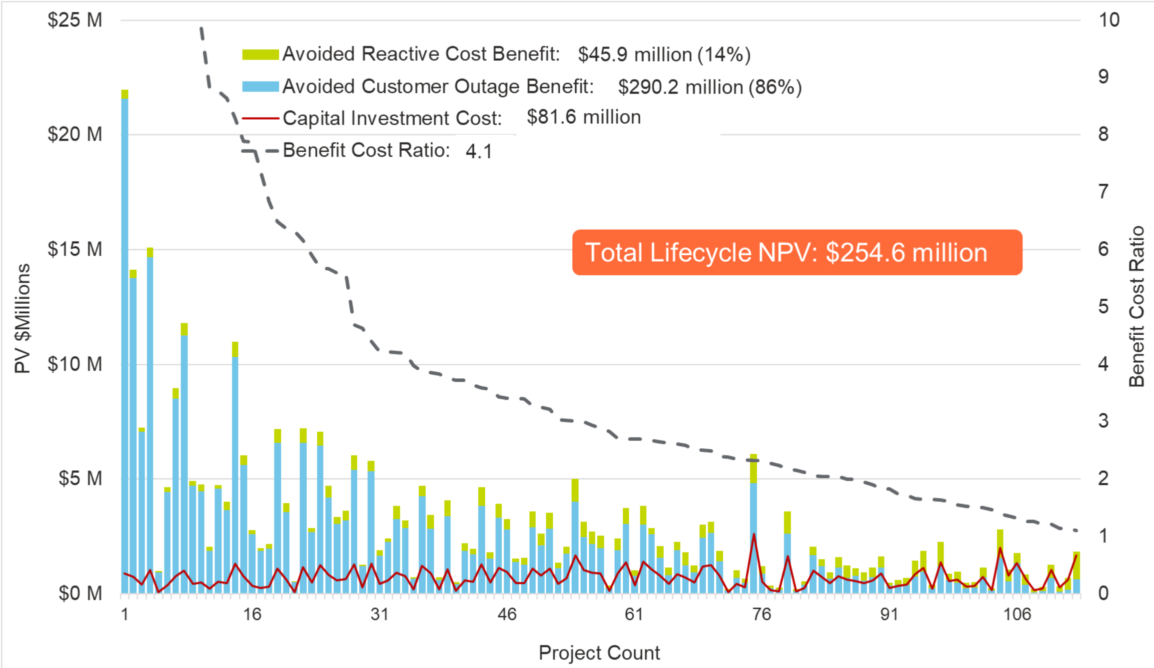
3.3.3 Business Case: Risk & Resiliency Analytics Based Projects

Maintain Reliability & Resiliency: Replacement of aging infrastructure reduces the risk of failure and more importantly the risk of catastrophic failure. Replacing at-risk, aged equipment increases reliability, since the risk of failure is inherently decreased. By upgrading existing assets to the current standard, the distribution grid is more resilient to outages.

Manage Asset Lifecycles: By proactively addressing the aged and dated distribution assets, CEI South is staying ahead of reactive restoration costs, which would be incurred during reactive replacements, while also managing lifecycle costs through building to the current design standard. By building to the current standard, CEI South is "future-proofing" their TDSIC investment. Should capacity requirements increase on the rebuilt distribution lines, the assets should be adequate since they have been built to an appropriate standard; therefore, reducing risk of needing to rebuild TDSIC assets in the upcoming years.

Figure 3-6 shows the total investment of $81.6 million dollars produces life cycle PV of benefits of $336.2 million. Approximately 14 percent of the benefits are from avoided reactive costs (manage asset lifecycles objective) and 86 percent from avoided customer outages (maintain reliability & resiliency objective). The risk & resiliency identified investments in aggregate have a positive quantified business case with a total NPV of 254.6 million for customers and a benefit cost ratio of 4.1 As the figure shows, all projects have quantified benefits in excess of cost (all BCRs are greater than or equal to 1).

