BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

GEORGIA POWER COMPANY'S	)	**DOCKET NO. 44280**
2022 RATE CASE	)	

DIRECT TESTIMONY

AND EXHIBITS

OF

PAUL J. ALVAREZ
AND
DENNIS STEPHENS

On Behalf of the

Georgia Public Service Commission
Public Interest Advocacy Staff

PUBLIC DISCLOSURE VERSION

October 20, 2022

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EXHIBIT LIST

Exhibit	Description
PA/DS-1	Curricula Vitae of Paul J. Alvarez
PA/DS-2	Curricula Vitae of Dennis Stephens
PA/DS-3	Trade Secret Attachment A provided in response to STF-WG-2-8 (”Customer Benefits Study, corrected k-factor”)
PA/DS-4	Attachment S, Appendix B (page 44) provided in response to STF-WG-1-1 (no longer Trade Secret per authorization e-mail from Georgia Power Counsel September 26, 2022
PA/DS-5	Summary of Grid Investment Plan revenue requirement calculations
PA/DS-6	Summary of Substation Equipment Failures Resulting in Outages calculations
PA/DS-7	Trade Secret Optimization Model screenshots provided informally by Georgia Power in follow-up to discovery conference held October 3, 2022
PA/DS-8	Trade Secret “Staff Scenario Summary” provided informally by Georgia Power in follow-up to discovery conference held October 3, 2022
PA/DS-9	Trade Secret Attachment G, Tab “EBA Valuation” provided in response to STF-WG-Informal-1 (Summary projections by year of Georgia Power’s proposed “80 SAIDI” Scenario for the Distribution Investment Plan
PA/DS-10	Sample Annual Performance Report from a utility to the Maryland Public Service Commission

I. INTRODUCTIONS AND PREVIEW

Q. MR. ALVAREZ, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Paul J. Alvarez. My business address is Wired Group, P.O. Box 620756, Littleton, Colorado 80162.

Q. WHAT IS YOUR OCCUPATION?

A. I lead the Wired Group, a small consultancy specializing in distribution utility planning, investment, regulation, and performance.

Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. It is presented in Exhibit PA/DS-1. This exhibit summarizes my educational background, professional experience, and appearances before state utility regulators.

Q. MR. STEPHENS, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dennis Stephens. My business address is 1153 Bergen Parkway, Suite 130, Evergreen, CO 80439.

Q. WHAT IS YOUR OCCUPATION?

A. I am an independent consultant specializing in utility distribution planning, investment, operations, asset management, reliability, and safety. I frequently work for the Wired Group in support of the firm's clients.

Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. It is presented in Exhibit PA/DS-2. This exhibit summarizes my educational background, professional experience, and appearances before state utility regulators.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. We are testifying in the public interest on behalf of the Georgia Public Service Commission Public Interest Advocacy Staff (Staff).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to provide recommendations for Commission consideration regarding Georgia Power Company's (Georgia Power or Company) proposed continuation of the Grid Investment Plan (GIP). With the exception of transmission lines, we have completed detailed reviews of, and discovery into, all aspects of the GIP. (Transmission lines are addressed in the testimony of Staff Witness Mr. Raj Rana, though many of the themes of our testimony are repeated in Mr. Rana's testimony, and many observations made by Mr. Rana are relevant to the portions of the GIP we examined.)

Q. PLEASE PREVIEW YOUR TESTIMONY

A. Our testimony begins in Section II with context regarding transmission and distribution investments related to reliability improvements, as well as perspectives on the associated timing and rate increases. (The Company claims the GIP is needed to maintain and improve service reliability.)[1] Later, our testimony presents analyses indicating that the largest components of GIP spending will not deliver reliability improvements sufficient to outweigh costs. But in this Section we observe 1) that electric rates are already poised to rise substantially in Georgia over the next few years; 2) that there is no pending reliability emergency or customer demand for the reliability improvements Georgia Power proposes to pursue; and 3) that the results of various GIP investments to date will not be known for at least a few more years. These observations strongly suggest a need to complete formal

[1] Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson On Behalf of Georgia Power Company ("APA-SPA-ADH-MBR Direct"), p. 15 at 7-13

and rigorous (independent) study of the results of Georgia Power's GIP spending so far before more such spending is authorized.

In Section III, we explain why the GIP investments the Company plans for its transmission grid will not deliver reliability benefits of sufficient value to outweigh associated rate increases. Proposed at $1.0 billion from 2023-2025, and representing a 278% increase over annual transmission spending in years prior to the GIP, the transmission investment plan (TIP) benefits shareholders far more than it will customers or Georgia's economy. Specifically, we challenge the Company's practice, new to the GIP, of replacing substation (and transmission line) equipment that has passed periodic, objective tests and inspections that all utilities, including Georgia Power, conduct routinely. The practice, which we call premature equipment replacement, relies on the estimated useful lives – typically employed only to inform accounting depreciation periods -- rather than objective test and inspection results, to determine when equipment should be replaced. We will explain why premature equipment replacement is inappropriate, and recommend all proposed investments from this practice be rejected. We favor the objective approaches Georgia Power has successfully employed in the past, and continues to employ in this rate case, to identify equipment for replacement.

In Section IV, we explain why some distribution investment packages in the Company's GIP will not deliver reliability benefits of sufficient value to outweigh associated rate increases. Proposed at $1.3 billion from 2023-2025, and part of a total distribution capital spending request amounting to a 131% increase (more than double) over annual distribution spending prior to the GIP (2009-2019), the distribution investment plan (DIP) is rendered cost-ineffective by circuit hardening and undergrounding investment packages. Not only are these packages cost-ineffective due to their extremely high cost per premise, the DIP ignores vastly less expensive practices almost all utilities employ to improve reliability, namely, more aggressive vegetation management and a more formal worst-performing circuit program. In this section we will also describe multiple flaws with the Optimization Model the Company uses to select circuits to treat and investment packages to deploy, and which the Company uses to justify its distribution investment plan. Finally, we summarize what the Maryland Commission has done to cost-effectively improve reliability, and recommend that proposed spending on circuit hardening and undergrounding be eliminated while preserving a 55% increase in overall distribution capital spending over the average levels prior to the GIP.

In Section V, we address the Company's plan to invest $100 million in a distributed energy resource management system, or DERMS. The level of distributed energy resources needed to justify such a system is high, and will not be reached by the time the proposed DERMS is fully depreciated in 2030, let alone by the end of the upcoming rate planning period in 2025. Further, Georgia Power already maintains systems and processes to manage distributed energy resources. We recommend this proposed spending be postponed until a future rate case, when the level of distributed energy resources on Georgia Power's grid provides sufficient justification for such a system.

Q. PLEASE SUMMARIZE THE SPENDING ADJUSTMENTS RECOMMENDED IN YOUR TESTIMONY

A. Table 1 below summarizes our recommended spending and cost recovery adjustments. These adjustments are translated into revenue requirement reductions in the testimony and exhibits of Staff Witnesses Mr. Ralph Smith and Mr. Robert Trokey (Smith-Trokey). It should be noted that the annual amount of transmission and distribution capital investment Staff does not recommend be rejected is still double the annual average for 2009 – 2021. This large increase that still remains is in contrast to the much smaller growth in number of customers, energy sales (MWhs), and peak demand (MW).

Table 1: Summary of Recommended T&D Capital Investment Reductions

($ in millions)	2009-2021 Average Actual	2023	2024	2025	’23-’25 Average
T&D Capital Requested		[redacted]	[redacted]	[redacted]	[redacted]
Transmission Investment Plan		(328)	(314)	(359)	(334)
Circuit Hardening		[redacted]	[redacted]	[redacted]	[redacted]
Undergrounding		[redacted]	[redacted]	[redacted]	[redacted]
T&D Capital Remaining	769	[redacted]	[redacted]	[redacted]	[redacted]
DERMS (Corporate)		[redacted]	[redacted]	[redacted]	[redacted]

Q. HAVE YOU ATTACHED ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. In addition to our qualifications, which are in Exhibit PA/DS-1 and PA/DS-2, we have attached Exhibits PA/DS-3 through PA/DS-10. These exhibits contain some of the more critical materials (or sub-sections) secured in discovery, as well as a few workpaper summaries and sample materials relevant to this testimony. We did not include all responses to data requests cited in our testimony, as these are collectively, and in many cases individually, too voluminous to include as exhibits. For these data request responses, we trust the administrative record will serve as an accurate and accessible repository.

II. TRANSMISSION AND DISTRIBUTION RATE INCREASES ARE BAD FOR GEORGIA'S BUSINESSES, CONSUMERS, AND ECONOMY UNLESS ACCOMPANIED BY RELIABILITY IMPROVEMENT VALUE SUFFICIENT TO OUTWEIGH THEM

Q. PLEASE PREVIEW THIS SECTION OF TESTIMONY.

A. This section of testimony will begin with a review of Georgia Power's Grid Investment Plan (GIP). It will provide context on transmission and distribution (T&D) rate increases for reliability improvements generally; present Georgia Power's recent reliability performance in the context of its peers; discuss the lack of customer demand for, or willingness to pay for, better reliability; present imminent rate increases heading toward Georgia's economy outside of the Company's or the Commission's control; and note that the results of over a billion dollars in GIP spending to date are not yet known. All of these call the timing of continued GIP spending in the upcoming rate case period into question.

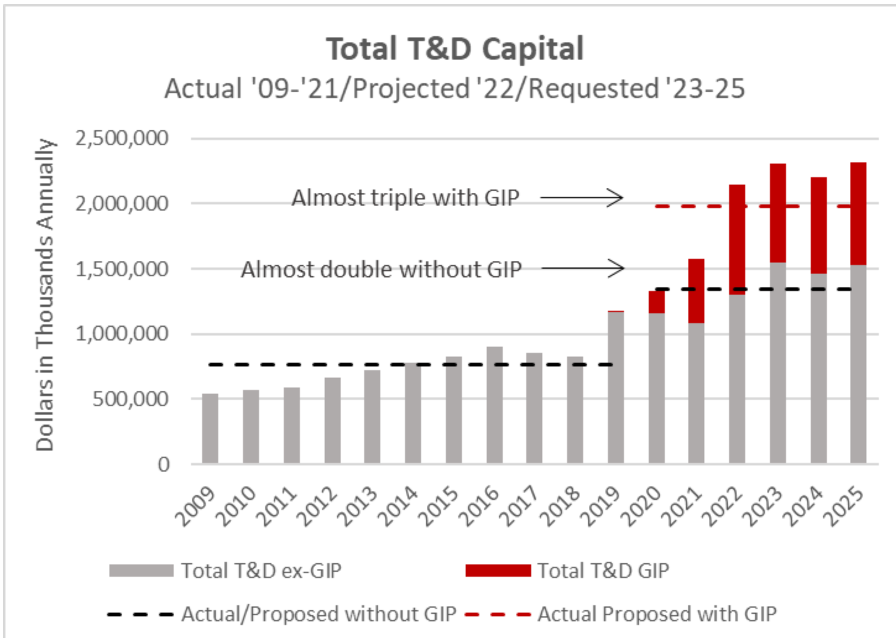
Q. PLEASE SUMMARIZE GEORGIA POWER'S GRID INVESTMENT PLAN.

A. In its 2019 rate case Georgia Power proposed a $7.5 billion Grid Investment Plan (GIP) to be completed over eleven years, from 2020 to 2031. The GIP consisted of $2.6 billion in transmission grid reliability investments (the Transmission Investment Plan, or TIP) and $4.9 billion in distribution grid reliability investments (the Distribution Investment Plan, or DIP).[2] The GIP, combined with requested increases in more typical T&D capital spending, delivers extreme increases in T&D investments relative to historic investment levels. Figure 1 below indicates that the Company's proposed T&D capital spending 2023-2025 is almost three times (296%) the historical levels of investment before the GIP. *Even without the GIP, proposed T&D capital spending increase is almost two times (197%) the*

[2] Georgia PSC Docket No. 42516. DIP Capital from the Attachment provided in response to STF-L&A-5-38, "(Initial) Customer Benefits Study", page (i). TIP capital from "2019 Base Rate Case Overview" Presentation to Staff dated June 27, 2019, p. 7. ($7.5 billion for GIP less $4.9 billion for DIP.)

historical levels of investment before 2020.[3]

Figure 1: Total T&D Capital Spending Actual '09-'21/Projected '22/Requested '23-'25.



Q. WHAT BENEFITS DID GEORGIA POWER PROJECT FROM THE GIP IN 2019 RATE CASE DOCKET 42516?

A. Georgia Power projected no reliability improvements at all from the TIP, and states that the TIP is designed only to maintain current transmission reliability levels.[4] At the time the DIP was initially proposed, Georgia Power projected the DIP would deliver a 50% reduction in system average interruption duration (SAIDI), from approximately 130 minutes on average at the time to 65 minutes on average by 2031. The Commission approved the Company's proposed GIP spending. By the end of this year, the Company anticipates completing $[redacted] in TIP investments and $[redacted] in DIP

[3] Actual spending per attachment provided in response to STF-WG-2-1(a); projected and requested spending per Trade Secret attachment provided in response to STF-PIA-4-4.

[4] Attachment provided in response to STF-WG-1-3 (d).

investments.[5]

Q. IS GEORGIA POWER PROPOSING TO CONTINUE GIP SPENDING IN THIS RATE CASE?

A. Yes, the Company proposes to continue its GIP in the amount of $2.3 billion from 2023 to 2025, including [redacted] in TIP spending and [redacted] in DIP spending.[6] The Company is making some adjustments to the DIP from its initial 2019 proposal. Based on the Company's experience implementing the DIP 2020-2022, it is discontinuing some spending programs. The total DIP capital requirement has thus fallen from $4.9 billion originally to about [redacted] in the current DIP,[7] a reduction of [redacted]. It has also reduced expectations for DIP-related reliability improvements. Originally projected at a system SAIDI of 65 minutes by 2031, the revised system SAIDI target is 80 minutes by 2031,[8] a 23.1% deterioration. This significant revision in target system SAIDI after only three years calls into question the Company's projection of the actual performance improvement customers will receive for very large capital investment made by Georgia Power. The TIP appears to be unmodified from its original proposal.

Q. DO GEORGIA POWER'S RELIABILITY IMPROVEMENT ESTIMATES AND CHANGES CAUSE YOU CONCERN?

A. Yes. We are concerned that the Company attributes no reliability improvements at all to its TIP spending. But our biggest concern relates to the lack of performance accountability, a subject we will return to in Section IV, which is dedicated to the DIP.

[5] Georgia PSC Docket No. 42516. "2019 Base Rate Case Overview" Presentation to Staff dated June 27, 2019, p. 7

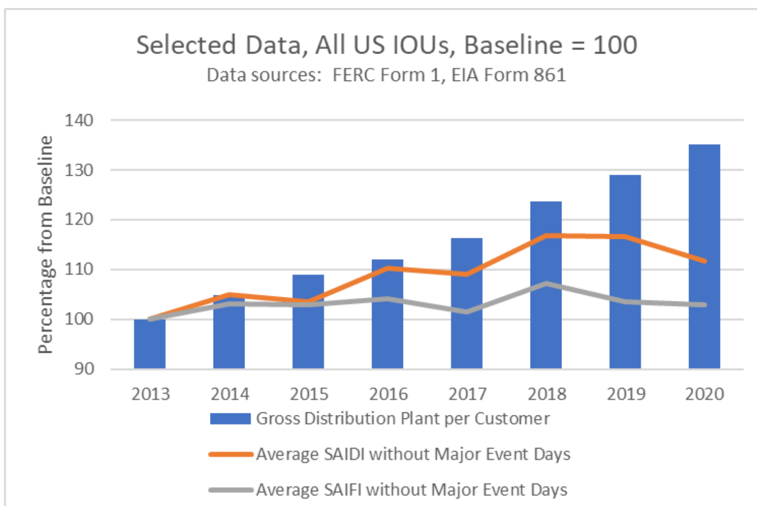
[6] Trade Secret attachment provided in response to STF-PIA-4-4.

[7] $3.4 billion to be spent over the remaining eight GIP years plus $[redacted] to be spent through December 31, 2022.

[8] Trade Secret Attachment A provided in response to STF-WG-2-8 ("Customer Benefits Study, corrected k-factor"), p. i.

We also note the 23.1% deterioration in the SAIDI target from the 2020-2022 DIP to the current DIP. Such a significant change in just three years is consistent with our experience that reliability improvements from increased grid investment are not a given, and that reliability-related investment performance varies dramatically from utility to utility, and among various types of spending packages. As indicated in Figure 2, reliability performance by U.S. Investor-Owned Utilities (IOUs) over the last ten years has not improved, and in fact has deteriorated, despite dramatic increases in grid investment per customer.[9] The lack of correlation between grid investment and grid performance has also been noted by other researchers.[10]

Figure 2: U.S. investor-owned utility reliability performance relative to distribution investment, 2013-2020.



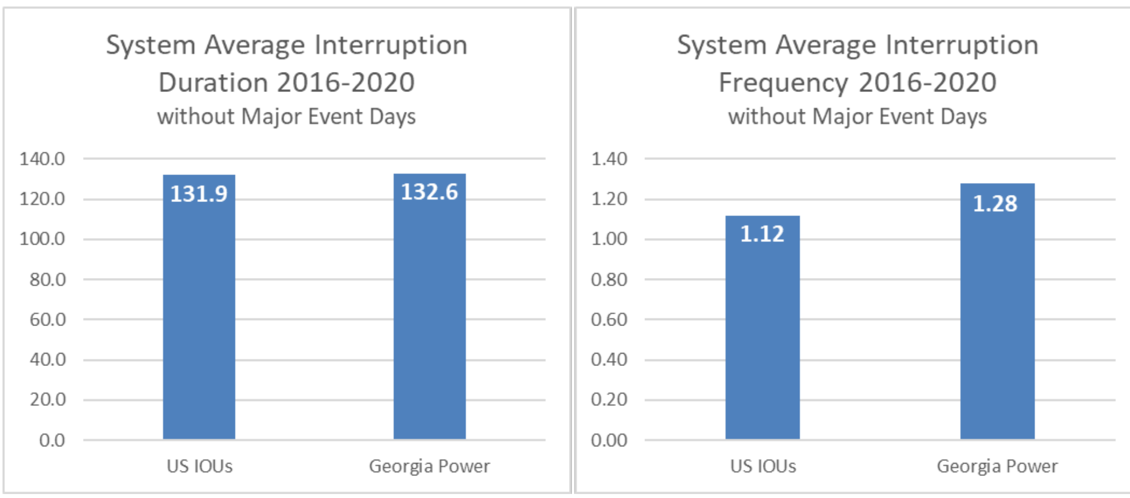
Q. HOW DOES GEORGIA POWER'S RELIABILITY PERFORMANCE COMPARE WITH OTHER INVESTOR-OWNED UTILITIES?

[9] Reliability data without major event days submitted by U.S. investor-owned utilities to the U.S. Energy Information Administration on Form 861; Gross Distribution Plant data submitted by U.S. investor-owned utilities to the FERC on Form 1 for FERC Accounts 360-374. SAIDI is system average interruption duration (in minutes); SAIFI is system average interruption frequency (per customer, per year).

[10] Larsen P et al. *Assessing Changes in the Reliability of the U.S. Electric Power System*. Ernest Orlando Lawrence Berkeley National Laboratory. Pages 37-38. August 2015.

A. As indicated in Figure 3, Georgia Power service interruption duration and frequency are about average for U.S. IOU peers over the last 5 years.[11] There does not appear to be any grid reliability emergency at Georgia Power that must be addressed immediately, or that would justify the massive increase in the transmission and distribution capital investment proposed by the Company.

Figure 3: 5-Year Reliability Performance Averages, Georgia Power vs. US IOUs



Q. WHAT ABOUT CUSTOMER DEMANDS? ARE CUSTOMERS DEMANDING RELIABILITY IMPROVEMENTS FROM GEORGIA POWER?

A. No. With but one exception, customer satisfaction surveys filed by the Company with the Commission in 2019, 2020, and 2021 indicate that both residential and business customers rate their satisfaction with Georgia Power reliability higher than they rate their satisfaction with Georgia Power overall.[12] (The lone exception is the residential customer class in 2021; this cohort reported reliability satisfaction slightly lower than overall satisfaction.)

[11] Reliability data without major event days submitted by U.S. investor-owned utilities, including Georgia Power, to the U.S. Energy Information Administration on Form 861, 2016-2020. System Average Interruption Duration is SAIDI (in minutes). System Average Interruption Frequency is SAIFI (per customer, per year).

[12] Trade Secret Attachment A provided in response to STF-WG-1-42.

Further, the Company's most recent "willingness to pay" research on reliability indicates that customers in all classes are willing to pay less than a 1.7% rate increase on average for significant (50%) improvements in reliability.[13] We estimate that the revenue requirement increase for the $7.5 billion GIP at the time Georgia Power first presented it in 2019 will be 10%,[14] or almost six times greater than what customers reported they were willing to spend, and for a reliability improvement which is projected to be much less than the 50% customers indicated they would be willing to pay a 1.7% rate increase to secure.

Q. YOU MENTIONED THAT RATE INCREASES FOR REASONS OTHER THAN THE GIP ARE IMMINENT. WHAT ARE THE SOURCES OF THESE RATE INCREASES AND HOW LARGE WILL THEY BE?

A. Multiple sources of large electric rate increases will be hitting Georgia businesses and consumers simultaneously in the next few years. We believe the Commission should consider the impact of these rate increases on Georgia's economy as it reviews Georgia Power's request to continue GIP spending. At least two sources of significant rate increases are imminent beyond the Company's request in this rate case, including 1) The full impact of Plant Vogtle has yet to hit rates; and 2) higher fuel rates to recover higher fuel cost and unpaid fuel balance. Staff estimates the combined impact of these factors with the rate increase Georgia Power requests in this rate case to be in excess of 40%.[15]

Q. WHAT IS THE RELEVANCE OF THESE RATE INCREASE PRESSURES?

A. These rate increase pressures are relevant because some of them, particularly fuel, are outside of the Commission's control. When likely rate increases outside the Commission's

[13] Trade Secret Attachment S provided in response to STF-WG-1-2, page 44. (Please note that the Company agreed to remove the Trade Secret designation for Attachment S via e-mail dated September 26, 2022 in response to Staff's request.)

[14] See Exhibit PA/DS-5 for a summary of calculations.

[15] See Opening Testimony of Staff Witnesses Mr. Ralph Smith and Mr. Robert Trokey dated October 20, 2022.

control are clearly apparent, it becomes more critical to scrutinize closely capital investment and expenses that are discretionary. GIP spending is clearly a source of rate increase under the Commission's control. Given that there is no reliability emergency, and that customer demand for, and willingness to pay for, reliability improvements is almost zero, we consider GIP capital spending to be discretionary. Further, the results of GIP spending to date are not yet known, and our analysis of the two largest DIP programs, circuit hardening and undergrounding, indicate that rate increases exceed benefits by a wide margin. We note that other researchers examining circuit hardening and undergrounding come to the same conclusions, and we will provide details in Section IV.

Rate increases negatively impact Georgia's businesses and economy. Research indicates that employment falls as energy costs rise.[16] We consider rate increases to be a precious resource; a tool to be drawn upon only when necessary. Accommodating all types of Georgia Power spending requests simultaneously leaves less gas in the Georgia economy's tank for unexpected emergencies outside of Commission or Georgia Power control (like rising costs for capital or natural gas).

Q. YOU MENTIONED THAT THE RESULTS OF GIP SPENDING TO DATE ARE NOT YET KNOWN. PLEASE EXPLAIN.

A. All we have so far are the Company's projected reliability improvements from DIP spending "packages". As noted above, Georgia Power provides no projected reliability improvements from TIP spending; there is little evidence that increasing grid investment delivers improved grid performance nationally; and we have significant concerns regarding DIP performance improvement accountability. Further, circuit-specific reliability is inherently variable year-to-year, with weather being the largest of many sources of

[16] Metcalf GE. *The Relationship Between Electricity Prices and Jobs in Missouri*. Tufts University. February 27, 2013. Exhibit 1.

variation. Finally, despite the massive amount of money spent to date, the numbers of circuits rebuilt (hardened) to date, and the number of customers undergrounded to date, are extremely small. Further, and significantly, vegetation management the Company completed on circuits that were hardened or partially undergrounded makes it impossible to isolate the level of improvement secured by new investment from the level of improvement secured by vegetation management, a dramatically lower-cost option. (We will return to these subjects in Section IV.) In short, it is impossible to reach any conclusions regarding the reliability improvements if any from Georgia Power's DIP spending so far.

We recommend a minimum of three years' post-deployment experience be used to determine actual reliability improvement delivered relative to cost for each of the Company's reliability improvement initiatives, including premature transmission equipment replacement (more on that in the transmission section of this testimony) and each of the distribution investment plan "packages". Further, controls for various performance impacts are needed. For example, vegetation management is typically conducted on circuits as they are rebuilt (circuit hardening in the Company's parlance); we ask, to what degree was any performance improvement the result of vegetation management and not circuit hardening? All of this increases the need to complete formal and rigorous (independent) study of the results of Georgia Power's GIP spending so far before more such spending is authorized. Given the lack of a reliability emergency, and the impending perfect storm of rate increases, the prudent thing to do now is to measure results to date before doubling down on the GIP.

Q. YOU SEEM TO BE QUESTIONING GEORGIA POWER'S INTEREST IN IMPROVING RELIABILITY. WHY WOULDN'T GEORGIA POWER WANT TO IMPROVE SERVICE RELIABILITY?

A. We are not questioning Georgia Power's interest in improving reliability. Certainly, Georgia Power wants to provide reliable service to its customers. What we do question are the Company's methods. As the Commission is well-aware, the Company has a fiduciary responsibility to uphold and advance shareholder interests. Shareholder interests are advanced when share prices grow. Share prices grow when earnings grow, and earnings grow when the rate base grows (all else being equal). Thus, as illustrated by the Company's GIP, capital bias looms large in IOU reliability improvement initiatives. Any utility can spend billions on its grid and improve reliability. The goal should be to improve reliability to as great an extent possible for the least possible cost to customers. As the rest of this testimony will indicate, Georgia Power's GIP is not only intended to improve reliability; it is intended to improve reliability while massively and unnecessarily growing the rate base.

Further, we are concerned that advance approval of the GIP virtually eliminates the risk of penalties (cost disallowances) associated with excess grid investment. Before multi-year rate plans, Georgia Power would make the grid investments it considered necessary for safe and reliable service, and bore the responsibility for proving that its spending was prudent after the fact. The cost-disallowance risk presented a potential price shareholders might pay if the Company over-invested. However, if a grid investment plan is approved with unnecessary investments, the potential penalty for overspending is significantly lessened, as the regulator is unlikely to reverse a previous decision. This creates a moral hazard situation in which there is little to discourage a utility from proposing extreme or even cost-ineffective investments.[17] (In 1996 this Commission was only the second state utility regulator in the U.S., after the California Public Utilities Commission, to authorize the use of multi-year rate plans in ratemaking.)[18] It is certainly plausible that Georgia Power considered capital bias and moral hazard as it developed its GIP.

[17] Alvarez P. et al. *Alternative Ratemaking in the US: A Prerequisite for Grid Modernization or an Unwarranted Shift of Risk to Customers?* Electricity Journal Vol. 35, Issue 8 (October 2022).

[18] Georgia PSC Docket No. 6292-U. Order dated February 16, 1996.

III. THE TRANSMISSION INVESTMENT PLAN (TIP) WILL NOT DELIVER RELIABILITY IMPROVEMENTS SUFFICIENT TO OUTWEIGH ASSOCIATED RATE INCREASES

Q. PLEASE PREVIEW THIS SECTION OF TESTIMONY.

A. This section of testimony examines Georgia Power's $2.6 billion Transmission Investment Plan (TIP) over the period 2020 -2031. The Company describes its TIP as the replacement of aging transmission infrastructure,[19] which laypersons are likely to perceive as reasonable and necessary. However experts like Mr. Stephens, who have held the responsibility for maximizing reliability performance for the least amount of capital spending at a utility, would not describe the replacement of transmission assets based primarily on age as a cost-effective way to improve reliability, nor would such experts describe replacements based primarily on age as reasonable or necessary. We will describe why the practice of replacing transmission assets based primarily on age, which we call premature equipment replacement, is vastly more costly for customers than the value of the tiny reliability improvements it will deliver to customers, and why premature equipment replacement is both unreasonable and unnecessary.

Q. WHAT IS PREMATURE EQUIPMENT REPLACEMENT?

A. Georgia Power defines aging transmission assets as those that have exceeded their "expected life".[20] The Company's TIP selects transmission line and T&D substation equipment for replacement based on asset age[21] relative to expected life. It is inappropriate to use expected life and asset age as the basis for transmission line and T&D substation equipment replacement.[22] The actual operating condition of T&D equipment as measured

[19] APA-SPA-ADH-MBR Direct, p. 50 at 3.

[20] Georgia PSC Docket No. 42516. Direct Testimony of David P. Poroch, Sarah P. Adams, and Michael B. Robinson On Behalf of Georgia Power Company ("DPP-SPA-MBR 2019 Rate Case Direct"). Page 59 at 28.

[21] Ibid, p. 60 at 13.

[22] Alvarez P, Ericson S, and Stephens P. *"Asset Replacement Based on Risk Modeling – Emergency Best Practice?*

by periodic, objective testing and inspection programs should be the primary drivers of replacement, not age.

Q. WHY IS IT INAPPROPRIATE TO USE THE AGE OF A PIECE OF EQUIPMENT, RELATIVE TO THE EXPECTED LIFE FOR EQUIPMENT OF THAT TYPE, AS THE BASIS FOR REPLACING THAT PIECE OF EQUIPMENT?

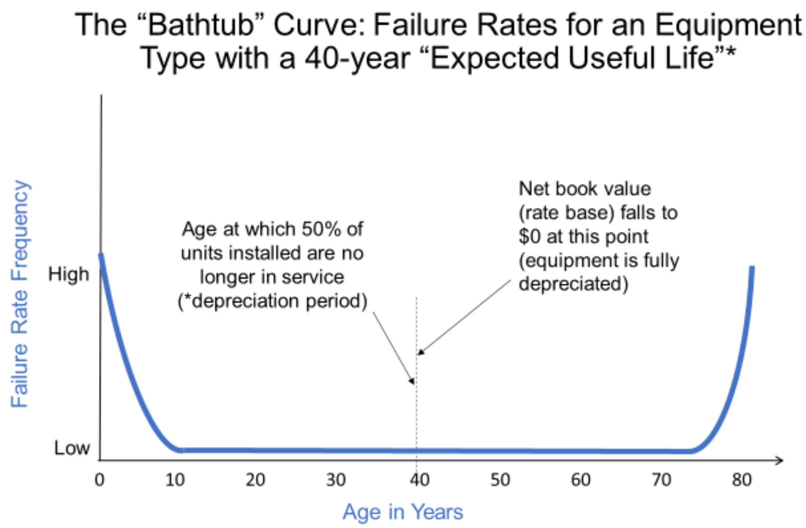
A. As the reader might imagine, there is significant variation between any individual piece of equipment's actual age at failure and the expected life for that type on average. If the expected life for a particular equipment type is 40 years on average, it means a few units of that type are likely to fail immediately, a few units of that type will likely still be operating safely and reliably after 80 years, and all the other units of that type will fail at some age between zero years and 80 years. For illustrative purposes, a representative chart depicting failure rates for a hypothetical equipment type with an expected life of 40 years is presented in Figure 4 below.[23] Most units of a particular equipment type will either fail very early in their lives ("infant mortality", due to manufacturing defects, design errors, or unobserved damage caused during installation, as examples) or very late in their lives. This failure rate characteristic gives a failure rate chart a "bathtub curve" shape (because it resembles the cross-section of a bathtub). Hearing attendees may recall Georgia Power Witness Mr. Robinson mentioning the bathtub curve.[24]

(Challenging Utility Grid Hardening Proposals). Part 1. Public Utilities Fortnightly. August 2020. P. 58.

[23] This is an illustrative chart. It is not based on any actual Iowa Curve used for any particular equipment type.

[24] Hearing Transcript September 27, 2022. Page 333 at 23; page 347 at 1.

Figure 4: Illustrative "Bathtub" Curve for a hypothetical equipment type with an average expected or estimated life of 40 years.



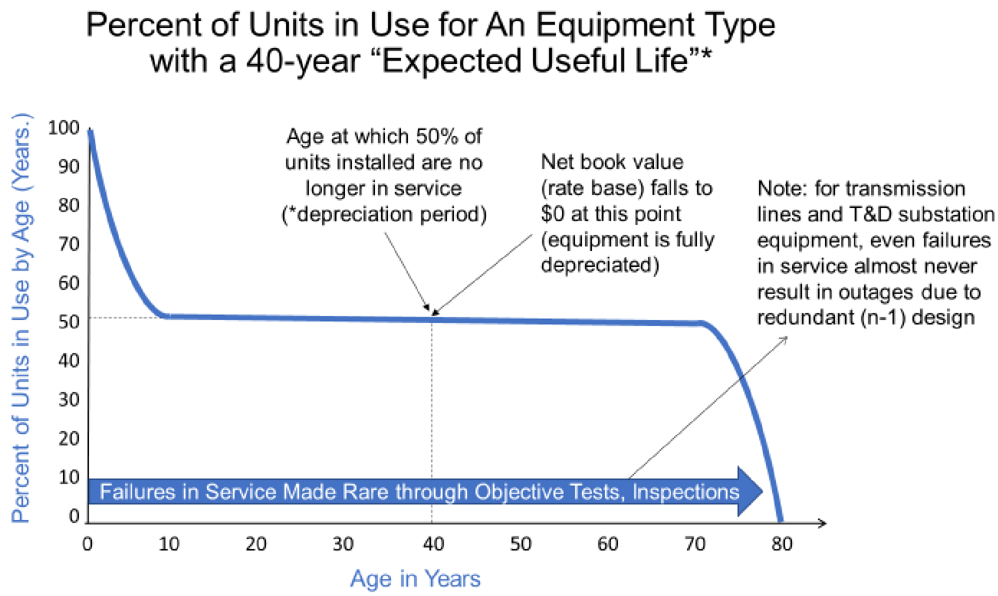
The illustrative bathtub failure rate curve can be plotted by percent of units of a particular equipment type in service by age, as depicted in Figure 5 below. As Figure 5 indicates, replacing a piece of equipment simply because it has reached its expected useful life is inappropriate because it deprives customers of decades of useful life from transmission equipment that has passed its tests or inspections, that has therefore been deemed capable of providing safe and reliable service, and for which customers have already paid in rates.[25] Premature equipment replacement thus increases rate base by "churning" assets unnecessarily, a practice which violates established regulatory precedent.[26] Investor-owned utilities are motivated to replace assets once they are fully depreciated, as fully

[25] Alvarez P, Ericson S, and Stephens P. *"Asset Replacement Based on Risk Modeling – Emergency Best Practice? (Challenging Utility Grid Hardening Proposals). Part 1*. Public Utilities Fortnightly. August 2020. P. 58.

[26] According to Averch and Johnson, "The firm has an incentive to acquire additional capital if the allowable rate of return exceeds the cost of capital." Like all other state utility regulators, the Commission provides Georgia Power with an allowable rate of return that exceeds the Company's cost of capital as an incentive to invest in its grid. All the Company needs is a reason to raise capital, and replacing assets before it is economically rational to do so represents one of those reasons. Averch and Johnson continues, "The firm has an incentive to (operate) in an uneconomic fashion that is difficult for the regulatory agency to detect." Averch H and Johnson L. *The Behavior of the Firm Under Regulatory Constraint.* The American Economic Review, December 1962, Vol. 52, No. 5, pp. 1052-1069

depreciated assets have no book value and earn no rate of return.

Figure 5: Application of illustrative Bathtub failure rate curve to percent of units in use by age.



Q. DOES PREMATURE REPLACEMENT IMPROVE RELIABILITY?

A. By the tiniest of amounts, yes, but almost imperceptibly. The degree of improvement is certainly not enough to justify the massive cost increases premature equipment replacements incur, for two reasons. First, all utilities, including Georgia Power, perform objective tests and inspections of transmission lines and critical T&D substation equipment on a routine, periodic basis. Any equipment which does not pass its tests or inspections is scheduled for repair or replacement, typically within a few months or a year. These objective tests are much more accurate predictors of equipment failure than age, which is precisely why utilities, including Georgia Power, have been using them for decades. Second, transmission systems are designed and operated based on the "N-1" criterion, explained in detail below. As a result of the N-1 criterion, in the already rare instance of a transmission line or T&D substation equipment failure, it is extremely unlikely such a failure will cause a service interruption for customers. Objective testing and inspection practices combined with the inherent redundancy in the transmission grid results in excellent transmission system reliability *without* premature equipment replacement. The opportunity to improve transmission line and T&D substation reliability through premature equipment replacement is therefore almost zero to begin with, as will be demonstrated with the Company's own data later in this Section.

Q. PLEASE DESCRIBE THESE OBJECTIVE TESTS AND INSPECTIONS.

A. Unlike distribution circuit equipment, for which any one asset may only serve a handful of customers, transmission lines and T&D substations can serve thousands of customers. The increased consequences of failure for transmission line and T&D substation equipment have motivated utilities to establish comprehensive testing and inspection programs for various pieces of equipment and lines. For example, utilities test T&D substation power transformers every three years or so through "dissolved gas analysis", or DGA. Increases in certain types of gasses in transformer oil indicate deterioration that should be monitored closely and addressed. Utilities thus use DGA test results to indicate when a substation power transformer needs to be replaced. Construction planning to replace a power transformer that fails its DGA tests typically begins immediately and is scheduled and completed on a reasonably prompt basis. With an objective test like DGA available, there is no need to replace assets prematurely based on age relative to an estimated or expected useful life.

Similarly, T&D substation circuit breakers, switches, relays, and load tap changers are the subject of routine, periodic (typically every three to five years) functional testing programs at all utilities. In these programs, devices are taken out of service (power is temporarily rerouted to nearby equipment during testing) and forced to operate under simulated severe disturbance scenarios. Equipment that does not respond in an expected manner within parameters specified by the manufacturer are scheduled for prompt repair or replacement. Transmission lines, equipment, and towers are the subject of formal inspections conducted periodically, complete with checklists and objective scoring mechanisms. Conductor, equipment, or towers that fail inspections are immediately scheduled for repairs or replacements in a controlled manner. Further, there is nothing prohibiting Georgia Power from increasing the frequency of testing and inspections for older equipment if it chooses.

To summarize, transmission line and substation equipment testing and inspection programs make the likelihood of equipment failures in service extremely rare. Moreover, the practice of prematurely replacing equipment based on age means that Georgia Power is replacing equipment that has passed its most recent tests and inspections, and was therefore operating safely and reliably at the time it was replaced. On this measure alone, premature equipment replacement is unreasonable and unnecessary, and a strong case could be made that the practice is imprudent. Furthermore, utilities maintain spare stocks of critical substation equipment, as well as power line structures and conductors, which helps to reduce repair/replacement time.

Q. PLEASE EXPLAIN N-1 CRITERION AND ASSOCIATED REDUNDANCY

A. Electric utilities are required to plan and operate their power systems using the N-1 criterion to comply with the NERC reliability standards. This means that the power system will operate safely and reliably following an outage of a single critical facility without causing thermal overloads or voltage problems on the facilities that remain in service. This also means that there is inherent redundancy in the system available to accommodate failures of critical network elements and equipment with no service interruptions for customers. Furthermore, the power system can operate reliably even with two network elements out due to options available to system operators such as temporary generation redispatch or network reconfiguration. Known as N-1-1 criteria, these additional options means that the power system can operate reliably in the event a critical network element fails and is followed by a second critical element failure. Once repairs/replacements are completed, the system is restored to a normal state of operation. Such built-in redundancy further reduces the likelihood that an equipment failure – already made rare through equipment testing and inspection practices – results in a service interruption for customers or causes any reliability problems.

