BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR AN ORDER OF THE COMMISSION	)	CAUSE NO. PUD 202100164
AUTHORIZING APPLICANT TO MODIFY ITS	)	
RATES, CHARGES, AND TARIFFS FOR RETAIL	)	
ELECTRIC SERVICE IN OKLAHOMA	)	

Direct Testimony

of

Jason D. De Stigter

on behalf of

Oklahoma Gas and Electric Company

December 30, 2021

1.0 INTRODUCTION

Q1. Please state your name and business address.

A1. My name is Jason De Stigter, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

Q2. By whom are you employed and in what capacity?

A2. I am employed by 1898 & Co. as a Director, and lead the Utility Investment Planning team as part of our Utility 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 over 250 consulting professionals serving the Manufacturing & Industrial, Oil & Gas, Power Generation, Transmission & Distribution, 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 8,300 engineers, architects, construction professionals, scientists, consultants, and entrepreneurs with more than 40 offices across the country and throughout the world.

Q3. Briefly describe your educational background and certifications.

A3. I have 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.

Q4. Please briefly describe your professional experience and duties at 1898 & Co.

A4. I am a professional engineer with 14 years of experience providing consulting services to electric utilities. I have extensive experience in asset management, capital planning and optimization, risk and resiliency 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 project manager, I have worked on and overseen risk and resiliency analysis consulting studies on a variety of electric power transmission and distribution assets, including developing complex and innovative risk and resiliency analysis models. My primary responsibilities are business development and project delivery within the Utility Consulting Practice with a focus on developing risk and resiliency-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 performing similar studies to the effort performed for Oklahoma Gas & Electric ("OG&E").

Q5. Have you previously testified before the Oklahoma Corporation Commission?

A5. I have not testified before the Oklahoma Corporation Commission; I ask that my credentials be accepted. I provided written, rebuttal, and oral testimony on behalf of Indianapolis Power & Light, now AES Indiana, before the Indiana Utility Regulatory Commission. Additionally, I provided written and rebuttal testimony on behalf of Tampa Electric Company before the Florida Public Service Commission. I have also supported many other regulatory filings. I have also testified in front the Alaska Senate Resources Committee.

Q6. Are you sponsoring any attachments in support of your testimony?

A6. Yes, I am sponsoring the Grid Enhancement Plan Business Case for 2020 & 2021 Investments Report prepared by 1898 & Co. ("1898 & Co. Report"), which is included as Direct Exhibit JDD-1.

Q7. Were your testimony and the attachment identified above prepared or assembled by you or under your direction or supervision?

A7. Yes.

Q8. What was the extent of your involvement in the preparation of the Grid Enhancement Business Case?

A8. I served as the 1898 & Co. project director on the OG&E Grid Enhancement Plan Business Case Assessment. I worked directly with the OG&E Team involved in the investment planning. I was responsible for the overall project and was involved in the development of the business case assessment, as well as being the main author of the report.

2.0 EXECUTIVE SUMMARY

Q9. What is the purpose of your direct testimony in this proceeding?

A9. The purpose of my testimony is to summarize the results and methodology used by 1898 & Co. to develop a business case for OG&E's 2020 and 2021 Grid Enhancement Plan with the following objectives:

1. Calculation of benefits from a customer centric perspective, mainly avoided future costs and customer outages.

2. Perform the business case evaluation using a bottoms-up approach to produce business cases at the project, circuit, substation, and portfolio levels.

3. Prepare the business case results using a revenue requirements methodology for avoided reactive cost benefits excluding customer outage benefits.

Through my testimony, I will describe the integrated and comprehensive nature of the Grid Enhancement Plan and how to understand the business case evaluation. I will describe the two main approaches utilized to estimate benefits for grid investments, the data that served as the foundation for the evaluation, and how benefits were mapped to investments. I will also describe results of the business case assessment performed for OG&E. Finally, I provide my conclusions and recommendations.

Q10. Please describe the assessment 1898 & Co. conducted for OG&E.

A10. 1898 & Co. developed a business case for the 2020 and 2021 Grid Enhancement Plan investments developed by OG&E. 1898 & Co. utilized a risk and resiliency-based planning approach to provide a business case for each Grid Enhancement investment. The evaluation leverages 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. Investment costs for each of the investments were provided by OG&E.

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[1]
  - Capital Expense
  - Operations & Maintenance (O&M) Expense
- Avoided Customer Outages
  - Customer Minutes Interrupted (CMI)
  - Monetization of avoided CMI using the DOE ICE Calculator[2]

The business case evaluation is customer centric, quantifying the life-cycle impact to customer rates and outage performance. The assessment was performed for the range of investment activities that are part of the Grid Enhancement Plan, 48 different investment types specifically including 645 substation asset replacements, rebuilding of 122 distribution circuits, and adding automation technologies to the system. The assessment was performed for 23 different benefit streams and mapped to each of the investments. The business case assessment was performed for several perspectives including specific investments, substation and circuit levels, resiliency and automation investment activities, and the portfolio. Additionally, the business case was performed on a cash flow and revenue requirements perspective.

---

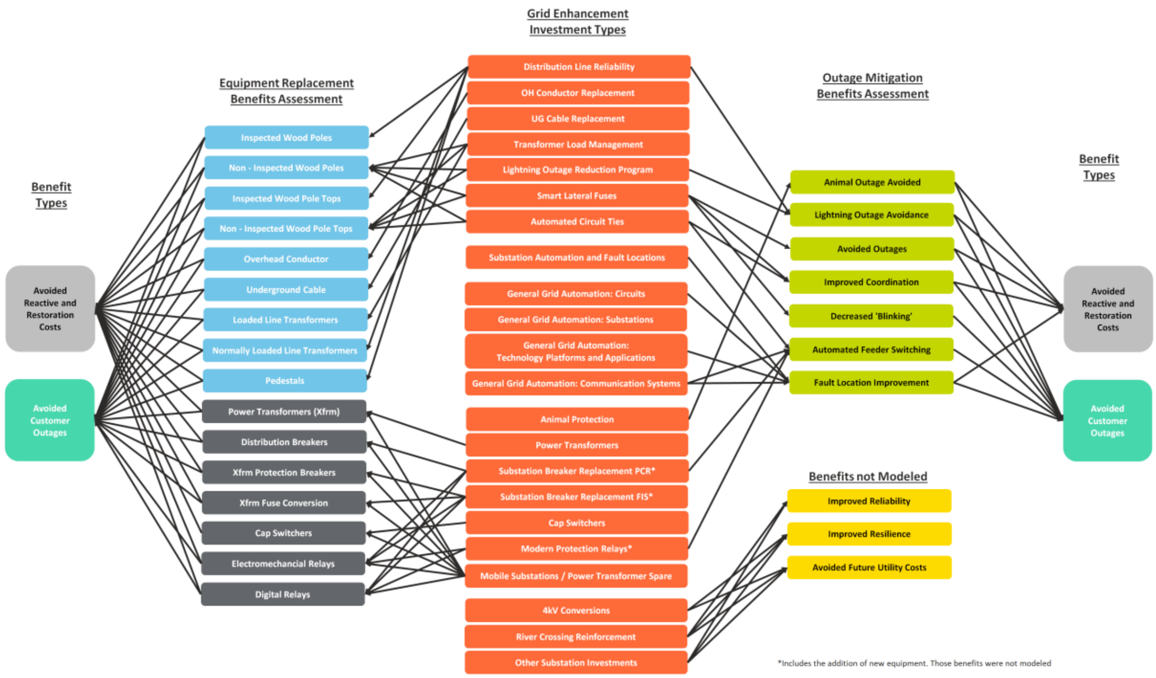
[1] Synonymous with OG&E's "Avoided Cost of Service" benefit stream
[2] Synonymous with OG&E's "Avoided Economic Harm" benefit stream

Q11. What will your testimony conclude regarding 2020 and 2021 Grid Enhancement Plan business case evaluation?

A11. My testimony will make three main conclusions.

Firstly, the Grid Enhancement Plan is an integrated and comprehensive set of investments designed to work in concert to provide value to customers. The following figure visually shows the integrated and comprehensive nature of the plan.

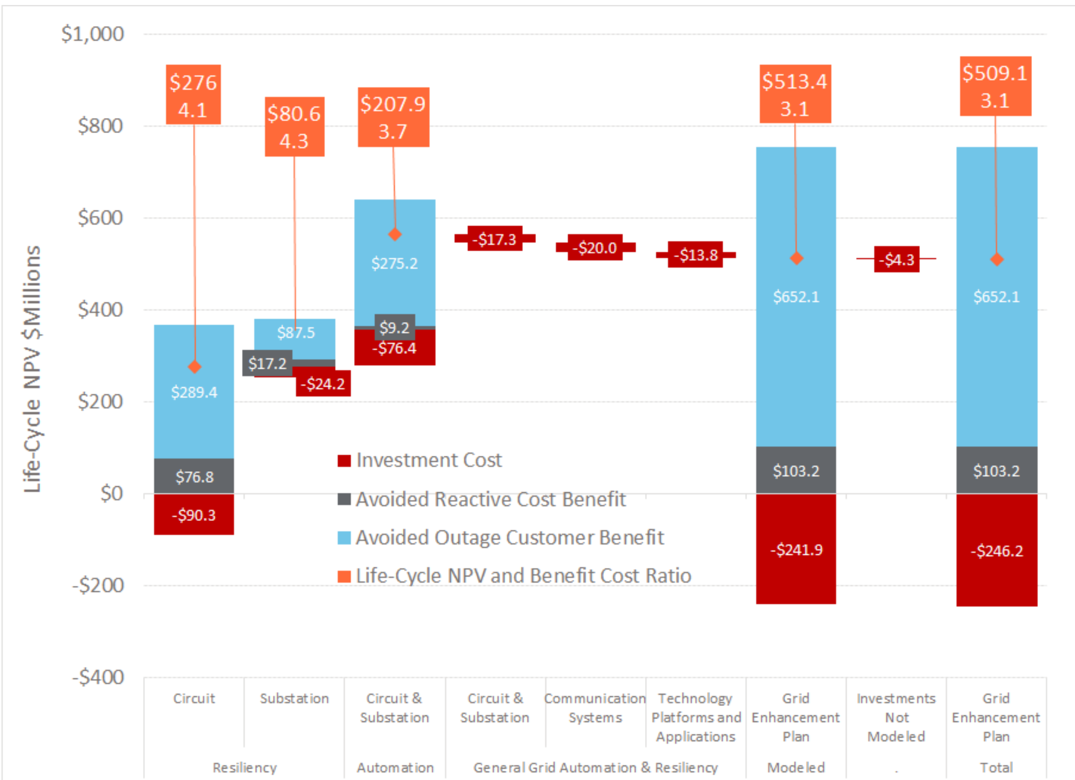
Figure 1: Investments and Benefits Mapping Diagram



While discrete investment activities are identified, solely evaluating the business case at these levels is not appropriate since the investments work together to solve a range of problems. Rather, the business case results should be viewed from several perspectives including individual investment activities, circuit and substation level, and the entire portfolio.

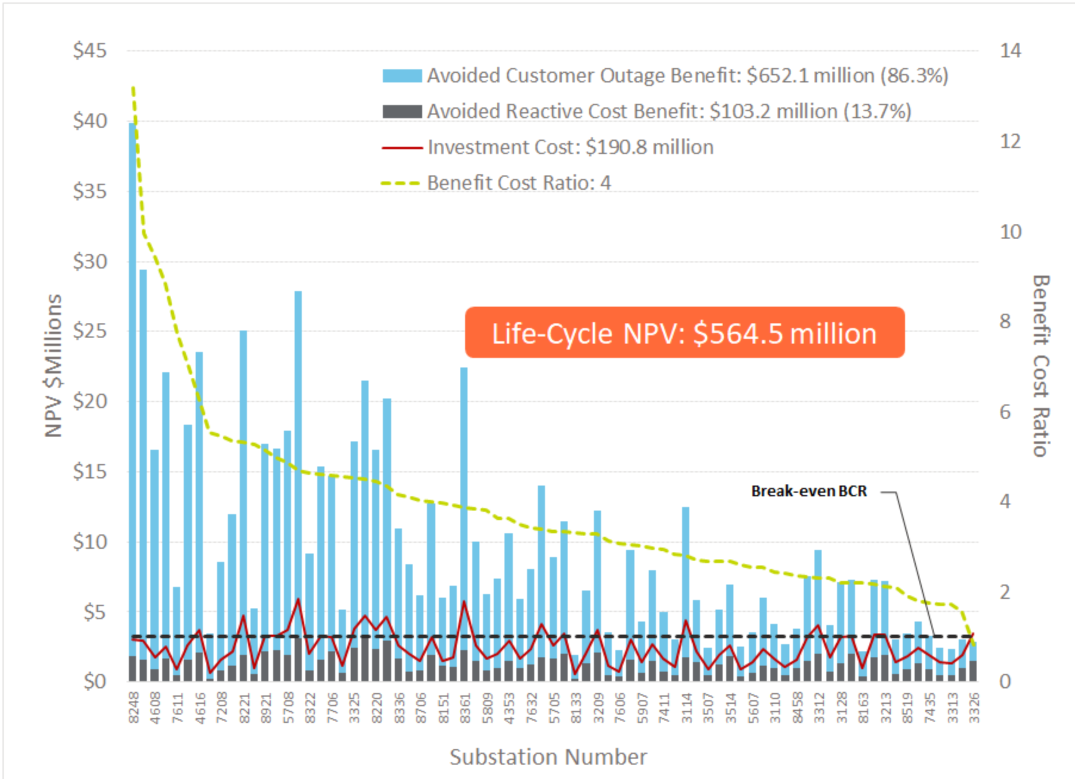
Second, the business case for the 2020 and 2021 Grid Enhancement Plan is robust from several perspectives. The following figure shows the investment of $246.2 million provides life cycle NPV benefit of $509.1 million with a benefit cost ratio of 3.1 for the entire portfolio.

Figure 2: Grid Enhancement Business Case Summary



Additionally, 76 of the 77 substations have positive business case with the one substation having a benefit cost ratio of 0.8 as shown in the following figure.

Figure 3: Circuits & Substations Business Case Results



Third, the 2020 and 2021 Grid Enhancement Plan investments are justified based on the two conclusions above.

3.0 RISK & RESILIENCY BENEFITS APPROACH

Q12. Where else have you performed similar evaluations?

A12. I have performed similar business case evaluations for regulatory filings for AES Indiana (formerly Indianapolis Power & Light) and Tampa Electric Company. In both cases, the filings were accepted. For those filings, I lead teams to identify, prioritize, and justify $2 billion of grid investments to manage aging infrastructure, improve reliability, and strengthen the grid against major storm events. Additionally, I have supported the development of investment plans and business cases for electric utility internal purposes.

In all, I have led and supported the plan development and justification for over $10 billion of investment across 12 electric utilities in the last 10 years.

Q13. Based on your experience, are OG&E's investments similar to other utilities' investment plans and reasonable?

A13. Yes. All the 48 investments categories that are part of the Grid Enhancement Plan are typical proactive investments other utilities are making. 1898 & Co. held several meetings and workshops with the OG&E asset management, engineering, and program teams to understand the approach and reasoning in developing Plan investments. Other utilities face similar issues to OG&E and are moving to upgrade their systems using similar investment approaches. From my perspective, OG&E's investment types are reasonable and in line with other utilities.

Q14. Did you review OG&E's business case approach as part of the original filing of the Grid Enhancement Plan?

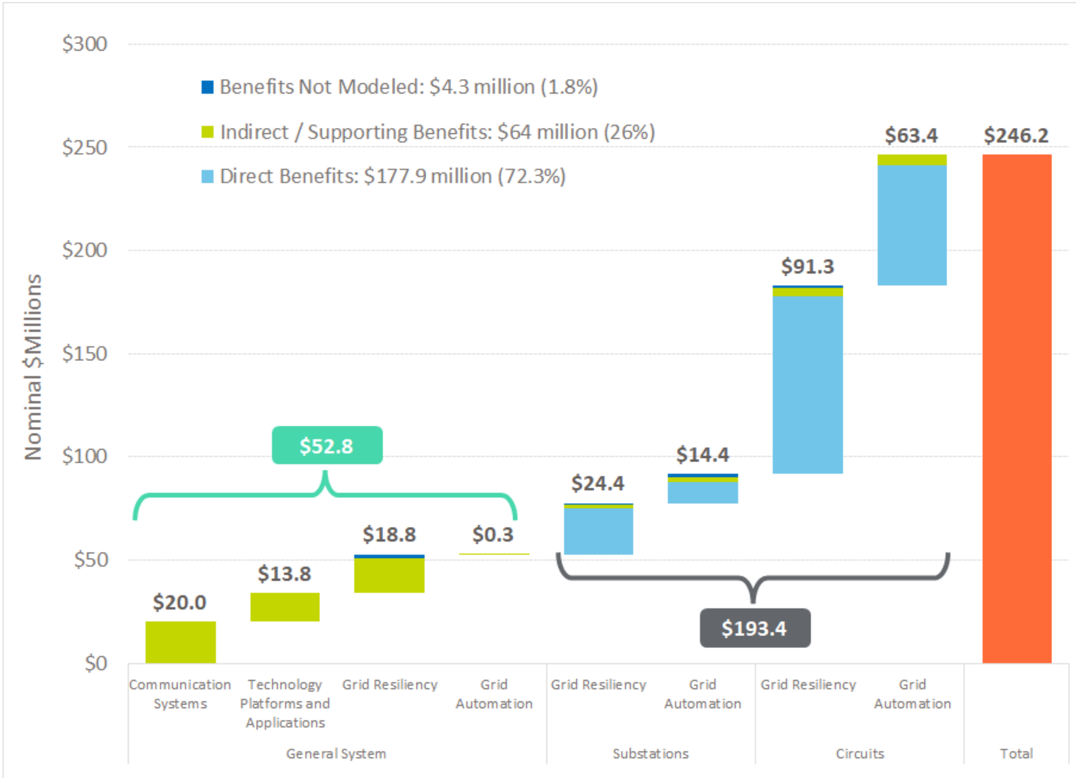
A14. Yes. OG&E provided the same example spreadsheets provided to the Commission for review. For the original intended business case purpose, that business case approach is sound, appropriate, and similar to efforts 1898 & Co. has completed for similar purposes.

Q15. Please provide an overview of the Grid Enhancement investments evaluated in the benefits assessment.

A15. The 2020 and 2021 Plan investment for the two years is approximately $246.2 million across 4 investment categories and 48 different investment types. It includes investment in 122 circuits and 77 substations. Investments are broken down into Communications Systems, Technology Platforms and Applications, Grid Resiliency, and Grid Automation.

In general, the Grid Resiliency and Grid Automation investments are at specific substations or circuits with direct linkage to benefit streams. Communications Systems, Technology Platforms and Applications, and some Automation or Resiliency investment are enabling or supporting investments to these direct investments. Without these indirect / supporting investments the benefits from the direct investments could not be achieved. Figure 4 provides a summary of the Grid Enhancement Plan for 2020 and 2021. The figure shows the split between the four main investment categories and their relationship to benefit assessments. Approximately 72.3 percent of the investment has direct alignment of benefits to either a circuit or substation. Approximately 26.0 percent of the investment indirectly supports the enablement of the direct benefits. The figure does show a small percentage of the plan's investment, 1.8 percent that was not included in the benefits assessment.

Figure 4: 2020 & 2021 Grid Enhancement Investment Summary



Q16. What investments are part of the "Benefits Not Modeled" Category?

A16. The $4.3 million of the investment that is part of the "Benefits Not Modeled" category is made up of 4 kV Conversions, River Crossing Reinforcement, spare power transformer, adding new breakers and relays, and other various minor substation upgrades. This accounts for 1.8 percent of the plan. Benefits were not modeled for several reasons. Firstly, the scope definition of some of the investment types did not allow for an accurate assessment of benefits. Secondly, the approach to calculate benefits for these investments is challenging and did not align with the two core approaches. Thirdly, the supporting data to evaluate benefits was not available. Fourth, these investments account for a small portion of the overall investment level, 1.8 percent, and the cost to estimate benefits did not seem valuable given the high level of benefits for the 98.2 percent of investments. 1898 & Co. expects these investments to have a positive business case.

Q17. What benefits streams were evaluated?

A17. 1898 & Co. reviewed the Grid Enhancement Plan investments for the types of benefit streams they are expected to produce, including the direct and indirect / supporting nature of the investments. Based on this evaluation, 23 different direct benefits assessments were identified using one of the two main approaches to estimate benefits:

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

These two approaches match the type of investment activities for the Grid Resiliency and Grid Automation categories of investment. The evaluation leverages 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. Each approach is discussed later in my testimony. Table 1 shows the 23 different benefit stream and which of the two main benefit streams they come from.

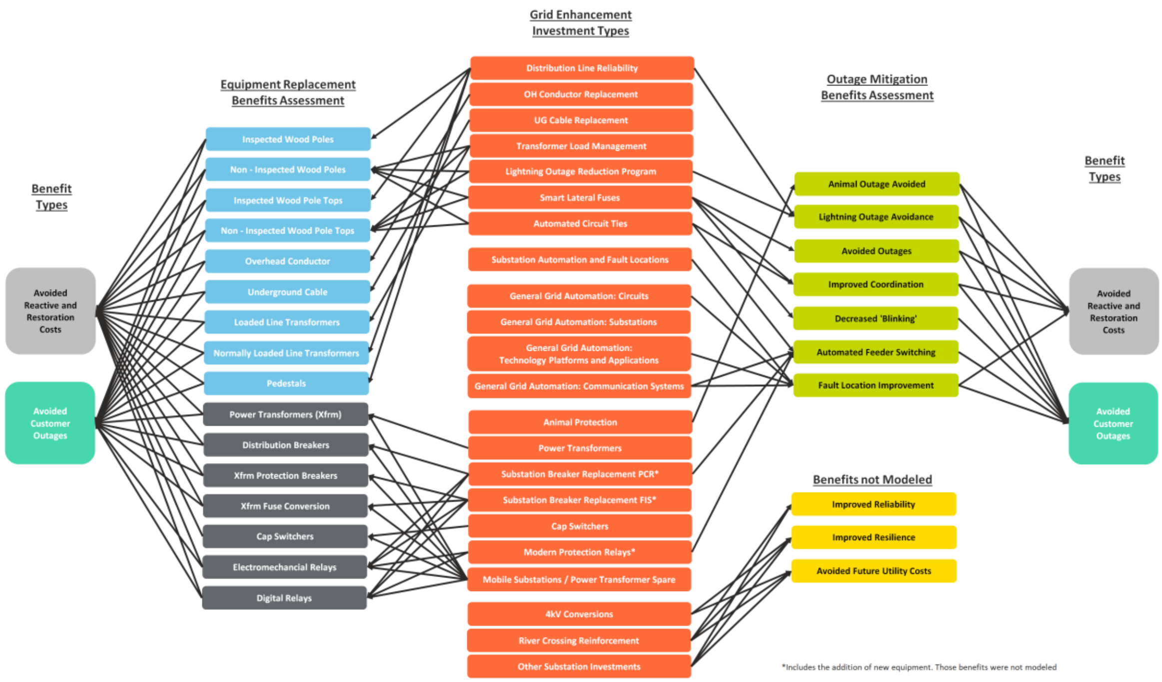
Table 1: Benefit Assessments Performed

Equipment Replacement		Outage Mitigation
Distribution Circuits	**Substations**	
Inspected Wood Poles	Power Transformers (Xfrm)	Animal Outages Avoided
Inspected Wood Pole Tops	Distribution Breakers	Lightning Outage Avoidance
Non-Inspected Poles	Xfrm Protection Breakers	Avoided Outages
Non-Inspected Pole Tops	Xfrm Fuse Conversion	Improved Coordination
Overhead Conductor	Cap Switcher	Decreased 'Blinking'
Underground Cable	Electromechanical Relays	Automated Feeder Switching
Overloaded Line Transformers	Digital Relays	Fault Location Improvement
Normally Loaded Line Transformers		
Pedestals		

Q18. You mentioned above that the business case was performed from several perspectives, why was this done?

A18. The integrated and comprehensive nature of the Grid Enhancement Plan necessitates viewing the business case from several perspectives. OG&E's objectives for the Grid Enhancement Plan are 1) improve reliability, 2) greater resiliency, 3) enhanced flexibility, 4) increased efficiency, 5) additional affordability, and 6) expand customer benefits. To achieve these objectives, OG&E identified a portfolio of interrelated and co-dependent investments to comprehensively solve a range of problems. While the investment activities are discrete, the business case cannot fully be evaluated at the same discrete levels. While parts of the plan include individual investments to solve specific issues most of the plan includes several investment categories designed to work in concert to provide value to customers. Figure 5 (referenced above as Figure 1) visualizes this integrated nature of the Grid Enhancement Plan.

Figure 5: Investments and Benefits Mapping Diagram



For the business case evaluation, 1898 & Co. mapped each of the 48 investment categories to the 23 benefit drivers at the investment level for each substation and circuit as shown in the figure. The orange boxes in the middle of the diagram show the 48 investment categories (summarized down to 22 categories). The benefit drivers are shown on either side of the orange boxes. The Equipment Failure Risk & Resiliency benefits assessments for circuit and substation assets are shown in the blue and dark grey boxes. The Outage Mitigation Risk & Resiliency benefits assessments are shown in the green boxes. The yellow boxes include benefit streams for the investments that do not include quantified benefits in this assessment. On the outsides of the diagram, the two boxes show the mapping of benefits driver to the two main benefit types, avoided reactive and restoration costs and avoided customer outages.

The figure shows the linkage of investment that drives benefit. As the figure shows there is a “spider’s web” of linkage between investment and benefits. The diagram graphically shows the integrated nature of the Grid Enhancement Plan with a portfolio of investments driving a suite of benefits. While the figure shows a few 1 to 1 relationships between investments and benefits, most of the time they involve many to many relationships. This integrated and comprehensive investment plan is typical for electric distribution systems.

The plan includes a direct investment portfolio with traditional infrastructure upgrades (resiliency) and deployment of proven grid modernization technologies (automation). Many of the direct investments are co-dependent on each other to drive benefits. Additionally, the plan includes supporting investment across the system in communications and technology applications to enable the full effectiveness for the resiliency and automation investment.

The integrated and comprehensive nature as well as the direct and indirect / supporting aspects of the portfolio necessitate that the business case be viewed from several perspectives when evaluating the benefits and prudency of investments. I discuss and show the results for the various perspectives later in my testimony.

Q19. What escalation rate and discount rate were used in the discounted cash flow calculation?

A19. The modeling assumes a 2.5 percent escalation rate. For the discount rate, OG&E's weighted average cost of capital of 7.55 percent was used. Both values were provided by OG&E and are consistent with previous business case analysis they have performed.

Q20. 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?

A20. The AssetLens Analytics Engine utilizes a robust and sophisticated set of data and algorithms at a very granular system level to model the benefits of each asset within the defined investment. OG&E data systems include a connectivity model that allows for the linkage of many foundational data sets - the Geographical Information System (GIS), Cascade, the Outage Management System (OMS), and Customer Information.

GIS - The GIS provides the list of assets in OG&E's distribution circuit system, their attributes (type, manufacturer, age), and how they are connected to each other, both physically and electrically. Significant for the 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 asset failures to customer impacts for mainline feeder, major lateral, and minor lateral assets.

Cascade - Cascade is the companion system to the GIS for the substation assets. OG&E provided detailed asset register tables for power transformers, breakers, fuses, and relays. 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. Two specific connectivity relationships were developed. The first is establishing the link between the GIS protection devices and Cascade breakers so that accurate customer outage impacts could be established. This connectivity allows the AssetLens Analytics Engine to connect customers from the distribution line transformer outside customer locations to the power transformer inside the substation. The second 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 10 years. The data include causes, duration, Customers Interrupted (CI), Customer Minutes Interrupted (CMI), and location for approximately 600,000 outage events. 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 - OG&E 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. This customer information is used for both benefits approaches. Since the Grid Enhancement Plan includes significant changes to each circuit's protection schemes, the linking of customers to protection devices was done for both the before and after state.

Q21. Please describe the approach to estimate Equipment Risk & Resiliency Benefits.

A21. 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.

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 upgraded to the new equipment standard. The benefit of replacing infrastructure is the difference between the two scenarios, the avoided reactive and restoration life-cycle costs.

Q22. What assets were evaluated using this approach?

A22. Table 2 provides a summary of the asset replacements for distribution circuits for the Grid Resiliency and Grid Automation categories. Poles have been divided up by those replaced due to inspection and those replaced to support other Grid Enhancement activities (device addition or replacement). Similarly, distribution line transformers have been separated into highly / overloaded and normally loaded.

Table 2: Distribution Asset Replacement Summary

Asset Type	Units	Grid Resiliency	Grid Automation	Total
Inspected Poles and Pole Tops	Count	8,938	0	8,938
Non-Inspected Poles and Pole Tops	Count	550	566	1,116
Lightning Arresters	Count	2,871	0	2,871
Overhead Conductor	Miles	4.69	0	4.69
Underground Cable	Miles	9.25	0	9.25
Overloaded Line Transformers	Count	770	0	770
Normally Loaded Line Transformers	Count	1,628	0	1,628
Pedestals	Count	323	0	323

Table 3 includes a summary of the substation assets that are part of the plan. A total of 645 Substation assets are modeled. 1898 & Co. and OG&E directly linked each of the assets from the plan to the Cascade data register. The power transformers modeled consist of a majority of non-LTC transformers with only a single LTC transformer. A variety of air magnetic, gas, oil, and vacuum circuit breakers are included in the plan. Relays are broken down into digital and electromechanical with most common replaced being electromechanical. Replacement of infrastructure may involve replacing several components for efficiency purposes. This is the case with the breakers and relays as it is cheaper from a lifecycle perspective to replace the combination of the two rather than individually. For this reason, the table shows counts of assets replaced based on replacement of the breaker or relays.

Table 3: Substation Asset Replacement Summary

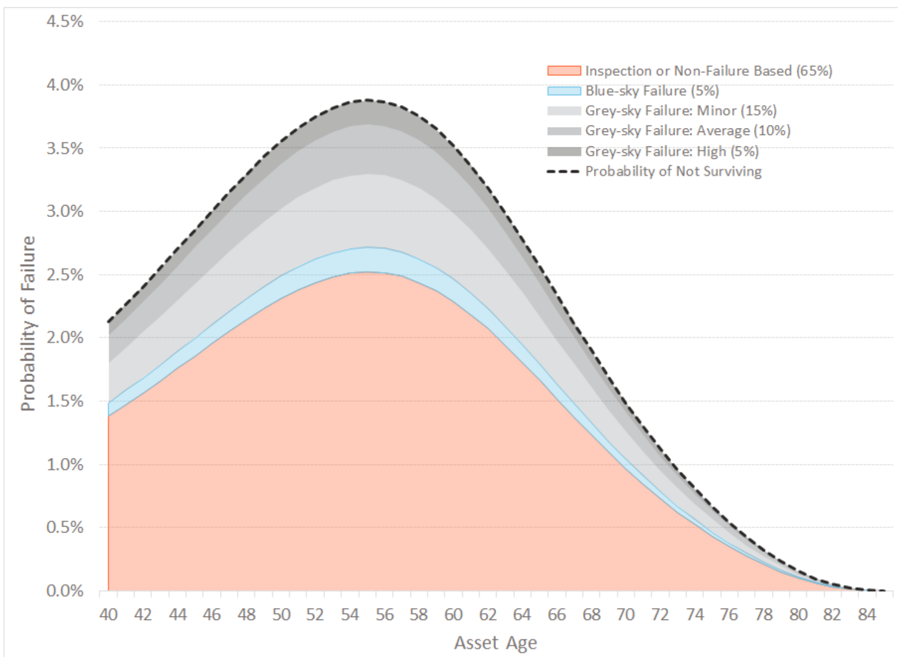
Asset Type	Grid Resiliency	Grid Automation	Total
Power Transformers	8		8
Distribution Protection Breakers	59	9	68
Cap Switcher Breaker	4		4
Power Xfrm Breakers	14		14
Fuse Conversion to Breaker	12		12
Relays	225	314	539
Total	322	323	645

Q23. How was the annual probability of failure for each failure type estimated?

A23. 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. Since most utilities work to prevent failures, there is simply not enough actual historical failure data to perform a statistical analysis and develop end-of-life curves. In the absence of historical failure rates, 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. As such, survivor curves are widely used in the utility industry and asset management organizations to forecast the probability of failing.

Based on 1898 & Co.'s collection of asset class expected lives, and referencing OG&E'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 transmission and distribution (T&D) systems. The 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 6 shows annual probabilities of failure for five different failure types for an example condition based 40-year-old wood pole.

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



Q24. What consequence factors were included in the evaluation?

A24. 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 assert 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 4 shows the range of consequence types evaluated and the asset classes that they apply to. The framework puts a monetary value to each of these consequence factors.

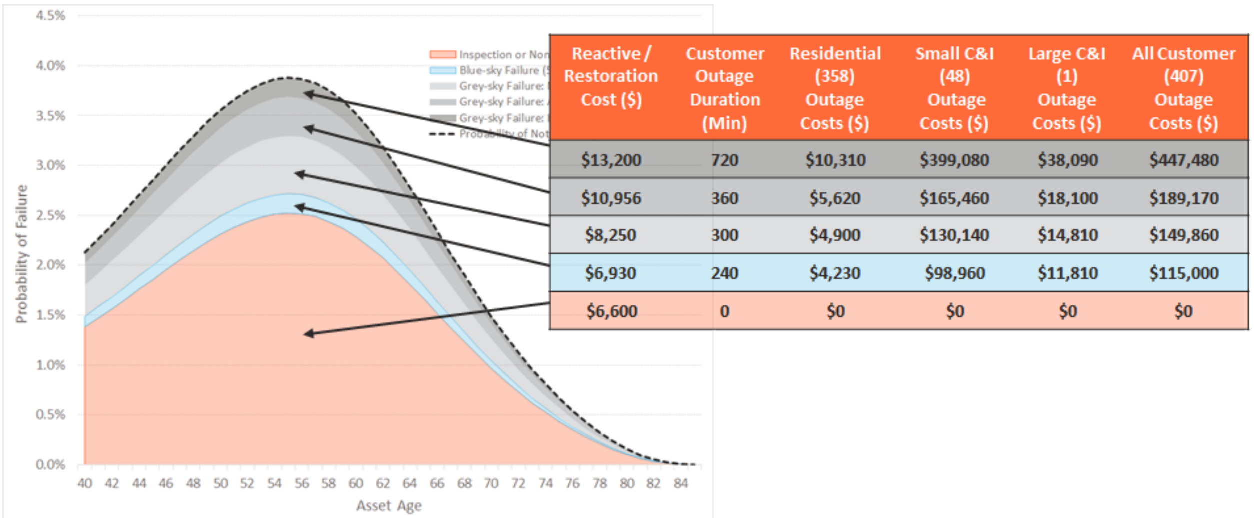
Table 4: Consequence Types and Asset Classes

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

Q25. Please describe how the Status Quo Scenario is estimated?

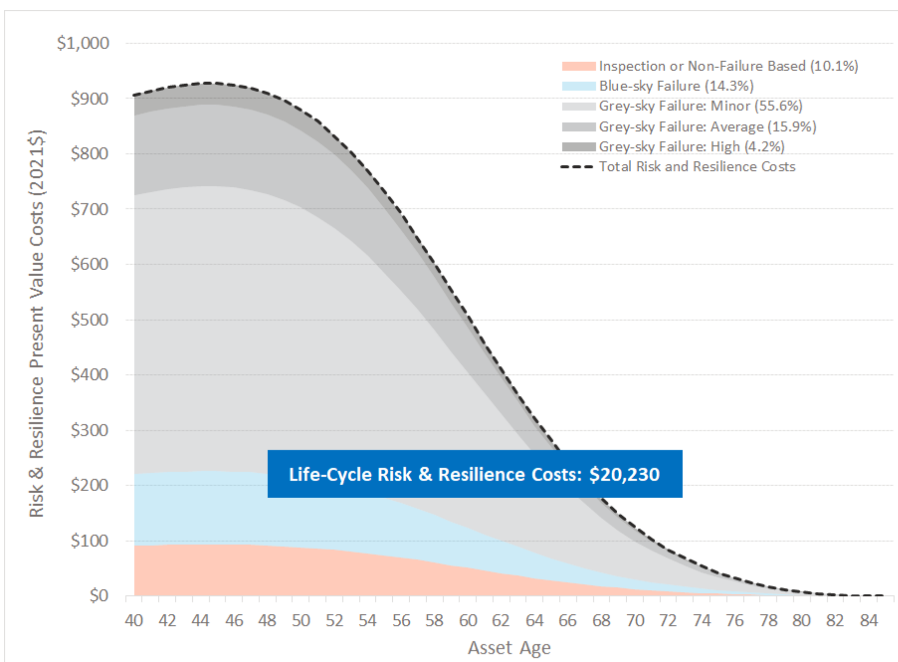
A25. The Status Quo scenario assumes the asset is not replaced and could incur risk costs over time. To calculate the Status Quo Risk & Resiliency costs over time, each of the probability of failures for each failure type is multiplied by each consequence of failure costs for each failure type. Figure 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 8 shows the resulting risk and resiliency cost profile by multiplying the annual failure type probabilities by the consequence costs from Figure 7 while factoring in the escalation and discount rate.

Figure 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

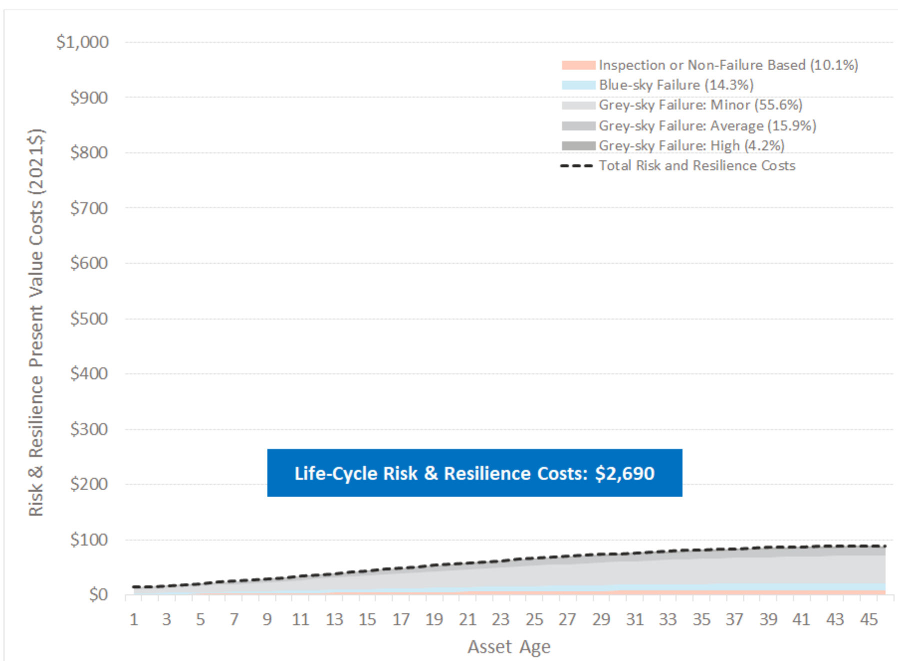
Figure 8: Status Quo Risk & Resiliency Reactive Costs Profile - 40-Year-Old Wood Pole



Q26. Please describe how was the Investment Scenario was estimated?

A26. 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 9 depicts this approach for the replacement of the 40-year-old wood pole example on a backbone with approximately 400 customers.

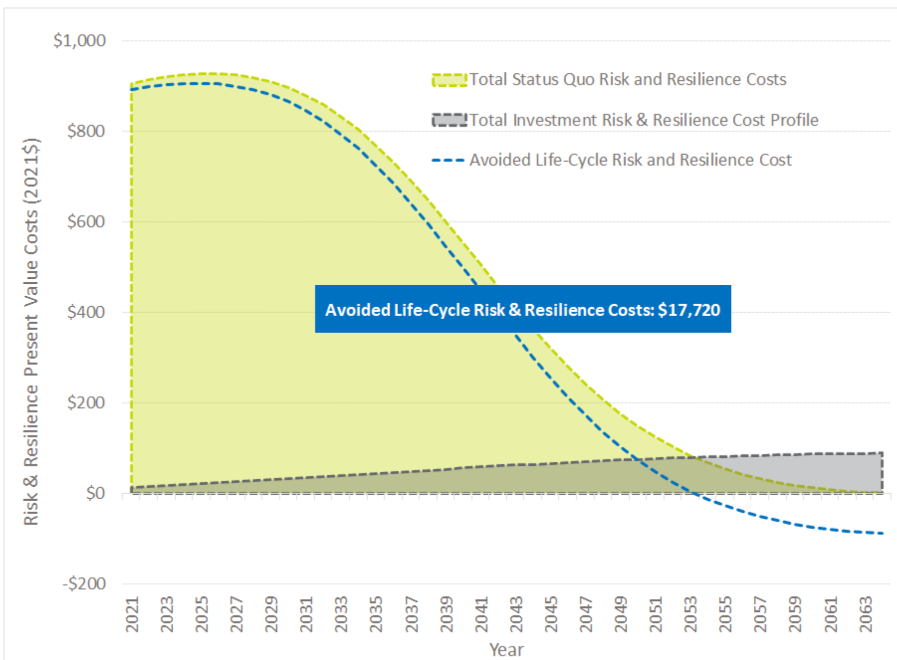
Figure 9: Investment Risk & Resiliency Reactive Costs Profile - 0-Year-Old Wood Pole



Q27. Please describe how the avoided costs were estimated?

A27. The avoided risk and resiliency costs are the annual difference between the Status Quo and Investment scenario results. Figure 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 switch over from positive to negative occurs earlier and decreases the avoided costs. This approach is used for all the assets outlined in Table 2 and Table 3 above and broken down for each of the consequence factors shown in Table 4 above.

Figure 10: Avoided Risk & Resiliency Cost Benefit



Q28. Please describe the approach to estimate Outage Mitigation Risk & Resiliency Benefits.

A28. The Outage Mitigation Risk & Resiliency modeling approach calculates the benefits for investments mainly aimed at decreasing customer outages. The approach leverages OG&E's historical outage records for the last 10 years, accounting for nearly 600,000 individual outage events. The assessment excludes the top 1 percent of outage days to be conservative. Each outage is re-calculated, assuming the Grid Enhancement investments had been in place. Additionally, the assessment estimates the decrease in truck rolls for outages that would be fully mitigated. This calculation produces the avoided customers impacted (CI), customer impacted minutes (CMI), and truck rolls 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 and truck rolls are calculated by adjusting for inflation and discount rate over the life cycle of the investment.

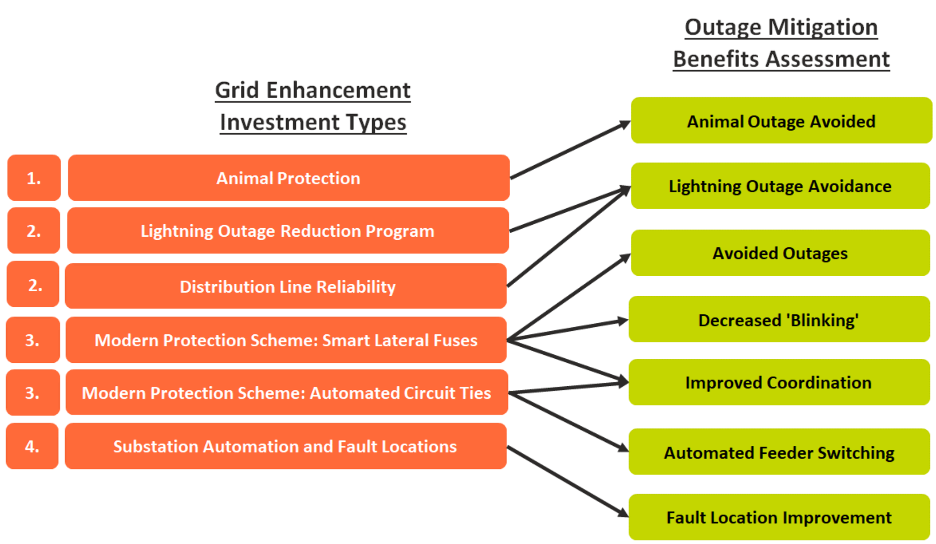
This approach to estimating benefits was used for six direct investment types to produce seven different benefit streams. It should be noted that other indirect investment types are needed to enable the seven different benefit streams.

To avoid double-counting, which would result in an over estimation of the benefits, the approach evaluates the benefits of each investment activity sequentially. In other words, the outage records are re-calculated for only one of the investment activities at a time. After one re-calculation is complete, the next one is evaluated based on the modified outage records.

Q29. How do the grid investments map to these benefits streams?

A29. Figure 11 shows the mapping of six Grid Enhancement Investment types to each of the seven Outage Mitigation Benefits streams and the sequencing order of investments. The figure shows the integrated and comprehensive nature of the Grid Enhancement Plan. Two investment programs, Lightning Outage Reduction Program and Distribution Line Reliability produce one combined benefit stream. It should also be noted that the Distribution Line Reliability program was evaluated under the Equipment Risk & Resiliency benefits approach. The figure also shows one to one mapping of investment to benefits for animal protection and fault location isolation. Finally, the figure shows two direct investment types for modern protection schemes produce four benefit streams.

Figure 11: Direct Investment Activity Sequencing Order



Q30. How should the Outage Mitigation Benefit business case results be assessed?

A30. 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. However, much of the investment aimed at decreasing outages work together systematically. Additionally, the sequencing of investment impacts the benefit allocation. For example, the benefits for Automated Circuit Tie Lines could be higher if it was evaluated against the outrage records before the Lightning Outage Reduction Program. Further, indirect / supporting investments are needed to enable the effectiveness of the direct investments. For these reasons, even though investment benefits can be directly linked to individual outages using this approach, the business case evaluation needs to be evaluated at several levels to include the whole circuit, substation, and system.

Q31. Why were avoided customer outages monetized?

A31. The availability of electric energy is one of the cornerstones of 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 your home, but also where you work, where you buy groceries, the daycare and school for your kids, the care facility for a parent, and all other facilities that are part of our daily lives. When these facilities are unable to carry on normal operations, the lives of many are disrupted, often with financial consequences to both the facilities and their customers. The level of disruption will grow as we become 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.

Q32. What approach was used to monetize outages?

A32. To monetize the cost of an outage, the benefits approach utilizes the Interruption Cost Estimator (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 commercial and industrial (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. Outages less than one minute, including 'Blinks', are assumed to have the same consequence as a 1-minute outage.

4.0 BUSINESS CASE RESULTS

Q33. Please explain how the business case results should be interpreted.

A33. The Grid Enhancement Plan is an integrated and comprehensive investment plan. Figure 5 above visually shows the integrated and comprehensive nature of the Grid Enhancement Plan investment. The business case results should be viewed from several perspectives.

Some of the investments have direct benefits linkage, while others are indirect / supporting that enable the achieving of the direct benefits. Additionally, the direct investments are integrated and dependent on each other. Further, the benefits for some investments are dependent on the order of laying in the investments into the analysis as discussed above. As such, the business case results need to be viewed from several perspectives before drawing conclusions. The business case results are viewed from the following perspectives:

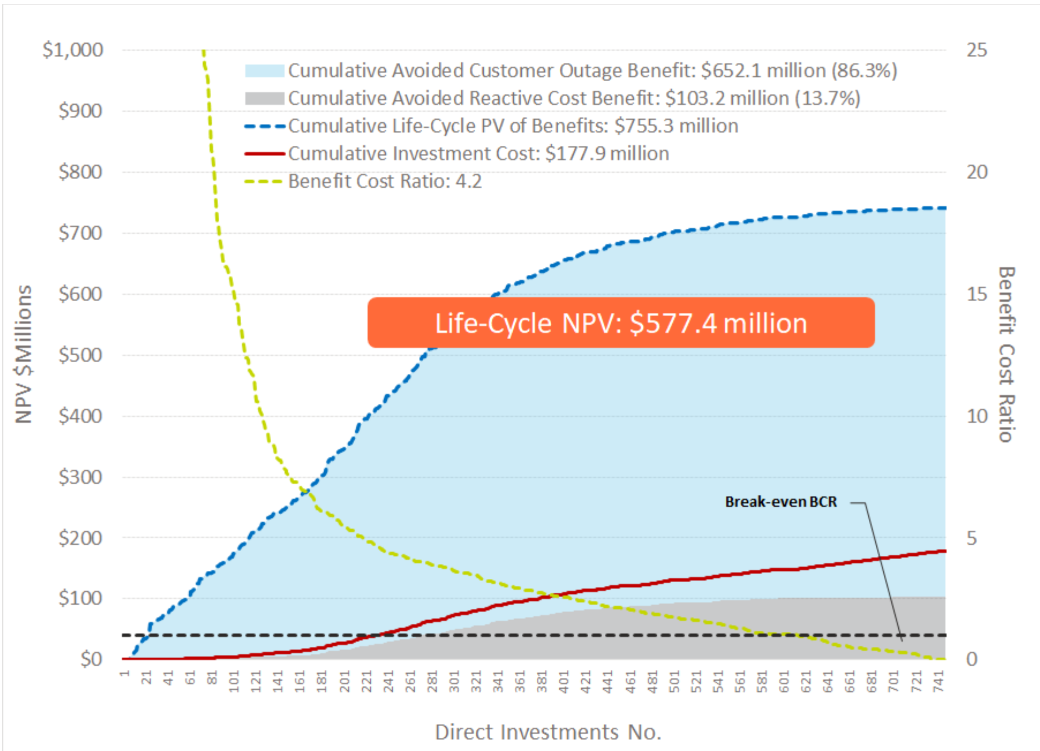
1. Individual investment level where investment can directly be mapped to benefits.
2. Substation or circuits level for each investment type, 11 in total.
3. Investment activity, resiliency and automation, for each substation and circuit.
4. Entire portfolio perspective.

Additionally, the business case results were evaluated from both a Cash Flow and Revenue Requirements perspective. Unless otherwise stated, the results shown are based on the Cash Flow methodology.

Q34. What are the results for each of the direct investments?

A34. Mapping the direct investments to the 23 benefit streams produces 749 individual investment business cases. Figure 12 shows the business case results for all 749 direct investments. The figure ranks the individual investments by benefit cost ratio and shows the cumulative investment, avoided reactive costs, avoided customer outages, and total. The green dotted line shows the benefit cost ratio for each of the individual investments. The black dotted line shows the break-even benefit cost ratio. Investments above the black dotted line have positive business case from the direct investment business case perspectives. The redline shows the cumulative investment up through the investment number totaling $177.9 million at investment number 749. Similarly, the grey and blue shaded areas show the cumulative reactive and customer avoided costs. The blue dotted line shows the cumulative benefits.

Figure 12: Direct Investments Business Case Results



As the figure shows, the total direct investment of $177.9 million produces life cycle NPV of $577.4 million for a benefit cost ratio of 4.2. From an aggregate perspective, all the direct investments together have a positive business case. Most of the benefits are from avoided customer costs, approximately 86.3 percent. The reactive cost benefits alone cover approximately 58.0 percent of the total investment. At the individual investment level, the figure shows approximately 82.0 percent of the individual investments, 614, have a benefit cost ratio greater than 1. 18.0 percent of the individual investments, 135, have a benefit cost ratio less than 1 when considered in isolation. The investment cost for these individual projects is $29.4 million for a total benefit of $14.1 million. This converts to 8.6 percent of the invested capital not having directly attributed benefits. Table 5 provides a summary of the 749 investment activities within the 14 direct investment categories. The table shows the total count of investment activities and the number with a benefit cost ratio greater than and less than 1.

Table 5: Direct Investment Benefit Cost Summary

Investment Category	Activity Count	Activity Count with BCR >= 1	Activity Count with BCR < 1
Distribution Line Reliability	122	122	0
Smart Lateral Fuses	121	81	40
Automated Circuit Ties	117	47	70
Transformer Load Management	112	112	0
Animal Protection	71	55	16
Fault Location Isolation	71	71	0
Lightning Outage Reduction Program	36	36	0
Modern Protection Relays	32	30	2
Substation Breaker Replacement PCR	31	28	3
Substation Breaker Replacement FIS	14	13	1
Power Transformers	8	7	1
OH Conductor Replacement	7	7	0
UG Cable Replacement	4	4	0
Substation Breaker Replacement Capacitor Switcher	3	1	2
Total	749	614	135

Q35. Are you concerned that some of the direct investment activities do not have benefit cost ratios greater than 1?

A35. No, as I have stated elsewhere in my testimony the business case results need to be viewed from several perspectives given the integrated and comprehensive nature of the Grid Enhancement Plan. The Automated Circuit Tie Lines, Smart Lateral Fuses, Fault Location Isolation, and Modern Relay Protection individual investment activities have systematically been designed together and their benefit allocations are dependent on the order sequencing as discussed above. As such, the individual investment activity is not the appropriate level to view the business case results. Rather, these investment activities results should be viewed at the circuit and substation level. These results are shown below in my testimony.

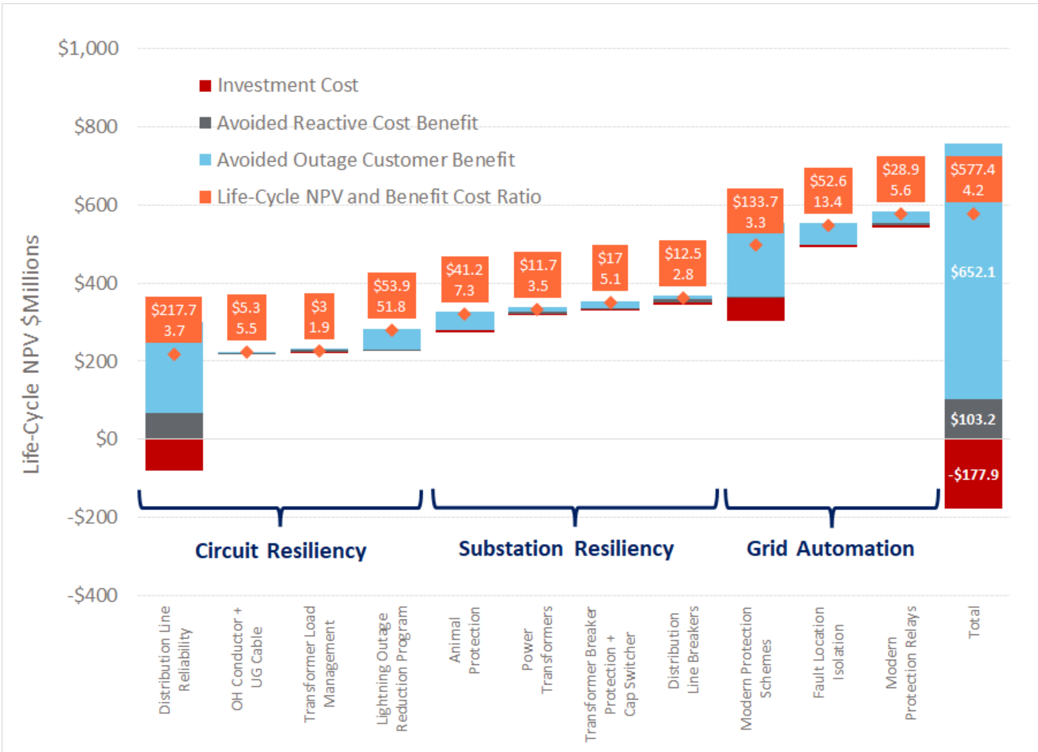
For the animal protection investments, these results need to be viewed based on the outage data deficiencies. For 13 of the 16 substations, the number of animal-based outage records were zero. This is likely a record keeping issue for OG&E and is a common problem across the industry. 1898 & Co. regularly reviews outage management records for utilities and found in general the outage data to be of high quality, especially for use with the Outage Mitigation Risk & Resiliency benefits assessment for circuits. However, similar to other utilities, there is room for improvement in recording and describing substation outages. These can be challenging to classify in an outage management system given that most software applications are circuit and device-centric, and substation outages don't easily map to these points. Additionally, the accurate collection of outage data is typically not top of mind for crews amidst the stress of restoring service at substations where high levels of customers are impacted. This deficiency in the historical outage classification records for substation is causing the business case results to be lower than expected. In the absence of data, it is appropriate to evaluate the animal protection business case results for those substations with animal outage records. The business case results are robust for these substations.

Q36. What are the results for each of the direct investments at the substation and circuit levels?

A36. At the substation and circuit levels, the direct investment business cases were organized into 11 different categories. Figure 13 shows the business case results for each of the 11 categories in aggregate. The 'stair-step' figure layers the benefit and costs on each direct investment to the previous starting from the life cycle NPV. The figure shows the breakdown of investment, avoided reactive cost benefits, and avoided customer benefits for each of the 11 direct investment categories. The figure helps to show the relative investment levels and benefits for each of the categories with the Distribution Line Reliability and Modern Protection Scheme investments being the largest two investment activities from a cost and benefits perspective. The investment of $177.9 million shown in the last Total column is the same as the Cumulative Investment Cost shown in Figure 12 above. In Aggregate the business case results show a life cycle NPV benefit of $577.4 million with a benefit cost ratio of 4.2. The figure also shows a mapping of the direct investment categories to either the Resiliency or Automation investment type. As the figure shows, each of the 11 business cases results have benefit cost ratios great than 1. Section

5.0 of the 1898 & Co. Report includes the substation and circuit level results for each of the 11 categories.