Figure 3-6: Distribution 12kV Circuit Rebuild Project Business Case



Safety: By upgrading the existing distribution equipment, CEI South will achieve a higher level of safety, as distribution lines are closer in proximity to the general public as compared to other utility assets. Replacing older, weaker poles with stronger, newer poles decreased the likelihood of failure and keeps the public safe. The current standard for distribution pole construction also adds an additional layer of safety.

3.3.4 Business Case: CEI South System Stakeholders Based Projects

Delivering Service: When power quality on the system is poor or voltage levels are not adequate, equipment on both the utility and customer side may be damaged or stop working, including the risk of overheating (which can create a hazard). Projects to support power quality and voltage regulation ensure customers appliances operate as intended.

3.4 Distribution Automation

3.4.1 Overview

Figure 3-7 provides an overview of the Distribution Automation program business case.

Figure 3-7: Distribution Automation Overview

Investment Identification	Nominal Cost (millions)	Project Count
Risk & Resiliency Analytics	$19.6*	43
System Stakeholders	N/A	N/A
Total	**$19.6**	**43**

Analytics Benefit (PV Millions)
$37.0
Analytics BCR
2.2

Investment Identification	CenterPoint Objectives / TDISC Criteria				
	Safety	Delivering Service	Maintain Reliability	Manage Asset Life-Cycle	Modernizing the Grid
Risk & Resiliency Analytics			□		□
System Stakeholders	N/A	N/A	N/A	N/A	N/A

□ Quantified Direct Alignment □Non-quantified Direct Alignment □Indirect Alignment
*Present value cost is $17.2 Million

3.4.2 Background & Project Identification

TDSIC 1.0 included investment in distribution automation. The investment in distribution automation is planned to continue as part of the Plan as well. The investment included placement of reclosures on the system to better sectionalize and tie to other circuits as to minimize the outage impact and duration.

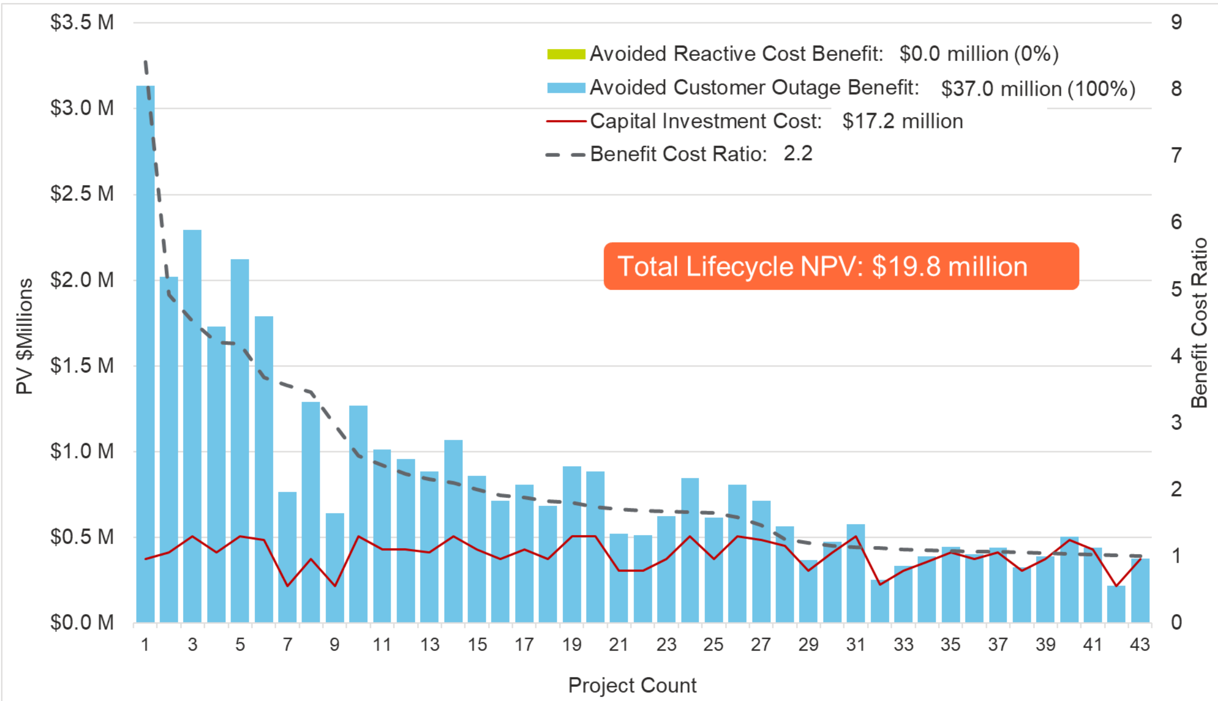
As described in Section 2.2, the value of distribution automation is to reduce the duration of outage experienced by customers. For each circuit a distribution automation project was scoped to provide sectionalization zones of approximately 400 customers. The outage mitigation risk & resiliency benefits assessment calculated the BCR for each of the circuits. Projects were ranked based on BCR and aggregate based on system requirements that factored in substation and circuit tie considerations.