Based on transmission outage and equipment failure data provided by the Company in discovery from 2012 to 2021 (10 years), we have calculated the likelihood that various types of T&D substation equipment will both fail in service *and* result in a service interruption for customers. Further, we have applied the cost of premature equipment replacements to these likelihoods, arriving at the system-wide investment required to avoid one service interruption per year over the expected life of the new equipment by equipment type. Table 2 presents these results of these calculations, and is an accurate representation of the size (tiny) of the reliability improvement opportunity available from premature equipment replacement, as well as its extremely high cost. (See Exhibit PA/DS-6 for more calculation details.) As Table 2 indicates, the opportunity to improve reliability through premature equipment replacement is incredibly small to begin with, and certainly not worth the $2.6 billion cost of the Transmission Investment Plan. (Staff Witness Mr. Rana completes a similar analysis for premature Transmission Line replacements.)

Table 2: Annual likelihoods of a failure in service resulting in a service interruption for various T&D substation equipment types Georgia Power is replacing prematurely as part of its GIP, and associated capital costs required to avoid one such service interruption per year.[27]

A	B	C	D	E
Substation Equipment Type	Annual Likelihood of a Failure Resulting in a Service Interruption[28]	Average Number of Customers per Interruption[29]	Equipment Replacements Required to Avoid One Service Interruption per Year	Capital Required to Replace the Counts of Equipment Identified in D (per Georgia Power Cost Data)[30]
Power Transformers	0.0045 (45 in 10,000)	690	224	$[redacted]
Circuit Breakers	0.0047 (47 in 10,000)	219	212	$[redacted]
Load Tap Changers	0.0002 (2 in 10,000)	9,503	4,510	$[redacted]

Q. BUT WHAT ABOUT INCREMENTAL REPLACEMENT COSTS? GEORGIA POWER CLAIMS THAT EMERGENCY REPLACEMENT COSTS ARE TWO TO THIRTEEN TIMES HIGHER THAN PLANNED REPLACEMENT COSTS.[31]

A. It is true that the costs to replace equipment in an emergency are higher than planned equipment replacements. But in our experience, replacements of equipment identified through equipment testing and inspection practices are planned, and do not constitute

[27] The values in column E represent capital investment. The present value of the revenue requirement (collections from customers) would be [redacted] higher per the Company's "k-factor".

[28] Service interruption data per Trade Secret attachment provided in response to STF-WG-2-26; System-wide equipment counts by type from response to STF-WG-1-33.

[29] Average Customer Counts per service interruption data per Trade Secret attachment provided in response to STF-WG-2-26.

[30] Georgia Power cost data by equipment type per Trade Secret response to STF-WG-1-34.

[31] Response to STF-WG-2-25 (b).

emergencies. These planned replacements are typically completed within reasonable timeframes of six to eighteen months, and do not incur incremental costs. Only replacements of equipment that fails in service *and* causes a service interruption constitute replacements so emergent as to incur such large incremental cost multiples. As Table 2 Column B indicates, such failures are incredibly rare. Thus while some amount of incremental emergency replacement cost can be avoided through premature replacement, the infrequency of emergency replacements makes these incremental replacement costs very low relative to the extreme incremental cost of premature replacement.

As an example, the rate of failure resulting in a service outage for substation circuit breakers is about five in one thousand per year, and Georgia Power reports having 1,868 circuit breakers. Thus, in an average year, about nine circuit breakers will need to be replaced on an emergency basis across the Company's entire system.[32] The incremental emergency replacement cost associated with replacing nine circuit breakers annually, even when combined with the reliability benefits of avoiding nine outages annually for 219 customers each outage, simply does not justify the $[redacted] capital cost of prematurely replacing 1,868 circuit breakers before a test indicates such replacements are necessary.[33]

Further, like most large utilities, Georgia Power maintains an inventory of T&D substation equipment of various types and sizes, and this significantly reduces the cost of emergency replacement in many instances.[34] The Edison Electric Institute, of which Georgia Power is a member, also maintains and/or participates in multiple T&D substation and transmission equipment access programs to reduce transmission and substation equipment procurement times and costs, including the Spare Transformer Equipment Program, SpareConnect, Grid

[32] 1868 circuit breakers multiplied by 0.005.

[33] 1,868 circuit breakers multiplied by an average replacement cost of [redacted].

[34] Response to STF-WG-4-2 (d).

Assurance, and RESTORE.[35]

Q. HOW DO YOU KNOW THAT PREMATURE REPLACEMENT OF TRANSMISSION LINE AND T&D SUBSTATION EQUIPMENT DOES NOT DELIVER BENEFITS TO CUSTOMERS IN EXCESS OF COSTS TO CUSTOMERS?

A. Georgia Power bears the burden to prove that premature equipment replacement is cost-effective for customers. Georgia Power has not prepared any cost-benefit analyses of its TIP,[36] or its premature equipment replacement program,[37] or its distribution investment plan packages (a subject to which we will return in Section IV). Indeed, Georgia Power Witness Mr. Robinson claimed that it is not possible to complete such cost-benefit analyses.[38] We do not agree, and Table 2 indicates the extreme costs of premature replacement relative to benefits, as informed by historical outage data. Further, neither we nor Georgia Power are aware of any industry studies or research indicating that premature equipment replacement is cost-effective.[39] Furthermore, there is no industry standard that transmission equipment should be replaced when it reaches its expected useful life, nor any industry standards for the expected useful lives (in years) of various types of transmission equipment.[40,41]

Q. HOW DO YOUR RESPOND TO MR. ROBINSON'S TESTIMONY THAT GEORGIA POWER WOULD NOT WAIT FOR EQUIPMENT FAILURE?

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35 *Spare Equipment and Grid Resilience Programs*. Edison Electric Institute document. June, 2021.

36 Georgia PSC Docket No. 42516. Response to STF-PIA-3-7.

37 Response to STF-WG-2-25 (b).

38 Hearing Transcript September 27, 2022. Page 348 at 1.

39 Ibid, subpart (c).

40 Response to STF-WG-4-5.

41 Response to STF-WG-4-6.

A. Mr. Robinson stated that “We don't want to be the utility to wait to failure. We have seen what happens across the United States when companies wait to failure, whether it is transmission lines or substation assets.”[42] “Waiting for failure,” is not an accurate description of Georgia Power’s historical approach to transmission reliability. Georgia Power has never simply waited for assets to fail. Through its equipment testing and inspections programs, Georgia Power has historically followed, and continues to follow, utility best practices for identifying equipment in need of repair or replacement in advance of failure. Through redundant design, Georgia Power has historically followed, and continues to follow, utility best practices for eliminating the consequences (service interruptions) associated with rare instances of transmission equipment failures in service. In our estimation, Georgia Power should continue to rely on the best practices it has followed in the past to continue to provide customers with exceptional transmission system reliability in the future.

Finally, we are not sure to which utilities Mr. Robinson was referring when he discussed what Georgia Power has seen “across the United States,” but we have a few observations to share. If Mr. Robinson was referring to the wildfires caused by Pacific Gas and Electric equipment failures, subsequent investigations blame those wildfires on a lack of inspections and maintenance (most commonly, vegetation management), not a lack of equipment replacement.[43] If he is referring to the lengthy service interruptions in Louisiana following Hurricane IDA, damage to transmission lines serving New Orleans was caused by a hurricane, not by a lack of Entergy equipment replacement or transmission investment.

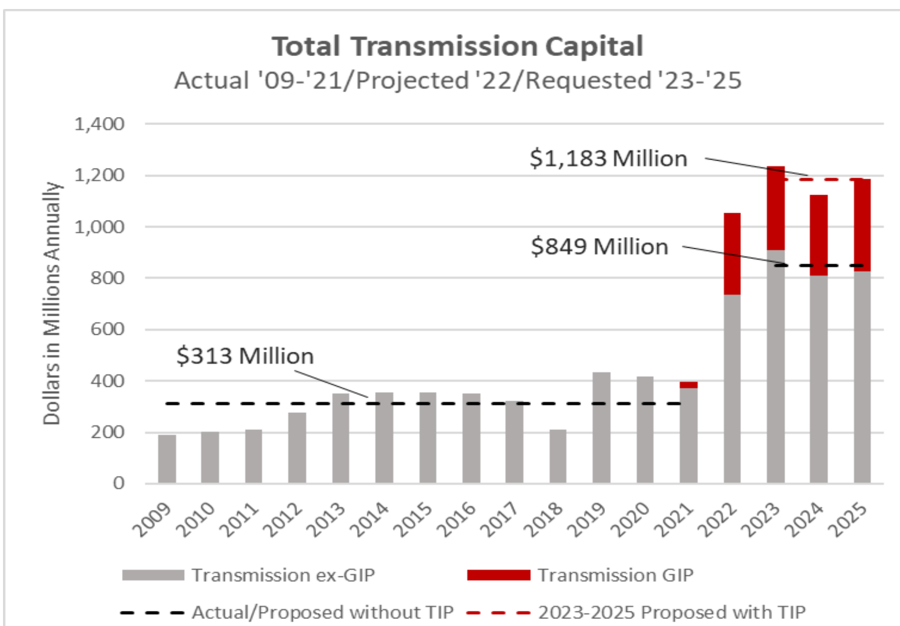
Georgia Power’s attempt to support its request through a vague reference to the experiences

[42] Hearing Transcript September 27. 2022. Page 346 at 9.

[43] 1) *The Camp Fire Public Report*. A summary of the Camp Fire investigation by the Butte County (California) District Attorney. June 16, 2020. Pages 82-87. 2) *October 2017 Fire Siege*. Report by the Safety and Enforcement Division of the California Public Utilities Commission. June 13, 2019. Pages 2-3.

of other utilities is misplaced given how Georgia Power's proposed increases compare to the transmission investments of other utilities. *Even if the Commission rejects the Company's entire $1 billion proposal to continue TIP spending 2023-2025, the remaining transmission investments proposed still represent a* [redacted] *increase (almost* [redacted]*, from $313 million per year to* [redacted] *million per year) over average annual transmission investment from 2009 to 2021 (before the TIP commenced in earnest).* Thus, the Commission should rest assured that such a rejection would not deprive the Company of an ample increase in capital spending to improve transmission reliability, assuming the Company operates in an efficient and economic manner. Figure 6 illustrates the situation clearly.[44] Given that energy sales (MWhs), peak demand (MW), and number of customers are expected to grow less than 2%, a 171% increase in capital spending should be more than enough to maintain and improve reliability under efficient and economic management.

Figure 6: Total Transmission Capital Spending, Actual 2009-2021/Projected 2022/Requested 2023-2025



[44] Actual spending per attachment provided in response to STF-WG-2-1(a); projected and requested spending per Trade Secret attachment provided in response to STF-PIA-4-4.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING GEORGIA POWER'S REQUEST TO CONTINUE TIP IMPLEMENTATION?

A. We recommend the Commission reject Georgia Power's [redacted] billion request to continue TIP implementation in its entirety, as summarized in the table below. The [redacted] increase over historical spending levels that remains after such a rejection (almost triple) will be more than sufficient to allow Georgia Power to make the investments required to maintain and improve transmission reliability. The amounts rejected are reflected in the revenue requirement adjustments found in the Smith-Trokey testimony and exhibits, and the rejection of TIP capital related to transmission lines (as distinguished from the T&D substation investments we discuss here) are addressed in the testimony of Staff Witness Mr. Rana.

Table 3: Summary of transmission capital request and recommended rejections.

($ in millions)	'09-'21 Average Actual	2023	2024	2025	'23-'25 Average
Transmission Capital Requested		[redacted]	[redacted]	[redacted]	[redacted]
Transmission Investment Plan		(327.8)	(314.1)	(358.7)	(333.5)
Transmission Capital Remaining	313.0	[redacted]	[redacted]	[redacted]	[redacted]

IV. GEORGIA POWER'S DISTRIBUTION INVESTMENT PLAN (DIP) WILL NOT DELIVER RELIABILITY IMPROVEMENTS SUFFICIENT TO OUTWEIGH RATE INCREASES

Q. PLEASE SUMMARIZE THIS SECTION OF TESTIMONY.

A. This section of testimony is organized as follows, as further introduced immediately below.

1. Summary of Georgia Power's Distribution Investment Plan
2. Circuit hardening is not a cost-effective way to improve reliability
3. Undergrounding is not a cost-effective way to improve reliability
4. The DIP applies costly DIP investment packages to too many circuits which do not need them
5. The DIP ignores dramatically more cost-effective approaches to improving reliability
6. The DIP is prompting premature retirement of reliable assets for which customers are paying
7. Why the Commission should afford little to no weight to the Company's Customer Benefits Study
8. The DIP offers no performance accountability
9. Summary of the Maryland Commission's efforts to improve reliability in a cost-effective manner
10. DIP Recommendations for Commission Consideration.

This section of testimony begins with a summary of Georgia Power's Distribution Investment Plan (DIP). We then critique the DIP, focusing on four problems: 1) The largest DIP investment packages by far, circuit hardening and undergrounding of overhead lines, are not remotely cost-effective approaches to improving reliability; 2) The Company applies costly DIP investment packages to too many circuits which already demonstrate reasonably good reliability performance, further damaging the cost-effectiveness of the DIP; 3) The DIP ignores dramatically more cost-effective approaches to improving reliability, including vegetation management and worst-performing circuit programs; and 4) The DIP appears to be causing premature retirement of reliable equipment customers continue to pay for in rates, as evidenced by $[redacted] in projected write-offs of equipment with book value remaining 2023-2025. (This is not only wasteful, but violates established legal and regulatory precedents).[45]

This Section also explains why the Commission should assign little or no weight to the Company's Customer Benefit Study. (The Customer Benefit Study is not a cost-effectiveness test or cost-benefit analysis, but rather an optimization of capital-intensive options and constraints designed specifically to justify large capital investments.) We will also describe our concerns regarding Georgia Power's accountability for securing DIP-related reliability improvements, and summarize the Maryland Public Service Commission's efforts to secure reliability improvements from utilities in a cost-effective manner, along with associated results. We will conclude with recommendations for Commission consideration, including a recommendation that the Commission reject Georgia Power's requests for the circuit hardening and undergrounding capital components of the DIP in their entirety. We note that if the Commission follows this recommendation, the remaining distribution capital budgets still represent an increase of 131% of historical distribution capital spending 2009-2019 (more than double). This increase should be more than enough to help Georgia Power improve the reliability of its distribution grid in a cost effective manner for customers.

[45] Averch and Johnson describe how cost-of-service regulation encourages regulated, for-profit utilities to raise and spend more capital than necessary for safe and reliable service (see footnote 27). Large-scale retirement of equipment with book value remaining is one indication that a utility is over-investing in its grid, resulting in premature removal of equipment operating safely and reliably.

1. Summary of Georgia Power's Distribution Investment Plan (DIP)

Q. PLEASE SUMMARIZE THE COMPANY'S DIP

A. Georgia Power's DIP consists of six investment "packages" the Company has defined to be applied to circuits to improve their performance. (Note that the packages do not include low-cost options, or options involving operations and maintenance spending, a subject we revisit later in this Section.) The Company uses an Optimization Model to determine which of the packages to apply to circuits in the third and fourth reliability performance quartiles (meaning, the circuits performing below the median circuit's performance), and in what priority. (Note that "median" is a much different measure than "average", and that the calculation and use of the median value determines the universe of circuits to which packages can be applied;[46] we will return to both observations later in this Section.) Of circuits performing below the median, additional criteria are applied to develop package lists per circuit. The packages are then implemented by a dedicated GIP project implementation department[47] over time (meaning, the twelve years and four rate cases from 2020 through 2031).

The Company defined each investment "package" to include a discrete set of actions and investments, along with implementation costs, resulting in both rate increases and reliability improvements for customers. These are the same definitions used in the Optimization Model. In that Model, "Rate Increases" reflect changes in O&M expenses and revenue requirements from capital investment, while reliability improvements are valued as customers might value them (meaning, as a reduction in the costs customers incur from service interruptions). The Optimization Model varies all of these as investment levels change; discrete investment levels, described as "scenarios", are associated with projected reliability improvements (system average interruption duration in minutes) by

[46] Customer Benefit Study, corrected k-factor, page (i).

[47] Discovery conference October 13, 2022.

the end of the DIP period (2032) for each investment level. The cost of service outages to customers falls as the count of package applications increases (up to a point, called the point of diminishing returns, at which the incremental implementation costs become higher than the fall in customer service outage costs). The Company's DIP capital requests thus represent the cost to implement the count of packages the Optimization Model determines to be optimum *given the packages and their attributes as the Company has defined them*. (We note this is not the same as the lowest-cost way to improve reliability, a subject to which we return later in this Section.)

Using its Optimization Model, the Company employed its 2017 reliability performance to place circuits into quartiles, thereby qualifying certain circuits (those below the performance of the median circuit in 2017) to receive DIP packages. These placements of circuits into quartiles, thus qualifying them to receive DIP packages, using 2017 data, remain static through to today.[48]

Brief descriptions of the six packages the Company has defined and proposed for 2023-2025 spending are presented in Table 4 below.[49] As indicated earlier, Georgia Power spent $[redacted] implementing DIP packages 2020-2022, and proposes $1.3 billion 2023-2025. As the chart indicates, packages "circuit hardening" and "undergrounding" are by far the largest categories of spending in the DIP, representing [redacted] of total DIP spending from 2020-2025 ([redacted] and [redacted] respectively).

[48] Trade Secret response to STF-WG-1-42 (c); Trade Secret Optimization Model screenshots provided informally in follow-up to the Optimization Model discovery conference held October 3, 2022.

[49] Trade Secret attachment provided in response to STF-WG-1-18.

Table 4: Summary of DIP packages, spending, applications, and cost per circuit.

Package	Description	Capital Request 2023-2025	Actual & Projected 2020-2022	Circuits Applied 2020-2022	Cost per Circuit 2020-2022
1. Add sections & distribution automation	Dividing circuits up into smaller sections increases fault isolation granularity so that fewer customers experience an outage.	[redacted]	[redacted]	[redacted]	$1.3 million
2. Add & Strengthen Ties	Adding ties increase flexibility for routing power to all but isolated customers. "Strengthening" means increasing tie capacity to ensure re-routing is possible during peak.	[redacted]	[redacted]	[redacted]	$7.8 million
3. Circuit Hardening	Replacing poles and/or crossarms; replacing fuses with TripSavers®; and add wildlife protection devices to reduce outage frequency.	[redacted]	[redacted]	[redacted]	$8.7 million
4. Break Feeder	Split an existing circuit into two smaller circuits (similar to #1)	[redacted]	[redacted]	[redacted]	$11.6 million
5. Bring Feeder to Road	To improve access (faster repair), relocate feeder from back lots with difficult access to front lots/streets.	[redacted]	[redacted]	[redacted]	$29.5 million
6. Underground Overhead Lines	Move lines, equipment, and services currently overhead to underground to reduce outage frequency.	[redacted]	[redacted]	[redacted]	$49.1 million
	Totals	[redacted]	[redacted]	[redacted]	$16.2 million

Q. WHAT RESULTS DOES THE COMPANY EXPECT FROM ITS DIP?

A. In its initial DIP in the 2019 rate case, the Company projected that a system-wide improvement in average interruption duration (SAIDI), currently 132.6 minutes on average over the last five years as reported in Figure 3 earlier, to 65 minutes by 2031.[50] (We note that the Company's five-year average SAIDI is within 1% of the five-year average for U.S. investor-owned utilities.) In the current DIP, as noted earlier, the Company revises its projection to a SAIDI target of 80 minutes. In just three years, the Company's projected reliability improvement has already deteriorated 23.1% from initial projections. In a discovery conference, the Company specified that Staff should not consider an 80-minute SAIDI as a goal (or as we prefer to say, an expectation), but rather as nothing more than a projection from its Optimization Model.[51] The low likelihood that the Company can be held responsible for securing projected reliability improvements is a significant DIP deficiency, and is yet another subject we will revisit later in this Section.

Q. WHAT RESULTS HAS THE COMPANY SECURED TO DATE FROM DIP INVESTMENTS?

A. As indicated in Section II of this testimony, it is far too early to determine results from DIP investments. Not only have relatively few of the most questionable packages implemented on circuits to date been completed (meaning, circuit hardening and undergrounding), there are insufficient years of experience (we recommend three years minimum) to make any conclusions. Significantly, packages have been deployed together, often in conjunction with vegetation management, making it impossible to determine if an investment package, or if simple and inexpensive vegetation management, was responsible for any improvements secured. We will return to this topic later in this Section.

[50] Georgia PSC Docket No. 42516. Attachment provided in response to STF-L&A-5-38.

[51] Optimization Model discovery conference held October 3, 2022.

2. Circuit Hardening Is Not a Cost-Effective Way to Improve Reliability

Q. WHAT IS CIRCUIT HARDENING?

A. The Company uses circuit hardening to describe a number of investments intended to reduce the frequency of service interruptions. Primary activities including replacing poles, replacing pole crossarms, installing animal guards, and replacing fuses with TripSaver® devices. The Company also claims circuit hardening investments will reduce operations and maintenance costs.

Q. PLEASE EXPLAIN WHY CIRCUIT HARDENING IS NOT A COST-EFFECTIVE WAY TO IMPROVE RELIABILITY.

A. Examining the cost-effectiveness of any grid investment involves comparing the benefits to customers from the investment (in this case, the value of reliability improvements) to the costs to customers of those investments (rate increases/revenue requirements). As the circuit hardening package includes multiple activities, it is difficult to parse these out individually. However, the analysis described below indicates that even if the Company secures the reliability improvements it projects from circuit hardening, the program is so costly on a per premises basis that it cannot deliver benefits to customers in excess of costs to customers.

Q. HOW EXPENSIVE IS CIRCUIT HARDENING?

A. Georgia Power reports that it will harden [redacted] circuits[52] at a cost of $[redacted] between 2020 and 2025, for an average cost per circuit of $6.45 million. Including carrying charges (costs of capital, taxes on Company income, sales and property taxes, etc.) the cost per circuit to customers grows to $[redacted] (the present value of the revenue requirement

[52] Trade Secret attachment provided in response to STF-WG-1-18.

on $6.45 million assuming the Company's "k-factor" of [redacted]).[53] Given that the average Georgia Power circuit serves [redacted],[54] this works out to $[redacted] in present value of revenue requirements *per average customer served by a hardened circuit*. We consider this to be quite expensive relative to the potential benefits available.

Q. HOW EFFECTIVE IS CIRCUIT HARDENING?

A. It is difficult to say. The Company projects a reduction in outage duration of [redacted] from circuit hardening. In discovery, the Company provided reliability data on 30 circuit hardening projects completed from 2012 to 2016. For these circuits, outage duration fell an average of 25% from pre-hardening performance,[55] which seems to validate the Company's projections. Unfortunately, vegetation management was completed concurrently on 50% of these circuits.[56] While concurrent completion of vegetation management on circuits being hardened is common and appropriate (to make room for the work being done), concurrent vegetation management makes it impossible to determine how much of the reliability improvement realized on hardened circuits is due to vegetation management, and how much is due to hardening investment.

Q. GIVEN THESE COSTS AND THE COMPANY'S EFFECTIVENESS PROJECTIONS, HOW DOES THE CUSTOMER VALUE OF RELIABILITY IMPROVEMENTS COMPARE TO CUSTOMER COSTS?

A. Unfortunately, not favorably. Our analysis finds that customers receive only $0.46 in reliability improvement value per dollar of rate increase. An explanation of our analysis follows.

[53] Customer Benefits Study, corrected k-factor, page 12. $6.45 million multiplied by the corrected k-factor is $[redacted]

[54] 2.6 million customers divided by 2,344 circuits; $[redacted] divided by 1,109 customers is $[redacted] each.

[55] Trade Secret attachment provided in response to STF-WG-1-8.

[56] Trade Secret Attachment B provided in response to STF-WG-2-16.

We applied the Company's current reliability improvement assumptions for the circuit hardening package to the average reliability 2017-2021 of the 25 circuits the Company selected for this package 2020-2022.[57] (Remember, according to the Company's Optimization Model, these first circuits prioritized for hardening should represent the worst circuits in the Company's distribution system.) From a starting average SAIDI of [redacted] minutes on these circuits, the Company's projected average improvement of [redacted] results in a reduction to [redacted] minutes. From a starting SAIFI on these circuits of [redacted] interruptions per year, the Company's projected average improvement of [redacted] results in a reduction to [redacted] interruptions per year. As an initial observation, we note that the customer "willingness to pay" research cited earlier indicates customers would be unwilling to incur costs amounting to $[redacted] each for such reliability improvement levels. But we continued our analysis through an additional step: utilizing the US Department of Energy's Interruption Cost Estimator (ICE) tool to quantify the dollar value to customers of reliability improvements from circuit hardening projected by Georgia Power. We can then compare this value to the average customer cost of $[redacted] million per circuit to determine the cost-effectiveness of circuit hardening (or lack thereof).

Q. WHAT IS THE DEPARTMENT OF ENERGY'S ICE TOOL?

A. The ICE tool is an internet-based software application designed specifically by the Department of Energy to help utilities estimate the value to customers of reliability improvements.[58] Georgia Power employed the ICE tool to estimate the cost of outages to customers as a reality check against its Customer Benefits Study results using the Company's own "cost of outage" estimates, secured from customer research conducted in 2011. (Customer Benefits Study results using the ICE tool estimates and using the

[57] Trade Secret attachment provided in response to STF-WG-1-18.

[58] The Interruption Cost Estimator for anyone to use at https://icecalculator.com/build-model?model=reliability

Company's own estimates were very similar.)[59] A different option the ICE tool offers, based on the same underlying "cost of outages to customers" research data, estimates the value to customers of reliability improvements.

Q. HOW DID YOU USE THE ICE TOOL TO ESTIMATE THE PRESENT VALUE OF RELIABILITY IMPROVEMENTS FROM CIRCUIT HARDENING?

A. We used the ICE tool's "value of reliability improvements" option to estimate the value to customers of the reliability improvements the Company projects from the circuit hardening package. We input the starting and improved SAIDI and SAIFI levels for the first 25 circuits described above into the ICE tool, as well as all other inputs the tool required specific to Georgia Power (customer counts by class for these circuits; inflation rate =[redacted]; discount rate = [redacted]; expected lifetime of benefits in years = [redacted]; etc.). Using all this Company-specific and circuit-specific data, the ICE tool calculates the present value of projected reliability improvements from hardening the first 25 circuits to be $94.9 million, or $3.8 million per circuit. Compared to the present value of the average cost to customers to harden a circuit ($[redacted] per circuit, per above), the ICE tool valuation of reliability improvements indicates that circuit hardening delivers just $0.46 in reliability improvement value for every $1 in customer rate increase.[60]

Thus, the circuit hardening package is cost-ineffective by a wide margin, and not in the interest of customers or the public. Recall that our analysis employed Georgia Power's own projections for costs and reliability improvements from circuit hardening; *it is entirely possible Georgia Power will not be able to deliver the reliability improvements it projects within the costs it estimates*. (Further, our finding is consistent with one of the most thorough studies of circuit hardening ever completed, on behalf of the Public Utilities

[59] Customer Benefits Study, corrected k-factor, p. 31-32.

[60] $3.8 million in benefit per circuit divided by $[redacted] in customer costs (PVRR) per circuit = $0.46

Commission of Texas. The study, which focused on hardening for hurricanes, determined that cost-effectiveness for circuit hardening was only indicated for about 1% of distribution structures, including only those within 50 miles of the Gulf of Mexico.[61]

3. Undergrounding of Overhead Lines Is Not a Cost-Effective Way to Improve Reliability

Q. PLEASE EXPLAIN WHY UNDERGROUNDING IS NOT A COST-EFFECTIVE WAY TO IMPROVE RELIABILITY.

A. As with circuit hardening, we cite undergrounding's extreme cost as the primary reason why undergrounding cannot possibly deliver reliability improvements sufficient to deliver value to customers in excess of rate increases. While our circuit hardening analysis identified a cost per circuit of $[redacted], and a cost per customer served by a hardened circuit of [redacted], the customer cost to underground overhead lines (present value of the revenue requirement) is 3.6 times more costly than circuit hardening on a per circuit basis ($[redacted]),[62] and more than twice as costly as circuit hardening on a customer-specific basis, at [redacted].[63] This customer-specific amount is far less than we have seen in the industry, at about $1 million in utility cost per overhead mile undergrounded, divided by the U.S. average of customers per distribution line mile of 40 ($25,000 per customer), which indicates that our customer-specific cost estimate (based on Georgia Power data) is likely understated by a significant amount. Recently, Pacific Gas & Electric Company reported an undergrounding cost of over $4 million per overhead line mile,[64] though

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[61] Brown R. *Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs*. Prepared by Quanta Technology on behalf of PUC Texas in Docket No. 36375. March 4, 2009.

[62] Trade Secret attachment provided in response to STF-WG-1-18. $[redacted] 2020-2025 divided by [redacted] circuits, multiplied by the corrected k-factor of [redacted] = $[redacted].

[63] Trade Secret attachment provided in response to STF-WG-1-18. Upon dividing, [redacted] customers to be undergrounded 2020-2025 (six years) at a cost of $[redacted] yields $[redacted] in utility costs per undergrounded customer. Multiplied by the corrected k-factor of [redacted] (for costs of capital, taxes, etc.) yields a cost to customers of $15,241 per undergrounded customer.

[64] California PUC Docket No. A.21-06-021. *2022 Wildfire Mitigation Plan and 2023 General Rate Case Updates*.

admittedly through rough terrain (steep, rocky, and heavily forested). In a discovery conference, Georgia Power admitted that one of the lessons learned from DIP implementation so far is that undergrounding costs more than original estimates due to the rocky nature of Georgia soil.[65]

Q. HOW EFFECTIVE IS UNDERGROUNDING AT IMPROVING RELIABILITY?

A. Undergrounding is quite effective at improving reliability. But high cost, not the level of effectiveness, is the problem. The Company reports using the reliability of circuits that are already undergrounded as the basis for its undergrounding reliability improvement projections (though it admits it has never implemented a massive undergrounding program in the past).[66] While this is a reasonable approach in the absence of actual undergrounding program data, the cost of undergrounding is so high as to render the undergrounding effectiveness question meaningless.

We know this because we applied a 100% SAIDI and SAIFI reduction to the eight circuits for which undergrounding was the only package the Company applied 2020-2022. In our analysis, using ICE tool values by customer class for the cost to customers of service interruptions, and the Company's cost projections[67] and other Company-specific assumptions, we found that the Company's costs (not even including profits and taxes customers must pay) exceeded the customer value of reliability improvements for every single one of the eight circuits, and for most of them, by a very wide margin. *This finding bears repeating: even at a 100% reliability improvement assumption (perfect reliability),*

Stakeholder presentation dated February 24, 2022. Slide 5.

[65] Discovery conference October 3; Customer Benefit Study, corrected k-factor, page (i).

[66] Response to STF-WG-2-7.

[67] Trade Secret Attachment A to STF-WG-1-49.

the customer value of reliability improvements from undergrounding did not exceed the Company's undergrounding costs.

Our contention that the extremely high cost of undergrounding overhead lines makes the practice a cost-ineffective way to improve reliability is well-supported by extensive amounts of research and state regulator evaluation. A study completed in follow-up to the aforementioned PUC Texas study (on circuit hardening) that focused exclusively on undergrounding found only $0.30 in benefits for every $1 spent to underground overhead lines.[68] Multiple other state utility regulators have studied the undergrounding question, including Florida, Maine, Maryland, North Carolina, and Virginia. In every instance but one, no state utility regulator has endorsed undergrounding of its own accord.[69] In the lone exception, the Virginia State Corporation Commission severely limited a utility's undergrounding application, though that Commission fully rejected two other undergrounding applications by the same utility.[70]

Q. WHAT OTHER EVIDENCE DO YOU HAVE THAT UNDERGROUNDING IS NOT A COST-EFFECTIVE WAY TO IMPROVE RELIABILITY?

A. As with Georgia Power's circuit hardening package, we used the ICE tool to estimate the reliability improvement value of the undergrounding package. We employed the same method for undergrounding as we did for circuit hardening, using the average SAIDI ([redacted] minutes) and SAIFI ([redacted] interruptions) 2017-2021 of the 16 circuits the Company selected

[68] Larsen P. A Method to Estimate the Costs and Benefits of Undergrounding Electricity Transmission and Distribution lines. Lawrence Berkeley National Laboratory report 1006394. Preprint page 42. Published in Energy Economics, Vol. 60, p. 47-61. November 2016.

[69] Brown R. *Undergrounding Assessment Phase 1 Final Report: Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion*. Florida PSC Docket No. 06-0351-PAAEI. Feb. 2007. Page 9.

[70] Virginia SCC Case Nos. PUE 2014-00089, Order dated July 30, 2015; PUE 2015-00114, Order dated August 22, 2016; PUR 2018-00100, Order dated January 17, 2019. Note that subsequent legislation in Virginia (S 1473 in 2017) and Florida (HB 797/SB796 in 2019) instructed regulators to permit recovery of undergrounding costs. We consider such legislation ill-informed, and a legislative overreach into state utility regulator authority.

for undergrounding 2020-2022 as the ICE tool starting point. We then input the reliability improvements the Company's Optimization Model assumes for the undergrounding package, along with all other variables specific to Georgia Power and these 16 circuits, just as we did for circuit hardening. Using the Company's own reliability improvement projections (SAIDI down to [redacted] and SAIFI down to [redacted]) and all other circuit-specific and Company-specific inputs, the ICE tool calculated a reliability improvement value of $170 million, or $10.6 million per circuit. Compared to the average cost per circuit of $[redacted], our analysis indicates that customers will receive only $0.36 in value per $1 of undergrounding rate increase[71] – not significantly different than the $0.30 per $1 found by the Texas undergrounding study cited above.

Q. HAVE YOU INCLUDED THE OPERATIONS AND MAINTENANCE (O&M) SAVINGS ASSOCIATED WITH CIRCUIT HARDENING OR UNDERGROUNDING IN YOUR COST-EFFECTIVENESS CALCULATIONS?

A. No. But as the Company's Customer Benefits Study indicates, avoided customer outage costs represent the greatest single value proposition of the Company's DIP by far.[72] Based on our finding that customer reliability value is dramatically insufficient to justify the cost of circuit hardening or undergrounding, it is not possible for the relatively small reduction in O&M costs associated with undergrounding (stemming largely from reductions in vegetation management) or circuit hardening to remotely make up the shortfall in customer reliability value relative to customer costs.

[71] $10.6 million in benefits per circuit divided by $29.5 million in customer costs per circuit is 0.36.

[72] Customer Benefits Study, corrected k-factor, p. v, Figure 2, "Present Value of Total Costs (to customers)"

4. The DIP applies costly DIP investment packages to too many circuits which do not need them.

Q. IN THE INTRODUCTION TO THIS DIP INVESTMENT SECTION YOU STATED "The Company applies costly DIP investment packages to too many circuits which already demonstrate reasonably good reliability performance, further damaging the cost-effectiveness of the DIP." PLEASE EXPLAIN THIS.

A. In our summary of the Company's DIP we related that the Company's DIP Optimization Model applies investment packages to circuits performing below the median (meaning, circuits performing in the third or fourth quartile) as measured in 2017. This criteria identifies half of all circuits as the best candidates for capital investment rather just the very worst performers. As the reader can imagine, one-half of the Company's circuits exhibit a very wide range of reliability performance, with many circuits performance close to the system average performance. Indeed, our examination of circuits with "below the median" reliability 2017 to 2021 identifies circuits with SAIDI as low as 99 minutes (the circuit ranked immediately below the median circuit) in the third quartile.[73] *Given that the Company's 5-year average SAIDI 2017-2021 is 131, this means that the Company's DIP will eventually apply investment packages to circuits with above-average reliability*.

Clearly, the application of costly investment packages to circuits with above-average reliability does not make sense. To be sure, focusing investment packages on the worst-performing circuits, and not those above the average, nor even those near the average, makes the most sense. Figure 7 below illustrates the problem with applying investment packages to circuits "below the median": it does not sufficiently focus DIP attention and investment on the worst-performing circuits.

[73] Georgia PSC Docket No. 44160. Trade Secret Attachment 1(b) provided in response to STF-WG-1-1.

Figure 7: Circuit Counts and SAIDI performance by quartile using the most-recent 5-year averages.

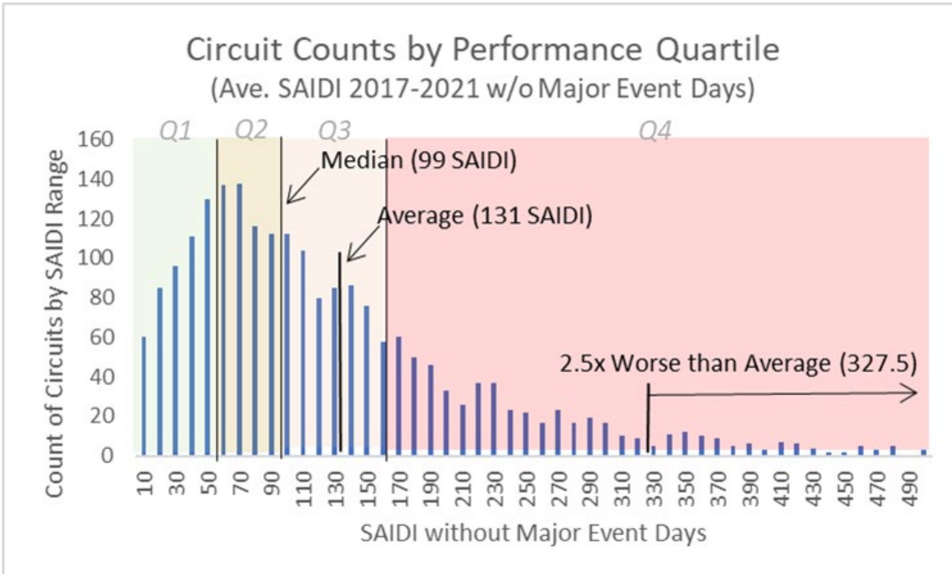

Figure 7 indicates that investing in so many circuits does not sufficiently concentrate spending to optimize package assignments. Unconcentrated spending increases the cost of the DIP and reduces the average reliability improvement per DIP capital dollar. This is because the very worst-performing circuits present a much larger performance improvement opportunity than circuits performing at, near, or above the average. For example, attention focused on circuits with SAIDI 2.5 times higher than average would address just 126 circuits at Georgia Power, not the 800 or so circuits that the Company's DIP targets for package deployment.[74]

Q. WHY DOES A FOCUS ON FEWER CIRCUITS DELIVER A BIGGER BANG FOR THE BUCK?

A. As the reader can appreciate, the starting point reliability for a circuit makes a big difference in the percentage of reliability improvement that might be expected from the

[74] Customer Benefit Study, corrected k-factor, page (i).

application of a package. For the sake of argument, assume that the average circuit's SAIDI after hardening will average about 99 (the median circuit at Georgia Power in 2017). For a circuit with a SAIDI of 131 before hardening, the resulting SAIDI improvement would be 24% (131 to 99). For circuit with a SAIDI of 400 before hardening, the resulting SAIDI improvement would be three times greater, at 75% (400 to 99). This illustrates why the performance improvement opportunity for a circuit with a SAIDI of 400 is much larger than the performance improvement opportunity for a circuit with a SAIDI of 131, and why a focus on 126 circuits with really poor reliability delivers much better "bang for the buck" than a focus on 800 circuits.