Figure 13: Direct Investment Business Case Summary Results



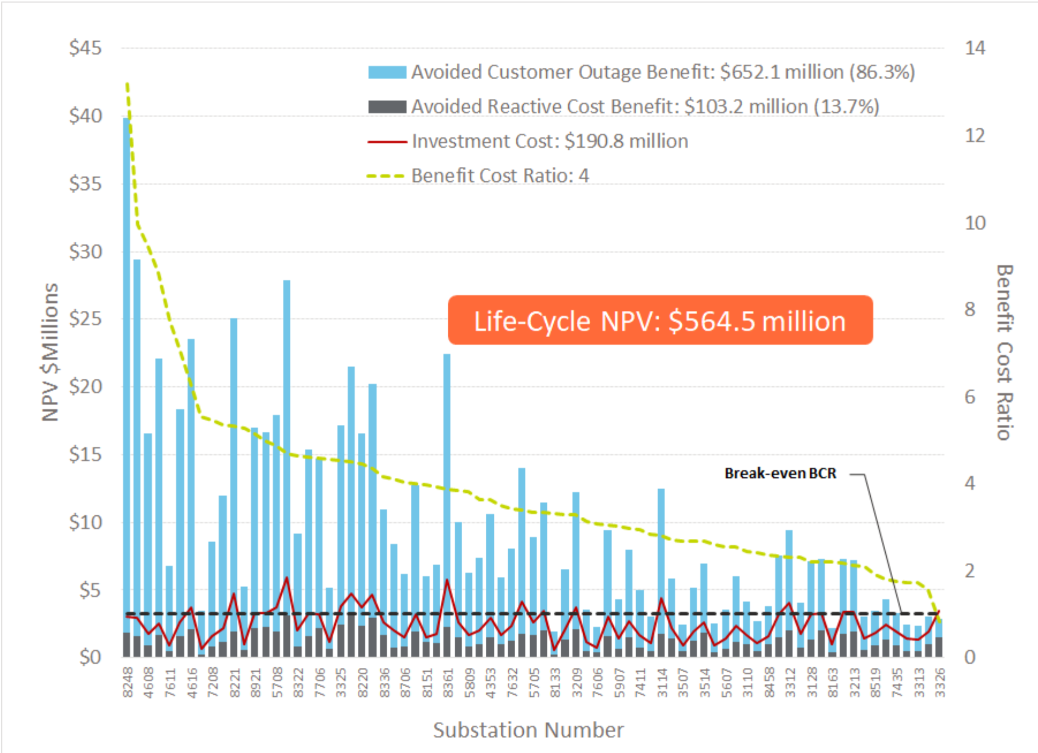
Q37. What are the results at the substation and circuit levels for the resiliency and automation investment activities?

A37. Even though the intent of the resiliency and automation investment can be itemized, the business case results cannot be fully segregated as they are integrated as well. First, there is integration of the direct investment activities since they have been designed to drive value together. Breaking them apart would erode value and make many of the investments irrelevant. Second, the approach to calculating benefits assumed an order to the investments that if changed would allocate benefits different between investments. Third, some integration exists from an execution perspective. The cost to execute portions of both investment types assume execution efficiencies. Executing these categories separately would cost more due to deployment and mobilization. Other linkages and synergies also exist between resiliency and automation investments. Because of this, another perspective for the business case is view the two programs together substation by substation.

Figure 14 (also shown as Figure 3 above) shows the substation-by-substation business case results for the combined resiliency and automation investment category. This figure includes all direct and indirect / supporting investment activities that can be assigned to a circuit or a substation. The investment of $190.8 million produces life cycle NPV of $564.5 million with a benefit cost ratio of 4.0. From a portfolio perspective, the investment in resiliency and automation has a positive business case. Most of the benefits come from avoided customer outage costs (86.3 percent) while the avoided reactive costs account for approximately 54.1 percent of the capital investment.

On an individual substation basis, the benefit cost ratios have a wide range going from a high of 13.2 to a low of 0.8. The figure shows that 76 substation (approximately 98.7 percent) have benefit cost ratio greater than 1. The other substation has a benefit cost ratio of 0.8 resulting in $641,000 of investment without any benefits. This is equivalent to 0.3% of the Grid Enhancement Plan investment of $246.2 million.

Figure 14: Circuits & Substations Business Case Results



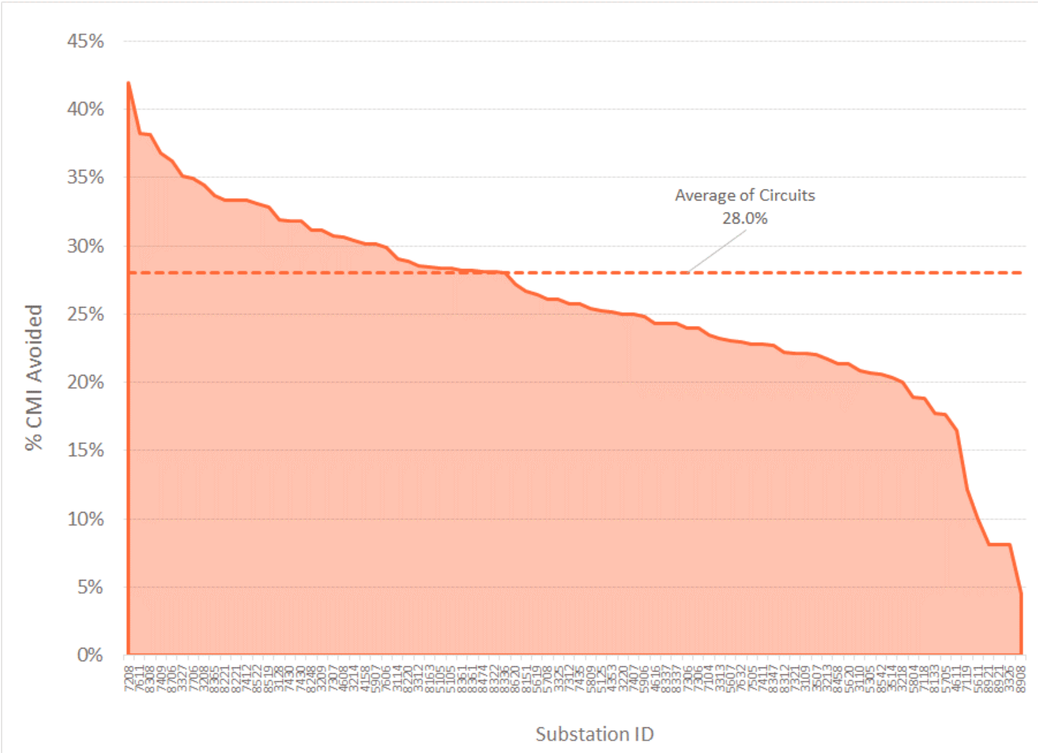
Q38. What is the expected improvement customer outages from the Outage Mitigation Risk & Resilience benefit approach?

A38. The expected improvement in customer minutes interrupted (CMI) for the Outage Mitigation Risk & Resilience benefit approach was estimated for each circuit and aggregated to the substation level. Assuming future outages are similar to historical outages, the investment in the 122 circuits is expected to decrease customer outages by approximately 28.0[3] percent. Figure 15 shows the expected improvement at the substation level with a high of 41.9 percent and low of 4.5 percent.

---

[3] Outage Mitigaiton Risk & Resilience benefit approach excludes the top 1 percent of outage days as a conservative assumption. Additionally, the estimate does not include outage reduction benefits from the Equipment Risk & Resilience approach.

Figure 15: Percentage Improvement in Performance at Substation Aggregation

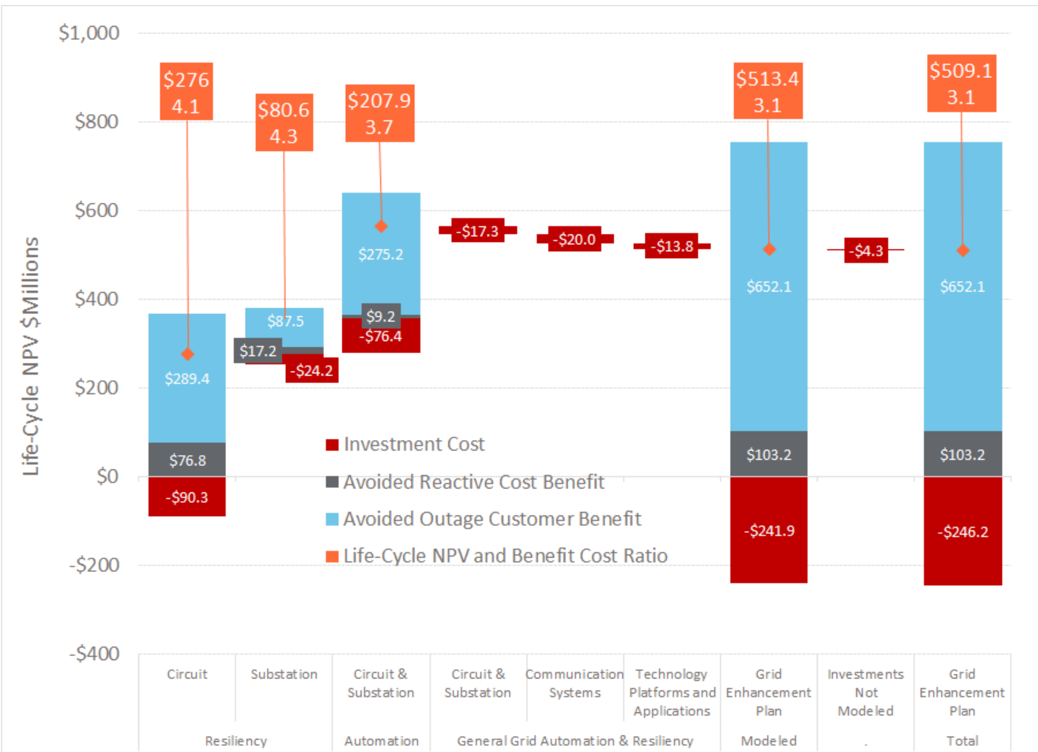


Q39. What are the results from the portfolio perspective?

A39. The final perspective in viewing the Grid Enhancement Plan business case is at the portfolio level. This includes adding the indirect / supporting investment that can't be directly mapped to substation or circuits and including investments there were not modeled. Much of the direct investment in the grid to specific substations or circuit is dependent on these enabling investments in communications system and technology platforms and applications to achieve their full benefits. Since these enabling investments cannot be directly mapped, the business case needs to be viewed from the entire portfolio perspective.

Figure 16 (also shown as Figure 2 above) includes this portfolio perspective showing the Grid Enhancement Plan business case. For all modeled investments, the results show life cycle NPV of $513.4 million with a benefit cost ratio of 3.1. The figure also shows the inclusion of the investment where benefits were not modeled. For the 2020 and 2021 Grid Enhancement Plan the investments drive $509.1 million in life cycle NPV with a benefit cost ratio of 3.1. This shows that from a portfolio perspective, the Grid Enhancement Plan has a highly positive business case.

Figure 16: Grid Enhancement Business Case Summary

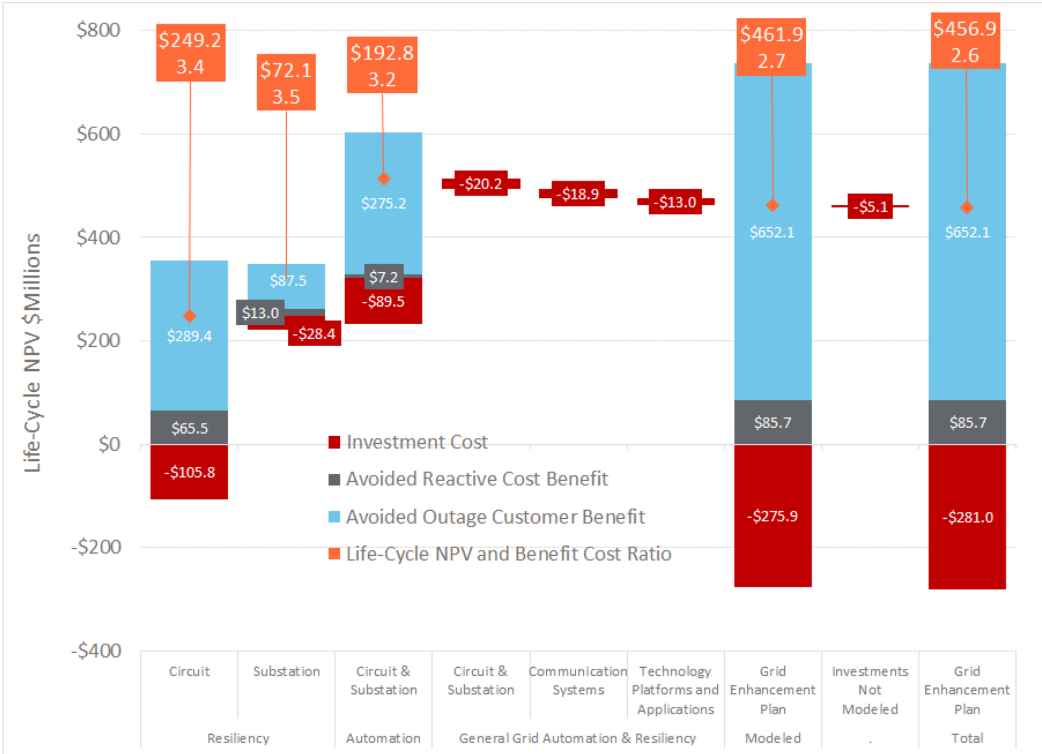


Q40. Did you also prepare the results from a revenue requirements perspective?

A40. Yes. OG&E provided 1898 & Co. with a Revenue Requirements Model to calculate the life-cycle benefits from a customer rate impact perspective. The revenue requirements model considers various depreciation rates, profit returns, taxes, and levelizing of capital investment. For each investment, 1898 & Co. input the investment cost, avoided capital cost annual profile, and the avoided O&M expense profile into the revenue requirements model to calculate the net impact to customers. This was performed at the individual investment activity level including the 749 direct investments.

Figure 17 shows the Grid Enhancement Plan's business case summary using this revenue requirements approach. The figure shows results in the same format as Figure 16. For net impact to revenue requirements exclude the 'blue' Avoided Customer Outage Benefit streams. The figure shows that the investment cost of the Grid Enhancement Plan will increase revenue requirements by approximately $281.0 million from a life cycle NPV perspective. The figure also shows that the investment will decrease future reactive and restoration costs by $85.7 million in life cycle NPV terms. The net impact to customer revenue requirements is an increase of $195.3 million. Monetizing the customer outages using the DOE ICE Calculator produces benefits of $652.1 million as shown in Figure 17.

Figure 17: Grid Enhancement Business Case Summary – Revenue Requirements



For reference, the 1898 & Co. report, Direct Exhibit JDD-1, includes the various business case perspective results shown throughout my testimony from the revenue requirements perspective.

5.0 CONCLUSION & RECOMMENDATIONS

Q41. What conclusions can be made from the business case results?

A41. The following includes the conclusions for the 2020 and 2021 Grid Enhancement Plan business case based on the approach and results outlined in this report.

- The Grid Enhancement Plan has a robust business case from several perspectives.
  - From the portfolio level, the investment produces a life cycle NPV of $509.1 and benefit cost ratio of 3.1 (cash flow approach).

- From an individual substation perspective. 76 of the 77 substations have benefit cost ratios great than 1, ranging from 13.2 to 1.6. The other substation has a benefit cost ratio of 0.8 resulting in $641,000of investment without any directly assigned benefits. This is equivalent to 0.3% of the investment of $246.2 million.
- All 11 of the Direct Investment business cases are economic at the system level. Very few of the individual substations or circuits are non-economic. Much of this is based on known data gaps in recording outages at substations.

- The Grid Enhancement Plan is an integrated and comprehensive set of investments where all the investments work together to produce synergistic benefits. The business case evaluation cannot be broken down to one number, rather it should be considered from several perspectives in drawing conclusions. Additionally, eliminating investment categories or types of investment within specific substation and circuits likely burdens the business case of other investments, mainly increasing their share of the system allocated costs.
- The Grid Enhancement Plan will improve the customer experience. Customer outages from the Outage Mitigation Risk and Resiliency benefit approach are estimated to decrease by approximately 28.0 percent. Additionally, the plan will significantly decease ‘blinking’, a complaint from customers.

- Even though some of the 749 individual business case results have benefit cost ratios less than one, many of those business case results should not be viewed at this level, rather the circuit or substation level is more appropriate. Additionally, the data deficiency OG&E is currently improving for substation outages causes the other remaining business case results to be less than 1.
- OG&E's range of grid investment activities mirrors the type of investment customer focused distribution utilities are making across the United States. Much of the plan investment is focused on improving the customer experience to meet customer expectations of reliability and resiliency.
- The benefits assessment is both customer centric and data-driven employing robust risk & resiliency analytics based on each investment's main benefit driver. This provides an unbiased "apples to apples" and transparent evaluation across all investments with the customer as the focus.

Q42. What is your recommendation for the Grid Enhancement Plan?

A42. I recommend the Oklahoma Corporation Commission approve in full the 2020 and 2021 Grid Enhancement Investment Plan for several reasons. Firstly, the plan and its individual investments are beneficial to customers. The business case assessment results described throughout my testimony show highly positive business case results at the portfolio level and at the individual business case investment level. Secondly, the plan is prudently incurred and reasonable. The Grid Enhancement Plan was developed with considerable thought and foresight with an integrated and comprehensive perspective of a portfolio of investments to solve a suite of system issues. The portfolio perspective to investment to achieve a range of objectives is necessary to decrease long-term life-cycle cost to customers. Re-investment risk increases when investments are organized to only solve one issues on the grid.

Q43. Does this conclude your prepared verified direct testimony?

A43. Yes.

Grid Enhancement Business Case for 2020 & 2021 Investments

OGE Energy Corp.

Oklahoma Gas & Electric

OG&E Grid Enhancement Benefits Report
Project No. 121429

Revision 0
12/30/2021

TABLE OF CONTENTS

Page No.

LIST OF TABLES

LIST OF FIGURES

Page No.

LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
AFS	Automated Feeder Switching
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
C&I	Commercial & Industrial
CI	Customers Interrupted
CMI	Customer Minutes Interrupted
DOE	Department of Energy
GIS	Geographic Information System
ICE	Interruption Cost Estimator
NERC	North American Electric Reliability Council
NPV	Net Present Value
OMS	Outage Management System
PV	Present Value
T&D	Transmission and Distribution

1.0 EXECUTIVE SUMMARY

Oklahoma Gas & Electric (OG&E) engaged the services of 1898 & Co, the advisory and technology consulting arm of Burns & McDonnell, to assist with the development of business cases for the Grid Enhancement Plan ("Plan") project investments. In collaboration, OG&E and 1898 & Co. utilized a risk and resiliency-based planning approach to provide a business case for each Grid Enhancement investment. The evaluation leverages 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. Investment costs for each of the investments were provided by OG&E. Key objectives for the Grid Enhancement business case evaluation are:

1. Calculation of benefits from a customer centric perspective, mainly avoided future costs and customer outages
2. Perform the business case evaluation using a bottoms-up approach to produce business cases at the project, circuit, substation, and portfolio levels.
3. Prepare the business case results using a revenue requirements methodology for avoided reactive cost benefits excluding customer outage benefits.

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[1]
  - Capital Expense
  - Operations & Maintenance (O&M) Expense
- Avoided Customer Outages
  - Customer Minutes Interrupted (CMI)
  - Monetization of avoided CMI using the DOE ICE Calculator[2]

As such, the business case evaluation is customer centric, quantifying the life-cycle impact to customer rates and outage performance.

[1] Synonyms with OG&E's "Avoided Cost of Service" benefit stream
[2] Synonyms with OG&E's "Avoided Economic Harm" benefit stream

This report includes the following:

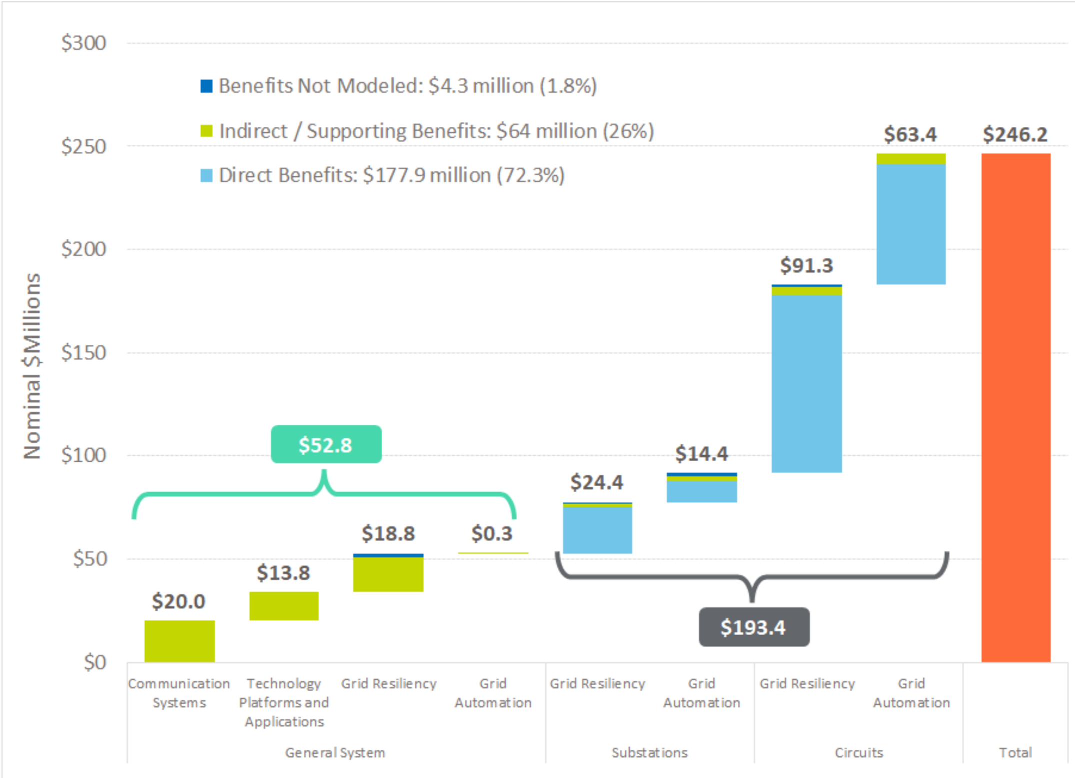
- Approach to estimating customer centric benefits for the wide range of investment types included in the Grid Enhancement Plan, Section 3.0.
- Results of 23 benefits assessment broken down at the substation or circuit level and by the type of customer benefits, Section 4.0.
- Approach to mapping the 48 different investment types that are part of the Grid Enhancement Plan for 2020 and 2021 to the 23 benefit assessments, Section 5.0.
- Direct Investment Business Case Results at the substation or circuit level for 11 investment categories, Section 5.0.
- Integrated Business Case Results at the circuit, substation, and portfolio level for the Grid Enhancement Plan, Section 6.0.
- Conclusions, Section 7.0.

1.1 2020 & 2021 Grid Enhancement Investment Summary

The Grid Enhancement Plan is an integrated and comprehensive portfolio of investments designed to produce a portfolio of benefits. Some investments provide direct benefits, other investments are needed to enable achievement of the direct benefits.

The Plan investment for the two years is approximately $246.2 million across 48 different investment types. Figure 1-1 provides a summary of the investments that are part of the Grid Enhancement Plan and approach to quantifying benefits. Approximately 72.3 percent of the investment has direct alignment of benefits to either a circuit or substation. Approximately 26.0 percent of the investment indirectly supports the enablement of the direct benefits. The indirect or supporting investment cannot be directly assigned to circuits or substations, rather it is system wide investment such as communications or technologies platforms that enable the direct investment in substations or circuits to be effective. The $4.3 million, approximately 1.8%, of the investment that is part of the “Benefits Not Modeled” category is made up 4 kV Conversions, River Crossing Reinforcement, adding new breakers and relays, and other various minor substation upgrades. Benefits were not modeled for several reasons including limited scope definitions, misalignment of benefit drivers to the core approaches, limited available data for the investments, and the small percentage of the plan.

Figure 1-1: 2020 & 2021 Grid Enhancement Investment Summary



1.2 Benefits Modeling Approach

The benefits assessment for the 2020 and 2021 Grid Enhancement Plan projects includes two main approaches:

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

These two approaches match the type of investment activities for the Grid Resiliency and Grid Automation categories of investment. The evaluation leverages 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. For each of the 23 benefits assessment one of these two approaches was utilized.

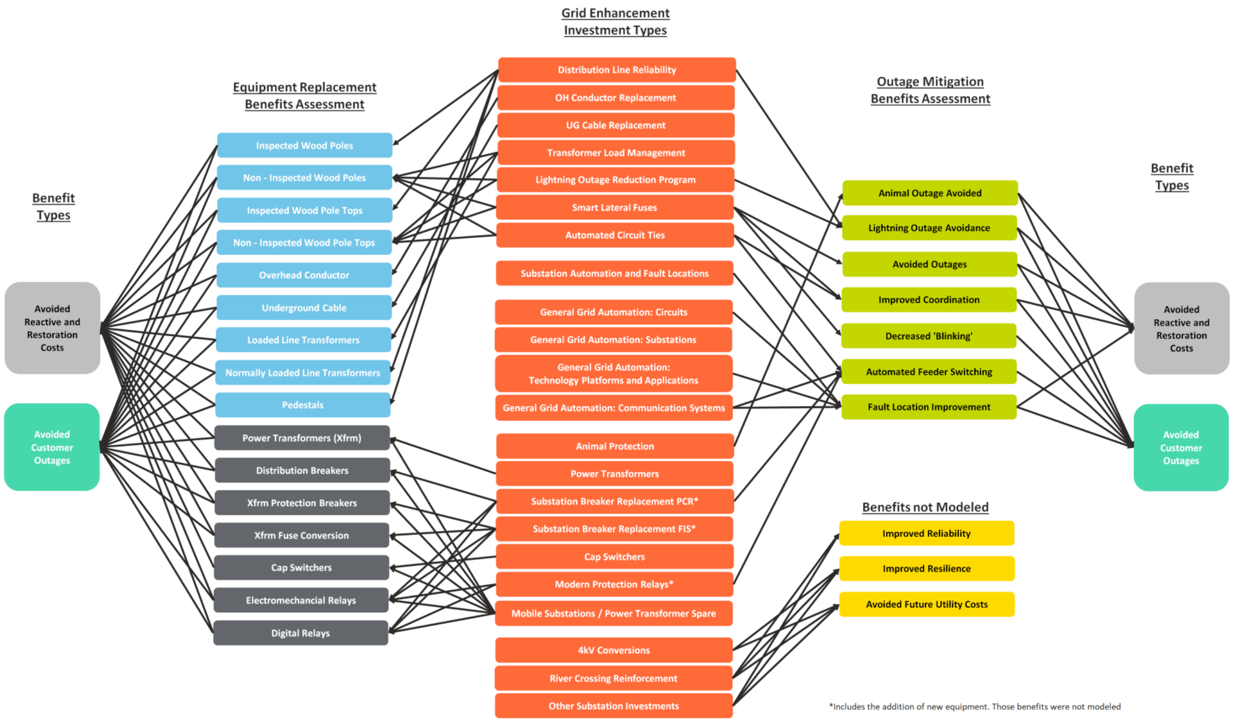
Grid Resiliency investment activities are primarily focused on aged or poor condition assets and known problematic equipment types. The Equipment Failure Risk & Resiliency approach estimates benefits for asset replacement investments. This approach utilizes a risk-based methodology to calculate the future reactive and restoration costs and customer outages. In general, the Equipment Failure Risk & Resiliency benefits approach is used for the Grid Resiliency investment types.

Grid Automation investment activities are primarily focused on decreasing customer outages. The Outage Mitigation Risk & Resiliency approach estimates benefits by re-calculating the historical outage records assuming the investments had been in place. Similarly, the Outage Mitigation Risk & Resiliency benefits approach is generally used for the Grid Automation investment activities.

1.3 Mapping Investments and Benefits

OG&E has identified 48 distinct investment types for the 2020 and 2021 investment years. The benefits assessment was performed for 23 different drivers. To perform the business case evaluation at a project level, 1898 & Co. mapped each of the 48 investment categories to the 23 benefit drivers. Figure 1-2 shows this mapping. The orange boxes in the middle of the diagram show the 48 investment categories (summarized down to 22 categories). The benefit drivers are shown on either side of the orange boxes. The Equipment Failure Risk & Resiliency benefits assessments for circuit and substation assets are shown in the blue and dark grey boxes. The Outage Mitigation Risk & Resiliency benefits assessments are shown in the green boxes. The yellow boxes include benefit streams for the investments that do not include quantified benefits in this assessment. On the outsides of the diagram show the mapping of benefits driver to the two main benefit types, avoided reactive costs and avoided customer outages.

Figure 1-2: Investment and Benefits Mapping Diagram



The figure shows the linkage of investment that drives benefit. As the figure shows there is a “spider’s web” of linkage between investment and benefits. The diagram graphically shows the integrated nature of the Grid Enhancement Plan with a portfolio of investments driving a suite of benefits. As such, the business case results need to be viewed and understood from a range of perspectives:

- Direct Investment where linkage between investment and benefits are tighter at the substation and circuit levels. 11 different results are shown in Section 5.0
- Integrated perspective at the substation and circuit level, Section 6.1
- Integrated from the entire portfolio perspective, Section 6.2.

1.4 Integrated Business Case Results Summary

Figure 1-3 shows the substation-by-substation business case results for the combined resiliency and automation investment category. The investment of $190.8 million produces life cycle NPV of $564.5million with a benefit cost ratio of 4.0. From a portfolio perspective, the investment in resiliency and automation has a positive business case. The majority of the benefits come from avoided future customer outage costs (86.3 percent) while the Avoided Reactive costs account for approximately 54.1 percent of the capital investment.

On an individual substation basis, the benefit cost ratios have a wide range going from a high of 13.2 to a low of 0.8. The figure shows that 76 substation (approximately 98.7 percent) have benefit cost ratio greater than 1. The other substation has a benefit cost ratio of 0.8 resulting in approximately $641,000 of investment without any benefits. This is equivalent to 0.3% of the Grid Enhancement Plan investment of $246.2 million.

Figure 1-3: Circuits & Substations Business Case Results

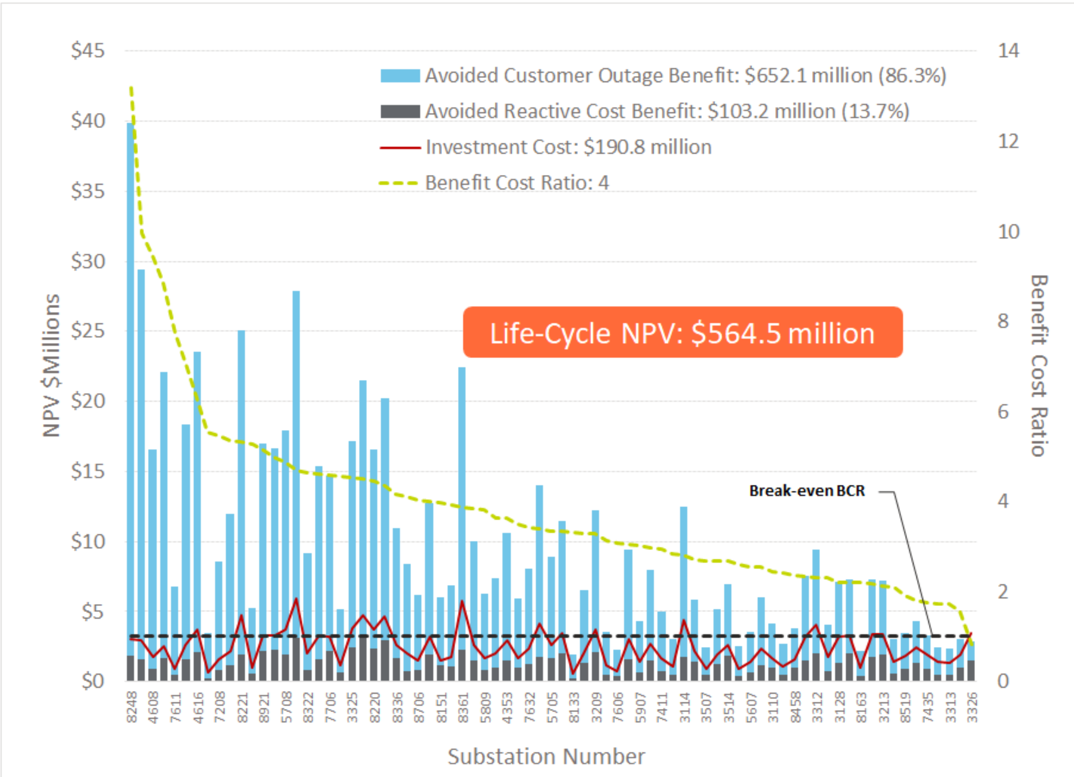


Figure 1-4 shows the percentage improvement in customer minutes interrupted for the Outage Risk Mitigation Benefit investments. The figure shows the results at the substation level. The figure shows a wide range of improvement from a high of approximately 41.9 percent to a low of 4.5 percent. The average improvement across all circuits is approximately 28.0 percent. These ranges in improvement are typical of investments in modern protection schema.

Figure 1-4: Percentage Improvement Performance at Substation Aggregation

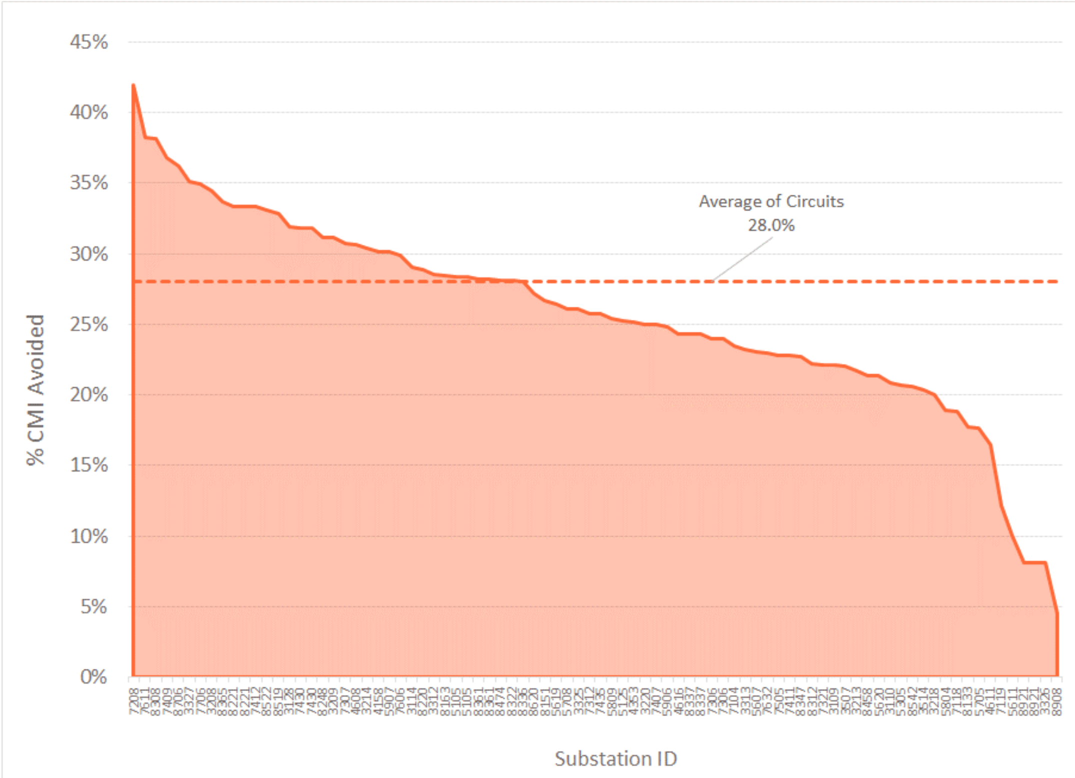
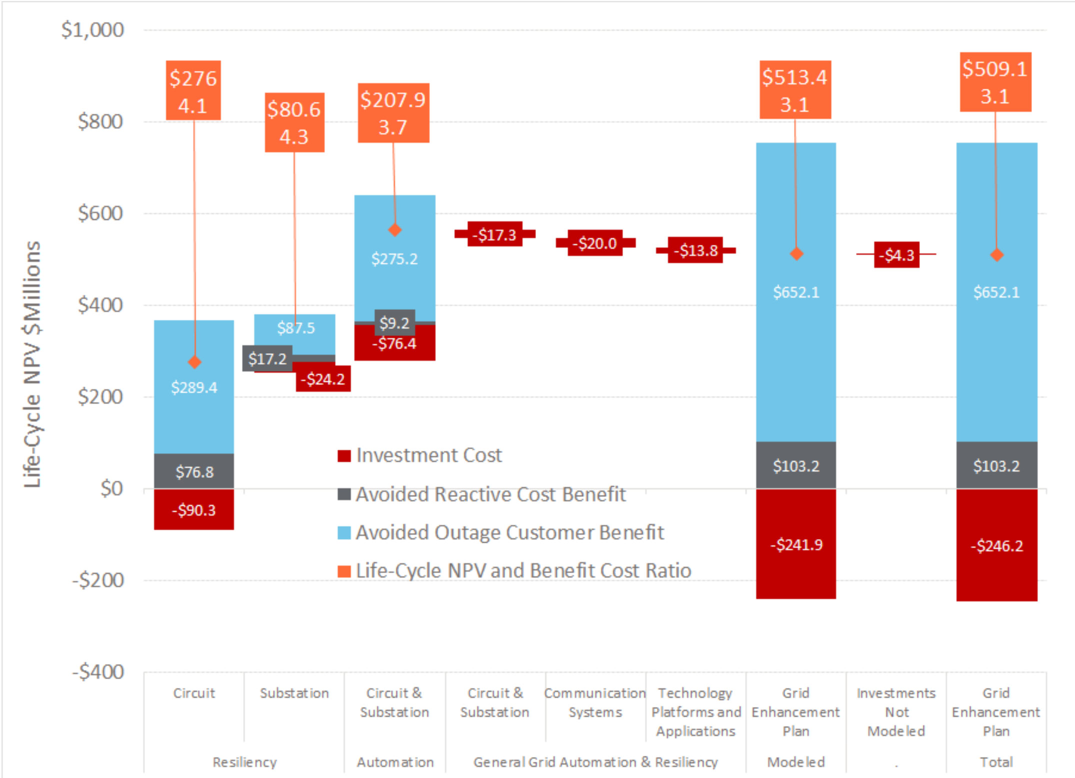


Figure 1-5 includes this portfolio perspective showing the Grid Enhancement Plan business case. For all modeled investments, the results show life cycle NPV of $513.4 million with a benefit cost ratio of 3.1. The figure also shows the inclusion of the investment where benefits were not modeled. For the 2020 and 2021 Grid Enhancement Plan the investments drive $509.1million in life cycle NPV with a benefit cost ratio of 3.1.

Figure 1-5: Grid Enhancement Business Case Summary

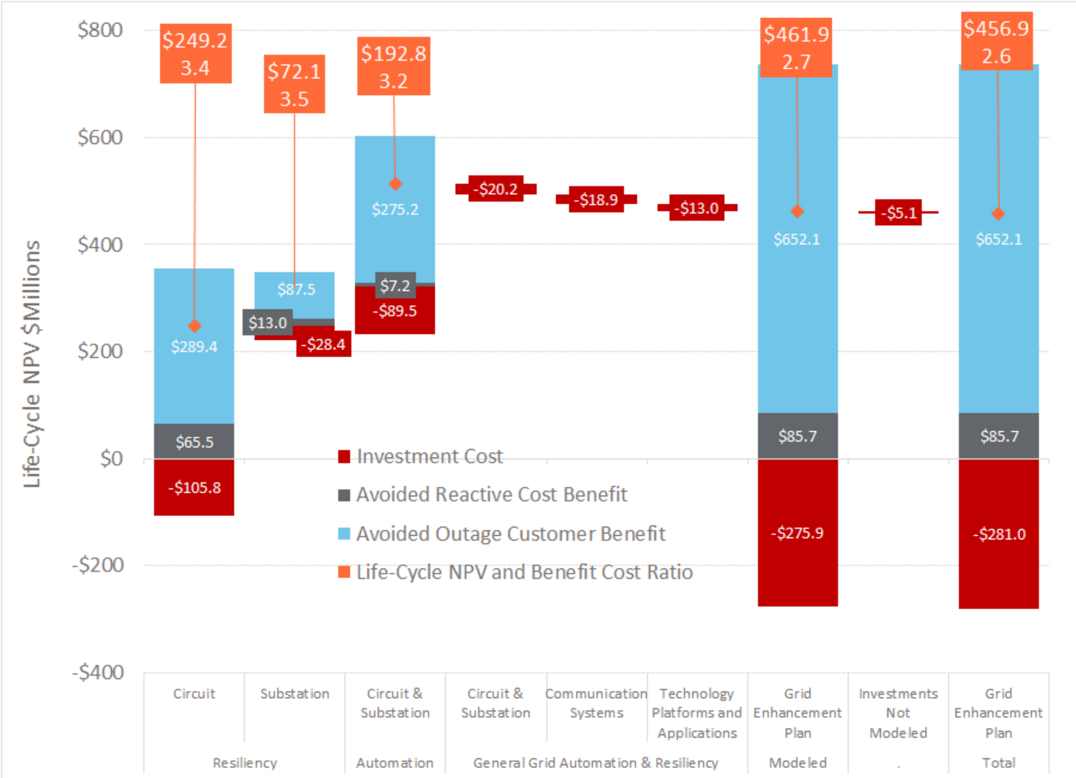


1.5 Grid Enhancement Revenue Requirements Business Case

OG&E provided a Revenue Requirements Model to evaluate the grid enhancement investments from an impact to rates perspective as part of the business case. The revenue requirements model considers various depreciation rates, profit returns, taxes, and levelizing of capital investment. For each investment, 1898 & Co. input the investment cost, avoided capital cost annual profile, and the avoided O&M expense profile into the revenue requirements model to calculate the net impact to customers.

Figure 1-6 shows the Grid Enhancement Plan's business case summary using this revenue requirements approach. The figure shows that the investment cost of the Grid Enhancement Plan will increase revenue requirements by approximately $281.0 million from a life cycle NPV perspective. The figure also shows that the investment will decrease future reactive and restoration costs by $85.7 million in life cycle NPV terms. The net impact to customer revenue requirements is an increase of $195.3 million. Monetizing the customer outages using the DOE ICE Calculator produces benefits of $652.1 million as shown in Figure 1-6.

Figure 1-6: Grid Enhancement Business Case Summary – Revenue Requirements



1.6 Conclusions

The following includes the conclusions for the 2020 and 2021 Grid Enhancement Plan business case based on the approach and results outlined in this report.

- The Grid Enhancement Plan has a robust business case from several perspectives.
  - From the portfolio level, the investment produces a life cycle NPV of $509.1 million and benefit cost ratio of 3.1 (cash flow approach).
  - From an individual substation perspective. 76 of the 77 substations have benefit cost ratios great than 1, ranging from 13.2 to 1.6. The other substation has a benefit cost ratio of 0.8 resulting in $641,000 of investment without any benefits. This is equivalent to 0.3% of the investment of $246.2 million.
  - All 11 of the Direct Investment business cases are economic at the system level. Very few of the individual substations or circuits are non-economic. Much of this is based on known data gaps in recording outages at substations.
- The Grid Enhancement Plan is an integrated and comprehensive set of investments where all the investments work together to produce synergistic benefits. The business case evaluation

cannot be broken down to one number, rather it should be considered from several perspectives in drawing conclusions. Additionally, eliminating investment categories or types of investment within specific substation and circuits likely burdens the business case of other investments, mainly increasing their share of the system allocated costs.

- The Grid Enhancement Plan will improve the customer experience. Customer outages from the Outage Mitigation Risk and Resiliency benefit approach are estimated to decrease by approximately 28.0 percent. Additionally, the plan will significantly decease ‘blinking’, a complaint from customers.
- Even though some of the 749 individual business case results have benefit cost ratios less than one, many of those business case results should not be viewed at this level, rather the circuit or substation level is more appropriate. Additionally, the data deficiency OG&E is currently improving for substation outages causes the other remaining business case results to be less than 1.
- The net impact to revenue requirements is $195.3 million
- OG&E’s range of grid investment activities mirrors the type of investment customer focused distribution utilities are making across the United States. Much of the plan investment is focused on improving the customer experience to meet customer expectations of reliability and resiliency.
- The benefits assessment is both customer centric and data-driven employing robust risk & resiliency analytics based on each investment’s main benefit driver. This provides an unbiased “apples to apples” and transparent evaluation across all investments with the customer as the focus.

2.0 INTRODUCTION

OG&E's objectives for the Grid Enhancement Plan are 1) improve reliability, 2) greater resiliency, 3) enhanced flexibility, 4) increased efficiency, 5) additional affordability, and 6) expand customer benefits. To achieve these objectives, OG&E identified an integrated and comprehensive set of investments across the distribution system. It includes a balanced investment portfolio with traditional infrastructure upgrades (resiliency) and deployment of proven grid modernization technologies (automation). Additionally, the plan includes supporting investment across the system in communications and technology applications to enable the full effectiveness for the resiliency and automation investment.

The plan includes investment over the 5-year period of 2020 through 2024 with approximately $246.2 million for years 2020 and 2021. This report outlines the approach to calculate benefits for the 2020 and 2021 investments and the results of the assessment. Specifically, this report covers the following topics:

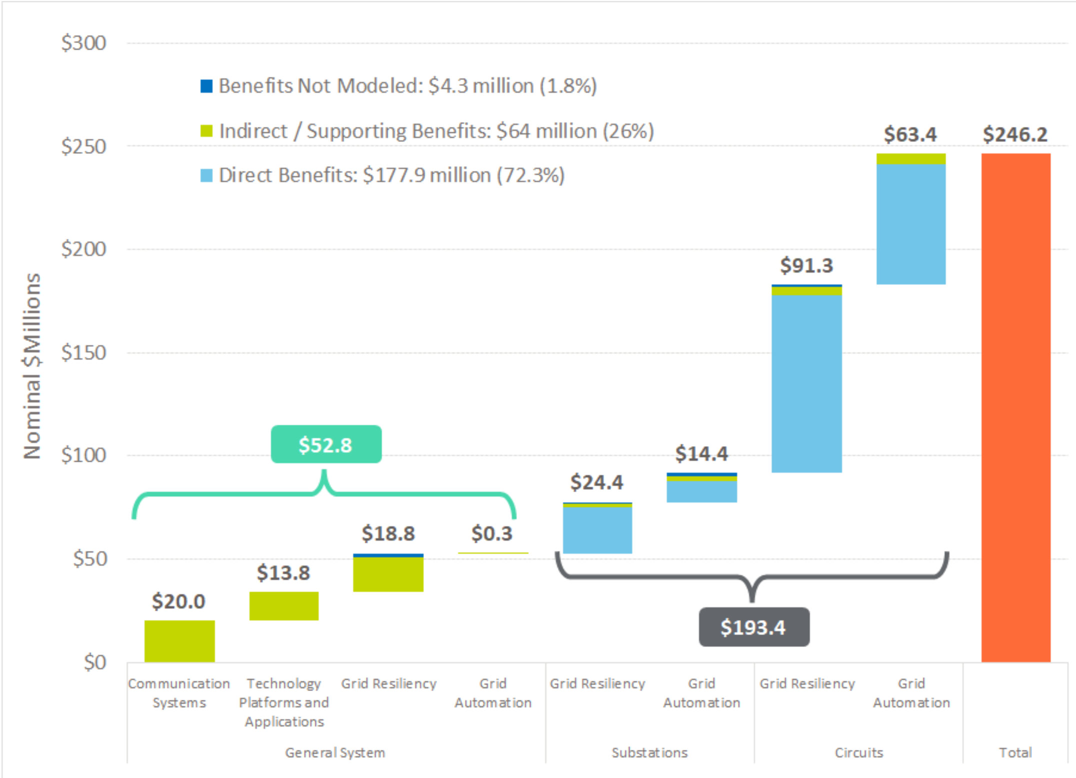
1. The approach to calculating benefits for asset replacements and investments to decrease outages
2. The results and drivers of each benefit assessment
3. The integrated and comprehensive nature of the investments and benefits of the Grid Enhancement Plan
4. The portfolio business case results

The following subsections provide a foundation for the rest of the report. The subsections include the Grid Enhancement Plan (Section 2.1 and 2.2), the benefits assessment (Section 2.3), and the mapping of investments to benefits (Section 2.4).

2.1 2020 & 2021 Grid Enhancement Investments

OG&E provided 1898 & Co. with the 2020 and 2021 Grid Enhancement Plan scope and estimated investment. This section outlines the investment level. The following section (Section 2.1) includes the corresponding asset base for the investment tied to circuits and substations. The Plan investment for the two years is approximately $246.2 million across 48 different investment types. Table 2-1 provides the investment level for each of the 48 categories (52 listed, 4 are various versions of Project Administration) ranked by level of investment. Figure 2-1 is a graphical summary of Table 2-1. The table also includes a "Business Case Investment Group" column that collapses the 48 categories into 23 for later mapping to benefits.

Figure 2-1: 2020 & 2021 Grid Enhancement Investment Summary



As discussed above, the Grid Enhancement Plan is an integrated and comprehensive portfolio of investments designed to produce a portfolio of benefits. Some investments provide direct benefits such as poor condition wood pole replacement or automated switching tie lines (reclosers on the backbone). Other investments are needed to enable achievement of the direct benefits such as communications and technology investments. These investments allow the Advanced Distribution Management System to communicate to reclosing devices to perform automated switching schemes. Table 2-1 and Figure 2-1 designate the difference between these two types of investment benefit drivers. Approximately 72.3 percent of the investment has direct alignment of benefits to either a circuit or substation. Approximately 26.0 percent of the investment indirectly supports the enablement of the direct benefits. The indirect or supporting investment cannot be directly assigned to circuits or substations, rather it is system wide investment such as communications or technologies platforms that enable the direct investment in substations or circuits to be effective.

The benefits calculated in this report are driven by 98.2 percent of the 2020 and 2021 Grid Enhancement Plan, $241.9 million ($246.2 million * 98.2%). For the remaining 1.8 percent of investment, 1898 & Co. did not calculate benefits. The $4.3 million of the investment that is part of the

“Benefits Not Modeled” category is made up 4 kV Conversions, River Crossing Reinforcement, adding new breakers and relays, and other various minor substation upgrades. Benefits were not modeled for several reasons. Firstly, the scope definition of some of the investment types did not allow for an accurate assessment of benefits. Secondly, the approach to calculate benefits for these investments is challenging and not aligned with the two core approaches. Thirdly, the supporting data to evaluate benefits was not available. Fourth, these investments account for a small portion of the overall investment level, 1.8 percent, and the cost to estimate benefits did not seem prudent given the high level of benefits for the 98.2 percent of investments. 1898 & Co. expects these investments to have a positive business case.

Table 2-1: 2020 & 2021 Grid Enhancement Plan Investment Types

No.	Category	System	Specific Investment	Business Case Investment Grouping	Benefits Calculation	Plan Investment
1	Grid Resiliency	Distribution Line	Distribution Line Reliability	Distribution Line Reliability	Direct Benefits	$80,915,336
2	Grid Automation	Distribution Line	Smart Lateral Fuses	Smart Lateral Fuses	Direct Benefits	$38,236,315
3	Grid Automation	Distribution Line	Automated Circuit Tie Lines	Automated Circuit Ties	Direct Benefits	$20,502,623
4	Communication Systems	Communication Systems	Field Area Network Backbone	General Grid Automation: Communication Systems	Indirect / Supporting Benefits	$19,639,669
5	Grid Resiliency	Distribution Substation	Mobile Substations	Mobile Substations / Power Transformer Spare	Indirect / Supporting Benefits	$16,600,000
6	Grid Resiliency	Distribution Substation	Substation Breaker Replacement PCR	Substation Breaker Replacement PCR	Direct Benefits	$6,950,000
7	Technology Platforms and Applications	Technology Platforms and Applications	Digital Field Services Management	General Grid Automation: Technology Platforms and Applications	Indirect / Supporting Benefits	$6,177,096
8	Grid Resiliency	Distribution Substation	Transformer Replacement	Power Transformers	Direct Benefits	$4,675,000
9	Grid Resiliency	Distribution Line	Project Administration	Project Administration	Indirect / Supporting Benefits	$3,896,660
10	Grid Resiliency	Distribution Substation	Transguard Fence	Animal Protection	Direct Benefits	$3,608,342
11	Grid Automation	Distribution Substation	Relay Replacement	Modern Protection Relays	Direct Benefits	$3,600,000
12	Grid Resiliency	Distribution Substation	Substation Breaker Replacement FIS	Substation Breaker Replacement FIS	Direct Benefits	$3,565,000
13	Grid Resiliency	Distribution Line	Transformer Load Management	Transformer Load Management	Direct Benefits	$3,188,531
14	Grid Resiliency	Distribution Substation	Cover Up	Animal Protection	Direct Benefits	$2,965,518

No.	Category	System	Specific Investment	Business Case Investment Grouping	Benefits Calculation	Plan Investment
15	Grid Automation	Distribution Substation	Relay Replacement XFMR Terminal	Modern Protection Relays	Direct Benefits	$2,615,600
16	Technology Platforms and Applications	Technology Platforms and Applications	ADMS Upgrade	General Grid Automation: Technology Platforms and Applications	Indirect / Supporting Benefits	$2,586,659
17	Grid Automation	Distribution Substation	New SCADA	Fault Location Isolation	Direct Benefits	$2,478,910
18	Grid Automation	Distribution Line	Project Administration	Project Administration	Indirect / Supporting Benefits	$2,346,851
19	Technology Platforms and Applications	Technology Platforms and Applications	Advanced EMS Apps	General Grid Automation: Technology Platforms and Applications	Indirect / Supporting Benefits	$2,069,516
20	Technology Platforms and Applications	Technology Platforms and Applications	Advanced EMS Apps	General Grid Automation: Technology Platforms and Applications	Indirect / Supporting Benefits	$1,700,000
21	Grid Resiliency	Distribution Substation	Project Administration	Project Administration	Indirect / Supporting Benefits	$1,352,763
22	Grid Automation	Distribution Line	Add Communications to Regulators	General Grid Automation: Circuits	Indirect / Supporting Benefits	$1,261,260
23	Grid Resiliency	Distribution Line	Lightning Outage Reduction Program	Lightning Outage Reduction Program	Direct Benefits	$1,060,007
24	Grid Automation	Distribution Line	Add Communications to Capacitors	General Grid Automation: Circuits	Indirect / Supporting Benefits	$1,013,380
25	Grid Resiliency	Distribution Substation	Oil Filled Stepdown Replacement	Other Substation Investments	Benefits not Modeled	$1,000,000
26	Grid Resiliency	Distribution Line	River Crossing Reinforcement	River Crossing Reinforcement	Benefits not Modeled	$1,000,000
27	Grid Automation	Distribution Substation	Fault Location SCADA Inputs	Fault Location Isolation	Direct Benefits	$904,000

No.	Category	System	Specific Investment	Business Case Investment Grouping	Benefits Calculation	Plan Investment
28	Grid Automation	Distribution Substation	RTU Replacement	Fault Location Isolation	Direct Benefits	$850,000
29	Grid Automation	Distribution Substation	Network	General Grid Automation: Substations	Indirect / Supporting Benefits	$785,000
30	Grid Resiliency	Distribution Line - UG	UG Cable Replacement	UG Cable Replacement	Direct Benefits	$756,863
31	Grid Resiliency	Distribution Line	4 KV Conversions	4 KV Conversions	Benefits not Modeled	$753,658
32	Grid Resiliency	Distribution Substation	Substation Breaker Replacement Capacitor Switcher	Substation Breaker Replacement Capacitor Switcher	Direct Benefits	$600,000
33	Technology Platforms and Applications	Technology Platforms and Applications	DER Interconnection Management	General Grid Automation: Technology Platforms and Applications	Indirect / Supporting Benefits	$600,000
34	Grid Resiliency	Distribution Substation	Substation Breaker Replacement FIS	Substation Breaker New FIS	Indirect / Supporting Benefits	$600,000
35	Grid Automation	Distribution Substation	Project Administration	Project Administration	Indirect / Supporting Benefits	$543,514
36	Technology Platforms and Applications	Technology Platforms and Applications	GIS substation model	General Grid Automation: Technology Platforms and Applications	Indirect / Supporting Benefits	$514,758
37	Grid Automation	Distribution Substation	SCADA Upgrade	General Grid Automation: Substations	Indirect / Supporting Benefits	$510,000
38	Grid Automation	Distribution Substation	Substation Enclosures Control House	Other Substation Investments	Benefits not Modeled	$465,275
39	Grid Automation	Distribution Substation	Small SCADA	General Grid Automation: Substations	Indirect / Supporting Benefits	$450,000
40	Grid Resiliency	Distribution Line	OH Conductor Replacement	OH Conductor Replacement	Direct Benefits	$435,067

No.	Category	System	Specific Investment	Business Case Investment Grouping	Benefits Calculation	Plan Investment
41	Grid Automation	Distribution Substation	Substation Enclosures PCC	Other Substation Investments	Benefits not Modeled	$377,250
42	Communication Systems	Communication Systems	Field Area Network Management	General Grid Automation: Communication Systems	Indirect / Supporting Benefits	$360,331
43	Grid Automation	Distribution Substation	Substation Enclosures Battery Cabinet	Other Substation Investments	Benefits not Modeled	$301,800
44	Grid Resiliency	Distribution Substation	Substation Breaker Replacement PCR	Substation Breaker New PCR	Indirect / Supporting Benefits	$275,000
45	Grid Automation	Distribution Line	FCI Pilot	General Grid Automation: Circuits	Indirect / Supporting Benefits	$250,000
46	Grid Automation	Distribution Substation	Relay Replacement MOS Control	Other Substation Investments	Benefits not Modeled	$226,350
47	Grid Automation	Distribution Substation	Relay Replacement	Modern Protection Relays (New)	Indirect / Supporting Benefits	$200,000
48	Grid Resiliency	Distribution Substation	Capacitor Replacement	Other Substation Investments	Benefits not Modeled	$200,000
49	Technology Platforms and Applications	Technology Platforms and Applications	Landing Page for SOM	General Grid Automation: Technology Platforms and Applications	Indirect / Supporting Benefits	$102,952
50	Grid Automation	Distribution Substation	GPS Clock	General Grid Automation: Substations	Indirect / Supporting Benefits	$80,000
51	Technology Platforms and Applications	Technology Platforms and Applications	Planning Tools	General Grid Automation: Technology Platforms and Applications	Indirect / Supporting Benefits	$67,250
52	Grid Automation	Distribution Substation	Replace S4/AD Meters with Smart Meters	General Grid Automation: Substations	Indirect / Supporting Benefits	$12,600
Total 2020 & 2021 Grid Enhancement Investment						**$246,226,703**

2.2 2020 & 2021 Grid Enhancement Plan Asset Base

The 2020 and 2021 Plan includes investment in 122 circuits and 77 substations. Table 2-2 provides a summary of the asset replacements for distribution circuits for the Grid Resiliency and Grid Automation categories. Poles have been divided up by those replaced due to inspection and those replaced to support other Grid Enhancement activities (device addition or replacement). Similarly, distribution line transformers have been separated into highly / overloaded and normally loaded.