3.4.3 Business Case: Risk & Resiliency Analytics Based Projects

Maintain Reliability & Resiliency: The investment included placement of reclosures on the system to better sectionalize and tie to other circuits as to minimize the outage impact and duration. Reduction of both impact and duration has a direct impact on maintaining and even improving reliability and resiliency.

Figure 3-8 shows the total investment of $17.2 million dollars produces life cycle PV of benefits of $37.0 million. The risk & resiliency identified investments in aggregate have a positive quantified business case with a total NPV of $19.8 million for customers and a benefit cost ratio of 2.2. As the figure shows, all projects have quantified benefits in excess of cost (all BCRs are greater than or equal to 1).

Figure 3-8: Distribution Automation Project Business Case



Modernizing the Grid: Distribution automation is part of the needed foundation to modernize the grid. The associated communications as well as the devices can be leveraged in the future to enable more complex schemes to manage the changes as the distribution system evolves to accommodate electric vehicles and distributed energy resources.

3.5 Underground Circuit Rebuild

3.5.1 Overview

Figure 3-9 provides an overview of the Underground Circuit Rebuild program business case.

Figure 3-9: Underground Circuit Rebuild Business Case Overview

Investment Identification	Nominal Cost (millions)	Project Count
Risk & Resiliency Analytics	$45.9*	80
System Stakeholders	N/A	N/A
Total	$45.9	80

Analytics Benefit (PV Millions)
$71.1
Analytics BCR
1.7

Investment Identification	CenterPoint Objectives / TDISC Criteria				
	Safety	Delivering Service	Maintain Reliability	Manage Asset Life-Cycle	Modernizing the Grid
Risk & Resiliency Analytics	□		□	□	□
System Stakeholders	N/A	N/A	N/A	N/A	N/A

□ Quantified Direct Alignment □Non-quantified Direct Alignment □Indirect Alignment
*Present value cost is $40.9 Million

3.5.2 Background & Project Identification

Early generation of underground infrastructure had some design standards that minimized the cost of installation, but many decades later are showing signs of deterioration. Unjacketed cable is an example of an asset class that is reaching the end of its useful life and needs to be replaced. Early generation padmount transformers and network transformers also fit this category.