Neither the Company's DIP nor its Optimization Model account for this difference in performance reliability opportunity. For all packages but undergrounding, the reliability improvement percentages the Optimization Model applies for a given package remain the same for all circuits receiving that package regardless of reliability starting point.[75] This Optimization Model flaw guarantees that the DIP applies packages to circuits that do not need them, resulting in more capital investment than necessary to achieve a given reliability performance target.

Q. BUT EARLIER YOU SAID THAT THE COMPANY'S OPTIMIZATION MODEL DOES PRIORITIZE CIRCUITS BASED ON RELIAIBILITY.

A. Yes, this is true. But focusing on circuits with reliability in the third quartile does not sufficiently focus attention and investment on the very worst circuits where the most benefit could be achieved for each dollar of capital investment. Indeed, we know of no utility that focuses reliability improvement attention on circuits even in the fourth quartile, or the bottom 25% of circuits. Instead, our experience is that most utilities operate "worst performing circuit" programs focused on circuits with reliability that is three times worse

[75] Response to STF-WG-6-1.

than the average circuit. The most aggressive of such programs focus on circuits with reliability that is 2.5 times worse than the average circuit. Such programs focus reliability improvement attention on far fewer than 25% or 50% of a utility's circuits, as Georgia Power's DIP does.

In Georgia Power's case, using 2017-2021 reliability data, a circuit with reliability performance 2.5 times worse than the 2017-2021 average of 131 minutes would be circuits with a SAIDI worse than [redacted] minutes. According to that definition, only 126 of Georgia Power's circuits, or 5.8% of the 2,162 circuits on which the Company provided 5-year SAIDI data,[76] merit attention. Attention and investment in the 5.8% of circuits with the worst performance is much more targeted than attention and investments in the bottom 50% of circuits (third quartile and below, about 1080 circuits), and more targeted even than investments in the bottom 25% of circuits (fourth quartile, about 540 circuits). Focusing attention and investment on the bottom 5.8% of circuits would provide much greater reliability improvement per dollar than focusing on circuits in the third or fourth quartiles (50% of the Company's circuits). This explains how the Company's DIP applies too many packages to circuits which do not need them, constituting a significant problem with the Company's DIP.

Q. EARLIER, YOU SAID THAT THE COMPANY USED 2017 RELIABILITY PERFORMANCE TO PLACE CIRCUITS INTO QUARTILES, AND THAT THE PLACEMENT OF CIRCUITS INTO QUARTILES USING 2017 DATA REMAINS STATIC THROUGH TO TODAY. IS THIS SIGNIFICANT? IF SO, HOW?

A. The static use of 2017 reliability performance to place circuits into quartiles is extremely significant, and extremely problematic. Georgia Power's reliability performance in 2017 was strong. In fact, reliability performance in 2017 was the best of any year from 2015 to

[76] Georgia PSC 44160. Trade Secret Attachment 1(b) provided in response to STF-WG-1-1.

2021. The Company reports that a SAIDI of [redacted] was the median in 2017, and that this value was used to qualify circuits for receipt of DIP packages.[77] *Applying such a SAIDI to actual reliability data 2017-2021, we found that a SAIDI of* [redacted] *is low enough to qualify about 75% of the Company's circuits for investment packages*. If the Commission allows the Company's DIP to continue as is, the reliability investment packages will eventually be applied to all but 25% of the Company's circuits. Applying packages and investments to 75% of circuits is the exact opposite of "focused" spending. Figure 8 indicates the severely unfocused and inappropriate nature of DIP spending permitted through the use of a SAIDI of 00.00 to qualify a circuit for costly DIP packages.

Figure 8: Counts of circuits qualifying for DIP packages using 2017 median performance as criteria

As we see it, the DIP Optimization Model and the Company's application of it are designed specifically to justify the greatest possible amount of rate base growth that also happens to improve reliability by some amount. It succeeds in this by including only high-cost, capital-

[77] Trade Secret response to STF-WG-1-42.

intensive package options in its Optimization Model, and by employing parameters which result in the application of those packages to far too many circuits. It is not difficult to improve reliability with capital; any utility can throw billions of dollars at its distribution grid and improve reliability. The real challenge is to identify the actions that improve reliability at a cost which is less than the value to customer of those reliability improvements. But as we shall explain, this is not what the Company's DIP or Optimization Model set out to do, because the DIP and Model ignore two extremely common and cost-effective approaches to improving reliability: more aggressive vegetation management and a more formalized approach to addressing worst-performing circuits.

5. The DIP ignores dramatically more cost-effective approaches to improving reliability.

Q. WHAT ARE THE DRAMATICALLY MORE COST-EFFECTIVE APPROACHES TO IMPROVING RELIABILITY THAT THE COMPANY'S DIP IGNORES?

A. The two dramatically more cost-effective approaches to improving reliability that almost all utilities employ are more aggressive vegetation management programs and more rigorous worst-performing circuit programs. The Company's Optimization Model and its resulting DIP do not consider such programs.

Q. DOESN'T GEORGIA POWER ALREADY HAVE SUCH PROGRAMS?

A. Yes, but our discovery indicates these programs are less formal and rigorous than we would have expected from a utility of Georgia Power's size and sophistication. Critically, we note that neither more aggressive vegetation management nor a more rigorous worst-performing circuit program have been evaluated as alternatives to DIP packages.

Q. WHY DO YOU DESCRIBE THE COMPANY'S VEGETATION MANAGEMENT PROGRAM AS LESS FORMAL AND RIGOROUS THAN YOU WOULD HAVE

EXPECTED?

A. Early in discovery, Georgia Power reported that its program completes vegetation management on circuits at a frequency of between every 24 and 60 months, with an average of 42 months (3.5 years).[78] Our examination of detailed historical "line miles cleared" data obtained through subsequent discovery[79] revealed a different picture. From 2012 through 2021, assuming 55,188 overhead distribution line miles,[80] Georgia Power actually completed vegetation management on circuits at a frequency of between two years and nine years, with an average of 4.4 years. We also noted that budgets for vegetation management varied widely from year to year, with a low of $44 million reported in 2017 to a high of $124 million reported in the twelve months ending May 31, 2022.[81]

Given Georgia's extended growing season, a more aggressive, formal, and consistent vegetation management program is the first place we would concentrate to secure cost-effective improvements in reliability. Indeed, an examination of outage cause data 2017-2021 indicates that vegetation contact was one of the most common causes of service interruptions, amounting to one-fifth of all service interruptions 2017-2021.[82] This is consistent with our experience across utilities.

Q. HOW INEXPENSIVE IS VEGETATION MANAGEMENT RELATIVE TO UNDERGROUNDING?

A. Georgia Power's vegetation management (O&M) costs averaged $[redacted] per line mile from 2016-2021.[83] As noted earlier, an industry rule of thumb for undergrounding is $1 million

[78] Response to STF-WG-1-27 (b).

[79] Trade Secret Attachment B provided in response to STF-WG-2-16 (c).

[80] Response to STF-WG-1-36 (a) + (c) + (e).

[81] Response to STF-LA-2-65.

[82] Trade Secret Attachments F through J provided in response to STF-WG-1-30. Includes all vegetation contact.

[83] Response to STF-LA-2-65 (vegetation management $ 2016-2021); Trade Secret Attachment B provided in response

capital cost per line mile. Granted, vegetation management costs must be incurred every four years or so. But at these price differentials, over the 40-year depreciation period typically applied to underground cable, no sophisticated analysis needs to be completed to recognize that vegetation management is tens of multiples less costly than undergrounding.[84]

Q. WHAT CHANGES TO GEORGIA POWER'S VEGETATION MANAGEMENT PROGRAM WOULD YOU RECOMMEND?

A. At a minimum, we would recommend strict compliance with a four-year vegetation management cycle. By "strict compliance", we mean that no section of any circuit should go more than four years without vegetation management. Further, reductions in vegetation management cycles to 3.5 years or even 3.0 years should not be ruled out. Indeed, we note the Company plans to increase its average annual vegetation management budget by more than 58% over recent years, from $63 million (2016-2020) to $100 million, in this rate case test period.[85] An increase of this magnitude could be expected to enable a reduction in the average vegetation management cycle from 4.5 years to 3.5 or even 3.0 years. We also recommend the Commission order an annual vegetation management report detailing miles cleared relative to the level required to maintain the Commission-approved vegetation management cycle, and to track resulting reliability improvements.

If the Commission wishes to focus on improving reliability in a cost-effective manner, more innovative vegetation management ideas can be considered. For example, California

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to STF-WG-2-16 (c) (vegetation management miles 2016-2021).

[84] Looking at just one mile, over 40 years, vegetation management would likely be completed 10 times at a cost of $[redacted] each time ($[redacted]). Compared to a $1 million capital cost to underground that same mile of overhead lines, a rough estimate is that undergrounding is about [redacted] times more costly than vegetation management ($1 million divided by $[redacted]).

[85] Attachment provided in response to STF-LA-2-65.

recently increased utility rights-of-way radii from 18 inches to as much as four feet.[86] A legislated expansion of utility rights-of-way in Georgia certainly represents one potential approach to improving reliability in a cost-effective manner. In Washington, Avista Utilities is developing a program to pay rebates to customers to trim (and possibly to remove) trees outside the right-of-way that pose a threat to distribution lines in windy conditions.[87] Indeed, the Company agrees that purchasing additional rights-of-way is an option.[88] But none of these approaches appear to have been evaluated on an economic or effectiveness basis as alternatives to capital-intensive circuit hardening or undergrounding packages the Company has defined.[89]

Q. MOVING ON TO WORST-PERFORMING CIRCUIT PROGRAMS, CAN YOU PROVIDE A DESCRIPTION OF A TYPICAL UTILITY PROGRAM?

A. A typical worst-performing circuit program consists of several steps. The first step, completed annually, is to compute one or more reliability metrics for each circuit to enable the identification of poor performers. While SAIDI and SAIFI (interruption duration and frequency) are the most common reliability metrics employed for this purpose, we have seen others used. Another popular metric is the count or percentage of customers on a circuit experiencing over a certain number of interruptions (for example five, six, or seven) in a year.[90] Other metrics we have seen include identifying circuits that have appeared on the worst-performing circuit list (however defined, see next) for two or more years in a row, or to use two-year averages to measure circuit reliability. (Year-to-year variation can cause too many "false positive" worst-performing circuit identifications when a single

[86] Accessed at https://www.pge.com/en_US/safety/yard-safety/powerlines-and-trees/laws-and-regulations.page

[87] Washington Utilities and Telecommunications Commission Docket No. UE-200900. Exhibit DRH-2 filed October 30, 2020 (Avista Utilities Wildfire Resilience Plan). Page 42.

[88] Response to STF-WG-2-18.

[89] Response to STF-WG-2-16.

[90] This statistic, commonly known as "customers experiencing multiple interruptions", or "CEMI" is typically expressed as "$CEMI_{(x)}$", where "x" is the number of interruptions used as the threshold for the metric.

year's reliability is measured. Georgia Power's program appropriately uses two-year averages to measure circuit reliability.)[91]

Once the reliability of all circuits is calculated, the next step is to identify those that warrant additional investigation as "worst-performing". As indicated earlier, most utilities establish an annual list of circuits performing at worse than three times the average circuit's interruption duration or frequency, though we have seen definitions using 2.5 times worse than the average circuit at some utilities. As indicated earlier, about 6% of Georgia Power's circuits would currently qualify for attention using a 2.5x definition.

For circuits identified as worst-performers, the next step is to complete root-cause analyses. Typically, the engineer responsible for the circuit's performance will examine outage cause data as the first step towards identifying any recurring outage root causes. The inability to identify a root cause of poor reliability is common; random variability due to weather or accidents often encourage root cause analysts to recommend no remediation, or to simply put such circuits on a watch list for future consideration. In summary, the challenge with identifying circuits in such programs is to avoid excluding circuits from the list that merit attention, nor to include on the list circuits that do not merit attention. To optimize spending, the ideal process for circuit identification/list creation is fairly sophisticated.[92] Georgia Power's approach – to identify every circuit below the median for potential application of packages – is not sophisticated at all and results in unnecessary capital investment.

When a recurring root cause is found, the next step is to develop and schedule remediation actions. In our experience the most common remediation activity is spot vegetation

[91] Response to STF-WG-1-27(c).

[92] Brown, R. *Identifying Worst Performing Feeders.* Eighth International Conference on Probabilistic Methods Applied to Power Systems, Iowa State University, Ames, lowa. September 12-16, 2004. Available from IEEE.

management, though sometimes a problematic piece of equipment is identified for replacement. Other common, and inexpensive, remediation actions include the installation of animal guards, or adjusting the settings of protective devices (such as reclosers) on a circuit. Root causes and associated remediation plans rarely involve large capital expenditures, though installation of additional reclosers, sectionalizing devices (to reduce the number of customers who are impacted by a fault), and distribution automation schemes are called for on occasion. (All of these latter options require capital spending.)

Q. WHY DO YOU DESCRIBE THE COMPANY'S WORST-PERFORMING CIRCUIT PROGRAM AS LESS FORMAL AND RIGOROUS THAN YOU WOULD HAVE EXPECTED?

A. First, the Company has no standard criteria for identifying circuits as "worst," thereby qualifying for additional attention. Instead, the Company seems to take actions commensurate with the level of spare capital budgets that might be available from year-to-year.[93] The Company seems to have no written policies to formalize its worst-performing circuit program,[94] nor do any dedicated capital or O&M budgets appear to exist for the program. Indeed, program spending has varied widely from year to year over the past 12 years, from a low of $[redacted] in 2010 to a high of over $[redacted] in 2018.[95]

Q. ARE WORST-PERFORMING CIRCUIT PROGRAMS COST-EFFECTIVE?

A. Judging by their popularity among utilities, we believe so. Anecdotal data from Georgia Power's program also appears to indicate that they might be, particularly relative to extremely costly DIP investment packages such as circuit hardening and undergrounding. Table 5 below provides the pre- and post-investment results for worst-performing circuit

[93] Response to STF-WG-2-19(a).

[94] Response to STF-WG-1-27(c).

[95] Trade Secret Attachment provided in response to STF-WG-2-37.

projects completed in 2017 and 2018, along with average project costs per circuit.[96] Note the dramatically lower capital costs per circuit of this program compared to the radical capital spending per circuit associated with Georgia Power's circuit hardening package.

Table 5: Average Costs and Effectiveness of Georgia Power's WPC Program, projects completed in 2017 and 2018.

Year projects completed	Count of Circuits w/projects completed	Ave. Capital Cost per Circuit	Ave. SAIDI 3 yrs. prior	Ave. SAIDI 3 yrs. post	Percent Improved	Ave SAIFI 3 yrs. prior	Ave. SAIFI 3 yrs. post	Percent Improved
2017	[redacted]							
2018								

Q. WHAT CHANGES TO GEORGIA POWER'S WORST-PERFORMING CIRCUIT PROGRAM WOULD YOU RECOMMEND?

A. We would recommend that the Company develop written policies to formalize its program, including clear criteria for identifying circuits for additional attention annually; standards for completing root-cause analyses; standards for developing remediation plans; and standards for reviewing plans and authorizing spending, as well as standards for tracking spending, projects, and results. We would also recommend that specific budgets for the program be established, and that personnel/organizational accountabilities for program administration, root cause analyses, and remediation plan development and implementation be established. The Commission may also wish to consider establishing annual reporting requirements for the program. The Maryland PSC has established a strong reliability performance improvement program, including both vegetation management and worst-performing circuit reporting features, that merits the Commission's attention. We will describe this program in more detail later in this Section.

[96] Ibid.

6. The DIP is prompting premature retirement of reliable assets for which customers are paying.

Q. DOES THE DIP PRESENT OTHER PROBLEMS FOR CUSTOMERS?

A. Yes. It appears that the DIP consists in large part of wholesale and indiscriminate equipment replacement, essentially constituting rebuilding or undergrounding entire circuits or sections of circuits, as examples. We believe the new equipment installed via the DIP is inadvertently displacing a great deal of existing equipment that is perfectly sound and is operating safely and reliably (in the same way that the transmission investment plan's premature replacement practice does). Replacing poles and cross-arms that have passed their most recent inspections, whether through circuit hardening or undergrounding packages, deprives customers of many years, or even decades, of useful life from equipment for which they have paid, or for which they continue to pay, in rates. This obviously represents a significant opportunity cost that should also be included in the Commission's evaluation of the Company's proposed DIP.

Q. WHAT IS YOUR EVIDENCE THAT THIS IS HAPPENING?

A. We can see from accounting details provided in discovery that the Company is retiring distribution assets with book value remaining at an alarming rate. A piece of equipment with book value means that it is still being depreciated. If a piece of equipment is still being depreciated, that means it has not yet reached the end of its estimated life, let alone the end of its operating life (meaning, fully depreciated but passing its inspections). To summarize, the opportunity costs to customers of the DIP makes the already negative cost-benefit ratio of packages like circuit hardening or undergrounding even more negative.

Q. WHY DO YOU CHARACTERIZE THE RETIREMENT OF DISTRIBUTION ASSETS WITH BOOK VALUE REMAINING AS "ALARMING"?

A. From 2023 to 2025, the Company projects that it will retire distribution equipment with a net book value of $[redacted].[97] Given that Company's entire distribution capital request 2023-2025 (including the DIP) is $[redacted],[98] our interpretation is that almost one quarter of the distribution capital the Company is requesting replaces assets that have not reached their estimated life. The replacement of equipment that is operating safely and reliably despite being fully depreciated comes on top of this amount. While a small amount of retirement is unavoidable (for example, government-requested facility relocations or accidents or storms that destroy equipment), we believe the DIP, and particularly its application to too many circuits not performing poorly enough to justify investment, is to blame for the extremely high level of equipment retirements Georgia Power projects.

The significant retirement of equipment with book value remaining is evidence of asset churn, or replacing assets with low (or no) book value simply to increase rate base and profits. There is legal and regulatory precedent against this practice,[99] and we encourage the Commission to consider the waste and opportunity cost caused by circuit hardening and undergrounding as just one more reason to reject capital requests for these DIP packages.

7. Why the Commission should afford little to no weight to the Company's Customer Benefits Study.

Q. YOU HAVE MADE SOME COMPELLING POINTS, BUT THE COMPANY'S CUSTOMER BENEFITS STUDY INDICATES ITS DIP IS COST-EFFECTIVE. HOW COULD THE COMPANY'S STUDY RESULTS BE SO DIFFERENT FROM YOUR FINDINGS?

[97] Trade Secret attachment provided in response to STF-LA-10-1.

[98] Trade Secret attachment provided in response to STF-PIA-4-4.

[99] See footnotes 27 and 45 for brief discussions of the Averch-Johnson effect and our application of it.

A. Actually, the Company's Customer Benefits Study provides no indication that the DIP is cost-effective (meaning, that it delivers economic benefits to customers in excess of associated rate increases). The Customer Benefits Study is not a cost-effectiveness test, nor is it a cost-benefit analysis, though the Company undoubtedly wants the Commission to consider it as such. Instead, the optimization modeling the Company presents in its DIP is a hypothetical exercise to optimize outcomes within a set of constraints self-imposed and designed by the Company. Neither the DIP nor the Optimization Model is designed to answer the question, "What are the most cost-effective ways to improve reliability?" Instead, the DIP consists of the following components:

1. A set of capital-intensive grid investment packages;
2. A set of implementation cost and customer cost reduction assumptions (from reliability improvements) for each package;
3. The application of constrained optimization modeling techniques to identify the mix and level of package implementation that results in the lowest total cost to customers *given the limited set of capital-intensive grid investment packages specified.*

The DIP provides the optimum results or plan given a limited set of solutions which exclude more cost-effective solutions such as more aggressive vegetation management, a more formalized worst performing circuit program, and a focus on fewer circuits with the most abject reliability performance. This is absolutely not the way to develop a cost-effective plan to improve reliability.

Q. HOW DO YOU BELIEVE A UTILITY SHOULD DEVELOP A COST-EFFECTIVE PLAN TO IMPROVE GRID RELIABLITY?

A. Instead of modeling a constrained set of options designed and limited by Georgia Power, the Company should have identified all commonly-employed approaches to improve reliability, including approaches that are not capital-intensive, such as more aggressive vegetation management and a more formalized worst-performing circuit program. For each approach identified – including vegetation management and worst-performing circuit approaches – the Company should have used historical cost and results data from previous applications to project the costs and benefits (a cost-benefit analysis) for each approach. Armed with a cost-benefit analysis for each approach, the Company could have selected those delivering the biggest reliability improvements per dollar, and applied them only to the circuits with the most dramatically poor reliability performance (rather than up to 75% of circuits, as the use of 2017 median circuit performance enables). The Company did not complete a cost-benefit analysis for any of the capital-intensive packages it defined,[100] let alone for any of the myriad, lower-cost alternatives to the six capital-intensive packages that exist. Nor did the Company consider limiting spending to a smaller number of circuits.

The Commission should give little or no weight to the Company's Customer Benefits Study because it answers an irrelevant question. The irrelevant question the Study answers is "Of the capital-intensive packages we have defined, what mix delivers the lowest total cost to customers?" The relevant question the DIP should answer is "What are the most cost-effective ways to improve reliability?" Until and unless the Company provides cost-benefit analyses for all commonly-employed approaches to improving reliability, thus enabling an answer to this relevant question, we recommend the Commission afford no weight to the Company's Customer Benefits Study and reject the Company's requests for capital to continue the most outrageously expensive and cost-ineffective DIP packages: circuit hardening and undergrounding.

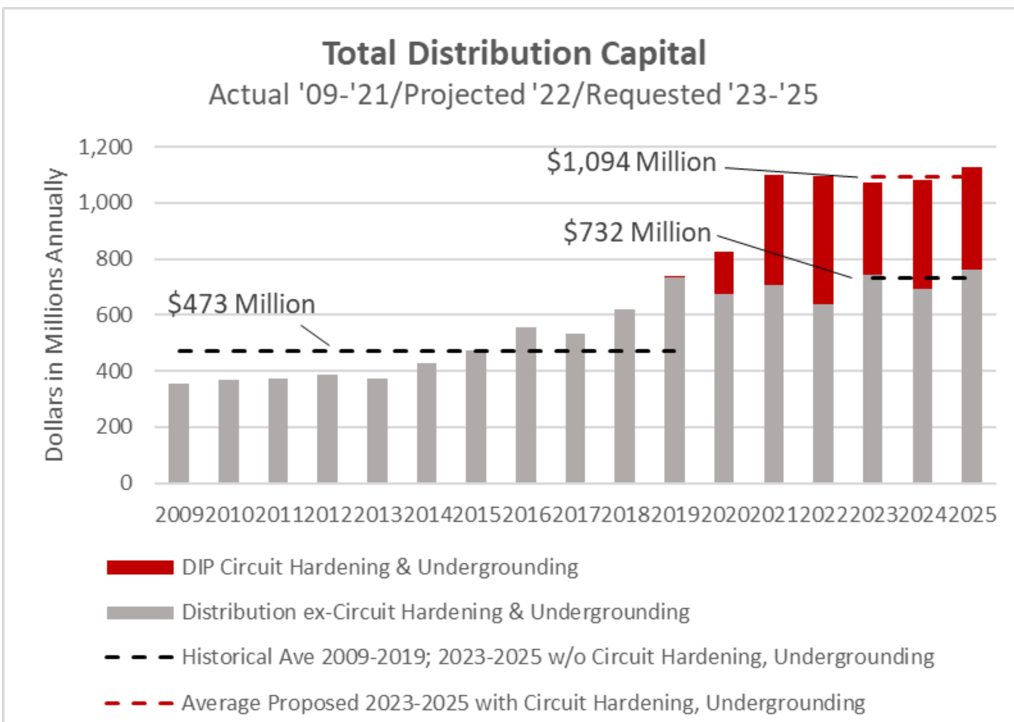
Q. BUT SHOULDN'T THE COMMISSION ENCOURAGE GEORGIA POWER TO IMPROVE ITS SERVICE RELIAIBLITY?

A. Of course it should, but not at any cost. There are many more cost-effective ways to improve reliability than those the Company chose for its DIP that can be, and should have

[100] Response to STF-WG-1-8(f).

been, considered. Figure 9 indicates that if the Commission follows our recommendation to reject continued investments in the circuit hardening and undergrounding packages 2023-2025 entirely, the remaining distribution investments proposed still represent a [redacted] increase (from $473 million per year to [redacted] million per year) over average annual distribution investment from 2009 to 2019 (before the DIP commenced). If the Commission follows our recommendations there is little to no risk that an authorized [redacted] increase could be perceived as disdainful of reliability improvement goals. Given such an increase, and assuming efficient and economic management, the Company should be able to maintain and improve service reliability without the circuit hardening and undergrounding components of the DIP.

Figure 9: Total Distribution Capital Actual '09-'21/Projected '22/Requested '23'-25



8. The DIP offers no performance accountability.

Q. DO YOU HAVE OTHER CONCERNS ABOUT GEORGIA POWER'S DIP?

A. Yes. Packages other than circuit hardening and undergrounding may also fail to deliver benefits to customers in excess of associated rate increases. The Company's spending on moving distribution lines from back lots to front lots falls in this category. As with circuit hardening and undergrounding, this package entails an extremely high cost per premise. The "add circuit ties" package becomes cost-ineffective when applied to increasingly rural circuits. While circuit ties in urban and suburban areas are relatively short, circuit ties in rural areas, where circuits are far apart, are much longer, and therefore much more costly to build. At the same time, low customer density on rural circuits means that dramatically fewer customers will benefit per dollar spent adding ties. Thus, at some point, adding more circuit ties will cross into the point of diminishing returns. (Though of course, less costly ways to improve rural circuit reliability are available, and those should be pursued as appropriate.) Even distribution automation and sectionalization, an approach to improving reliability we generally favor, has its limits. At some point, the cost to add more sections and distribution automation schemes exceeds the resulting reliability improvements. None of these packages should be approved without cost-benefit tests to determine cost-effectiveness and the point of diminishing returns.

But the period for discovery is limited, and the Company's permitted response times are long.[101] We simply did not have sufficient opportunity to investigate all DIP packages to the extent we would have preferred. Regarding other DIP concerns, the largest by far is our concern that the DIP offers no opportunities for holding Georgia Power accountable for

[101] In our experience, data request response time in all cases in which we have served our clients has never been longer than 14 calendar days or 10 business days, approximately half of what Georgia Power is allowed. This extended response time severely limited the number of follow-up rounds of discovery we could complete within procedural schedule limits. Given the complexity of distribution grids and investment plans, the ability to complete multiple rounds of discovery is critical to completing full investigations of distribution grid investments proposed by utilities.

securing the reliability improvements the Company projects from DIP spending.

Q. WHY IS ACCOUNTABILITY A CONCERN? THE COMPANY'S CUSTOMER BENEFITS STUDY CLEARLY INDICATES AN EXPECTATION THAT ITS DIP WILL ACHIEVE A SYSTEM-WIDE SAIDI GOAL OF 80 MINUTES.

A. An expectation does not constitute actual performance by the Company, nor an actual benefit from capital investment. Georgia Power's Customer Benefits Study states "The revised plan . . . is expected to invest [redacted] over the remaining 8 years and achieve an end-state overall company SAIDI of ~80 by 2031."[102] However in a discovery conference to review the Optimization Model the Company used to develop the DIP, the Company corrected our characterization of the system wide SAIDI of 80 minutes as a "target". The Company explained that the 80-minute SAIDI cited was nothing more than the Optimization Model's projected improvement from the level of spending the Company proposes in its DIP, and should not be considered a target. The Company also rejected any notion that its cost recovery vary with the actual reliability performance delivered.[103] (There is an emerging trend in the US towards performance-based ratemaking, particularly in jurisdictions employing a forward-looking/multi-year rate plan approach to ratemaking, which Georgia Power has enjoyed since the mid-1990s).

We also note that if reliability fails to improve by 2032, or improves only modestly, the Company's shareholders will win, while the Company's customers will lose. Shareholders will benefit from earnings and share price growth associated with billions of dollars in rate base growth. Customers will lose, saddled with decades of rate increases with little or no reliability improvement to show for it. Customers, not shareholders, bear the risk that GIP rate increases will not be offset by reliability improvements. This is what we mean when

[102] Customer Benefits Study with corrected k-factor, p. (i).

[103] Response to STF-WG-1-4(d).

we say the DIP includes no performance accountability for Georgia Power.

Finally, we assume the Commission relied heavily on the reliability projection the Company provided with its first DIP, in 2019, which indicated a system-wide SAIDI of 65 minutes. We imagine the Commission is interested to know that the Company has not only relaxed its original SAIDI projection to 80 minutes, but also corrected our characterization of the SAIDI projection as a reliability performance target. These are not encouraging signs that the Company can deliver the reliability improvements it projects from its DIP.

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT THE COMMISSION'S ABILITY TO HOLD THE COMPANY ACCOUNTABLE FOR DIP RELIABILITY IMPROVEMENTS?

A. Yes. We note that all the DIP packages but one (package #5, "Bring Feeder to Road", which is designed primarily to reduce outage duration by speeding repairs) are designed primarily to reduce the frequency of service interruptions (defined as those lasting longer than five minutes). Yet the Customer Benefits Study only publicly identifies a system-wide SAIDI (interruption duration) projection, and no system-wide SAIFI projection (interruption frequency). While a system-wide SAIFI projection for 2032 can be found in a trade secret response to an informal data request ([redacted]),[104] the Company's hesitation to publicly provide a system-wide interruption frequency projection is concerning.

Interruption frequency and interruption duration are two vastly different measures of reliability, and both are important. We are concerned that the discrepancy between investment intentions (to reduce interruption frequency) and investment performance measurement (interruption duration) will make it difficult if not impossible for future Commissions to hold the Company accountable for delivering actual reliability

[104] Trade Secret Attachment G provided in response to WG-Informal-1. Tab "EBA Evaluation", cell N11.

improvements from the DIP.

9. Summary of the Maryland Commission's efforts to cost-effectively improve reliability, and associated results.

Q. HAVE YOU SEEN OTHER STATE UTILITY COMMISSIONS SUCCESSFULLY SECURE RELIABILITY IMPROVEMENTS IN A COST-EFFECTIVE MANNER?

A. Yes. We have become particularly familiar with the Maryland Commission's efforts to improve distribution reliability in a cost-effective manner through our work on behalf of the Maryland Office of People's Counsel. We are encouraged by the results of the Commission's efforts, which are focused largely on annual performance reporting requirements.

Q. PLEASE SUMMARIZE THE MARYLAND COMMISSION'S EFFORTS.

A. After a series of storms in 2010 and 2011 involving prolonged (1-2 week) service interruptions for many thousands of customers, the Maryland legislature tasked the Public Service Commission with implementing service quality and reliability standards for electric distribution utilities.[105] After a series of stakeholder working groups led by the Maryland Staff, the Commission approved the addition of Chapter 20.50.12 to the utility section of the Code of Maryland Regulations, "Service Quality and Reliability Standards". The Chapter specified minimum annual performance reporting requirements as well as the minimum reliability statistics (SAIDI and SAIFI, along with multiple variations) the utilities must measure. The initial Chapter included minimum SAIDI and SAIFI values the regulated utilities were required to achieve by year for the first few years.

Subsequent workshops refined the reporting requirements, and periodic updates to the

[105] Maryland General Assembly, 2011 General Session. HB 391/SB 692. Signed into law May 10, 2011.

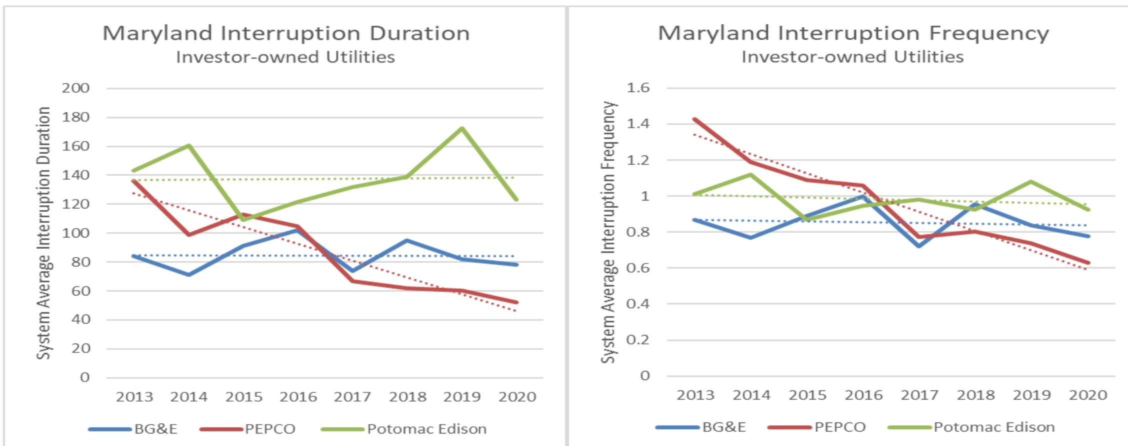
minimum SAIDI and SAIFI values have slowly required more stringent performance expectations over the years. An example of an annual performance report from a Maryland utility is provided as Exhibit PA/DS-10. As the reader can observe, there is a significant focus on vegetation management and worst-performing circuit programs, along with a focus on documented remediation action plans for failures to meet various performance expectations. In summary, the old adage "what gets measured, gets managed" applies.

Q. HOW HAVE THE MARYLAND UTILITIES' RELIABILITY PERFORMANCE LEVELS IMPROVED?

A. Maryland utility reliability has held constant or improved since the standards and reporting requirements were implemented,[106] as presented in Figure 10. Maryland utility reliability has bucked the trend of deteriorating reliability exhibited by U.S. investor-owned utilities in recent years (See Figure 2), *and at a reasonable cost*. (No significant reliability improvement investment plans were implemented by Maryland utilities from 2013 to 2020.) If the Georgia Commission wishes to focus on improving reliability in a cost-effective manner, it might want to consider a similar type of effort. However, such efforts will not reduce the requirement to complete cost-benefit analyses on any reliability-related investments Georgia Power might propose.

[106] Data submitted by Maryland investor-owned utilities to the Energy Information Administration on Form 861.

Figure 10: Maryland reliability performance of investor-owned utilities 2013-2020.



10. DIP recommendations for the Commission's consideration.

Q. PLEASE SUMMARIZE YOUR DIP RECOMMENDATIONS FOR THE COMMISSION.

A. Our primary recommendation is for the Commission to reject the circuit hardening and undergrounding components of Georgia Power's distribution investment plan. The rejected amounts are presented below, and reflected in the revenue requirement adjustments detailed in the Smith/Trokey testimony and exhibits.

Table 6: Summary of distribution capital request and recommended rejections.

($ in millions)	2009-2019 Actual Average	2023	2024	2025	2023-2025 Average
Distribution Capital Requested		[redacted]	[redacted]	[redacted]	[redacted]
Circuit Hardening		[redacted]	[redacted]	[redacted]	[redacted]
Undergrounding		[redacted]	[redacted]	[redacted]	[redacted]
Distribution Capital Remaining	473.3	[redacted]	[redacted]	[redacted]	[redacted]

In addition, we recommend the Commission secure at least three years' data on the reliability improvements delivered by DIP packages implemented to date before drawing any conclusions on package effectiveness. The Commission must take care to isolate the beneficial impacts of individual DIP packages from other packages implemented, and from vegetation management actions taken on the same circuits, as these will undoubtedly improve the results of any individual package.

For any remaining DIP program components the Commission does not reject, we strongly recommend that the Commission document Company projections for SAIDI and SAIFI in 2032, and that the Commission hold the Company accountable for securing those projected reliability improvements. We believe the Commission would be within its rights to disallow recovery of any costs that ultimately do not deliver the reliability improvements the Company projects it will secure from the remaining DIP. Commission approval of the Company's investment plans in advance minimizes risks to the Company of disallowances and removes incentives to cost-effectively improve reliability.

Finally, we recommend the Commission require formal policies, budgets, and annual performance reporting for the Company's vegetation management and worst performing circuit programs. The Commission may also wish to consider implementing a long-term effort dedicated to cost-effective reliability improvement, using the Maryland Commission's efforts as an example.

VI. THE LEVEL OF DISTRIBUTED ENERGY RESOURCES GEORGIA POWER MUST MANAGE DOES NOT WARRANT A $100 MILLION DERMS

Q. WHAT IS A DISTRIBUTED ENERGY RESOURCE MANAGMENT SYSTEM?

A. A distributed energy resource management system (DERMS) is a software package which can, when combined with data from and remote control of customer and field equipment, help a utility meet the challenges of increasing levels of distributed energy resources on its grid. Distributed energy resources (DERs) can consist of synchronous generators (meaning a spinning turbine, such as an industrial customer might own), or inverter-based generators and energy storage devices (PV solar panels and batteries, also known as asynchronous).

Q. WHAT "CHALLENGES" DO SYNCHRONOUS AND INVERTER-BASED DERS PRESENT TO UTILITIES?

A. Utilities typically describe four challenges DERs may present to grid operations. First, they are concerned that DER generation can "confuse" circuit breakers and other protective equipment, causing them not to operate when they should (leading to equipment damage), or causing them to operate when they should not (leading to service interruptions). Second, they are concerned that DERs will continue to put power onto the grid during a power outage (unintentional islanding), presenting a safety issue. Third, they are concerned that DERs can increase grid voltage levels above prescribed limits in localized areas. Fourth, they are concerned that DERs "mask" loads that utilities must be prepared to serve if the DERs on a circuit discontinue power delivery unexpectedly.

Q. ARE THESE CONCERNS WARRANTED?

A. To some extent, but every situation is different, and we believe utility concerns regarding DERs to be overblown generally. For example, synchronous (spinning turbine) DER are known to confuse circuit breakers and other protective equipment. However, inverter-based (asynchronous, meaning PV solar and battery) DER are not known to cause such confusion. Further, Georgia Power's interconnection standards require all DERs to follow IEEE 1547. IEEE 1547 requires all interconnected DERs be installed with a switch which disconnects the DER from the grid within seconds of a loss of grid power. This helps address unintentional islanding concerns. Switches also disconnect DER when voltage rises above prescribed limits, and switch "ride through" settings (which permit DER to remain connected until prescribed ranges of voltage or frequency disturbance are exceeded) can help ensure DERs do not disconnect unexpectedly. Finally, simply tracking the types and capacities of DER installed on a circuit can help a utility understand masked load levels.

One study modeled various combinations of PV Solar locations and penetration levels (the peak DER capacity on a circuit relative to the circuit's peak load) to determine PV Solar "tolerance" on 16 representative circuits. The model indicated that in more than two-thirds of cases, circuits tolerated PV Solar penetration of 90% or more relative to peak loads. The same study indicated that only 16% of circuits could not tolerate PV Solar penetration levels of 15% (a limit commonly applied to DER penetration by utilities with little DER accommodation experience).[107] All of these observations indicate that utility concerns over DER penetration generally, and PV Solar/battery penetration specifically, are overblown.

Q. DOES GEORGIA POWER HAVE SYSTEMS IN PLACE TODAY TO MANAGE DER ON ITS TRANSMISSION AND DISTRIBUTION GRIDS?

A. Yes. Georgia Power reports that it uses SCADA systems (supervisory control and data acquisition) to manage DER connected to its transmission and distribution grids today.[108]

[107] A. Hoke et al. *"Steady-State Analysis of Maximum Photovoltaic Penetration Levels on Typical Distribution Feeders."* IEEE Transactions on Sustainable Energy, vol. 4, no. 2, pp. 350-357, April 2013.

[108] Response to STF-WG-2-1 (a), (b), and (c).