Table 2-2: Distribution Asset Replacement Summary

Asset Type	Units	Grid Resiliency	Grid Automation	Total
Inspected Poles and Pole Tops	Count	8,938	0	8,938
Non-Inspected Poles and Pole Tops	Count	550	566	1,116
Lightning Arresters	Count	2,871	0	2,871
Overhead Conductor	Miles	4.69	0	4.69
Underground Cable	Miles	9.25	0	9.25
Overloaded Line Transformers	Count	770	0	770
Normally Loaded Line Transformers	Count	1,628	0	1,628
Pedestals	Count	323	0	323

Table 2-3 includes a summary of the substation assets that are part of the plan. A total of 645 Substation assets are modeled. 1898 & Co. and OG&E directly linked each of assets from the plan to the Cascade data register. The power transformers modeled consist of a majority of non-LTC transformers with only a single LTC transformer. A variety of air magnetic, gas, oil, and vacuum circuit breakers are included in the plan. Relays are broken down into digital and electromechanical with most common replaced being electromechanical. Replacement of infrastructure may involve replacing several components for efficiency purposes. This is the case with the breakers and relays as it is cheaper to replace the combination of the two rather than individually. For this reason, the table shows counts of assets replaced based on replacement of the breaker or relays.

Table 2-3: Substation Asset Replacement Summary

Asset Type	Grid Resiliency	Grid Automation	Total
Power Transformers	8		8
Distribution Protection Breakers	59	9	68
Cap Switcher Breaker	4		4
Power Xfrm Breakers	14		14
Fuse Conversion to Breaker	12		12
Relays	225	314	539
Total	322	323	645

As discussed below in Section 3.1.2, 1898 & Co. established connectivity between the substation assets, mainly the breakers and relays. This connectivity developed the count of assets for replacement accounting for these combined efficiencies.

The plan also includes significant investment in grid automation protection devices, mainly IntelliRupters® for the circuit mainline feeder and TripSavers® for the major laterals. Table 2-4 provides a summary of the device counts for Grid Automation. It should be noted that these counts are based on a detailed planning effort to design the automation schemes.

Table 2-4: Grid Automation Device Summary

Scope Year	IntelliRupters®	TripSavers®	Fuses
2020	56	1,054	642
2021	174	3,369	1,810
Total	230	4,423	2,452

2.3 Benefits Assessment Overview

The benefits assessment utilized a risk and resiliency-based planning approach to estimates the customer benefits for each Grid Enhancement investment. The evaluation leverages 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 benefits assessment employs a data-driven, 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[3]
  - Capital Expense
  - Operations & Maintenance (O&M) Expense
- Avoided Customer Outages
  - Customer Minutes Interrupted (CMI)
  - Monetized of avoided CMI (reviewed in more detail below)[4]

This approach provides a business case evaluation that is customer centric. To evaluate the benefits of the 2020 and 2021 Grid Enhancement Investment, 1898 & Co. utilized two main approaches:

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

The Equipment Failure Risk & Resiliency approach estimates benefits for asset replacement investments. This approach utilizes a risk-based methodology to calculate the future reactive and restoration costs and customer outages for both the status quo and asset replacement scenarios. The evaluation is performed for all the assets replacements that are part of the Plan. The approach was executed for the asset types shown in Table 2-5. Section 3.3 describes the approach to evaluate the benefit for asset replacements. Sections 4.1 for circuit assets and 4.2 for substation assets provide the benefit results for each of the asset types in Table 2-5.

[3] Synonyms with OG&E's "Avoided Cost of Service" benefit stream
[4] Synonyms with OG&E's "Avoided Economic Harm" benefit stream

Table 2-5: Equipment Evaluated for Failure Risk & Resiliency Benefit

Circuit Assets	Substation Assets
Inspected Wood Poles	Power Transformers (Xfrm)
Inspected Wood Pole Tops	Distribution Line Breakers
Non-inspected Wood Poles	Xfrm Protection Breakers
Non-inspected Wood Pole Tops	Xfrm Fuse Conversions
Overhead Conductor	Cap Switchers
Underground Cable	Electromechancial Relays
Highly Loaded / Overloaded Line Transformers	Digital Relays
Normally Loaded Line Transformers	
Pedestals	

The Outage Mitigation Risk & Resiliency approach estimates benefits for investment activities that primarily decrease customer outages. This approach utilizes OG&E's historical outage data to estimate the impact of each outage assuming the Grid Investments had been in place. The approach utilizes 10 years of historical outage records. Based on the specific investment types within the Plan the approach estimates avoided Customer Minutes Interrupted and truck rolls for the following categories:

- Substation Animal Outages Avoided
- Lightning Outages Avoided
- Avoided Outages
- Improved Coordination
- Decreased "Blinking"
- Backbone Automation
- Fault Location Improvement

Section 3.4 provides additional detail on the approach and assumptions to calculating benefits using this approach. Section 4.3 provides the benefit results for each of the categories listed above. In all, the benefit evaluation includes 23 benefits assessments for the portfolio of investments.

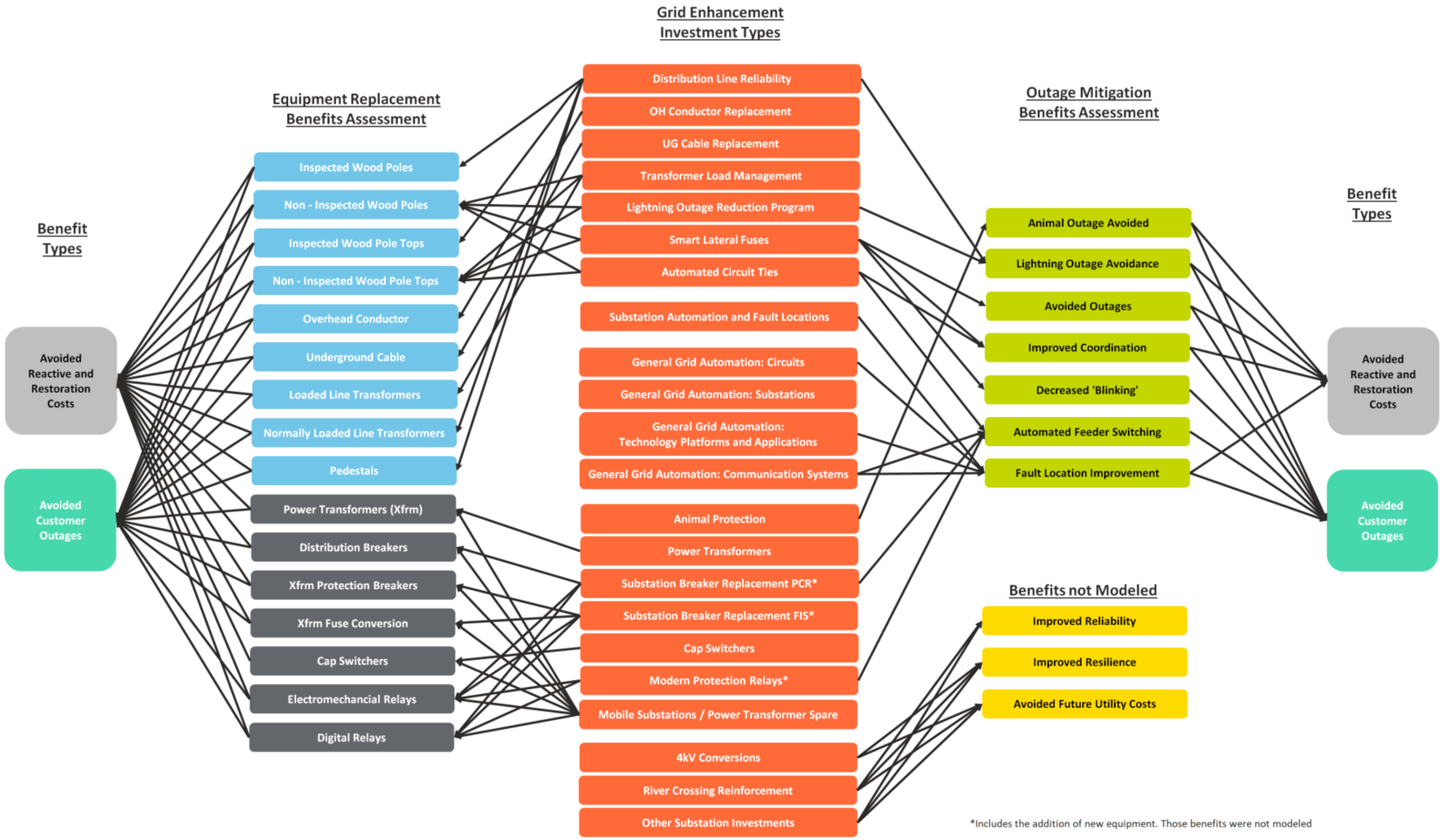
2.4 Mapping Investments and Benefits

The Grid Enhancement Plan includes an integrated and comprehensive set of investments across the distribution system. OG&E has identified 48 distinct investment types for the 2020 and 2021 investment years. While the investment types are discrete, many of them are required to be done together to provide benefits. For instance, without communication infrastructure, the Advanced Distribution Management System cannot initiate the automated switching schemes for the automated circuit ties project to decrease customer outages.

The benefits assessment was performed for 23 different drivers (see Section 2.2 above). To perform the business case evaluation at an investment level, 1898 & Co. mapped each of the 48 investment categories to the 23 benefit drivers at the investment level for each substation and circuit. Figure 2-2 shows this mapping. The orange boxes in the middle of the diagram show the 48 investment categories (summarized down to 22 categories). The benefit drivers are shown on either side of the orange boxes. The Equipment Failure Risk & Resiliency benefits assessments for circuit and substation assets are shown in the blue and dark grey boxes. The Outage Mitigation Risk & Resiliency benefits assessments are shown in the green boxes. The yellow boxes include benefit streams for the investments that do not include quantified benefits in this assessment. On the outsides of the diagram show the mapping of benefits driver to the two main benefit types, avoided reactive costs and avoided customer outages.

The figure shows the linkage of investment that drives benefit. As the figure shows there is a “spider’s web” of linkage between investment and benefits. The diagram graphically shows the integrated nature of the Grid Enhancement Plan with a portfolio of investments driving a suite of benefits. While the figure shows a few 1 to 1 relationships between investments and benefits, most of the time they involve many to many relationships. This integrated and comprehensive investment plan is typical for electric distribution systems, the grid.

Figure 2-2: Investment and Benefits Mapping Diagram



3.0 BENEFITS MODELING APPROACH

The benefits assessment for the 2020 and 2021 Grid Enhancement Plan projects includes two main approaches:

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

These two approaches match the type of investment activities for the Grid Resiliency and Grid Automation categories of investment. Grid Resiliency investment activities primarily focus on aged or poor condition assets and known problematic equipment types The Equipment Failure Risk & Resiliency approach estimates benefits for asset replacement investments. This approach utilizes a risk-based methodology to calculate the future reactive and restoration costs and customer outages. In general, the Equipment Failure Risk & Resiliency benefits approach is used for the Grid Resiliency investment types.

Grid Automation investment activities are primarily focused on decreasing customer outages. The Outage Mitigation Risk & Resiliency approach estimates benefits by re-calculating the historical outage records assuming the investments had been in place. Similarly, the Outage Mitigation Risk & Resiliency benefits approach is generally used for the Grid Automation investment activities.

The following sections outline the data sources used to support both business case approaches, general assumptions, each business case approach, and the revenue requirements modeling.

3.1 Data Sources

As discussed above, the benefits assessment approach is data driven. This section outlines the core data sets utilized within the AssetLens Analytics Engine. OG&E’s data systems include a connectivity model that allows for the linkage of many foundational data sets - the Geographical Information System (GIS), Cascade, 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.

3.1.1 GIS

The Geographic Information System (GIS) serves as the first foundational data set for the AssetLens Analytic Engine. The GIS provides the list of assets in OG&E's distribution circuit system, their attributes (type, manufacturer, age), and how they are connected to each other, both physically and electrically.

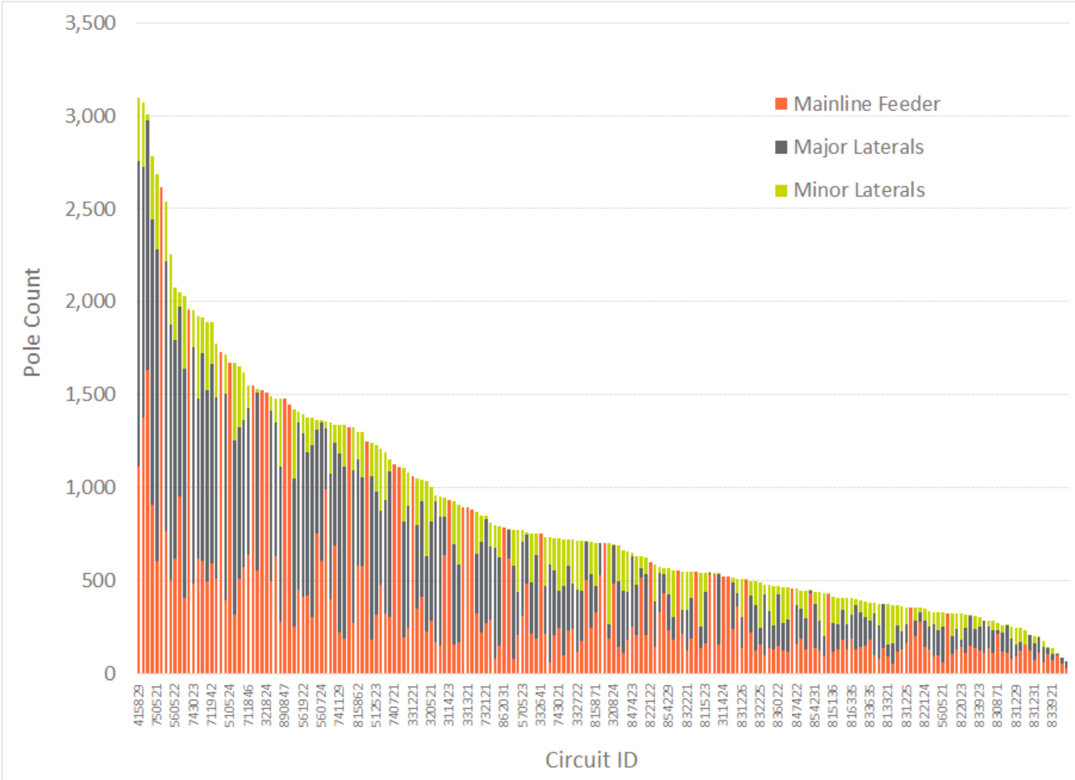
Significant for the business case evaluation is the relationship between assets and customers. The connectivity model provides the relationship between assets and their upstream protection device. If an asset fails, the upstream protection device operates, locking out downstream customers. With this connectivity, the AssetLens Analytics Engine links asset failures to customer impacts. Section 3.1.4 outlines the results of this connectivity by customer type and device type.

1898 & Co. organized distribution circuits by protection zone type for the benefits evaluation:

1. Backbone or Mainline Feeder – the 3-phase portion of the circuit starting at the substation breaker which laterals 'tap-off' from. It carries the majority of the load. Any outages on the backbone typically lock out a breaker or reclosing device. Commercial and Industrial customers can be directly fed off the mainline feeder, however, most are fed from laterals. Residential customers are typically served from a lateral.
2. Major Laterals – the initial tap off the mainline feeder, to include 1, 2, and 3 phases. For this report, major laterals have more than 50 customers downstream, with several minor laterals tapping off them. They are or will be protected by a fuse or TripSaver®. Commercial and Industrial customers are typically served from major laterals. Residential customers in apartment complexes are also served from major laterals.
3. Minor Laterals – for this report, serve less than 50 customers and are protected by a fuse. They can either tap off the mainline feeder or a major lateral. Typically, minor laterals serve single-family residential neighborhoods or smaller apartment complexes.

Figure 3-1 shows the pole count by circuit protection category for the 2020 and 2021 Grid Enhancement Plan circuits. This information is used to calculate the consequence of failure for assets within each protection category (see Section 3.3 for general approach and 3.3.3.1 for specific approach). It should be noted that Figure 3-1 includes the pole count for the entire circuit, the poles that are part of the Grid Enhancement Plan are a subset of these poles.

Figure 3-1: Pole Count by Circuit



3.1.2 Cascade

Cascade is the companion system to the GIS for the substation assets. OG&E provided detailed asset register tables for the following:

- Power Transformers
- Breakers
- Fuses
- Relays

The tables include equipment type, high-level position within the substation, age, and other attributes. 1898 & Co. leveraged this information in Cascade to establish additional connectivity within the asset base. Two specific connectivity relationships were developed. The first is establishing the link between the GIS protection devices and Cascade breakers so that accurate customer outage impacts could be established. This connectivity allows the AssetLens Analytics Engine to connect customers from the distribution line transformer outside customer locations to the power transformer inside the substation. The second 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. Section 3.1.4 includes the results of this connectivity modeling for each substation.

3.1.3 Outage Management System (OMS)

The third foundational data set is the Outage Management System (OMS). The OMS includes detailed outage information by cause code for each protection device over the last 10 years. The data include causes, duration, Customers Interrupted (CI), Customer Minutes Interrupted (CMI), and location for approximately 600,000 outage events. Section 3.4.1 discusses the OMS in greater detail. 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.

3.1.4 Customer Data

OG&E 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. This customer information is used for both benefits approaches. Since the Grid Enhancement Plan includes significant changes to each circuit's protection schemes, the linking of customers to protection devices was done for both the before and after state. Figure 3-2, Figure 3-3, and Figure 3-4 show the average number of customers by circuit for mainline feeders, major laterals, and minor laterals, respectively. The numbers presented in these figures are based on the redesigned protection schemes.

Figure 3-2: Average Customer Impacted from Mainline Feeders Outages

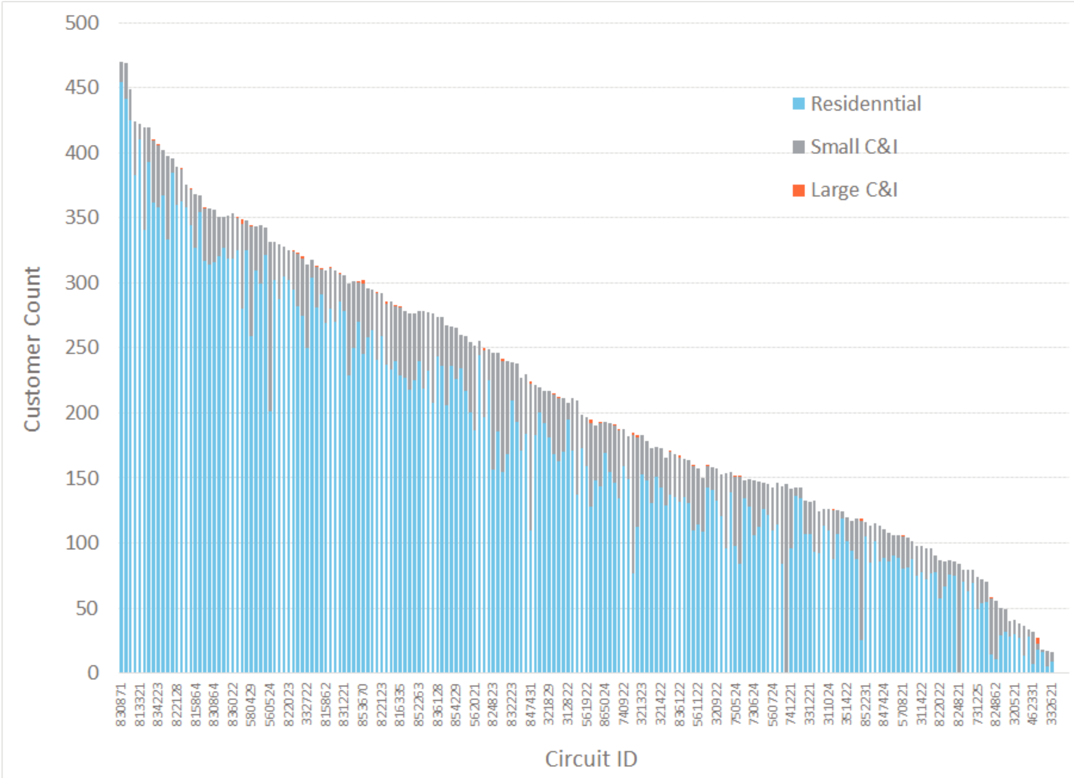


Figure 3-3: Average Customer Impacted from Major Lateral Outages

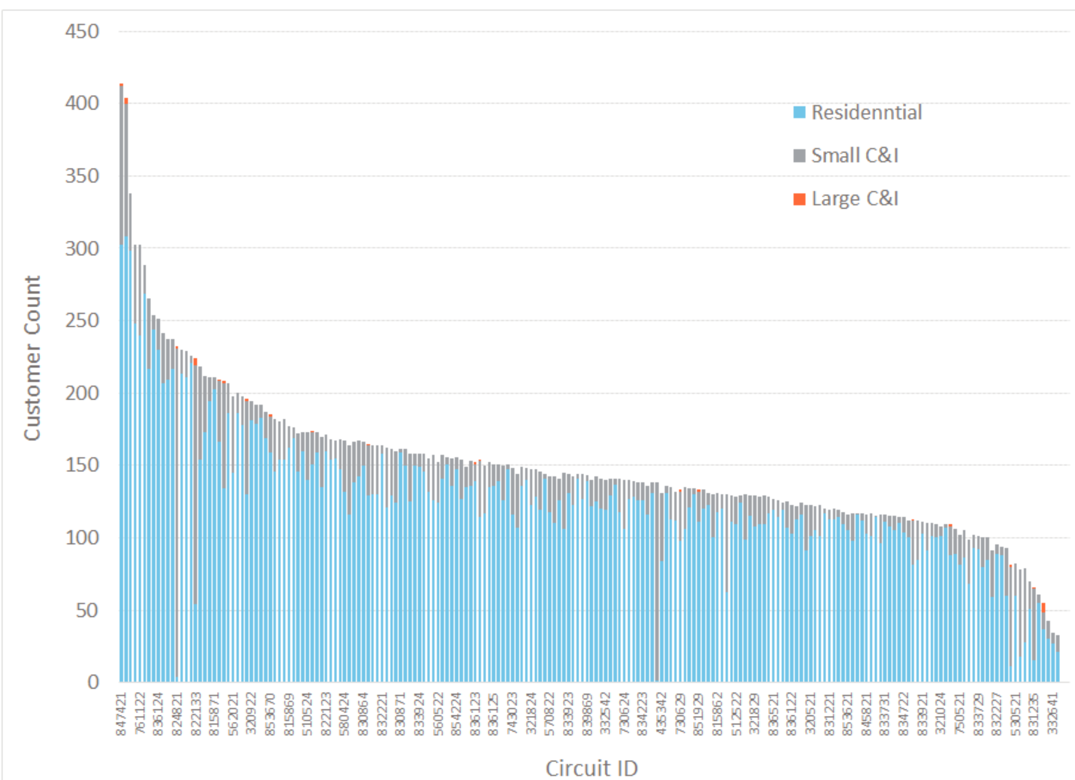


Figure 3-4: Average Customer Impacted from Minor Lateral Outages

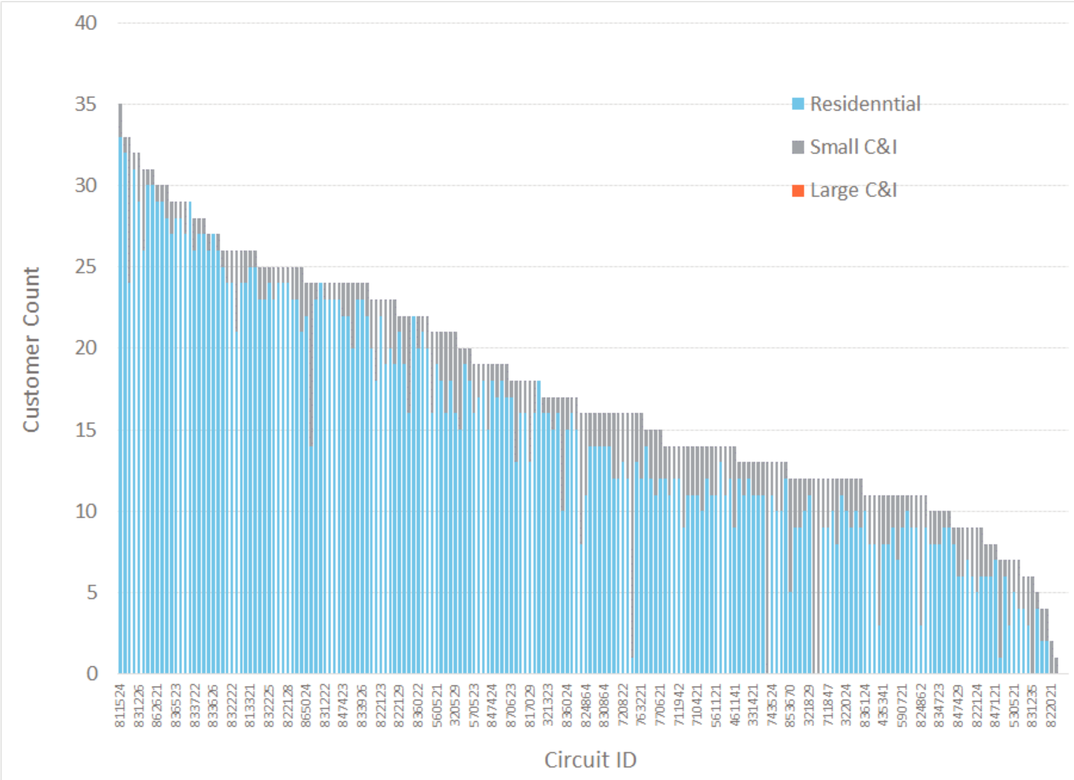
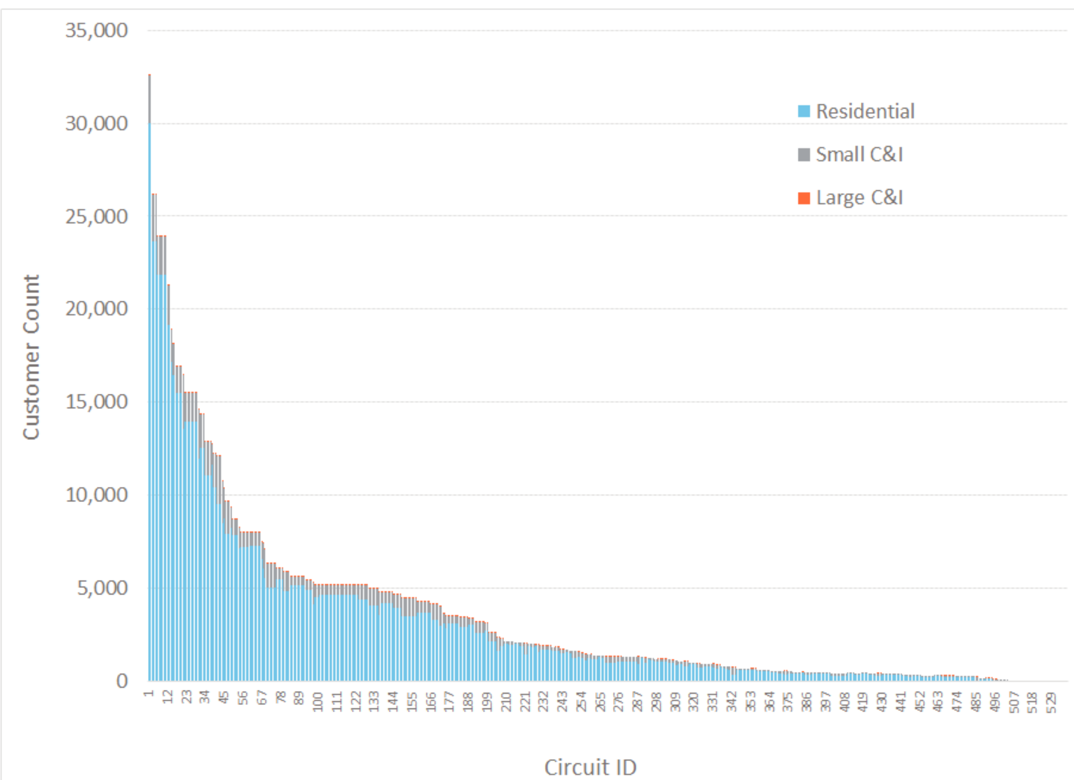


Figure 3-5: Customer Impacted for Substation Assets

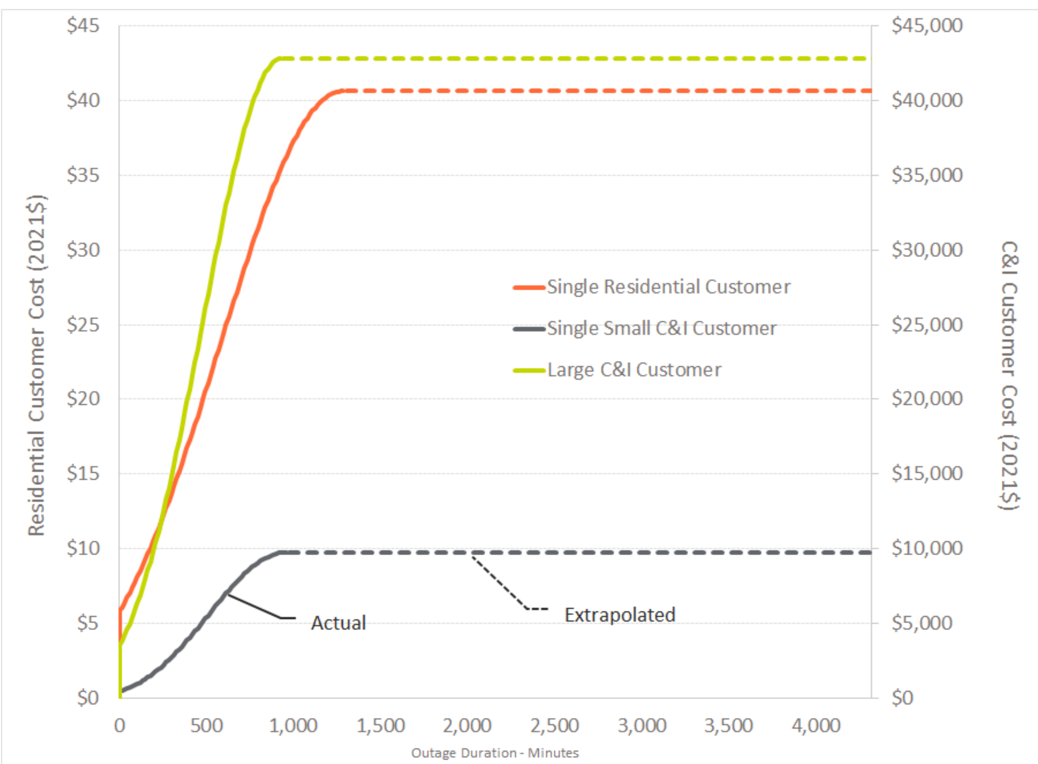


3.1.5 ICE Calculator

To monetize the cost of an outage, the benefits approach utilizes the Interruption Cost Estimator (ICE) Calculator. The ICE Calculator is an 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 (DOE).

The calculator includes the estimated interruption costs for residential, small commercial and industrial (C&I), and large C&I customers for a range of durations. 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. Outages less than one minute, including ‘Blinks’, are assumed to have the same consequence as a 1-minute outage.

Figure 3-6: ICE Calculator Monetized Cost of Outage Summary



3.2 General Assumptions

Table 3-1 shows the general assumptions used for the business case and revenue requirements modeling.

Table 3-1: General Assumptions

Assumption Description	Units	Value
Inflation	[%]	2.50%
Weighted Average Cost of Capital (WACC) / Discount Rate	[%]	7.55%
Total Tax Rate for ADIT	[%]	25.82%
Return on Rate Base	[%]	9.07%
Ad Valorem Tax Rate	[%]	0.65%
Useful Life and Analysis Period: Grid Resiliency	[Years]	50
Useful Life and Analysis Period: Grid Automation	[Years]	25
Useful Life and Analysis Period: Communications Systems	[Years]	25
Useful Life and Analysis Period: Tech Platforms & Apps	[Years]	25
Revenue Requirement Evaluation Period	[Years]	30
Substation Truck Roll	[$/truck roll]	$1500
Circuit Truck Roll	[$/truck roll]	$500

3.3 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 assert 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 upgraded to the new 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 benefit calculations. The same approach was used for all asset classes shown in Table 2-5.

3.3.1 Probability of Surviving

Many of the asset classes included within the Grid Enhancement Plan are typically replaced before failure-causing outages. This replacement is because the consequence of failure typically exceeds utilities 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. Within Utilities, depreciation studies utilize property accounting records to designate Iowa Survivor Curves for asset types to establish rates.

Based on OG&E's depreciation study and 1898 & Co.'s collection of the asset expected lives, each asset class designated in Table 2-5 was assigned an Iowa Survivor Curve inside the AssetLens Analytics Engine. Figure 3-7 shows an example End-of-Life (Iowa Survivor Curve) for wood poles. Wood poles are expected to have an average service life of 50 years. Figure 3-8 shows the approach to calculate the annual probability of not surviving for a 40-year-old wood pole asset.

Figure 3-7: Example Survivor Curve for Wood Poles

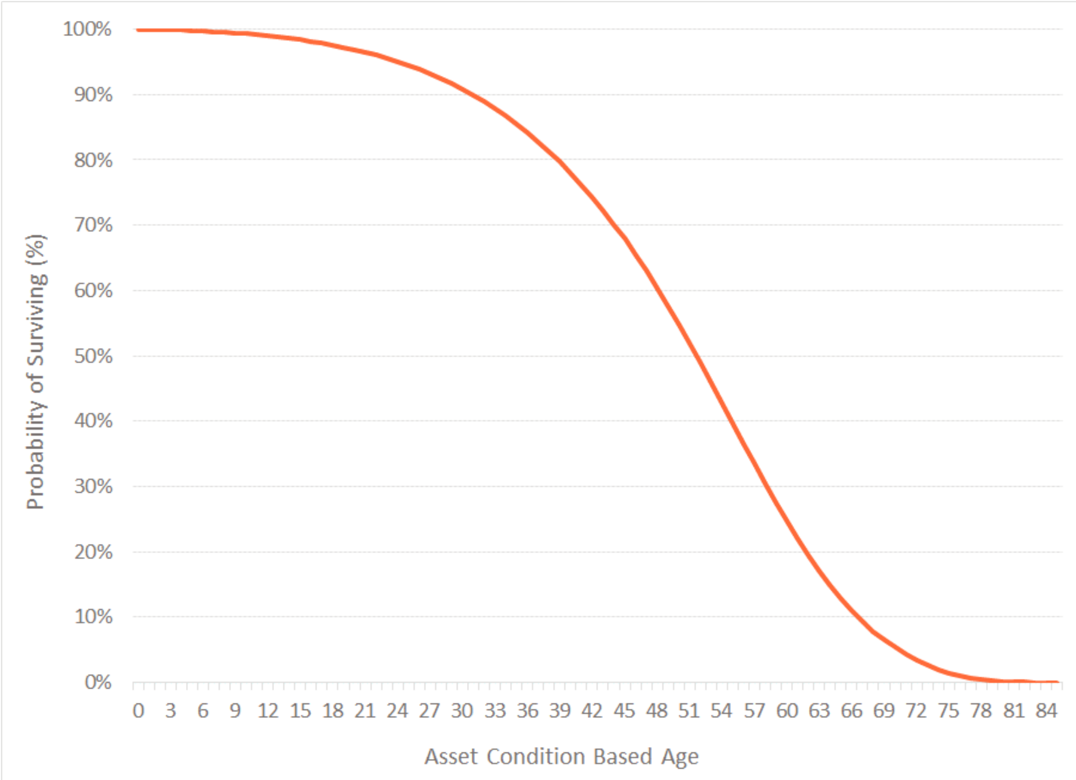
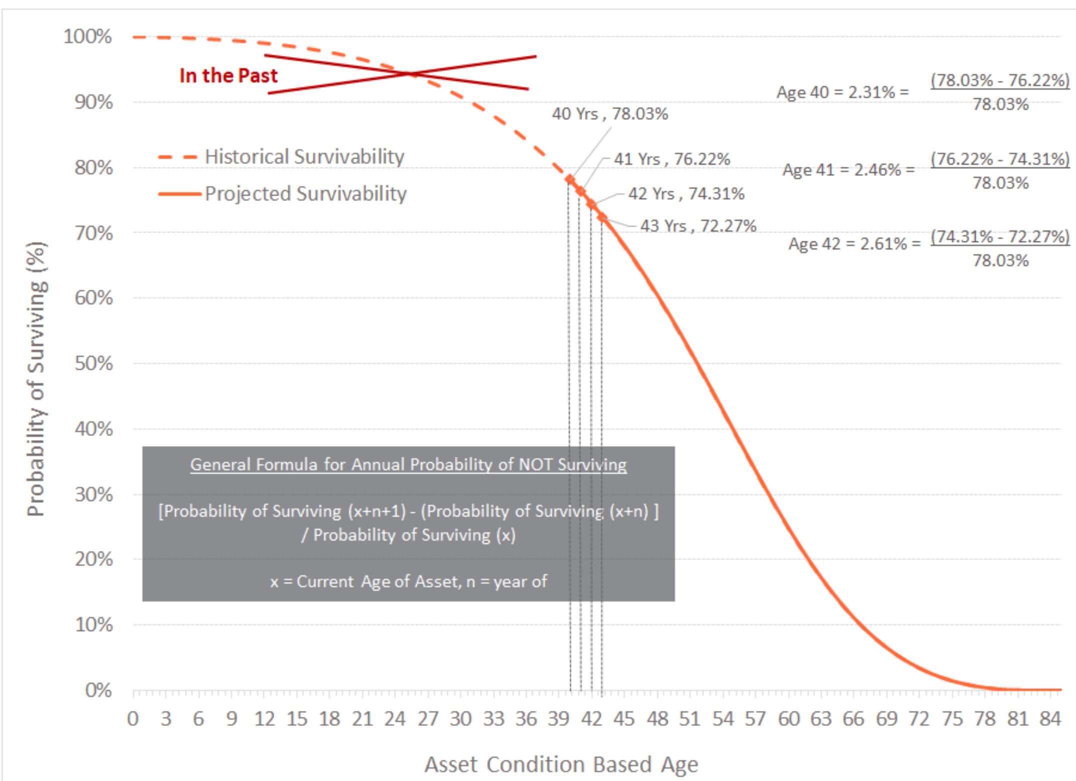


Figure 3-8: Annual Probability of Not Surviving Example – 40-Year-Old Wood Pole



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 3-9 shows the annual probability of not surviving for a range of wood pole ages based on the mathematical approach shown in Figure 3-8. The figure shows that as assets get older the 100 percent probability of not surviving is distributed over fewer years.

Figure 3-9: Survivor Curves to Annual Probability of Not Surviving Profiles for Wood Poles

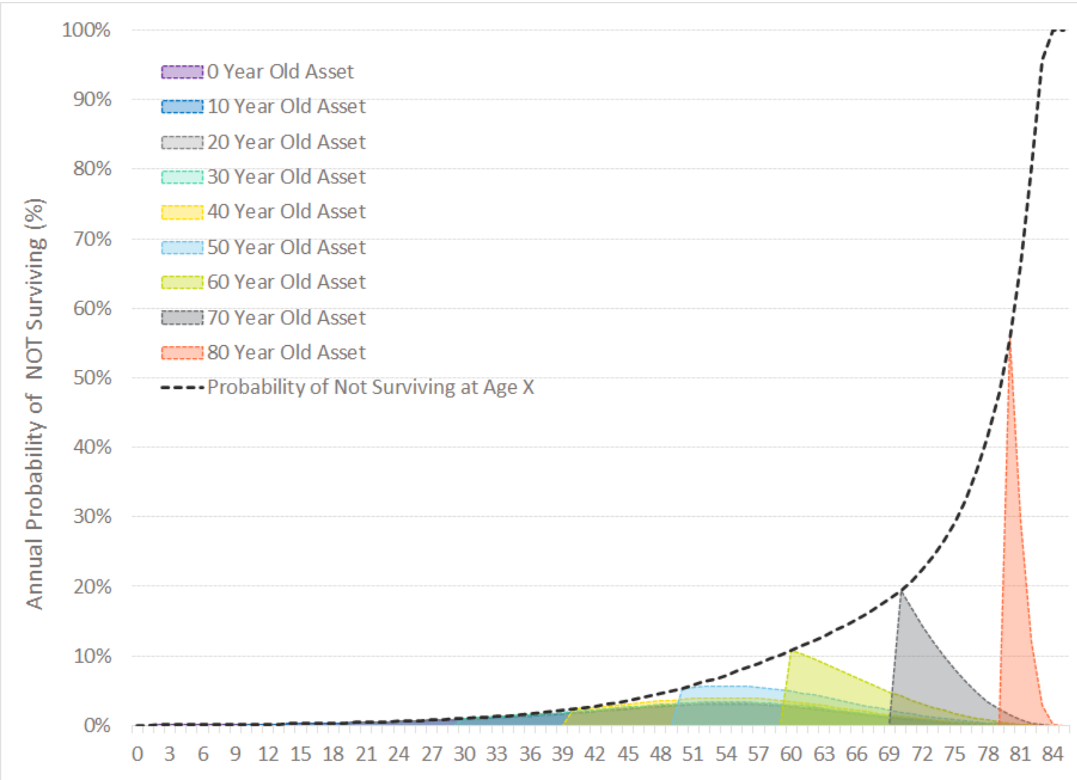
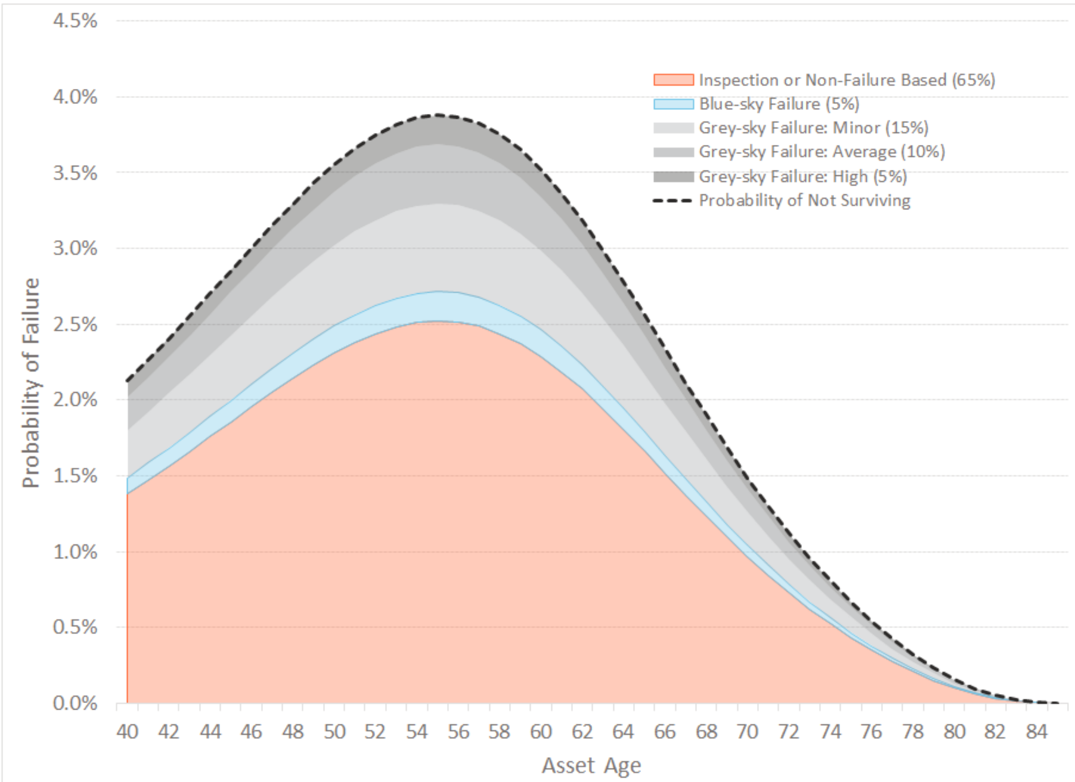


Figure 3-9 also shows the probability of not surviving at each age (Probability of Not Surviving at Age X). It is important to note that this representation of the Survivor curve produces a 'Bath-tub' curve for wood poles. Each asset class survivor curve is different representation of failure rate profiles as assets age. The AssetLens Analytics Engine calculates the probability of not surviving for each asset included in the evaluation.

3.3.2 Failure Types and Probability of Failure

The previous section, Section 3.3.1, 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 3-10 shows the probability of failure profile for each failure type for the example 40-year-old wood pole.

Figure 3-10: 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.

3.3.3 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 3-2 shows the range of consequence types evaluated and the asset classes that they apply to. The table also shows the avoided cost type. The framework puts a monetary value to each of these consequence factors.

Table 3-2: 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		■

3.3.3.1 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. As discussed in Section 3.1, the relationship between assets and customers was established for all circuit and substation assets. Section 3.1.4 shows the results of this connectivity. The customer totals assume the grid automation investment in Automated Circuit Tie Lines and Smart Lateral Fuses is in place. 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 3.5 to 4.5 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 12 hours for backbone poles, 24 hours for major laterals, and 72 hours for minor laterals. 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 for each asset and expected customers impacted (Section 3.1.4), including type, the approach calculates the risk-weighted customer minutes interrupted

(CMI) for each asset. This risk-weighted CMI is monetized using the DOE ICE Calculator (see Section 3.1.5 and Figure 3-6) to estimate each asset's risk-weighted monetized CMI over time.

3.3.3.2 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 3-10. 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.

3.3.3.3 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 asset 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 for each substation asset category. These end-of-life costs are then incorporated in the estimation of benefit cost ratios for the various substation investments.

3.3.3.4 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 new 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.

3.3.3.5 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.

3.3.3.6 Re-replacement Costs

Either through special circumstances, acquisitions, or strategies to minimize acquisition costs, non-standard equipment is 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 the 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 new standard requires engineering. Changing to the new 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. These costs are then probability-weighted and incorporated in the estimation of benefit cost ratio for the various substation investments. Some assets have a higher probability than others of being replaced with non-standard assets requiring re-replacement later. A proactive investment approach allows OG&E 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.

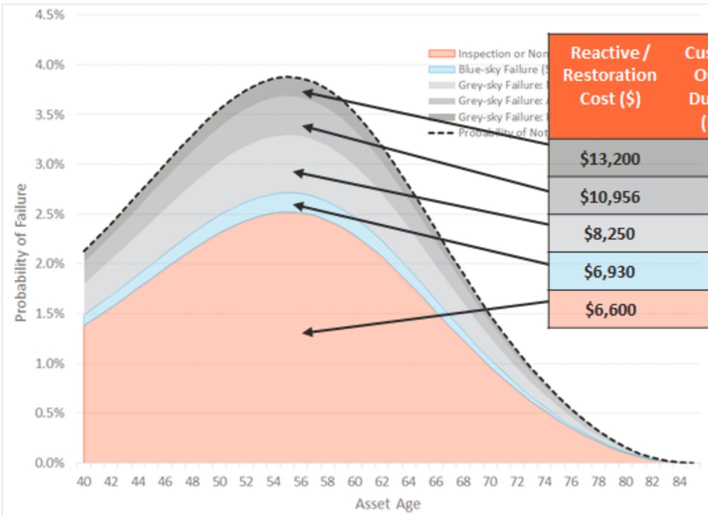
3.3.4 Status Quo Risk & Resiliency Profile

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 3-11 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 3-12 and Figure 3-13 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 3-11 by the consequences and applying escalation and discount rate from Table 3-1. Figure 3-12 and Figure 3-13 both show the percentage of total risk and resiliency costs for each failure type. Figure

3-14 is the sum of Figure 3-12 and Figure 3-13 for each year and shows the total risk & resiliency costs for the 40-year-old wood pole.

Figure 3-11: 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 3-12: Status Quo Risk & Resiliency Reactive Costs Profile - 40-Year-Old Wood Pole

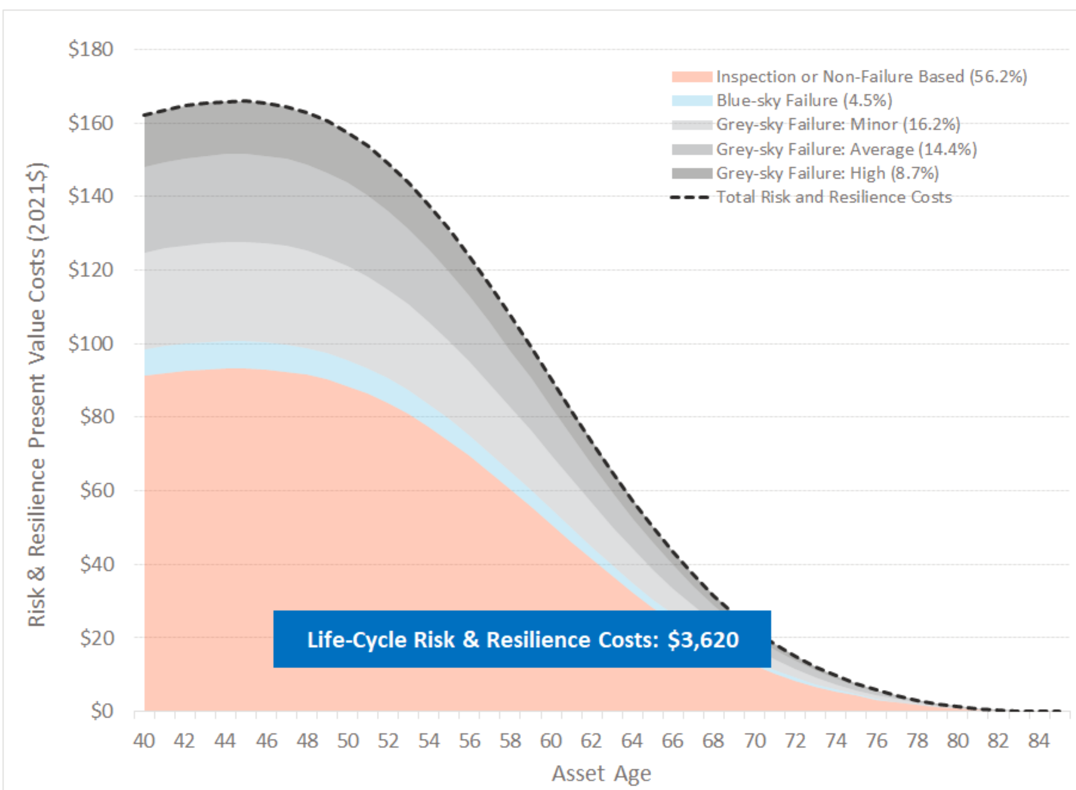


Figure 3-13: Status Quo Risk & Resiliency Customer Costs Profile - 40-Year-Old Wood Pole

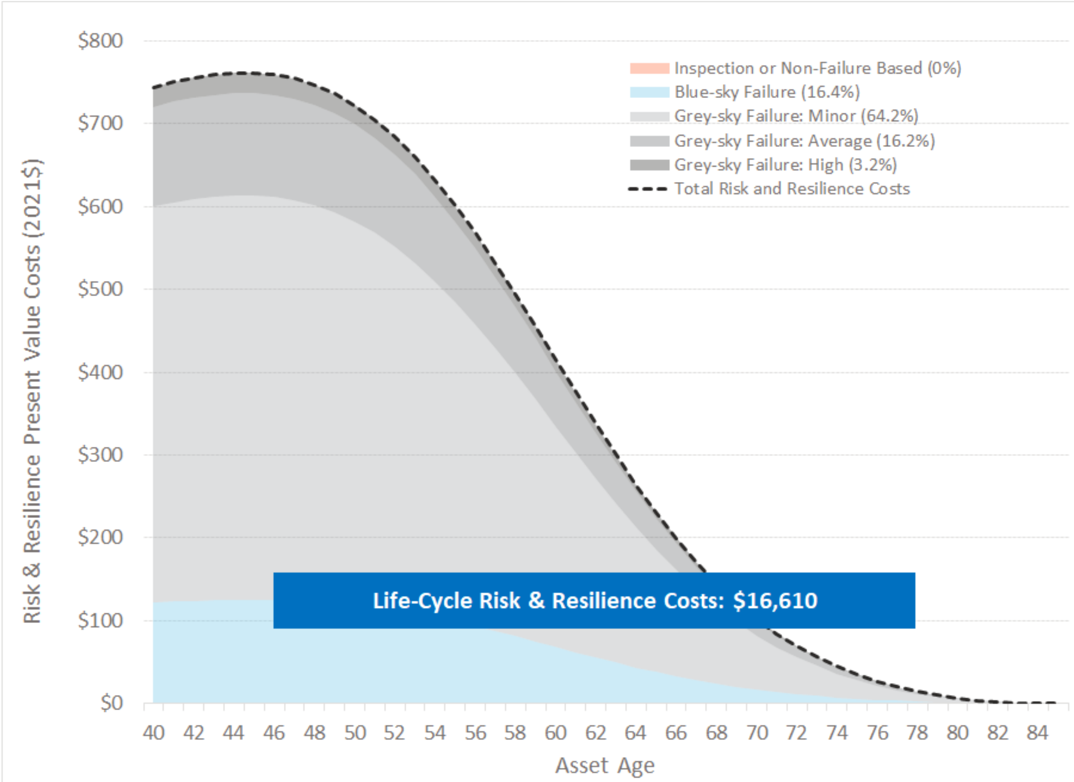
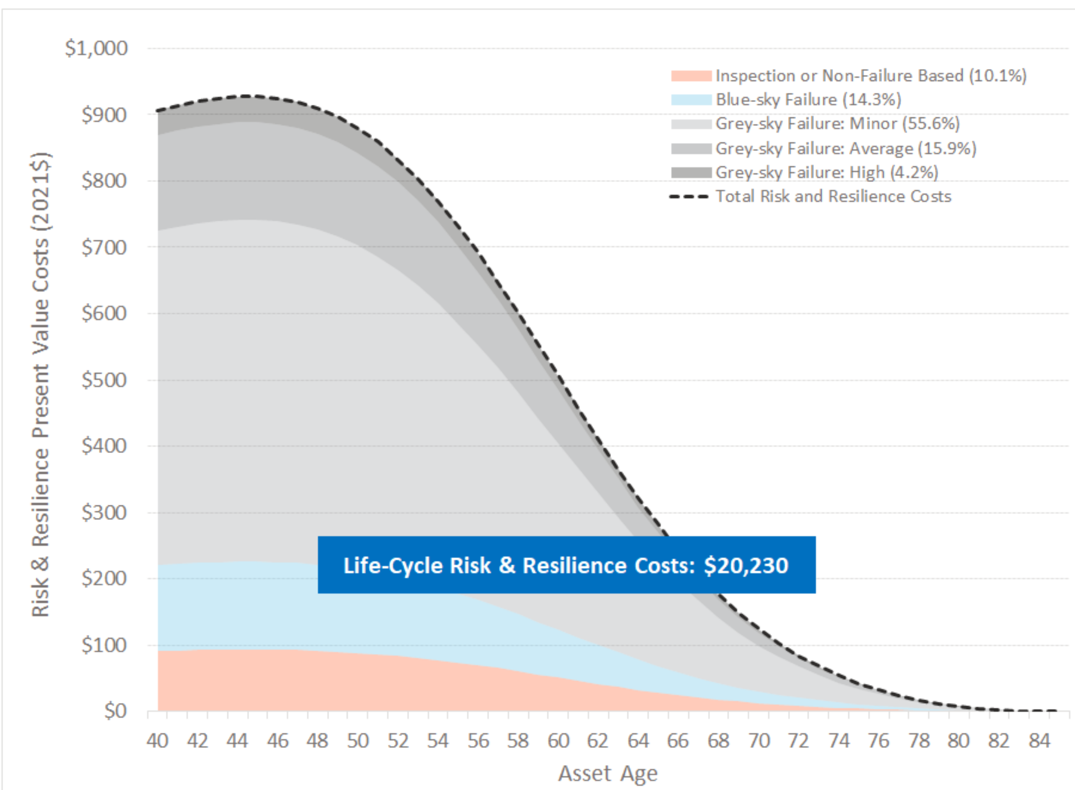


Figure 3-14: Status Quo Risk & Resiliency Costs Profile - 40-Year-Old Wood Pole



3.3.5 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 3-15 and Figure 3-16 shows the failure probabilities of the Status Quo and Investment scenarios for the example 40-year-old wood pole. Over the 44-year expected remaining life for the 40-year-old wood pole, there is a 100 percent probability of not surviving. 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 3-15: Status Quo Probability of Failure Profiles

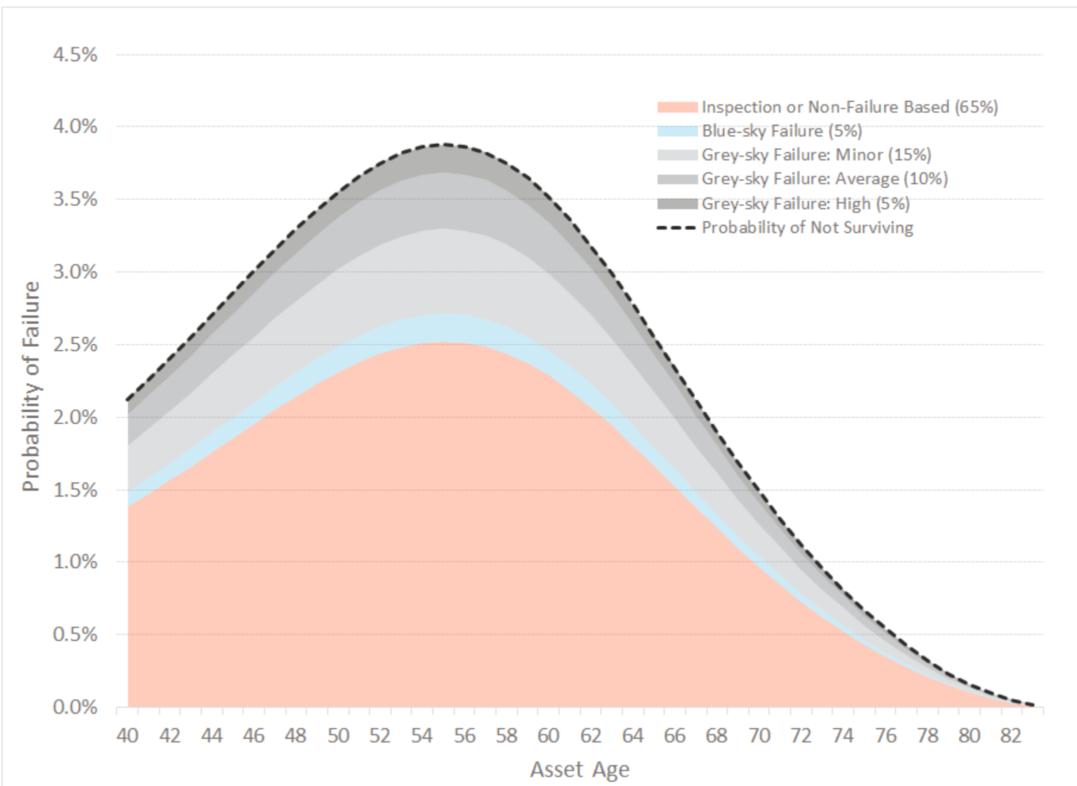


Figure 3-16: Investment Scenario Probability of Failure Profiles

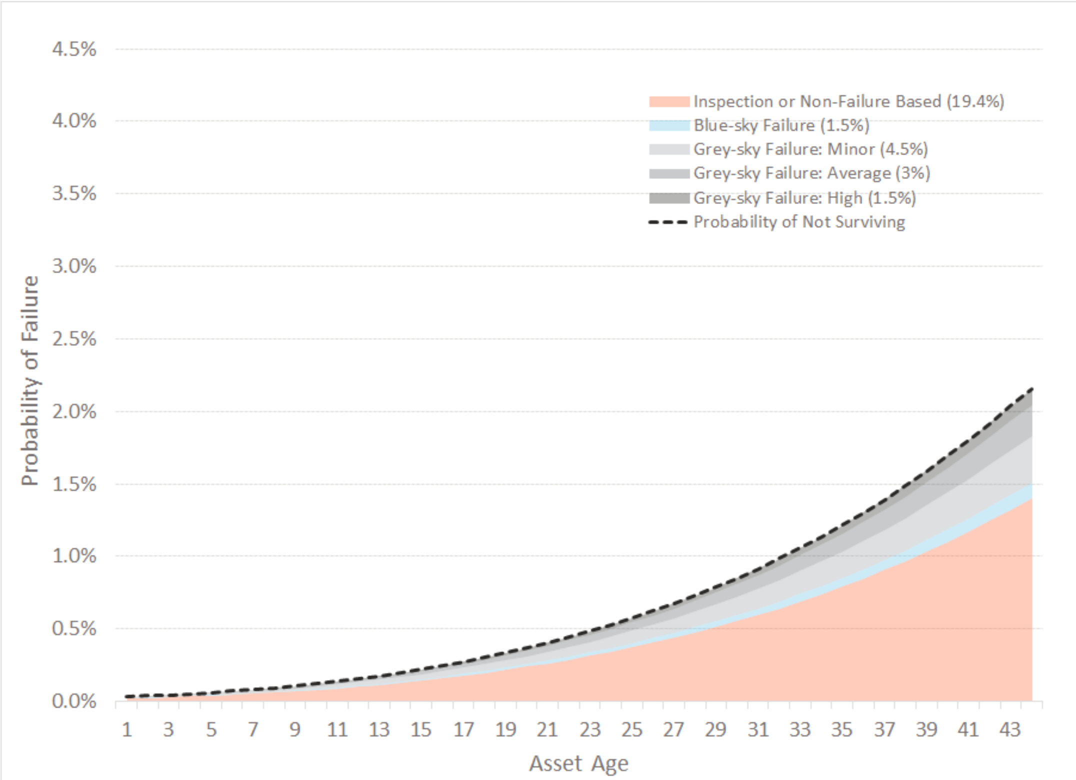


Figure 3-17 and Figure 3-18 show the companion risk and resiliency cost profiles for the Status Quo and Investment scenarios. Figure 3-19 shows the total values from Figure 3-17 and Figure 3-18 and the annual difference (Status Quo – Investment). The annual difference is the avoided annual costs for 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 $17,720 (present value in 2021$) for replacing the pole. If the pole were younger the annual avoided costs would turn negative sooner and make the project less beneficial.