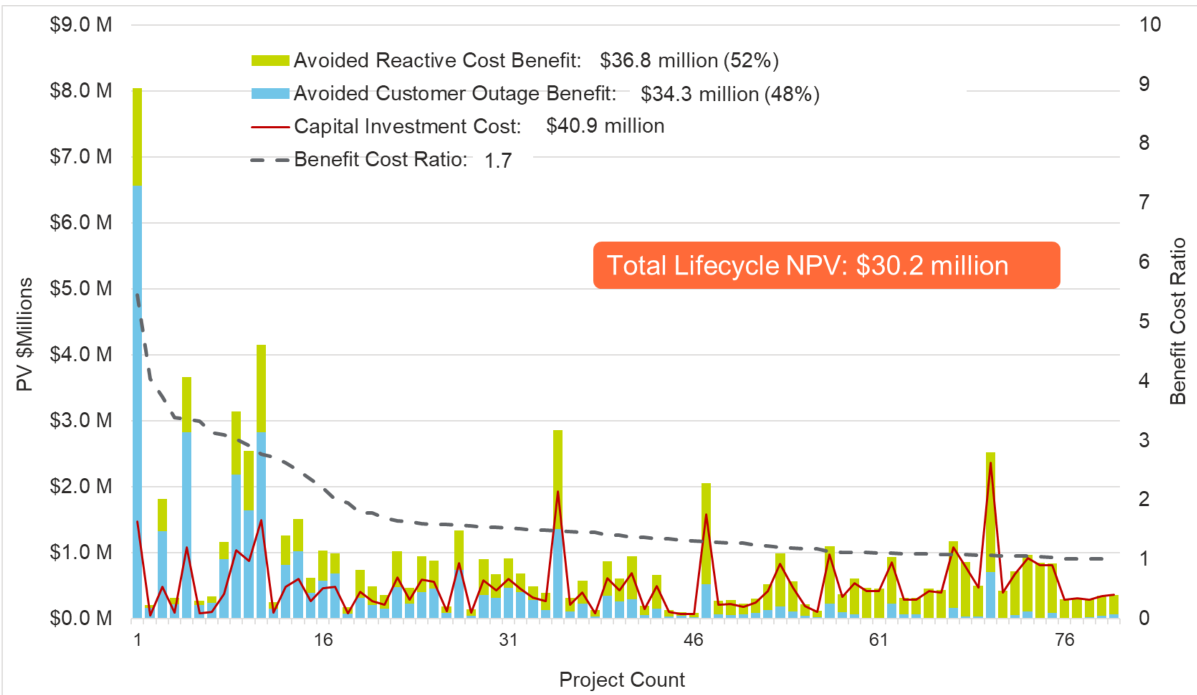
The network transformers replacements can be complex and consideration of protection schemes for the new network transformers was considered in developing the full project scope. Business cases were developed for each of the potential projects and ranked to aid in the final selection process. Project execution, service area, and project complexity were other factors considered.

3.5.3 Business Case: Risk & Resiliency Analytics Based Projects

Maintain Reliability & Resiliency & Manage Asset Lifecycles: Underground infrastructure is protected by many hazards. However, when it reaches its end-of-life it is very difficult to access and replace. Proactive replacement allows these long outages to be avoided as the underground infrastructure can be installed and then energized while the original underground infrastructure remains in service until it is time to energize the new underground infrastructure.

Figure 3-10 shows the total investment of $40.9 million dollars produces life cycle PV of benefits of $71.1 million. Approximately 52 percent of the benefits are from avoided reactive costs (manage asset lifecycles objective) and 48 percent from avoided customer outages (maintain reliability & resiliency objective). The risk & resiliency identified investments in aggregate have a positive quantified business case with a total NPV of $30.2 million for customers and a benefit cost ratio of 1.7. As the figure shows, all projects have quantified benefits in excess of cost (all BCRs are greater than or equal to 1).

Figure 3-10: Underground Circuit Rebuild Project Business Case



Safety: If left completely unchecked, underground infrastructure can produce stray voltage and present a hazard. This is mitigated by proactively addressing end-of-life issues before they present a safety issue.

3.6 Wood Pole Replacement

3.6.1 Overview

Figure 3-11 provides an overview of the Wood Pole Replacement program business case.