Q. HAVE OTHER UTILITIES INSTALLED DERMS TO MANAGE DERS?

A. Very few utilities have installed DERMS, due largely to the low penetration of DER on most utilities' grids. Southern California Edison has installed a DERMS,[109] but its overall DER penetration is somewhat high at over 17% of system peak load.[110] Of note, Hawaiian Electric Company has not yet installed a DERMS[111] despite overall DER penetration on Oahu Island of almost 50% of system peak load.[112]

Q. WHAT IS THE DER PENETRATION AT GEORGIA POWER?

The Company reports having [redacted] MW of peak DER relative to 15,831 MW of system peak load,[113] for a system-wide DER penetration of [redacted]%. In addition, the 2022 Integrated Resource Plan approved by the Commission calls for as much as 200 MW of DER to be procured and up to 250 MW of DER to be installed under the Company's new DER Customer Program.[114] Even if these efforts are 100% subscribed, and even if all of this DER capacity is connected to the distribution grid (much will likely be connected to the transmission grid), it is highly unlikely DER capacity will exceed [redacted] MW, for a DER penetration of only [redacted]% at most, by 2025.

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109 Response to STF-WG-2-5.

110 *Southern California Edison's Grid Modernization Plan*. Stakeholder workshop presentation June 10, 2019, slide 9 (installed DER capacity forecast at 4,000 MW in 2020). System peak of 23,328 MW from Southern California Edison's 2020 Form 861 submission to the U.S. Energy Information Administration.

111 Hawaii Public Service Commission Docket No. 2019-0327. *Application of Hawaiian Electric Company Inc*. September 30, 2019. Figure 2, Page 12.

112 Hawaii Public Service Commission Docket No. 2019-0327. Hawaiian Electric Company response to CA-SIR-i(i). Forecast DER capacity, Oahu, 2021 = 532.1 MW. System Peak of 1,087 MW from Hawaiian Electric Company's 2020 Form 861 submission to the U.S. Energy Information Administration.

113 Georgia PSC Docket No. 44160. Trade Secret response to STF-WG-1-1(b). Columns T and V. System peak of 15,831 MW from Georgia Power's 2020 Form 861 submission to the U.S. Energy Information Administration.

114 Georgia PSC Docket No. 44160. Stipulation dated June 10, 2022. Page 6, paragraph 22 and page 9, paragraph 33.

Q. WHAT INCREMENTAL CAPABILITIES WILL DERMS OFFER THAT GEORGIA POWER DOES NOT HAVE TODAY?

A. The principal value propositions of a DERMS are 1) Tracking types and capacities of (large) DER installed on each circuit; and 2) Monitoring and controlling large customer DERs and relevant field equipment settings remotely.

Q. ARE THESE CAPABILITIES REQUIRED DURING THE RATE CASE PERIOD?

A. No. First, tracking the types and capacities of (large) DERs on each circuit is not a demanding task, particularly given the relatively small number of (large) DERs connected to the Company's distribution grid. Hawaiian Electric Company tracks these DER attributes through the use of an inexpensive Demand Response Management System.[115] Second, the SCADA systems the Company currently uses to manage DERs on the Company's transmission and distribution grids already offer the ability to monitor customer DERs and to disconnect them in an emergency.[116] (Emergency situations are the only ones in which we believe the Company should be able to exert control over customer DER absent written customer permission. Please see the testimony of Staff Witness Ms. Barber for more on Company control over customer-owned DER.) Third, while there is some merit to a capability to control field equipment settings remotely, we believe few field devices with remote communication and control capabilities have been installed, and note that linemen can be dispatched to modify equipment settings in any event. In short, the small incremental benefits and the low DER penetration likely during the rate case period simply do not justify the extremely high DERMS price tag.

Q. HOW MUCH CAPITAL INVESTMENT IS THE COMPANY REQUESTING TO INSTALL DERMS IN THIS RATE CASE?

[115] Hawaii Public Service Commission Docket No. 2019-0327. Application of Hawaiian Electric Company Inc. September 30, 2019. Figure 2, Page 12.

[116] Response to STF-WG-2-3.

A. Georgia Power is requesting $100 million to install DERMS in this rate case.[117] This amounts to at least [redacted] per MW of installed DER capacity ([redacted] at most) we expect will be installed on the Company's distribution grid by the end of the rate case period. Given that the cost to install DER capacity is likely around $1.8 million per MW,[118] the cost to implement DERMS is roughly equivalent to a minimum 6.7% cost premium on top of the costs the Company or its customers incur to install DERs. This represents a high level of overhead for very little benefit.

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE COMPANY'S PROPOSAL TO INSTALL DERMS?

A. Yes. If approved by the Commission, the Company proposes to depreciate its DERMS investment over five years.[119] For such an extensive system with significant capabilities, we believe DERMS constitutes a major software package. Any DERMS spending the Commission authorizes should be depreciated over 10 years, not five, consistent with a major software classification.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE COMPANY'S $100 MILLION REQUEST TO INSTALL A DERMS?

A. We recommend the Commission reject the Company's capital request to install DERMS in its entirety due to the small incremental benefits and relatively low DER penetration the Company expects on its grids by the end of the rate case period. The fact that the Company is successfully managing large DERs connected to the Company's grids today figures prominently into this recommendation. The Commission can always reconsider any capital requests to install DERMS the Company might make in the future as the number and

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[117] Response to STF-WG-1-1

[118] U.S. Energy Information Administration. "*Average U.S. Construction Costs for Solar Generation Continued to Fall in 2019*." Available via internet at https://www.eia.gov/todayinenergy/detail.php?id=48736. July 16, 2021.

[119] Trade Secret response to STF-WG-2-3.

capacity of large DERs on Company's grid increases. This recommendation is reflected in the revenue requirement reductions addressed in the Smith-Trokey testimony.

VII. SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR TESTMONY PROVIDING PERSPECTIVES ON T&D RATE INCREASES, RELIABILITY, AND INVESTMENTS/TIMING.

A. In the perspectives section we relayed that rate increases are bad for Georgia's businesses, consumers, and economy unless accompanied by reliability improvements of sufficient value to outweigh them. We characterized Georgia Power's Grid Investment Plan (GIP) as discretionary, citing as evidence 1) Georgia Power's reliability is about average relative to other investor-owned utilities; 2) customers are satisfied with current levels of reliability; and 3) customers are unwilling to pay much for reliability improvements. We described the exceptional electricity bill increases (estimated by Staff at over 40%) that are heading toward Georgia in the next rate case period, stemming largely from sources outside of Commission control. We also noted that the results of over $1 billion in GIP spending to date will not be known or measurable for a few more years. Finally, we observe that even if the Commission rejects the Company's proposed continuation of the GIP in its entirety (which we do not recommend), the proposed transmission and distribution capital spending that remains still constitutes a doubling of Georgia Power's average annual investment from 2009 to 2019 (pre-GIP). We conclude this section of testimony by calling into question the timing, necessity, and wisdom of continued GIP spending in the upcoming rate case period.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS REGARDING GEORGIA POWER'S TRANSMISSION INVESTMENT PLAN.

A. The transmission portion of the Company's GIP (which we call the Transmission Investment Plan, or TIP) consists entirely of premature equipment replacement, or what the Company calls "the replacement of aging transmission infrastructure". While laypersons are likely to perceive aging equipment replacement as reasonable and necessary, we exposed the replacement of equipment based on age as the wasteful and cost-ineffective practice that it is. We described the objective testing and inspection practices all utilities use to determine the appropriate times for equipment replacement, and how these practices plus "N-1" criterion (redundant design and operation) make service interruptions resulting from transmission equipment failure exceedingly rare. For example, using Georgia Power's own data, we calculated the likelihood that a substation power transformer will both fail *and* result in a service interruption at 45 in 10,000 per year. To summarize, the opportunity to improve reliability through preemptive equipment replacement is almost zero to begin with, making the extremely costly and wasteful practice unnecessary and unreasonable. We recommend the Commission reject the transmission portion of the GIP in its entirety as a result, which still leaves a [redacted] increase over historical spending levels in place.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS REGARDING GEORGIA POWER'S PROPOSED DISTRIBUTION INVESTMENT PLAN.

A. We began with a summary of the distribution portion of Georgia Power's GIP, which we refer to as the Distribution Investment Plan (DIP). We then critiqued the DIP, focusing on three problems: 1) The largest DIP investment packages by far, circuit hardening and undergrounding of overhead lines, are not cost-effective approaches to improving reliability; 2) The Company applies costly DIP investment packages to too many circuits which already demonstrate reasonably good reliability performance, further damaging the cost-effectiveness of the DIP; 3) The DIP ignores dramatically more cost-effective approaches to improving reliability, including vegetation management and worst-performing circuit programs; and 4) The DIP is causing premature retirements of distribution equipment operating safely and reliably, incurring large customer opportunity costs not otherwise being considered or accounted for.

We also explained that the Commission should ignore the Company's Customer Benefit Study, because that study is not a cost-benefit analysis of DIP packages, and therefore irrelevant to the task at hand (identifying the most cost-effective ways to improve reliability). We described our concern that the DIP is leading to premature equipment retirement, and our concerns regarding Georgia Power accountability for securing DIP-related reliability improvements. Finally, we summarized the Maryland Public Service Commission's efforts to secure reliability improvements from utilities in a cost-effective manner, and concluded with a recommendation that the Commission reject Georgia Power's requests for the circuit hardening and undergrounding capital components of the GIP in their entirety. We noted that the distribution capital budgets that remain still represent an increase of [redacted] over historical distribution capital spending pre-GIP, which should be more than enough to maintain and improve distribution reliability.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS REGARDING GEORGIA POWER'S $100 MILLION PROPOSAL TO IMPLEMENT A DISTRIBUTED ENERGY RESOURCE MANAGEMENT SYSTEM.

In this section of testimony we described the challenges of managing high levels of distributed energy resources. But we also explained why utility claims that these challenges are imminent are generally overblown. We described how utilities with high levels of DER are managing the challenges, in at least one case (Hawaiian Electric Co., with extremely high levels of DER) with no DERMS at all. We identify the systems Georgia Power has been using to manage DER to date, and can continue to use in the future. Finally, we supported our belief that even under the most aggressive growth scenarios, Georgia Power DER levels will remain relatively low through 2025 as compared to other utilities. We recommend this proposed spending be postponed until some future rate case, when the level of distributed energy resources on Georgia Power's grid provides sufficient justification for such a system.

Q. DO YOU HAVE ANY CONCLUDING REMARKS FOR COMMISSION CONSIDERATION?

A. Yes. As indicated in our perspectives Section of testimony, the Company's GIP spending is discretionary. However, the electric bill increases heading toward Georgia are unavoidable. Given our testimony on the cost-ineffectiveness of the transmission, circuit hardening, and undergrounding portions of the GIP, we are convinced these investments are not in the public interest. What's more, there is no reliability emergency, and no harm in measuring the results of $1 billion in GIP spending to date, before approving more of the same.

Finally, we believe the Commission should consider the positives of limiting T&D capital spending to "only" a doubling of pre-GIP levels. All businesses in Georgia other than regulated monopolies are required by market forces to restrain capital spending. The managers of these business face a constant challenge: how to deliver products and services the market wants for the least possible amount of capital. This forces them to restrict capital spending to only the most critical and immediate needs, and as a result, these businesses are putting their limited capital to its highest and best possible use. By rejecting some of the Company's proposed capital spending through the recommendations we suggest, the Commission will simply be requiring the same type of discipline from the Company's managers as other Georgia businesses must maintain. That is a very good thing. After all, utility regulation evolved as a way to replace the market forces lacking in authorized monopoly businesses.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Curriculum Vitae -- Paul J. Alvarez MM, NPDP

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Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement for Xcel Energy in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed conflicts between ratemaking and benefit maximization. Since 2012 Mr. Alvarez has led the Wired Group, a boutique consultancy serving consumer, business, and environmental advocates, and regulators in matters of distribution planning, investment, and performance measurement.

Appearances and Research Projects in Regulatory Proceedings

Evaluate Pacific Gas & Electric's 2023-2026 Multi-year Rate Plan. Panel testimony with Dennis Stephens on behalf of AARP. California PUC A.21-06-021. June 10, 2022.

Evaluate the Distribution Business Components of Georgia Power Company's Integrated Resource Plan. Panel testimony with Dennis Stephens on behalf of Public Interest Advocacy Staff. Georgia PSC 44160. May 6, 2022.

Evaluate Policy Issues and Precedents Associated with Oklahoma Gas & Electric Company's Grid Modernization Factor. Testimony on behalf of the Office of Attorney General in PUD 2021000164. April 27, 2022.

Evaluate Grid Modernization and Advanced Metering Proposals by Massachusetts Utilities. Panel testimonies with Dennis Stephens on behalf of the Office of Attorney General in D.P.U. 21-80, 21-81, and 21-82. January 19, 2022.

Evaluate Dominion's Grid Transformation Plan. Testimony on behalf of Appalachian Voices/Southern Environmental Law Center. Virginia SCC PUR-2021-00127. September 13, 2021.

Investigate Avista Utilities' Electric Distribution and Wildfire Spending, Plans, and Processes. Panel testimony with Dennis Stephens on behalf of Public Counsel. WUTC 200900. April 29, 2021.

Evaluate Kentucky Utilities/Louisville Gas & Electric's CPCN to Install Advanced Meters. Testimony on behalf of the Attorney General. Kentucky PSC 2020-00349/00350. March 5, 2021.

Examine Potomac Electric Power Company's Electric Distribution Spending and Plan. Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel. MD PSC 9655. March 3, 2021.

Determine If Customer Interest Is Served by Smart Meter Stipulation. Testimony before the Ohio PUC on behalf of the Office of Consumer Counsel. Ohio PUC 18-1875-EL-GRD. December 17, 2020.

Critique Public Service Electric & Gas Company's Smart Meter Deployment Plan. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Rate Counsel. NJ BPU EO18101115. Aug. 31, 2020.

Examine Oklahoma Gas and Electric's $800 million Grid Enhancement Plan. Testimony before the Oklahoma Corporations Commission on behalf of AARP. PUD 202000021. August 25, 2020.

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Critique of Investment in Traditional Meters (Equipped with AMR). Testimony before the New Hampshire Public Utilities Commission recommending rejection of cost recovery. DE 19-057. December 20, 2019.

Critique of Smart Meter Benefits Claimed by Puget Sound Energy. Testimony before the Washington Utility and Telecom Commission recommending rejection of cost recovery pending demonstration of benefits in excess of costs. UE-190529 and UG-190530. November 22, 2019.

Critique of Smart Meter Benefits Claimed by Rockland Electric Company. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Consumer Advocate recommending rejection of cost recovery pending demonstration of benefits in excess of costs. ER19050552. October 11, 2019.

Critique of Grid Improvement Plan Proposed by Indianapolis Power and Light. Testimony before the Indiana Utility Regulatory Commission recommending reductions in the size of the plan ($1.2 billion) based on benefit-cost analyses of plan components. Cause 45264. October 7, 2019.

Investigation into Distribution Planning Processes. Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

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Critique of Smart Meter Replacement Program Implied by Proposed Duke Energy Ohio Global Settlement Agreement. Testimony before the Public Utilities Commission of Ohio on behalf of the Office of Consumer Counsel. Numerous cases including 17-0032-EL-AIR. June 25, 2018.

Support for Considering Duke Energy Grid Modernization Investments in a Distinct Proceeding. Testimony before the North Carolina Utilities Commission on behalf of the Environmental Defense Fund. E-2 Sub 1142, October 18, 2017 and E-7 Sub 1146, January 19, 2018.

Evaluation of Southern California Edison's Request to Invest $2.3 Billion in its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network. A16-09-001. May 2, 2017.

Evaluation of Kentucky Utilities/Louisville Gas & Electric Smart Meter Deployment Plan. Testimony before the Kentucky Public Service Commission on behalf of the Kentucky Attorney General in 2016-00370/2016-00371. March 3, 2017. Also in 2018-00005 May 18, 2018

Evaluation of National Grid's Massachusetts Smart Meter Deployment Plan. Testimony before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General in 15-120. March 10, 2017. Also Unitil in 15-121 and Eversource in 15-122/123, March 10, 2017

Evaluation of Pacific Gas & Electric's Request to Invest $100 Million in Its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network, A15-09-001. April 29, 2016

Recommendations on Metropolitan Edison's Grid Modernization Plan. Testimony before the Pennsylvania Public Utilities Commission on behalf of the Environmental Defense Fund in R-2016-2547449. July 21, 2016.

Arguments to Consider Duke Energy's Smart Meter CPCN in the Context of a Rate Case. Testimony before the Kentucky Public Service Commission on behalf of the Attorney General in 2016-00152. July 18, 2016.

Evaluation of Westar Energy's Proposal To Mandate a Rate Specific to Distributed Generation-Owning Customers. Testimony before the Kansas Corporation Commission on Behalf of the Environmental Defense Fund, case 15-WSEE-115-RTS. July 9, 2015.

Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest. Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

Duke Energy Ohio Smart Grid Audit and Assessment. Primary research and report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

SmartGridCity™ Demonstration Project Evaluation Summary. Primary research and report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. October 21, 2011.

Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. Second edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 360 pages. 2018.

Noteworthy Publications

Utility Regulation Through Legislation: A Cautionary Tale for Legislators, Regulators, Stakeholders, and Utilities. With Sean Ericson and Dennis Stephens. Electricity Journal. Volume 34 (October, 2021).

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Carolina Customers. Whitepaper co-authored with Dennis Stephens for GridLab. January 31, 2019

Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Dennis Stephens for GridLab. October 5, 2018.

Measuring Distribution Performance? Benchmarking Warrants Your Attention. With Sean Ericson. Electricity Journal. Volume 31 (April, 2018), pages 1-6.

Busting Myths: Investor-Owned Utility Performance Can be Credibly Benchmarked. With Joel Leonard. Electricity Journal. Volume 30 (October, 2017), pages 45-48.

Price Cap Electric Ratemaking: Does it Merit Consideration? With Bill Steele. Electricity Journal. Volume 30, (October, 2017), pages 1-7.

Integrated Distribution Planning: An Idea Whose Time has Come. Public Utilities Fortnightly. November, 2014; also International Confederation of Energy Regulators Chronicle, 3rd Ed, March, 2015

Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January, 2012.

Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments. Public Utilities Fortnightly. December, 2009.

Notable Presentations

NASUCA Annual Meeting. *Reinventing Distribution Planning in New Hampshire.* With D. Maurice Kreis, Executive Director, Office of Consumer Advocate. San Antonio, TX. November 19, 2019.

National Council on Electricity Policy Annual Meeting. Trainer on the economics of distribution grid interoperability and standard compliance; Presentation on communication network economics. Austin, TX. Sept 10-12, 2019.

NASUCA Annual Meeting. *Grid Modernization: Basic Technical Challenges Advocates Should Assert.* Orlando, FL. November 13, 2018.

Illinois Commerce Commission, NextGrid Working Group 7. *Using Peer Comparisons in Distributor Performance Evaluation.* Workshop 3 Presentation. Chicago, IL. July 30, 2018.

NARUC Committee on Electricity. *Using Peer Comparisons in Distributor Performance Evaluation.* Smart Money in Grid Modernization Panel Presentation. Scottsdale, AZ. July 16, 2018.

Public Utilities Commission of Ohio, Power Forward Proceeding Phase 2. *Getting a Smart Grid for FREE.* Columbus, Ohio. July 26, 2017.

NASUCA Mid-Year Meeting. *Using Performance Benchmarking to Gain Leverage in an "Infrastructure Oriented" Environment.* Denver, CO. June 6, 2017.

NARUC Committee on Energy Resources and the Environment. *How big data can lead to better decisions for utilities, customers, and regulators***.** Washington DC. February 15, 2016.

National Conference of Regulatory Attorneys 2014 Annual Meeting. *Smart Grid Hype & Reality.* Columbus, Ohio. June 16, 2014.

NASUCA 2013 Annual Conference. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando, FL. November 18, 2013.

NARUC Subcommittee on Energy Resources and the Environment. *The Distributed Generation (R)Evolution.* Orlando, FL. November 17, 2013.

IEEE Power and Energy Society, ISGT 2013. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

Great Lakes Smart Grid Symposium. *What Smart Grid Deployment Evaluations are Telling Us*. Chicago. September 26, 2012.

Mid-Atlantic Distributed Resource Initiative. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012

DistribuTECH 2012. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25.

DistribuTECH 2012. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23.

NARUC Subcommittee on Electricity. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators*. St. Louis, MO. November 13, 2011.

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Toronto, Canada. January 23, 2011.

Teaching

Post-graduate Adjunct Professor. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

Guest Lecturer. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

Education

Master's Degree in Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Finance, Accounting, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Finance, Marketing.

Certifications

New Product Development Professional. Product Development and Management Association. 2007.

Curriculum Vitae – Dennis Stephens

Wired Group, PO Box 620756, Littleton, CO 80162 dstephens@wiredgroup.net 303.434.0957

Profile

Mr. Stephens has over 40 years' experience in electric and gas distribution grid planning, design, operations management, and asset management, and the innovative use of technology to assist with these functions. He spent his entire career at Xcel Energy and its subsidiary Public Service Company of Colorado, a distribution utility serving 1.5 million electric customers and 1.4 million gas customers. After a series of electrical and gas engineering and management roles of increasing responsibility, Mr. Stephens retired as the Director of Innovation and Smart Grid Investments for all of Xcel Energy's electric and gas distribution businesses in 2011. He now works for the Wired Group and its clients on a part-time basis.

Career History (all positions with Public Service Company of Colorado or its parent, Xcel Energy)

1976 -- Planning Engineer. Performed electric distribution system planning for Southeast Denver, Boulder, Front Range and Cheyenne divisions, including system protection, voltage support and distribution system design.

1983 – Senior Engineer, Electric Distribution Planning. Provided direction and guidance for junior engineers. Led special projects relating to electric distribution system reliability and design. Promoted to Supervisor of Electric Distribution Planning with a staff of 12 electrical engineers with responsibility for capacity and reliability planning.

1988 -- Manager of Operations, Colorado Front Range Division. Responsible for all electric and gas distribution operations, including a high-pressure gas system (engineering, operations, and construction).

1994 -- Manager of Operations & Maintenance Engineering, Southeast Denver. Managed the design of gas and electric distribution system replacements.

1997 -- Manager, Distribution Reliability Assessment, Xcel Energy South (CO, WY, TX, OK). Led an engineering team focused on electric distribution grid reliability and capacity.

1998 -- Director of Electric and Gas Operations, Southwest Denver Division. Responsible for all aspects of electric and gas engineering, operations, and construction in the Southwest Denver Division.

1999 -- Director of Operations, City and County of Denver Division. Responsible for all aspects of electric and gas engineering, operations, and construction for Division, including downtown Denver. Promoted to Director, New Construction of electric and gas systems for the entire metro area.

2001 -- Director Electric Distribution Asset Strategy, Xcel Energy. Developed and implemented asset management strategies for all electric distribution assets in Xcel Energy's 8-state service area.

2005 -- Director of Utility Innovations and Smart Grid Investments. Led Xcel Energy's Utility Innovations department, developing and implementing new technologies and business processes in multiple electric and gas distribution functional areas. Advanced the concept of an Intelligent Network at Xcel Energy, and led several aspects of the SmartGridCity® demonstration project in Boulder, Colorado. Department secured a national Edison Award for Innovation in 2006. Retired in 2011.

2016 – Senior Technical Consultant, Wired Group.

Noteworthy Projects

Smart Grid Solutions Development, 2010. Worked with several large solution providers to develop and implement technical distribution grid solutions and innovations, including IBM, ABB, and Siemens**.**

DER Integration Strategy and Roadmap Development, 2009. Established DER integration strategy and road-maps for Xcel Energy, including technology and capability roadmap for high DER penetration geographies in Boulder, Colorado.

SmartGridCity™ Project Development, 2008. Developed the technical foundations for the SmartGridCity project in Boulder, Colorado (46,000 customers).

Distribution Automation Design, 2007. Worked with ABB Corporation to design software to identify and locate failures in underground cable. The ABB Smart Analyzer™ was programmed with three traps to capture detailed information using Oscillography/Digital Fault Records (O/DFR).

Utility Innovations Program Development, 2006. Led the development of Xcel Energy's Utility Innovations program, for which Mr. Stephens' team receive a national Edison Award.

Distribution Asset Optimization Process, 2005. Taking advantage of SPL's Centricity Outage Management Program and Itron's Real Time Performance Management system (RTPM), developed a Distribution Asset Optimization process by mining AMI meter data and asset utilization information in the development of an enhanced asset loading forecasting process. The process took advantage of the systems' abilities to forecast sudden changes in usage patterns to take proactive mediation of equipment overloading.

Distribution Asset Optimization Software Development, 2004. Worked with Itron on the development of a Distribution Asset Optimization software program.

Fixed AMI Communications Network Development, 2003. Worked with Itron to pilot one of the first applications of a fixed wireless radio network to collect data from customer meters.

Electric Asset Management Strategy Development, 2002. Developed Xcel Energy's Electric Distribution Asset Management Strategy

Automated Switching System Deployment, 2001. Worked with S&C Electric Corporation to deploy its Intelliteam™ devices on Xcel Energy's distribution grid to reduce the number of customers impacted by an outage by isolate faults through automated switching routines.

High Pressure Gas Pipe Replacement Program, 1988. Initiated and managed the renewal and replacement of 26 miles of high pressure gas pipe, over a 5 year period, reducing the likelihood of seam failures as outlined in an "Alert Notice" issued by the Department of Transportation's Office of Pipeline Safety. Project roles included community engagement, government and regulator relations (PUC, DOT, EPA), and contractor management. Project completed 1 year ahead of schedule and 14% under budget.

Regulatory Appearances

Evaluate Pacific Gas & Electric's 2023-2026 Multi-year Rate Plan. Panel testimony with Paul Alvarez on behalf of AARP. California PUC A.21-06-021. June 10, 2022.

Evaluate the Distribution Business Components of Georgia Power Company's Integrated Resource Plan. Panel testimony with Paul J. Alvarez on behalf of Public Interest Advocacy Staff. Georgia PSC 44160. May 6, 2022.

Evaluate Oklahoma Gas & Electric Company Grid Modernization Spending and Plans. Testimony on behalf of the Office of Attorney General in PUD 202100164. April 27, 2022.

Evaluate Grid Modernization and Advanced Metering Proposals by Massachusetts Utilities. Panel testimonies with Paul J. Alvarez on behalf of the Office of Attorney General in D.P.U. 21-80, 21-81, and 21-82. January 19, 2022.

Dominion Grid Modernization Plan Review. Testimony on behalf of Appalachian Voices/Southern Environmental Law Center. PUR-2021-00127. September 13, 2021.

Avista Utilities' Electric Distribution and Wildfire Spending, Plans, and Processes. Panel testimony with Paul J. Alvarez on behalf of Public Counsel. WUTC 200900, 200901, and 200894. April 29, 2021.

Pepco's 2021-2023 Grid Investment and Plan. Panel testimony with Paul J. Alvarez on behalf of the Maryland Office of People's Counsel. MDPSC 9655. March 3, 2021

Baltimore Gas & Electric Company's 2021-2023 Grid Investment and Operations Plan. Panel testimony with Paul J. Alvarez on behalf of the Maryland Office of People's Counsel. MD PSC 9645. Aug 14, 2020.

Review of Maryland Utilities' 2019 Annual Performance Reports. Comments of the Office of People's Counsel. MD PSC 9353. June 8, 2020

Duke Energy Carolinas/Duke Energy Progress $2.3 billion Grid Improvement Plan. Testimony before the North Carolina Utilities Commission critiquing Duke Energy's Plan on behalf of a group of environmental and consumer advocates. NCUC E-7, Sub 1214 Feb 18, 2020 & E-2, Sub 1219 Mar 25, 2020.

Indianapolis Power and Light's proposed $1.2 billion Grid Improvement Plan. Testimony before the Indiana Utility Regulatory Commission on behalf of the City of Indianapolis critiquing Indianapolis Power and Light's proposed $1.2 billion Grid Improvement Plan. Cause 45264. October 7, 2019.

Investigation into Distribution Planning Processes. Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

New Hampshire Public Utilities Commission Distribution Planning/Grid Modernization Proceeding. Comments in IR 15-296 describing a transparent, stakeholder-engaged distribution planning process.

Pacific Gas and Electric 2019 General Rate Case. Testimony in A.18-12-009 on behalf of TURN related to $270 million in proposed "Integrated Grid Platform" investments.

Southern California Edison 2017 General Rate Case. Testimony in A.16-09-001 on behalf of TURN related to $2.3 billion in proposed grid modernization investments.

Pacific Gas and Electric 2016 General Rate Case. Testimony in A.15-09-001 on behalf of related to $100 million in proposed grid modernization investments.

Notable Publications and Presentations

Utility Regulation Through Legislation: A Cautionary Tale for Legislators, Regulators, Stakeholders, and Utilities. With Paul Alvarez and Sean Ericson. Electricity Journal. Volume 34 (October, 2021).

Florida Storm Protection Plans: A Bonanza for Utilities, A Bust for Consumers and the State. Whitepaper co-authored with Paul J. Alvarez for AARP-Florida. October 5, 2020.

Challenging Utility Grid Modernization Proposals. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. Part 1, August, 2020, pages 59-62; Part 2 to be published September, 2020.

The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Paul Alvarez & Sean Ericson. Accepted for publication by Public Utilities Fortnightly. Anticipated publication June, 2019.

Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. Whitepaper co-authored with Paul Alvarez for GridLab. January 31, 2019

Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Paul Alvarez for GridLab. October 5, 2018.

DistribuTECH 2010, Tampa, Florida. "Realizing the Benefits of DER, DG and DR in the Context of Smart Grid"

OSI 2008 User's Conference, Denver, Colorado; DistribuTECH 2007, San Diego, California. "Smart Grid City: A blueprint for a connected, intelligent grid community"

ABB 2007 World Conference, Jacksonville, Florida. "Use of Distribution Automation Systems to identify Underground Cable Failure"

North American T&D Conference 2005, Toronto, Canada; Itron 2005 User Conference, Boca Raton, Florida. "Xcel Energy Utility Innovations and Distribution Asset Optimization"

DistribuTECH 2005, San Diego, California. "How Advanced Metering Technology is Driving Innovation at Xcel Energy"

Education

Bachelor of Science Degree in Electrical Engineering, 1975, University of Missouri at Rolla.

Awards

Led Xcel Energy team that received a National Edison Award for Utility Innovations, 2006.

A Customer Benefit Study of Distribution Investment for the Georgia Power Company System

August 2022

EXECUTIVE SUMMARY

Electric utility customers expect and depend on high levels of service reliability at a reasonable cost. As such, when developing a reliability improvement plan, a diligent utility must carefully evaluate the costs and benefits that accrue to customers under such a plan. The purpose of this Distribution Investment Study for the Georgia Power Company ("GPC") system is to determine the range of investment in GPC's distribution system that is optimal from a customer perspective.

This study is an updated version of the Economic Benefit Analysis completed in 2019 and reviews a revised Distribution Investment Plan that reflects lessons learned over the last 3 years. This study analyzes the best set of investments to be made under the Grid Investment Plan starting in 2023. This study concludes that the revised 8-year investment plan in the amount of ~$3.4B is within the optimal range of investment.

As background, GPC conducted an Economic Benefit Analysis on its original Distribution Investment Plan in 2019 to ensure that the plan was within the optimal range of investment from a customer perspective. The original plan was a ~$4.9B, 11-year plan that sought to improve approximately 800 of GPC's worst-performing distribution feeder circuits (also referred to as "circuits") with a target end-state SAIDI of ~65 by 2031 (also referred to as "Original Plan").

GPC has updated the Original Plan based on lessons learned through the execution of the plan over the last 3 years. Changes from the Original Plan are primarily driven by:

(1) Revised investment criteria, which select circuits with sustained poor performance.

(2) Increased capital requirements by investment package due to increases in the scope and cost of work required to achieve expected reliability improvements.

(3) A refined optimization methodology which relaxes the investment package hierarchy used in 2019 and allows for a larger set of possible investments to be evaluated when determining the optimal set of investments for a given scenario.

The revised plan (also referred to as "Distribution Investment Plan" or "the Plan") is expected to invest ~$3.4B over the remaining 8 years and achieve an end-state overall company SAIDI of ~80 by 2031. By targeting GPC's worst-performing circuits, the plan strives to equalize the customer experience and improve overall company reliability.

To create the Distribution Investment Plan, 15 alternate investment plans were constructed targeting end-state system reliability scores ranging from ~155 SAIDI to ~30 SAIDI. The plan that resulted in the lowest total cost to the customer under the most sensible set of assumptions was selected as the go-forward Distribution Investment Plan (also referred to as the "Base Case").

Plans targeting end-state SAIDIs lower than ~80 represent higher levels of investment than the Base Case. Plans targeting end-state SAIDIs higher than ~80 represent lower levels of investment than the Base Case. The "No Incremental-Investment" plan represents a scenario in which GPC does not invest any incremental capital in its distribution system above historical levels, leading to a forecasted decline in GPC reliability and an end-state SAIDI of ~155 by 2031. See III.A for further discussion of investment scenarios.

Consistent with findings from the Original Plan, the Base Case shows that higher levels of investment result in diminishing reliability improvement (see Figure 1). This is because circuits with the poorest reliability that represent the highest improvement opportunities are invested in first. Increasing capital investment means investing in circuits with relatively better reliability that represent lower improvement opportunities.

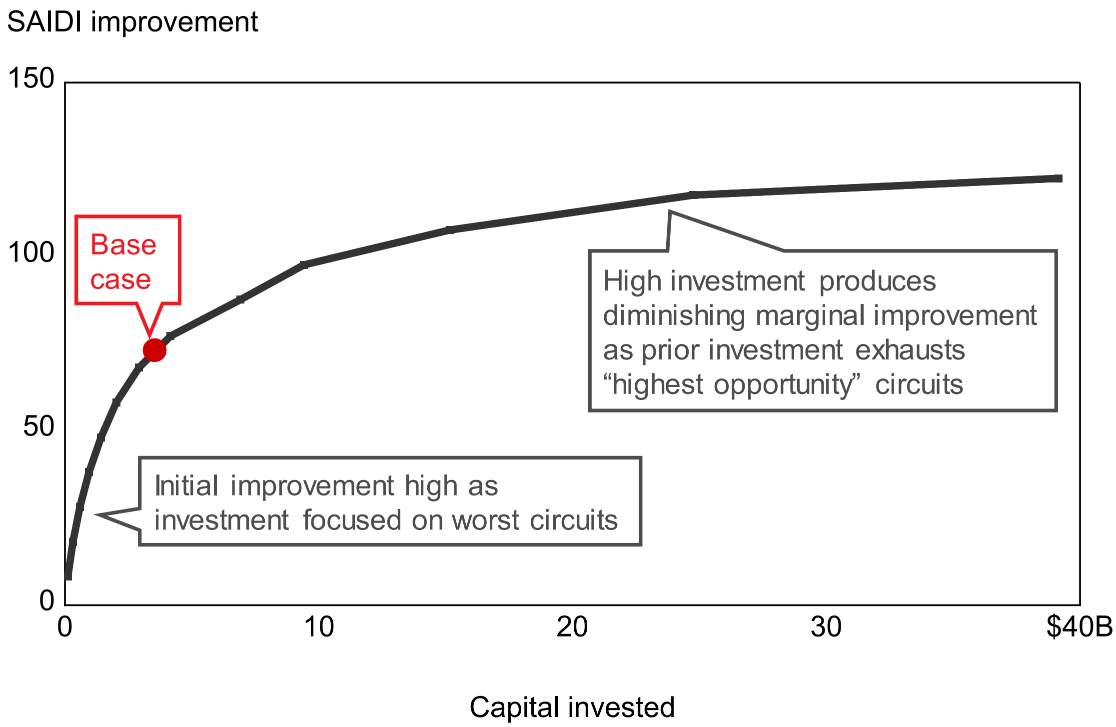

Figure 1. Diminishing Reliability Improvement

As illustrated in Figure 1, incremental customer benefit from distribution investment levels off after a certain amount of spending. The Base Case plan corresponds to the level of investment that includes the highest opportunity investments but excludes investments that produce diminishing returns. See III.B for further discussion of diminishing reliability improvement.

To evaluate the Distribution Investment Plan from the customers’ perspective, the present values of three types of costs were evaluated for each scenario. These include:

- **Capital Revenue Requirement:** Capital revenue requirement refers to the direct monetary cost customers incur as a result of GPC’s capital investment. On a present value basis this is equal to the amount of capital GPC is required to spend under each scenario multiplied by GPC’s distribution capital k-factor of [redacted][120]. See I.N for further discussion of capital revenue requirement assumptions and calculations.

[120] GPC’s k-factor is used to convert GPC’s capital investment into a present value of revenue requirements to customers.

- **Economic Cost:** Economic cost refers to the implicit costs customers incur as a result of outages. For the purposes of this study, economic cost strictly refers to the costs customers incur as a result of distribution outages in each scenario. See I.O for further discussion of economic cost assumptions and calculations.
- **Operations and Maintenance Expense ("O&M"):** In this study, O&M refers to outage repair-related and vegetation management O&M. Only these pieces of O&M are included, as investment in GPC's distribution system will not impact other components of O&M. See I.P for further discussion of O&M assumptions and calculations.

Because all of these costs are explicitly or implicitly borne by customers, an investment plan that minimizes the sum of these costs is considered to be within the optimal range of investment.

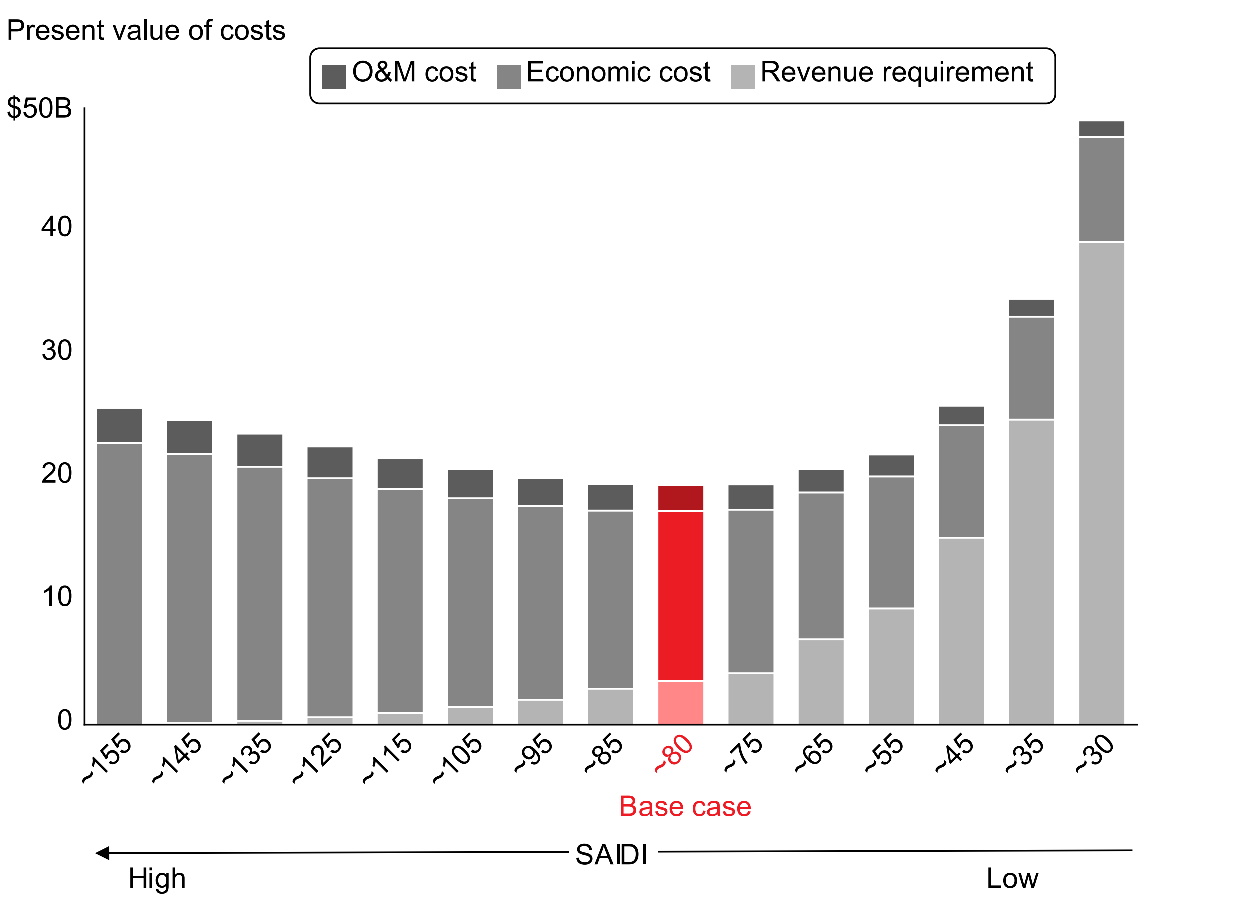

Figure 2. Present Value of Total Cost

Figure 2 demonstrates the total of these three costs (capital revenue requirement, economic cost, O&M) for each scenario. Moving from left to right along the chart's x-axis, capital revenue requirements increase as more aggressive reliability targets are achieved, while both economic costs and O&M costs decrease. Of the 15 scenarios evaluated, the Base Case scenario results in the minimum present value of costs and should thus be seen as the preferred option for customers.