The calculation approach for the two scenarios is repeated for all the assets in Table 2-2 and Table 2-3.

Figure 3-17: Status Quo Risk & Resiliency Cost Profiles

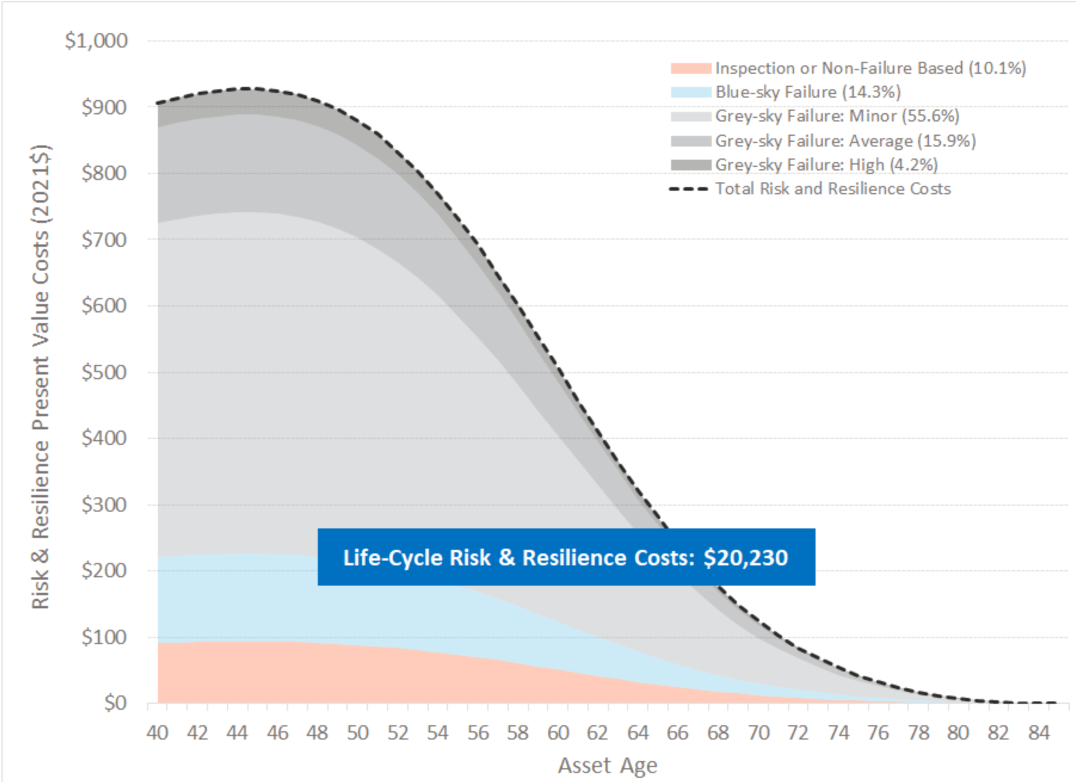


Figure 3-18: Investment Scenario Risk & Resiliency Cost Profiles

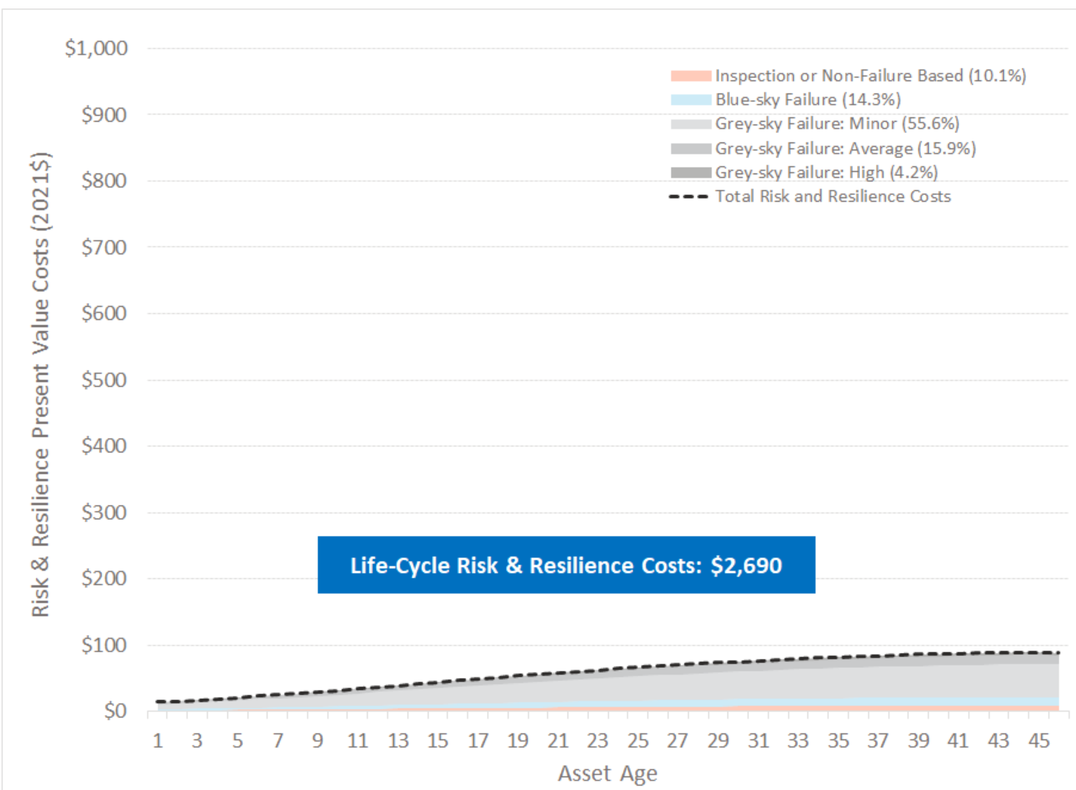
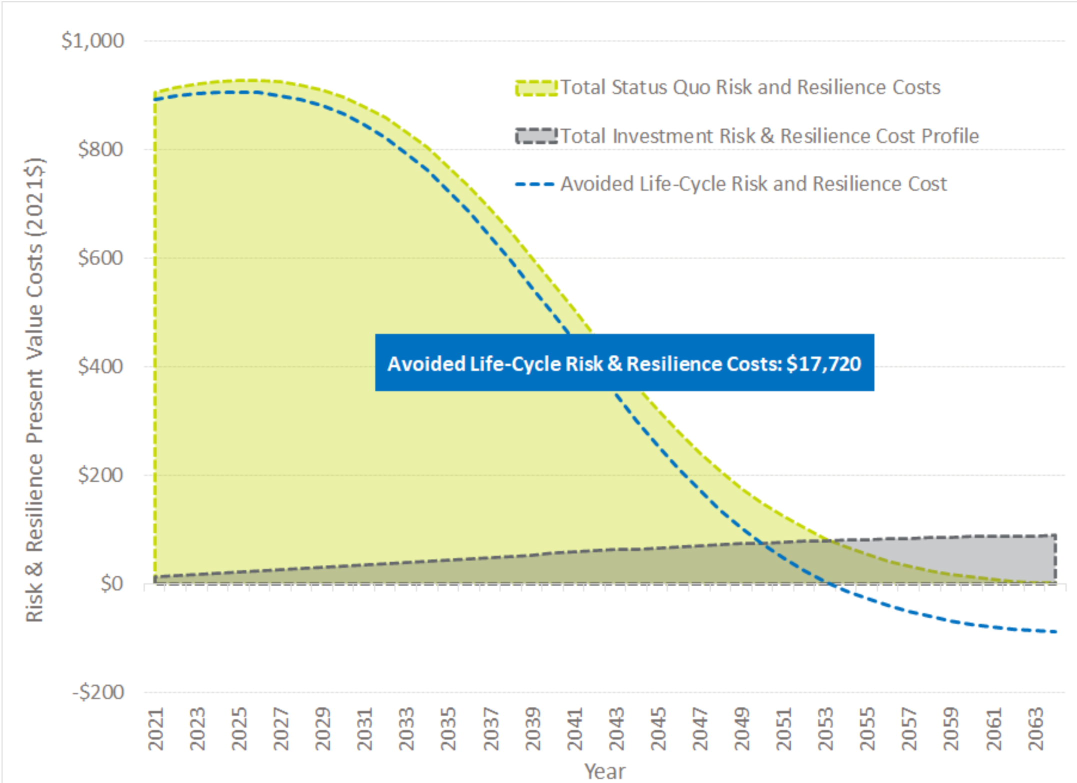


Figure 3-19: Avoided Risk & Resiliency Cost Benefit



3.4 Outage Mitigation Risk & Resiliency Benefits Assessment

The Grid Enhancement Plan includes a significant level of investment aimed at decreasing customer outages and improving the customer experience. The Outage Mitigation Risk & Resiliency modeling approach calculates the benefits for these investment types. The approach leverages OG&E’s historical outage records for the last 10 years, accounting for nearly 600,000 individual outage events. Each outage is re-calculated, assuming the Grid Enhancement investments had been in place. This calculation produces the avoided customers impacted (CI) and customer impacted minutes (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. Even though investment benefits can be directly linked to individual outages using this approach, the business case evaluation needs to be evaluated at several levels to include the whole circuit, substation, and system. Much of the investment aimed at decreasing outages work together systematically. For example, smart lateral fuses

(TripSavers®) are programed to work with the automated circuit tie line devices (IntelliRupters®). The devices coordinate so that each outage results in the least customers interrupted (CI). TripSavers® would not be as effective without IntelliRupters® and vice versa. Further, the IntelliRupters® are communicating devices. Without the communications investment, these devices would not operate effectively.

The devices could not 'talk' without communications, which enable the automated feeder switching (AFS). within minutes of an outage to minimize the number of customers impacted. Similarly, the communication investment enables the fault sensing equipment in the substation to decrease the time it takes for crews to identify the outage location, further decreasing the time customers are without service. This investment is another example of the integrated and comprehensive nature of the Grid Enhancement Plan for these four investment activities: 1. Smart Lateral Fuses, 2. Automated Circuit Tie Lines, 3. Communications Systems, and 4. Fault Location Isolation. The following sub-sections outline the Outage Mitigation Risk & Resiliency benefit calculation approach in further detail.

3.4.1 Outage Management System Data and Customer Types

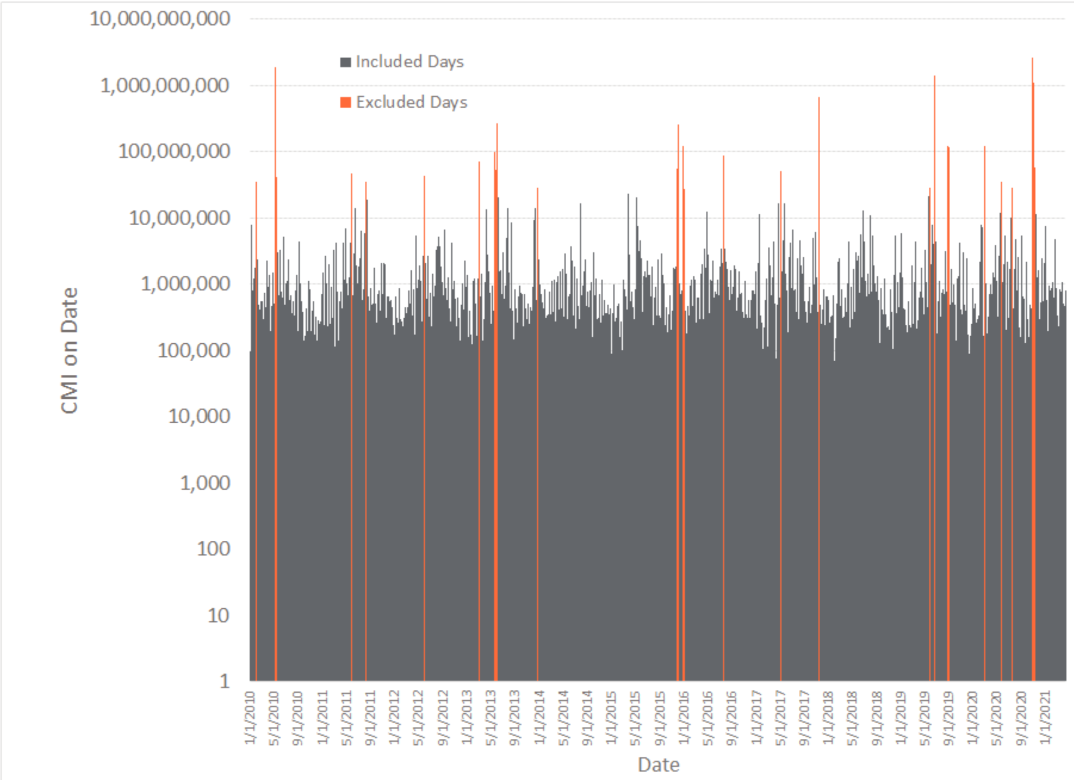
As discussed above, the Outage Mitigation Risk & Resiliency benefit approach is data centric. OG&E provided 1898 & Co. with 10 years of historical outage records. Regulated utilities are required to document customers' outages for NERC reporting. This record-keeping is typically done within the Outage Management System (OMS), a software package designed for utilities to record outages.

The outage data is derived from two OMS systems: CGI v2 (2010-2019) and OSI v4 (2019-2021). The new OSI data framework has every restoration step to restore the system, whereas the legacy CGI data only has specific location and timing data without precise electric power restoration steps. This improvement in data accuracy is due to improvement in OMS systems. Each system aggregates outages to a single event in the same manner.

The full data set spans 4,122 days and includes 599,282 unique events with 613,078 restoration steps. These encompass 6 different switching/protection devices protecting 140 types of equipment. Altogether, 35.8 million customer interruptions (CI) lead to 12.8 trillion customer minutes interrupted (CMI) over the 10-year period.

As the results show, the Grid Enhancement investments are expected to significantly decrease customer outages. However, during major events these investments may not operate since the supporting infrastructure is impacted. The analysis excludes the top 1 percent of outage days to be conservative. Figure 3-20 demonstrates the portion of outages that were excluded. It should be noted that the y-axis is logarithmic to show the range of outages. To put this in perspective, the top 1 percent of outage days account for over 82% of CMI since 2010.

Figure 3-20: Excluded Outage Dates by CMI



The outage mitigation investments should mitigate some outages with these major events, but they were not included in the benefit assessment to be conservative.

1898 & Co. regularly reviews outage management records for utilities. Typically, utility crews document the cause codes for each outage. Based on a utility's business processes, the cause code data within the OMS can range in quality over time and between different divisions and crews. OG&E's record-keeping and outage data within the Outage Management Systems is similar to other electric utilities. In general, 1898 & Co. found the outage data to be high quality, especially for use with the Outage Mitigation Risk & Resiliency benefits assessment.

However, similar to other utilities, there is room for improvement in recording and describing outages. The main area for improvement is for substation outages. These can be challenging to classify in an OMS given that most outage management systems are circuit and device-centric, and substation outages don't easily map to these points. Additionally, the accurate collection of outage data is typically not top of mind for crews amidst the stress of restoring service at substations where high levels of customers are impacted. This outage records data gap is minor in the scheme of the overall benefits assessment, but it does impact it at a few substations. This gap is discussed below in Section 5.4.

As noted in Section 3.1.4, OG&E 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 nearly 600,000 outages in the OMS. This data allows for the monetization of outages with customer types and the DOE ICE calculator.

3.4.2 Outage Improvement Investments and Mapping to Outage Data

The Outage Mitigation Risk & Resiliency benefits assessment applies to the investment activities outlined Table 3-3.

Table 3-3: Outage Mitigation Investments

Category	System	Investment Type	Specific Investment
Grid Automation	Distribution Line	Automated Circuit Tie Lines	Automated Circuit Tie Lines
Grid Automation	Distribution Line	Automated Lateral Lines	Smart Lateral Fuses
Grid Automation	Distribution Substation	Remote Fault Location	Fault Location SCADA Inputs
Grid Automation	Distribution Substation	Substation Automation	New SCADA
Grid Resiliency	Distribution Line	Equipment Upgrades	Lightning Outage Reduction Program
Grid Resiliency	Distribution Substation	Animal Protection	Cover Up
Grid Resiliency	Distribution Substation	Animal Protection	TransGard Fence
Grid Resiliency	Distribution Substation	Animal Protection	Transguard Fence
Grid Resiliency	Distribution Substation	Substation Resiliency	TransGard Fence

For the Automated Circuit Tie Lines and Smart Lateral Fuses investment activities, 1898 & Co. utilized planning and engineering studies showing the expected locations of new protection devices. These planning and engineering studies utilized sophisticated circuit planning models to help identify ideal locations for new protection devices to optimize circuit reliability performance and meet OG&E planning standards. Often the location of a new smart device was the same as an existing switch or fuse. With this information, 1898 & Co. mapped the new devices directly to the OMS, allowing for improved analytic precision on the expected decrease in customer outages. The mapping to the OMS was based at the circuit mainline or substation level for the other investment activities.

3.4.3 Avoided Outage Calculations

The Outage Risk & Resiliency benefit assessment is based on re-calculating the historical outrage 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. 1898 & Co. calculated seven different benefit streams using this approach. They are shown in Figure 2-2 and listed below:

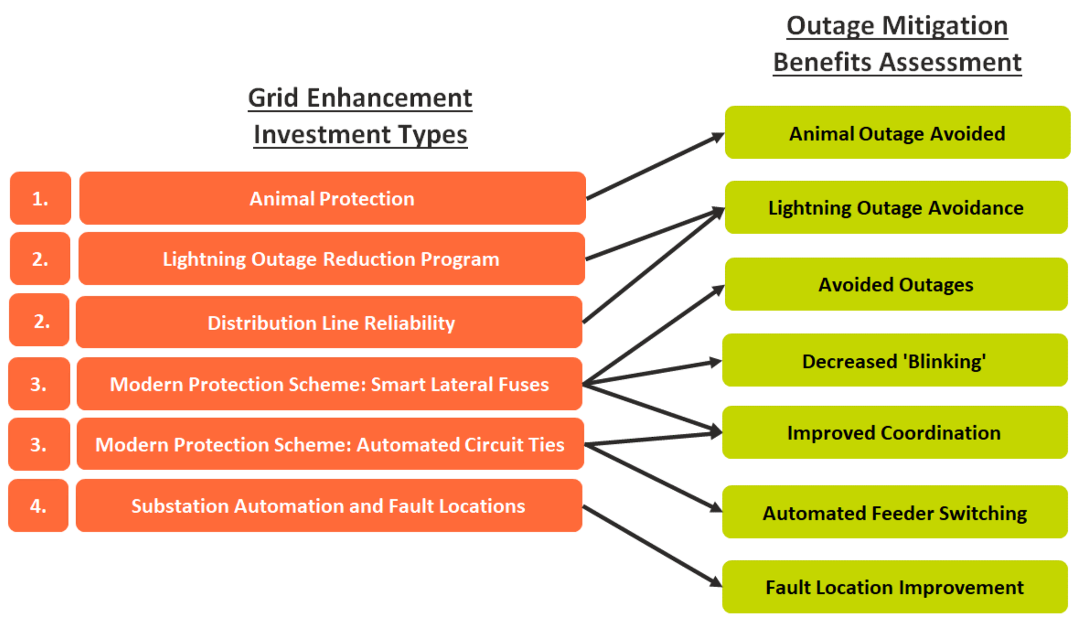
1. Animal Outages Avoided
2. Lightning Outages Avoidance
3. Avoided Outages
4. Decreased 'Blinking'
5. Improved Coordination
6. Automated Feeder Switching
7. Fault Location Improvement

To avoid double-counting, the approach evaluates the benefits of each investment activity sequentially. In other words, the outage records are re-calculated for only one of the investment activities at a time. After one re-calculation is complete, the next one is evaluated based on the modified outage records.

While this approach avoids double counting, it creates challenges to fully understanding the benefits of individual investment activities. To illustrate this challenge, the investments of Lightning Outage Mitigation and Automated Circuit Tie Lines are helpful. The Lightning Outage Mitigation investment activity adds lightning arresters to the mainline circuits to decrease the number of lightning outages. It should be noted that while this investment is effective in decreases lightning outages, it does not eliminate them. The Automated Circuit Tie Lines investment activities enable automated switching of load to other circuits during outages, including lightning. The order of the investment activities has a significant impact on the benefit streams of these two programs. While the calculation can be performed for each investment activity incrementally, it is important to view the business case results at the circuit level in this example to see if the aggregate of the benefits outweighs the costs. This example showcases the integrated and comprehensive nature of the Grid Enhancement Plan.

Figure 3-21 shows the order of sequencing of direct investment activities for re-calculating outages and the corresponding benefits streams. It should be noted that other indirect or supporting investments are needed to achieve these benefits. For instance, without the supporting investment of communications, the Automated Feeder Switching and Remote Fault Location benefit streams could not be fully achieved.

Figure 3-21: Direct Investment Activity Sequencing Order



The following sections provide additional information on the approach to recalculating outages for benefit type.

3.4.3.2 Animal Outages Avoided

Animal protection solutions are proven to be quite effective at keeping the animals away from the equipment. For the benefits assessment, 1898 & Co. and OG&E assumed an effectiveness of 95 percent for substations with animal protection investment. The 95 percent improvement was applied to substation outages with animal cause codes and a portion of the 'other' cause code. The evaluation also estimated the decrease in truck rolls and restoring service in the substation at $1,500 for each mitigated event.

3.4.3.3 Lightning Outages Avoidance

The Distribution Line Reliability and Lightning Outage Reduction Program include adding arresters to each circuit. 1898 & Co. and OG&E assumed an effectiveness of 80 percent for the addition of lightning arresters for circuits with the Lightning Outage Reduction Program and 20 percent for circuits with the Distribution Line Reliability. The Lightning Outage Reduction Program is a systematic deployment of arrestors on circuits whereas the Distribution Line Reliability program adds arrestors to upgrade replaced poles to the new equipment standard. The percentage improvement was applied to circuit outages with a lightning cause code. Additionally, the assessment estimated the decrease in truck rolls and restoring service at $500 for each mitigated event.

3.4.3.4 Modern Protection Schemes Outage Benefits

The investment Modern Protection Schemes that include Smart Lateral Fusing and Automated Circuit Tie Lines are evaluated together given their integrated nature. Circuit protection is designed to work together to lock out circuits in the event of a fault and to minimize the number of customers impacted. The Grid Enhancement Plan includes significant investment to redesign and modernize systems protection schemas for each circuit to leverage new devices, communications, and technology applications.

OG&E's current protection schemes generally use mid-point reclosers on the circuit mainline with fuses for laterals. OG&E also utilizes a "fuse-saving" strategy which is designed to minimize the impact of nuisance outages on laterals such as tree 'slapping' conductors or minor animal incidences. With a "fuse-saving" approach, the recloser and fuse are designed to work together to evaluate whether fault currents are real outages or nuisance outages. The current approach provides the benefits of locking out the circuit in the event of a fault current that could cause harm to the system and more importantly the general public while only 'blinking' customers for nuisance events instead of full lock-out causing customer outages and truck rolls.

The new modern approach uses several smart reclosing devices (IntelliRupters®) on the mainline with smart lateral fuses (TripSavers®) for each tap off the mainline. All devices are designed to work in concert, locking out the portion of the circuit where the fault occurred (sectionalizing) and minimize the number of customers impacted. The smart lateral fuses decrease the number of customer experience 'blinking' for the "fuse-saving" strategy. The smart reclosing devices provide additional mainline circuit sectionalizing to decrease the number of downstream impacted customers while also enabling communication between devices to shift loads to other circuits given an event. Rather than a recloser locking out 1,500 customers for the current scheme, the smart reclosing devices would work together to only impact 500 customers by moving 1,000 to another circuit. These actions are done within minutes of the device identifying a fault.

As discussed above, detailed planning and engineering studies were developed for each circuit to identify locations for new IntelliRupters® (mainline smart reclosing device) and TripSavers® (smart lateral devices). 1898 & Co. utilized these studies to map the new device placement to the outage management system. Often the mapping was to existing switches or fuses.

1898 & Co. evaluated the outage records to understand how each new protection scheme would have impacted historical outages. Based on this evaluation, the following benefits streams were identified and ranked:

1. **Avoided Outages**
2. **Decreased 'Blinking'**
3. **Improved Coordination**
4. **Automated Feeder Switching**

The following sections outline the benefits modeling approach and the concepts behind the approach.

3.4.3.4.2 Avoided Outages

While the "fuse-saving" strategy is designed to decrease the number of nuisance outages, the schemes are not always effective due to coordination challenges between devices. 1898 & Co. reviewed the historical outage records and identified likely nuisance outages where the "fuse-saving" strategy mis-coordinated. These include animal, lightning, or vegetation outages less than 60 minutes in duration, the duration for a crew to drive to the circuit, find the fault location, and re-set the fuse. The redesigned protection schema with TripSavers® changes these events to 'blinks', saving customers from 60-minute outages and the cost of rolling a truck. As the results show, this benefit stream is minor compared to the Decreased 'Blinking' and Automated Feeder Switching.

3.4.3.4.3 Reduced 'Blinking'

As discussed above, the "fuse-saving" strategy uses the current mainline recloser to evaluate nuisance outages on laterals. This causes 'blinking' or momentaries for thousands of customers. OG&E has received negative customer feedback on the number of 'blinks.' The modern schemas use TripSaver® to detect momentaries, meaning the number of customers with 'blinking' dramatically changes from thousands to hundreds. Based on the mapping of devices to the outage records, 1898 & Co. identified the 'blinking' recloser devices and recalculated the number of customers 'blinked" based on the number of customers downstream of the TripSaver® devices. While the TripSaver® devices provide a range of benefits, the decrease in 'blinking' is the main benefit driver. It should be noted that decreases in 'Blinking' does not show up in the official system performance metrics OG&E submits to NERC since they qualify as momentary outages. The investment is intended to improve service to customers based on their feedback.

3.4.3.4.4 Improved Coordination

In evaluating the outage records, 1898 & Co identified miscoordination from two perspectives. The first was fuses locking out for nuisance outages when the upstream recloser should have 'blinked'. The redesigned and modern protection schema will mitigate this mis-coordination. This is the Avoided Outages benefit stream discussed above in Section 3.4.3.4.2.

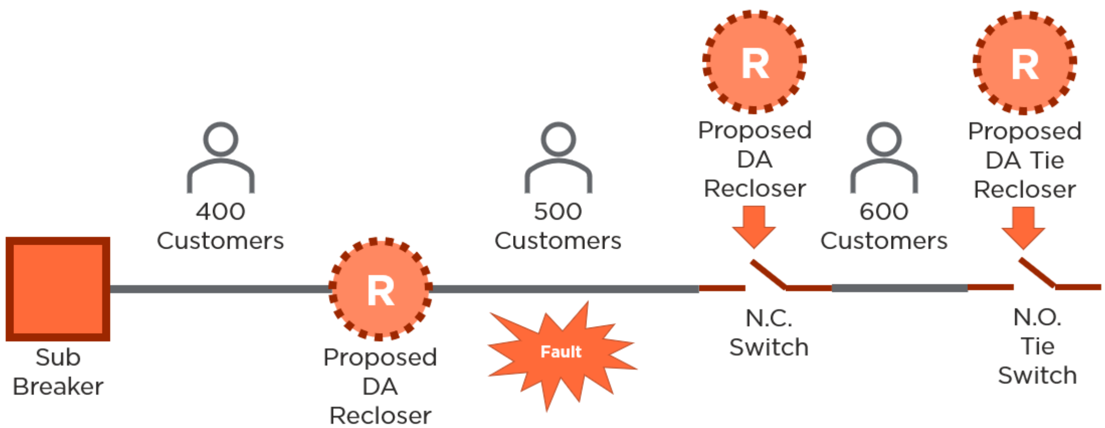
Before smart lateral fusing's advent, the fuse-saving setting of the reclosers attempted to protect several protection levels. In some cases, the recloser will 'blink' before the fuse trips, causing twice as many CI at a minimum. This is the second mis-coordination 1898 & Co. identified. Similarly, the redesigned and modern protection schema of TripSavers® and IntelliRupters® mitigates this type of miscoordination, decreasing the number of customers impacted. As the results show, this benefit stream is minor compared to the Decreased 'Blinking' and Automated Feeder Switching.

3.4.3.4.5 Automated Feeder Switching (AFS) Outages

The Avoided Outages, Reduced 'Blinking', and Improved Coordination benefits streams result from having the Smart Lateral Fuses evaluate nuisance outages on laterals and respond accordingly rather than reclosers on the circuit mainline evaluate lateral outages. The Smart Lateral Fuses have hundreds of downstream customers while the circuit mainline reclosers typically have 1,000 to 2,000 downstream customers.

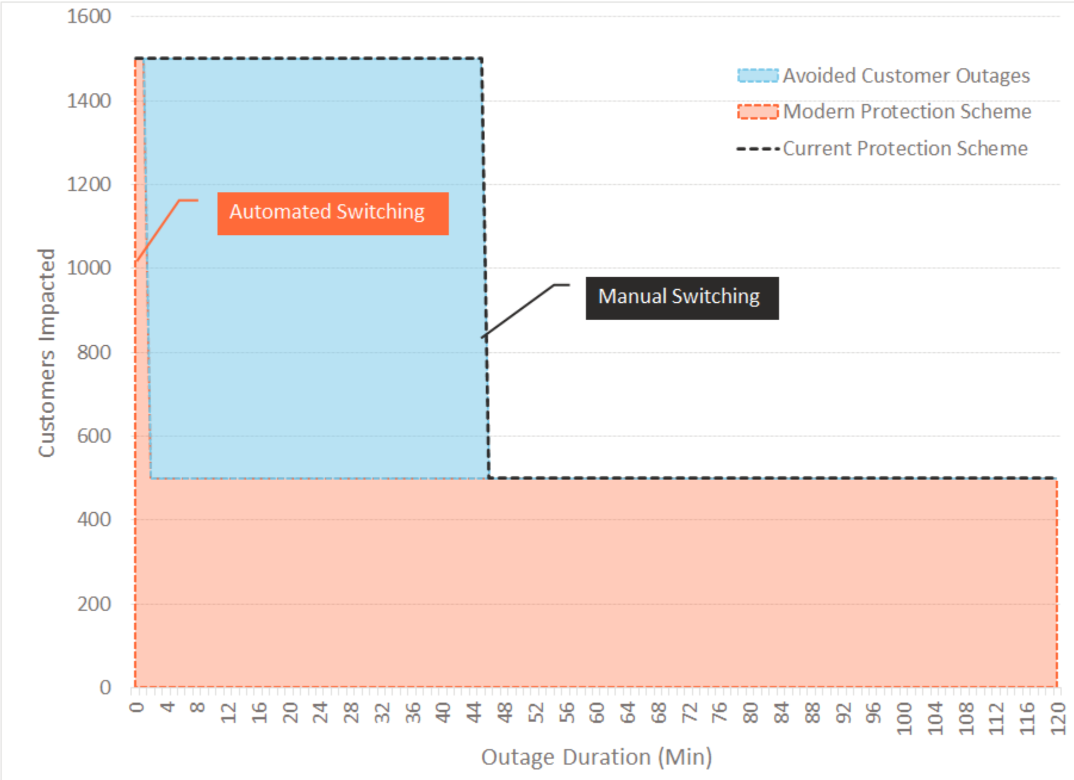
For mainline circuit outages, the current protection schema includes a substation protection device or a mid-point recloser. This topology means a mainline outage would impact approximately 1,500 to 2,500 customers when the substation protection device operates and 750 to 1,500 impacted if the mid-point recloser operates. The modern mainline protection schema includes additional sectionalization to each circuit creating sectionalization pods of approximately 400 to 500 customers. With this sectionalization and ability to transfer load to adjacent circuits the number of customers for a mainline outage can be significantly reduced. For the modern schema a mainline outage would lock-out customers for a few minutes and then sectionalize the pod and transfer the remaining downstream pods to another circuit. Figure 3-22 provides 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 ability to transfer load to the adjacent circuit.

Figure 3-22: Simplified Circuit for AFS 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 3-23 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 feeder 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 switching decreases the overall customer minutes interrupted by approximately 41.3 percent. 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 reported. This means the initial outage before switching would not be reported.

Figure 3-23: Mainline Outage Profile before and after AFS Investment



3.4.3.5 Fault Location Improvement

The Grid Enhancement Plan also includes investment in the substation to improve fault detection. As part of the restoration process, crews patrol the circuit or protection zone to identify where a fault occurred. Some faults can be challenging to identify, causing customers to be without service for longer durations. The investment in new communications and fault location devices enables OG&E to decrease the time it takes crews to identify the fault location After adjusting for previous investments, 1898 & Co. recalculated the duration of all outages assuming the outages could be identified sooner. 1898 & Co. assumed a decrease of 20 percent or 20 minutes, whichever provided less benefit.

3.4.4 Normalization, Monetization, and Life-Cycle Benefits Calculation

The avoided outage improvement was normalized and annualized to a single year, averaging any significant year-to-year discrepancies between outage types, outage causes, and circuits. The normalized and annualized value was then monetized using the DOE ICE Calculator and customer profile for each outage. Section 3.1.5 outlines the ICE Calculator assumptions and the benefit of avoiding ‘blinks. Applying escalation, discount rate, and expected useful life for the investments, mainly 25 years, the life-cycle benefit was calculated for each outage event and rolled up to the circuit level.

3.5 Revenue Requirements Modeling

OG&E provided 1898 & Co. with a Revenue Requirements Model to calculate the life-cycle benefits from a customer rate impact perspective. The revenue requirements model considers various depreciation rates, profit returns, taxes, and levelizing of capital investment. For each investment, 1898 & Co. input the investment cost, avoided capital cost annual profile, and the avoided O&M expense profile into the revenue requirements model to calculate the net impact to customers. This was performed at the individual investment activity level including the 754 direct investments. The results in Section 4.0, 5.0, and 6.0 show the benefit in cash flow terms. For Section 5.0 and 6.0, Appendix A includes the same results from a revenue requirements perspective.

4.0 BENEFITS ASSESSMENT RESULTS

Section 3.0 outlined the data, assumptions, and approach for the two main benefits approaches. This section includes the results for the 23 different benefits assessments. It also includes additional commentary on the specific application of each approach for the benefit driver. It should be noted that the reactive cost benefits shown in this section are on a cash flow basis as opposed to the revenue-requirements basis.

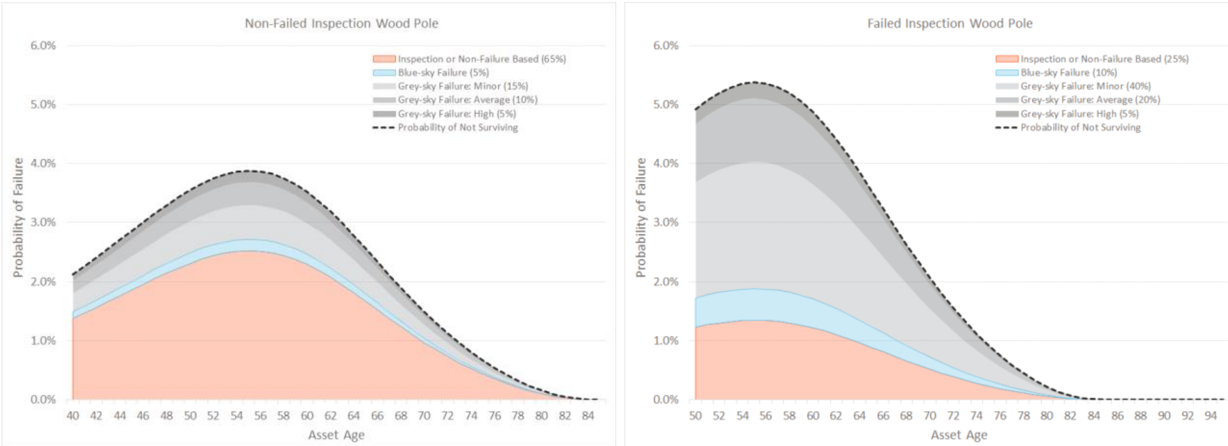
4.1 Equipment Failure Risk & Resiliency – Distribution Circuit Assets

4.1.1 Inspected Wood Poles and Pole Tops

The distribution line reliability investment category's main purpose is to replace wood pole assets that fail inspection. OG&E has established inspection criteria for wood poles and wood pole tops (cross-arms, brackets, insulators, pole cap). Assets with known defects (ground-line rot or circumference deterioration, wood-pecker holes, other deterioration) are targeted for replacement. Within the Grid Enhancement Plan, OG&E has estimated the number of poles that are expected to fail inspection. These poles are allocated to each circuit protection zone type (see Section 3.1.1) based on the circuit distribution of poles across the three zones (see Figure 3-1). This approach provides the linkage between customers and poles. This is important because the value of replacing a wood pole on the mainline feeder with hundreds of customers is different than the wood pole within a minor lateral with less than 50 customers.

As discussed above (Section 3.3.2), the most common failure type for wood poles is inspection based. Once a pole has failed inspection it has a much different failure profile and expected remaining life since known issues exist. Figure 4-1 shows the failure profile for a non-failed inspected 40-year-old wood pole and a failed inspected wood pole.

Figure 4-1: Non-Failed vs Failed Inspected Wood Pole Failure Profile



As the figure shows, the 40-year-old non-failed inspection wood pole has a much longer expected remaining life and failure types with lower consequences. It would take a very strong event or a series of events between inspection periods for this example 40-year-old pole to have an outage-based failure.

For the failed inspection wood pole, the figure shows that the expected remaining life is much shorter as the asset has effectively entered the ‘end-of-life’ stage. End-of-life for wood poles and wood pole tops is modeled as 50 and 45 years old, respectively. At these ages the pole or pole top has a slightly greater than 50 percent probability of not surviving in the next 10 years. Additionally, the figure shows higher consequence failure types as the pole would not be expected to live through storm events with a known defect. Not replacing failed inspection wood poles and pole tops would expose the utility to higher risk levels as replacing wood poles during storm events has a much higher cost than replacing proactively, sometimes twice as much. Additionally, customer outage time can be much longer as crews are constrained given the number of infrastructure issues during events.

Figure 4-2 shows failure profiles for the failed inspected wood pole vs replacing the wood pole. As the figure shows, there is a significant benefit in decreased probabilities and failure types if the asset is replaced. Figure 4-3 shows the corresponding risk costs profile after multiplying the consequences for each failure type and applying escalation and discounting. As Section 3.3.4 outlines, the consequence of failure includes both reactive costs and customer outage costs factoring in the number of customers as well as the type of customers.

Figure 4-2: Failed Inspected vs Replaced Wood Pole Failure Profile

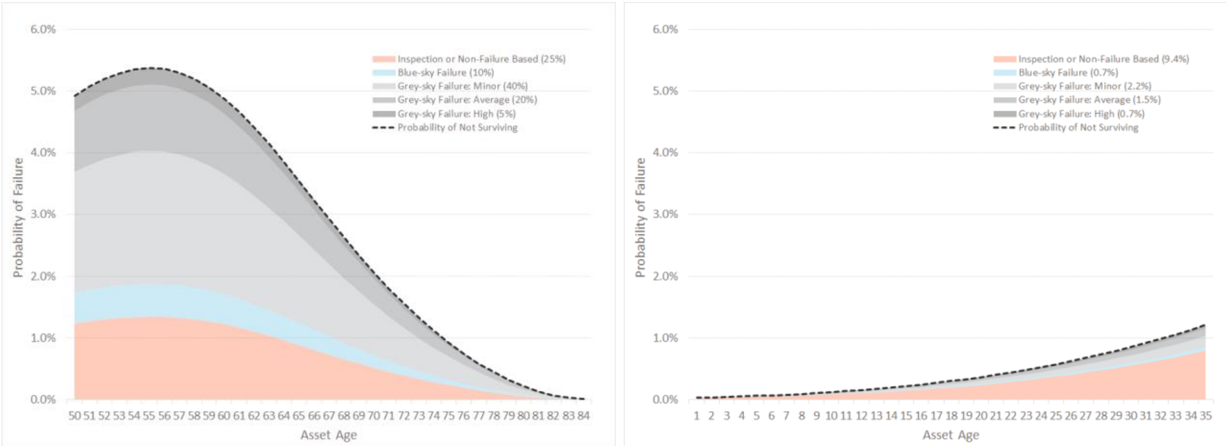


Figure 4-3: Failed Inspected vs Replaced Wood Pole Risk Cost Profile

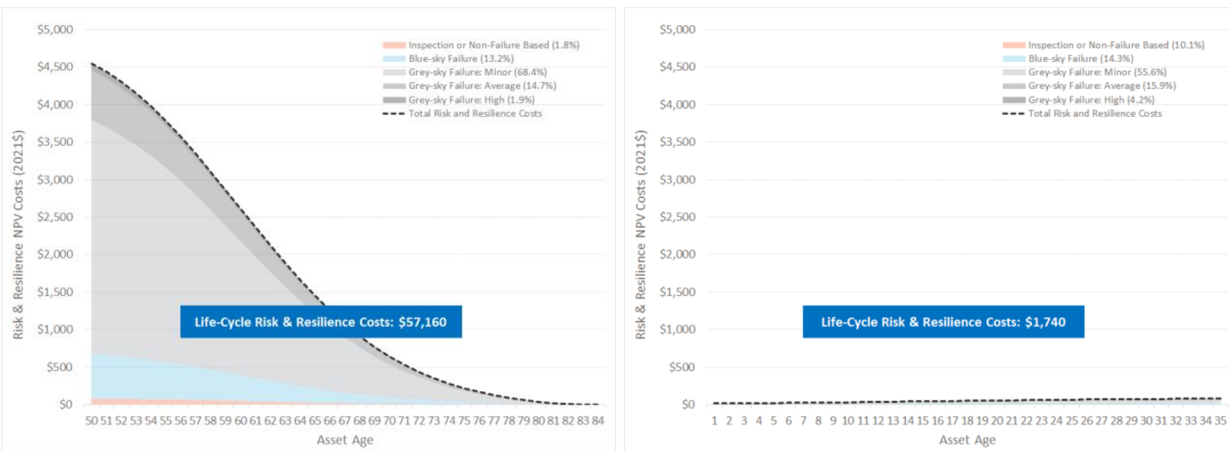


Figure 4-2 shows a significant NPV benefit of approximately $55,420 ($57,160 - $1,740) to replacing the failed inspected wood pole. Figure 4-4 and Figure 4-5 show the benefits for wood poles and wood pole tops for each circuit. The figure also includes the total benefit for all circuits.

Figure 4-4: Inspected Wood Poles Benefits Profile

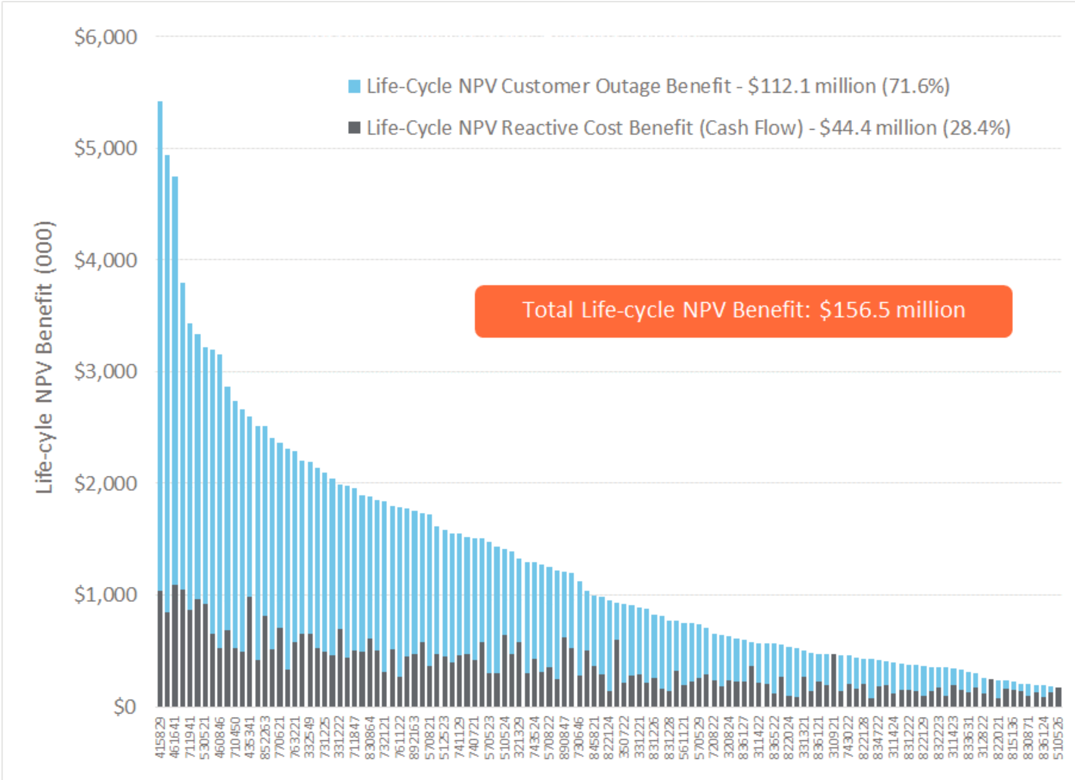
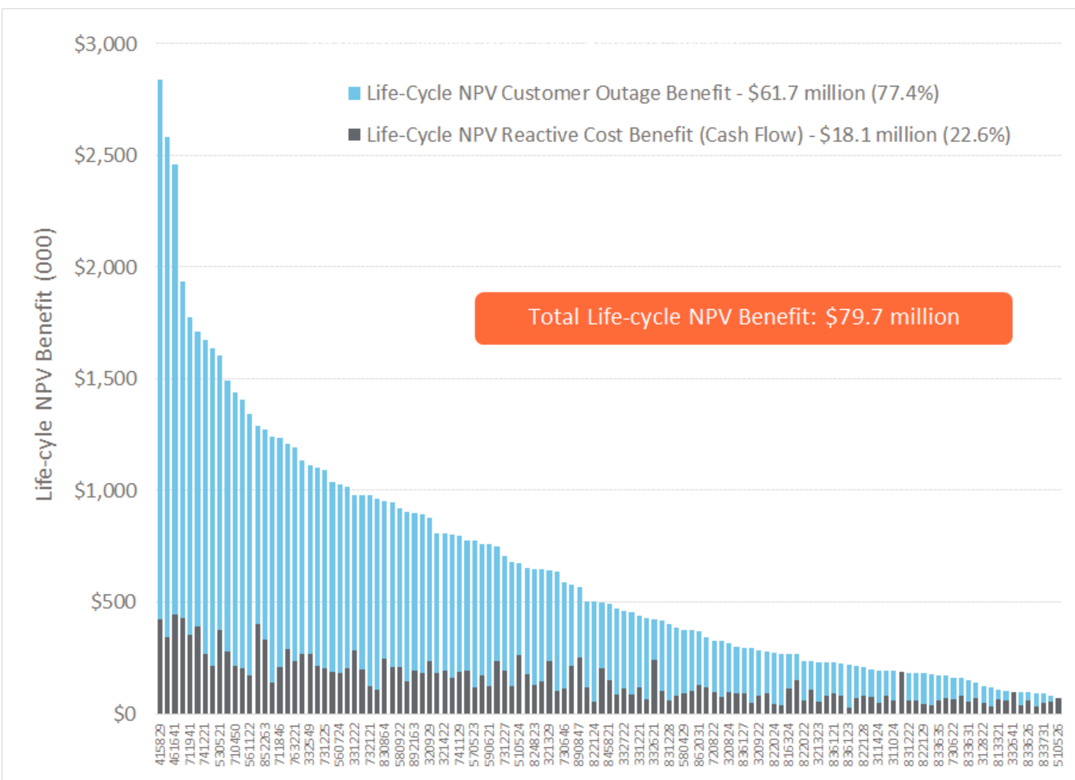


Figure 4-5: Inspected Wood Pole Tops Benefits Profile



4.1.2 Overhead Conductor and Underground Cable

As part of the Grid Enhancement Plan, OG&E has identified small or historically problematic overhead conductor and underground cable. Small backbone overhead conductor is problematic with the planned switching schemes and includes higher levels of risk of burning if overloaded. For the underground cable, the plan includes replacement of unjacketed cable. Utilities across the nation target replacement of this cable since the concentric neutral tends to erode over time causing higher frequency of outages for customers. The 2020 and 2021 Plan includes replacement of these conductors for 11 circuits.

Figure 4-6 and Figure 4-7 show the benefit assessment results for the overhead conductor and underground cable, respectively.

Figure 4-6: Overhead Conductor Benefits Profile

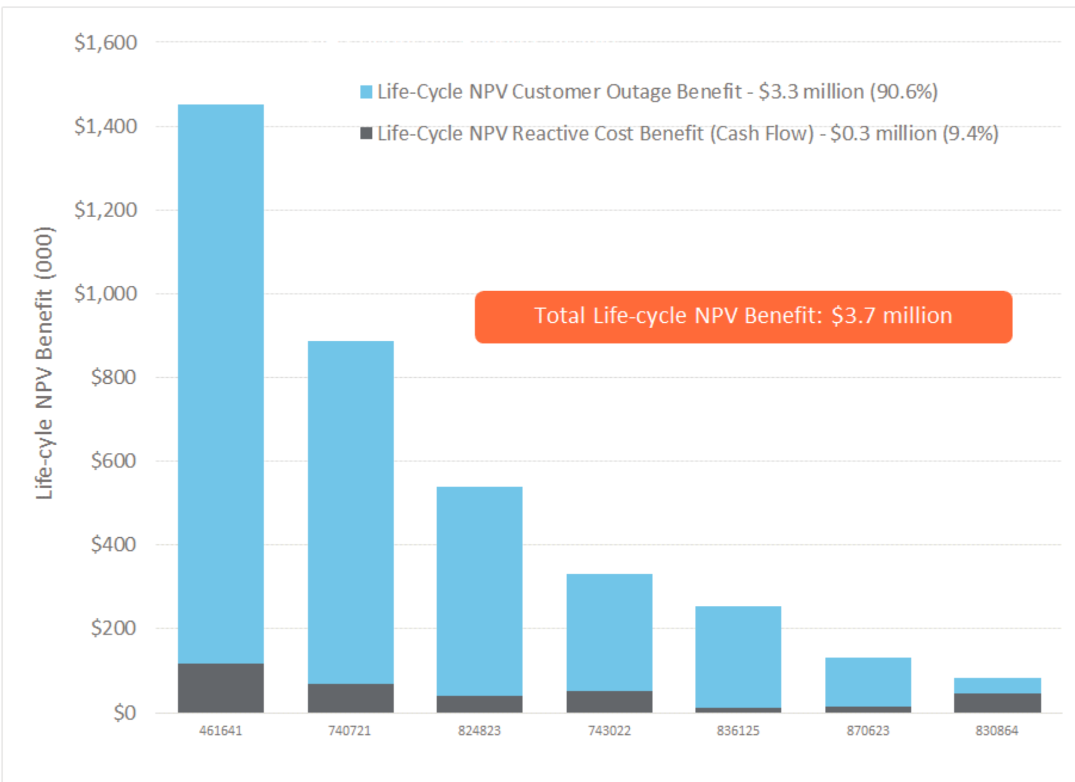
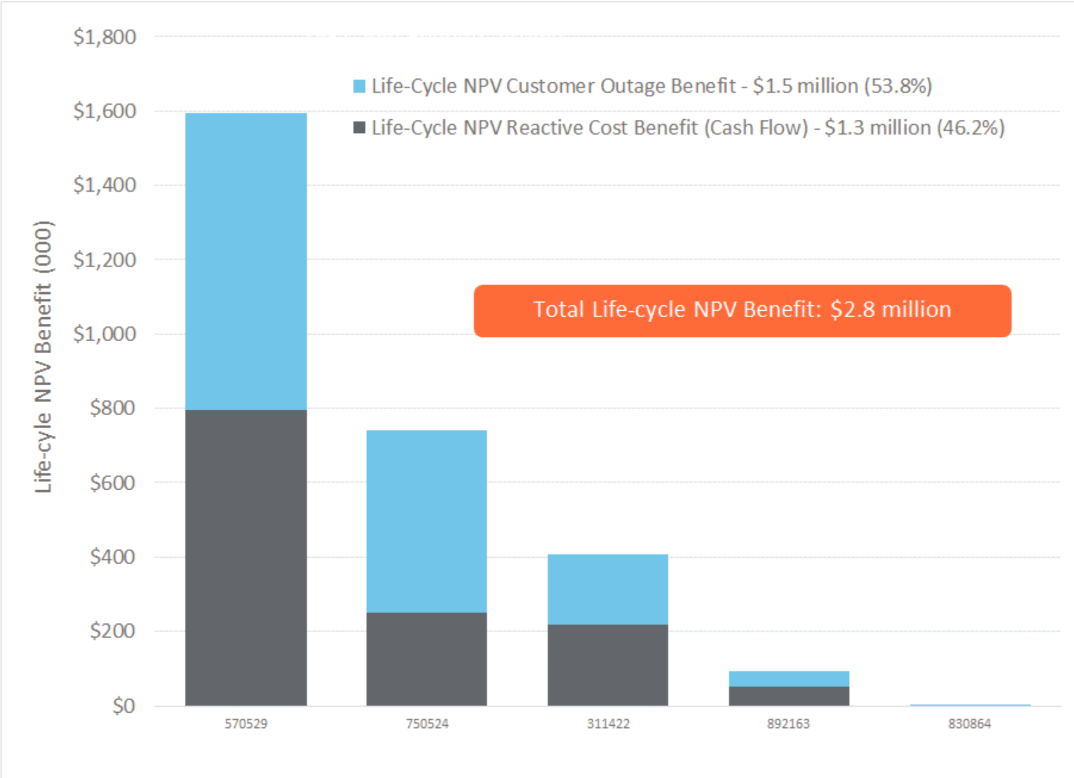


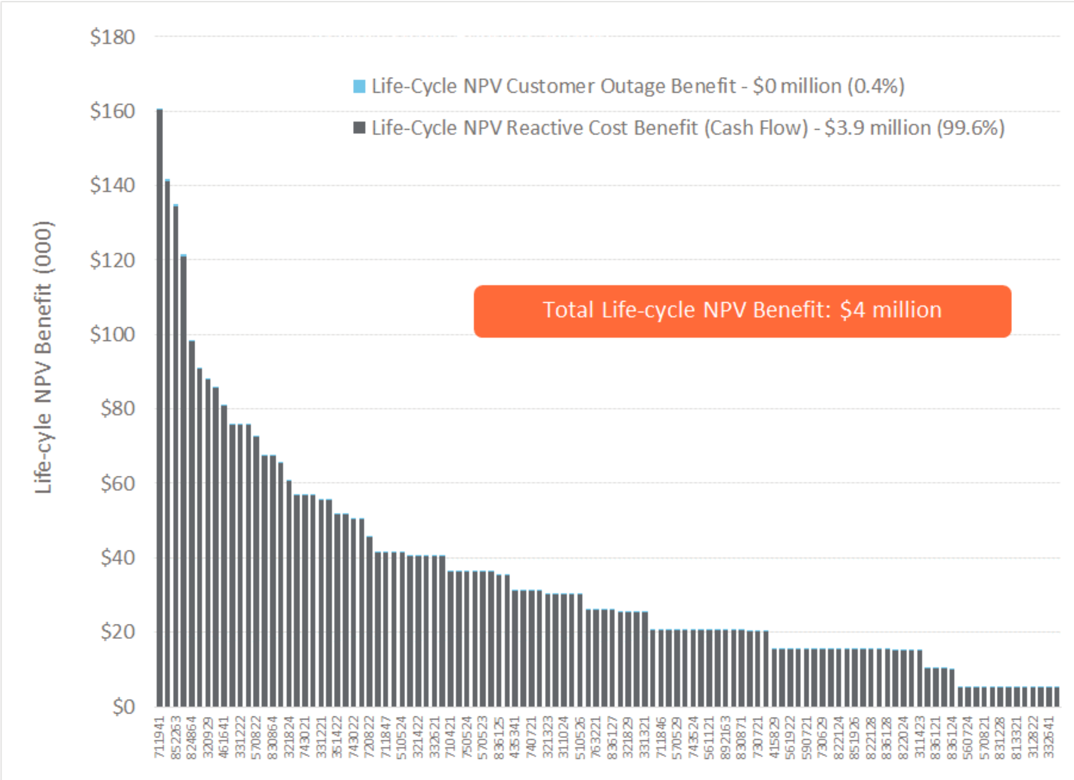
Figure 4-7: Underground Cable Benefits Profile



4.1.3 Highly Loaded / Overloaded Line Transformers

The 2020 and 2021 Plan includes the replacement of highly loaded or overloaded line transformers. Using their Advanced Metering Infrastructure (AMI) data, OG&E has collected hourly loading data on the distribution line transformers and compared it to the manufacturer's loading capacity. Not replacing infrastructure that experiences overloads or near overload increases the risk of the transformer overheating and catching fire. This is primarily a safety concern but also these events are costly to restore and leave the customers without service. Similar to the failed inspected wood poles, the benefits assessment assumes these assets are at end-of-life. Additionally, the risk and resiliency cost forecast includes high probabilities of the infrastructure failing more catastrophically (i.e., burning down) than normally loaded line transformers. Figure 4-8 shows the benefits of replacing these line transformers for each circuit. The figure shows that most of the benefit is in avoiding costly replacements. The customer benefit is small relative to other infrastructure since line transformers failures typically only impact 1 to 5 residential customers.