Figure 3-11: Wood Pole Replacement Business Case Overview

Investment Identification	Nominal Cost (millions)	Project Count
Risk & Resiliency Analytics	N/A	N/A
System Stakeholders	$45.0	1
Total	**$45.0**	**1**

Analytics Benefit (PV Millions)
N/A
Analytics BCR
N/A

Investment Identification	CenterPoint Objectives / TDISC Criteria				
	Safety	Delivering Service	Maintain Reliability	Manage Asset Life-Cycle	Modernizing the Grid
Risk & Resiliency Analytics	N/A	N/A	N/A	N/A	N/A
System Stakeholders	□		□	□	□

□ Quantified Direct Alignment □Non-quantified Direct Alignment □Indirect Alignment

3.6.2 Background & Project Identification

Wood poles represent a common and essential infrastructure element as electric utilities deliver energy to their customers. The wood poles deteriorate over time based on many factors including moisture, surrounding vegetation, insects, birds, weather cycles, etc. Ground line inspection is an important management tool for managing the deterioration of pole by replacing defective poles proactively as directed by the findings of the inspection results. The industry practice is generally a ten-year cycle. CenterPoint started a formal and systematic wood pole inspection program approximately 7 years ago. The current reject rate is somewhat high during the first pass of the inspection and is expected to be lower in a couple years when the 10-year cycle will start to repeat. The rejection rate is expected to drop from 10 percent to 6 percent once the initial ten-year cycle is complete and a corresponding reduction in program spending is assumed.

The inspection reports provide information regarding ground line pole decay, above ground pole decay, pole top damage, and other defects that may affect the integrity of the pole. The first category is a "non-priority reject" inspection failure. These poles fail inspection criteria but do not need immediate attention. While these poles do not need immediate attention they still need to be addressed. Non-

Priority Reject poles are scheduled for replacement no later than the year following the failed inspection. The second category is a "Priority Reject" inspection failure. These poles need timely attention. The priority reject classified poles are targeted for replacement within 30 days of failing inspection.

3.6.3 Business Case: CEI South System Stakeholders Based Projects

Safety: Replacing inspected poles that have been identified as having defects that require attention improves both employee safety and public safety. These poles have been identified be in implication to have a significantly elevated likelihood of failing. By replacing the poles proactively in a control manner in generally good weather, it can be completed much more safely as compared to the likely storm restoration scenario. The risk mitigated includes energized conductor below required clearances and the crush hazard should the pole fail completely.

Maintain Reliability & Resiliency: Replacement of at-risk assets with new assets that meet the current standard contributes to maintaining reliability standards and improves reliability as compared to leaving known high-risk assets on the system.

Manage Asset Lifecycles: Condition based asset replacements are sensible as the unintended consequences of a significant failure are greatly mitigated. Failure to take action based on the inspection results could result in significant liability exposure and harm. Therefore, while a quantitative business case exercise would produce a positive business case based on the risk mitigation value, it was not performed as not replacing defective poles is not viable strategy.

3.7 Substation Physical Security

3.7.1 Overview

Figure 3-12 provides an overview of the Substation Physical Security program business case.

Figure 3-12: Substation Physical Security Business Case Overview

Investment Identification	Nominal Cost (millions)	Project Count
Risk & Resiliency Analytics	N/A	N/A
System Stakeholders	$14.0	9
Total	**$14.0**	**9**

Analytics Benefit (PV Millions)
N/A
Analytics BCR
N/A

Investment Identification	CenterPoint Objectives / TDISC Criteria				
	Safety	Delivering Service	Maintain Reliability	Manage Asset Life-Cycle	Modernizing the Grid
Risk & Resiliency Analytics	N/A	N/A	N/A	N/A	N/A
System Stakeholders	□	□	□		

□ Quantified Direct Alignment □Non-quantified Direct Alignment □Indirect Alignment

3.7.2 Background & Project Identification

Substations represent critical assets that have recently seen and an uptick is intentional vandalism. Vandals can cause millions of dollars in damage at each substation. Physical security investments are designed to deter intentional vandalism and provide remote monitoring of substation assets.

3.7.3 Business Case: CEI South System Stakeholders Based Projects

Safety: Substations are high energy locations that present a significant hazard to those who have not received proper training. Keeping access limited to authorized personnel through substation physical security upgrades keeps the public and would be vandals from significant harm including death.

Maintain Reliability & Resiliency: Substation equipment damage can cause a significant disruption in the ability to serve customers. Substation physical security measures reduce the likelihood that substation equipment is damaged intentionally.

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