Minimizing the present value of total customer cost is equivalent to maximizing the net present value of investment.

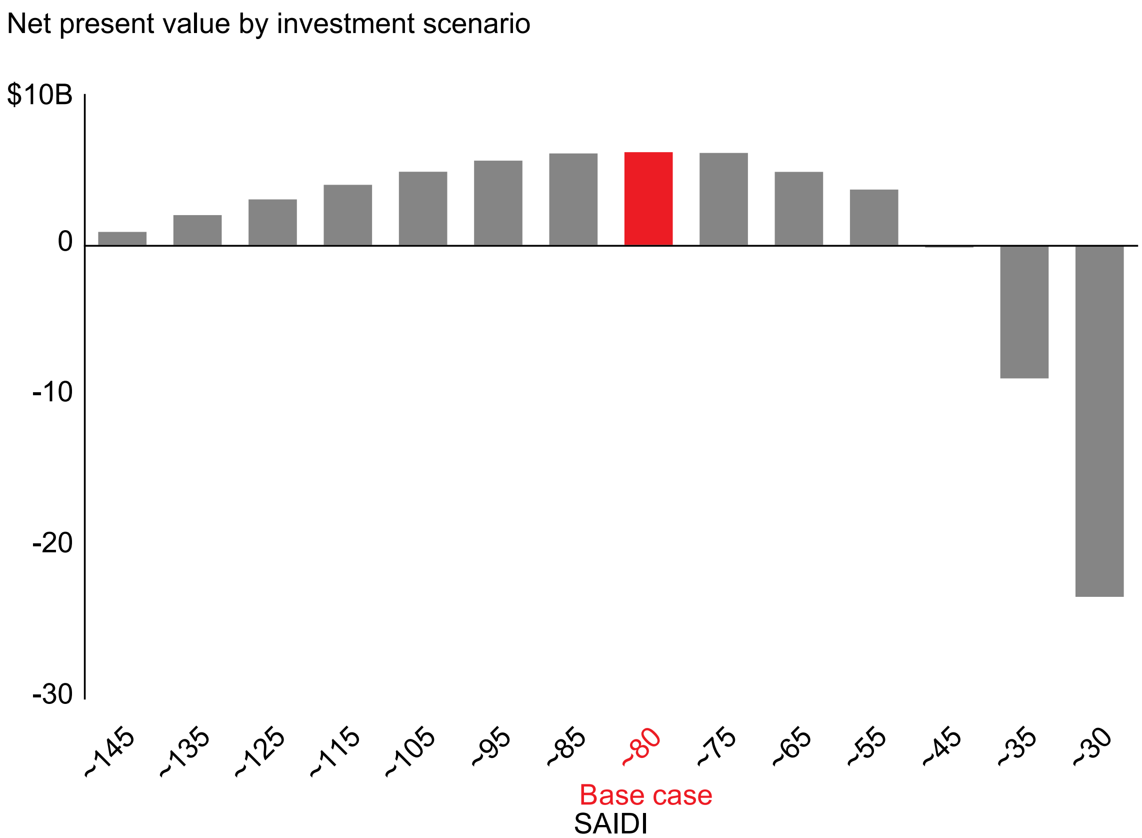

Figure 3. Net Present Value

Figure 3 shows the net present value ("NPV") of customer costs for each scenario. The NPV for any given scenario (for example, scenario "S") is calculated by taking the difference between the

No Incremental-Investment scenario's present value of costs and scenario S's present value of costs. The Base Case scenario has the highest associated NPV of all scenarios and therefore creates more customer value than any other scenario analyzed. See Section III for a further discussion of scenario cost calculation.

In addition, seven sensitivity analyses on key inputs to the model were conducted. While these sensitivities result in increases or decreases to the overall costs incurred by customers under each scenario, the Base Case plan remains in the optimal range of investment across all sensitivities. As an example, Figure 4 shows a sensitivity on this study's capital investment cost assumptions. To capture potential deviations from current investment cost estimates, cost assumptions were flexed up and down 10% to determine the impact on the optimal investment range. As shown in figure 4, the Base Case has the lowest total cost using both the 90% and 110% assumptions and therefore remains in the optimal range of investment under both assumptions. See Section IV for a further discussion of sensitivity analyses.

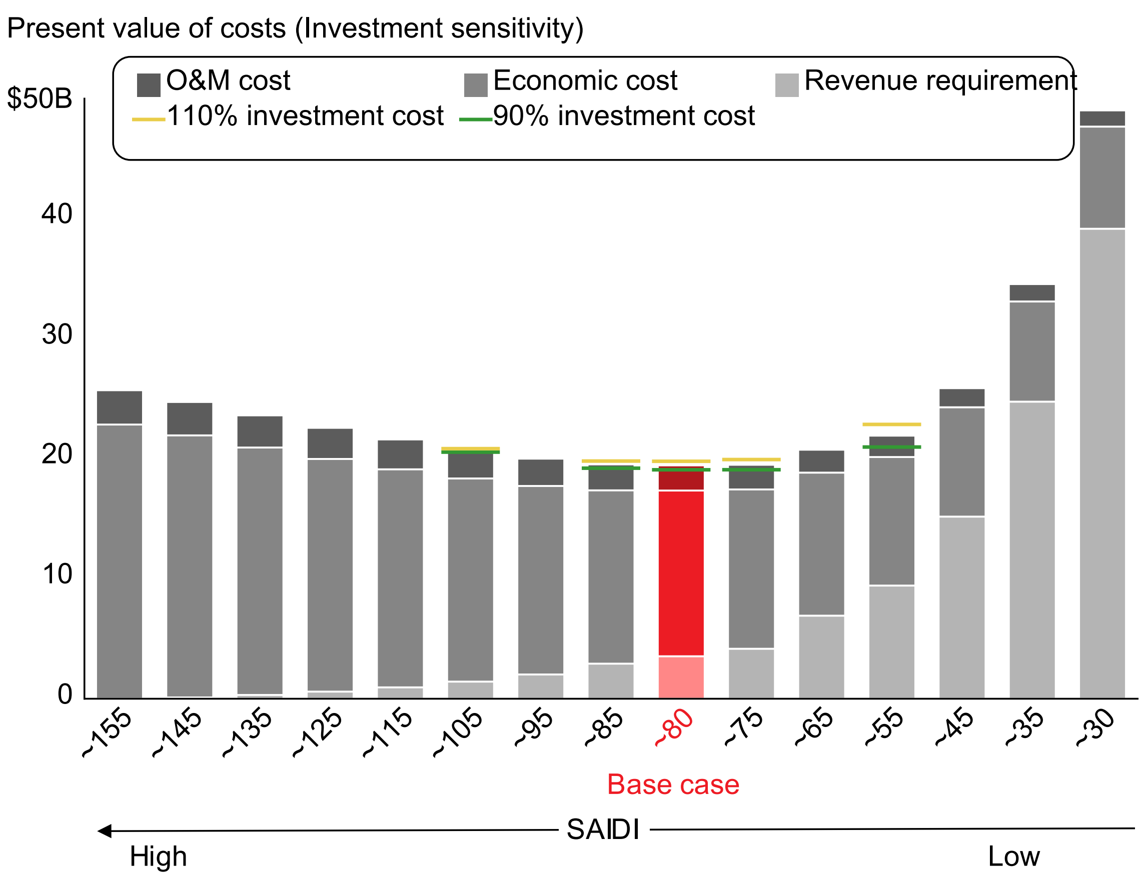

Figure 4. Investment Cost Sensitivity

Because the Distribution Investment Plan remains in the optimal range across all sensitivities, the Base Case investment plan should be considered the preferred option for GPC customers.

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I. ASSUMPTIONS

The following sections of this report provide detailed discussions related to the input assumptions associated with the 2022 Distribution Investment Plan.

Explanation of Investment Packages

The Distribution Investment Plan assumes that GPC distribution circuits can receive any one (or multiple) of 6 different "investment packages." The menu of circuit investment packages was developed by GPC distribution engineers based on prior investments that GPC has successfully implemented in its distribution system. Packages are listed in Table I.1 below:

Table I. 1. Description of Investment Packages

Number	Name	Description
1	Add sectionalizing, DA devices	• Install additional intelligent line devices on overhead line to achieve segmentation
2	Add / strengthen ties	For circuits without a tie: • Add new tie(s) to other circuit(s) For circuits with existing tie(s): • Increase capacity of tie points that offer increased ability to restore load • In some cases, create a new tie on a radial branch of the circuit
3	Circuit hardening (BIL)	• Replace wooden and steel pole arms with fiberglass brackets • Add wildlife protective equipment
4	Break feeder	• Introduce a new source (e.g., new breaker at existing substation) to split an existing circuit into two smaller circuits while applying segmentation

5	Relocate feeder; bring to road	• Identify inaccessible lines and rebuild on private property along accessible roadway
6	Underground the feeder	• Underground 100% of multiphase overhead lines

Criteria for Package Investment

To determine which (if any) investment package(s) should be applied to each circuit, specific criteria are set for each package. Criteria for each package are chosen to tailor package choice to each circuit based on that circuit's specific characteristics. A circuit must meet ALL criteria thresholds in order to qualify for an investment package. The criteria thresholds used in the Base Case scenario are listed below in Table I.2:

Table I. 2. List of Package Investment Criteria

Number	Name	Criteria for Investment
1	Add sectionalizing, DA devices	[redacted]
2	Add / strengthen ties	[redacted]

3	Circuit hardening (BIL)	[redacted] [redacted] [redacted]
4	Break feeder	[redacted] [redacted] [redacted] [redacted]
5	Relocate feeder; bring to road	[redacted] [redacted] [redacted] [redacted] [redacted]
6	Underground the feeder	[redacted] [redacted] [redacted] [redacted]

The criteria above were determined in collaboration with GPC distribution engineers and subject matter experts to isolate circuits with “systemic issues” that are in most need of investment and most likely to experience further reliability decline in the absence of investment. For the purposes of this study, circuits with “systemic issues” are those with poor reliability stemming from topographical conditions (e.g., vegetation growth), unaddressed customer or load growth, or legacy design specifications. The criteria above have been updated slightly from 2019 based on lessons learned over the last 3 years. A key difference from the Original Plan is the transition to utilizing 5 years of reliability data to determine which circuits qualify for investment. Utilizing the average reliability performance across 5 years allows GPC to better identify circuits with consistently poor reliability.

Data from ~2300 distribution circuits were analyzed against these criteria to determine if circuits were ‘qualified’ for each investment package. In many cases, circuits qualify for just a single investment package. In cases where a circuit qualifies for multiple packages, the following logic is applied to determine the set of investments the model can select from:

[redacted]

[redacted]

[redacted]

After all qualified investment packages are identified, the model evaluates combinations of potential investments to determine the optimal subset of investments to achieve the lowest total cost to the customer for a given SAIDI (details on the selection approach are described in section I.F below).

Each subset of investments selected represents a single scenario and each scenario is identified by the end-state SAIDI achieved. As part of this study, 15 scenarios were ultimately created for SAIDIs ranging from ~155 to ~30.

To create investment scenarios with SAIDIs below 60, certain of the above criteria are flexed to be more permissive, allowing more circuits to qualify for, and receive, investment. This change in criteria is necessary to reach the lowest SAIDIs.

Package Investment Cost Drivers

Estimated capital required for each circuit investment is determined based on the cost driver(s) of the package(s) the circuit receives. Cost drivers and unit costs for each package were determined by GPC engineers based on analysis of test projects and were then updated based on the first 3 years of implementation experience. In addition, over the last three years, the Company has determined that additional work is required to complete certain investments. Therefore, a scope multiplier has been added to the sectionalizing, circuit hardening, and undergrounding investments. See Table I.3 for the list of drivers, scope multipliers, and unit costs.

Table I. 3. List of Package Cost Drivers and Unit Costs

Number	Name	Driver	Unit Cost
1	Add sectionalizing, DA devices	[redacted]	
2	Add / strengthen ties		
3	Circuit hardening (BIL)		
4	Break feeder		
5	Relocate feeder; bring to road		
6	Underground the feeder		

Expected Investment Package Reliability Benefit

Expected SAIDI and SAIFI improvement for each circuit receiving an investment is determined based on the package(s) it receives. Expected SAIDI and SAIFI improvements for each package are based on past GPC projects.[121] While initial investments from the first 3 years of the Grid Investment Plan have resulted in positive reliability benefits, GPC has not updated the expected benefits due to the small sample size of investments that have been completed for a full calendar year and desire to remain conservative in estimating potential benefits.

The scope of the Distribution Investment Study only extends to forecasting SAIDI and SAIFI values scrubbed of major weather events for each circuit. See Table I.4 for a list of expected package reliability improvements.

Table I. 4. Estimated Reliability Improvements for Package Investment

Number	Name	SAIDI Reduction	SAIFI Reduction
1	Add sectionalizing, DA devices	[redacted]	
2	Add / strengthen ties		
3	Circuit hardening (BIL)		
4	Break feeder		
5	Relocate feeder; bring to road		
6	Underground the feeder		

121 [redacted]

Expected Package Investment Benefit Length

All package benefits are forecasted to last 25 years past the investment period of 2020 to 2030 (i.e., to 2055). This reflects a conservative estimate of the average useful life of package improvements[122] and is in line with historical GPC experience.

Investment Selection

Once it is determined which package(s) a circuit qualifies for, a projection for the cost and benefit of each possible investment occurring in each possible year is made in the optimization model. An optimization model then evaluates possible combinations of investments to determine which subset of investments generates the greatest benefits for the customer (in terms of reduced O&M and reduced economic cost of outages) for each invested dollar. The optimal subset of investments selected produces the lowest total cost to the customer for a given SAIDI score.

Using this approach, 15 different scenarios were created, each targeting an end-state system reliability score ranging from ~155 SAIDI to ~30 SAIDI. The 15 scenarios were compared to determine which scenario produced the lowest overall total cost to the customer. This overall lowest total cost to the customer scenario corresponds to the Base Case and go-forward Distribution Investment Plan.

Investment Sequencing

Circuit investments are sequenced for execution over the remaining 8-year investment horizon (2023-2030). Exact investment sequencing is determined based on several factors:

- **Annual spend:** Fluctuation in annual overhead and underground investment cost is minimized from year to year as spikes in either overhead or underground spend and labor requirements would be difficult to manage from an operational and supply chain perspective.
- **Region-by-region approach:** The region by region sequencing established in 2019 was maintained with 2 exceptions: The South region was shifted forward 1 position to start in advance of the West region and the Northeast region was shifted forward 1 position to start in advance of the Metro North region. These switches were made in order to balance the amount of overhead and underground spend and labor required from year

[122] Brown (2009) states underground and overhead T&D infrastructure have 40 and 60 year lifespans, respectively. See section IV.E for a sensitivity analysis on this assumption.

to year given the new set of investments selected for the revised Distribution Plan. In keeping with the 2019 plan, all circuits selected for investment in a particular region are addressed in sequence, such that once investment in a region begins, that region is invested in every year until investment in that region is completed.

- **Annual regional spend:** Year over year fluctuation in total investment per region is minimized to ensure that no one region is oversaturated with investment in one particular year, as concentrated construction may pose operational difficulties and negatively impact customer experience.
- **Circuit ordering:** Within the constraints described above, circuits in each region which present the worst reliability are prioritized for investment. In order to minimize travel, disruption, and switching costs, investments within a single substation were grouped where possible.

Reliability Decline

Without continued maintenance or investment, certain circuits are expected to experience reliability decline over the long term[123]. To reflect this, the roughly 1000 circuits identified as having systemic issues (as discussed in I.B) and hence qualifying for investment are projected to experience a modest yearly reliability decline across the investment period[124] or until invested in.

[123] Because of the multitude of factors impacting circuit reliability in a given year (e.g., weather, traffic incidents, wildlife incidents) reliability cannot be forecasted accurately on a yearly basis. That said, over a longer period (e.g., 10 years) reliability can be expected to follow a forecasted trend.

[124] Note that reliability decline is capped after the investment benefit period.

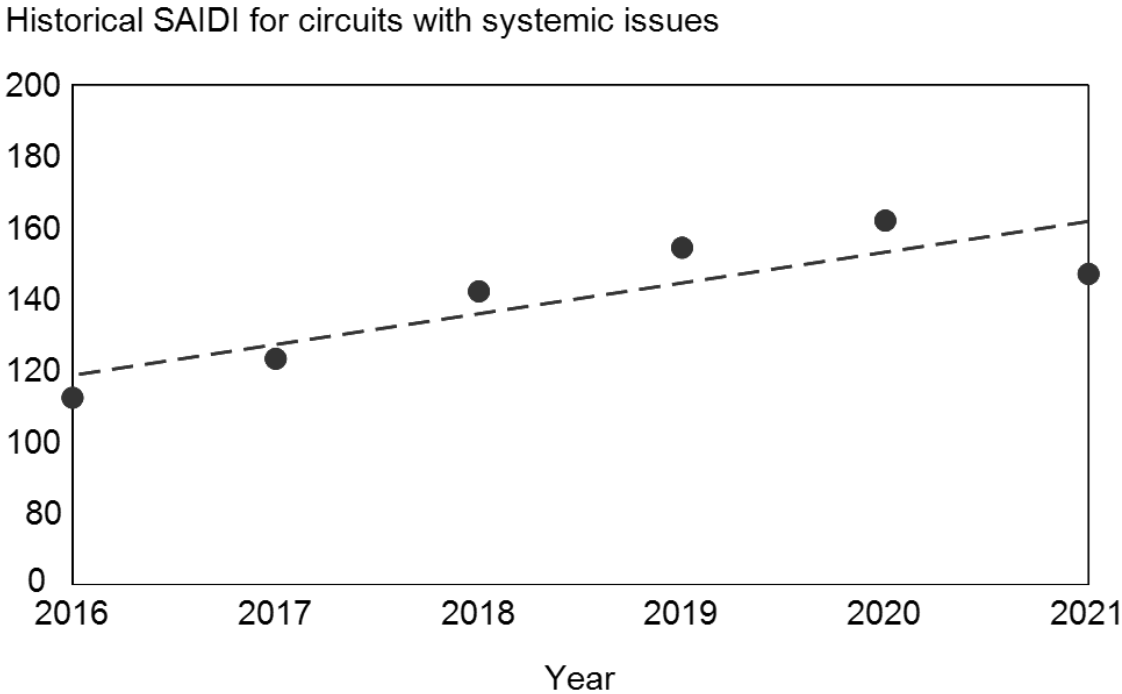

Figure I. 1. Historical SAIDI of Circuits with Systemic Issues

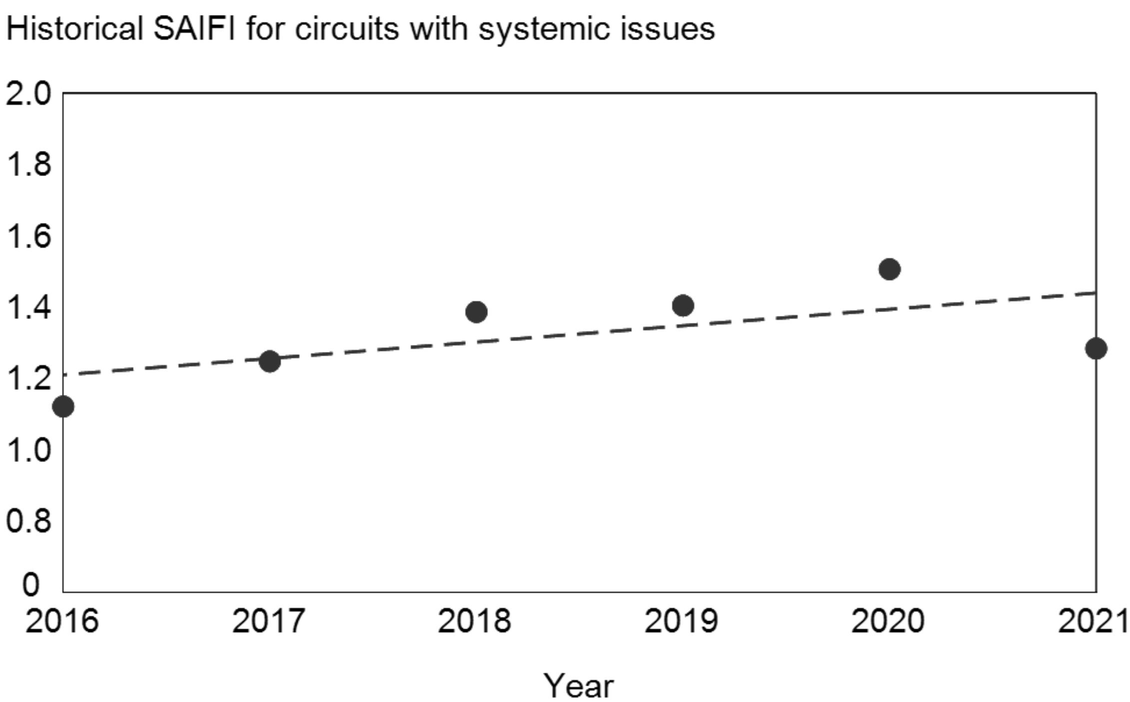

Figure I. 2. Historical SAIFI of Circuits with Systemic Issues

Figures I. 1 and I. 2 show the historical SAIDI and SAIFI, respectively, of roughly 1000 circuits identified as having systemic issues. Within the last six years, these circuits have experienced an average of ~6% SAIDI and ~3% SAIFI increase per year. To be conservative, SAIDI is projected to decline 4% for these circuits. SAIFI is projected to decline at 3%, in line with historical trends and the previous study.

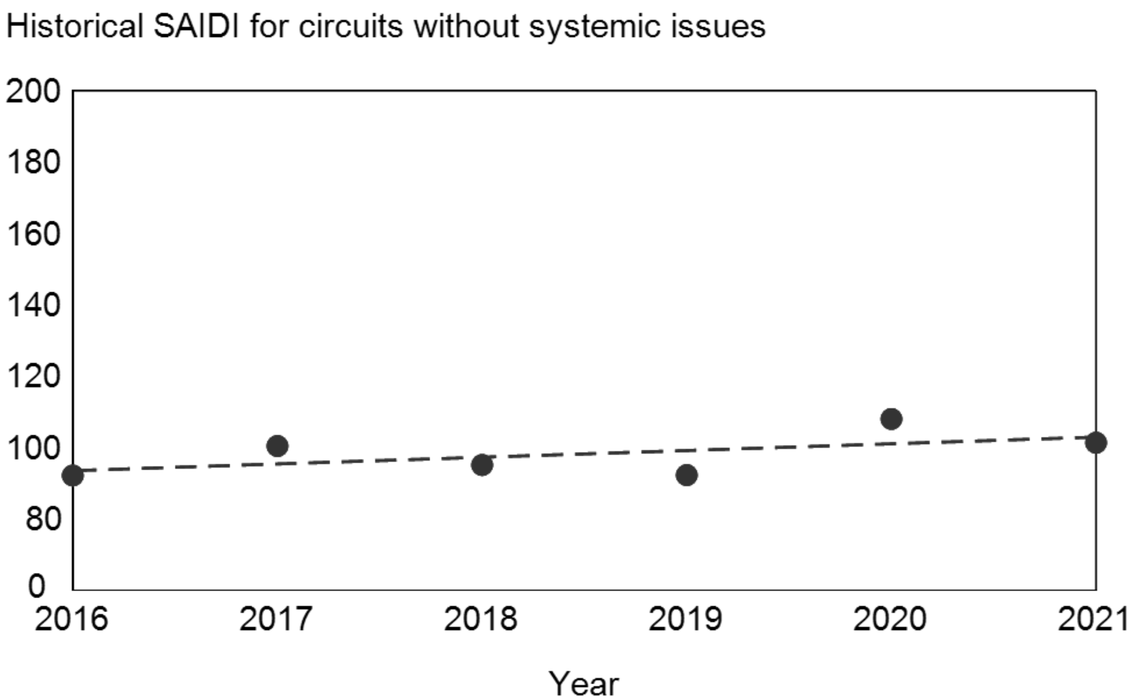

Figure I. 3. Historical SAIDI of Circuits without Systemic Issues

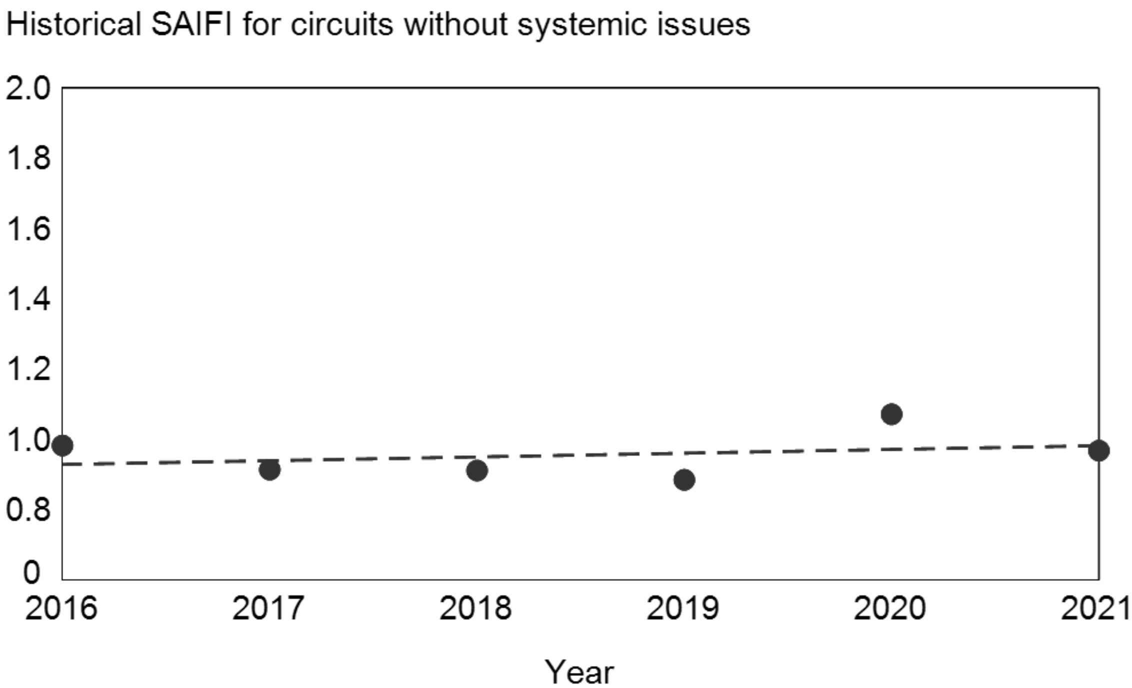

Figure I. 4. Historical SAIFI of Circuits without Systemic Issues

Figures I. 3 and I. 4 show the historical SAIDI and SAIFI trends, respectively, of the remaining ~1300 GPC circuits that were not identified as having systemic issues. In the last six years, reliability for these circuits has been flat to improving. As such, this study assumes each of these circuits will experience no reliability increases or decreases over the course of the investment period and these circuits do not qualify for investment as part of the GIP.

Package Investment Benefit Timing

To reflect variations in the timing of circuit investment completions, for packages 1-5, only 1/3 of expected reliability benefit is realized during investment. The remaining 2/3 of benefit is realized in the year following completion.

For package 6 specifically, as no benefit can be realized until investment is complete and customers transitioned to the new line, no benefit is realized during investment. Instead, 100% of the reliability benefit is achieved in the year following completion.

Population Growth

GPC's customer base is assumed to grow at an annual rate of [redacted]% between 2023 and 2055, based on GPC subject matter expert projections.

System Load Growth

Customer power usage (measured in MWh) is assumed to decline at an annual rate of [redacted]% between 2023 and the end of the investment period, based on GPC subject matter expert projections.

Weighted Average Cost of Capital

GPC's corporate WACC (Weighted Average Cost of Capital) of [redacted]% is used for all discounting.

Historical Inflation Rate

An inflation rate of [redacted]% is used to correct historical dollar figures to 2022 values, to discount projected costs, and to estimate expected investment cost increases over time. This figure is used for consistency with other GPC studies and reports[125].

Capital Revenue Requirement

Capital revenue requirement refers to the direct monetary cost customers incur as a result of GPC's capital investment on a present value basis. This is equal to the amount of capital GPC is required to spend under each scenario multiplied by GPC's distribution capital k-factor of [redacted][126].

Investment values in each year are multiplied by GPC's distribution capital k-factor of [redacted] to achieve a revenue requirement number for each year. Revenue requirement numbers for each year's expenditures are then discounted back to 2022 values to achieve the present value of capital revenue requirement for a given investment plan.

[redacted]

[126] GPC's k-factor is used to convert GPC's capital investment into a present value of revenue requirement to customers.

Economic Cost

Economic cost refers to the implicit costs customers incur as a result of outages. Economic costs in the utility setting are often measured in terms of willingness to pay to avoid an outage or lost production as a result of an outage. For the purposes of this study, economic cost strictly refers to the costs customers incur as a result of distribution outages[127] in each scenario.

To facilitate estimating the economic cost of outages, Freeman, Sullivan & Company conducted a Cost of Expected Unserved Energy (EUE) survey of GPC and Mississippi Power Company (MPC) in 2011. This survey was conducted among the following four customer classes:

- Residential
- Commercial (below 1 MW average demand)
- Industrial (below 1 MW average demand)
- Large Business (commercial and industrial customers above 1 MW average demand)

The cost of EUE (in 2022 dollars) for these four customer classes is shown in Table I. 5.

Table I. 5. Cost of Expected Unserved Energy by Customer Class*[128]*

Customer Class	Cost per Unserved KWh (2022)
Residential	[redacted]
Commercial	[redacted]
Industrial	[redacted]
Large Business	[redacted]

[127] A "distribution outage" is defined as an outage that originates on a distribution circuit (as opposed to originating from, for example, a transmission substation).

[128] Values are an average of summer and winter dollar amounts from the survey. Values are adjusted to 2022 dollars.

The yearly economic cost of distribution-related outages on a system level is calculated using the following formula:

*Economic cost for system = SAIDI * Average KWh Usage per Minute * Cost per Unserved KWh*

Where:
Economic cost for system = Nominal economic cost of unserved power for customers on the system;
SAIDI = System Average Interruption Duration Index in minutes;
Average KWh Usage per Minute = Amount of energy used in the average minute for customers on the system; and
Cost per Unserved KWh = weighted average EUE cost survey value for customers across the system

System nominal economic costs for each year are discounted back to 2022 dollars and summed together to calculate the present value of economic cost.

Implicit in these formulas is that system economic cost (a) declines as reliability of the system improves and (b) declines as system load decreases. Since package investment is sequenced across the investment period of 2023-2030 and full reliability benefit for each circuit is only realized after investments are completed, an investment plan targeting an end-state reliability figure will see a gradual improvement of economic cost until end-state reliability is reached in 2031.

Operations and Maintenance Expense Impacted by Investment

In this study, Operations and Maintenance Expense ("O&M") refers only to portions of GPC O&M that could be impacted by the circuit investments analyzed in this study. Specifically, this study forecasts two pieces of O&M:

- **Outage Repair-Related O&M:** Costs that are related to the restoration of power when outages occur. When reliability improves and the frequency and duration of outages decreases, these O&M costs are expected to decline.
- **Vegetation Management O&M:** Costs associated with the trimming of plant foliage and removal of trees adjacent to distribution lines and within GPC's right-of-way. Vegetation

management costs are incurred to ensure that plant foliage and trees do not interfere with overhead distribution circuits. For distribution circuits receiving package 6 (undergrounding) vegetation management is expected to decline.

These two pieces of O&M are assumed to grow or decline with the following:

- **Outage Repair-Related O&M:** Increases or decreases with SAIFI
- **Vegetation Management O&M:** Increases at historical CAGR of ~2.2%, decreases with proportion of overhead 2&3-phase line miles undergrounded

As such, outage repair-related O&M decreases with investment as system reliability improves. Vegetation management O&M also decreases to a lesser degree with investment as 2&3-phase line miles are undergrounded.

Outage repair-related O&M is projected using the prior year's system outage O&M spend, disaggregated to the circuit level based on a circuit's contribution to system level SAIFI. Vegetation management O&M is projected using a historical 3-year average[129] of system total vegetation spend, disaggregated to the circuit level based on a circuit's proportion of 2 and 3 phase overhead line miles.

As with capital revenue requirement and economic cost, O&M is forecasted out for each year in the investment period in nominal terms and then discounted back to 2022 dollars to obtain a present value of O&M.

Optimal Investment Range Determination

Customers directly or indirectly incur capital revenue requirement costs, O&M costs, and economic costs. As such, customers prefer investment plans that offer a lower present value of capital revenue requirement, O&M, and economic costs over plans that offer a higher present value of these costs. Thus, an investment plan that minimizes the present value of the sum of these three costs is considered optimal from the customer's perspective. Because only a finite number of investment plans can be tested, for the purposes of this study, the investment plan that minimizes the present value of costs is assumed to be in the optimal investment *range* (as opposed to the exact optimal investment plan).

[129] GPC uses a three-year vegetation management cycle for most circuits.

II. SIMULATION PROCEDURE

The following sections of this report provide detailed discussions related to the steps taken to generate each investment scenario and arrive at total costs (including capital revenue requirement costs, economic costs, and O&M costs) for that scenario.

A. Application of Investment Criteria and Selection of Investments

Circuit data are evaluated against investment criteria for each investment package (see Table I. 2 for a list of criteria and baseline values) to determine which investment package(s) each circuit qualifies for.

As described in I.F above, a projection is then created to determine the cost and benefit of undertaking every qualified investment using the cost drivers and benefit estimates described in I.C and I.D respectively. An optimization model then evaluates possible combinations of these investments to determine which subset produces the lowest total cost to the customer for a given SAIDI.

Sequencing of Investments

After investments are selected, circuits are sequenced according to the procedure outlined in I.G. This places each circuit investment into a specific investment year within the 2023-2030 investment window.

Forecasting Circuit Reliability

GPC circuit reliability scores are then projected out for each year in the investment horizon. The projection takes the following variables as inputs:

- 5-year average (2017-2021) SAIDI and SAIFI for each circuit
- For circuits that are part of the investment plan for the scenario in question: Selected package(s), timing of investment, and expected reliability improvement
- For circuits with systemic issues: Assumed reliability decline in the absence of, or until, investment

Forecasting Circuit CMI and Customer Interruptions[130]

By using the circuit-level forecasted reliability figures from II.C, customer counts for each circuit, and the GPC compound annual growth rate to forecast customer counts for each circuit for each year in the investment horizon, we forecast each circuit's CMI and customer interruptions for each year in the investment horizon.

Calculating Aggregate Reliability Scores

System-wide SAIDI is calculated by summing together each circuit's forecasted CMI and dividing by the projected number of GPC customers in each year. System-wide SAIFI is calculated by summing together each circuit's forecasted customer interruptions and dividing by the projected number of GPC customers in each year.

Forecasting Capital Revenue Requirement

Capital revenue requirement for each year is calculated by summing the investment costs of circuits that will be invested in a given year and multiplying by the k-factor of [redacted], as discussed in I.N.

Forecasting Economic Cost

The economic cost of outages across GPC for each year is determined by summing up the economic costs (calculated using methods described in I.O) of all distribution circuits.

Forecasting Operations and Maintenance Expense

Outage repair-related O&M is forecasted on an aggregate level for 2020-2031 in proportion to system SAIFI projections (see I.P).

Vegetation management O&M is forecasted at a circuit level using the 3-year average of spend. As mentioned (see I.P), vegetation management O&M increases at historical rates and decreases with the proportion of overhead 3-phase line miles undergrounded.

[130] Annual "customer interruptions" for a circuit is the sum of the number of customers impacted by an outage across each of a circuit's outages in a given year. Customer Interruptions = SAIFI * Total Number of Customers.

Discounting Projected Costs

Using GPC's WACC (see I.L) and the assumed inflation rate (see I.M), projected capital revenue requirement, economic cost of outages, and O&M for each year in the investment horizon are discounted back to 2022 dollars.

Calculating Terminal Value of Costs

Since benefits of investment are expected to last well beyond 2031 (see I.E), the present value of costs beyond the investment horizon is calculated using a bounded terminal value. Economic and O&M costs are estimated to continue to grow at a terminal growth rate equal to the estimated population growth (see I.J). Since traditional terminal value calculation assumes an infinite time horizon, a bounded terminal value is calculated using the following formula:

$$TV_{2033\text{-}2055} = TV_{2033} - TV_{2056}$$

Where:

$TV_{2033\text{-}2055}$ = Present value of costs from 2033 to 2055;

TV_{2033} = Present value of costs from 2033 onward; and

TV_{2056} = Present value of costs from 2056 onward

This figure is discounted back to 2022 dollars to calculate the present value of 2033-2055 economic and O&M costs.

Calculating Present Value of Costs

Summing the present value of 2023-2032 costs and 2033-2055 costs yields a total present value of costs for a given investment plan.

III. SCENARIO RESULTS

A. Summary of Scenarios and Selection of Base Case

For this analysis, 15 alternative investment scenarios were evaluated. Each scenario was created by determining the optimal subset of potential investments that delivers the lowest total cost to the customer for a given SAIDI score ranging from ~155 to ~30. The results of these scenarios were then compared to determine which of the scenarios produced the overall lowest total cost to the customer. This scenario was then selected as the 'Base Case'.

Under the Base Case, roughly 870 circuits are marked for investment for the remainder of the plan. The set of circuits and associated investment packages in the Base Case scenario make up GPC's proposed Distribution Investment Plan[131]. The Base Case set of investments is projected to cost ~$3.4B over the remaining 8 years (using the cost estimates discussed in I.C). Under the Base Case scenario, GPC reliability is projected to reach ~80 SAIDI by 2031 (using reliability improvement estimates outlined in I.D).

As noted in section I.B, to achieve end-state SAIDI below 60 requires significant undergrounding and so the undergrounding investment criteria were relaxed to allow more circuits to qualify for undergrounding investments in all scenarios with SAIDIs below 60.