Figure 4-8: Highly Loaded / Overloaded Line Transformer Benefits Profile



4.1.4 Passively Replaced Infrastructure

Many of the investment types require the replacement of infrastructure to support the rebuild. For example, a wood pole that failed inspection may have a distribution line transformer that is replaced to standard. Alternatively, deploying new protection devices may require pole replacement if the dynamic loading on the pole is exceeded. Non-inspected wood poles and pole tops, line transformers, and pedestals fall into this category where the infrastructure is replaced passively. It is important to note that this investment is needed to capture the benefits for these other investment types, such as automated circuit ties or failed inspected wood poles.

The benefits assessment uses the average age of the assets on the circuit to estimate end-of-life and the failure type probabilities. Section 3.1.1 includes the average age of these asset types for each circuit. Figure 4-9, Figure 4-10, Figure 4-11, and Figure 4-12 include the benefits profile by circuit for these four asset classes.

Figure 4-9: Non-Inspected Wood Poles Benefits Profile

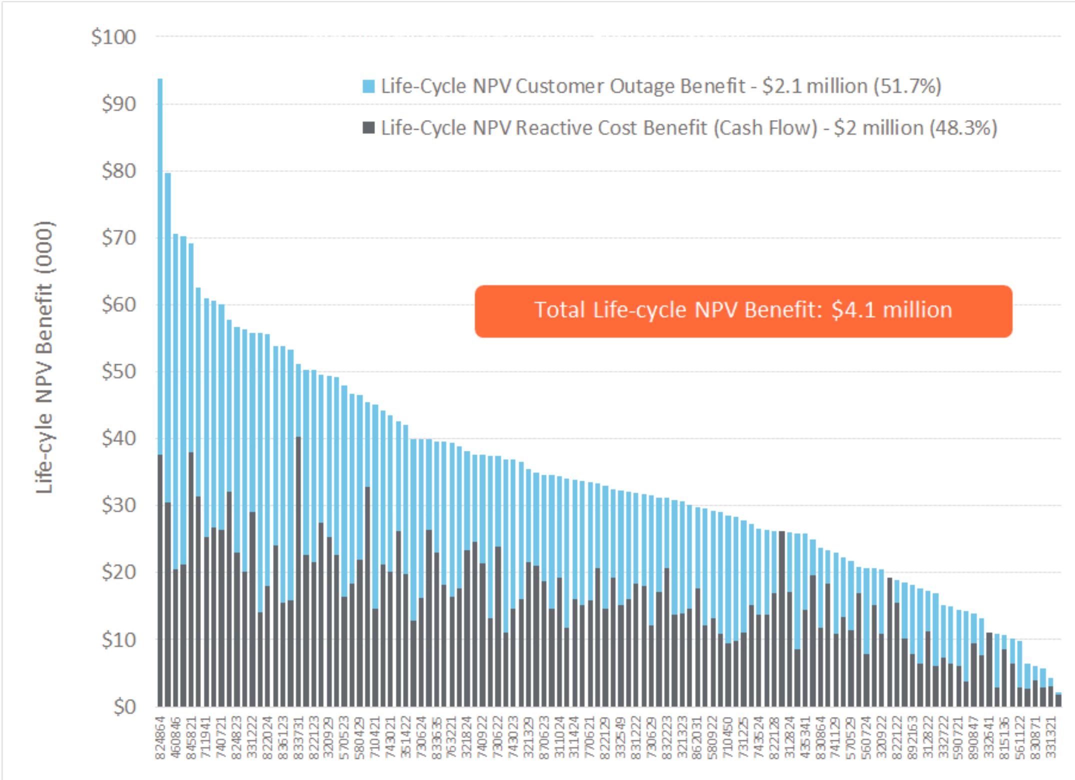


Figure 4-10: Non-Inspected Wood Pole Top Benefits Profile

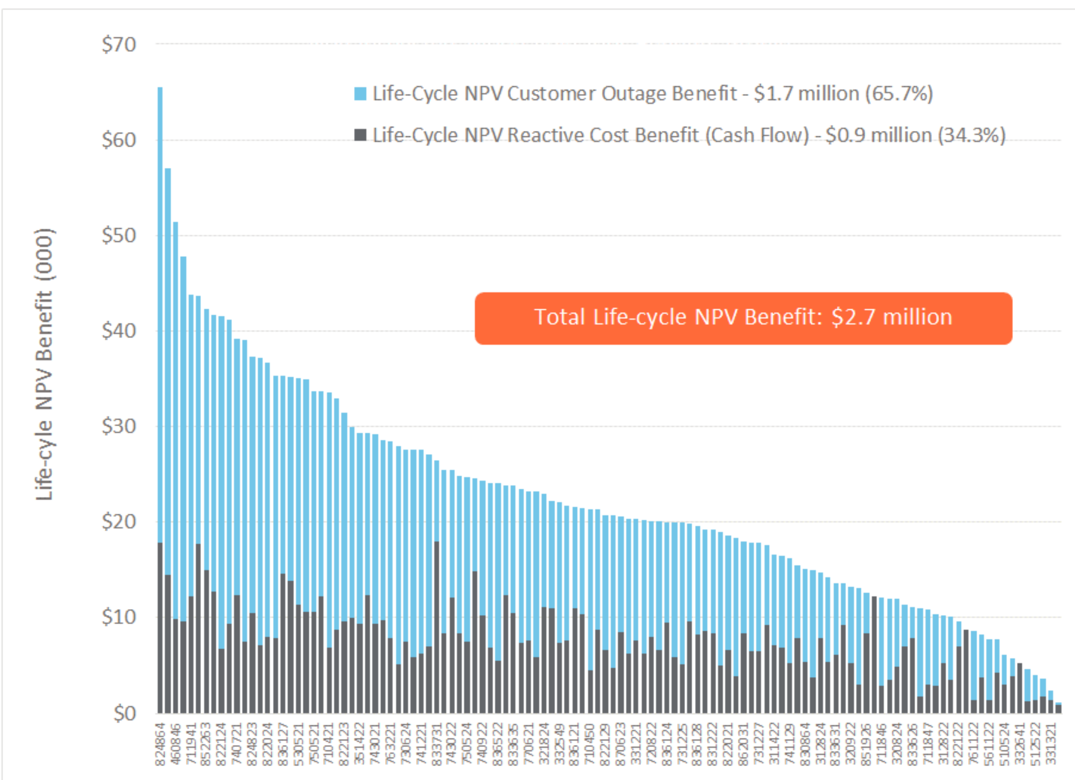


Figure 4-11: Normally Loaded Line Transformer Benefits Profile

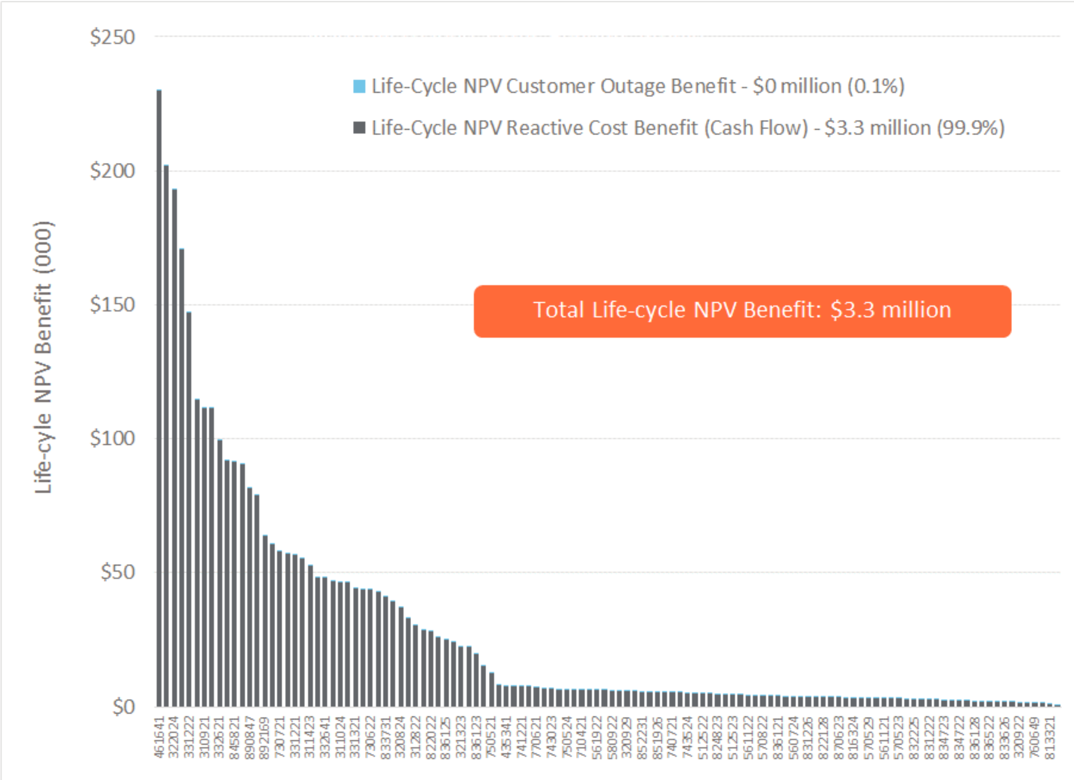
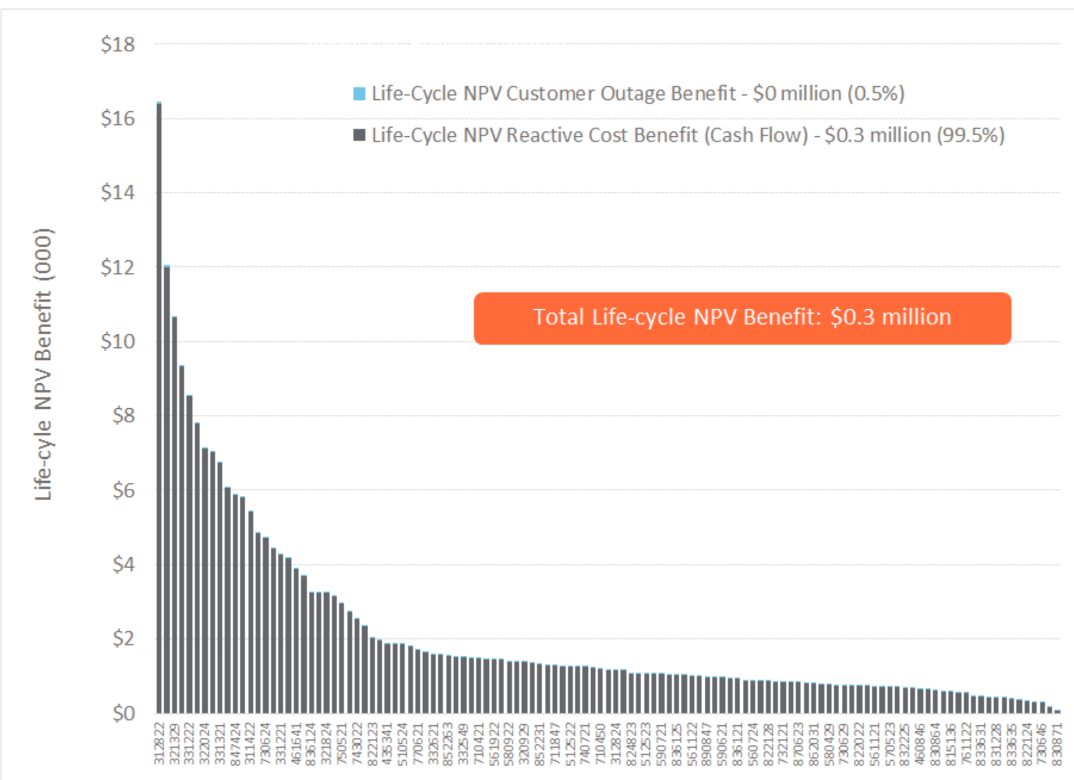


Figure 4-12: Pedestals Benefits Profile



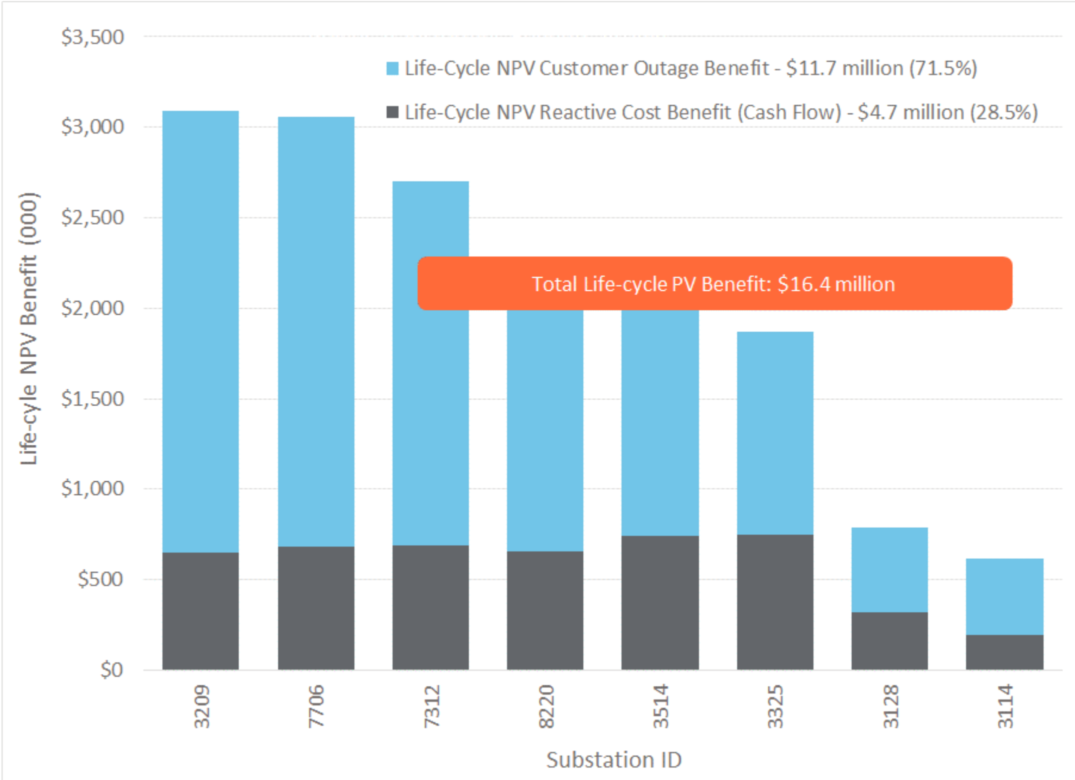
4.2 Equipment Failure Risk & Resiliency – Substation Assets

4.2.1 Power Transformers

The 2020 and 2021 Plan includes the replacement of power transformers within specific substations. The power transformer within the substation is a critical asset that bridges the high voltage transmission system and lower voltage distribution systems. Multiple evaluation criteria were used to determine the fitness of the asset to remain in service. These criteria included dissolved gas analysis, visual inspection, age, and industry-recognized design issues with some models. Not replacing infrastructure with discovered deficiencies raises considerably the possibility of failure resulting in catastrophic consequences, including some chance of fire or explosion. This event is primarily a safety concern but also costly to restore and leaves many customers without service. Lead time can be considerable; lead times greater than 1 year are common. Thus, proactive actions are warranted.

1898 & Co. mapped each of the power transformers that are part of the plan (8 in total) to the Cascade data set to capture age, condition, and consequence information (mainly customers). Figure 4-13 shows the benefits of replacing these power transformers at each of the relevant substations. The total benefit is approximately $16.4 million. The figure shows that most of the benefit, approximately 71.5 percent, is in avoiding customer outages while the 28.5 percent of the benefit is from avoiding future reactive and restoration costs.

Figure 4-13: Power Transformer Benefits Profile



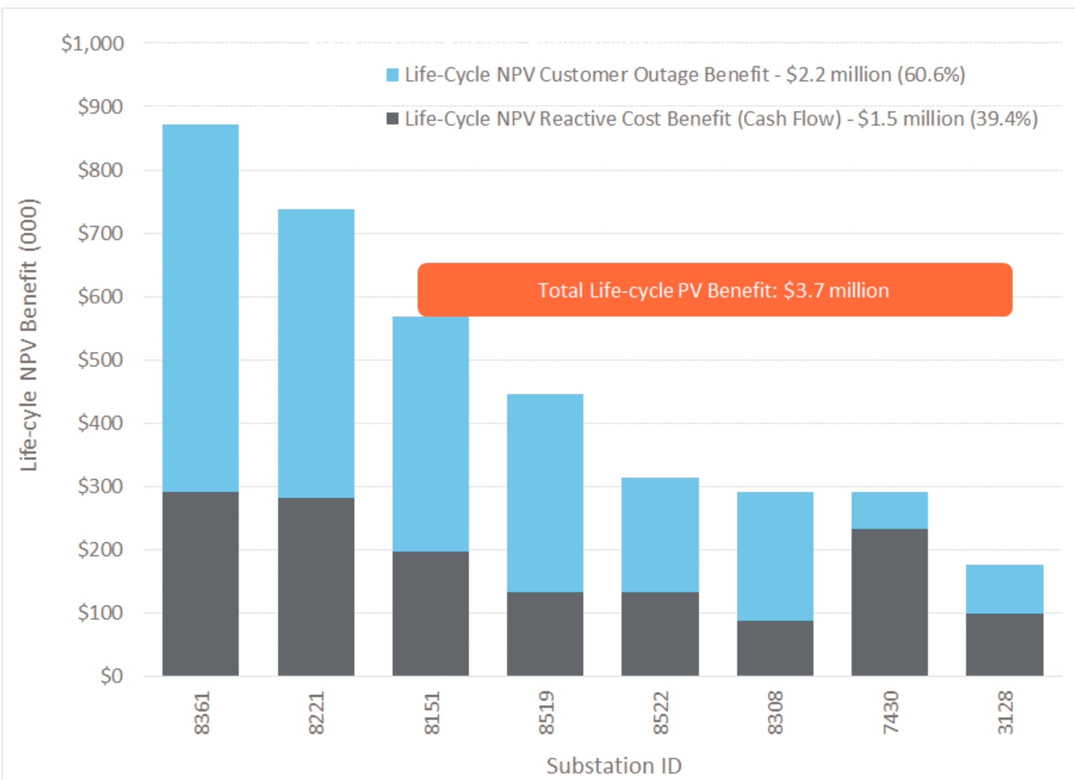
4.2.2 Transformer Breaker Protection

As discussed above, the power transformer is a critical asset that bridges the gap between the high voltage transmission system and the lower voltage distribution system. During normal operation, the transmission system delivers energy in a controlled manner to the distribution system. However, during a fault situation, the energy transfer can be very destructive to the power transformer and other systems if not interrupted. To ensure that this does not happen, transformer breaker protection prevents adverse consequences by interrupting the power flow when directed by the specific protective relays. Therefore, transformer breakers also serve a critical role within the substation.

Multiple evaluation criteria were used to determine the fitness of the asset to remain in service. These criteria included obsolescence, availability of spare parts, insulation type (oil), historical maintenance costs, and known industry deficiencies with specific breaker types. Not replacing infrastructure with discovered deficiencies considerably raises the possibility of failure resulting in catastrophic consequences including some chance of fire or explosion (primarily with oil circuit breakers). Maintaining the protection system is primarily a safety concern but also leaves many customers without service when it fails. In addition, oil circuit breakers require additional maintenance as they near end of life to maintain seals and address a shortened inspection interval.

Similar to the power transformers, 1898 & Co. mapped each of the breakers providing protection to power transformers to the Cascade data set to capture age, condition, and consequence information (mainly customers). Additionally, the mapping included breaker to relays. This mapping is important because OG&E's protection design includes encasing the breaker and relays together inside one enclosure. Decisions for maintenance and replacement of either asset involves factoring in the other. Figure 4-14 shows the benefits of replacing these breakers at each of the relevant substations. The total benefit is approximately $3.7 million. The figure shows that most of the benefit, approximately 60.6 percent, is in avoiding customer outages while the 39.4 percent of the benefit is from avoiding future reactive and restoration costs.

Figure 4-14: Transformer Breaker Benefits Profile

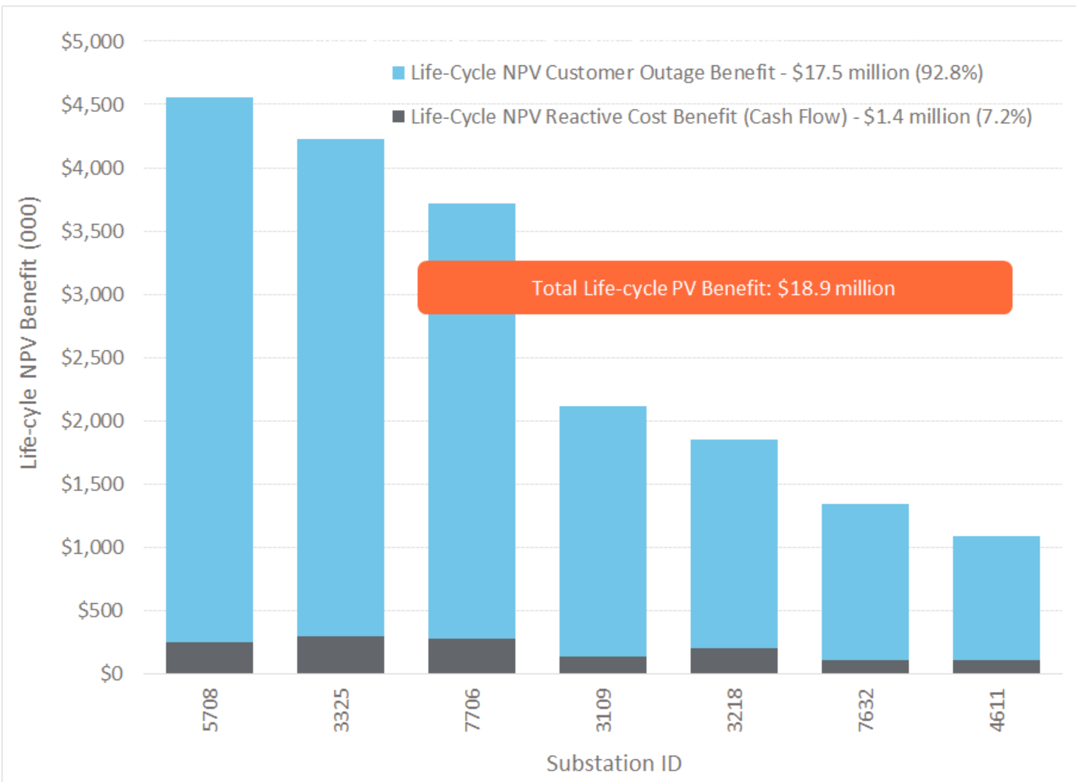


4.2.3 Transformer Fuse to Breaker Conversion

Power transformer protection can be provided by either a fuse or a breaker. Protection via fuse is an old standard, and these assets are generally past their expected service lives. Breaker protection is a better approach for protection and generally allows for quicker restoration of customers once the fault is cleared.

1898 & Co. also mapped each of the conversions to existing fuses within the Cascade data set. The plan includes upgrading the fuse protection to OG&E's breaker equipment standard. Figure 4-15 shows the benefits of replacing these fuses with breakers at each of the relevant substations. The total benefit is approximately $18.9 million. The figure shows that most of the benefit, approximately 92.8 percent, is in avoiding customer outages while the 7.2 percent of the benefit is from avoiding future reactive and restoration costs.

Figure 4-15: Transformer Fuse to Breaker Conversion Benefits Profile

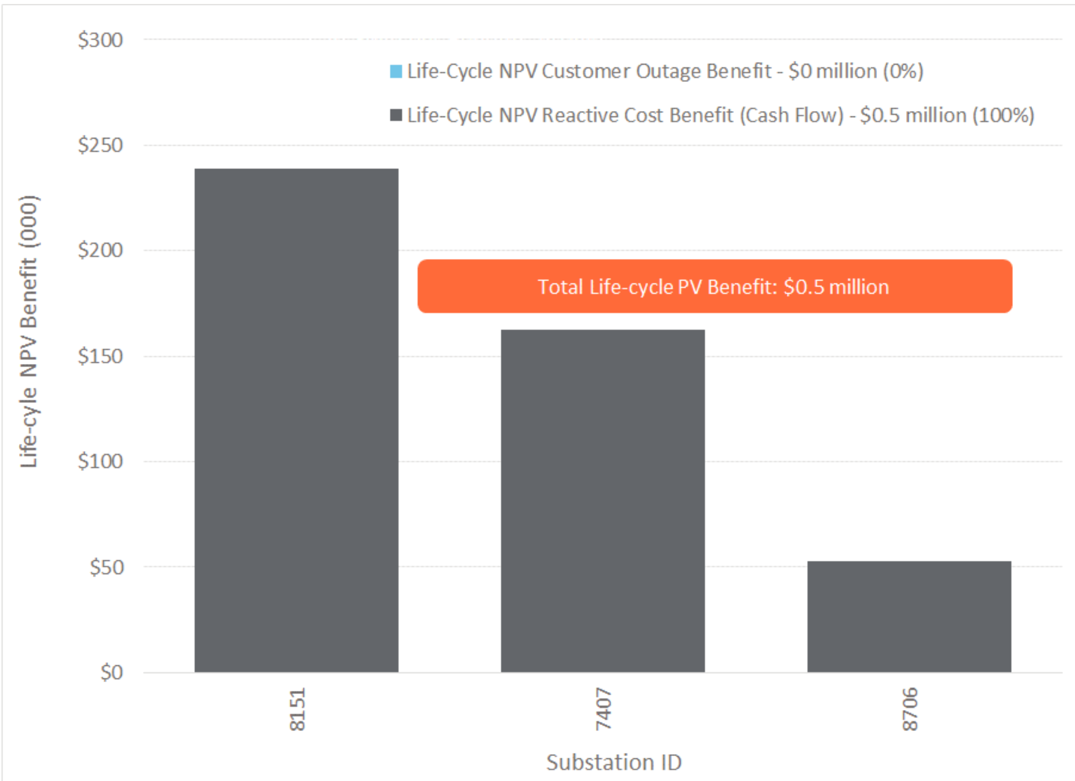


4.2.4 Cap Switcher

A Cap switcher is a capacitor switching device specifically designed to meet the power quality needs of today's electrical systems. The benefits for the evaluation are based on the benefits of proactive versus reactive asset management. While power quality is a necessity of a modern grid, no value was assigned to a power quality requirement.

1898 & Co. also mapped cap switchers that are part of the plan within the Cascade data set. Figure 4-16 shows the benefits of replacing the cap switchers. The total benefit is approximately $0.5 million. All the benefits are from avoided future reactive and restoration costs as cap switchers are internal to the substation and do not provide protection.

Figure 4-16: Cap Switcher Benefits Profile



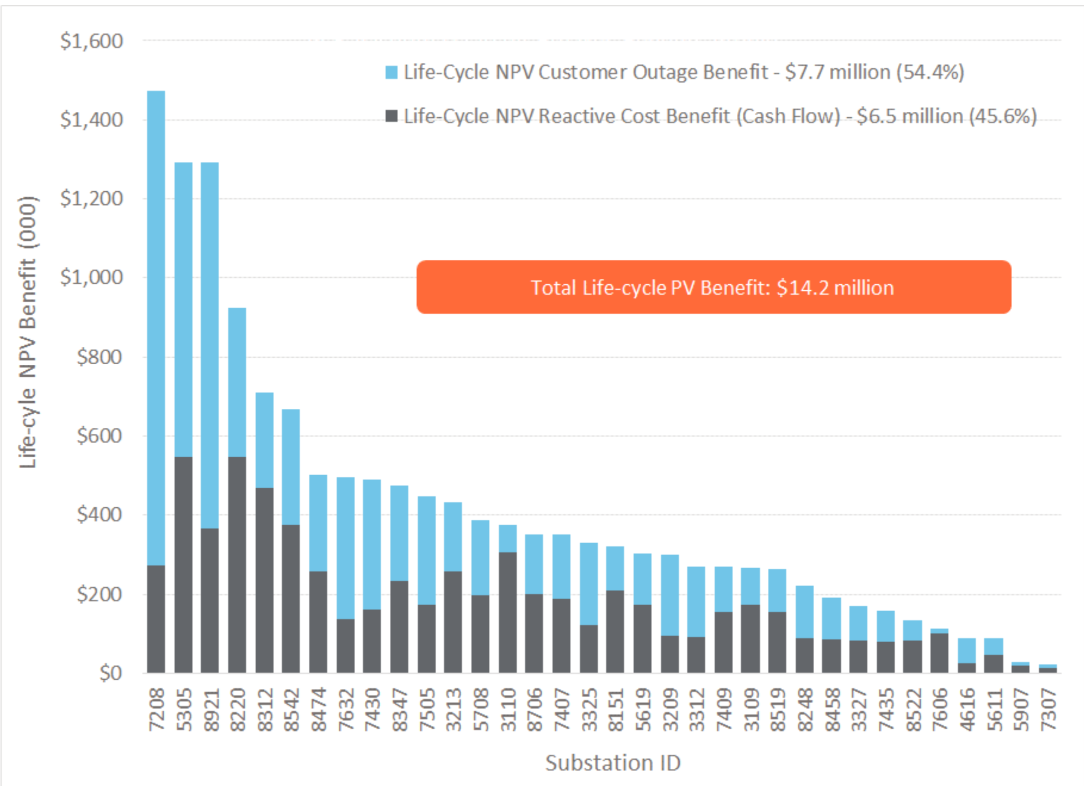
4.2.5 Distribution Circuit Breakers

The distribution circuit breaker's primary role is to protect customers and quickly reenergize the circuit once the fault is cleared. Breakers are mechanical devices and wear with age and number of actuations. This aging amplifies the risk of failure and the resulting consequences.

Multiple evaluation criteria were used to determine the fitness of the asset to remain in service. These criteria included obsolescence, availability of spare parts, insulation type (oil), historical maintenance costs, and known industry deficiencies with specific breaker types. Additionally, the breakers may be replaced as part of an effort to replace the relays. Not replacing infrastructure with discovered deficiencies considerably raises the possibility of failure resulting in catastrophic consequences, including some chance of fire or explosion (primarily with oil circuit breakers). Maintaining the protection system is primarily a safety concern but also leaves many customers without service when it fails. In addition, oil circuit breakers require additional maintenance as they near end-of-life to maintain seals and address a shortened inspection interval.

Similar to the other substation assets, 1898 & Co. mapped each distribution asset to the Cascade data set to capture age, condition, and consequence information (mainly customers). Similar to the power transformer protection breakers, the mapping included breaker to relays. This mapping is important because OG&E's protection design includes encasing the breaker and relays together inside one enclosure. Decisions for maintenance and replacement of either asset involves factoring in the other. Figure 4-17 shows the benefits of replacing these breakers at each of the relevant substations. The total benefit is approximately $14.2 million. The figure shows that benefit is mixed with approximately 54.4 percent from customers and 45.6 percent from avoiding future reactive and restoration costs.

Figure 4-17: Distribution Circuit Breakers Benefits Profile



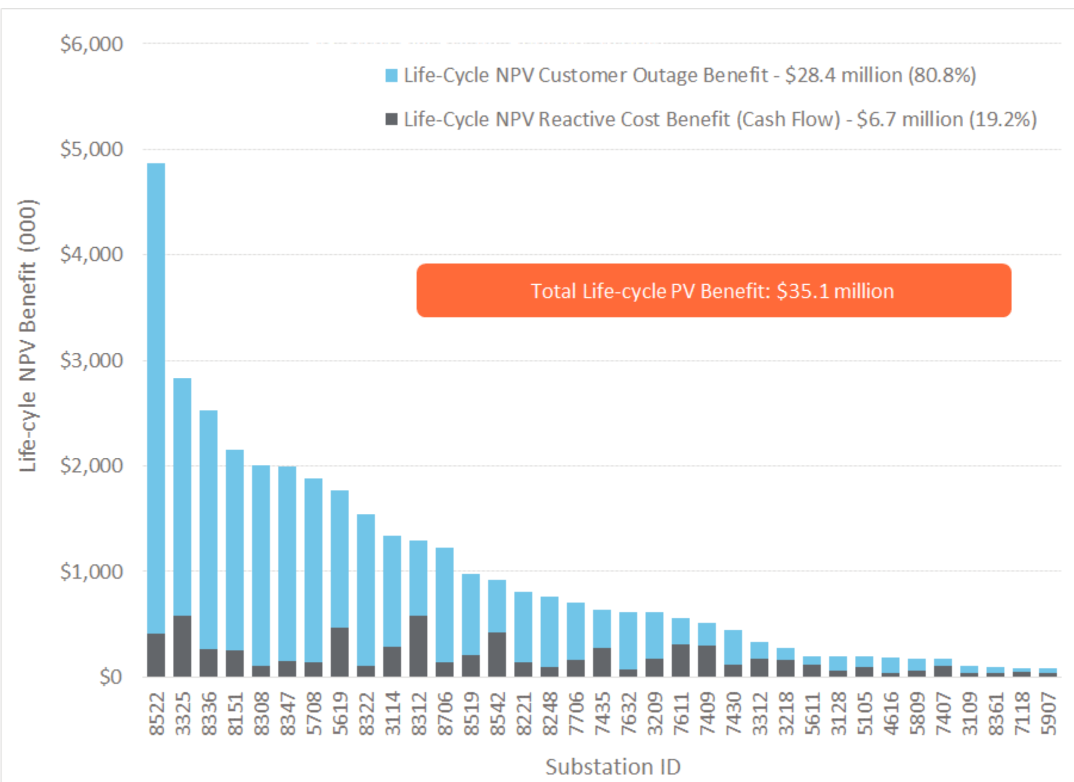
4.2.6 Electromechanical Relays

Protection schemes require the coordination of both the fault sensing equipment (relays) and the interruption device (breaker). Hence relays perform a critical protection function. Electromechanical relays have performed this role well for many decades, but now microprocessor relays can perform the protection sensing more efficiently including self-diagnostics. In addition, electromechanical relays are no longer manufactured making them an obsolete equipment. Utilities across the United States are upgrading to digital relays because of this obsolescence.

1898 & Co. also performed the mapping of plan assets to the Cascade system. Additionally, the mapping included linking the breakers and relays to cover the costs and benefits of the replacement together. The mapping provides the needed customer impact information to evaluate consequences for each relay.

Figure 4-18 shows the benefits of upgrading the electromechanical relays at each of the relevant substations. The total benefit is approximately $35.1 million. The figure shows that most of the benefit is from customer avoided outages at approximately 80.8 percent. The other 19.2 percent from avoiding future reactive and restoration costs.

Figure 4-18: Electromechanical Relay Benefits Profile

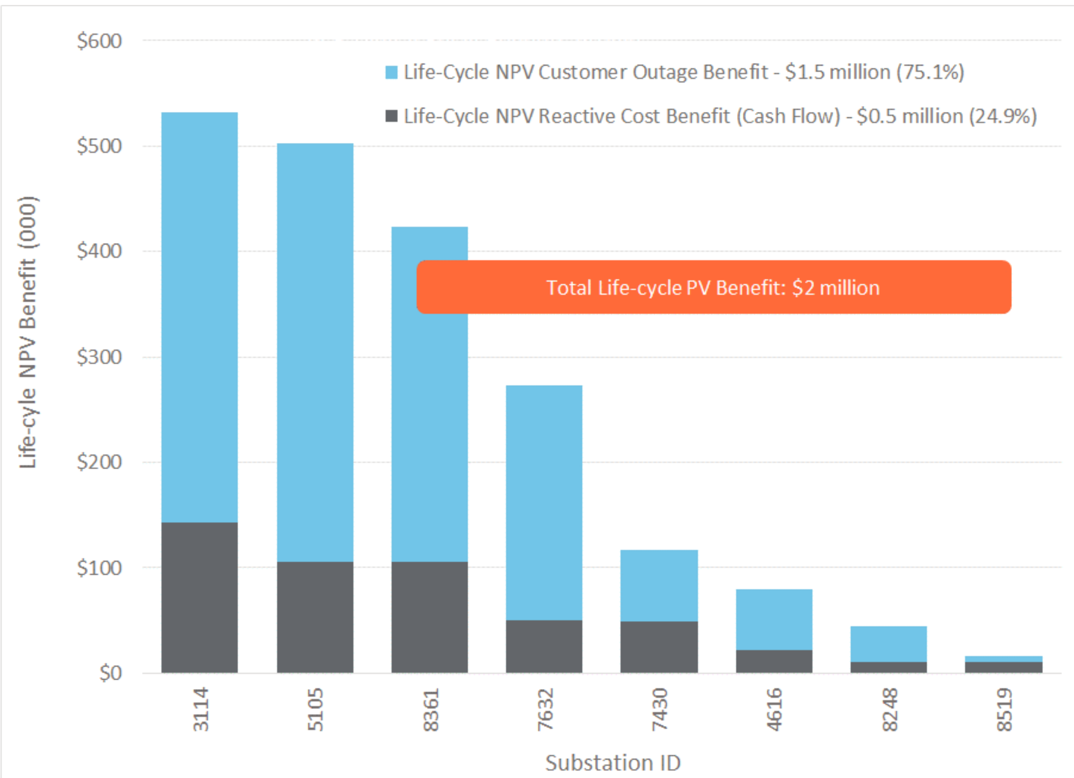


4.2.7 Digital Relays

The plan also includes the replacement of digital or microprocessor relays. As discussed above, the protection equipment inside the substation is all enclosed together and provides life-cycle cost efficiencies replacing them at the same time. Because of this, breaker replacements also replace digital relays. Additionally, early generation digital relays have shown systematic deficiencies. Digital relays were included in the plan for both of these reasons.

Figure 4-19 shows the benefits of replacing digital relays at each of the relevant substations. The total benefit is approximately $2.0 million. The figure shows that most of the benefit is from customer avoided outages at approximately 75.1 percent. The other 24.9 percent from avoiding future reactive and restoration costs.

Figure 4-19: Digital Relays Benefits Profile



4.3 Outage Mitigation Risk & Resiliency Benefits Results

4.3.1 Animal Outages Avoided

Animal-caused outages within substations can have significant impacts. Snakes, squirrels, beavers, and other small animals easily make it through fencing and seek shelter within the substation equipment, causing outages. Outages within substations can cause thousands of customers to be without service since several circuits are impacted. Animal protection solutions are proven to be quite effective at keeping the animals away from the equipment. As discussed above, the benefits assessment assumes an effectiveness of 95 percent in decreasing substation animal outages. Figure 4-20 shows the avoided CMI benefit by substation ranked highest to lowest. The figure shows a wide range of avoided CMI by substation. Some of this spread is due to the proximity of substations to animal populations and others due to accurate outage record keeping. Figure 4-21 shows the economic benefit for adding animal protection to each substation. This is based on monetizing the outages in Figure 4-20 using the DOE ICE Calculator and accounting for mitigated substation truck rolls. The total benefit is approximately 53.5 million life cycle CMI and in $48.9 million in economic terms. The figure shows that most of the benefit is from customer avoided outages at approximately 99.1 percent. The other 0.9 percent from avoiding future reactive and restoration costs.

Figure 4-20: Animal Outages Avoided CMI Benefits Profile

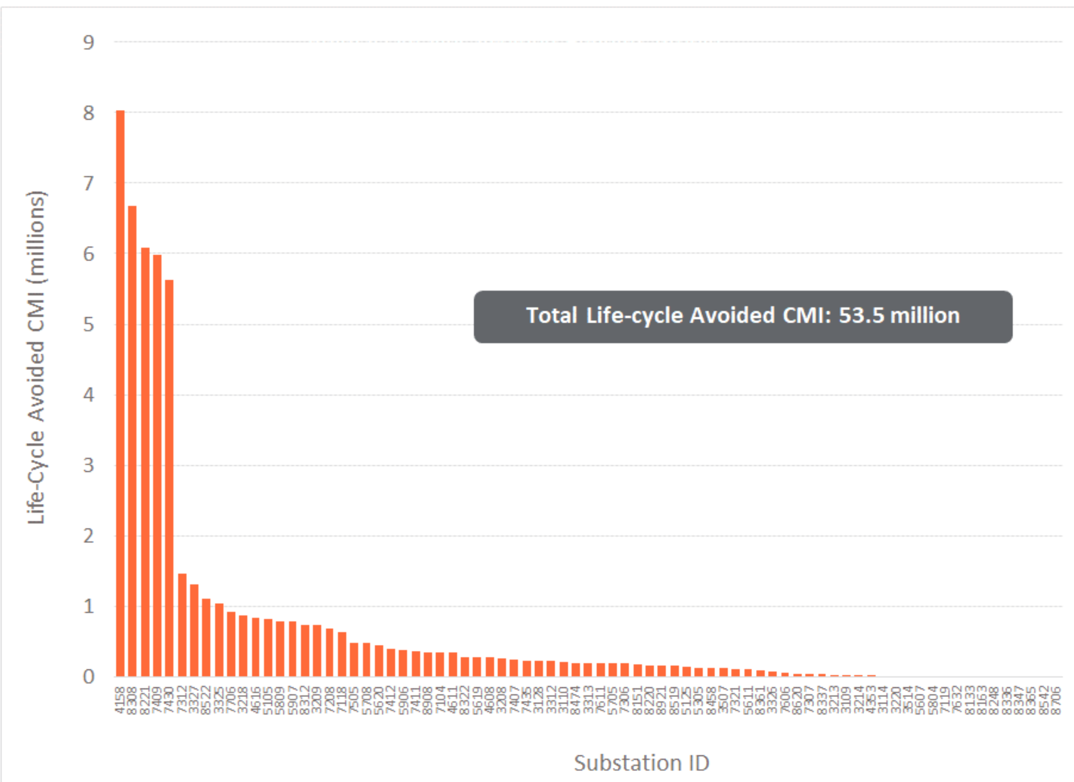
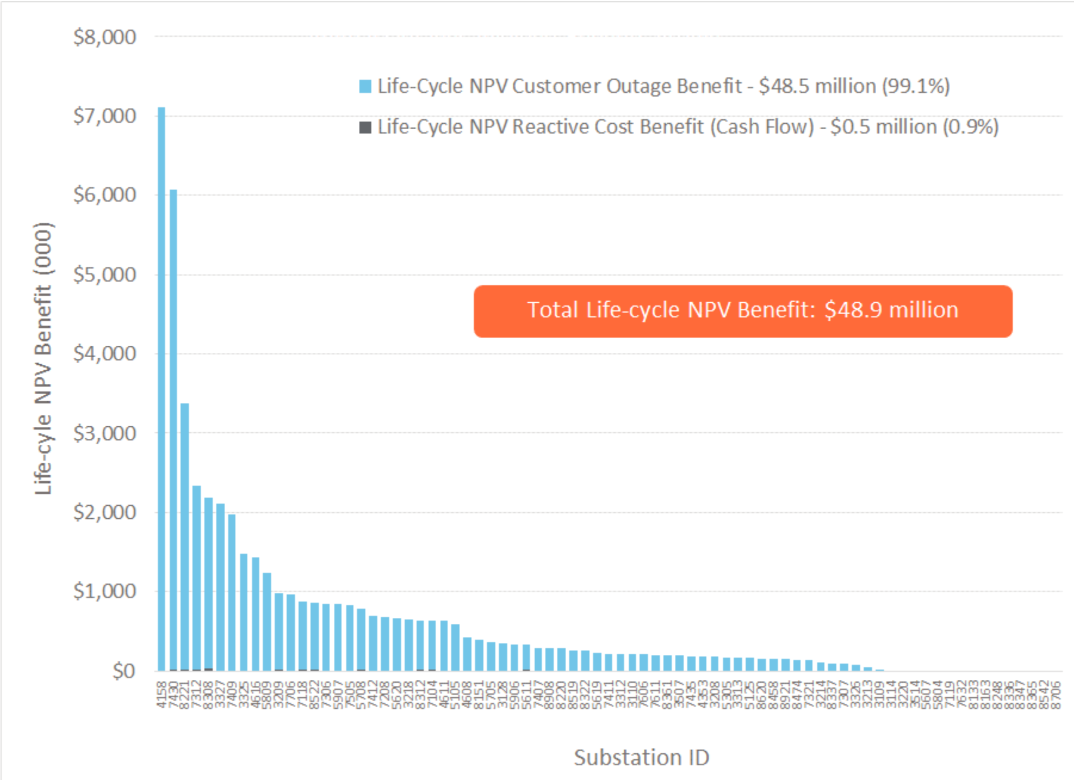


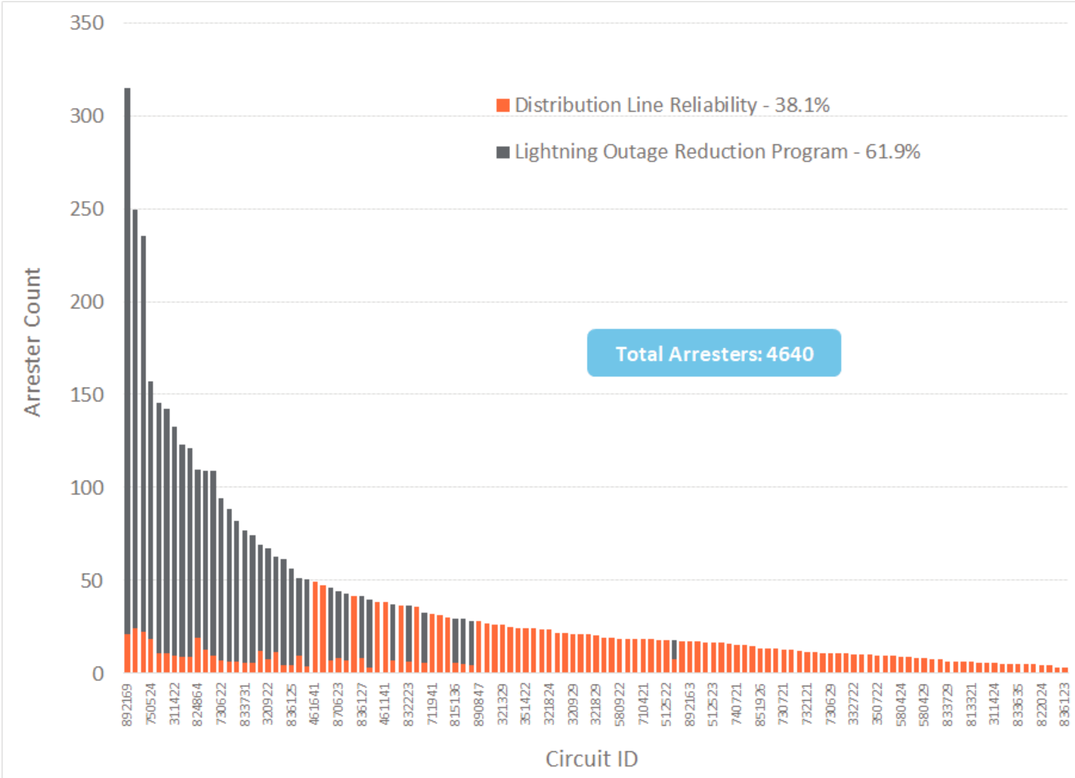
Figure 4-21: Animal Outages Avoided Benefits Profile



4.3.2 Lightning Outages Avoided

The Distribution Line Reliability and Lightning Outage Reduction Program include adding lightning arresters to each circuit. Figure 4-22 shows the planned arrester additions for each circuit and the investment category under which they would be added. Approximately 4,640 arresters are a part of the Grid Enhancement Plan, with approximately 38 percent from Distribution Line Reliability and approximately 62 percent from the Lightning Outage Reduction Program. The number of added arresters to each circuit is based on the number of existing arresters and the length of the circuit mainline.

Figure 4-22: Planned Arrester Additions by Circuit



As discussed above, the benefits assessment assumes an effectiveness of 80 percent in decreasing lightning outages for circuits with the Lightning Outage Reduction Program and 20 percent for the Distribution Line Reliability circuits. Figure 4-23 shows the avoided CMI benefit by circuit ranked highest to lowest. Figure 4-24 shows the economic benefit of adding lightning arresters to each circuit. This is based on monetizing the outages in Figure 4-23 using the DOE ICE Calculator and accounting for mitigated substation truck rolls. The total benefit is approximately 153.3 million life cycle CMI and in $113.8 million in economic terms. The figure shows that most of the benefit is from customer avoided outages at approximately 96.3 percent. The other 3.7 percent from avoiding truck rolls.

Figure 4-23: Lightning Outages Avoided CMI Benefits Profile

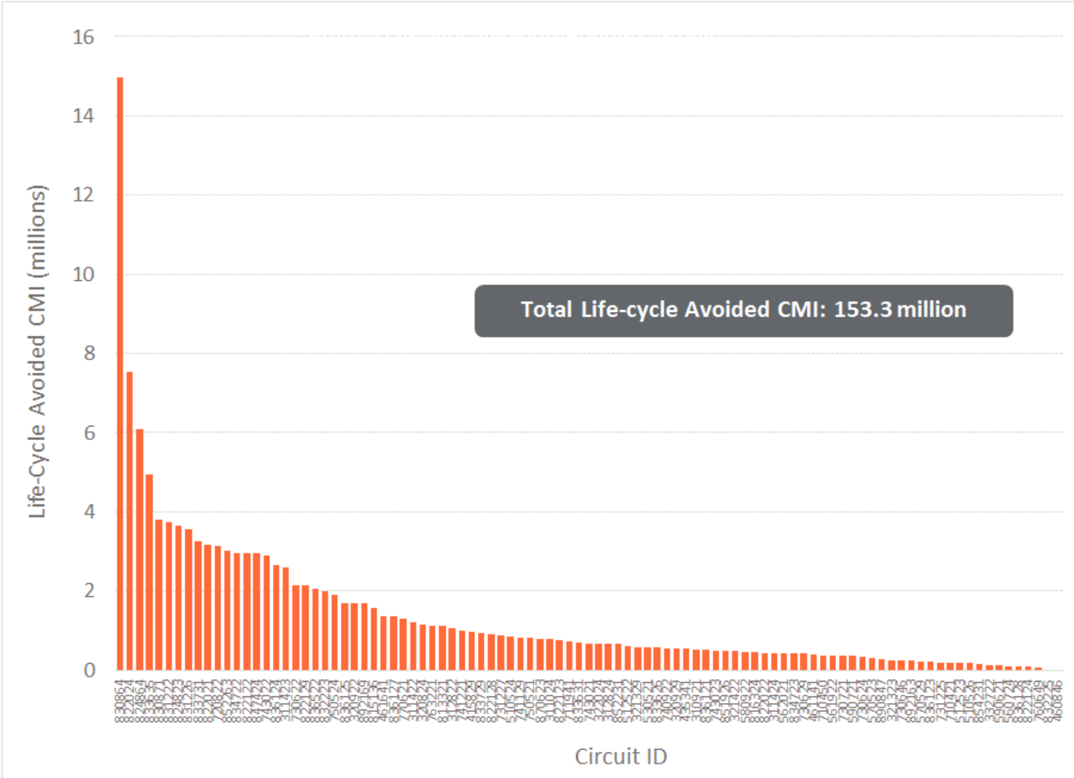
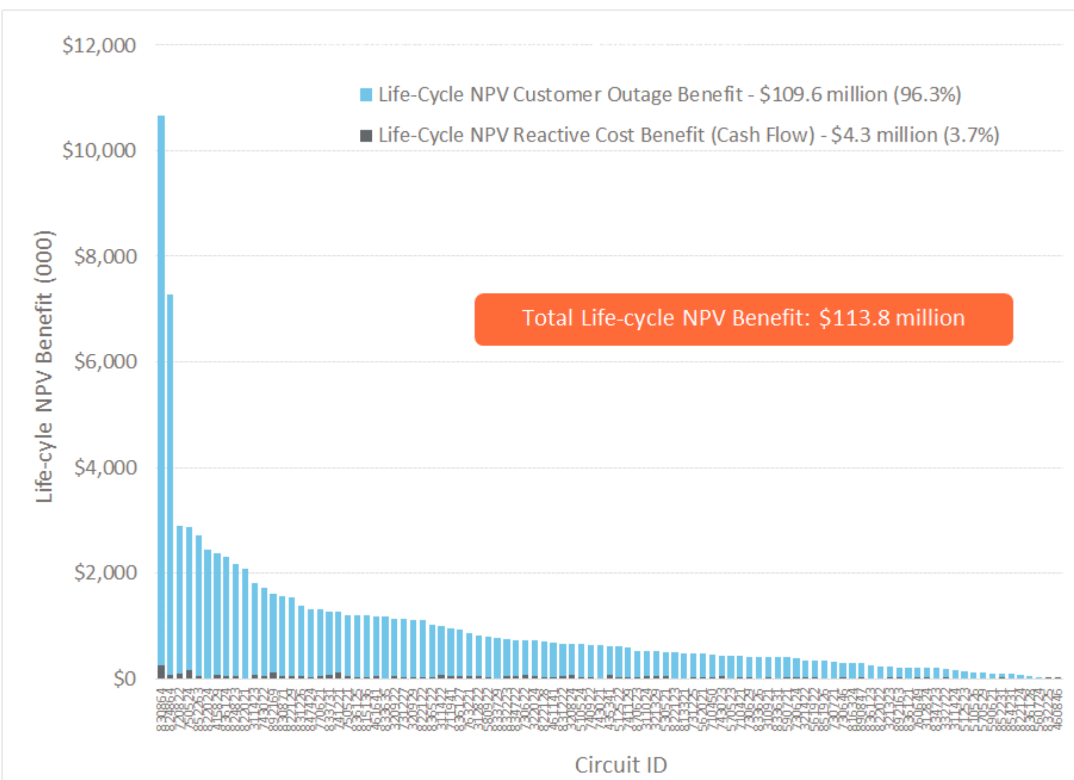


Figure 4-24: Lightning Outages Avoided Benefits Profile



4.3.3 Avoided Outages

The investment in a modernized protection schema, including the Smart Lateral Fuses and Automated Circuit Tie Lines investment categories, provides many different benefits streams as outlined in Section 3.4.3.4. The first benefit stream is the mitigation of miscoordination in the current protection schema where nuisance outages trip a fuse, resulting in customer outages and truck rolls instead of 'blinking.' This concept is outlined in more detail in Section 3.4.3.4.2.