The worst reliability scenario (the "No Incremental-Investment" scenario) results in an end state of ~155 SAIDI, based on the assumption that GPC does not invest any incremental capital in its distribution system between 2023 and 2030 and that circuits with systemic issues continue to decline during this period. The best reliability scenario targets an end state of ~30 SAIDI, which is the lowest feasible end-state SAIDI target under current input assumptions. To reach this scenario's end-state would require a very large increase in total capital spend (roughly 11x as much capital as required in the Base Case) and number of circuits invested in (roughly 2x as many circuits as are included in the Base Case). In addition, reaching an end state of ~30 SAIDI would require undergrounding far more circuits than are undergrounded in the Base Case[132] (roughly 35x).

Diminishing Reliability Improvements with Investment

Moving from the worst reliability scenario, in which no incremental investments are made, to each successive reliability scenario, which target better customer reliability experience and lower end-state SAIDI, requires adding circuits to the investment plan. As more circuits receive investment, a better end-state SAIDI is expected.

[131] Exact set of circuits and investment timing in Base Case scenario will closely mirror final proposed Distribution Investment Plan; however, slight updates to the Distribution Investment Plan may be made after this study is published. As such, the Base Case scenario in this study may differ slightly from GPC's final Distribution Investment Plan.

[132] This is due to the fact that the undergrounding package generally results in the lowest reliability end-state compared to any other investment package.

The circuits with the worst reliability tend to be the circuits that, when invested in, are expected to produce the largest reliability improvement. As a result, higher investments (i.e. investment scenarios targeting more circuits and better end-state reliability) result in diminishing reliability improvements. This is because the worst circuits presenting the highest reliability improvement opportunity have already been added to the investment plan and incremental circuits added to the plan present lower reliability improvement opportunity. As a result, reliability benefit per invested dollar diminishes as investment scope increases. In Figure III. 1 one can see a visualization of this process.

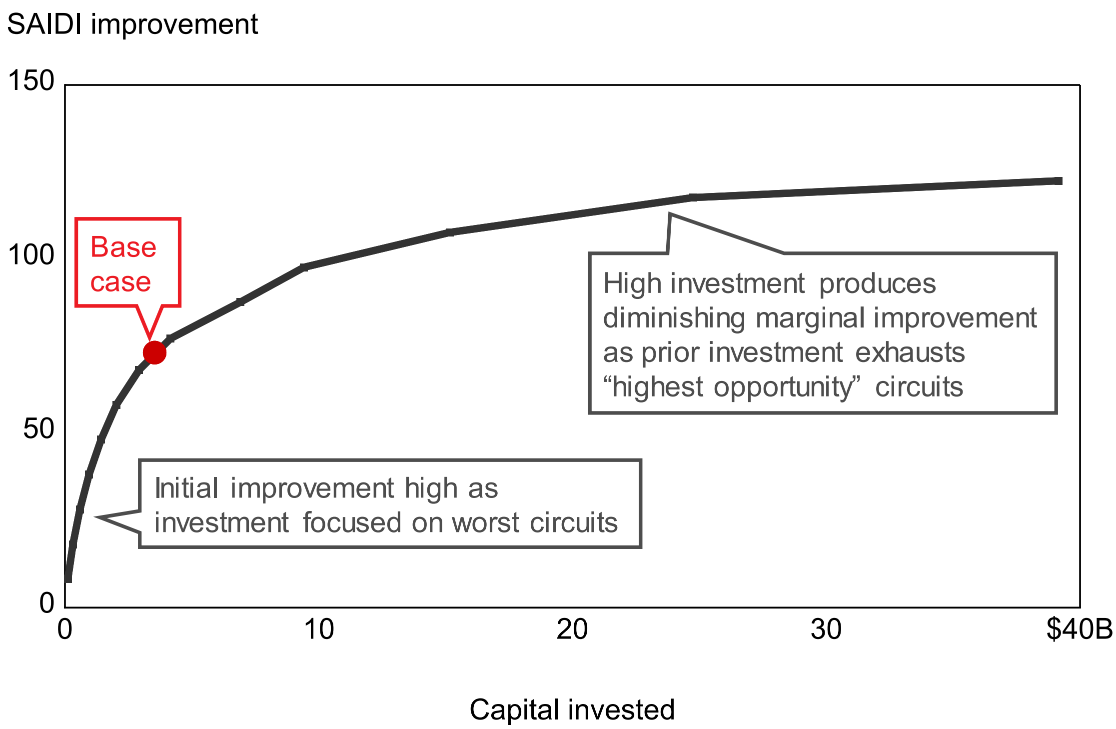

Figure III. 1. Diminishing Reliability Improvement[133]

The slope of the curve is initially high as investment focuses on the worst circuits. As successive incremental investment is restricted to better and better circuits, however, reliability improvement per dollar falls and the slope tapers off. Investment past the Base Case (i.e. targeting end-state GPC SAIDI values lower than ~80) requires investing in circuits with relatively better reliability and shows a pronounced decline in reliability improvement per dollar invested.

133 "SAIDI improvement" is the difference between a scenario's end-state SAIDI and the No Incremental-Investment end-state SAIDI; each point represents a scenario.

Introduction and Discussion of U-Curve

As discussed in I.Q, the optimal range of investment from a customer perspective is that which minimizes the summed present values of capital revenue requirement, economic cost, and O&M. Taking the identified scenarios as the domain of investment plans, the optimal range of investment can be identified by calculating the present value of each of these costs for each investment plan.

i. Present value of capital revenue requirement

The present value of capital revenue requirement for each scenario is shown below in Figure III. 2:

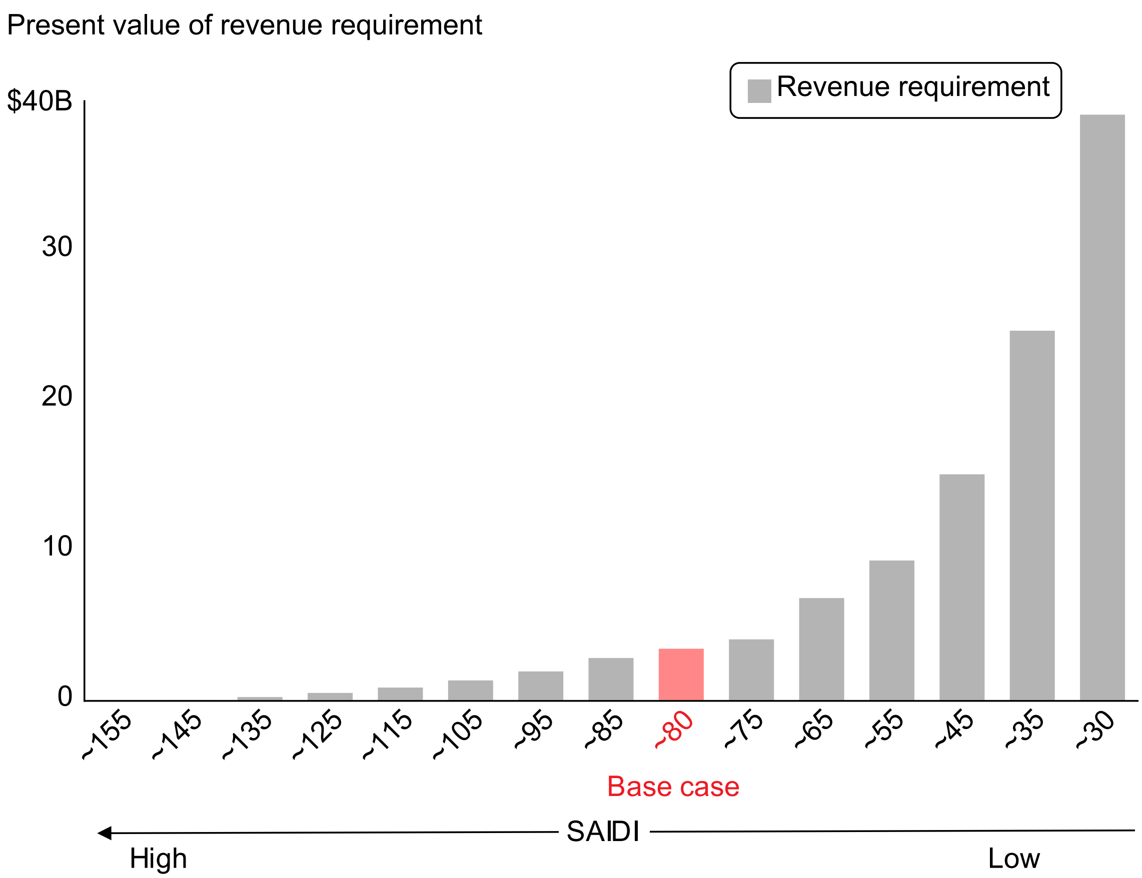

Figure III. 2. Present Value of Capital Revenue Requirement

As mentioned above, the worst reliability scenario with end state ~155 SAIDI assumes that no incremental investment is made in the distribution system during the investment period and thus has a present value of capital revenue requirement equal to $0. Moving right along the axis, the slope of the curve increases as equal reliability improvements can only be attained via higher and higher levels of capital investment in the distribution system which results in higher and higher revenue requirements. This is due to diminishing reliability improvement, as discussed in Section III.B. The right most scenarios targeting the most aggressive end-state reliability scores require increasingly large investment amounts as incremental investment is restricted to relatively better circuits with lower reliability improvement opportunity.

ii. Present value of outage economic cost

The present value of outage economic cost for each scenario is shown below in Figure III. 3:

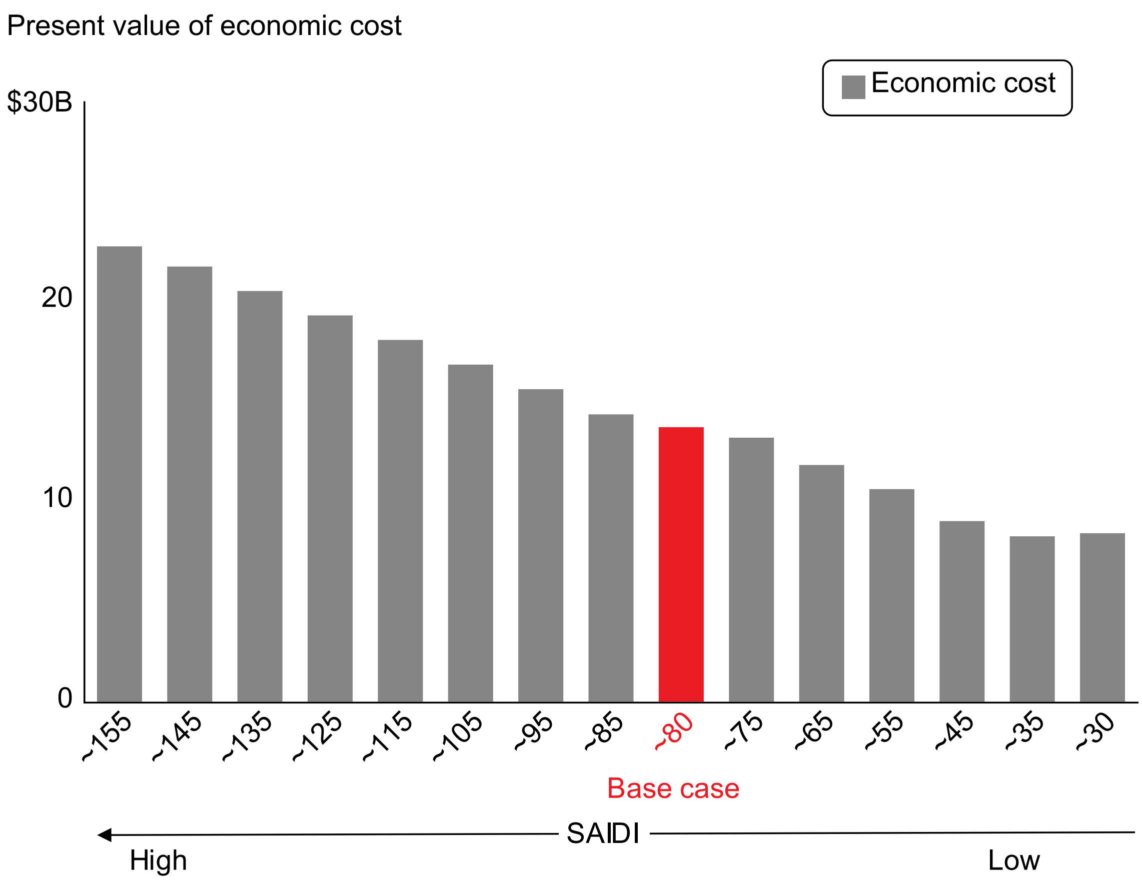

Figure III. 3. Present Value of Economic Cost from Outages

The present value of economic cost decreases moving from left to right along the x-axis. As end-state reliability improves, customers face less outage time and incur less economic cost as a result.

The concave nature of the curve pictured is due to two factors:

- **Gradual reliability improvement:** As discussed in Section I.O, end-state reliability for a given investment plan is only reached in 2031. Between 2023 and 2031, reliability benefit accrues gradually as GPC invests in more circuits. As such, the differences between scenarios is less pronounced in earlier years.
- **Discounting:** Due to the compounded discounting of economic costs, the economic costs of the investment period's early years (when scenarios' reliability differences are less pronounced) are given more weight than later years (when scenarios' reliability differences are more pronounced).

iii. Present value of O&M

The present value of O&M cost for each scenario is shown below in Figure III. 4:

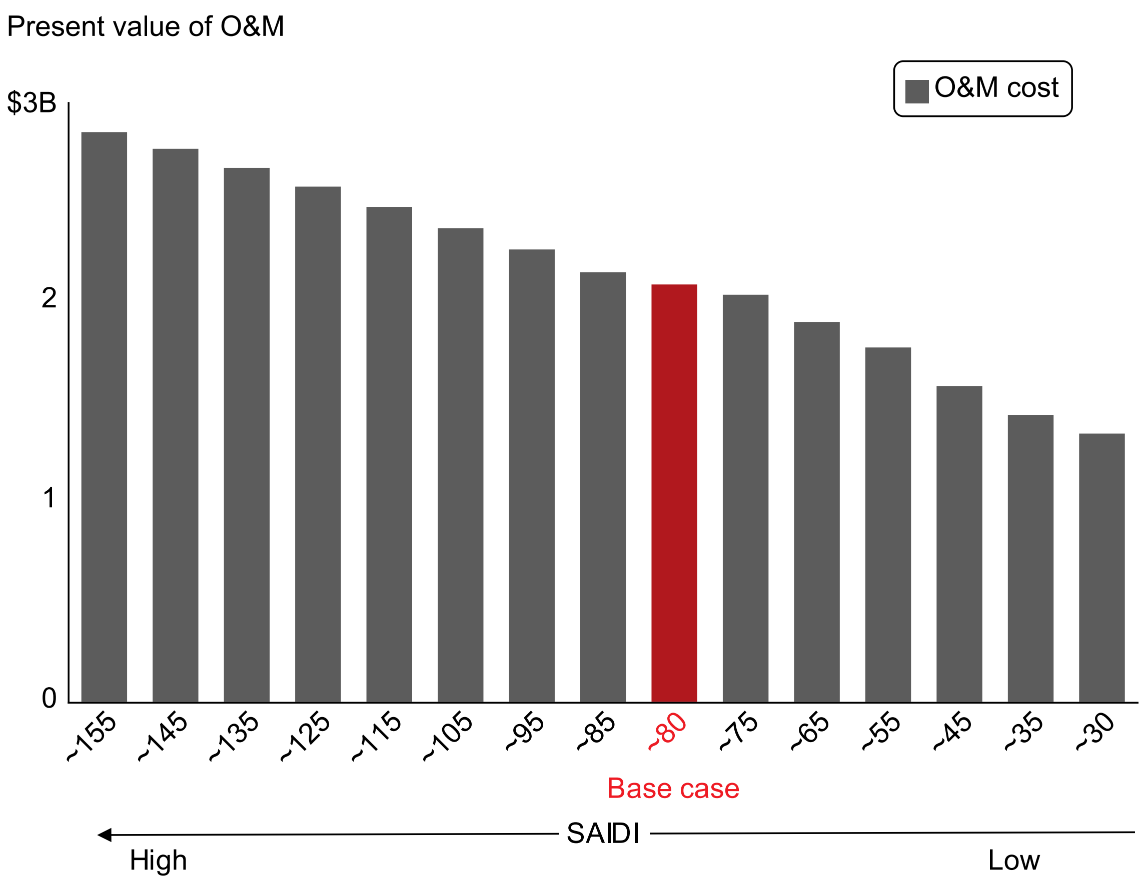

Figure III. 4. Present Value of O&M

The present value of O&M steadily decreases as lower SAIDI end-states are targeted. This is due to declining system SAIFI (resulting in lower outage restoration costs) and increased undergrounding (resulting in lower vegetation management costs). Notably, O&M represents a much smaller portion of total cost than economic costs and capital costs. Again, the concave nature of the pictured function is due to gradual reliability improvement and discounting, similar to economic cost.

iv. Present value of total cost

The present value of all costs for each scenario is shown below in Figure III. 5:

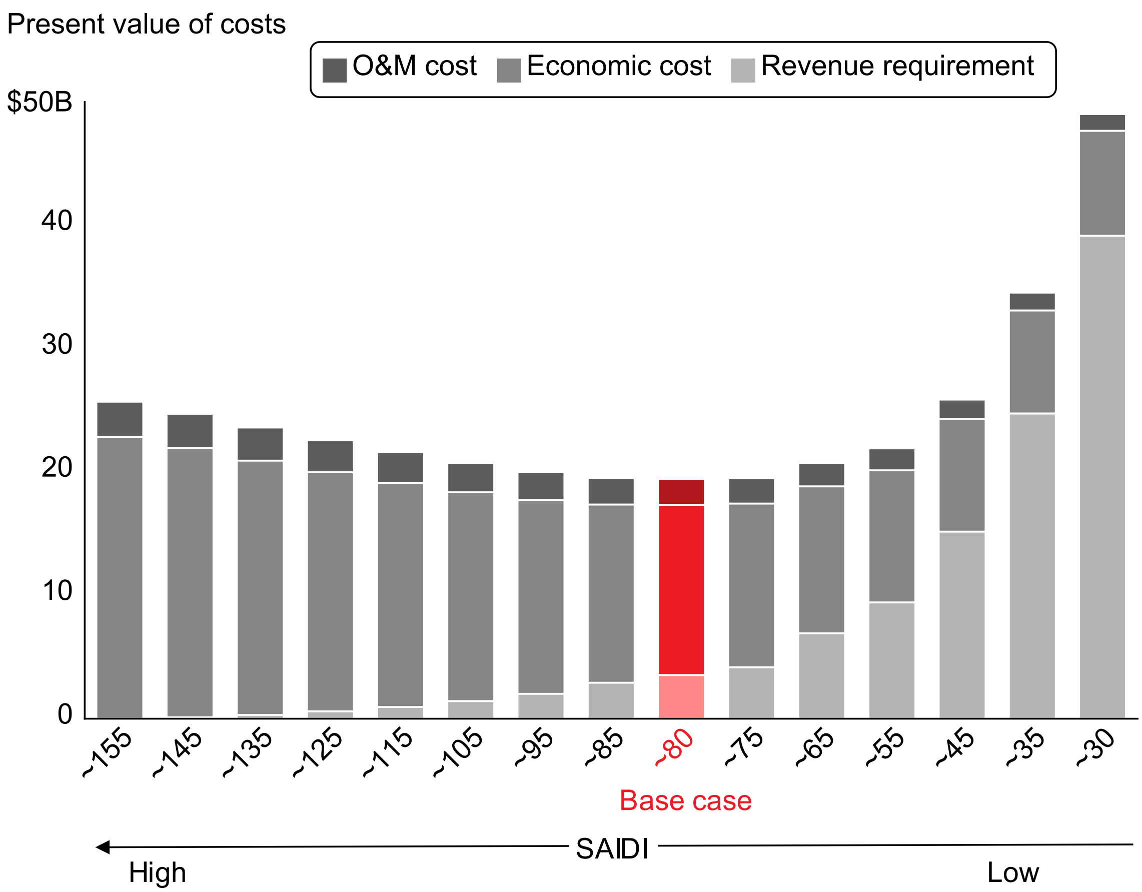

Figure III. 5. Present Value of Total Cost

Moving from left to right along the x-axis, capital revenue requirement increases for each successive scenario while O&M and economic cost decrease. The Base Case scenario lies at the minimum of the U-curve and is therefore the plan that minimizes customer costs under default assumptions.

Net Present Value of Investment Scenarios

The net present value (NPV) of an investment scenario S is the measure of its benefit compared to investing $0 incrementally and is calculated using the following formula:

$$NPV_S = PVC_{NI} - PVC_S$$

Where:
NPV_S = Net present value of scenario S;
PVC_{NI} = Present value of costs for the No Incremental-Investment scenario; and
PVC_S = Present value of costs for scenario S

When the NPV of a scenario is positive, that scenario's investment plan represents a net benefit for customers, with a present value equal to the NPV. When the NPV of a scenario is negative, that scenario's investment plan represents a net loss for customers, with a present value equal to the NPV. If scenario S' has a higher NPV than scenario S, S' represents a higher benefit for customers and should be preferred for investment. The "optimal range" is represented by the scenario with the highest NPV.

The net present value for each scenario is shown below in Figure III. 6:

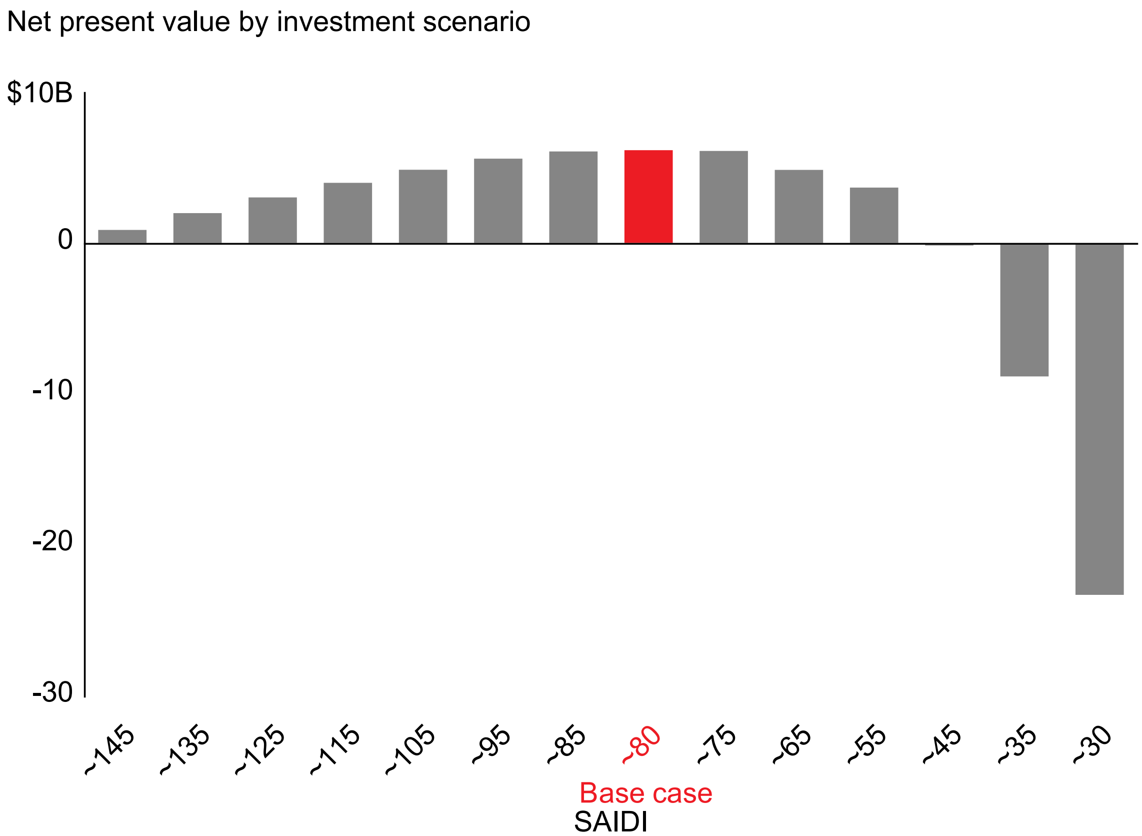

Figure III. 6. Net Present Value

Of note is that Figure III. 6 is a derivative of Figure III. 5's present value U-curve. The NPV for each scenario (for example, scenario "S") is calculated by taking the *difference* between the No Incremental-Investment scenario's present value of costs (the left-most bar) and scenario S's present value of costs. Hence, the NPV of the No Incremental-Investment scenario is $0 and is therefore not pictured in this figure.

As shown in Figure III. 6, the Base Case scenario represents the optimal investment plan with an NPV of ~$6.3B. Each investment scenario, with the exception of the 3 scenarios targeting ~45, ~35, and ~30 SAIDI end-state, is NPV positive, indicating that investment is strictly more beneficial to customers than non-investment. Moving from left to right along the x-axis, NPV begins falling after reaching the Base Case scenario. This is because incremental investment is restricted to the highest performing circuits. Reaching ~45 or below SAIDI as an end-state would result in a net detriment to customers as increased capital revenue requirement would outweigh any reduction in economic costs and O&M.

Marginal Benefit of Grid Investment

As mentioned in III.B, reliability improvement per invested dollar declines as investment increases. This relationship can also be analyzed by calculating *marginal benefit per invested dollar* (MBID)[134], where marginal benefit is calculated using the following formula:

$$MBID = -1 * \Delta\ Benefit\ /\ \Delta\ Capital\ Revenue\ Requirement$$

Where:
MBID = Customer value gained per dollar of investment, moving from S to S', where S and S' are adjacent scenarios
Δ Benefit = $PV_{S'}$(Economic cost) – PV_S(Economic cost) + $PV_{S'}$(O&M) – PV_S(O&M)
Δ Revenue Requirement = $PV_{S'}$(Capital revenue requirement) – PV_S(Capital revenue requirement)

When MBID is greater than \$1, additional investment benefits customers more than it costs customers. This is because the additional reliability improvement grants customers greater savings in economic cost and O&M than it costs them in capital revenue requirement. When MBID is less than \$1, additional investment costs customers more than it benefits them. This is because the additional reliability improvement costs customers more in capital revenue requirement than it saves them in economic cost and O&M. Thus, an MBID of \$1 represents an "efficiency cutoff" for investment.

The MBID for each reliability end-state is shown below in Figure III. 7:

[134] Denominator is expressed in terms of capital revenue requirement because this is the cost of investment from the customer's perspective.

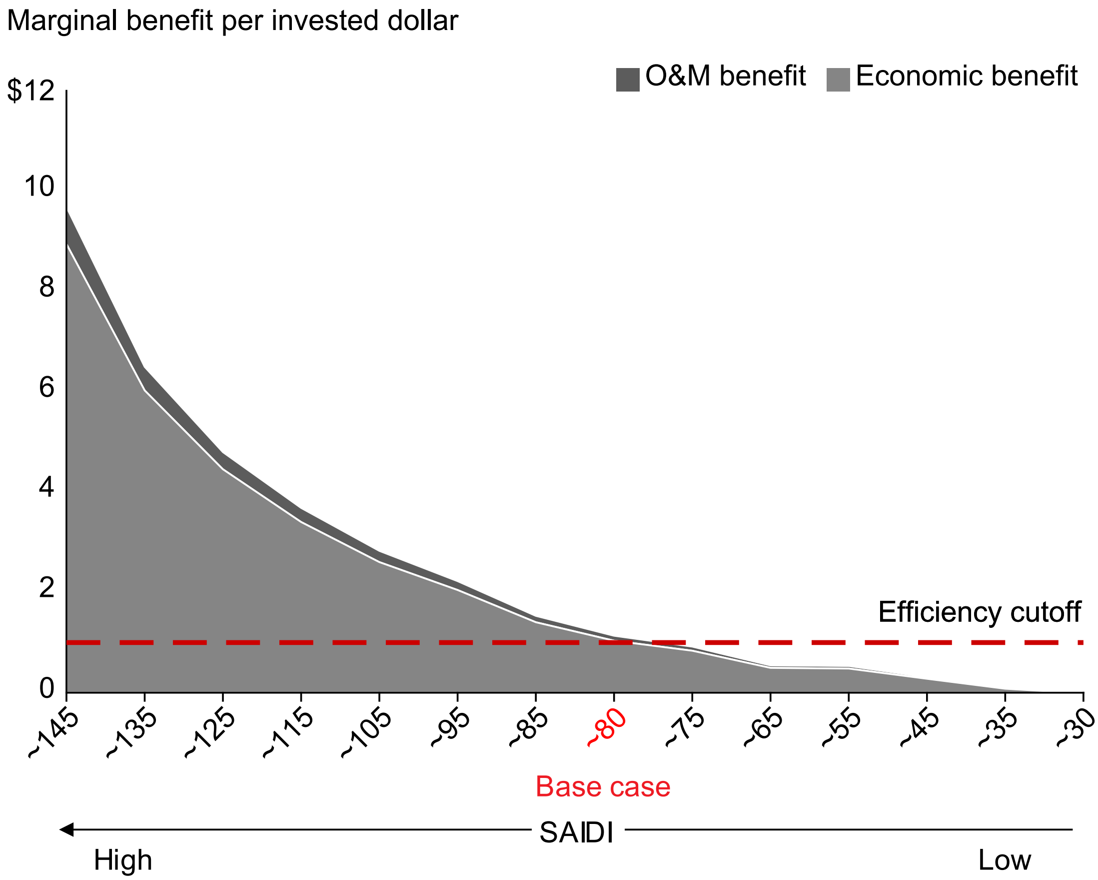

Figure III. 7. Marginal Benefit per Invested Dollar[135]

MBID is initially high as investment focuses on the worst circuits but declines as target SAIDI end-states get lower. Continued investment is above the efficiency cutoff, and therefore beneficial to customers, until reliability end-state passes ~80 SAIDI, after which point continued investment is no longer sensible.

IV. SENSITIVITY ANALYSES

The following sensitivities were run to determine the optimal ranges of investment under varying model conditions, and whether optimality shifts when assumptions are adjusted. For each sensitivity, excluding IV.A, two sets of analysis were run for each sensitivity, one in which the

[135] Curve represents the best-fitting exponential line.

assumptions were flexed up above the baseline assumption and one in which the assumptions were flexed down below the baseline assumption. Note that all sensitivities were conducted on only a subset of investment scenarios above and below the Base Case. This approach was taken to balance thoroughness and efficiency.

A. Publicly Available Cost of EUE

The first sensitivity run uses publicly available EUE data to replace internal EUE survey data. Specifically, this sensitivity uses the Interruption Cost Estimate Calculator[136], developed by Nexant and funded by Lawrence Berkeley National Laboratory and the Department of Energy, to estimate the present value of the economic cost of outages for each scenario.

The ICE calculator differs from this study's default economic cost methodology in several ways:

- EUE values are estimated based off proprietary Nexant surveys
- Economic cost calculation incorporates SAIFI in addition to SAIDI
- ICE incorporates household income, the distribution of outages over the course of the day, industry breakdown among business customers, and prevalence of backup generation as additional factors

The present value of costs U-curve using the ICE calculator to estimate the economic cost of outages is below in Figure IV. 1:

[136] The ICE calculator is available for use at http://icecalculator.com

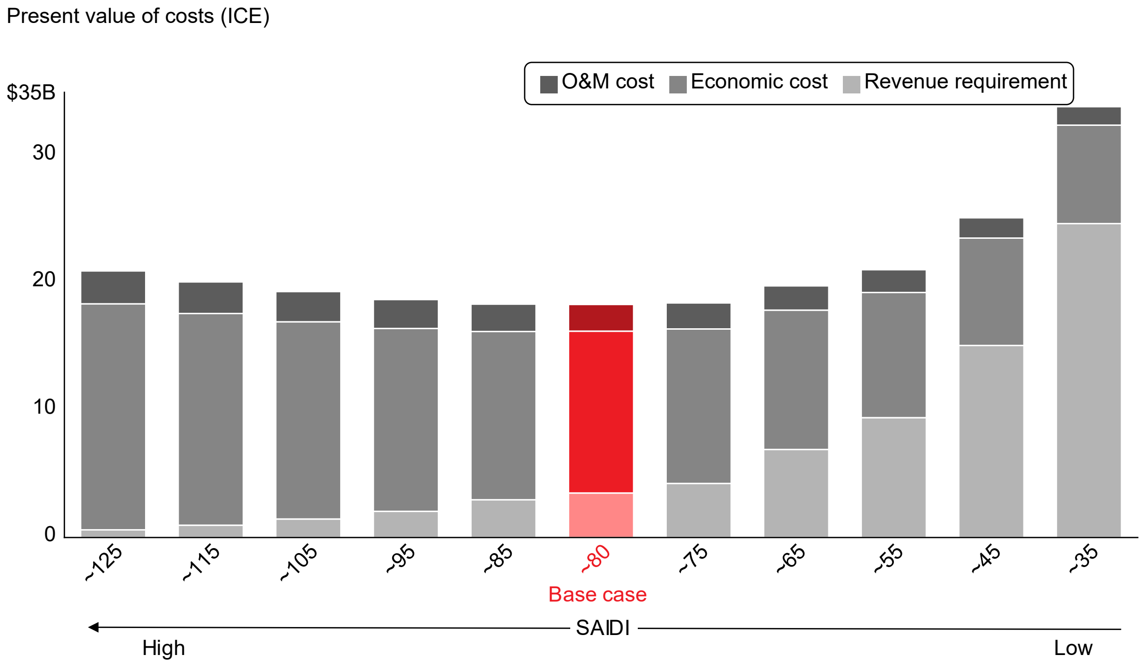

Figure IV. 1. Present Value of U-Curve with ICE Economic Costs

Compared to the Base Case EUE calculation in Figure III. 5, the economic cost of outages is slightly lower for each scenario. This has the effect of flattening the curve and therefore compressing the gap between scenarios. O&M and capital revenue requirement remain the same for each scenario. This is because the calculation of economic cost has no influence on either. The Base Case remains in the optimal investment range, targeting an end-state of ~80 SAIDI.

Internal EUE Estimates

Since customer electricity reliability expectations may change during the investment period, EUE cost estimates were flexed up and down by 10% to determine the impact on economic cost calculations and the optimal investment range. Flexing EUE cost estimates impacts the economic cost bar only, as capital revenue requirement and O&M cost bars are not affected by this variable. Figure IV. 2 shows the sensitivity calculations for the Base Case and four points around the Base Case. The Base Case remains in the optimal investment range under both 90% and 110% of default EUE cost assumptions.

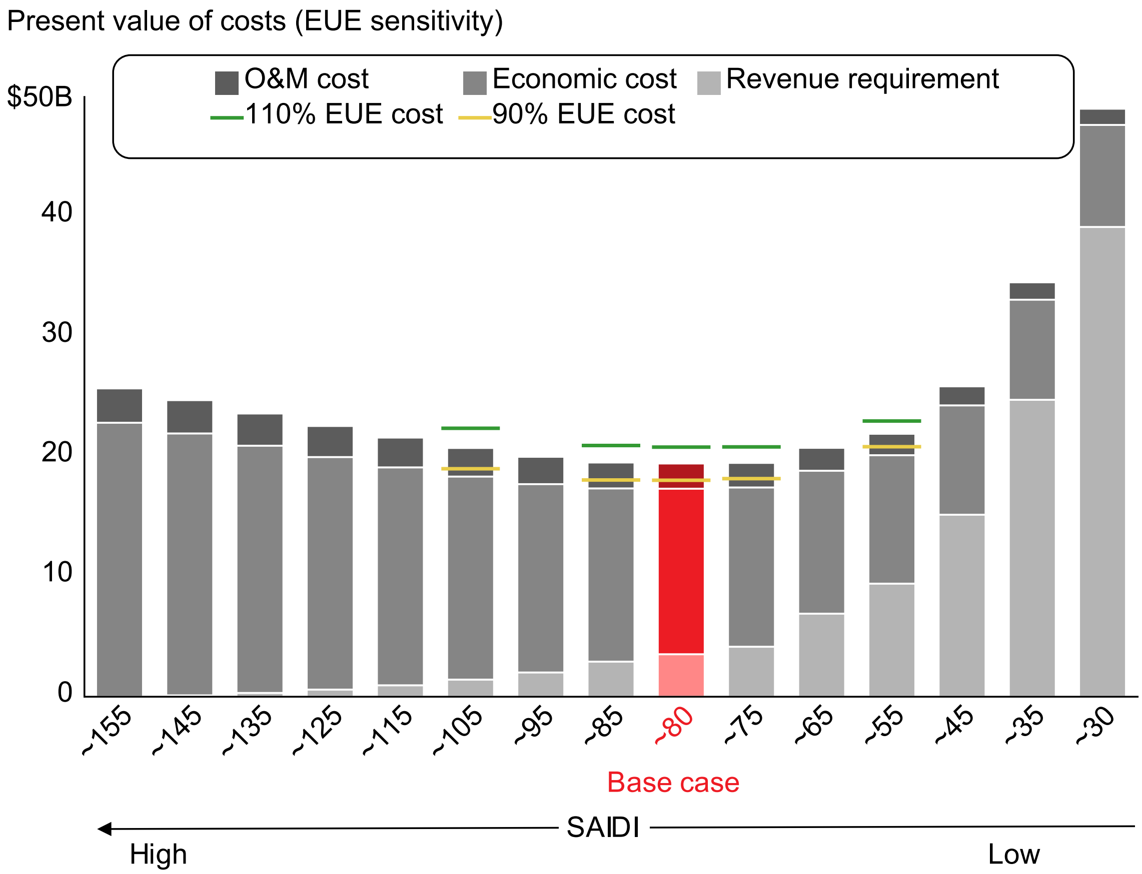

Figure IV. 2. Internal EUE Estimate Sensitivity

Investment Cost

To capture potential deviations from current investment cost estimates, investment cost assumptions were flexed up and down 10% to determine the impact on capital revenue requirement and the optimal investment range. Flexing investment cost assumptions only affects the capital revenue requirement cost bar as economic cost and O&M are unaffected by investment cost. Figure IV. 3 shows the sensitivity calculations for the Base Case and four points about the Base Case. The Base Case remains in the optimal investment range under both 90% and 110% of default investment cost assumptions.

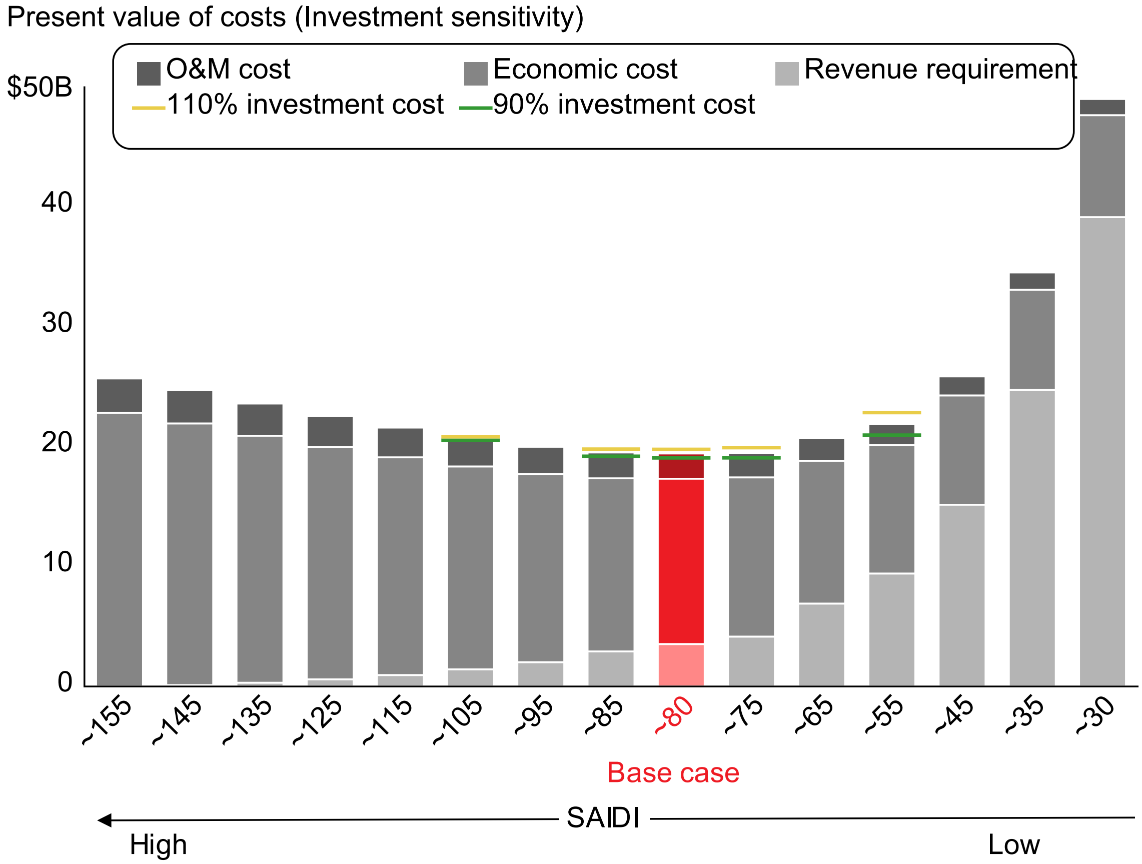

Figure IV. 3. Investment Cost Sensitivity

Load Growth

As discussed in I.K, default assumptions, electricity demand per customer is projected to decline [redacted]% annually over the course of the investment period. To capture possible load growth changes, estimated load growth was flexed up and down by 1 percentage point to determine the impact on economic cost and the optimal investment range. Flexing load growth assumptions affects the economic cost bar by changing the volume of unused energy during loss of service. Capital revenue requirement and O&M are unaffected by flexing load growth assumptions. Figure IV. 4 shows the sensitivity calculations for the Base Case and four points about the Base Case.

The Base Case remains in the optimal investment range under both [redacted]% and [redacted]% load growth assumptions.

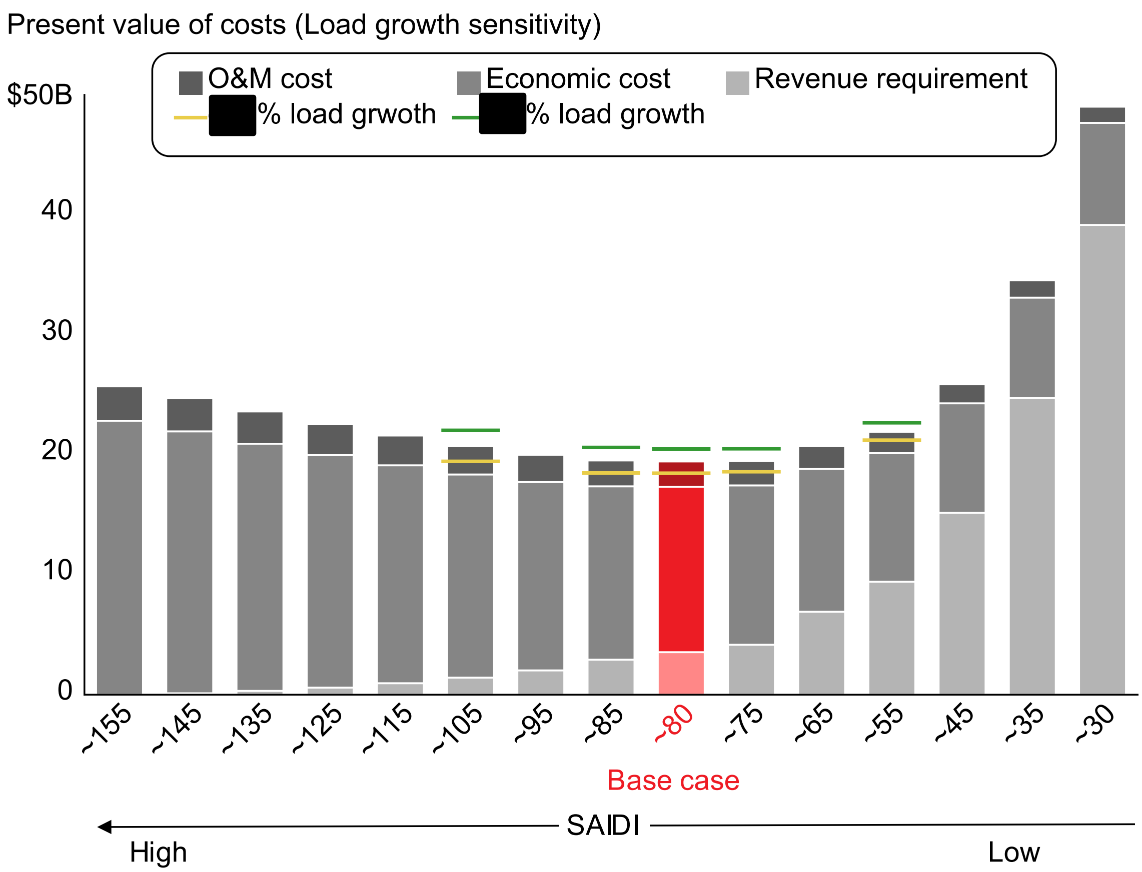

Figure IV. 4. Load Growth Sensitivity

Benefit Length

As discussed in I.E, under default assumptions package investment benefit is expected to last until 2055, 25 years past the end of the investment period of 2023-2030. To capture variation in realized benefit length, estimated benefit length was flexed up and down by 10 years on a system level to determine the impact on economic cost and the optimal investment range. Flexing benefit length assumptions affects both the economic cost and O&M bars by extending the valuation horizon. Capital revenue requirement is unaffected by changes to the assumed benefit length. Figure IV. 5 shows the sensitivity calculations for the Base Case and four points about the Base Case.

Under a 15-year benefit assumption, the optimal point shifts to the ~85 SAIDI scenario and using the 35-year benefit assumption, the optimal point decreases to ~75 SAIDI. However, in both scenarios, the Base Case SAIDI remains in the optimal investment range.

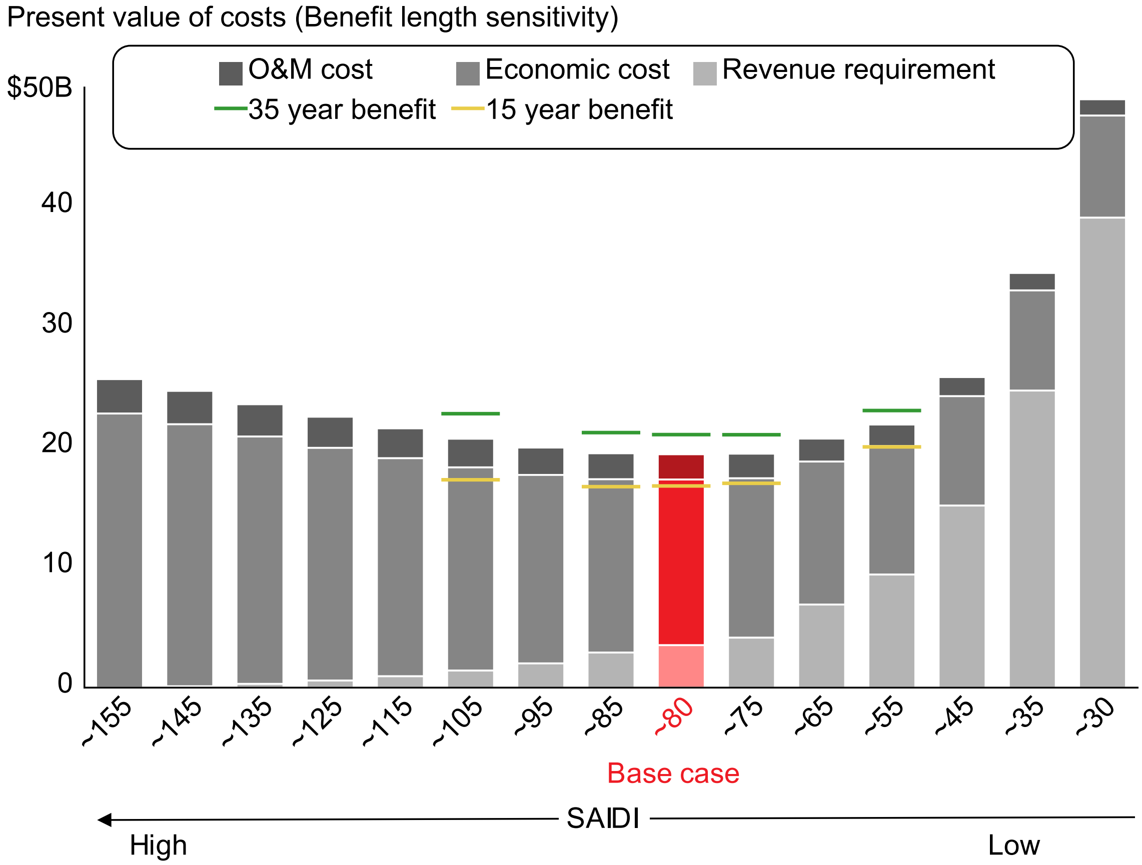

Figure IV. 5. Benefit Length Sensitivity

Load Growth / Benefit Length Interaction

Load growth and benefit length are unique among the study's assumptions in that they interact with one another. High load growth can strain circuit infrastructure, decreasing the expected benefit length of circuit investment. Low load growth can increase benefit length by extending circuit infrastructure useful life. To capture this variation, two separate model variants were run: (1) [redacted]% load growth and 35 year benefit, and (2[redacted]% load growth and 15 year benefit. Both variants affect the economic cost and O&M bars, while capital revenue requirement remains unchanged. Figure IV. 6 shows the sensitivity calculations for the Base Case and four points about the Base Case. The Base Case remains in the optimal investment range under the [redacted]% load growth and 35-year benefit assumption. Under the 15-year benefit and [redacted]% load growth assumption, the optimal point shifts to the ~85 SAIDI scenario.

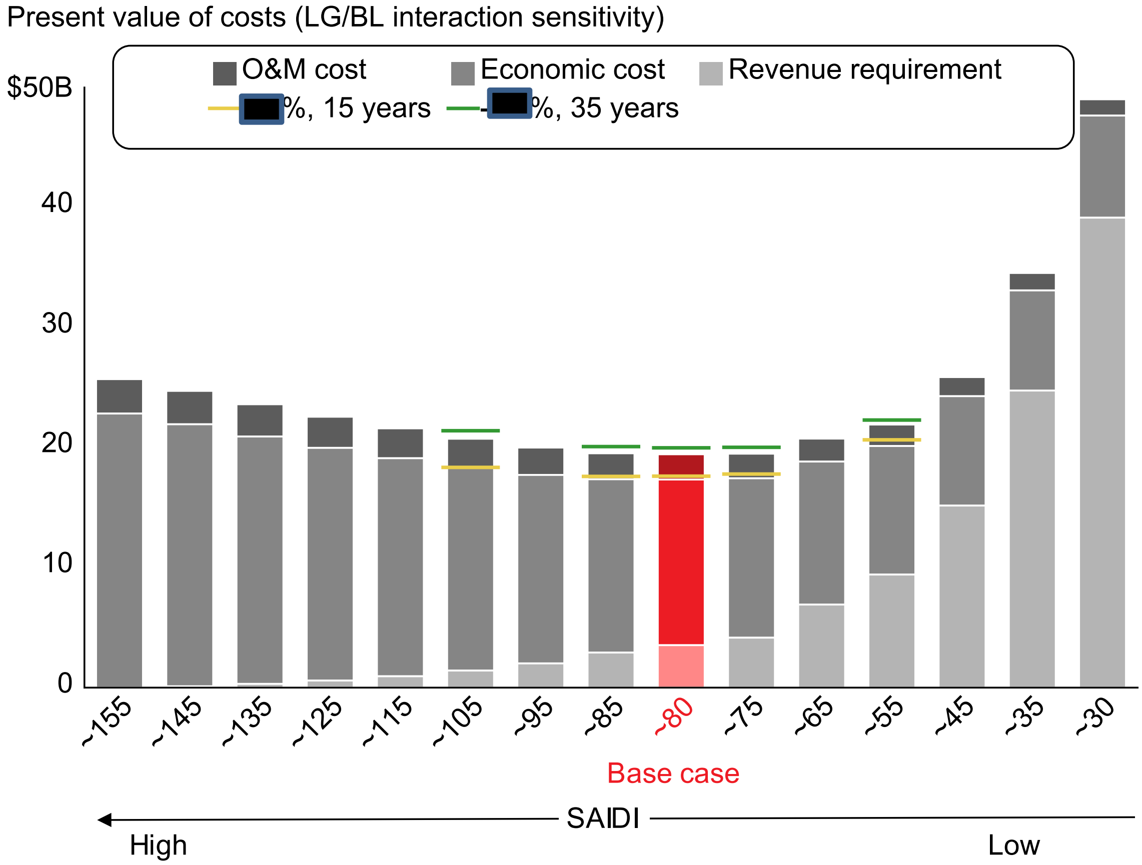

Figure IV. 6. Load Growth / Benefit Length Interaction Sensitivity

Rate of Reliability Decline

As discussed in I.H, the roughly 1000 circuits identified as having systemic reliability issues are projected to continue to experience reliability decline at conservative annual SAIDI and SAIFI rates of ~4% and ~3%, respectively, for each year in the investment horizon or until invested in. Given that reliability can vary year-by-year due to factors such as weather patterns, traffic, and wildlife events, possible reliability decline differences were captured by varying SAIDI and SAIFI decline rates up or down by 2 percentage points. Figure IV. 7 shows the sensitivity calculations for the Base Case and four points about the Base case. The Base Case remains in the optimal investment range under both high-decline and low-decline assumptions.

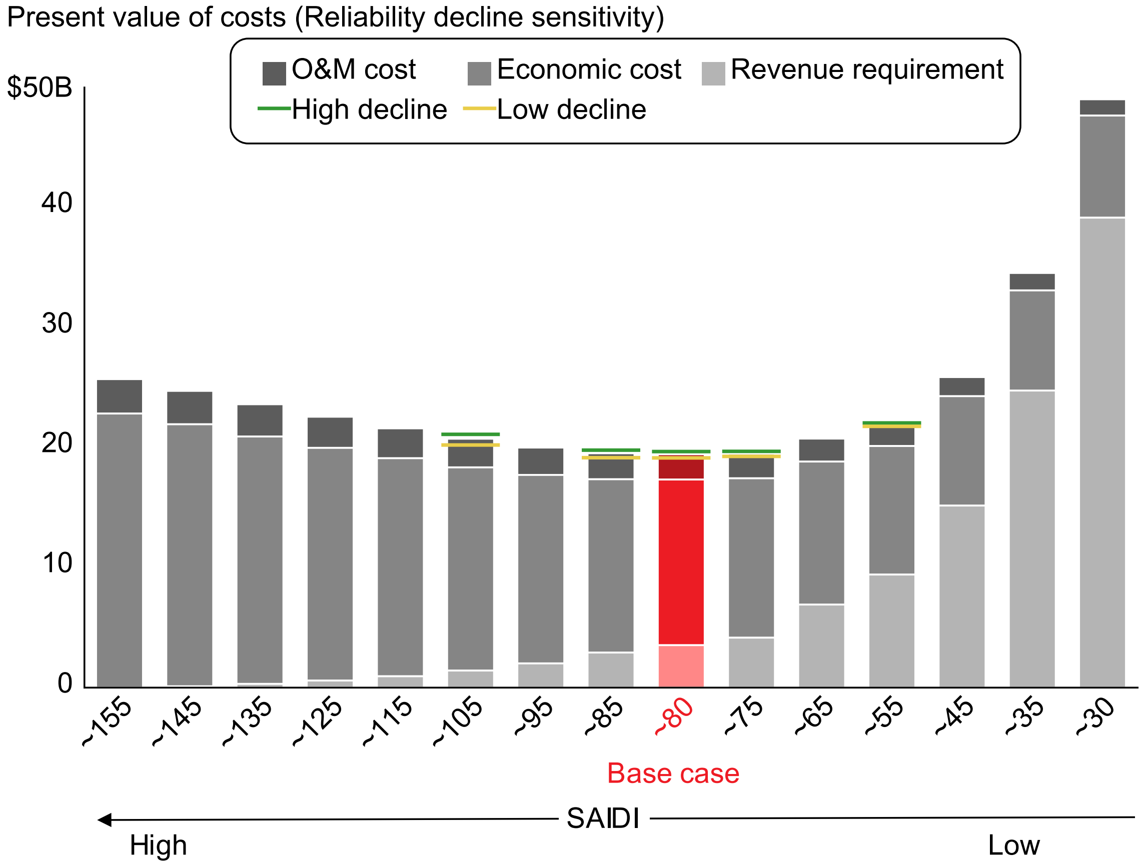

Figure IV. 7. Reliability Decline Sensitivity

V. CONCLUSION

The 2022 Distribution Investment Study is aimed at determining the optimal investment range for GPC's proposed Distribution Investment Plan by comparing the costs and benefits across various investment scenarios. As shown in Figure III. 1 (reproduced below) investment scenarios targeting more circuits and better end-state reliability result in diminishing reliability improvements. As noted, this is because the "highest opportunity circuits" are the first to be invested in. The Base Case plan corresponds to the level of investment that includes the highest opportunity investments but excludes investments that produce diminishing returns.

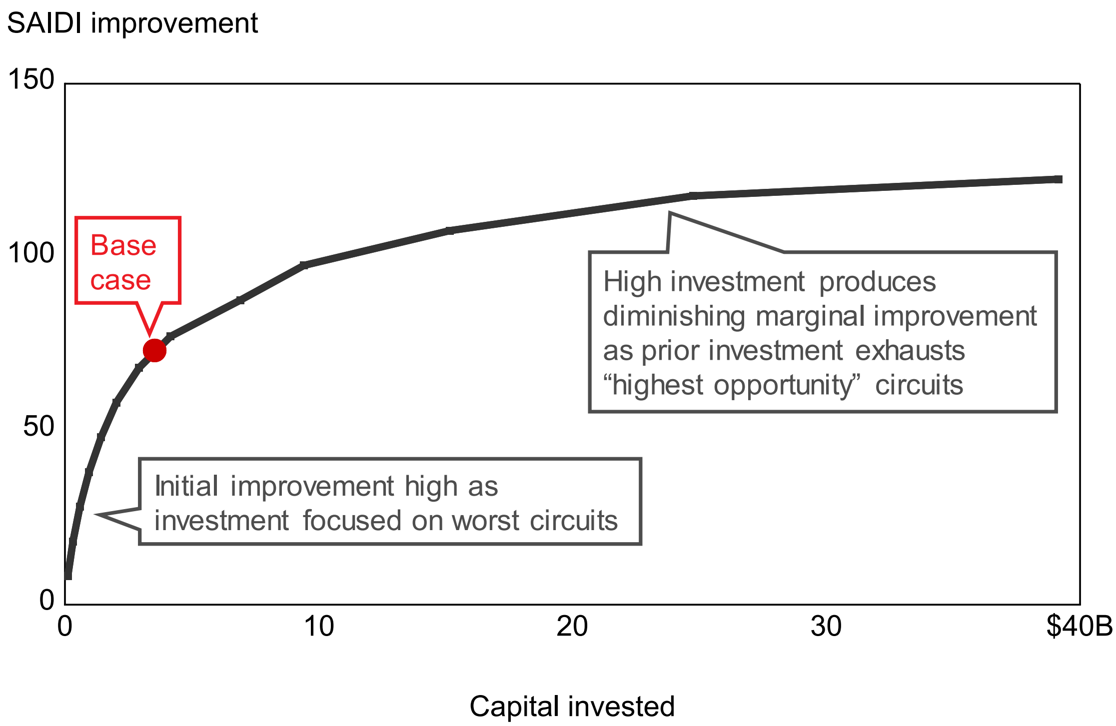

Figure III. 1. Diminishing Reliability Improvement

As discussed above in I.Q, the investment scenario that minimizes capital revenue requirements, economic costs, and O&M can be seen as optimal from the customer's perspective. This is because all of these costs are either directly or indirectly borne by customers. As shown in Figure III. 5 (reproduced below), of the 15 scenarios run, the Base Case scenario results in the minimum cost and should therefore be seen as the preferred option for customers.

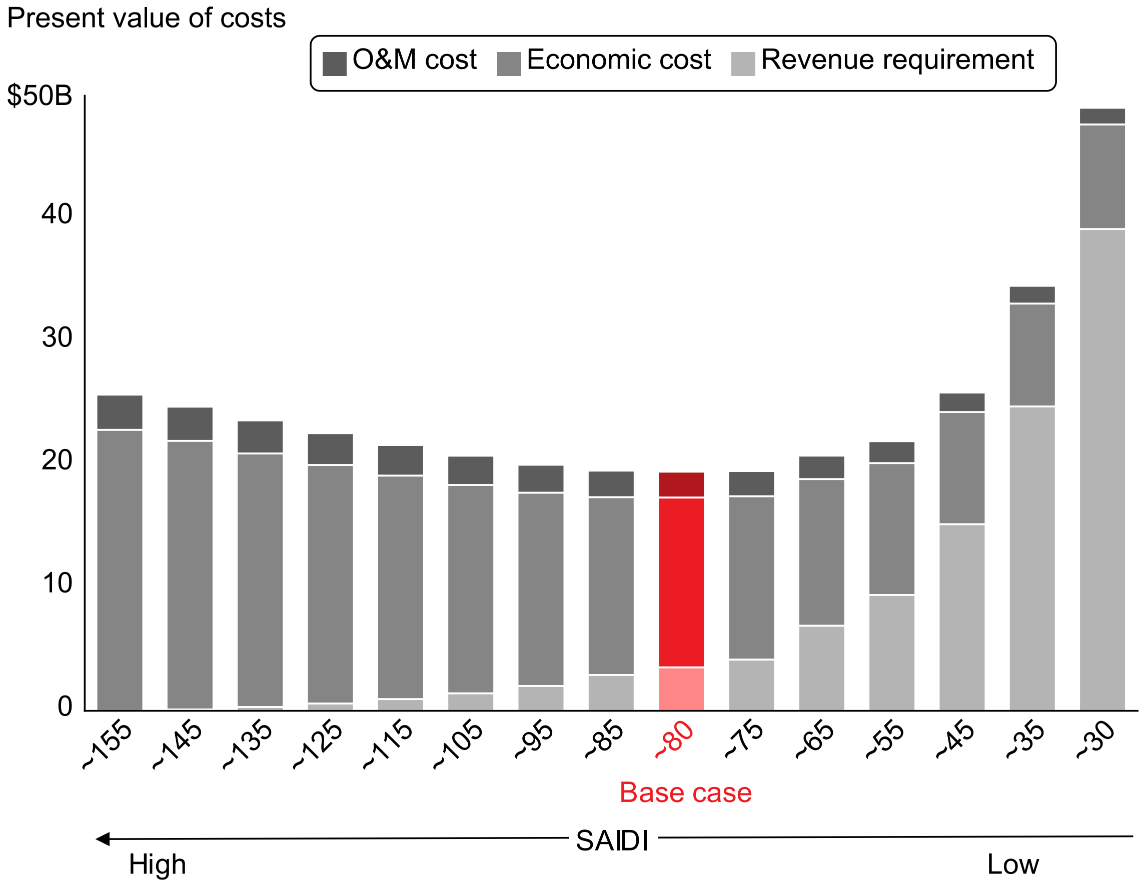

Figure III. 5. Present Value of Total Cost

Minimizing total customer cost is equivalent to maximizing the net present value of investment.

Figure III. 6, reproduced below, shows NPV of each scenario.

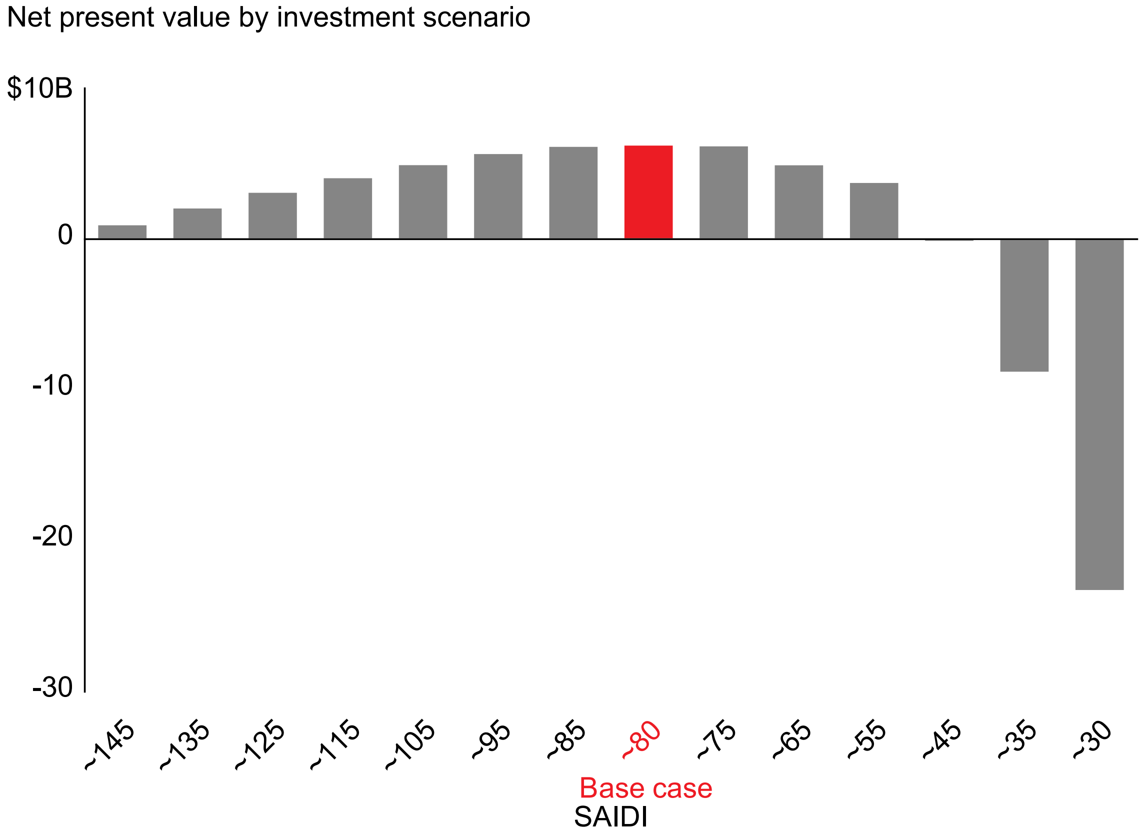

Figure III. 6. Net Present Value

Lastly, seven sensitivity analyses on key inputs to the Distribution Plan have been conducted. While these sensitivities result in increases or decreases to the overall cost bars, the Base Case investment plan remains in the *optimal range* of investment across all sensitivities. It is thus the conclusion of this report that the Base Case investment plan (the "Distribution Investment Plan") should be the preferred solution from the customer's perspective.

Appendix B. Alternative Valuation of Service Reliability

The survey instruments included two additional questions related to the value of service reliability. These two questions were presented to respondents after all of the outage scenario questions were completed. The questions were worded as follows:

- Suppose your utility provided an option to experience half as many outages as you currently receive. If you were charged more for this option, what would be the highest acceptable rate increase?
- Suppose your utility provided an option to experience twice as many outages as you currently receive. If you received a discount for this option, what would be the lowest acceptable rate discount?

Both questions were designed to link the change in reliability to the customer's electricity bill. Although framing the questions in this manner may have made them more relevant to the respondent, these questions had many of the same drawbacks that the willingness-to-pay (WTP) questions did for residential. As explained in Section 4.1.1, some respondents are confused by WTP questions or end up answering a question that is quite different from the one that is being asked. For example, customers sometimes react to questions about WTP by redefining the question so that it relates to their ability to pay, their satisfaction with service or whether they think they are being fairly charged for the service they are receiving. Such redefining of the question is probably even more likely when the question involves the customer's electricity bill, as it does in these two additional questions.

Table B-1 provides the average response by customer class for the first question, which relates to the highest acceptable rate increase in exchange for experiencing half as many outages. Outliers were not dropped from this analysis because the responses were naturally constrained between 0% and 100%. The average response is similar for residential, commercial and industrial customers. If there was a rate option for which they would experience half as many outages, the average residential, commercial and industrial customer would be willing to pay up to around 1.7% more for electricity. Large business customers did not value the 50% reduction in outage frequency as highly. Large business customers were only willing to accept a 1.2% increase in electricity cost for this improvement in reliability. Among non-residential customers, this finding is consistent with the EUE cost estimates for which large business customers placed the lowest value on electricity on a per kWh basis.

Table B-1: Highest Acceptable Rate Increase for Half as Many Outages – by Customer Class

Customer Class	N	Average Response	95% Confidence Interval	
			Lower Bound	Upper Bound
Residential	1,232	1.75%	1.55%	1.96%
Commercial	1,348	1.68%	1.41%	1.95%
Industrial	662	1.69%	1.34%	2.05%
Large Business	92	1.21%	0.54%	1.88%

Wired Group Estimate of GIP Revenue Requirements (in $000s) and Percentage Increases Over 2019 Baseline Revenue Requirements ("Rates")

Invest	Revenue Requirements for Investment Year ___ Recovered in:											
Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
2020	20,401	19,817	19,233	18,649	18,065	17,482	16,898	16,314	15,730	15,146	14,562	13,978
2021		56,973	55,342	53,711	52,081	50,450	48,820	47,189	45,559	43,928	42,298	40,667
2022			101,459	98,555	95,652	92,748	89,844	86,940	84,037	81,133	78,229	75,326
2023				90,025	87,449	84,872	82,296	79,719	77,143	74,566	71,990	69,414
2024					88,355	85,826	83,297	80,769	78,240	75,711	73,183	70,654
2025						93,713	91,031	88,349	85,667	82,985	80,303	77,621
2026							73,346	71,247	69,148	67,048	64,949	62,850
2027								73,346	71,247	69,148	67,048	64,949
2028									73,346	71,247	69,148	67,048
2029										73,346	71,247	69,148
2030											73,346	71,247
2031												73,346
GIP RR by Yr	20	77	176	261	342	425	486	544	600	654	706	756
2019 RR (baseline RR)	7,577	7,577	7,577	7,577	7,577	7,577	7,577	7,577	7,577	7,577	7,577	7,577
GIP RR Percent Increase	0.27%	1.01%	2.32%	3.44%	4.51%	5.61%	6.41%	7.18%	7.92%	8.63%	9.32%	9.98%

Georgia Transmission Equipment Analysis	**Using TODB DATA from 2012 to 2021**								
	Georgia Equpment outage classification	**Source #**	**Total number of Units/miles on the system**	**Failure unit count**	**Period of measure Years**	**Failure Rate/yr**	**Annual probability of Failure rate/unit**	**# of units or miles to Rpl to eliminate 1 failure**	**Cost to to eliminate 1 failure**
Source: TODB = Transmission Outage Data base			***DR to Utility***	***ODB/utility***	***TODB***	***Calc***	***Calc***	***Calc***	***Calc***
Equipment									
Substation Transformers **(TODB)**		1	2,264	101	10	10	0.00446	224.16	[redacted]
Circuit Breakers (**TODB)**		1	1,868	88	10	9	0.00471	212.27	[redacted]
Low side Breakers	**Low side Breakers**	1	1,705						
High side breakers	**High side breakers**	1	163						
Load Tap Changers **(TODB)**	**Voltage Regulation**	1	451	1	10	0.100	0.00022	4,510	[redacted]
Outlined cells are those presented in Table 2.									
		Source #							
Transmission outage Data base STF-WG-2-26-Attachment		**TODB**	**("TODB" is an acronym for transmission outage database)**						
Equipment counts STF-WG-1-33		**1**							
Transmissin Equipment replacment cost cost STF-WG-1-34 TRADE SECR		**2**							

(TRADE SECRET Optimization Model Inputs, Circuit Hardening Package)

REDACTED

(TRADE SECRET) Optimization Model Inputs, Undergrounding Package)

REDACTED

(Staff e-mail to Company requesting an alternative Scenario to be run through the Optimization Model, October 5)

Cheryl,

In follow-up to the demonstration of the Optimization Model provided by the Company on October 3, Staff requests the Company run a scenario specified by Staff. In this scenario, Staff requests no changes be made to the model except for the thresholds for 3rd and 4th Quartile SAIDI and SAIFI the Company uses to qualify circuits to receive various Distribution Investment Plan packages in various timeframes. Staff specifies the following thresholds:

	3rd Quartile	4th Quartile
SAIDI	98.96	165.87
SAIFI	0.9332	1.4446

Staff requests all the same outputs from the Staff-specified scenario that the Company typically secures from the model, including components of the Company's Economic Benefits Analysis (Present value of revenue requirements, Costs to customers of remaining service interruptions, and O&M costs); resulting SAIDI; resulting SAIFI; and the Model's output list of circuits, the packages they would receive, and the timing of those upgrades (in a manner similar to that provided by the Company in response to STF-WG- 2-7 Attachment TS). Please also provide the capital cost detail by year which resulted in the present value of revenue requirements.

Thank you, and please reach out with questions.

Rob Trokey
Director, Electric Unit
Georgia Public Service Commission
Office: (404) 656-4549
Mobile: (404) 825-1284

(TRADE SECRET Georgia Power Summary of Optimization Model Results from the Staff Scenario)

REDACTED

(TRADE SECRET Summary of Optimization Model projections by year of Georgia Power's proposed "80 SAIDI" Scenario for the Distribution Investment Plan)

REDACTED

PotomacEdison
A FirstEnergy Company

10802 Bower Avenue
Williamsport, MD 21795

Jeffrey P. Trout

Telephone: 301.790.6116
Fax: 330.436.8124
jtrout2@firstenergycorp.com

March 24, 2021

VIA E-FILE

Andrew S. Johnston, Executive Secretary
Maryland Public Service Commission
6 St. Paul Street
Baltimore, MD
21202

Re: **Annual Reliability Report of The Potomac Edison Company**

Dear Secretary Johnston:

Pursuant to COMAR 20.50.12.11, enclosed please find the Annual Reliability Report prepared by The Potomac Edison Company ("Potomac Edison") pursuant to COMAR 20.50.12.11.

If you have any questions about this matter, please do not hesitate to contact me.

Very truly yours,

Jeffrey P. Trout
Senior Corporate Counsel

JP/dml

Enclosure

cc: Michael Dean, PSC Staff; Jacob Ouslander, OPC

The annual performance report is submitted to the State of Maryland Public Service Commission on behalf of The Potomac Edison Company ("Potomac Edison" or the "Company"). Potomac Edison is a wholly owned subsidiary of FirstEnergy Corp. and a public utility in the state of Maryland. This annual performance report is filed pursuant to Code of the Maryland Regulations 20.50.12.11 for the calendar year 2020.

20.50.12.11(A)(1) The reliability index information and results required in this chapter, including a table showing the actual values of the reliability indices required in this chapter for each of the preceding 3 calendar years;
20.50.12.11(A)(2) Annual year-end and 3-year average performance results as required under Public Utilities Article, § 7-213(g)(2)(i) and (ii), Annotated Code of Maryland, including a table showing the actual values for each of the preceding 3 calendar years.
20.50.12.05 Additional Reliability Indices Reporting
A. CAIDI, SAIDI and SAIFI excluding major event days. A utility shall calculate and report the following information for its Maryland service territory:

1. ***CAIDI, SAIDI and SAIFI excluding major event days;***
2. ***All IEEE major event days; and***
3. ***The reliability indices, including and excluding planned outages.***

The table below provides the required reliability index results for system average interruption frequency index ("SAIFI"), system average interruption duration index ("SAIDI") and customer average interruption duration index ("CAIDI") for the Potomac Edison ("PE") system. PE's annual SAIFI and SAIDI results were lower than the calendar year 2020 reliability standard identified in COMAR 20.50.12.02(D)(1)(d). Therefore, PE is not required to provide a corrective action plan as the standards were satisfied.

	Outage	Index	2018	2019	2020	3-Year Avg	2020 COMAR
Including Planned Outages	All Interruption Data	SAIFI[1]	1.12	1.42	0.95	1.16	N/A
		SAIDI[2] (Min)	264.5	392.3	133.8	263.5	N/A
		CAIDI[3] (Min)	236.9	276.6	140.7	218.1	N/A
	All Interruption Data Minus Major Outage Event Interruption Data	SAIFI	0.89	1.42	0.95	1.09	N/A
		SAIDI (Min)	145.4	392.3	133.8	223.8	N/A
		CAIDI (Min)	162.7	276.6	140.7	193.3	N/A
	All Interruption Data Minus Major Outage Event Interruption Data & Minus Outage Data Resulting from an Outage Event Occuring on Another Utility's Electric System	SAIFI	N/A	N/A	N/A	N/A	N/A
		SAIDI (Min)	N/A	N/A	N/A	N/A	N/A
		CAIDI (Min)	N/A	N/A	N/A	N/A	N/A
	All Interruption Data Minus IEEE Major Event Day Interruption Data	SAIFI	0.92	1.08	0.90	0.97	1.06
		SAIDI (Min)	138.8	172.4	117.8	143.0	142.0
		CAIDI (Min)	150.1	159.8	131.4	147.1	N/A
Excluding Planned Outages	All Interruption Data	SAIFI	1.07	1.36	0.92	1.12	N/A
		SAIDI (Min)	259.9	385.4	129.3	258.2	N/A
		CAIDI (Min)	242.8	282.9	140.5	222.1	N/A
	All Interruption Data Minus Major Outage Event Interruption Data	SAIFI	0.85	1.36	0.92	1.04	N/A
		SAIDI (Min)	141.2	385.4	129.3	218.6	N/A
		CAIDI (Min)	166.1	282.9	140.5	196.5	N/A
	All Interruption Data Minus Major Outage Event Interruption Data & Minus Outage Data Resulting from an Outage Event Occuring on Another Utility's Electric System	SAIFI	N/A	N/A	N/A	N/A	N/A
		SAIDI (Min)	N/A	N/A	N/A	N/A	N/A
		CAIDI (Min)	N/A	N/A	N/A	N/A	N/A
	All Interruption Data Minus IEEE Major Event Day Interruption Data	SAIFI	0.88	1.02	0.87	0.92	N/A
		SAIDI (Min)	134.2	165.7	113.3	137.7	N/A
		CAIDI (Min)	152.8	161.9	130.9	148.5	N/A

[1] SAIFI represents system average interruption frequency index, a reliability indicator to measure the average number of interruptions that a customer would experience. It is in units of interruptions.
[2] SAIDI represents system average interruption duration index, a reliability indicator which measures the average outage duration for each customer served in utility service territory and can be in hours or minutes. COMAR uses minutes for SAIDI. Each utility shall report SAIDI in minutes.
[3] CAIDI represents customer average interruption duration, a reliability indicator to measure average outage duration that any given customer would experience and is reported in minutes.

20.50.12.11(B)(8) Any corrective action plans required under Public Utilities Article, §7-213(e)(1)(iii), Annotated Code of Maryland, or this chapter.

PE satisfied the standards of this regulation in 2020, therefore, a corrective action plan is not required. However, as reported in the 2019 Annual Reliability Report of the Potomac Edison Company, the annual SAIFI and SAIDI results were identified as being higher than the calendar year 2019 reliability standard identified in COMAR 20.50.12.02(D)(1)(d). Therefore, a Corrective Action Plan was implemented and beginning on January 1, 2021 PE transitioned its vegetation management trimming cycle from five years to four years.