The benefits of this value stream were quantified by identifying these mis coordinated outages in the historical outage records and adjusting them accordingly. Figure 4-25 shows the avoided CMI benefit by circuit ranked highest to lowest for a total of 2.6 million of avoided life cycle CMI. Figure 4-26 shows the economic benefit for each circuit. This is based on monetizing the outages in Figure 4-25 using the DOE ICE Calculator and accounting for mitigated truck rolls. The figure shows total benefits of $5.6 million with approximately 87.5 percent from customer benefits and the remaining from reactive cost benefits. Relative to the other benefit streams for the new modern protection schema investments, this one is minor. As the figure shows, approximately 40 percent of the benefit originates from fewer truck rolls ($500 per truck roll).

Figure 4-25: Avoided Outages Benefits CMI Profile

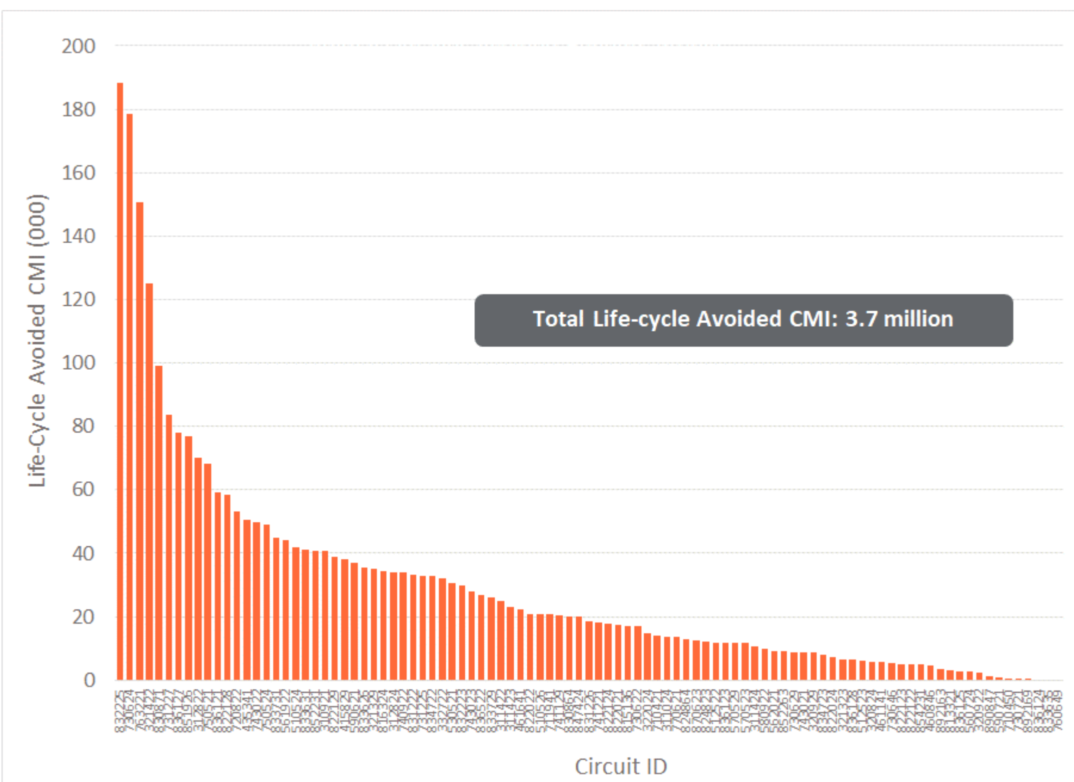
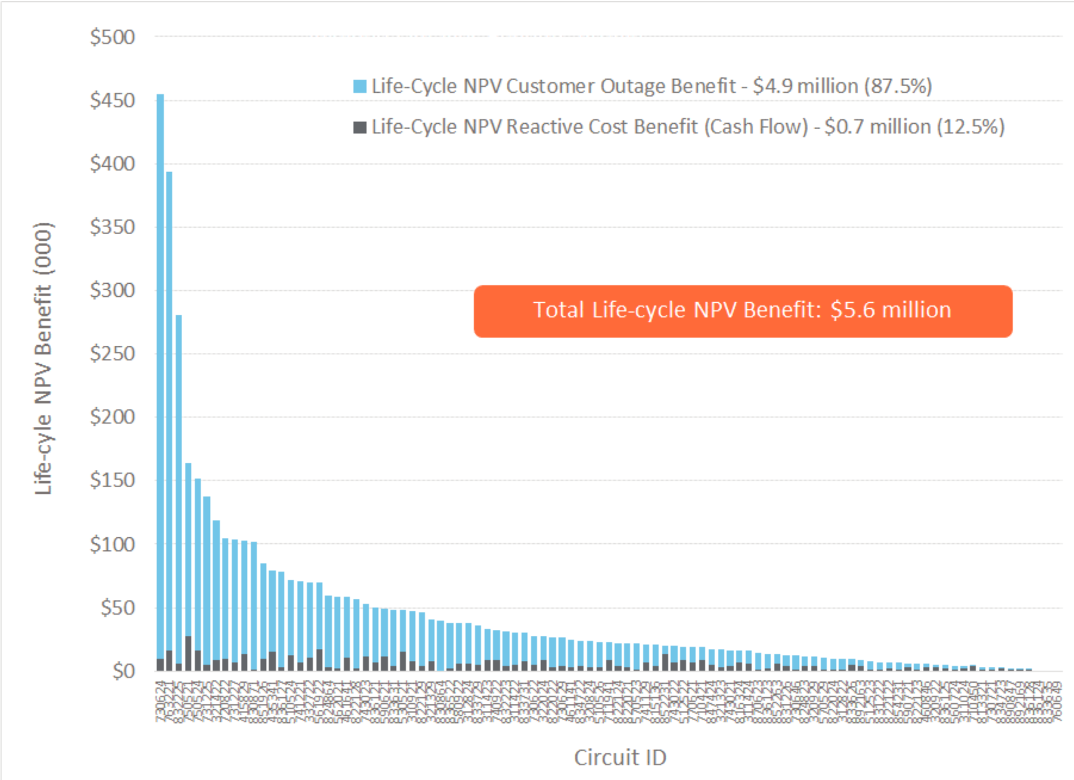


Figure 4-26: Avoided Outages Benefits Profile



4.3.4 Decreased ‘Blinking’

Decreased ‘Blinking’ is the second value stream of the new modern protection schema. ‘Blinking’ occurs when specific protection devices ’sense’ nuisance outages via a reclosing mechanism. The device locks out for a short period of time (typically a few cycles) and then closes the circuit again to ‘sense’ if the fault cleared or not. The main benefit of the Smart Lateral Fuse investment is to decrease ‘blinking’ by having the ‘sensing’ devices be a TripSaver® with hundreds of downstream customers rather than a recloser with 750 to 2,000 downstream customers. It should be noted that OG&E has received negative customer feedback related to the amount of ‘blinking’ on the system. Refer to Section 3.4.3.4.3 for additional information.

Figure 4-27 shows the avoided CMI benefit by circuit ranked highest to lowest for a total of 4.1 million of avoided life cycle CMI. Figure 4-28 shows the economic benefit for each circuit. This benefit is based on monetizing the ‘blinking’ outages in Figure 4-27 using the DOE ICE Calculator as a basis for estimating the impact to customers of ‘blinks.’’ Figure 4-28 shows total benefits of $118.9 million all coming from customer.

Figure 4-27: Decreased 'Blinking' CMI Benefits Profile

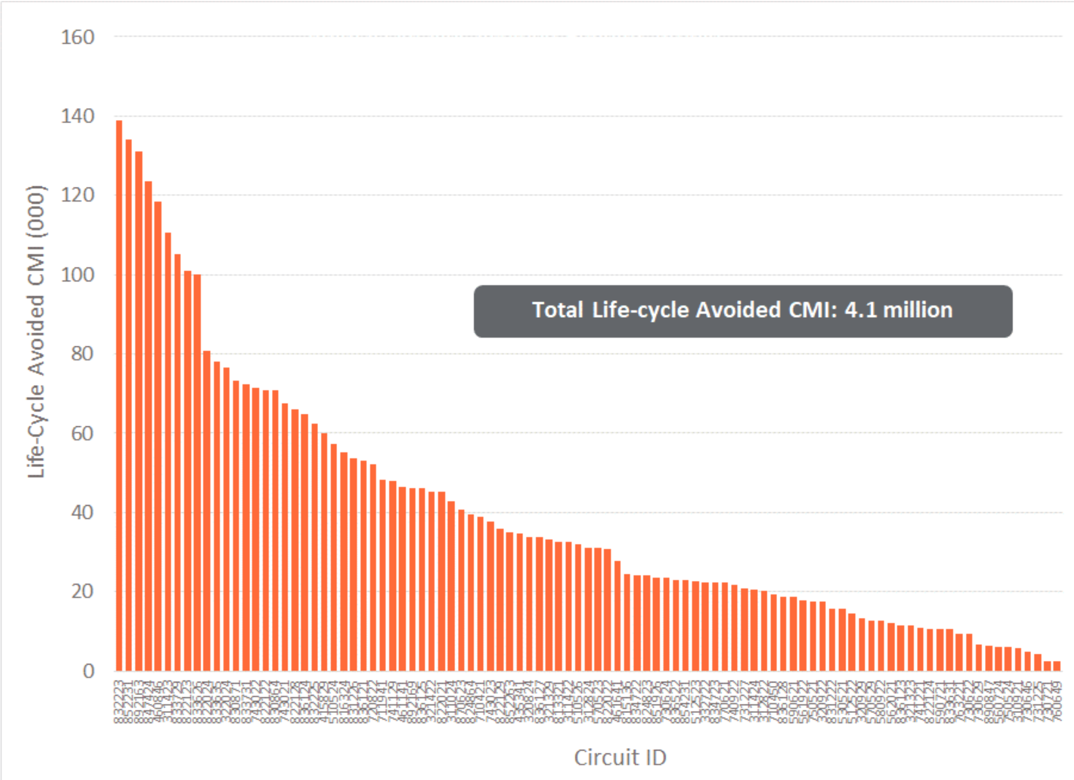
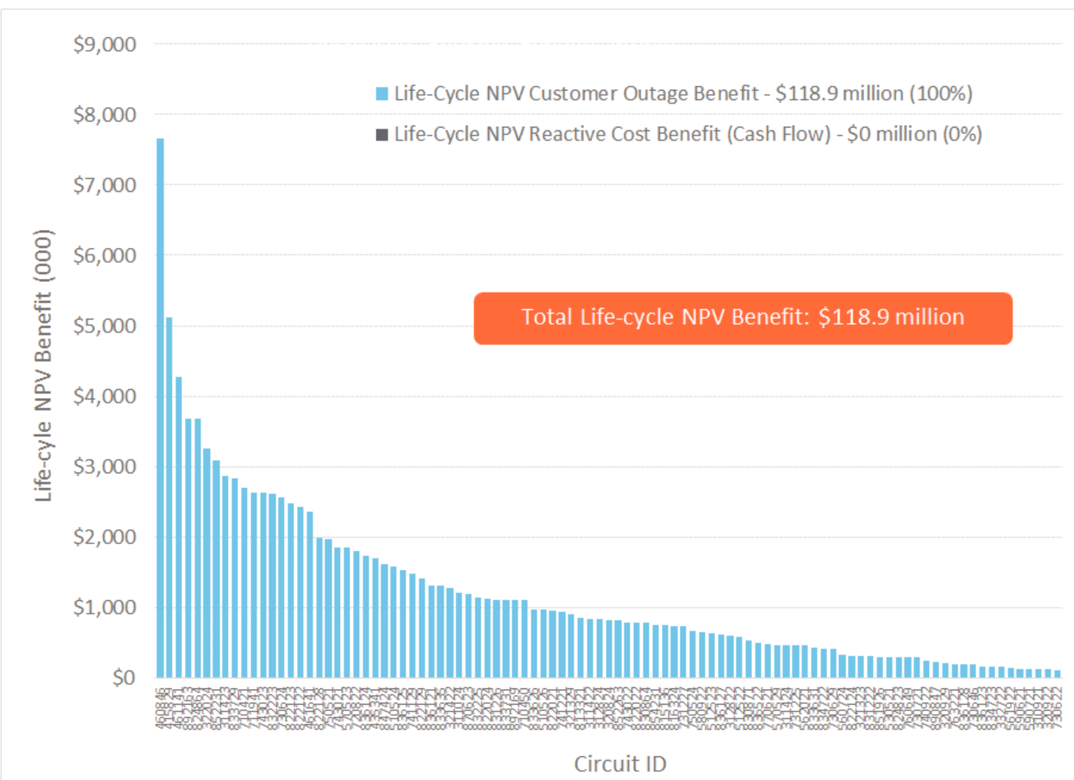


Figure 4-28: Decreased 'Blinking' Benefits Profile



4.3.5 Improved Coordination

The third benefit stream of the modern protection schema is improved coordination where mainline reclosing protection devices lock out when the fuse should have locked out and provided protection. This mis-coordination locks out more customers than necessary (thousands instead of hundreds) and is challenging to identify the location of the fault making the duration to restore service longer than needed. As outlined in Section 3.4.3.4.4, 1898 & Co. identified these outages in the historical outage records and adjusted accordingly.

Figure 4-29 shows the avoided CMI benefit by circuit ranked highest to lowest for a total of 0.1 million of avoided life cycle CMI. Figure 4-30 shows the economic benefit for each circuit. This benefit is based on monetizing the outages in Figure 4-29 using the DOE ICE Calculator and the customer profile for each protection device. Figure 4-30 shows total benefits of $4.9 million all coming from customer. Additionally, the figures show the benefit is relatively low compared the Decreased 'Blinking' and Automated Feeder Switching (next section) benefit streams.

Figure 4-29: Improved Coordination CMI Benefits Profile

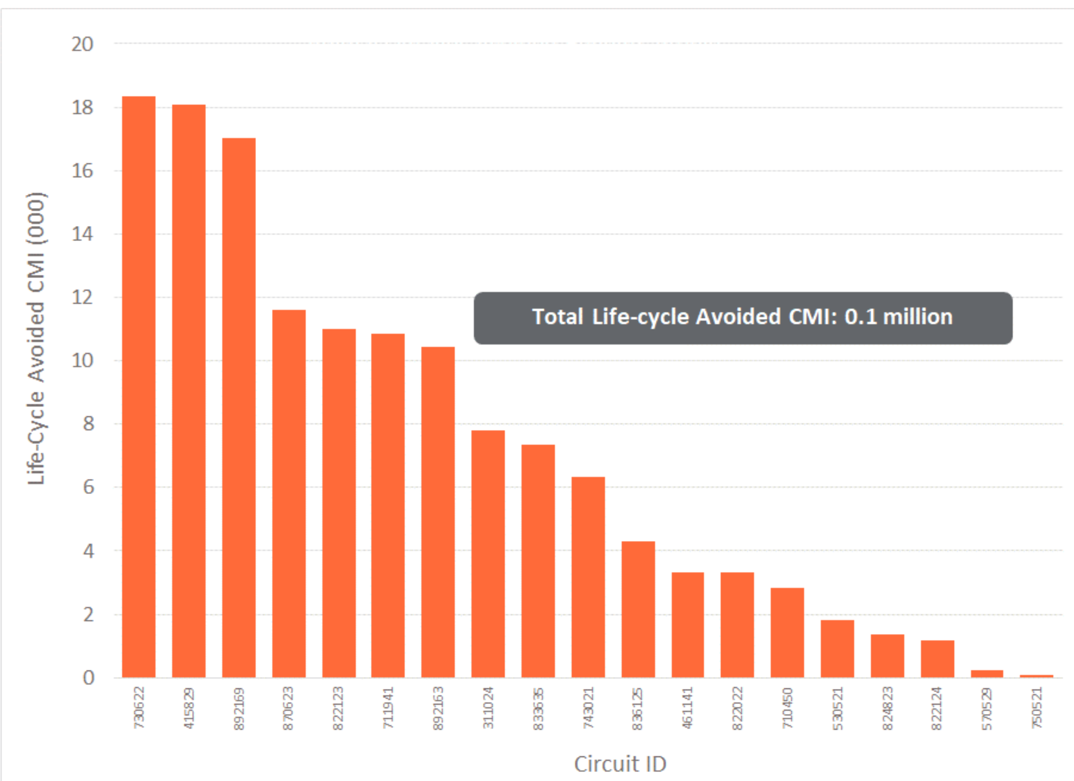
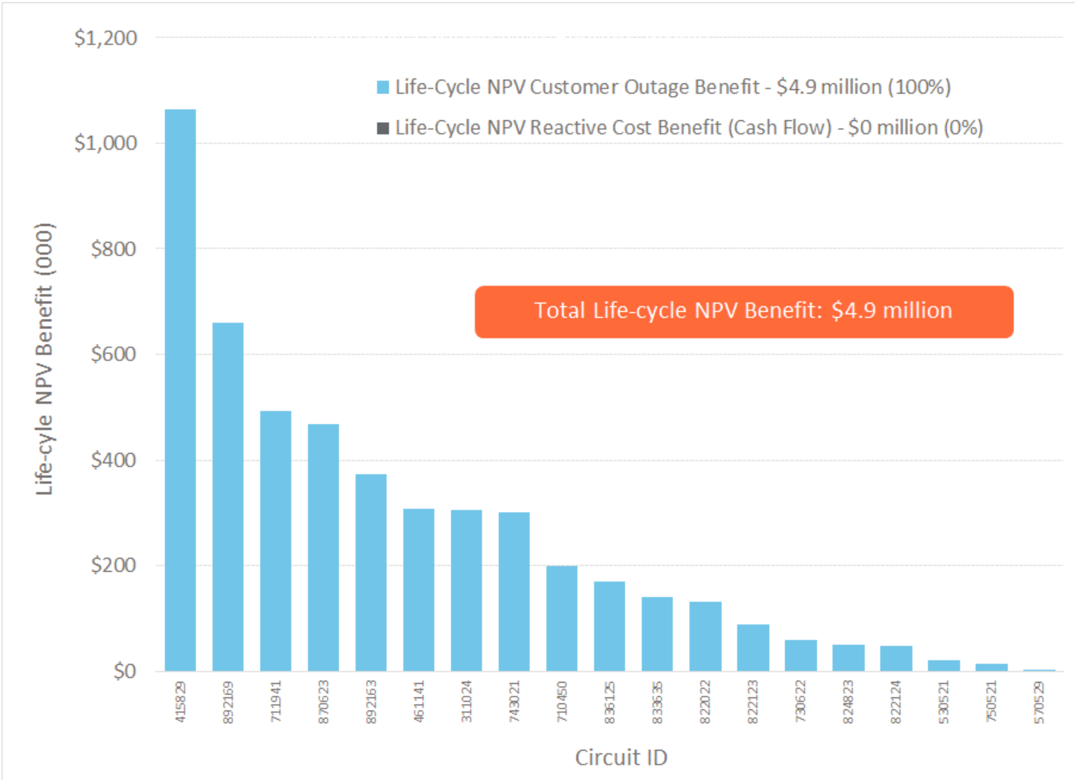


Figure 4-30: Improved Coordination Benefits Profile



4.3.6 Automated Feeder Switching

As discussed in Section 3.4.3.4.5, the new modern protection schema will allow for the transfer of customer to adjacent circuits for mainline outages. Since outages on mainline feeders typically impact 1,000 to 2,000 customers there is significant value to customers in sectionalizing the impact down to 400 to 500 customers and moving the remaining downstream customers to the adjacent circuit. Section 3.4.3.4.5 describes the approach to estimating the avoided customer outages.

Figure 4-31 shows the avoided CMI benefit by circuit ranked highest to lowest for a total of 1.8 billion of avoided life cycle CMI. Figure 4-32 shows the economic benefit for each circuit. This is based on monetizing the outages in Figure 4-31 using the DOE ICE Calculator and customer profile for each protection device. Figure 4-32 shows total benefits of $60.6 million all coming from customer.

Figure 4-31: Automated Feeder Switching CMI Benefits Profile

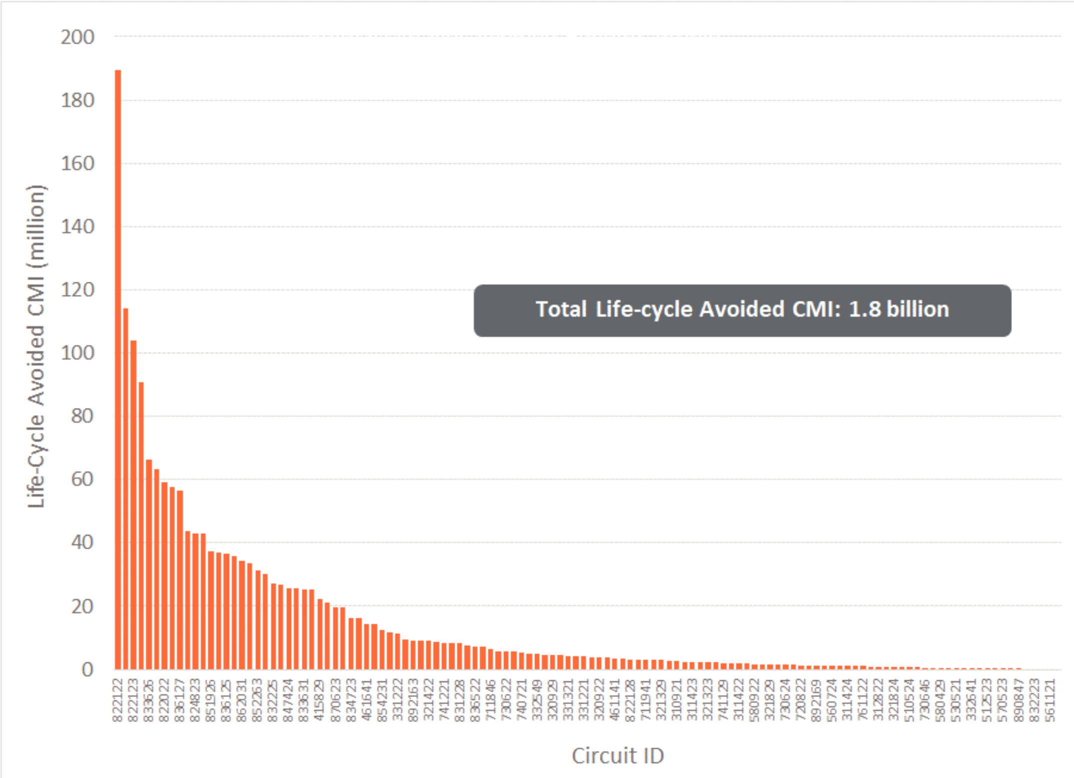
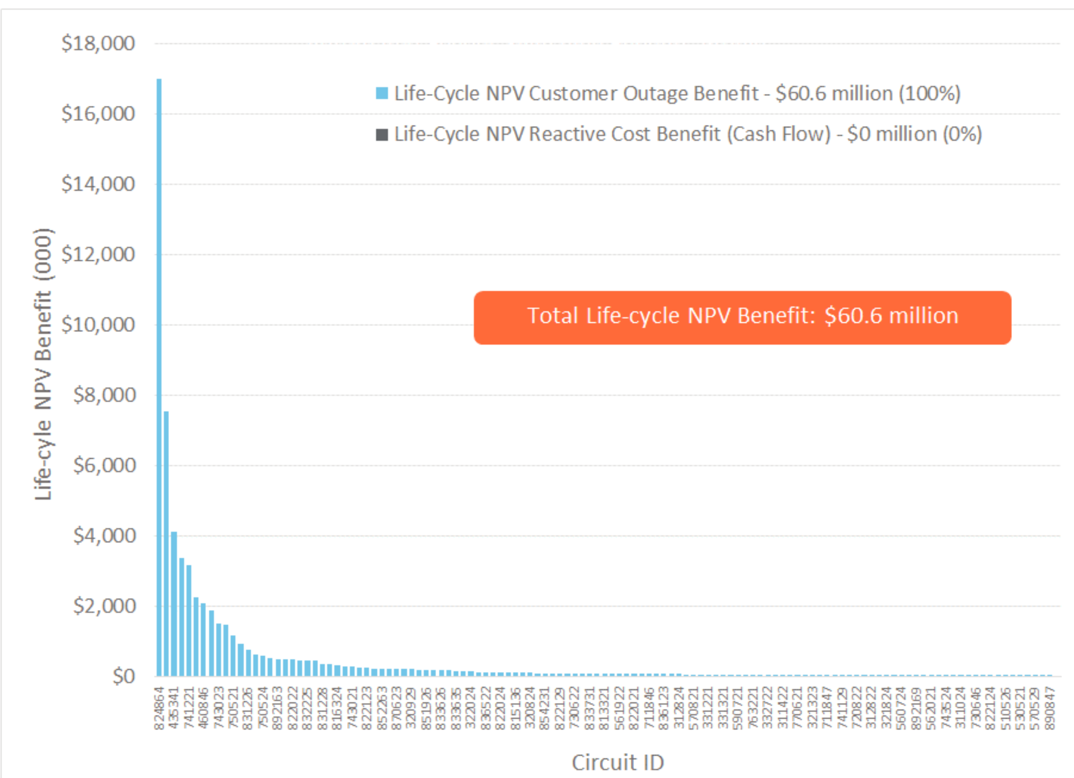


Figure 4-32: Automated Feeder Switching Benefits Profile



4.3.7 Fault Location Improvement

As discussed in Section 3.4.3.5, the plan includes investment in new communications and fault sensing equipment within the substations to aid in identifying the location of the fault on a circuit. This saves crews time identifying the location of the outage and decreases the duration customers are without service. Section 3.4.3.5 describes the approach to estimating these benefits.

Figure 4-33 shows the avoided CMI benefit by circuit ranked highest to lowest for a total of 107.8 million of avoided life cycle CMI. Figure 4-34 shows the economic benefit for each circuit. This is based on monetizing the outages in Figure 4-33 using the DOE ICE Calculator and the customer profile for each outage device. Figure 4-34 shows total benefits of $61.6 million mainly for customers' improved experience; however, there is a small amount of Reactive-based benefits from the decreased cost of crews to identify outages.

Figure 4-33: Fault Location Improvement CMI Benefits Profile

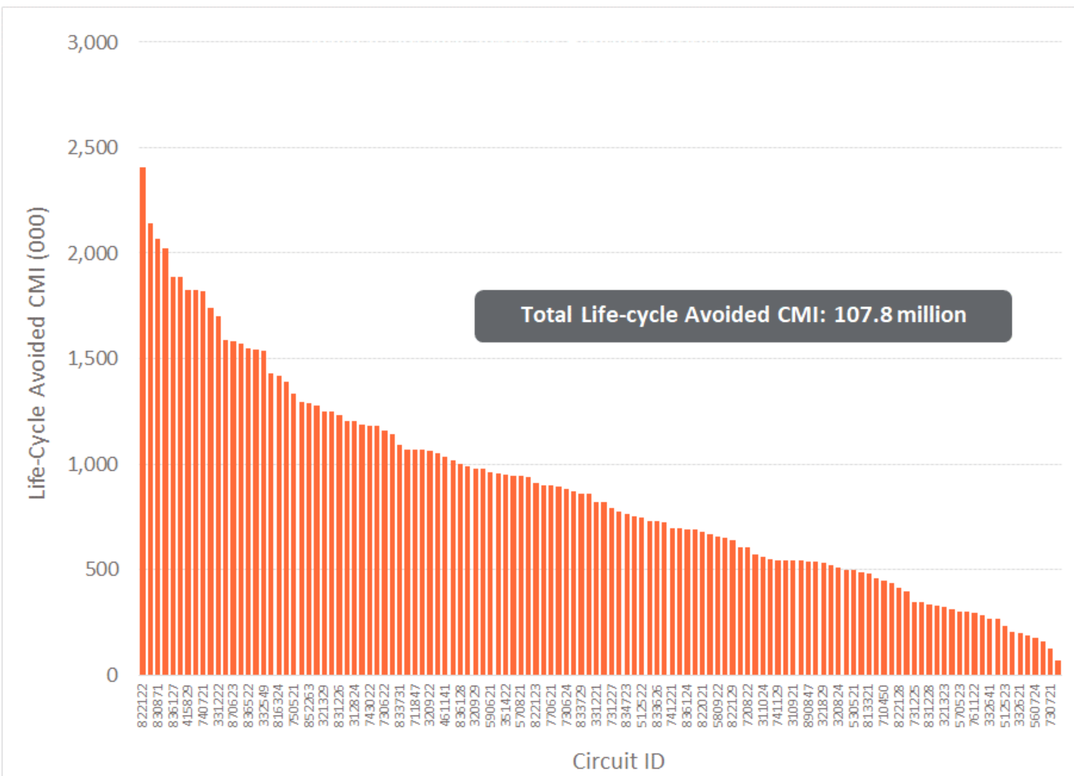
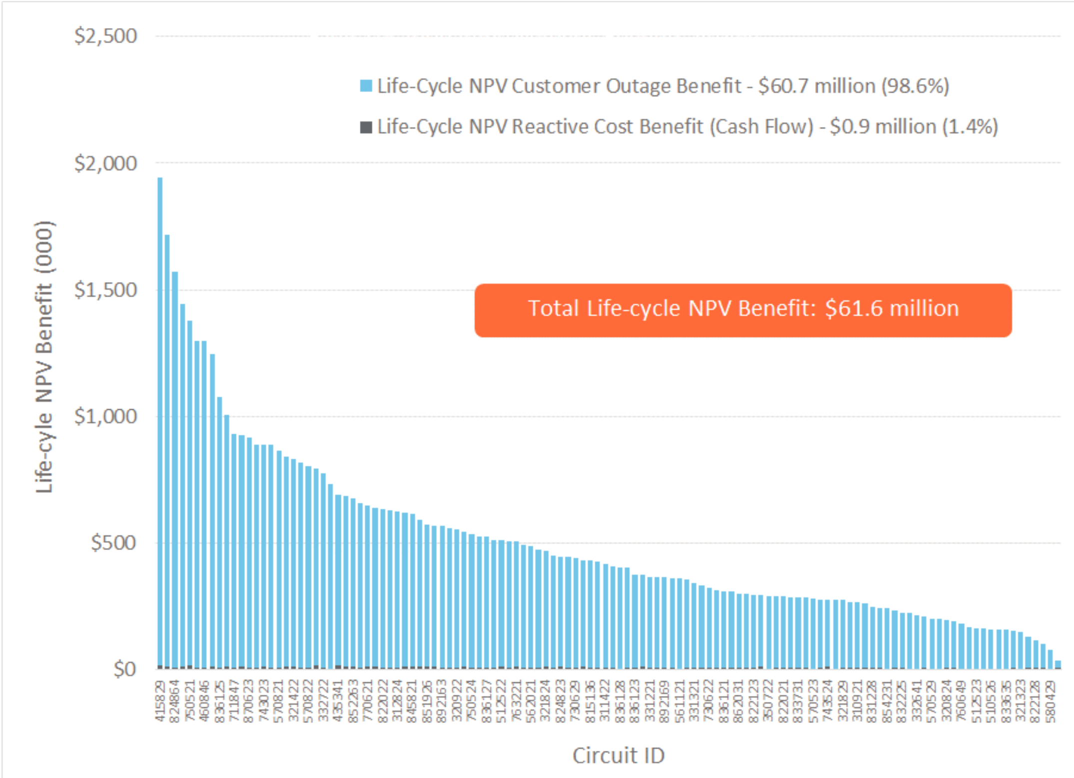


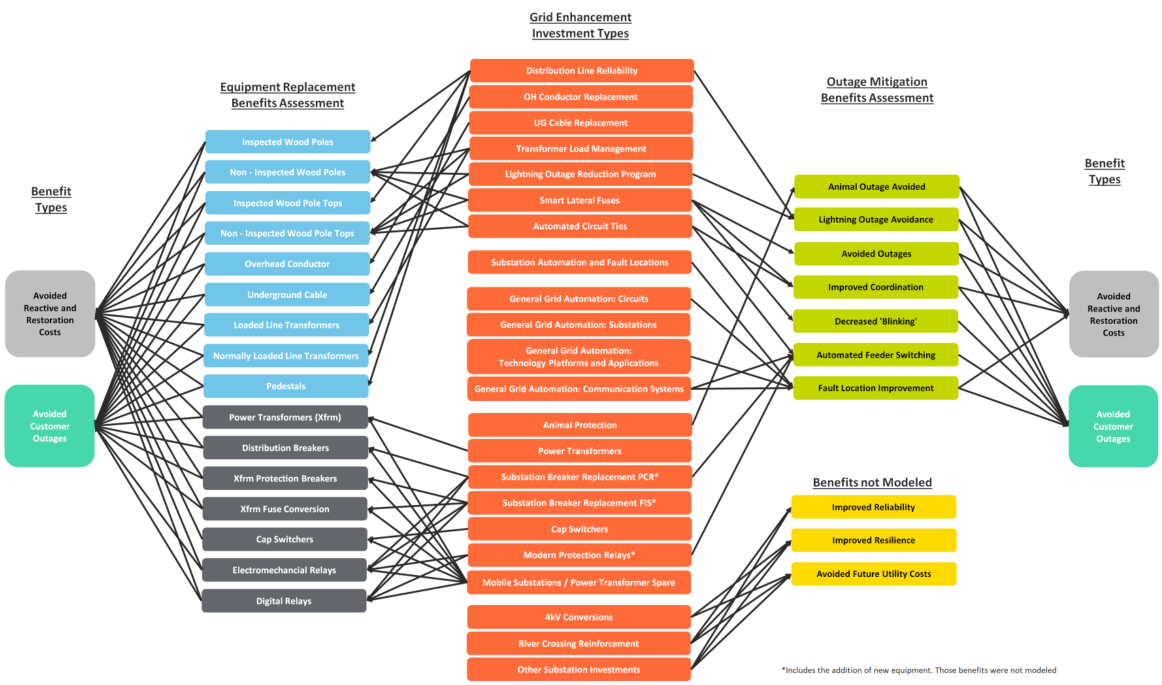
Figure 4-34: Fault Location Improvement Benefits Profile



5.0 DIRECT INVESTMENT BUSINESS CASE EVALUATION

The Grid Enhancement Plan is an integrated and comprehensive portfolio of investments designed to meet a range of objectives. All the investments work together to achieve the set of objectives. While the investments can be broken down into discrete activities as shown in Table 2-1, Figure 2-2 shows the investments work together to produce benefits. Figure 2-2 is repeated below in Figure 5-1 for ease of reference. The figure shows the Plan includes all the different combinations for mapping investments to benefits steams; 1 to 1, 1 to many, many to 1, and many to many.

Figure 5-1: Investment and Benefits Mapping Diagram



Adding to the integrated nature of the Plan is that some investments are supportive of other investments. For example, investments in system-wide communication infrastructure are needed to allow the circuit-by-circuit investment in IntelliRupters® to be effective. Only investing in communication provides only minor value. Investing in IntelliRupters® without the ability to communicate also provides minor value. The two together are needed to capture value for customers. While the investment in IntelliRupters® can be directly tied to circuits, the communication investment is system wide. Given this fact, 1898 & Co. classified each investment as direct or indirect/supporting. This designation is shown in Table 2-1 for each investment activity.

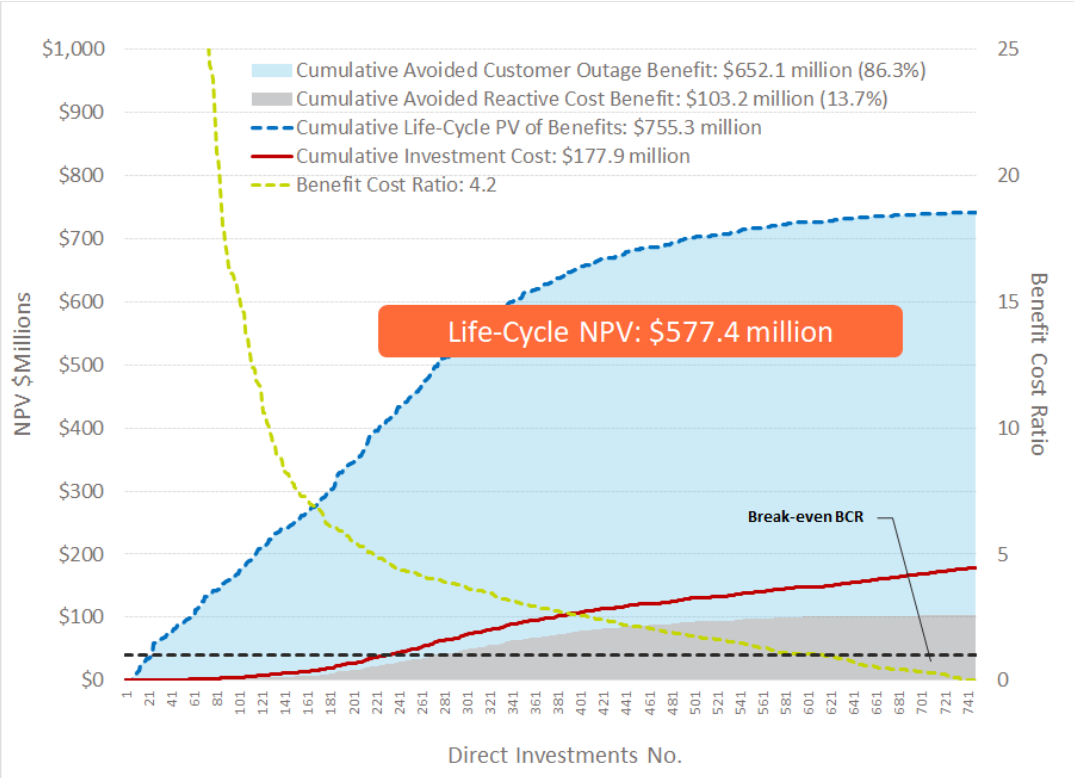
For this reason, the Grid Enhancement business case results need to be viewed from several perspectives. This section provides the perspective of the business case results for the direct investments, activities that can be directly linked to a circuit or a substation. It should be noted that the NPV benefits shown for each discrete investment activity in this section cannot be achieved without some of the other direct investment activities and the indirect / supporting investment. Also, as described above the benefits for the direct investment business case can be different if the order of the business case benefits calculation were changed. Section 5.0 includes the business case results for the combined investment perspective. In evaluating the Grid Enhancement Plan business case, views from both perspectives are key and neither should be viewed in isolation.

Using the mapping in Figure 5-1 for each circuit and substation, the following direct investment business cases were developed:

1. Distribution Line Reliability
2. Overhead Conductor and Underground Cable
3. Transformer Load Management
4. Substation Animal Protection
5. Lightning Outage Reduction Program
6. Modern Protection Schemes
7. Fault Location Isolation
8. Power Transformers
9. Substation Breaker Replacement PCR
10. Substation Breaker Replacement FIS and Cap Switchers
11. Modern Protection Relays

Mapping the Grid Investments for direct investments to the 23 benefit streams produces 749 individual investment business cases. Figure 5-2 shows the business case results for all 749 direct investments. The figure ranks the project by benefit cost ratio and shows the cumulative investment, avoided reactive costs, avoided customer outages, and total. The green dotted line shows the benefit cost ratio for each of the individual investments. The black dotted line shows the break-even benefit cost ratio. Investments above the black dotted line have positive business case from the direct investment business case perspectives. The redline shows the cumulative investment up through the investment number totaling $177.9 million at investment number 749. Similarly, the grey and blue shaded areas show the cumulative reactive and customer avoided costs. The blue dotted line shows the cumulative benefits.

Figure 5-2: Direct Investments Business Case Results



As the figure shows, the total direct investment of $177.9 million produces life cycle NPV of $577.4 million for a benefit cost ratio of 4.2. From an aggregate perspective, all the direct investments together have a positive business case. Most of the benefits are from avoided customer costs, approximately 86.3 percent. The reactive cost benefits alone cover approximately 58.0 percent ($103.2 divided by $177.9) of the total investment. At the individual investment level, the figure shows approximately 82.0 percent of the individual investments has a benefit cost ratio greater than 1. 18.0 percent of the individual investments have a benefit cost ratio less than 1. The investment cost for these individual projects is $29.4 million for a total benefit of $14.1 million. This converts to 8.6 percent of the direct invested capital not having benefits. Table 5-1 provides a summary of the 749 investment activities within the 14 direct investment categories. The table shows the total count of investment activities and the number with a benefit cost ratio greater than and less than 1.

Table 5-1: Direct Investment Benefit Cost Summary

Investment Category	Activity Count	Activity Count with BCR >= 1	Activity Count with BCR < 1
Distribution Line Reliability	122	122	0
Smart Lateral Fuses	121	81	40
Automated Circuit Ties	117	47	70
Transformer Load Management	112	112	0
Animal Protection	71	55	16
Fault Location Isolation	71	71	0
Lightning Outage Reduction Program	36	36	0
Modern Protection Relays	32	30	2
Substation Breaker Replacement PCR	31	28	3
Substation Breaker Replacement FIS	14	13	1
Power Transformers	8	7	1
OH Conductor Replacement	7	7	0
UG Cable Replacement	4	4	0
Substation Breaker Replacement Capacitor Switcher	3	1	2
Total	749	614	135

The number of direct business cases with benefit cost ratio less than one is an incomplete view of the Grid Enhancement business case. Firstly, the Automated Circuit Tie Lines Smart Lateral Fuses, Fault Location Isolation, and Modern Relay Protection individual investment activities have systematically been designed together and their benefit allocations are dependent on the order sequencing as discussed above. As such, the individual investment activity is not the appropriate level to view the business case results. Rather, these investment activities results should be viewed at the circuit and substation level. These results are shown below in my testimony. Secondly, as discussed in more detail below, their outage data deficiencies for substation.

The following sections provide the circuit-by-circuit or substation-by-substation business case results for each of the direct investment business cases listed above. Within those sections, the investments with benefit cost ratios less than 1 are discussed. The business case results in this section are based on a cash flow analysis. Appendix A includes corresponding results from a revenue requirements basis.

5.1 Distribution Line Reliability

The Distribution Line Reliability investment category is the highest dollar investment category in the 2020 and 2021 Grid Enhancement Plan at $80.9 million. As discussed above in Section 4.1.1, the investment category is mainly focused on replacing wood poles that fail inspection. As part of this effort, when poles are replaced, the rebuild is to OG&E's equipment standard. That includes a more resilient pole class standard, pole top configuration (if needed), new line transformers and pedestals, and lightning arresters. The plan estimates the number of poles expected to fail inspection as well as the other equipment electrically or physically linked to the pole.

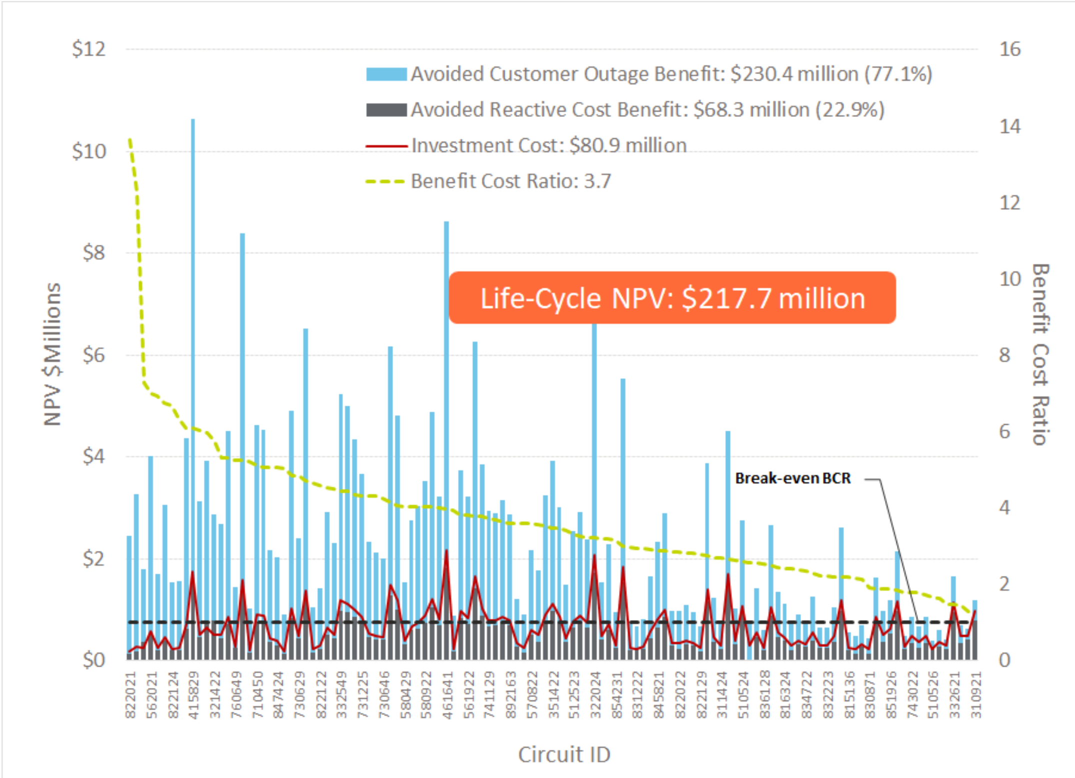
The benefits (see Figure 5-1) of the distribution line reliability investment category include:

- Inspected Wood Poles
- Inspected Wood Pole Tops
- Normally Loaded Line Transformers
- Pedestals
- Lightning Outage Reduction (based on percentage of arresters)

These five benefits streams were aggregated to calculate the circuit-by-circuit benefits. The costs for each circuit were based on the plan costs. Figure 5-3 shows the business case results for distribution line reliability investments. The red line shows the estimated cost for each circuit with a total estimated investment of $80.9 million. The bars on the chart show the benefits by circuit. The grey bar shows the avoided reactive and restoration costs, while the blue bar shows the benefit of avoided customer outages. The approach to calculate both of these is described in Section 3.0. The green dotted line shows the benefit cost ratio for each circuit ranked from highest to lowest. The remaining figures in this section show similar figures.

As the figure shows, the total investment of $80.9 million produces life cycle NPV of $217.7 million for a benefit cost ratio of 3.7. From an aggregate perspective, the investment category has a positive business case. The reactive cost benefits alone cover approximately 84.4 percent of the total investment. At the individual circuit level, the figure also shows that the benefits outweigh the costs for all circuits with benefit cost ratio in the range of 13.6 to 1.2.

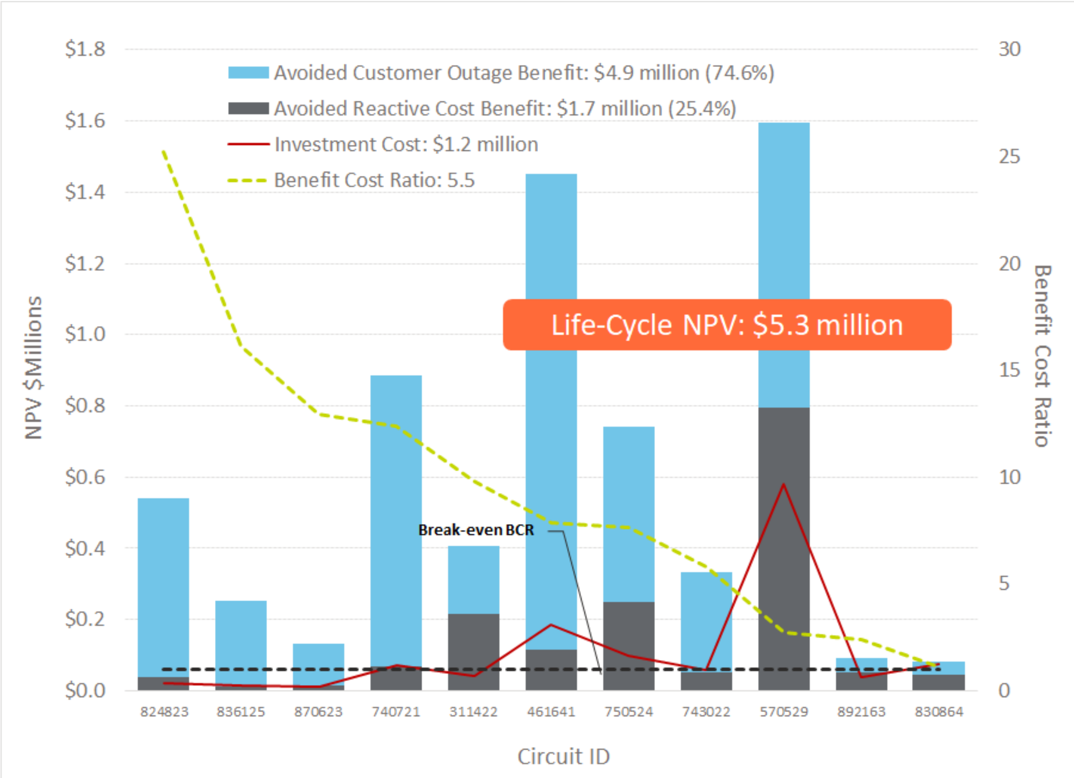
Figure 5-3: Distribution Line Reliability Business Case Results



5.2 Overhead Conductor and Underground Cable

For the 2020 and 2021 Grid Enhancement Plan, investments in the overhead conductor and underground cable are approximately $1.2 million on 11 circuits. As discussed in Section 4.1.2, this investment is focused on replacement of problematic and aged conductor types on circuits. Figure 5-4 shows the circuit-by-circuit business case results. The investment of $1.2 million in conductor and cable produce life cycle NPV of $5.3 million with a benefit cost ratio of 5.5. The Avoided Reactive Cost Benefits alone provide a positive business case (BCR of 1.4) for all circuits. On an individual circuit basis, the figure shows all eleven circuits have a benefit cost ratio above 1 ranging between 25.2 and 1.1.

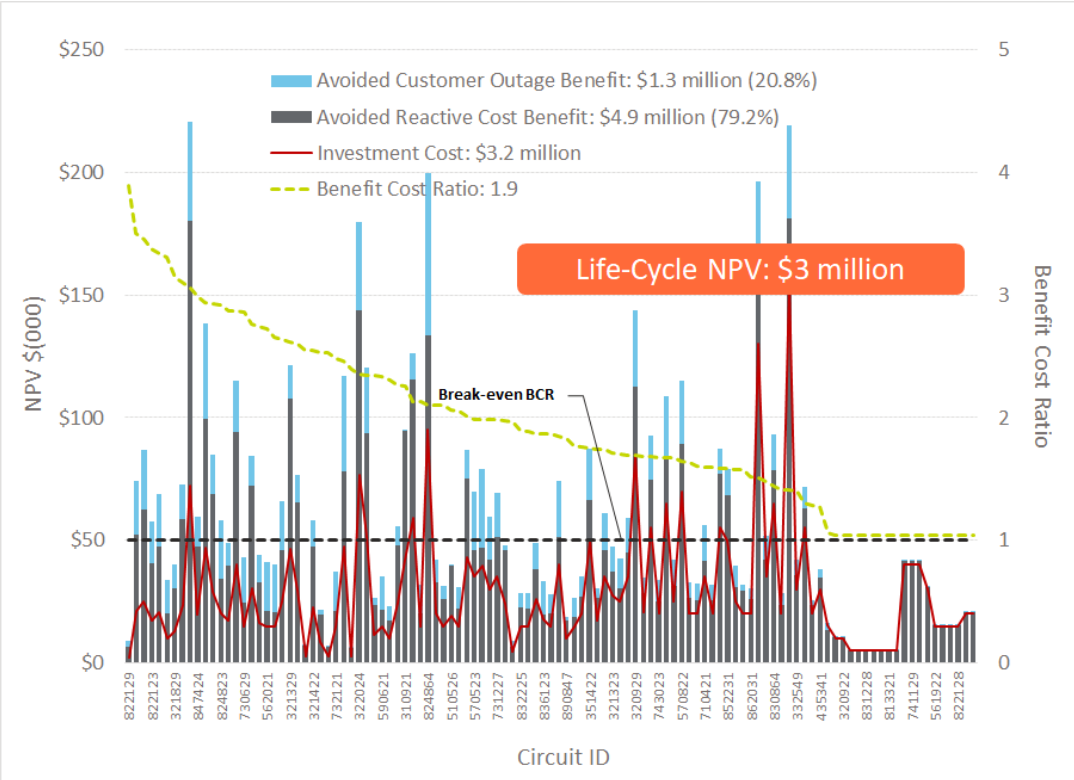
Figure 5-4: Overhead Conductor and Underground Cable Business Case Results



5.3 Transformer Load Management

The 2020 and 2021 Grid Enhancement Plan includes investment of approximately $3.2 million for the transformer load management investment category. As discussed in Section 4.1.3, this investment is focused on replacement of high loaded or overloaded distribution line transformers based on AMI data on circuits. Figure 5-5 shows the circuit-by-circuit business case results. The investment of $3.2 million produces life cycle NPV of $3.0 million with a benefit cost ratio of 1.9. The majority of the benefits come from avoided future reactive costs (79.2 percent). The Avoided Reactive Cost Benefits alone provide a positive business case (BCR of 1.5) for all circuits. On an individual circuit basis, the figure shows that all circuits have positive economics with benefit cost ratios ranging from 3.9 to 1.0.

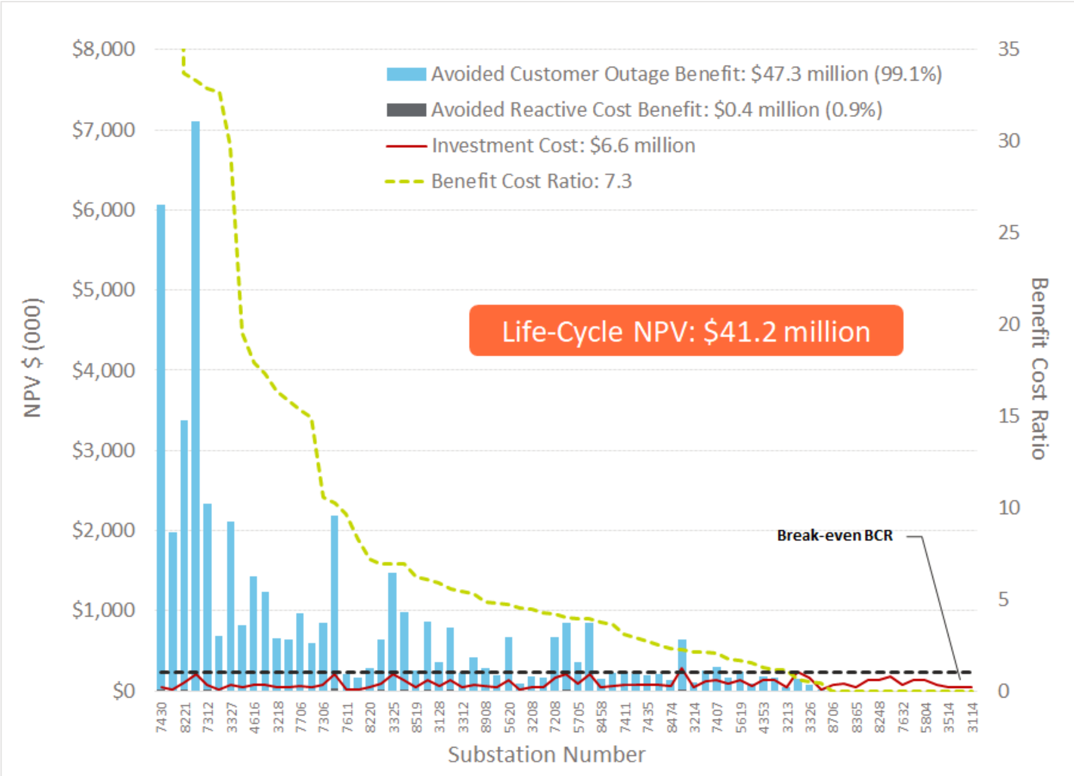
Figure 5-5: Transformer Load Management Business Case Results



5.4 Substation Animal Protection

The 2020 and 2021 Grid Enhancement Plan includes investment of approximately $6.6 for the Substation Animal Protection investment category. As discussed in Section 4.3.1, this investment is focused on adding animal protection solutions to substation to mitigate outages that are costly to restore and impact thousands of customers. Figure 5-6 shows the substation-by-substation business case results. The investment of $6.6 million produces life cycle NPV of $41.2 million with a benefit cost ratio of 7.3. Avoided customer outages is the primary benefit driver of this investment category with approximately 0.9 percent of the benefits from avoided reactive costs. On an individual substation basis, the figure shows that approximately 77.5 percent of the substations have positive economics.

Figure 5-6: Substation Animal Protection Business Case Results



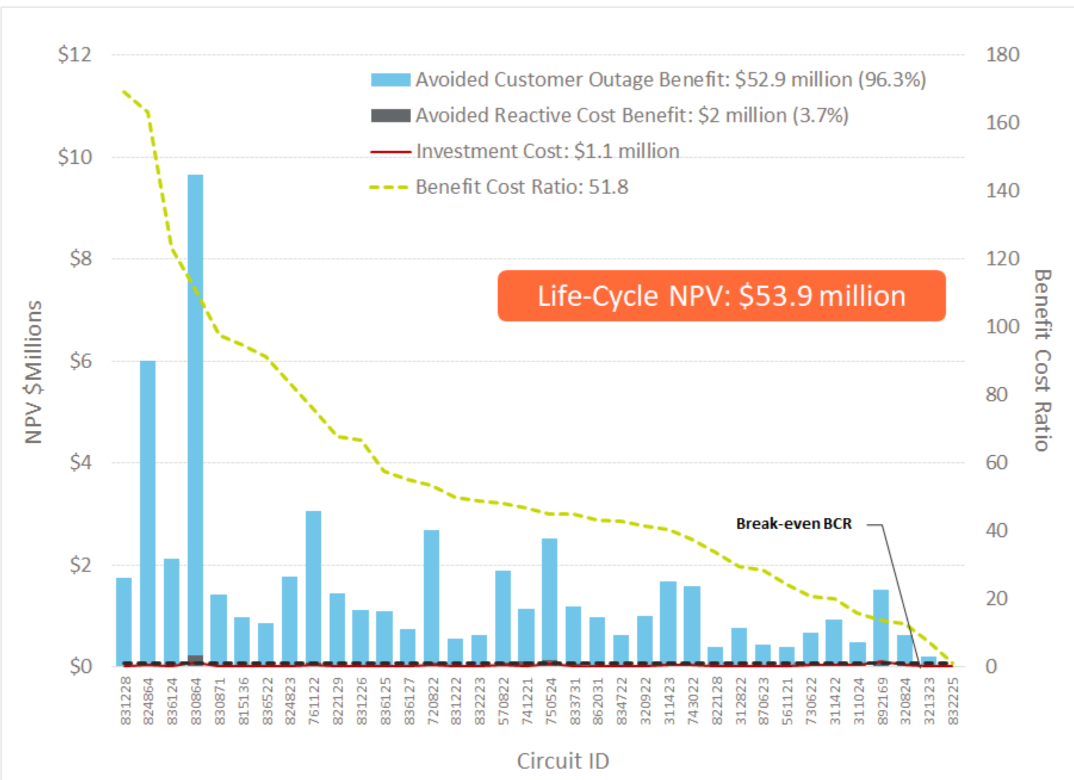
While the business case shows that approximately 22.5 percent of the substations are non-economic it is important to note some deficiencies in the underlying data used to develop the business case results. The Animal Outages Avoided benefits were estimated using the Outage Mitigation Risk & Resiliency benefits approach. The approach recalculates historical outages assuming the investments had been in place. As outlined in Sections 3.4.1 and 4.3.1, historical outage record keeping within substations is an area of improvement for OG&E. Additionally, outage management systems are more circuit and device centric with respect to recording outages. This can make it difficult to record substation outages. Sometimes these outages get recorded to the circuits coming out of the substations. The 13 of the 16 substations with zero benefit had no recorded animal outages over the last 10 years. This is likely due to outages accurately recorded based on the real cause code or recording of the outages to the circuit instead. This deficiency in outage record keeping in substation also impacts the business case results for the other substations. Without the accurate record keeping across all substations it would be difficult to quantify benefits for this investment category.

In absence of accurate records for these substations, the business case for substations where outage data is recorded is instructive. Where outage data is available, the business case for adding animal protection is highly beneficial. Based on this, 1898 & Co. considers the investment in animal protection for all 71 substations to be prudent.

5.5 Lightning Outage Reduction Program

The 2020 and 2021 Grid Enhancement Plan includes investment of approximately $1.1 for the transformer load management investment category. As discussed in Section 4.1.3, this investment is focused on the addition of lightning protection based on OMS data on circuits. Figure 5-5 shows the circuit-by-circuit business case results. The investment of $1.1 million produces life cycle NPV of $53.9 million with a benefit cost ratio of approximately 51.8. The majority of the benefits come from avoided customer outages (96.3 percent). On an individual circuit basis, the figure shows that all the circuits have positive economics with exceptional benefit cost ratios. This is expected given the high number of lightning outages on the system.

Figure 5-7: Lightning Outage Reduction Program Benefit Cost Results



5.6 Modern Protection Schemes

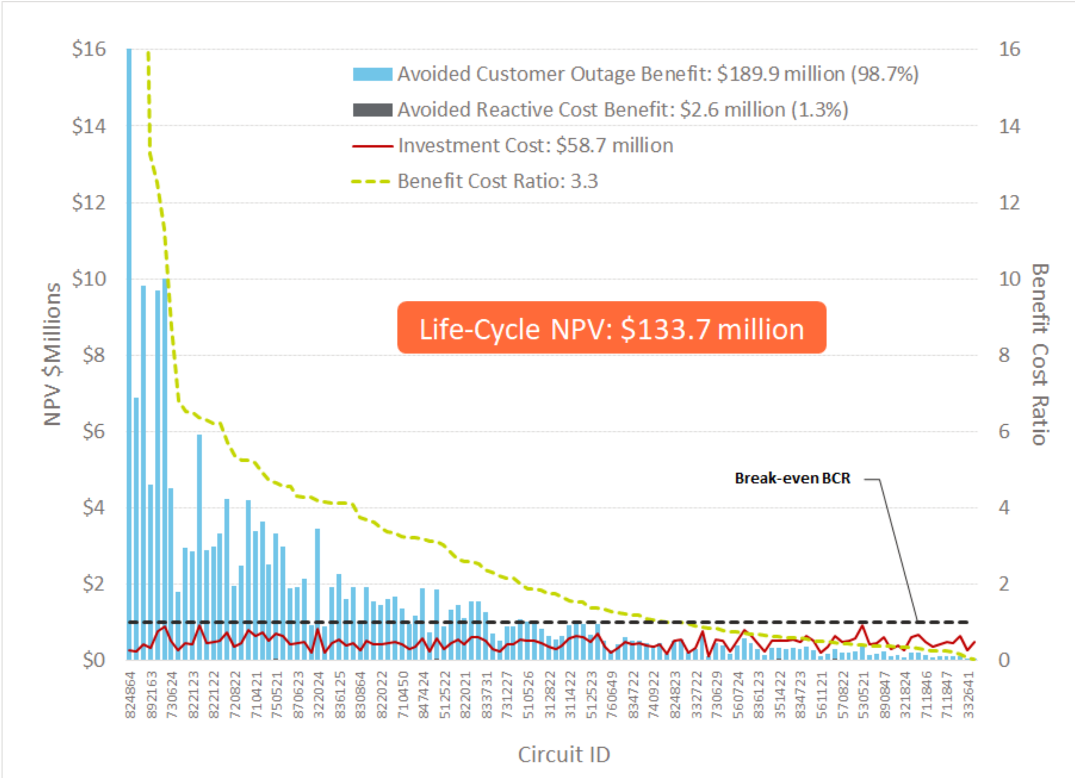
The investment in modern protection schema devices is the second highest dollar investment category in the 2020 and 2021 Grid Enhancement Plan at $58.7 million. As discussed above in Section 3.4.3.4, the investment category is mainly focused on redesigning and modernizing the protection schema with new protection devices (IntelliRupters® and TripSavers®). The benefits (see Figure 5-1) of the Modern Protection Scheme investment categories of Smart Lateral Fuses and Automated Circuit Tie Lines include:

- Avoided Outages
- Decreased 'Blinking'
- Improved Coordination
- Automated Feeder Switching

These four benefits streams were aggregated to calculate the circuit-by-circuit benefits. The costs for each circuit were based on the plan costs provided by OG&E. Figure 5-8 shows the circuit-by-circuit business case results for the modern protection schemes. As the figure shows, the total investment of $58.7 million produces life cycle NPV of $133.7million for a benefit cost ratio of 3.3. From an aggregate perspective, the investment category has a positive business case. Most of the benefits, approximately 98.7 percent, are to improving the customer experience. The Avoided Reactive cost benefits are for reduced truck rolls. At the individual circuit level, some of the circuits produce very high benefit to cost ratios, 5 circuits above 10 while others are less than 1. This wide range is expected given the customer profiles, geographies, and ages differences across circuits. Approximately 34.4 percent of the circuits have a benefit cost ratio less than 1.

While on the surface it appears these circuit's investments are non-economic, the integrated nature of the automation investment must be considered as well as the investment order in developing the benefits. While the entire Grid Enhancement Plan is integrated, the automation investment is especially integrated. Figure 5-8 shows the benefits produced by the direct investment in circuit protection devices. However, to achieve these benefits communications and technology applications are needed which are investment that are difficult to directly link to circuits. Additionally, if the modern protection schemes investment were to be evaluated ahead of lightning the benefits across all circuits would be higher. For these reasons, the business case should also be viewed from the integrated perspective at the circuit, substation, and portfolio level. Section 6.0 shows these results.

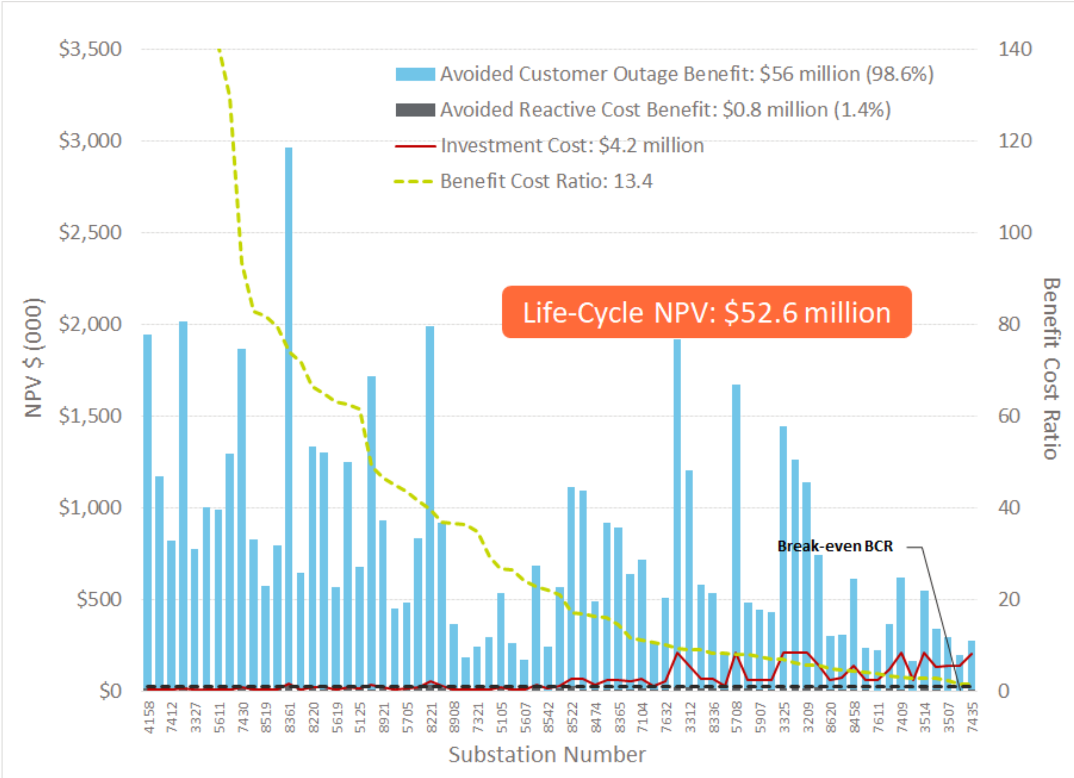
Figure 5-8: Modern Protection Schemes Business Case Results



5.7 Fault Location Isolation

The 2020 and 2021 Grid Enhancement Plan includes investment of approximately $4.2 for the fault location isolation investment category. As discussed in Section 4.3.7, this investment is focused on adding fault location isolation. Figure 5-5 shows the substation-by-substation business case results. The investment of $4.2 million produces life cycle NPV of $52.6 million with a benefit cost ratio of 13.4. A majority of the benefits come from avoided future customer outage benefits (98.6 percent). The fault location isolation is designed to lessen customer outages durations. On an individual circuit basis, the figure shows that all substation investments have positive economics. Similar to the modern protection schemes, the business case results should also be viewed in aggregate, especially at the portfolio level given the communications infrastructure needed to capture these benefits.

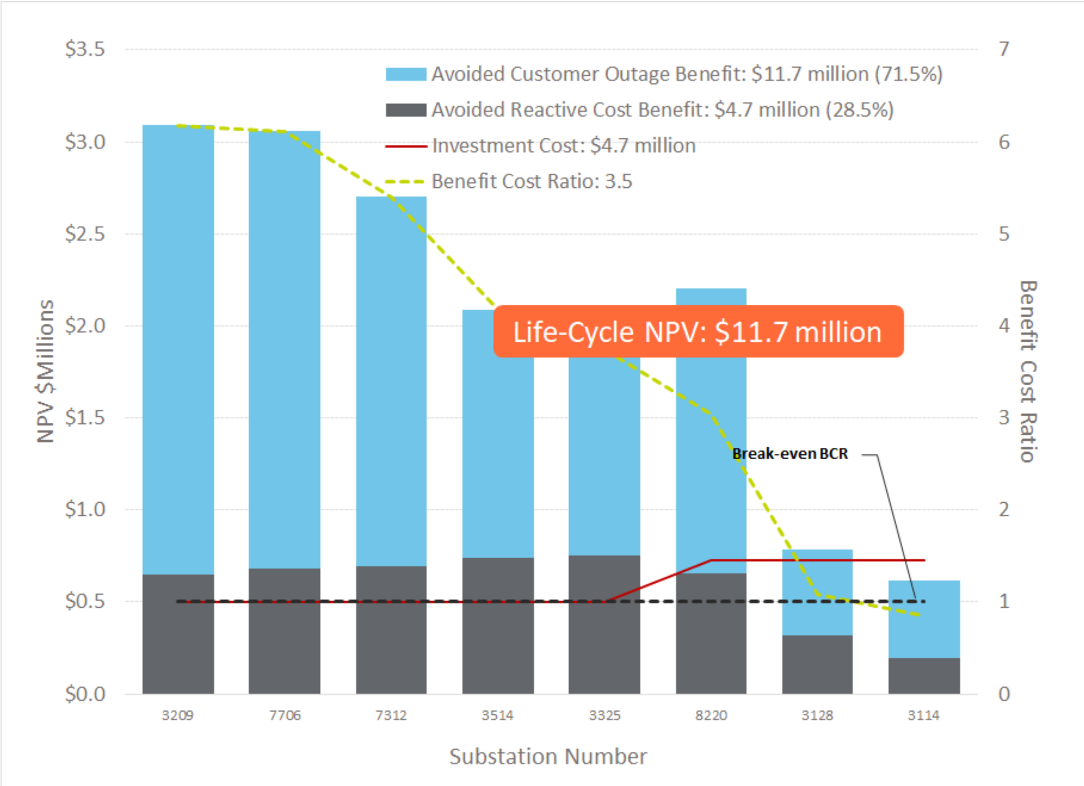
Figure 5-9: Fault Location Isolation Business Case Results



5.8 Power Transformers

The 2020 and 2021 Grid Enhancement Plan includes investment of approximately $4.7 for the power transformer investment category. As discussed in Section 4.2.1, this investment is focused on replacement of substation power transformers based on a combination of age and asset health. Figure 5-10 shows the substation-by-substation business case results. The investment of $4.7 million produces life cycle NPV of $11.7 million with a benefit cost ratio of 3.5. A majority of the benefits come from avoided customer outage benefit (71.5 percent). The Avoided Reactive Cost Benefits alone generally provides a positive business case for the majority of substations. On an individual substation basis, the figure shows that all but 1 substation has positive economics with benefit cost ratios ranging from 6.2 to 1.1. The one transformer has a benefit cost ratio of 0.8.

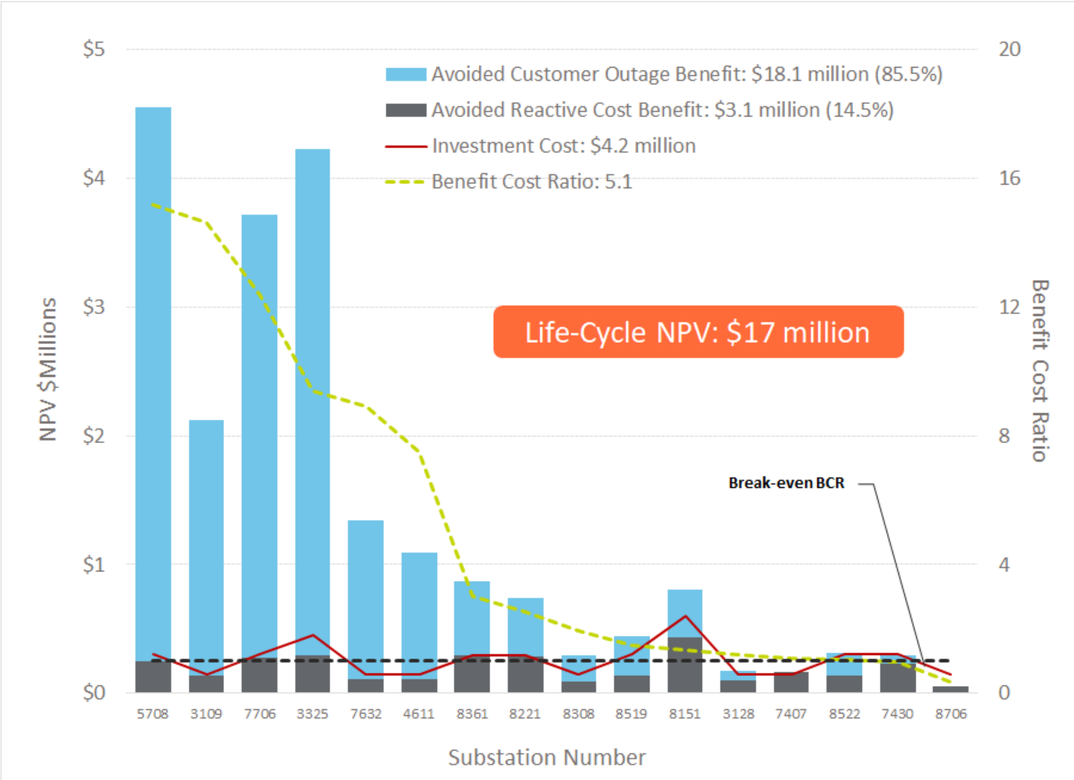
Figure 5-10: Power Transformer Business Case Results



5.9 Transformer Breaker Protection & Cap Switchers

The 2020 and 2021 Grid Enhancement Plan includes investment of approximately $4.2 for transformer breaker protection and cap switchers investment category. As discussed in Sections 4.2.2, this investment is focused on replacement of transformer breakers and their associated relays and cap switchers. Figure 5-11 shows the substation-by-substation business case results. The investment of $4.2 million produces life cycle NPV of $17.0 million with a benefit cost ratio of 4.2. The majority of the benefits come from avoided customer outage benefits (85.5 percent). At the aggregate level, the investment has a positive business case. On an individual substation basis, the figure shows that 2 substations have benefit cost ratios less than 1.

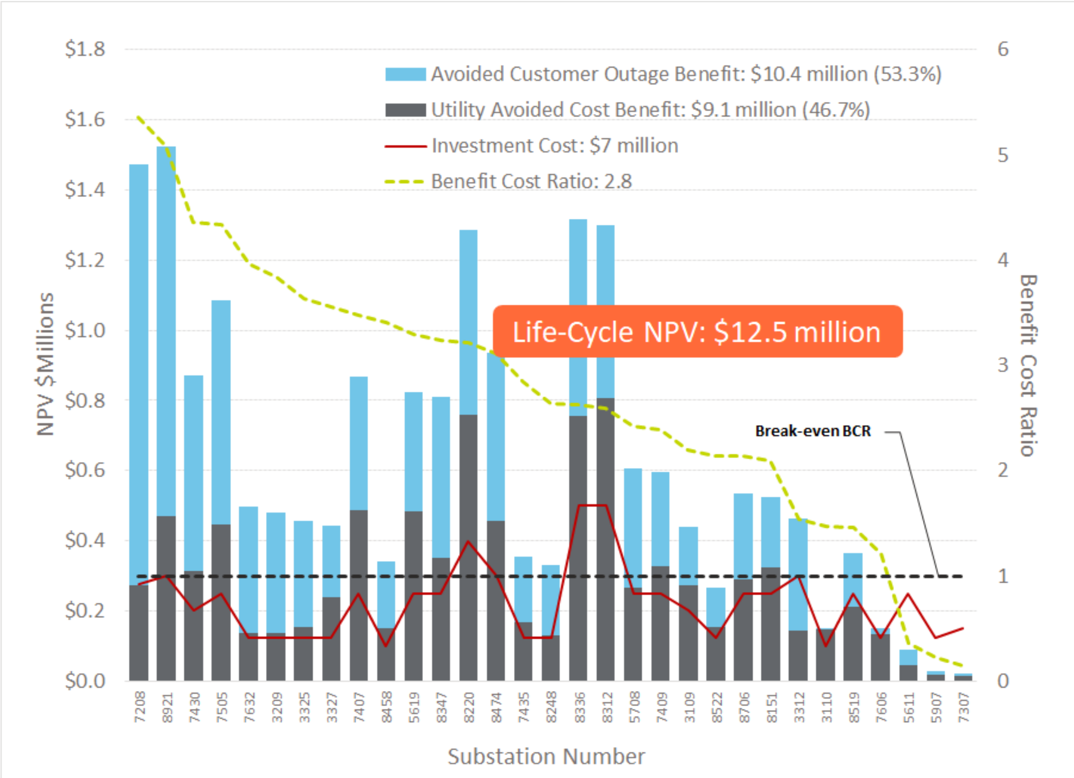
Figure 5-11: Transformer Protection and Cap Switcher Business Case Results



5.10 Distribution Line Breakers

The 2020 and 2021 Grid Enhancement Plan includes investment of approximately $7.0 for the distribution line breaker investment category. As discussed in Section 4.2.5, this investment is focused on replacement of distribution line breakers and associated relays. Figure 5-12 shows the substation-by-substation business case results. The investment of $7.0 million produces life cycle NPV of $12.5 million with a benefit cost ratio of 2.8. A benefit is almost half from avoided customer outages benefit and half avoided reactive cost benefit. The Avoided Reactive Cost Benefits alone provide a positive business case for many of the circuits. On an individual circuit basis, the figure shows that over 90 percent of the substations have positive economics. In the whole, the economic case is positive.

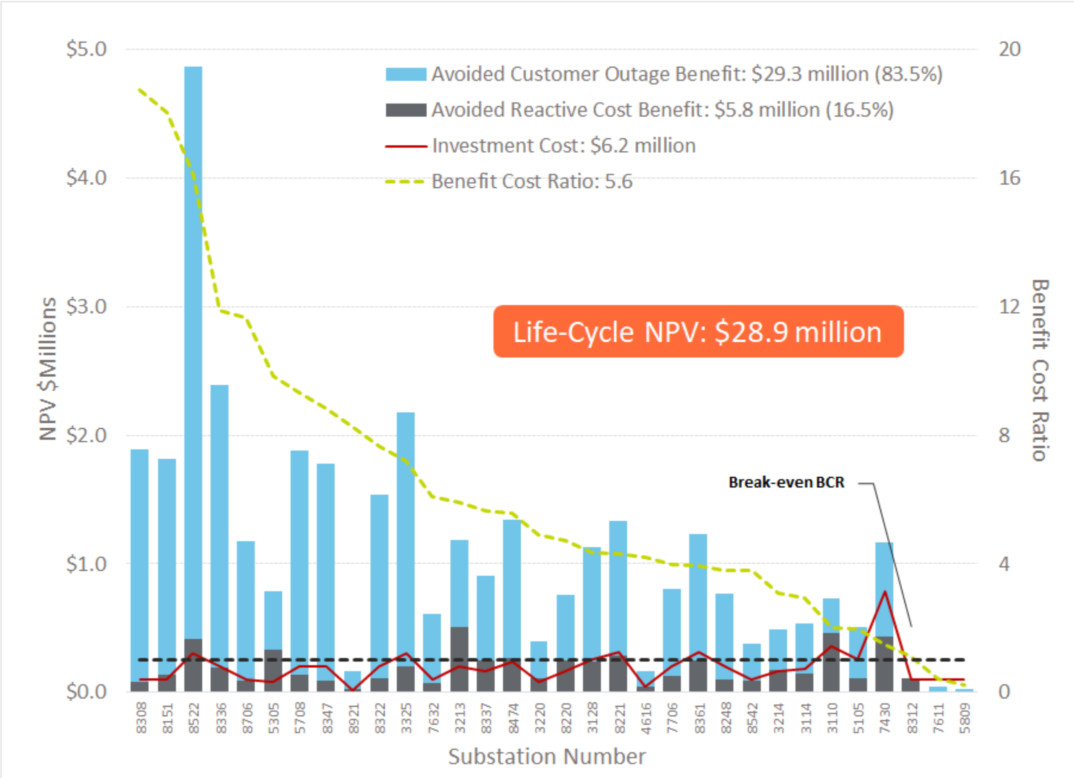
Figure 5-12: Substation Distribution Breaker Replacement Business Case Results



5.11 Modern Relay Protection

The 2020 and 2021 Grid Enhancement Plan includes investment of approximately $6.2 for modern relay protection investment category. As discussed in Section 4.2.6 and 4.2.7, this investment is focused on replacement of relays based on obsolescence and their associated breakers. Figure 5-13 shows the substation-by-substation business case results. The investment of $6.2 million produces life cycle NPV of $28.9 million with a benefit cost ratio of 5.6. A majority of the benefits come from avoided future customer outage costs (83.5 percent). On an individual substation basis, the figure shows that the majority of the substation have positive economics, with only 2 (~6 percent) having a benefit cost ratio less than 1. On the whole, the economic case is positive.

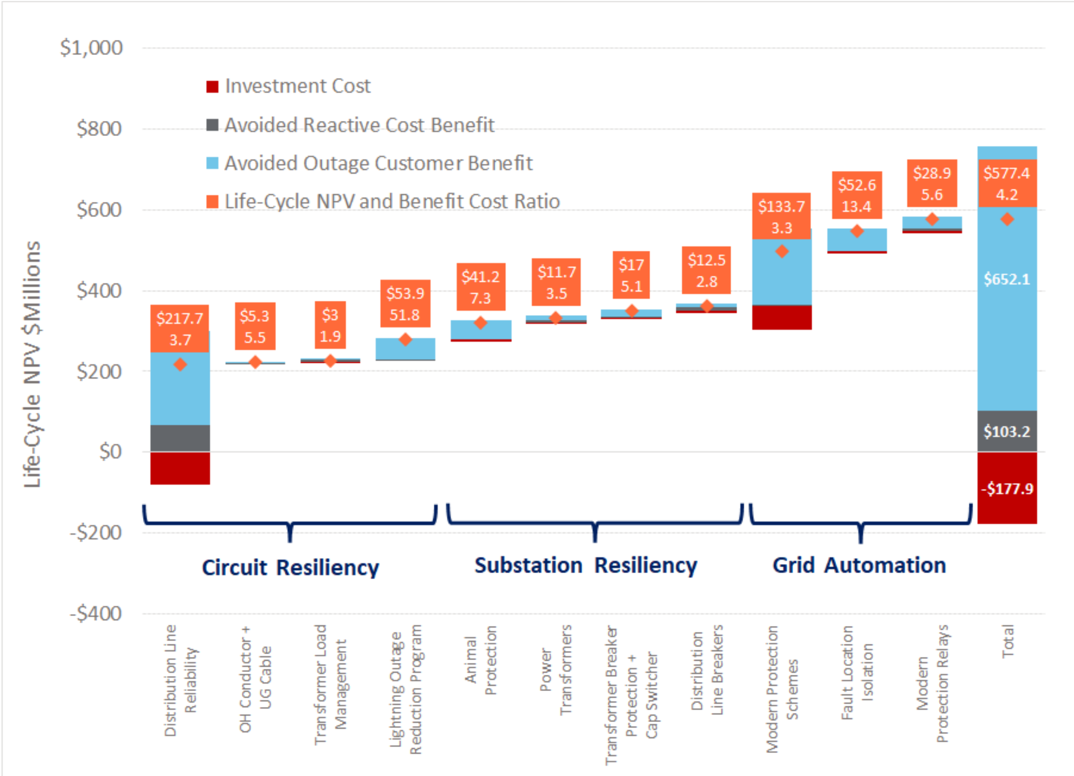
Figure 5-13: Modern Relay Protection Business Case Results



5.12 Direct Investment Business Case Summary

Figure 5-14 shows a summary of the 11 direct investment business case results from the previous sections. The 'stair-step' figure layers the benefit and costs on each direct investment to the previous starting from the life cycle NPV. The investment of $177.8 million shown in the last Total column is the same as the 'Direct Benefits' level of investment shown in Figure 2-1 above. The figure also shows a mapping of the direct investment categories to either the Resiliency or Automation investment type. As the figure shows, each of the 11 direct investment categories has a positive business case from an aggregate perspective. The figure also shows the relative costs and benefits for each of the categories with the Distribution Line Reliability and Modern Protection Schemes categories being the two largest.

Figure 5-14: Direct Investment Business Case Summary Results



6.0 INTEGRATED INVESTMENT BUSINESS CASE

As discussed throughout this report, the Grid Enhancement Plan is an integrated and comprehensive set of investments designed to meet a range of objectives and produce a suite of benefits. This is typical and expected of grid investments since the grid itself is an integrated set of assets designed to serve customers. This means business cases for investments in the grid cannot always be viewed as one investment to one benefit, but rather many investments to many benefits. As such, the business case needs to be viewed from several perspectives.

Section 5.0 provided the business case results more from the one-to-one perspective where benefits and investments could directly be mapped. It shows the results circuit by circuit and substation by substation. As the Section 5.0 notes in the introduction, the business case results for each direct investment category cannot be achieved without some of the other direct investment activities and the indirect/supporting investment. The integrated nature of the Grid Enhancement Plan is also shown in Figure 2-2. Additionally, as noted in Section 5.0 the business case results of some of the direct investments are dependent on the order of calculating benefits. For these reasons, evaluating the Grid Enhancement Plan from an aggregated perspective is needed.

This section provides the more integrated view of the business case results showing a range of many investments to many benefits aggregated at the circuit and substation levels to the entire portfolio. In reviewing the Grid Enhancement Plan business case, both the direct and integrated views should be evaluated and considered.

6.1 Grid Resiliency and Automation Business Cases

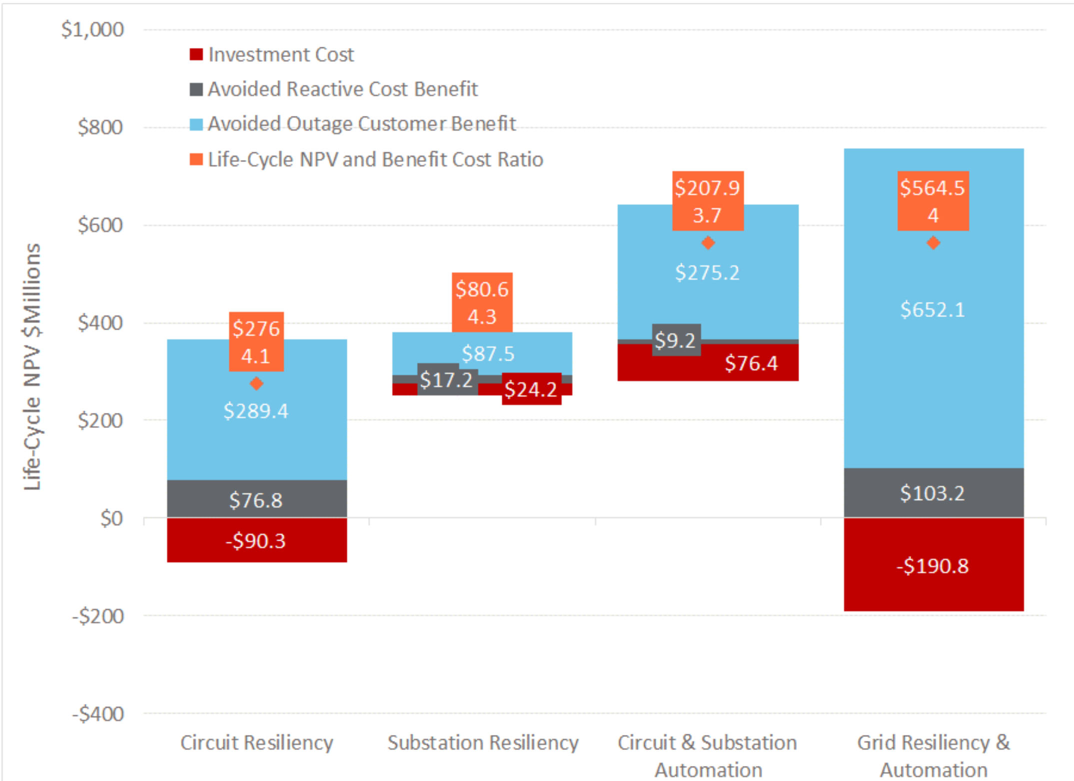
The Grid Enhancement Plan includes four main types of investments:

1. **Grid Resiliency**
2. **Grid Automation**
3. **Communications Systems**
4. **Technology Platforms and Applications**

This section provides the business case results for the Grid Resiliency and Grid Automation direct and indirect / supporting investments. Figure 6-1 shows the summary business case results for the Grid

Resiliency and Grid Automation investments. Figure 6-1 is a summary of Figure 5-14 with the inclusion of the indirect / supporting investments.

Figure 6-1: Grid Resiliency & Automation Business Case Summary Results



As the figure shows the investment at each of the portfolio and sub-portfolio levels have a positive business case with benefit cost ratios in the range of 3.7 to 4.3 with an average of 4.0. The following sub-sections show these results for each circuit and substation.

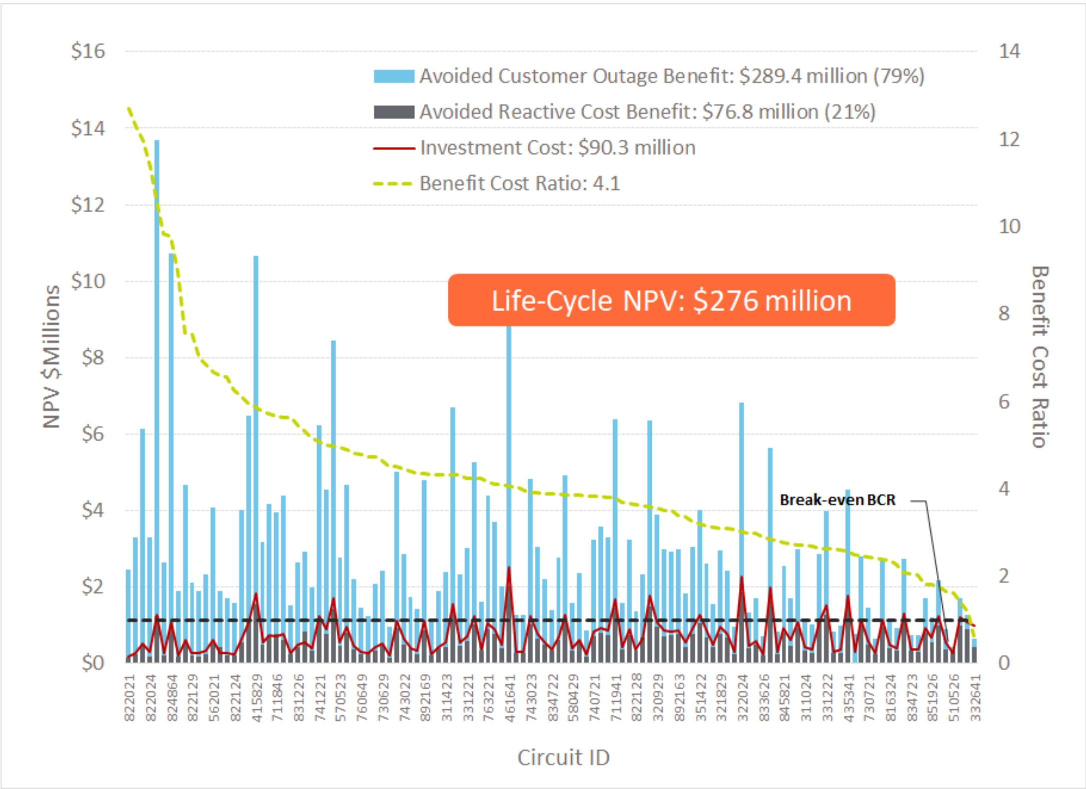
6.1.2 Circuit Resiliency

The Circuit Resiliency business case results are an aggregation of the following:

- Distribution Line Reliability
- Overhead Conductor and Underground Cable
- Transformer Load Management
- Lightning Outage Reduction Program
- Project Management

Figure 6-2 shows the circuit-by-circuit business case results for resiliency investment category. The investment of $90.3 million produces life cycle NPV of $276.0 million with a benefit cost ratio of 4.1. A majority of the benefits come from avoided future customer outage costs (79.0 percent). The Avoided Reactive Cost Benefits alone cover approximately 85.0 percent of the investment for circuit resiliency. On an individual circuit basis, the figure shows that all but 1 circuit has a positive business case. The one circuit has a benefit cost ratio of 0.6.

Figure 6-2: Circuits Resiliency Business Case Results



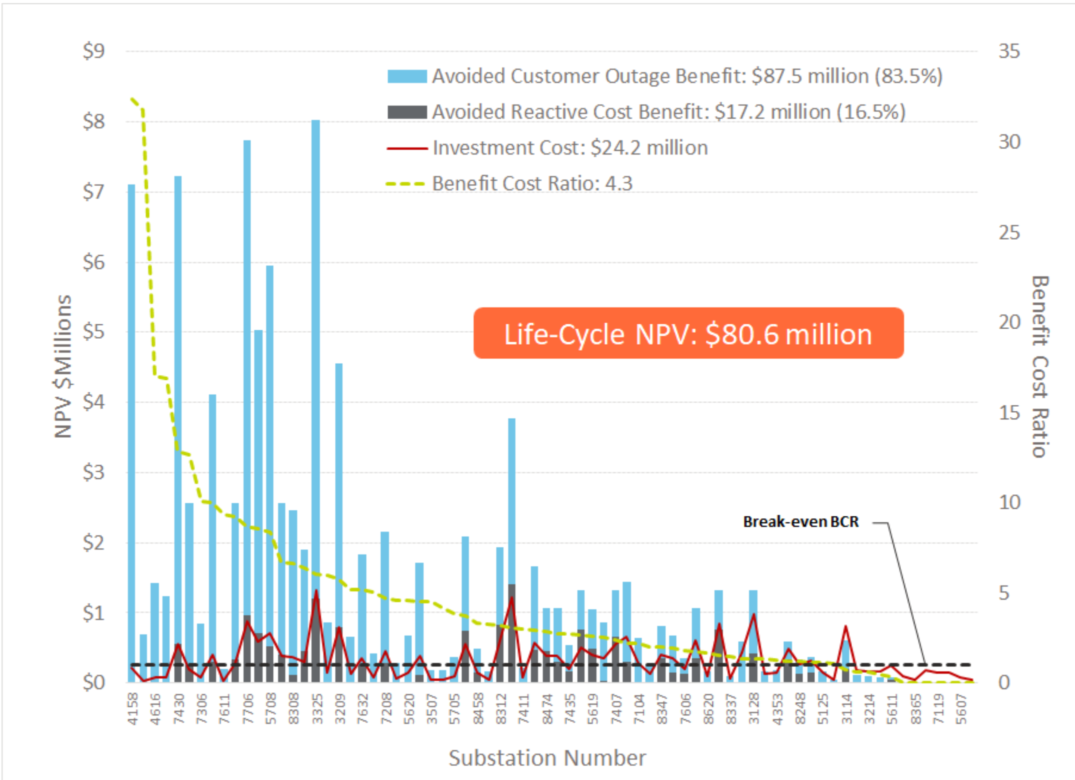
6.1.3 Substation Resiliency

The Substation Resiliency business case results are an aggregation of the following:

- Animal Protection
- Power Transformers
- Transformer Breaker Protection + Cap Switcher
- Distribution Line Breaker
- Project Management

Figure 6-3 shows the substation-by-substation business case results for the resiliency investment category.

Figure 6-3: Substations Resiliency Business Case Results



The investment of $24.2 million produces life cycle NPV of $80.6 million with a benefit cost ratio of 4.3. The majority of the benefits come from avoided future customer outage costs (83.5 percent). The Avoided Reactive Cost Benefits alone cover approximately 71.1 percent of the investment. On an individual substation basis, the figure shows that approximately 16.2 percent (12 of 74) of the substations have a benefit cost ratio less than 1. This is mainly due to the animal protection investment.

Sections 3.4.1 and 5.4 describe the outage data records gap in substation outages and animal outages specifically. This data gap causes the business case results to under-report the actual benefits. This causes 7 of the 12 substations to show benefit cost ratios below 1.

6.1.4 Circuit & Substation Automation

The automation business case results are an aggregation of the following:

- Modern Protection Schemes

- Smart Lateral Fuses
- Automated Circuit Tie Lines

- Fault Location Isolation
- Modern Protection Relays
- Project Management

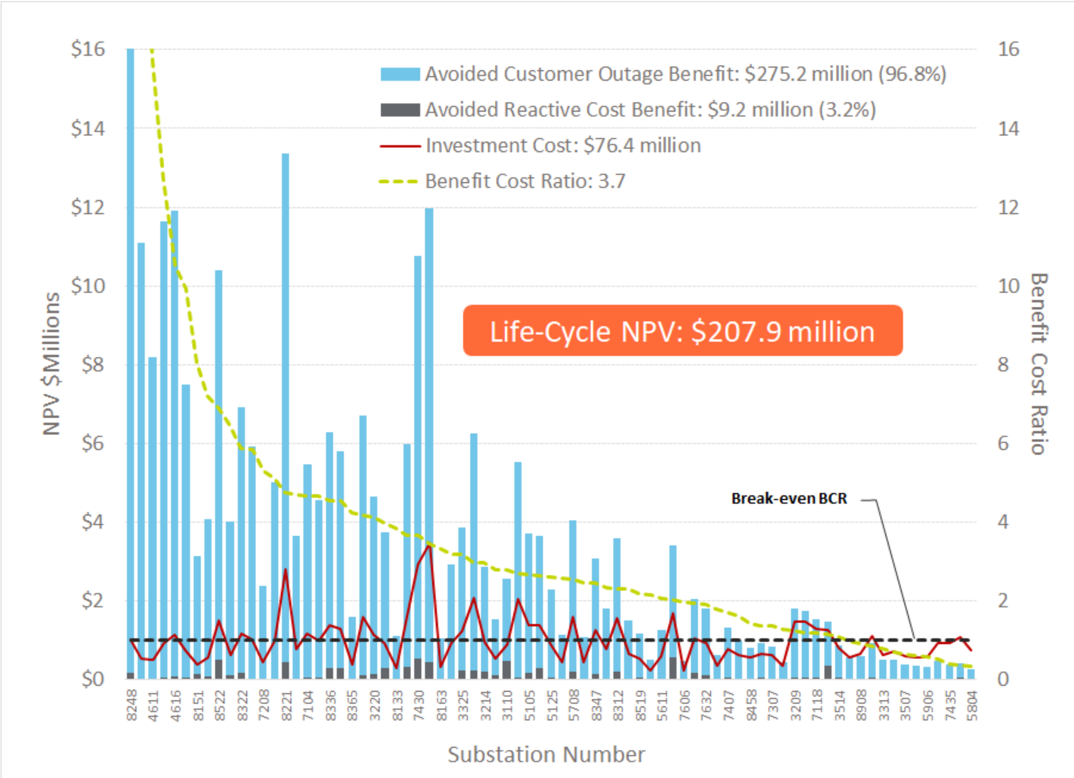
While Section 5.0 includes the direct investment business cases for each of these, it is important to view the business case from this aggregated perspective. Firstly, the investments are integrated and while they can be shown discretely for this analysis, they cannot be designed and executed discretely. Each investment is reliant on the other to fully achieve their benefits. Secondly, as noted in Section 3.4.3, the order of laying the investments into Outage Mitigation Risk & Resiliency analysis impacts benefits. For these two reasons, it is important to view the business case results in automation from this aggregate perspective.

The investment in Grid Automation includes a balance in devices on the circuits and in the substations. The nature of this type of automation is that while the investment is in the substation, it drives benefits at the circuit level. One example of this is the fault location isolation. This investment includes adding New SCADA and fault location devices inside the substation with an intent of easier identification of outages on the circuit. Given this integrated nature of the investment in automation, the business case results are presented at the substation level.

Figure 6-4 shows the substation-by-substation business case results for the automation investment category. The investment of $76.4 million produces life cycle NPV of $207.9 million with a benefit cost ratio of 3.7. From a portfolio perspective, the investment in automation has a positive business case. The majority of the benefits come from avoided future customer outage costs (96.8 percent) with $9.2 million from Avoided Reactive costs. This is expected from automation investment which is mainly intended to decrease the impact of outages on customers.

On an individual substation basis, the benefit cost ratios have a wide range going as high 23.4 to a low of 0.4. This wide range is also expected given the customer profile, geography, and age range of the circuits. The figure shows that 12 substations (approximately 15.6 percent) have benefit cost ratio less than 1.

Figure 6-4: Circuits & Substations Automation Business Case Results



6.1.5 Circuit & Substation Business Case Results

Even though the intent of the resiliency and automation investment can be itemized, the business case results cannot be fully segregated as they are integrated as well. First, there is integration of the investment drivers. Figure 2-2 shows this integration between resiliency and automation investment with the upgrades to substation protection and relays. The full benefits of automation require the protection within the substation to be upgraded. The upgrades to substation protection provide both resiliency and automation benefits. The direct investment business cases allocated the full benefits of the breaker upgrades to the resiliency category while the modern protection relay upgrades are allocated to the automation category. While not fully shown because the linkages are less direct, there is linkage between the Distribution Line Reliability investment (resiliency focused) and modern protection schemes (Smart Lateral Fuses and Automated Circuit Tie Lines). Second, the approach to calculating benefits assumed an order to the investments that if changed would allocate benefits different between investments. Third, some integration exists from an execution perspective. The cost to execute portions of both of these investment types assumes execution efficiencies. Executing these categories separately would cost more due to deployment and mobilization. Other linkages and synergies also exist between resiliency and automation investments. Because of this, another perspective for the business case is view the two programs together substation by substation.

Figure 6-5 shows the substation-by-substation business case results for the combined resiliency and automation investment category. This is an aggregation of Figure 6-2, Figure 6-3, and Figure 6-4 at the substation level. The investment of $190.8 million produces life cycle NPV of $564.5 million with a benefit cost ratio of 4.0. From a portfolio perspective, the investment in resiliency and automation has a positive business case. The majority of the benefits come from avoided customer outage costs (86.3 percent) while the avoided reactive costs account for approximately 54.1 percent of the capital investment.

On an individual substation basis, the benefit cost ratios have a wide range going from a high of 13.2 to a low of 0.8. The figure shows that 76 substation (approximately 98.7 percent) have benefit cost ratio greater than 1. The other substation has a benefit cost ratio of 0.8 resulting in $641,000 of investment without any benefits. This is equivalent to 0.3% of the Grid Enhancement Plan investment of $246.2 million.

Figure 6-5: Circuits & Substations Business Case Results

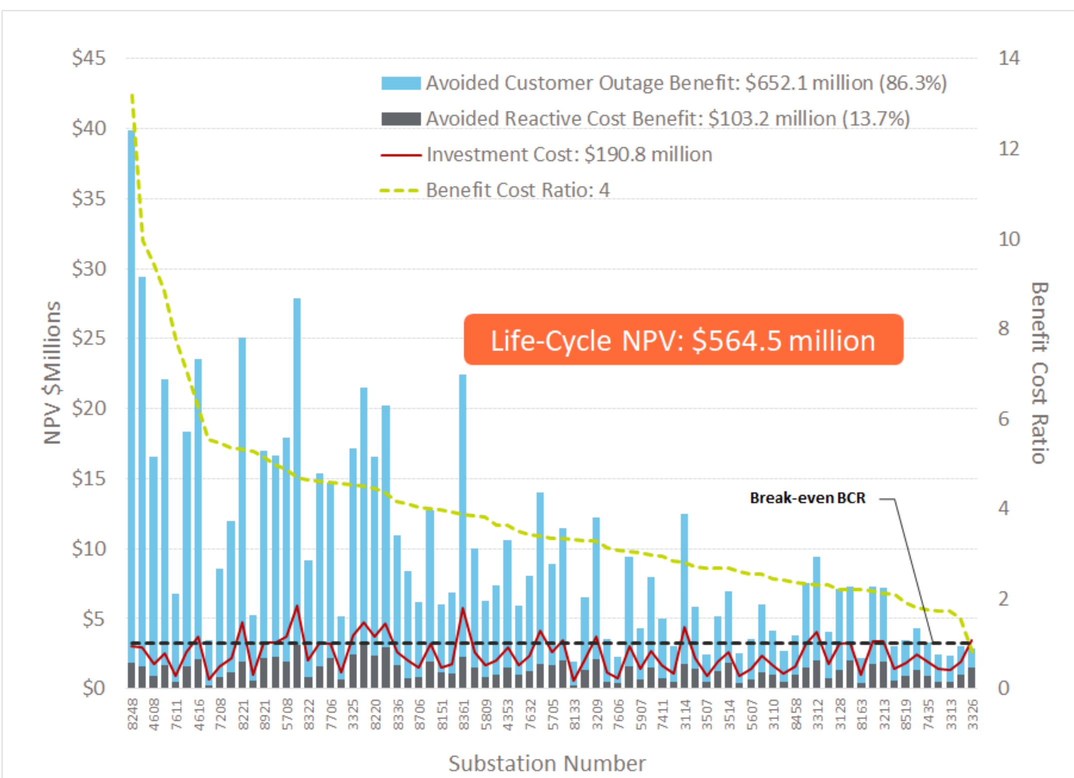
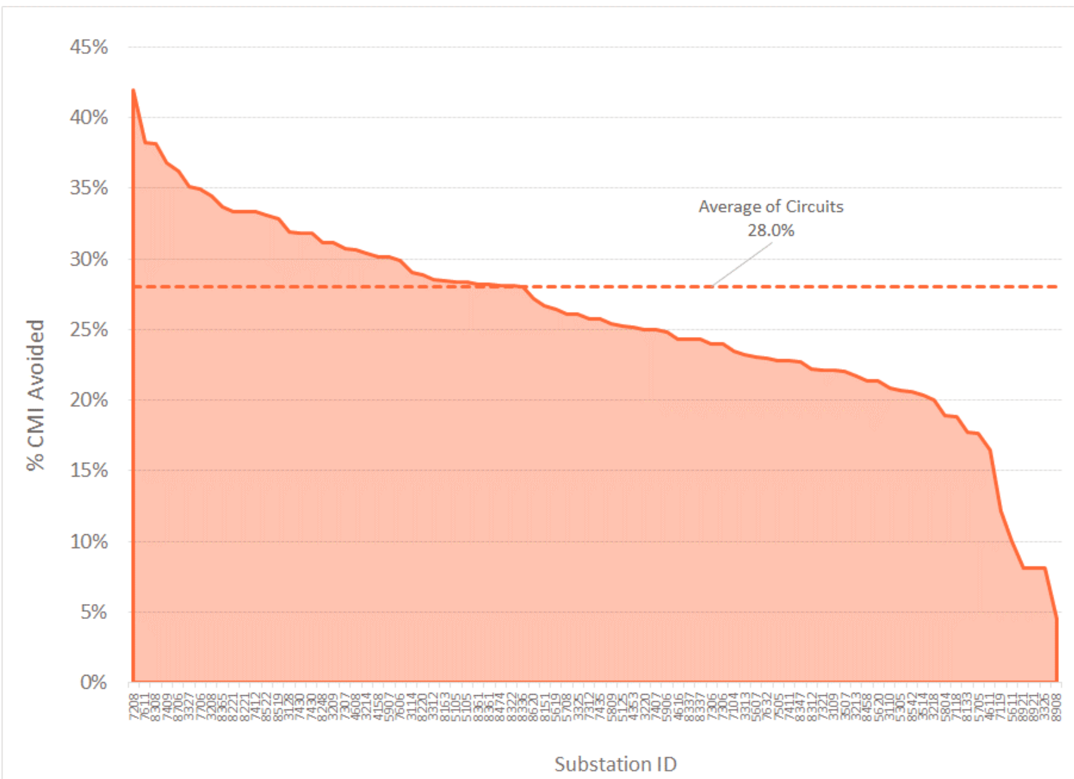


Figure 6-6 shows the percentage improvement in customer minutes interrupted for the Outage Risk Mitigation Benefit investments. The figure shows the results at the substation level. The figure shows a wide range of improvement from a high of approximately 41.9 percent to a low of 4.5 percent. The average improvement across all circuits is approximately 28.0 percent. These ranges in improvement are typical of investments in modern protection schema. The impact to performance metrics reported to NERC will be higher as outages less than 5 minutes are excluded.

Figure 6-6: Percentage Performance Improvement at Substation Aggregation

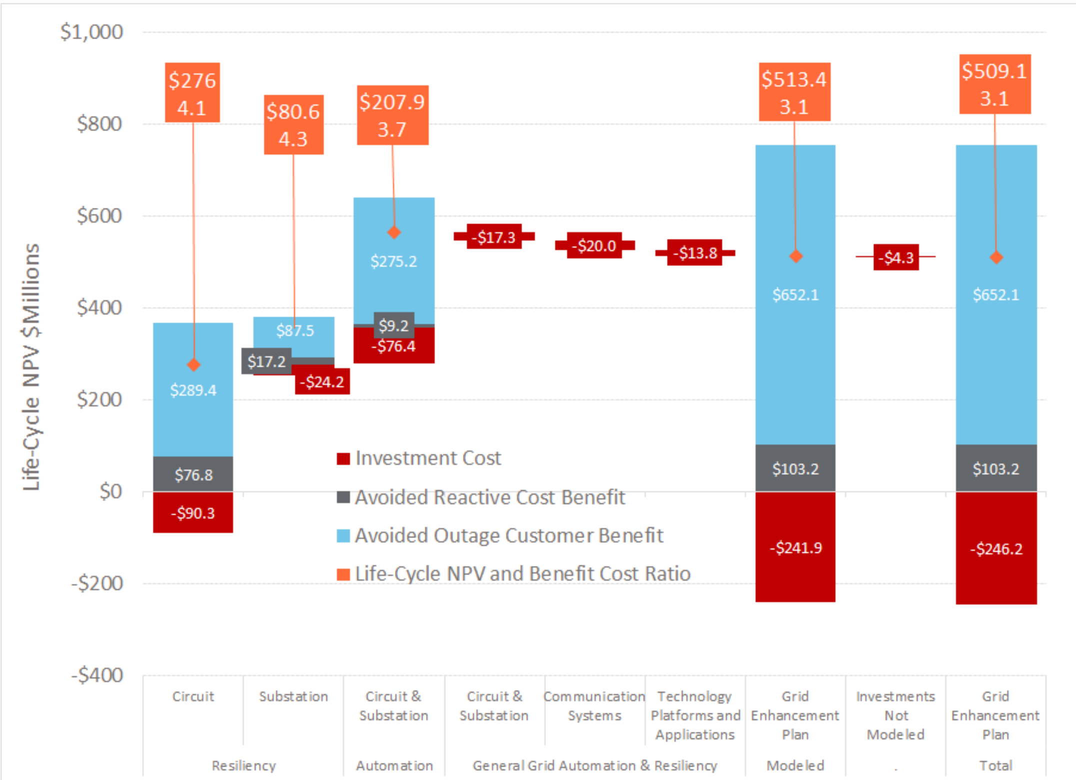


6.2 Grid Enhancement Business Cases

The final perspective in viewing the Grid Enhancement Plan business case is at the portfolio level. This includes adding the indirect / supporting investment that can't be directly mapped to substation or circuits and including investments there were not modeled. Much of the direct investment in the grid to specific substations or circuit is dependent on these enabling investments in communications system and technology platforms and applications to achieve their full benefits. Since these enabling investments cannot be directly mapped, the business case needs to be viewed from the entire portfolio perspective.

Figure 6-7 includes this portfolio perspective showing the Grid Enhancement Plan business case. For all modeled investments, the results show life cycle NPV of $513.4 million with a benefit cost ratio of 3.1. The figure also shows the inclusion of the investment where benefits were not modeled. For the 2020 and 2021 Grid Enhancement Plan the investments drive $509.1 million in life cycle NPV with a benefit cost ratio of 3.1. This shows that from a portfolio perspective, the Grid Enhancement Plan has a highly positive business case.

Figure 6-7: Grid Enhancement Business Case Summary

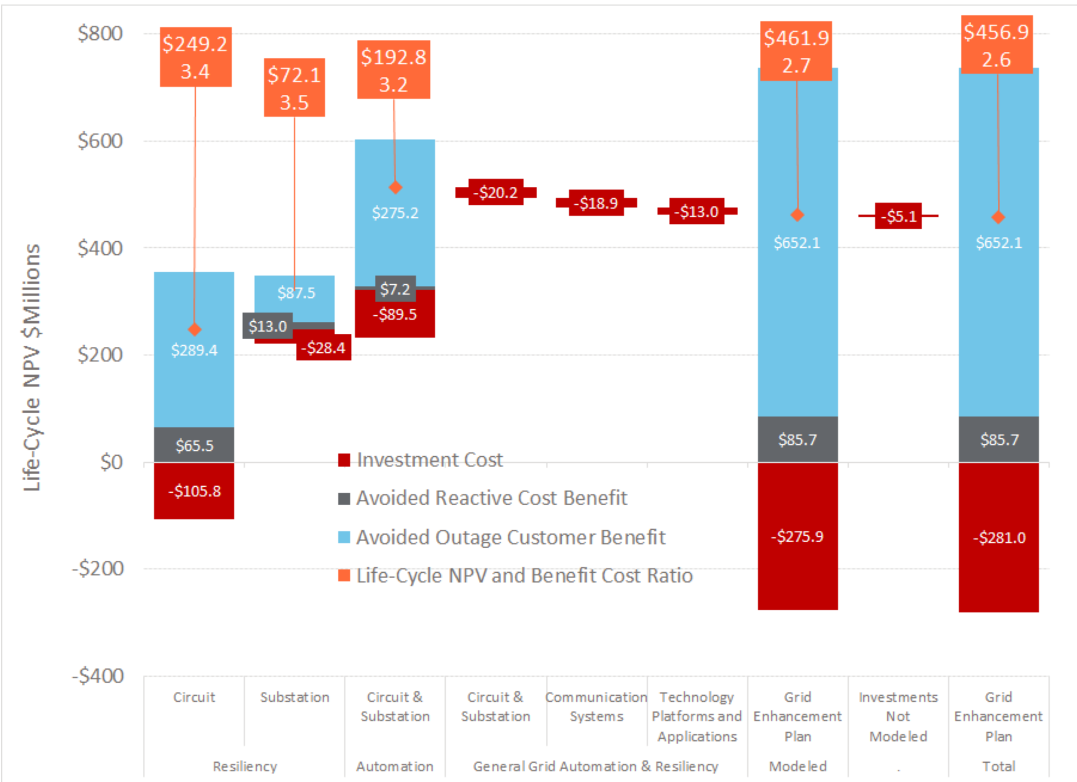


6.3 Grid Enhancement Revenue Requirements Business Case

As discussed in Section 3.5, OG&E provided a Revenue Requirements Model to evaluate the grid enhancement investments from an impact to rates perspective as part of the business case. All results till now have been shown from a cash flow basis. The revenue requirements model considers various depreciation rates, profit returns, taxes, and levelizing of capital investment. For each investment, 1898 & Co. input the investment cost, avoided capital cost annual profile, and the avoided O&M expense profile into the revenue requirements model to calculate the net impact to customers.

Figure 6-8 shows the Grid Enhancement Plan's business case summary using this revenue requirements approach. The figure shows results in the same format as Figure 6-7. Figure 6-8 shows that the investment cost of the Grid Enhancement Plan will increase revenue requirements by approximately $281.0 million from a life cycle PV perspective. The figure also shows that the investment will decrease future reactive and restoration costs by $85.7 million in life cycle NPV terms. The net impact to customer revenue requirements is an increase of $195.3 million. Monetizing the customer outages using the DOE ICE Calculator produces benefits of $652.1 million as shown in Figure 6-8.

Figure 6-8: Grid Enhancement Business Case Summary – Revenue Requirements



Appendix A includes the various business case perspective results from the revenue requirements perspective. It includes similar figures to all those shown in Sections 5.0 and 6.0

7.0 CONCLUSIONS

The following includes the conclusions for the 2020 and 2021 Grid Enhancement Plan business case based on the approach and results outlined in this report.

- The Grid Enhancement Plan has a robust business case from several perspectives.
  - From the portfolio level, the investment produces a life cycle NPV of $509.1 million and benefit cost ratio of 3.1 (cash flow approach).
  - From an individual substation perspective. 76 of the 77 substations have benefit cost ratios great than 1, ranging from 13.2 to 1.6. The other substation has a benefit cost ratio of 0.8 resulting in $641,000 of investment without any benefits. This is equivalent to 0.3% of the investment of $246.2 million.
  - All 11 of the Direct Investment business cases are economic at the system level. Very few of the individual substations or circuits are non-economic. Much of this is based on known data gaps in recording outages at substations.
- The Grid Enhancement Plan is an integrated and comprehensive set of investments where all the investments work together to produce synergistic benefits. The business case evaluation cannot be broken down to one number, rather it should be considered from several perspectives in drawing conclusions. Additionally, eliminating investment categories or types of investment within specific substation and circuits likely burdens the business case of other investments, mainly increasing their share of the system allocated costs.
- The Grid Enhancement Plan will improve the customer experience. Customer outages from the Outage Mitigation Risk and Resiliency benefit approach are estimated to decrease by approximately 28.0 percent. Additionally, the plan will significantly decease ‘blinking’, a complaint from customers.
- Even though some of the 749 individual business case results have benefit cost ratios less than one, many of those business case results should not be viewed at this level, rather the circuit or substation level is more appropriate. Additionally, the data deficiency OG&E is currently improving for substation outages causes the other remaining business case results to be less than 1.
- The net impact to revenue requirements is $195.3 million

- OG&E’s range of grid investment activities mirrors the type of investment customer focused distribution utilities are making across the United States. Much of the plan investment is focused on improving the customer experience to meet customer expectations of reliability and resiliency.
- The benefits assessment is both customer centric and data-driven employing robust risk & resiliency analytics based on each investment’s main benefit driver. This provides an unbiased “apples to apples” and transparent evaluation across all investments with the customer as the focus.

APPENDIX A: REVENUE REQUIREMENTS RESULTS

The following figures shows the business case results from a revenue requirements perspective. The net impact to revenue requirements equals the Investment Cost minus the Avoided Reactive Cost Benefit. If the Avoided Reactive Cost Benefit is greater than the Investment Cost revenue requirements will decrease. Graphically, if the red line is below the grey bar revenue requirements will decrease.

Figure A-1: 2020 & 2021 Grid Enhancement Investment Summary

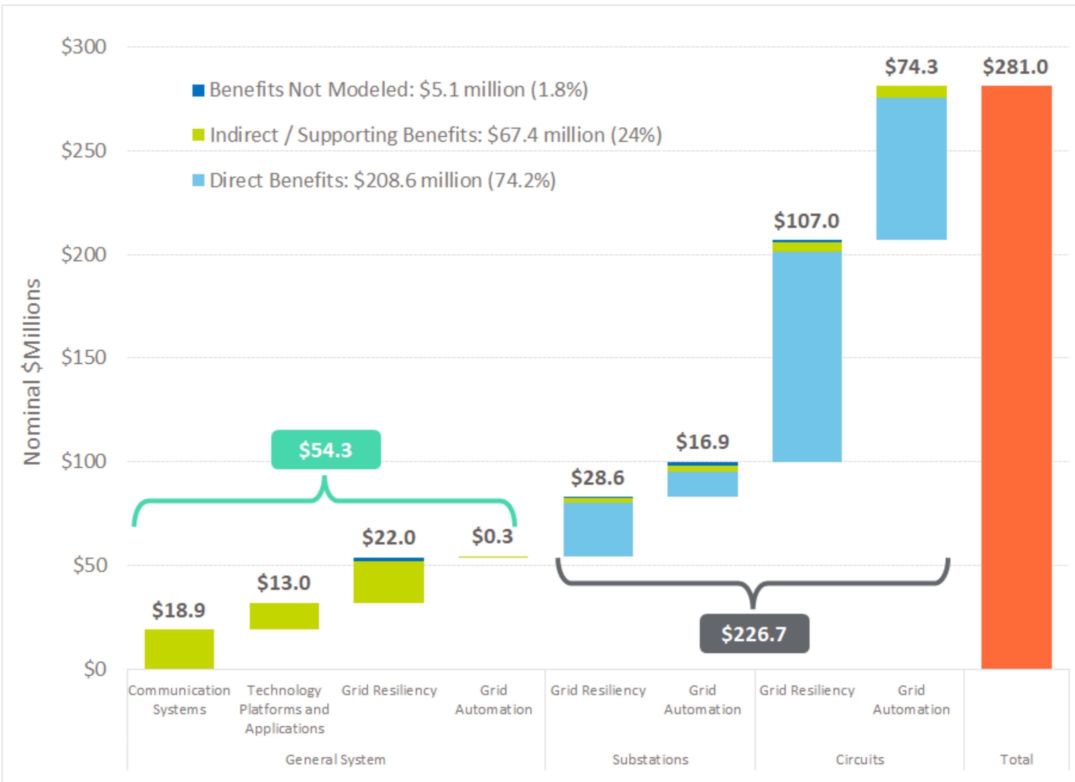


Figure A-2: Direct Investments Business Case Results

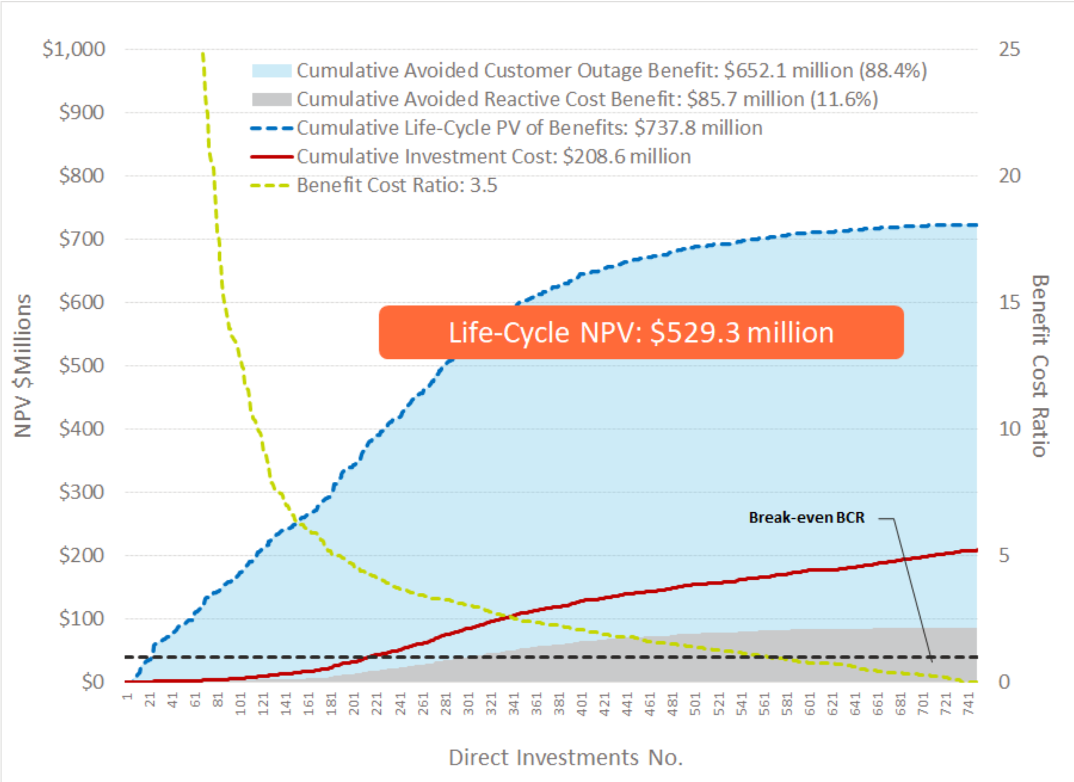


Figure A-3: Distribution Line Reliability Business Case Results

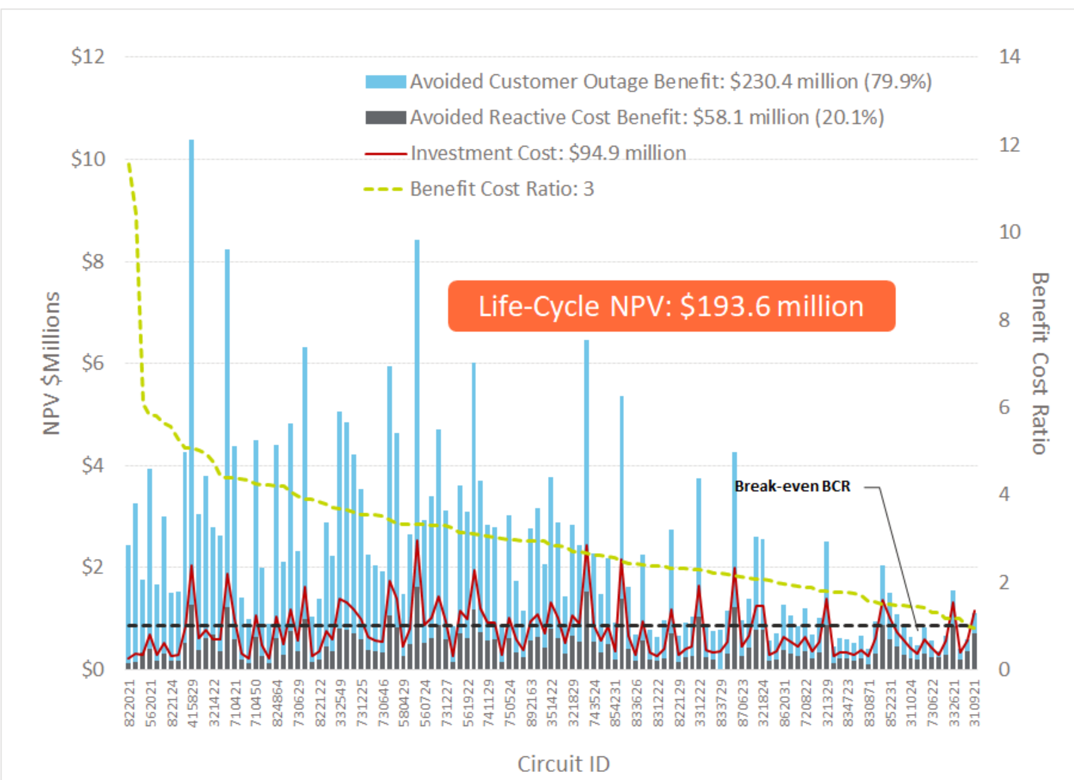


Figure A-4: Overhead Conductor and Underground Cable Business Case Results

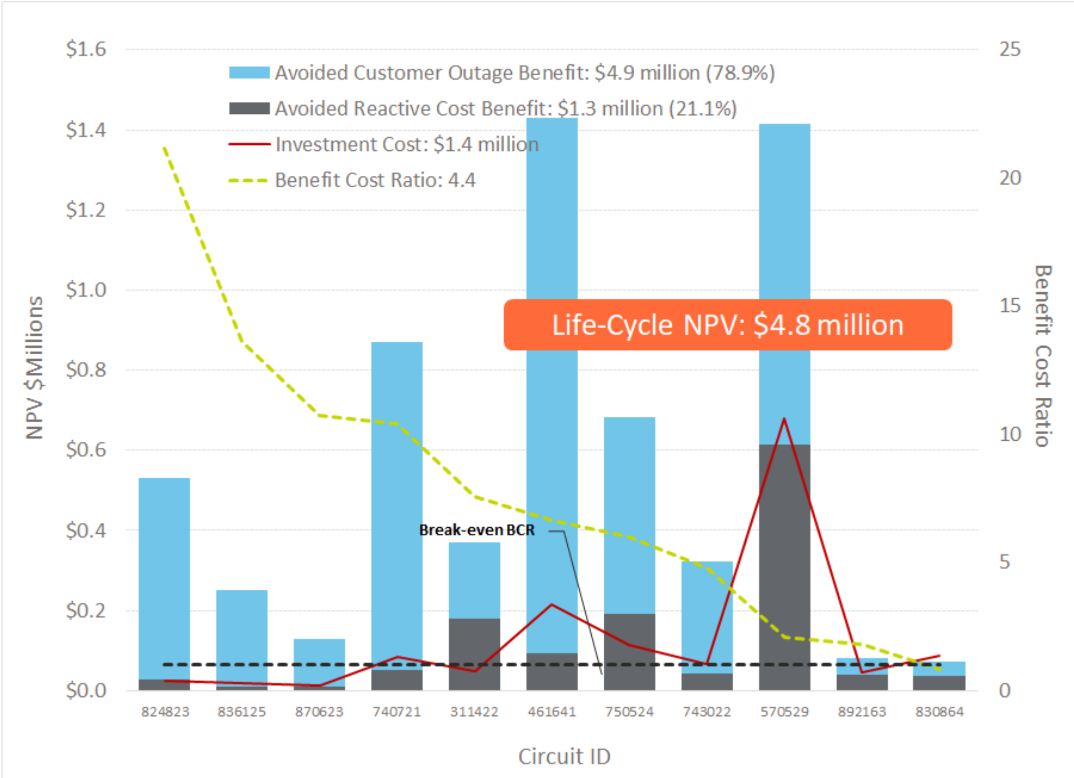


Figure A-5: Transformer Load Management Business Case Results

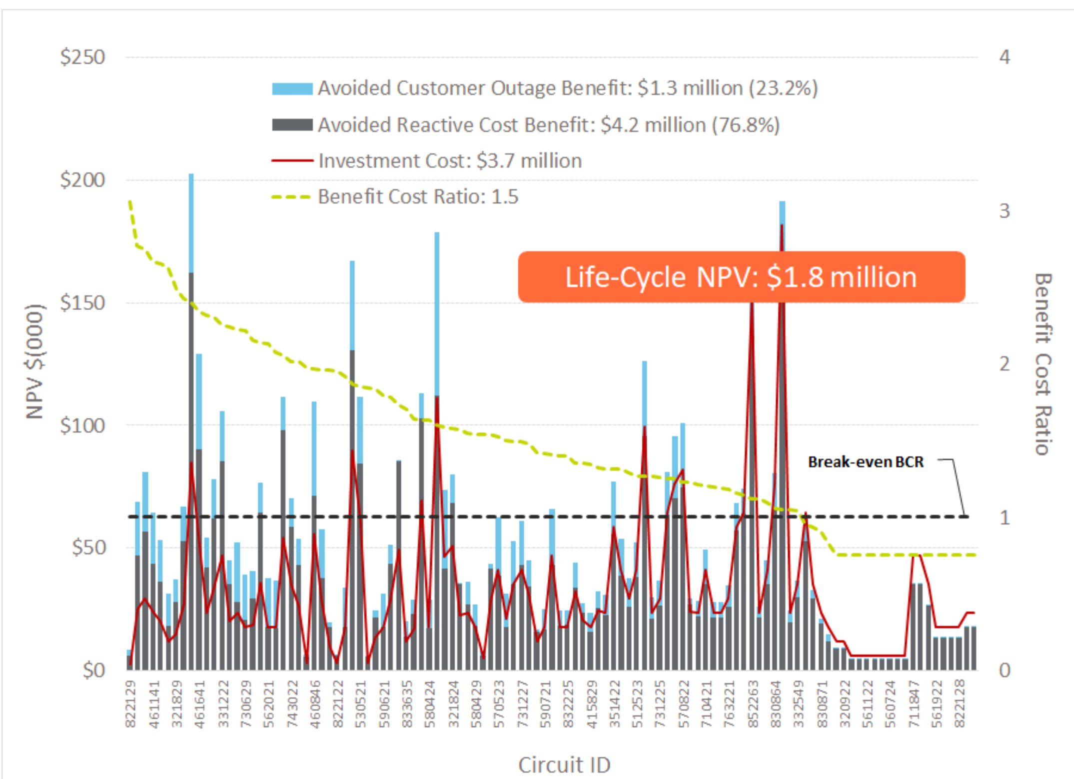


Figure A-6: Substation Animal Protection Business Case Results

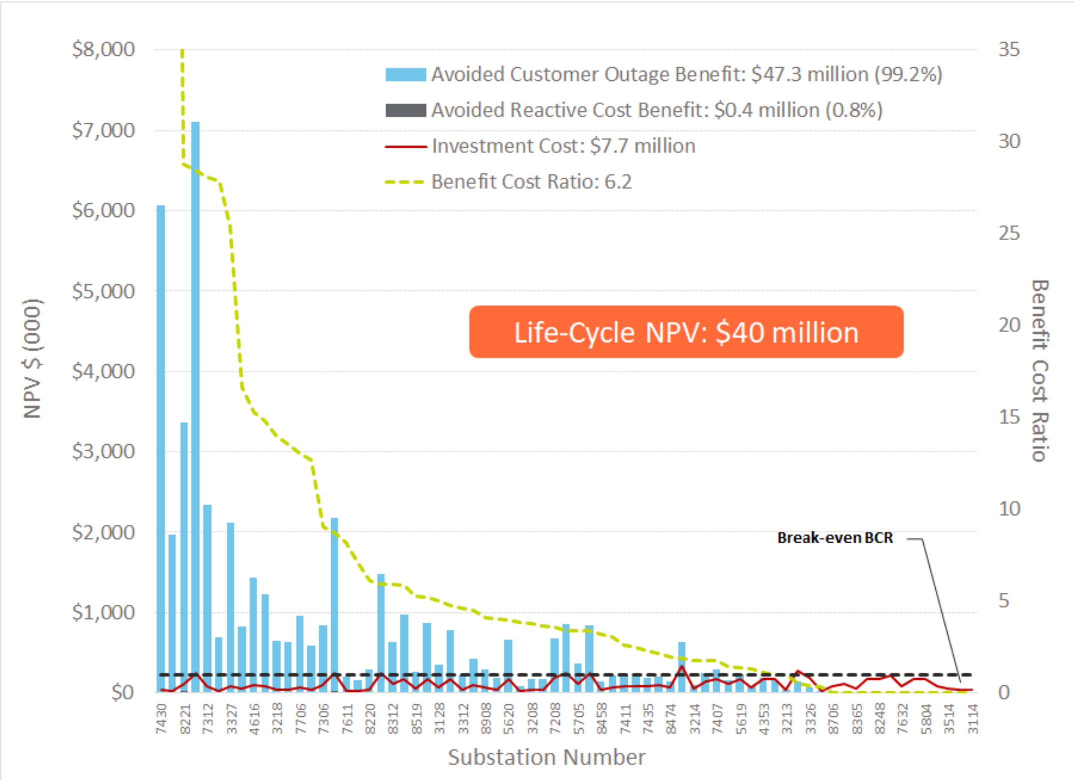


Figure A-7: Lightning Outage Reduction Program Benefit Cost Results

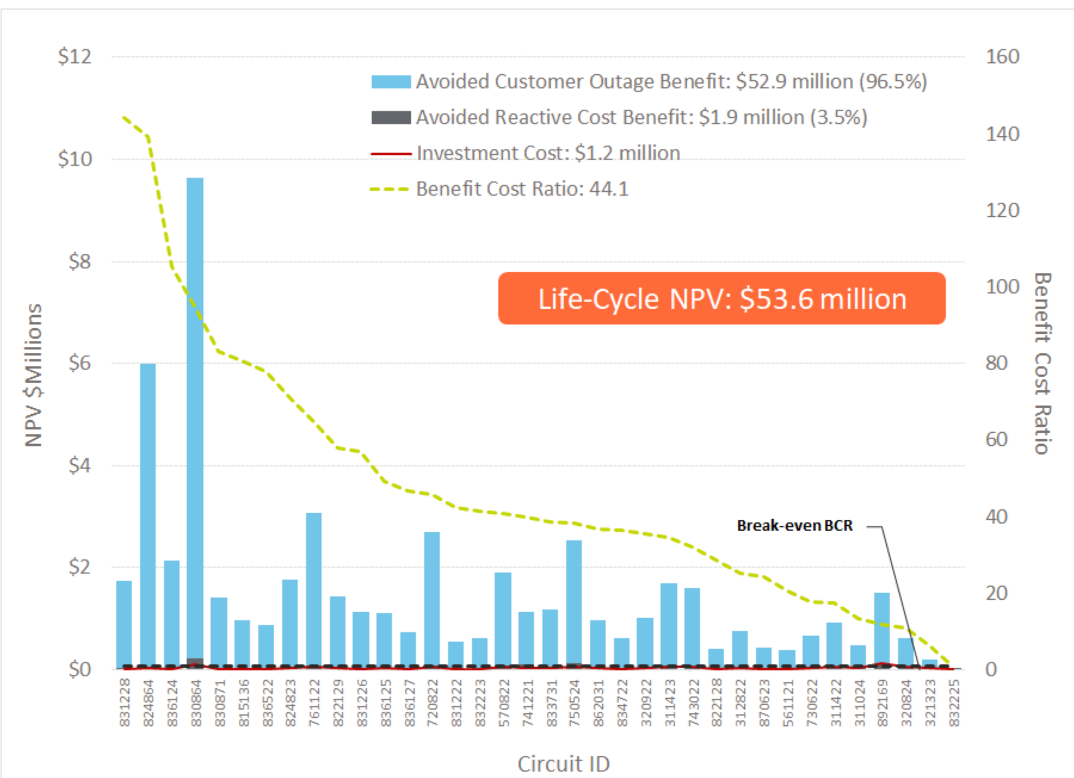


Figure A-8: Modern Protection Schemes Business Case Results

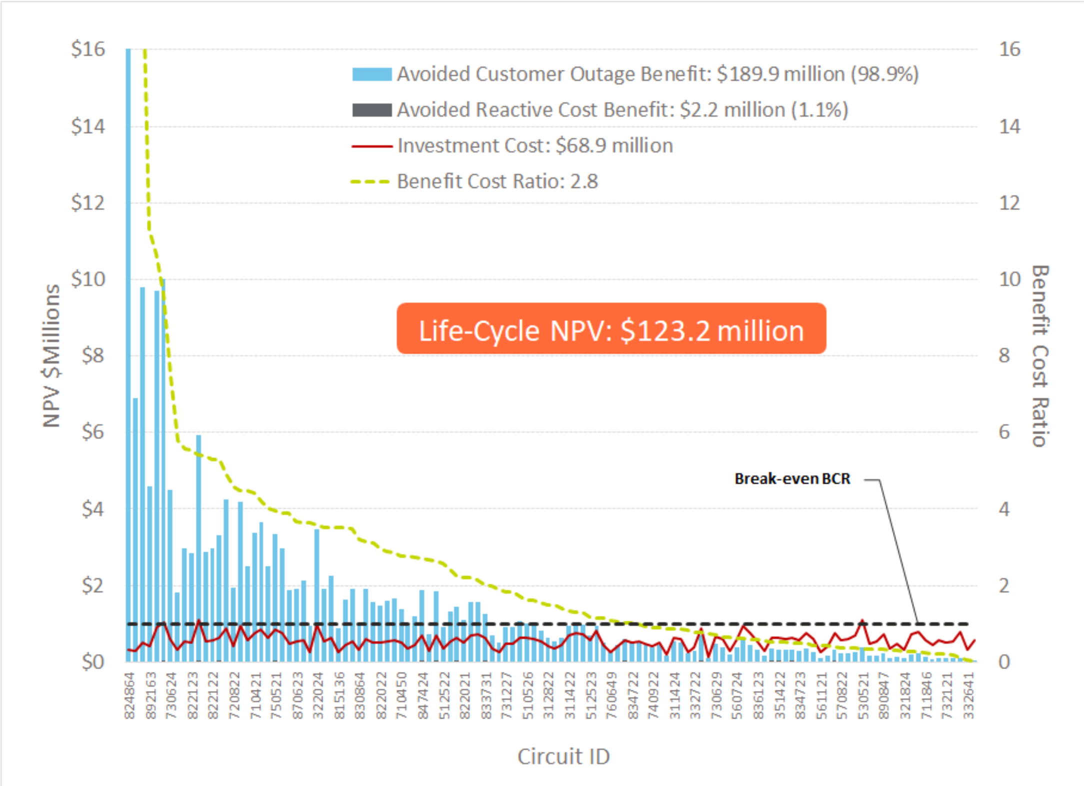


Figure A-9: Fault Location Isolation Business Case Results

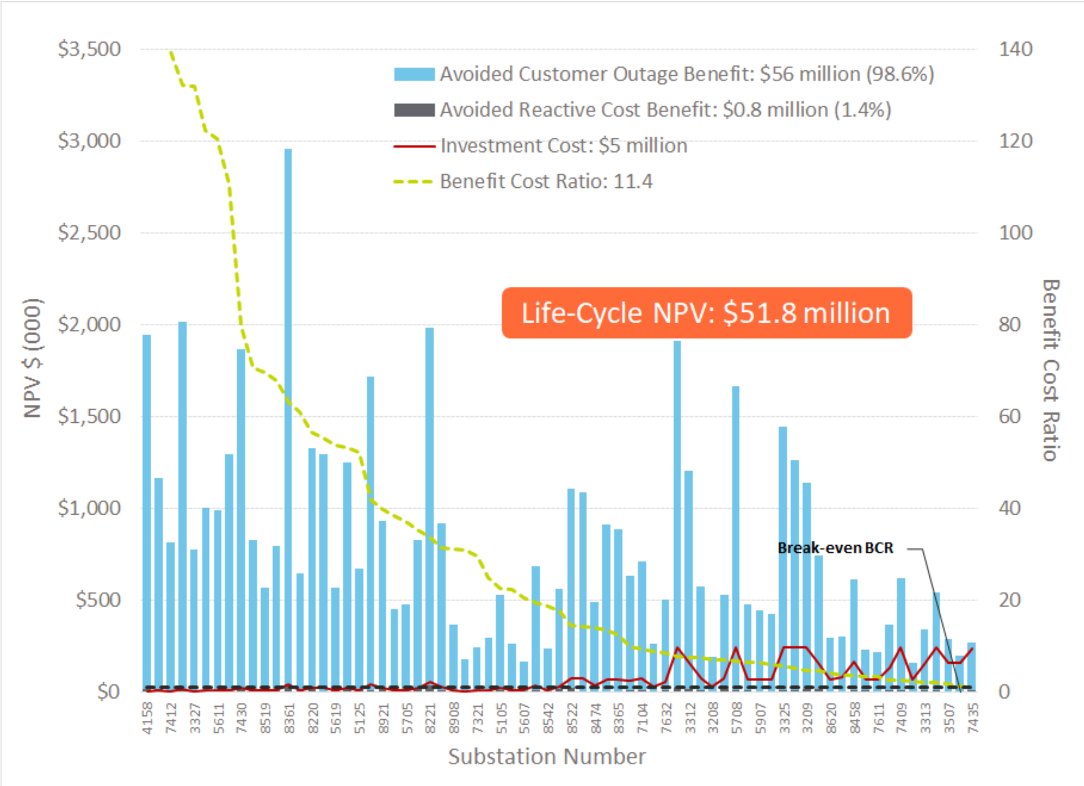


Figure A-10: Power Transformer Business Case Results

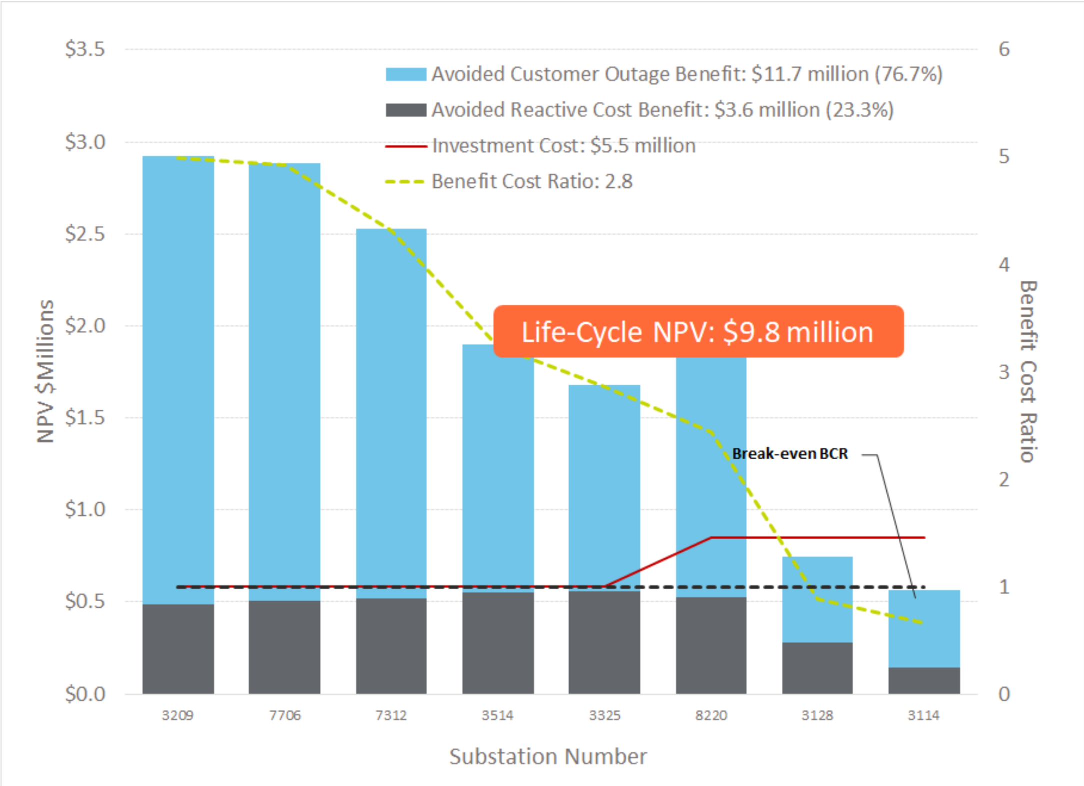


Figure A-11: Transformer Protection and Cap Switcher Business Case Results

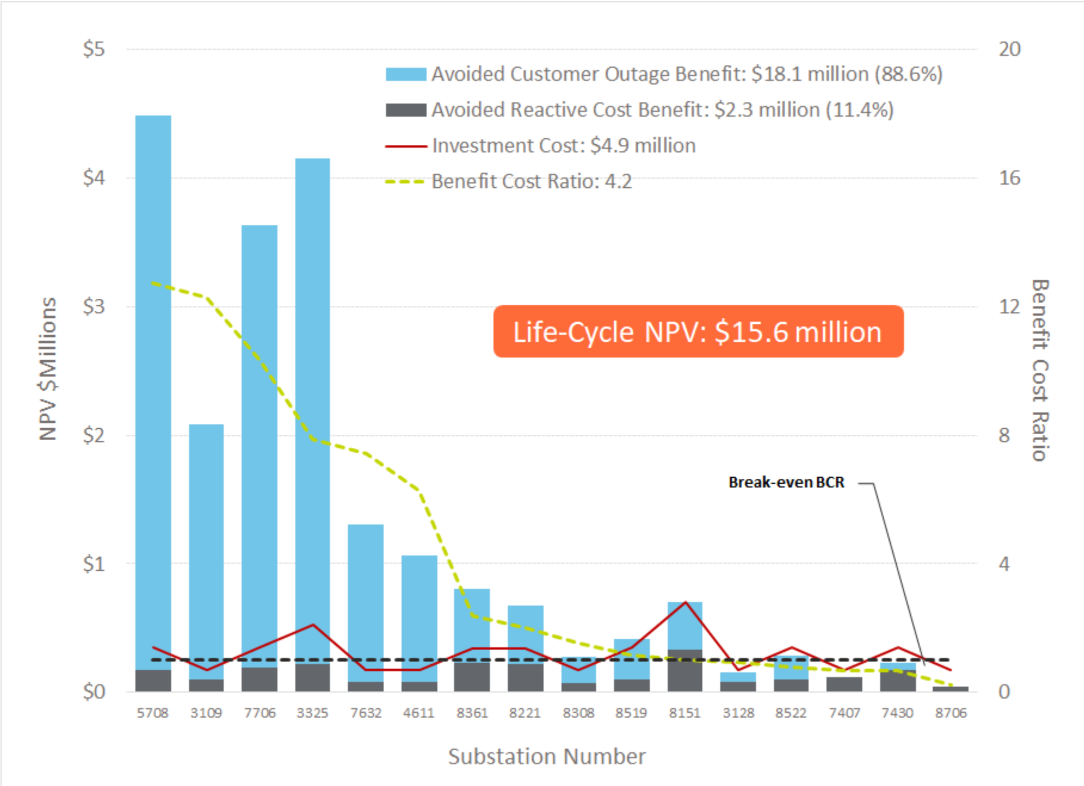


Figure A-12: Substation Distribution Breaker Replacement Business Case Results

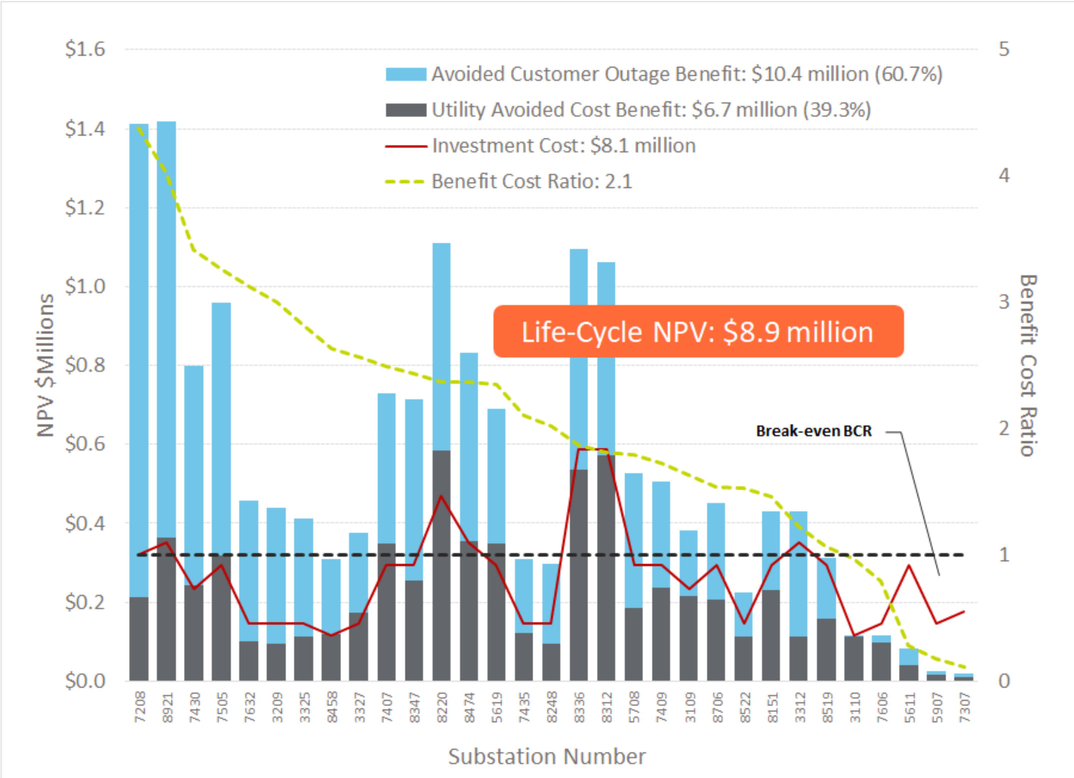


Figure A-13: Modern Relay Protection Business Case Results

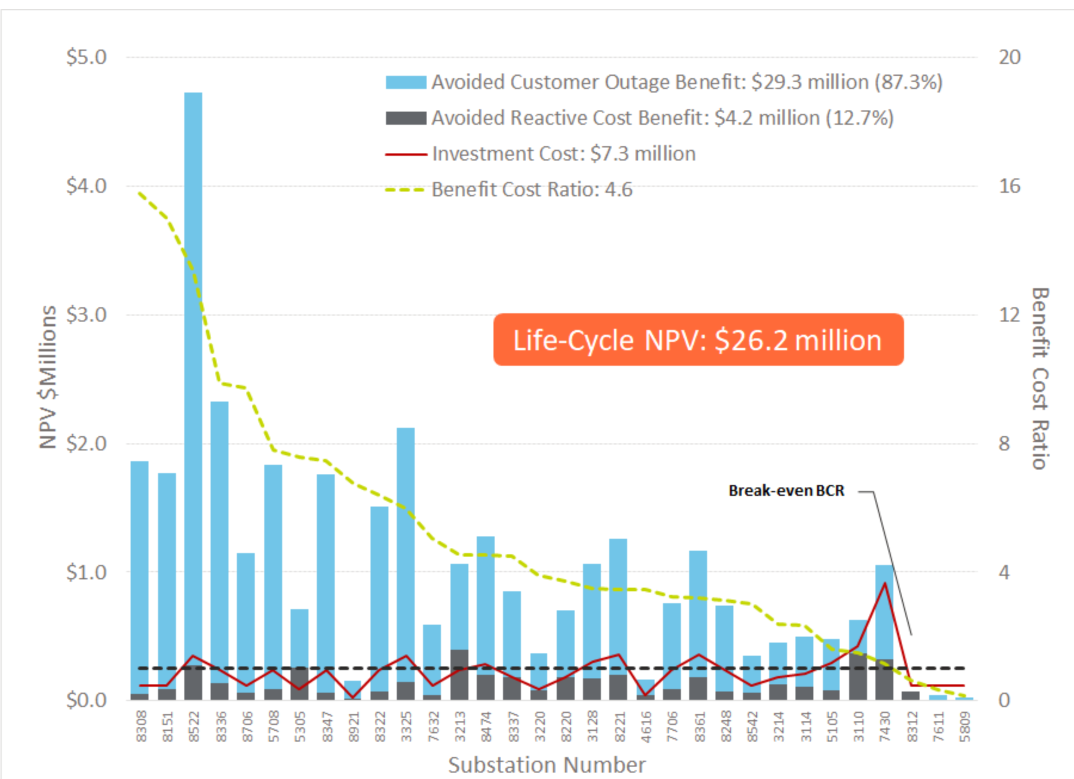


Figure A-14: Direct Investment Business Case Summary Results

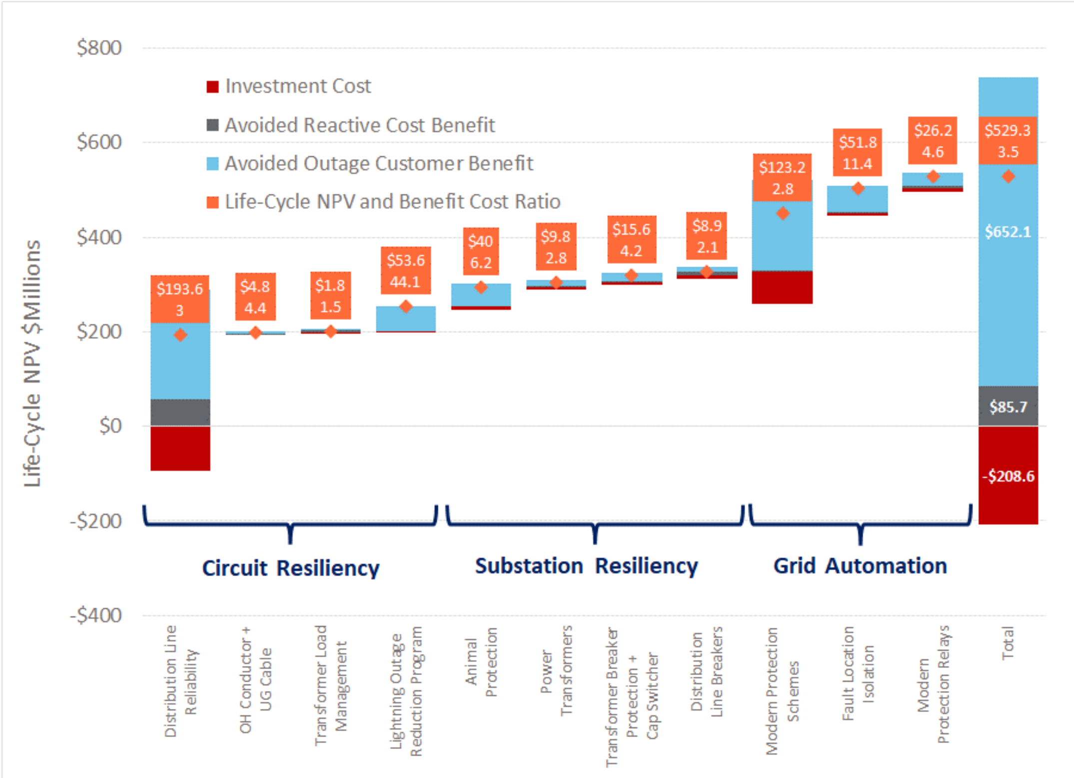


Figure A-15: Grid Resiliency & Automation Business Case Summary Results

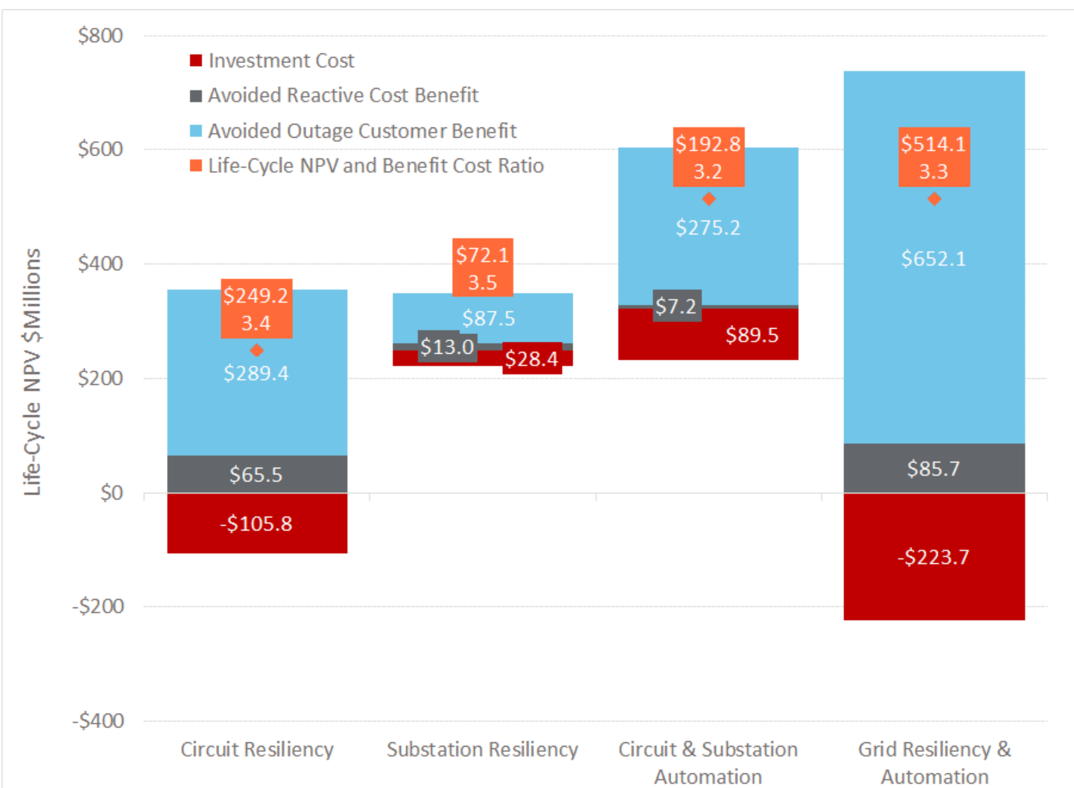


Figure A-16: Circuits Resiliency Business Case Results

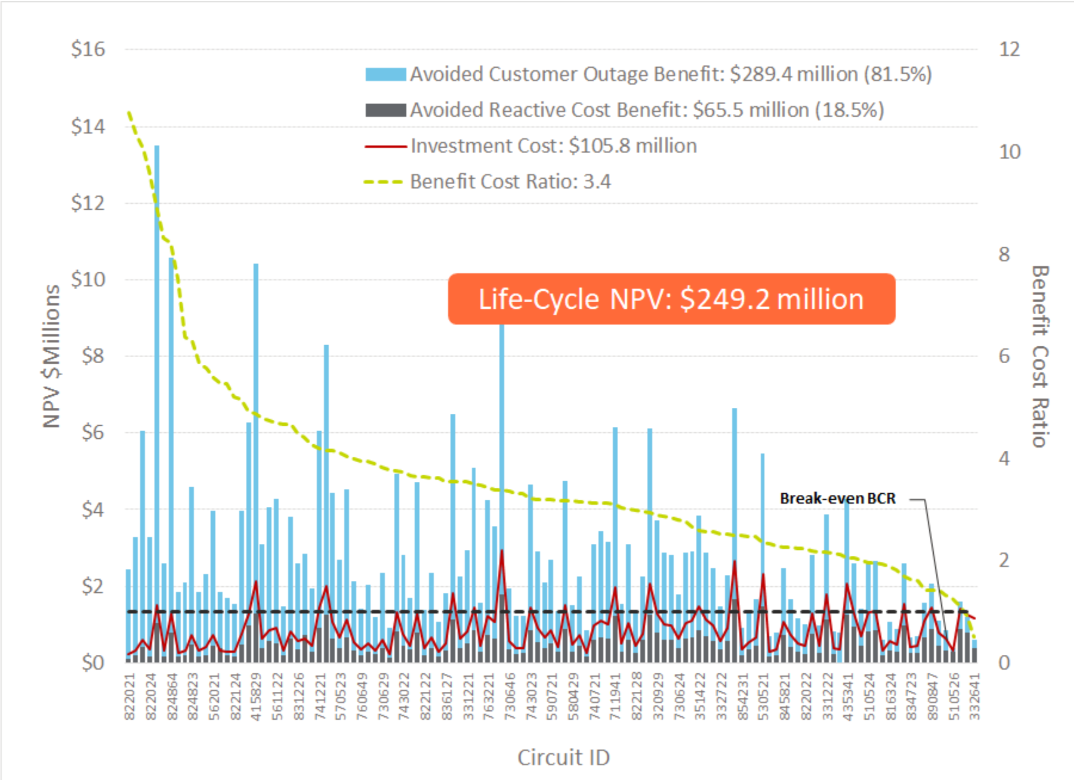


Figure A-17: Substations Resiliency Business Case Results

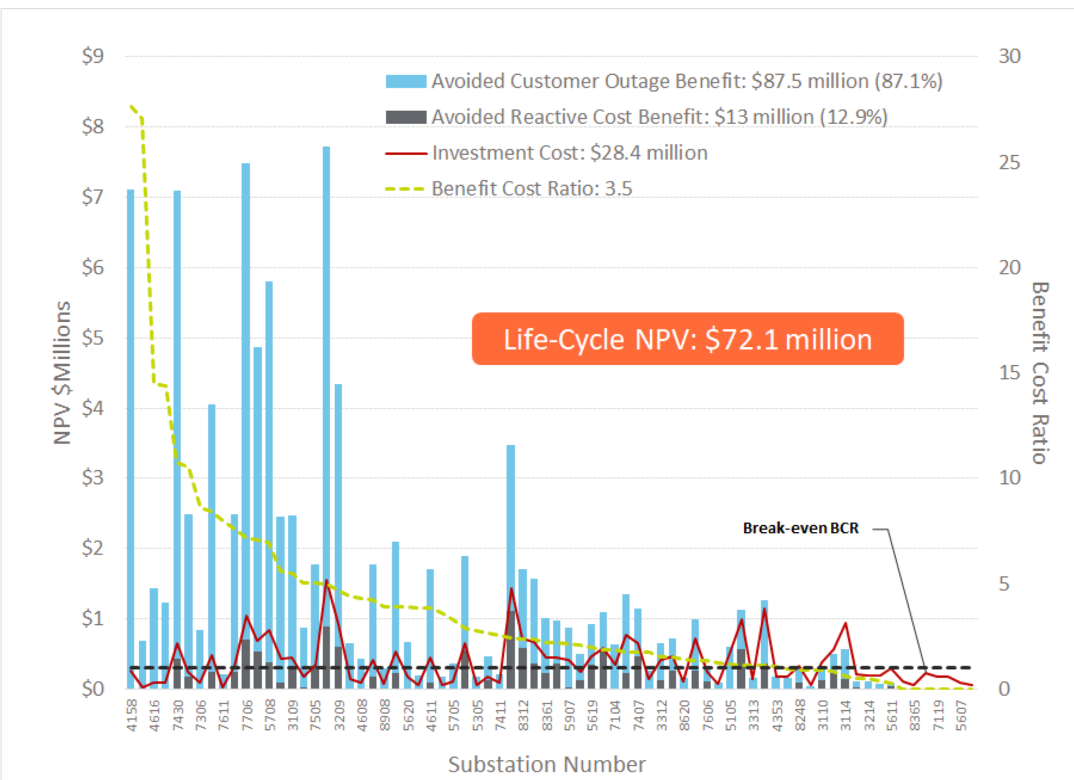


Figure A-18: Circuits & Substations Automation Business Case Results

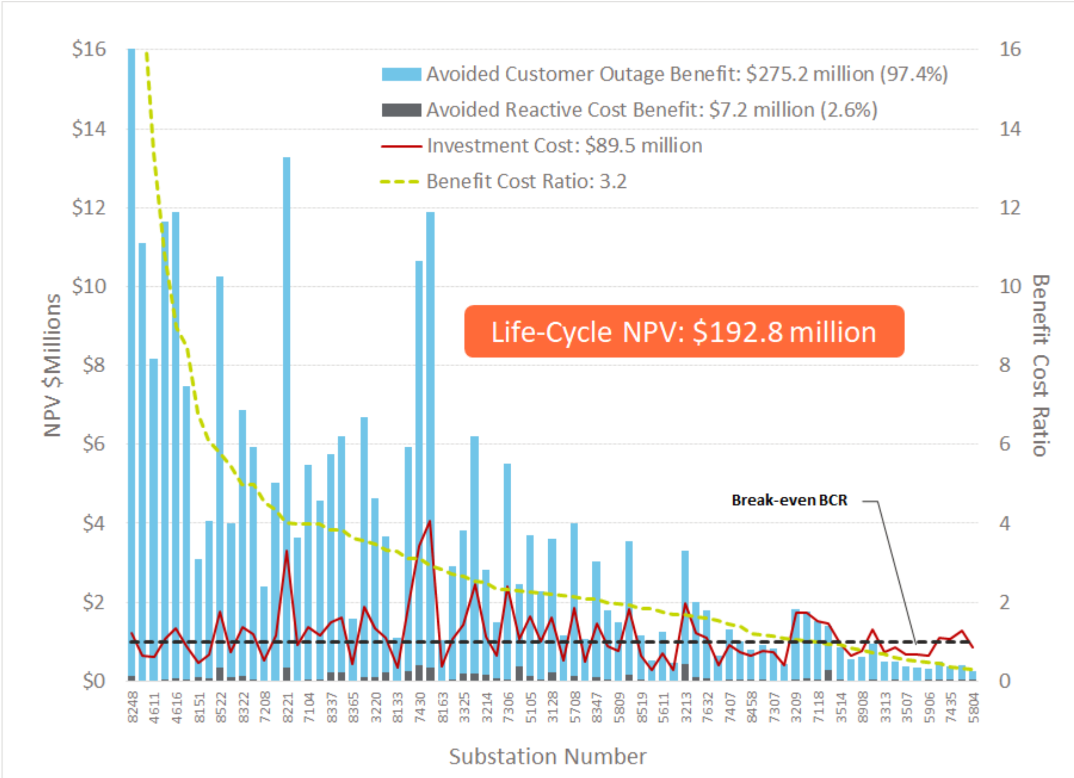


Figure A-19: Circuits & Substations Business Case Results

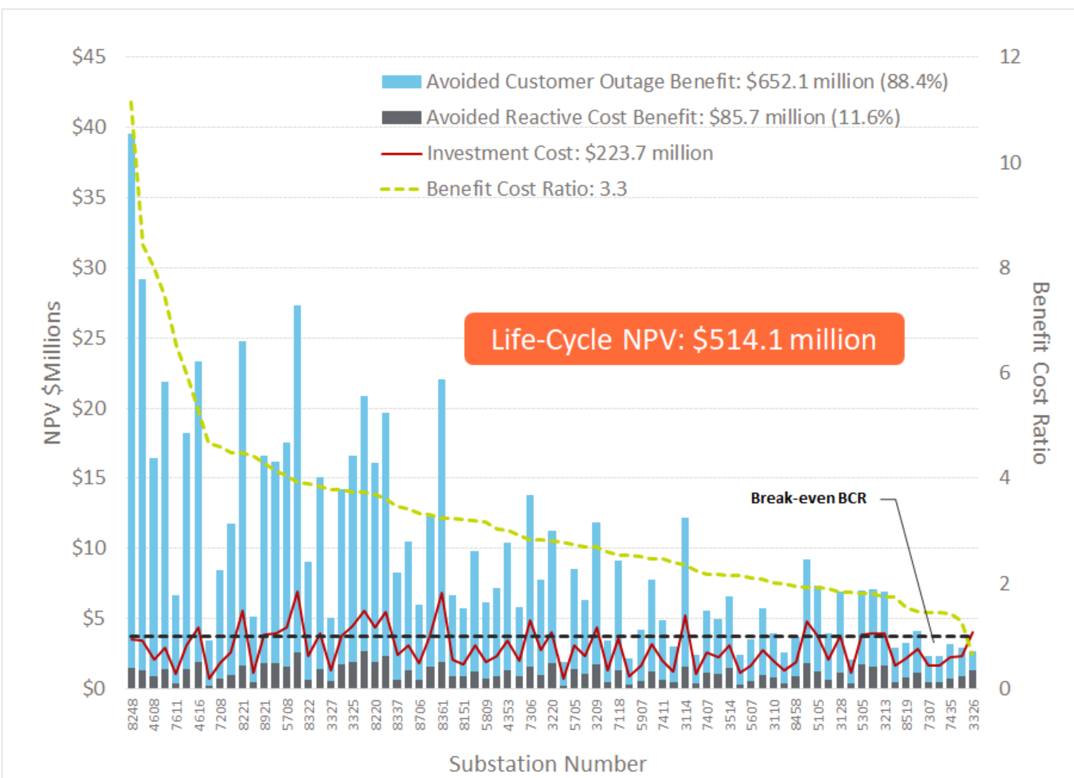
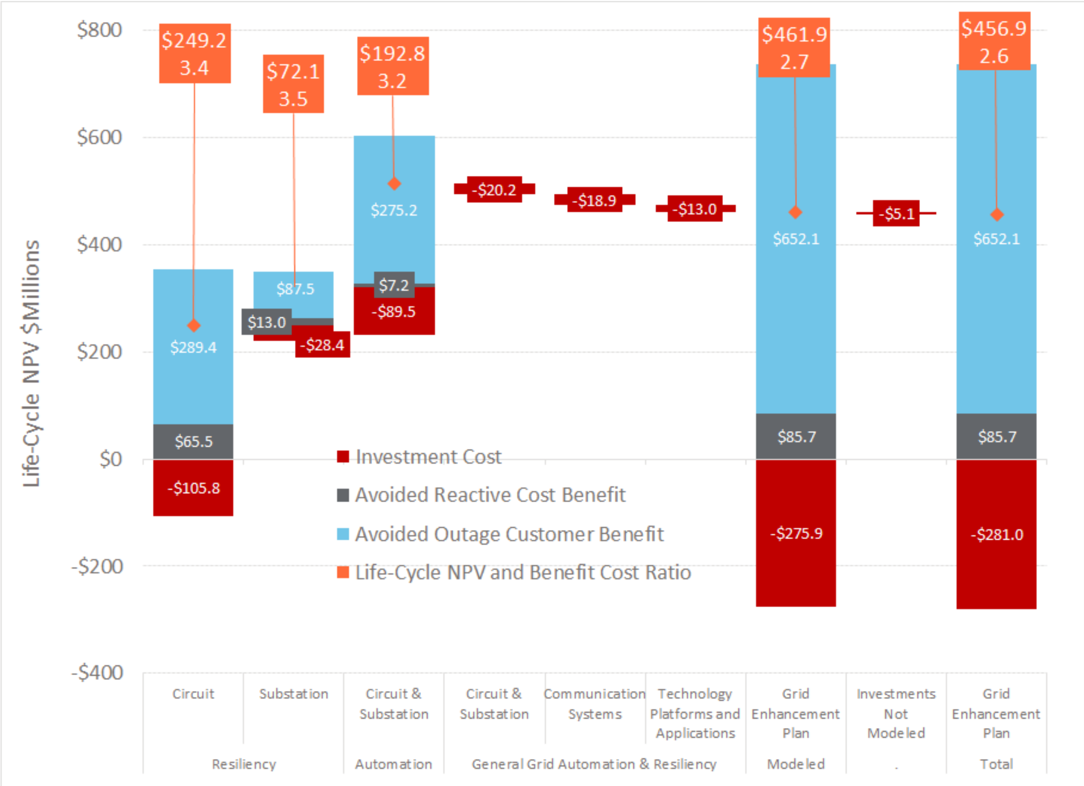


Figure A-20: Grid Enhancement Business Case Summary



1898 & CO

PART OF BURNS & McDONNELL

9400 Ward Parkway
Kansas City, MO

816-605-7800
1898andCo.com