20.50.12.05(B) A utility shall report an annual $CEMI_n$[1] for customers experiencing three or more ($CEMI_2$), five or more ($CEMI_4$), seven or more ($CEMI_6$) and nine or more ($CEMI_8$) sustained interruptions.

	$CEMI_2$	$CEMI_4$	$CEMI_6$	$CEMI_8$
All Interruption Data	11.42%	2.74%	0.66%	0.21%
All Interruption Data Minus Major Event Data	11.42%	2.74%	0.66%	0.21%

20.50.12.05(C). A utility shall calculate and report in its supplemental annual performance report an annual ($MAIFI_E$) for its Maryland service territory unless it does not have the means to make the calculation, in which case it shall provide an explanation of the reason, and an estimate of the cost to provide the information going forward.

	$MAIFI_E$[2]
All Interruption Data	12.3
All Interruption Data Minus Major Event Data	N/A[3]

20.50.12.11(A)(3) The time periods during which major outage event interruption data was excluded from CAIDI, SAIDI and SAIFI indices, including a brief description of the interruption causes during each time period.

Potomac Edison did not experience any major outage events in 2020 but did experience two Major Event Days.

[1] CEMI is defined as customers experiencing multiple interruptions.
[2] Please note that PE is able to report MAIFI, but not $MAIFI_E$. PE does not have smart meters and must rely on gathering data by manually reading counters from line reclosers annually. Reclosers are set to reclose as many as three times before locking out on the fourth operation. Adjacent reclosers can operate in succession for the same fault. There can be as many as five counter readings for each fault on the overhead system.
[3] PE is unable to calculate MAIFI excluding major event data. The data is gathered by manually reading counters from line reclosers annually. Operations during major events cannot be differentiated. The ability to calculate this excluding major event data would require a multimillion-dollar investment in smart meters.

20.50.12.11(A)(4) A description of the utility's reliability objectives, planned actions and projects, and programs for providing reliable electric service.

20.50.12.11(A)(5) An assessment of the results and effectiveness of the utility's reliability objectives, planned actions and projects, programs and load studies in achieving an acceptable reliability level.

PE strives to provide safe, affordable and reliable electric service to its customers and, as such, supports several programs to maintain reliability of the system. The operation and maintenance ("O&M") programs impose schedules for regular inspection of distribution facilities, which in turn, reduces the potential of distribution line and equipment caused outages.

PE's O&M programs and practices balance cost and benefit while identifying and repairing unsafe conditions or areas that may adversely affect service reliability or system performance. Within these practices, schedules are established for regular inspection of distribution facilities. Specifically, PE conducts:

- A visual inspection of distribution circuits and equipment from the substation to the first protective device every two years, as well as a total circuit line and equipment inspection every six years;
- A visual inspection, and when necessary, a physical inspection of wood poles every ten years;
- A visual inspection of above-ground pad-mounted transformers and distribution underground equipment every five years;
- A visual inspection of distribution line capacitors annually; and
- A visual inspection of distribution substation equipment and a distribution substation safety and security inspection every two months.

These inspections provide an important basis for information in determining the need for, and prioritizing, the repair, improvement or replacement of PE's distribution facilities.

In addition to O&M, the Company utilizes other routine programs to ensure the reliability of its distribution system. First, the Company has maintained a 5-year cycle vegetation management program to support continued and safe operation of its distribution and subtransmission system. A more vigorous 4-year cycle program has been implemented beginning in 2021. Second, the Multiple Device Activation and CEMI programs both focus on clusters of devices and customers that experience frequent or repeated outages or other issues, such as momentary outages. These programs target enhanced system performance and establish a method to reduce the frequency of outages at the customer level. Third, PE continues to focus on remediation activities of the poorest performing feeders ("PPFs"), in efforts to improve reliability. Fourth, the Company engages in a reactive program for underground cable and targets those cables that have exhibited a history of failures. Within this program, projects are identified and ranked based on the number of customers affected, the number of failures and the impact on customer satisfaction. The program identifies underground cable in need of replacement and improves reliability and customer satisfaction. This program was increased significantly in 2020 as part of the Company's Electric Distribution Infrastructure Surcharge ("EDIS") program.

In addition to PE's 2021 projects related to its PPFs,[4] the Company also has several planned reliability projects to be implemented across its service territory. These include:

- Install a 230-34.5 kV substation and associated equipment west of Jefferson, MD. Since 2012, Potomac Edison has experienced nineteen source outages to Brunswick and Jefferson substations totaling 29.6 minutes of SAIDI. This averages 3.3 minutes per year. Adding the West Jefferson substation will help strengthen the subtransmission line feeding these substations. This will allow automatic restoration to each substation during all times of the year. This project will improve service to approximately 5,500 customers.
- Install two distribution automation (DA) schemes. A five-recloser DA scheme will tie together the Carroll – CW12 and Unionville – Route 31 circuits. This project is expected to save 276 customer interruptions and 30,647 customer minutes interrupted each year. Also, a five-recloser scheme will be installed that will tie together the Garrett – Hoyes Run Road and Thayerville – Mayhew Inn Road circuits. This project is expected to save 2,242 customer interruptions and 575,000 customer minutes interrupted each year. Additional details of these projects are provided in the company's 2020 Annual EDIS report.[5]
- Replace thirteen substation reclosers with single-pole tripping devices. The new reclosers are designed to only interrupt the faulted circuit phase(s) in the event of a fault that does not impact all three circuit phases. Existing substation circuit reclosers are usually three-phase devices that operate all three phases even when a fault occurs only on a single circuit phase. During momentary faults, the new reclosers analyze real-time data in order to minimize the number of customers interrupted. They also have remote-operation capabilities that allow system operators in the Distribution Control Center to operate the reclosers remotely and assist line workers in the field during restoration activities. Additional details and reliability savings of each installation are provided in the company's 2020 Annual EDIS report.[6]

20.50.12.11(A)(6) Current year expenditures, an estimate or budget amount for the following 2 calendar years, if available, current year labor resources hours, and progress measures for each capital and maintenance program designed to support the maintenance of reliable electric service.

20.50.12.11(B)(1) The actual operation and maintenance and capital expenditures for the past 3 calendar years for each utility's reliability programs, including, but not limited to underground and overhead distribution plant inspection, maintenance and replacement programs, vegetation management, subtransmission inspection and maintenance programs, and distribution substation plant inspection and maintenance programs.

[4] See section 20.50.12.03(C) of this report for PE's PFF remedial actions.
[5] Reference Maillog #232729 dated November 25, 2020
[6] Ibid

The tables below provide the 2020, 2021 and 2022 forecasted capital budgets, the 2018, 2019 and 2020 actual capital expenditures, plus operation and maintenance reliability- specific expenditures for the same periods, broken down by investment reason.

Note that the hours worked in 2019 and 2020 do not include contractor hours.

Capital Expenditures[7]
(Designed to Support Maintenance of Reliable Electric Service)

Program	Actual ($)		Budget ($)	Actual ($)	Labor Hours		Forecasted Budget ($)	
	2018	2019	2020	2020	2019	2020	2021	2022
Distribution								
Condition	9,763,816	5,138,888	7,385,211	6,369,100	17,363	24,288	7,228,546	17,558,112
Forced	25,860,387	48,843,028	44,644,753	42,220,281	166,664	130,325	39,881,167	38,079,236
Miscellaneous	3,093,446	3,658,335	2,895,986	4,175,304	21,078	22,240	3,015,147	2,980,930
System Reinforcement	972,205	651,278	2,143,865	3,669,795	2,070	10,910	4,018,861	1,139,752
Vegetation Management	3,241,788	4,308,956	4,809,080	3,719,946	4,172	3,425	5,771,469	5,934,634
Sub-Total	42,931,643	62,600,484	61,878,894	60,154,426	211,348	191,188	59,915,190	65,692,663
Transmission								
Condition	6,962,106	12,383,915	9,348,624	3,594,833	13,995	4,351	7,870,302	9,977,912
Forced	3,318,813	980,244	251,730	461,090	-	184	2,498,823	109,603
Miscellaneous	113,750	619,824	272,568	99,571	10,882	11,566	0	-
System Reinforcement	2,127,679	1,827,273	9,875,799	4,631,571	12,476	4,883	10,368,063	65,437,601
Vegetation Management	465,925	593,481	1,558,209	973,743	1,790	1,837	1,369,353	1,097,316
Sub-Total	12,988,274	16,404,737	21,306,930	9,760,808	39,143	22,821	22,106,542	76,622,433
TOTAL	55,919,917	79,005,221	83,185,824	69,915,234	250,491	214,008	82,021,732	142,315,097

Distribution Variances	
2020 Budget vs. Actual	
Condition	Under budget due to internal labor, contractor, material, and overhead costs being lower than planned.
Forced	Not applicable
Miscellaneous	Over budget due to internal labor, contractor, material, and overhead costs being greater than planned.
System Reinforcement	Over budget due to internal labor, contractor, material, and overhead costs being greater than planned.
Vegetation Management	Under budget due to the second cycle trim work required to achieve specification was slightly less than anticipated and the quantity of off corridor removals (capital) were not as high as projected.

Transmission Variances	
2020 Budget vs. Actual	
Condition	Under budget due to contractor, labor, material costs and related overheads being lower than planned.
Forced	Over budget due to contractor costs and related overheads being higher than planned.
Miscellaneous	Under budget due to contractor costs and related overheads being lower than planned.
System Reinforcement	Under budget due to labor, material costs and related overheads being lower than planned.
Vegetation Management	Under budget due to related overheads being lower than planned.

Definitions:
Condition – costs associated with replacement of outdated and/or poor performing equipment and reliability related costs Forced – costs associated with storm outage restoration, failed substation or line equipment and devices, regulatory required and relocations of facilities associated with roadways and bridge projects.
Miscellaneous – costs associated with corrective maintenance, operations, lighting and meter System
Reinforcement – costs associated with system reinforcement
Vegetation Management – costs associated with planned and unplanned tree trimming and vegetation management programs.

[7] Transmission expenditures have been updated from the 2019 Annual Reliability Report to include costs inadvertently excluded.

Operating & Maintenance Expenditures[8]
(Designed to Support Maintenance of Reliable Electric Service)

Program	Actual ($)		Budget ($)	Actual ($)	Labor Hours		Forecasted Budget ($)	
	2018	2019	2020	2020	2019	2020	2021	2022
Distribution								
Scheduled Maintenance	20,948	22,208	43,664	26,346	0	0	47,524	41,992
Corrective Maintenance	2,565,181	2,539,074	2,291,271	3,045,615	17,615	20,521	743,219	674,150
Vegetation Management	4,633,262	5,770,597	5,041,890	6,336,762	4,412	3,942	7,735,589	7,821,116
Other: Condition	1,952,741	2,033,169	2,605,333	2,380,514	23,114	23,985	1,775,463	3,933,081
Other: Forced	3,659,535	7,244,516	6,122,289	3,772,959	45,474	23,781	13,365,414	10,121,093
Other: Miscellaneous	1,461,945	1,536,546	1,146,833	1,653,155	17,004	18,213	957,884	1,024,281
Sub-Total	14,293,612	19,146,111	17,251,280	17,215,351	107,619	90,442	24,625,094	23,615,712
Transmission								
Scheduled Maintenance	113,707	124,877	881,265	284,367	12,405	1,931	1,448,596	1,457,785
Corrective Maintenance	1,285,183	1,531,100	868,322	1,335,436	14,331	13,596	952,720	976,921
Vegetation Management	919,070	729,537	1,298,232	1,139,129	3,182	2,075	2,278,873	2,154,655
Other: Condition	146,131	504,530	410,455	397,317	220	1,576	1,365,106	1,396,999
Other: Forced	543,776	546,873	-	157,798	-	1,050	13,340	13,323
Other: Miscellaneous	428,072	413,862	799,972	632,702	1,971	1,903	603,516	693,451
Sub-Total	3,435,939	3,850,779	4,258,246	3,946,749	32,109	22,130	6,662,151	6,693,135
Total	17,729,550	22,996,890	21,509,526	21,162,101	139,728	112,572	31,287,245	30,308,847

Distribution Variances	
2020 Budget vs. Actual	
Scheduled Maintenance	Under budget due to internal labor, contractor, material, and overhead costs being lower than planned.
Corrective Maintenance	Over budget due to internal labor, contractor, material, and overhead costs being greater than planned.
Vegetation Management	Over budget due to internal labor, contractor, material, and overhead costs being greater than planned.
Other: Condition	Not applicable
Other: Forced	Under budget due to internal labor, contractor, material, and overhead costs being lower than planned.
Other: Miscellaneous	Over budget due to internal labor, contractor, material, and overhead costs being greater than planned.

Transmission Variances	
2020 Budget vs. Actual	
Scheduled Maintenance	Under budget due to labor costs being lower than planned.
Corrective Maintenance	Over budget due to labor and transportation costs being higher than planned.
Vegetation Management	Under budget due to labor and Vegetation Management contractor costs being lower than planned.
Other: Condition	Not applicable
Other: Forced	Over budget due to labor and contractor costs being higher than planned.
Other: Miscellaneous	Under budget due to labor costs being lower than planned.

Definitions:
Condition – costs associated with obsolete equipment, fix-it-now, and reliability
Corrective Maintenance – costs associated with corrective maintenance, operations and preventative maintenance Forced – costs associated with failures, IPP/Municipal connect, relocations, storms and substation failures Miscellaneous – costs associated with system reinforcement, lighting and meter
Scheduled Maintenance – costs associated with scheduled maintenance
Vegetation Management – costs associated with planned and unplanned vegetation management activities

8 Transmission expenditures have been updated from the 2019 Annual Reliability Report to include costs inadvertently excluded.

20.50.12.11(A)(8) The number of outages by outage type including planned outage, non- planned outage minus major outage event, and major outage event.

20.50.12.11(A)(9) The number of outages by outage cause including, but not limited to, animals, overhead equipment failure and underground equipment failure.

20.50.12.11(A)(10)(11) The total number of customers that experienced an outage and the total number of customer minutes of outage time

Outage Category	Number of Outages	Customers Affected	Customer Outage Minutes
Planned	786	8,334	1,221,016
Non-Planned Minus Major Outage Events	4,705	251,687	35,371,777
Major Outage Events	0	0	0
Total	**5,491**	**260,021**	**36,592,793**

The table below represents a breakdown of the above table into specific outage causes, excluding the major outage events.

Outage Cause	Number of Outages	Customers Affected	Customer Outage Minutes
Vegetation	1,222	88,398	16,957,628
Overhead ("OH") Equipment Failure	686	54,327	6,101,452
Underground ("UG") Equipment Failure	715	19,135	3,078,855
Weather (not lightning)	55	12,251	2,142,366
Lightning Strike	53	2,982	350,674
Equipment Hit	94	9,609	1,210,378
Animals	966	20,987	2,038,586
Overload	5	572	49,641
Other[9]	384	22,202	1,529,192
Planned Outages	786	8,334	1,221,016
Unplanned Planned Outages[10]	0	0	0
Unknown	525	21,224	1,913,005
Total	**5,491**	**260,021**	**36,592,793**

[9] Other: Human Error Company, Forced Outage, UG Dig-up, Fire, Object Contact with Line, Customer Equipment, Vandalism, Human Error Non-Company, Other Utility-Non Electric

[10] PE does not record unplanned planned outages in the manner defined by Maryland PSC Staff and is, therefore, reporting zero in this category.

20.50.12.11(A)(12) To the extent practicable, a breakdown, by the number of days each customer was without electric service, of the number of customers that experienced an outage.

The following chart provides a breakdown of the number of customers that were associated with outages lasting less than one day, between one day and two days, and so on. The sum of these values is equal to the total number of customers interrupted by a sustained outage during reporting year 2020 (i.e. 642 customers were impacted by an outage event lasting longer than one day but less than two days).

	≤1 day	>1 & ≤2 Days	>2 & ≤3 days	>3 & ≤4 days	>4 & ≤ 5 days	>5 & ≤6 days	>6 & ≤7 days	>7 & ≤8 days	>8 days
All Interruptions	259,379	642	0	0	0	0	0	0	0
All Interruptions Minus Major Outages	259,379	642	0	0	0	0	0	0	0

20.50.12.11(A)(13) Poorest performing feeder information and results.

20.50.12.03(A)(1) A utility shall report CAIDI, SAIDI and SAIFI indices of all feeders assigned to Maryland that are identified by the utility as having the poorest feeder reliability.

20.50.12.03(A)(2) Each index shall be calculated and reported in the annual performance report using all interruption data minus the following exclusions:

(a) Source loss, including any outage that occurs on the feeder by an event occurring external to the feeder;
(b) Major outage events; and
(c) Planned outages.

20.50.12.03(D)(2)(a) The feeders used in determining the utility's system-wide SAIDI and SAIFI performance results as reported to the Commission by the utility's 2010 annual reliability report shall be assigned to Maryland unless otherwise directed by the Commission.

20.50.12.03(A)(3) For each utility, the feeders with poorest reliability shall be all feeders having circuit reliability performance 250 percent or more above the utility's System-Wide SAIFI and SAIDI, which shall be calculated in accordance with the exclusions identified in §A(2) of this regulation.

PE has 353[11] distribution circuits serving at least one customer in the state of Maryland. Of these 353 circuits, PE submits five distribution circuits that have the poorest reliability based on the ranking method described in COMAR 20.50.12.03.

[11] PE notes that the 353-circuit count includes 339 circuits which are assigned to Maryland and are used to calculate PE's reliability statistics. The 353-circuit count also includes 14 circuits which are not assigned to Maryland and are therefore not used to calculate PE's reliability statistics, but which serve at least one Maryland customer, and are therefore included in order to evaluate PE's PPFs.

Feeder Name	Substation	No. of Customers on Feeder	All Interruptions			All Interruptions Minus Major Outage Events			Special Medical Needs Facilites Served	Repeat PPF from 2019? (Y/N)
			SAIFI	SAIDI (Min)	CAIDI (Min)	SAIFI	SAIDI (Min)	CAIDI (Min)		
Little Orleans	Great Cacapon	335	4.50	3,300.19	734.1	4.50	3,300.19	734.1	0	Y
Mayhew Inn Road	Thayerville	1,497	4.33	1,574.95	364.1	4.33	1,574.95	364.1	0	N
Bartholows	Mt. Airy	455	3.70	813.14	219.8	3.70	813.14	219.8	0	N
Lynn Burke	New Market	951	3.42	1,401.01	410.1	3.42	1,401.01	410.1	0	N
Pysell Crosscut	Oakpark	1,735	3.40	2,240.42	659.3	3.40	2,240.42	659.3	0	N

20.50.12.03(A)(4) No feeder shall appear in a utility's list of poorest performing feeders during three consecutive 12-month reporting periods, unless the utility has undertaken reasonable remediation measures to improve the performance of the feeder.

Poorest Performing Feeders 2018

Feeder Name	Substation	Rank History		
		2018	2019	2020
Little Orleans	Great Cacapon	1	1	1
Catoctin Furnace	Catoctin	2	N/A	N/A
Williams Road	Messick Road	3	N/A	N/A
South	Lonaconing	4	N/A	N/A
Hampshire Mine	Mt. Zion	5	N/A	N/A

Poorest Performing Feeders 2019

Feeder Name	Substation	Rank History	
		2019	2020
Little Orleans	Great Cacapon	1	1
Green Ridge	Flintstone	2	N/A
Bittinger	Jennings	3	N/A
Route 144	Ridgeville	4	N/A
Town Hill	Hancock	5	N/A

Poorest Performing Feeders 2020

Feeder Name	Substation	Rank History
		2020
Little Orleans	Great Cacapon	1
Pysell Crosscut	Oakpark	2
Mayhew Inn Road	Thayerville	3
Lynn Burke	New Market	4
Bartholows	Mt. Airy	5

Despite remediation work that was completed on the Little Orleans circuit in years 2019 and 2020, its performance ranked it as a repeating Poorest Performing Feeder (PPF) in the 2020 reporting period. An overview of the circuit and its historical performance is provided in the tables below.

Little Orleans Circuit Description		
Length (miles)	Cust. Served	Description
23.7	335	Rural, heavily treed circuit area which serves load primarily in the Hancock and Little Orleans, Maryland areas

Little Orleans Reliability Performance					
Period	Incidents	CMI	SAIDI	SAIFI	CAIDI
2018	21	1,038,270	3,099	6.62	468
2019	18	1,248,007	3,725	7.32	509
2020	8	1,105,562	3,300	4.50	734

Little Orleans Top Outage Causes	
Period	Description
2018	Trees
2019	Trees
2020	Trees, Vehicle/Helicopter

Little Orleans circuit was originally ranked as a PPF in the 2018 reporting period with twenty-one outage incidents and a total of 1,038,270 customer minutes interrupted (CMI). Little Orleans appeared as a 2018 PPF primarily due to four large incidents that accounted for 811,567 or 78% of the total CMI. These four incidents were caused by off ROW trees involving more than 300 customers and more than 130,000 CMI each. Of the twenty-one incidents, seventeen were caused by trees which accounted for more than 99% of the total CMI on the circuit.

During 2019, Potomac Edison completed a scheduled full circuit tree trim, which included the removal of danger trees, and completed the scheduled overhead circuit inspection. The Company also completed follow-up construction for issues identified during the inspection as needing repaired or replaced.

Despite the remediation work that was completed on the Little Orleans circuit during 2019, its performance resulted in a PPF ranking again in the 2019 reporting period with eighteen outage incidents and a total of 1,248,007 CMI. Little Orleans appeared as a 2019 PPF primarily due to seven large incidents caused by off-ROW trees involving more than 300 customers and more than 65,000 CMI each. Those seven incidents totaled 1,018,401 CMI for 82.6% of the total. Four of the seven incidents occurred during storms with the largest occurring on February 25, 2019 with 474,118 CMI.

In 2020, a danger tree patrol was completed, and identified trees were removed from a 4,500 foot section of the circuit that has been susceptible to incidents caused by off- ROW trees.

Potomac Edison also attempted to install SCADA-controlled reclosers at strategic locations along the circuit to more efficiently route the line crews to the problem area. However, due to poor signal strength throughout the rural area of this circuit, communications (microwave and cellular) needed for SCADA indication and control were not able to be established and the project was discontinued.

A Distribution Automation scheme was also considered as a solution to the Little Orleans reliability issue. However, due to its rural location with no adjacent circuit ties, extensive construction work would be required to implement this solution. The Little Orleans circuit was then proposed as an Energy Storage Device candidate under the MD Energy Storage Pilot Program for completion in 2022. A battery-storage system would have provided the second source to Little Orleans during outages by strategically placing it on the circuit away from the areas where most of the off-ROW tree incidents occurred. This would have allowed an automation scheme to be established to automatically isolate the faulted section of the circuit and automatically restore power to the remaining portion of the circuit serving the most customers. The battery system would have been sized to provide ride-through for the typical outage durations until repairs could be made and the normal source re-established to serve the load. This project was outsourced to a consultant for engineering and design where it ultimately was discovered that the battery-storage system could not properly be applied to the Little Orleans circuit since it is a single-phase circuit for most of its length. The Energy Storage project for Little Orleans circuit was abandoned due to this finding.

Despite the remediation work that was completed on the Little Orleans circuit in years 2019 and 2020, its performance ranked it as a repeating PPF in the 2020 reporting period with eight outage incidents and a total of 1,105,562 CMI. Little Orleans appeared on the PPF list in the 2020 reporting period primarily due to one very large incident, caused by an off-ROW tree, which occurred during a storm on November 2, 2019 and accounted for 64% of the total CMI of 708,794. A second large incident caused by an off-ROW tree resulted in 140,140 CMI and a third large incident caused by a helicopter clipping the conductors on a 1,300-foot span across the Potomac River resulted in 158,543 CMI.

A full overhead circuit inspection was completed on the Little Orleans circuit on May 11, 2020 from which repair work has been identified and scheduled for construction in 2021.

Despite implementing all traditional remediation measures, Little Orleans continues to experience incidents caused by off-ROW trees placing it on the PPF list. Potomac Edison has therefore focused on a more robust solution to this reliability issue. Several overhead sections of the Little Orleans circuit most prone to off-ROW tree outages have been evaluated and two portions have been identified to be relocated and placed underground. Potomac Edison does not normally propose placing existing overhead facilities to underground for reliability improvement, but in this case, it appears to be a viable option. To immediately address the Little Orleans repeater PPF in 2021, Potomac Edison designed the following two projects to place existing overhead facilities underground:

1. Approximately 3,000 feet of an existing overhead portion of circuit in Washington County, Maryland
2. Approximately 2,000 feet of an existing overhead portion of circuit in Allegany County, Maryland.

Potomac Edison is planning to complete these two projects by December 31, 2021.

20.50.12.03(C) Evaluation of Remedial Actions. For the feeders identified as having the poorest performing performance, the utility shall provide the following information:
(1) In the annual performance report in which the feeders are identified as requiring reasonable remediation measures, a brief description of the actions taken or proposed, if any, to improve reliability and the actual or expected completion date of the action

Below are PE's remedial actions to the performance based poorest performing feeders, including a brief description of any actions taken or proposed, to improve reliability and expected completion date.

Feeder Name	Substation	Remedial Action Description	Actual/Expected Completion Date
Little Orleans	Great Cacapon	1) Convert an overhead portion of circuit to underground in Washington County, Maryland 2) Convert an overhead portion of circuit to underground in Allegheny County, Maryland	12/31/2021 12/31/2021
Pysell Crosscut	Oakpark	1) Complete fuse coordination on portion of circuit	9/30/2021
Mayhew Inn Road	Thayerville	1) Complete EDIS Distributon Automation (DA) Scheme with Hoyes Run Road circuit	12/31/2021
Lynn Burke	New Market	1) Completed 11/18/2020: Installed electronic line recloser for additional sectionalizing. 2) Install additional sectionalizing devices, install fault indicators, externally fuse and animal guard	11/18/2020 9/30/2021
Bartholows	Mt. Airy	1) Forestry completed full circuit trim on regular cycle in 2020 2) Install additional sectionalizing devices, complete fuse coordination on portions of circuit, externally fuse	5/23/2020 9/30/2021

20.50.12.03(B) Poorest Performing Feeder Standard for Feeders Not Assigned to Maryland.

(1) Report the feeder's CAIDI, SAIDI, and SAIFI indices; if the feeder would have been included on the poorest performing feeder list but for the fact that the feeder is not assigned to Maryland.
(2) Report the number of customers located in Maryland and the number of customers located in a bordering jurisdiction
(3) Implement reasonable remediation measures to improve the performance of the feeder portion serving Maryland customers.

PE does not have any PPFs to report in this section.

20.50.12.11(A)(14) Multiple device activation information and results

20.50.12.04(A) Report the number of devices that activated five or more times during the prior 12-month reporting period causing sustained interruptions in electric service, including during major outage events, to more than ten Maryland customers.

20.50.12.04(B) For each device referenced in § A, evaluate and report the cause of the multiple activations.

20.50.12.04(C) For each device referenced in §A, implement reasonable remediation measures to reduce the number of activations and describe the measures

The table below provides a list of the protective devices that activated five or more times during the reporting period causing sustained interruptions in electric service, including during major events, to more than ten Maryland customers. Protective devices are defined as substation breakers and reclosers, line reclosers, line sectionalizing equipment and line fuses.

Protective Device ID	Device Description/ Type	Outage Cause(s)	No. of times activated	No. of Customers Affected	Remediation Measures	Repeat from 2017 (Y/N)	Repeat from 2018 (Y/N)	Repeat from 2019 (Y/N)	Special Medical Needs Facilities Served (Y/N)
G13845-PE18	Fuse	Trees, Ice	5	13	1. Complete fuse coordination on portion of circuit	N	N	N	N
A1517-PE11	Recloser	Trees, Line failure, Forced outage	5	126	1. Complete fuse coordination on portion of circuit	N	N	N	N
G11459-PE11	Fuse	Trees, Unknown, Ice	6	10	1. Complete fuse coordination on portion of circuit	N	N	N	N
G9431-PE18	Recloser	Trees, Vehicle	5	46	1. Complete fuse coordination on portion of circuit	N	N	N	N
G3126-PE11	Fuse	Unknown, Trees, Line failure	7	84	1. Complete fuse coordination on portion of circuit	N	N	N	N
F21920-PE12	Fuse	Trees, Wind	5	13	1. Completed 2/13/2021 - Forestry completed full circuit trim. 2. Install additional sectionalizing devices, install animal guards on OH transformers.	N	N	N	N
F41328-PE12	Recloser	Trees, Wind	5	67	1. Install additional sectionalizing devices. 2. Forestry to complete danger tree patrol on portion of tap.	N	N	Y	N
F54675-PE12	Fuse	Line failure (UG Cable), Planned	6	33	1. Completed 2/21/2020 - replaced several failed spans of primary UG cable. 2. Replace UG cable 2021: Replace remaining spans of UG cable on this tap.	N	N	N	N
MD2387A-PE19	Fuse	Unknown, Trees, Line failure	6	12	1. Completed 2/13/21 - Forestry completed full circuit trim. 2. Install additional sectionalizing devices, install animal guards on OH transformers.	N	N	N	N
U3529-PE19	Fuse	Trees, Unknown, Line failure	5	43	1. Forestry to complete full circuit trim. 2. Install additional sectionalizing devices, install animal guards on OH transformers.	N	N	N	N
F27408-PE15	Fuse	Trees, Forced, Planned	5	33	1. Install additional sectionalizing devices, complete fuse coordination on portion of circuit, install animal guards on OH transformers.	N	N	N	N

20.50.12.11(B)(2) Service restoration requirement information and results.

20.50.12.06(A) A utility shall restore service within 8 hours, measured from when the utility knew or should have known of the outage, to at least 92 percent of its customers experiencing sustained interruptions during normal conditions.

20.50.12.06(B) A utility shall restore service within 50 hours, measured from when the utility knew or should have known of the outage, to at least 95 percent of its customers experiencing sustained interruptions during major outage events where the total number of sustained interruptions is less than or equal to 400,000 or 40 percent of the utility's total number of customers, whichever is less.

Normal Conditions		Major Outage Events	
% of Interruptions Restored within 8 Hours		% of Interruptions Restored within 50 Hours	
Actual	COMAR Standard	Actual	COMAR Standard
96.44%	92%	N/A	95%

20.50.12.06(E) If a utility fails to satisfy the standard during the previous calendar year, it shall provide a corrective action plan.

PE satisfied the standards of this regulation in 2020, therefore, a corrective action plan is not required.

20.50.12.11(B)(3) Downed wire response performance information and results.

Considering data for normal and major event conditions, PE responded to a government agency responder guarded downed electric utility wire within three hours or less after notification 99.06% of the time during the 2020 reporting period.

Government Emergency Responder Guarded Downed Wires	
% of Gov't Emergency Responder Guarded Downed Wires Responded to Within 3 Hours After Notification by a Fire Department, Police Department or 911 emergency dispatcher	COMAR Standard
99.06%	90.0%

20.50.12.07(B) If a utility fails to satisfy the standard during the previous calendar year, it shall provide a corrective action plan.

PE satisfied the standards of this regulation in 2020, therefore, a corrective action plan is not required.

20.50.12.11(B)(7) For the immediately preceding calendar year, and considering normal conditions only:

(a) The number of downed electric utility wires to which the utility responded in:
(i) 4 hours or less;
(ii) More than 4 hours but less than 8 hours;
(iii) 8 hours or more; and
(b) The total number of downed electric utility wires reported to the utility

During the reporting period, PE received 1,126 reports of downed electric wires during normal conditions. The tables below show the number of downed electric utility wires in which PE responded.

	Total Reported Downed Wires	Total Utility Responsible Wires	3 Hours or Less	More than 3 Hours but Less than 8 Hours	8 Hours or More
Normal Condition Downed Wires	1,126	747	572	121	54

20.50.12.11(B)(4) Customer communications performance information and results.

20.50.12.08(A) Customer Telephone Call Answer Time Standard. Each utility shall answer within 30 seconds, on an annual basis, at least 75 percent of all calls offered to the utility for customer service or outage reporting purposes.

20.50.12.08(B) Abandoned Call Rate Standard. Each utility shall achieve an annual average abandoned call percentage rate of 5 percent or less, calculated by dividing the total number of abandoned calls by the total number of calls offered to the utility for customer service or outage reporting purposes.

% of Calls Answered within 30 seconds	COMAR Standard	% Annual Abandoned Calls	COMAR Standard
87%	≥75%	2.36%	≤5%

Customer telephone call answer time rate and abandoned call rate includes calls offered to a customer service representative, interactive voice response system ("IVR") or an overflow system. The abandoned call rate is calculated by dividing the total number of abandoned calls by the total number of calls offered to the utility for customer service or outage reporting purposes.

20.50.12.08(H) Corrective Action Plan. If a utility fails to satisfy the standard in § A, B or C, of this regulation, it shall provide a corrective action plan in its annual performance report.

PE satisfied the standards of this regulation in 2020, therefore, a corrective action plan is not required.

20.50.12.08(D) Other Customer Communications Information. Each utility shall state in its supplemental annual performance report:

(1) Based solely upon those calls offered to its customer service representatives:
- ***(a) The percentage of calls that are answered within 30 seconds; and***
- ***(b) The abandoned call percentage rate; and***

(2) The average speed of answer, which shall be calculated by dividing the total amount of time callers spend in queue after requesting to speak to a customer service representative through the automated voice response system by the total number of calls handled, including calls handled by the automated voice response system.

% of Calls Answered Within 30 Seconds	% Abandoned Calls	Average Speed of Answer (Seconds)
62%	7.11%	35

20.50.12.09(C)(3) Each utility shall include a summary of the information required under §C(2) of this regulation about its vegetation management during the preceding calendar year, and shall describe vegetation management planned for the current calendar year, as part of the annual performance report.

See Appendix A for a summary of the vegetation management work completed in 2020. When performing vegetation management, PE physically performs the following methods: brush removal by cutting or mowing, brush control utilizing hydraulic foliage, low volume basal, and cut surface herbicide application techniques, off and on corridor tree removal, including off corridor hazard trees, property owner notification, and the pruning of trees which can originate either from off or on the corridor. All vegetation activities are performed with oversight by a Maryland Licensed Tree Expert, and all vegetation management activities are documented for each circuit in the Company's inspection records.

20.50.12.09(C)(3)(a)(b) Expenditures for vegetation management in the preceding calendar year and vegetation management budget for the current calendar year.

See the charts in section 20.50.12.11(A)(6) on pages six and seven of this report for the distribution and subtransmission expenditures for 2020, as well as the budget for 2021 and 2022.

20.50.12.09(C)(3)(c) Circuits or substations, completion dates, and the estimated number of

overhead circuit miles trimmed in the preceding calendar year in compliance with the cyclical vegetation management requirements.

See Appendix A for a summary of the 1,264 circuit miles that PE completed vegetation management on in 2020. This summary identifies feeders where vegetation management is 100% complete.

Six feeders that were originally scheduled for 2020 were not started but will be 100% completed in 2021. These feeders are:

Potomac Park – 20.8 miles (to be completed first quarter 2021)
Bidle Hill – 14.9 miles (completed first quarter 2021)
Cone Branch Road – 3.0 miles (completed first quarter 2021)
Town – 14.8 miles (to be completed first quarter 2021)
AB3 – 3.9 miles (to be completed second quarter 2021)
FA3 – 3.6 miles (completed first quarter 2021)

Six feeders that were originally scheduled in 2020 were only partially completed but will be 100% completed in 2021. These feeders are:

#3 North Branch (MD Portion) – 1.2 miles (to be completed third quarter 2021)
North – 48.6 miles (completed first quarter 2021)
Woodville – 29.3 miles (completed first quarter 2021)
Marsh Pike - 24.4 miles (completed first quarter 2021)
Tall Oaks – 8.9 miles (completed first quarter 2021)
WB1 – 6.6 miles (completed first quarter 2021)

Twelve feeders were added to the schedule and completed in 2020. The additional feeders are:

Rosemont - 0.9 miles
Largent (MD Portion) - 0.3 miles
Rock Creek – 23.9 miles
Nolans Ferry - 0.8 miles
RA 2 - 3.5 miles
WT2 - 0.8 miles
WD3 - 5.3 miles
SM2 - 3.3 miles
WH0 - 0.8 miles
PR - 0.6 miles
RG1 - 0.4 miles
RA1 - 2.6 miles

20.50.12.09(C)(3)(d) Circuits or substations and the estimated number of overhead miles scheduled for the current calendar year in compliance with the cyclical vegetation management requirements.

See Appendix B for a list of the circuits which represent the 1,494 overhead circuit miles of vegetation management scheduled to be completed in 2021.

20.50.12.09(C)(3)(e) Total overhead circuit miles for the system.

PE currently has 6,059 miles of overhead circuit miles on its system.

20.50.12.09(C)(3)(f) If applicable, a corrective action plan.

COMAR 20.50.12.09(F)(2) states that in the third year of a five-year trim cycle a utility shall perform vegetation management on not less than fifty-six percent of its total distribution miles. PE performed vegetation management in 2020 for a combined total of fifty-six percent of its overhead circuit miles therefore a corrective action plan is not required.

20.50.12.11(B)(6) Periodic equipment inspection information and results

PE has adopted written procedures for the inspection of its equipment in order to maintain safe and reliable service. On March 31, 2020, these programs were filed with the Commission. The O&M filing included programs for wood poles, overhead circuits and equipment, pad-mounted transformers and underground equipment, line capacitors and substation patrols.

PEs compliance with its 2020 planned inspection program is demonstrated in the chart below:

<table>
<tr><th colspan="5">Potomac Edison</th></tr>
<tr><th colspan="2"></th><th>Frequency</th><th>Planned</th><th>Completed</th></tr>
<tr><td rowspan="6">Distribution</td><td>Wood Poles</td><td>10 years</td><td>20,680</td><td>23,593</td></tr>
<tr><td>Overhead Circuits and Equipment from Substation to First Protective Device</td><td>2 years</td><td>157</td><td>157</td></tr>
<tr><td>Overhead Circuits and Equipment</td><td>6 years</td><td>62</td><td>62</td></tr>
<tr><td colspan="2">Total Circuits Inspected</td><td>219</td><td>219</td></tr>
<tr><td>Pad-mounted Transformers & Underground Equipment</td><td>5 years</td><td>15,183</td><td>15,183</td></tr>
<tr><td>Line Capacitors</td><td>Annual</td><td>449</td><td>449</td></tr>
<tr><td>Substation</td><td>Patrol Inspections[12]</td><td>2 months</td><td>320</td><td>320</td></tr>
</table>

[12] In addition to the patrol inspections that are completed, twice a year PE also conducts an open cabinet inspection to obtain equipment readings and perform seasonal preventative maintenance.

APPENDIX

APPENDIX A

Substation Name	Feeder/Circuit	Overhead Mileage	Date Complete
Bedford Road	Lake Gordon (MD Portion)	14.8	5/13/2020
Bedford Road	Rt 220 North (MD Portion)	0.1	1/23/2020
Bedford Road	Rt 220 South	27.3	5/12/2020
Braddock Heights	Boulevard	16.5	7/22/2020
Braddock Heights	Hollow Road	7.0	5/20/2020
Braddock Heights	Route 40 A	7.3	7/9/2020
Brunswick	Sandy Hook	40.5	1/2/2020
Brunswick	Rosemont	0.9	1/9/2020
Catoctin	Catoctin Furnace	48.6	3/18/2020
Coverwood	Bishop Walsh Drive	7.8	5/20/2020
Coverwood	Searstown	3.5	5/11/2020
Cresaptown	Bel-Aire	4.1	11/5/2020
Cresaptown	McMullen Hwy	19.0	12/26/2020
Damascus	Purdum	37.3	4/2/2020
Damascus	Howard Chapel	9.2	3/18/2020
Eaglehead	Mt. Pleasant	37.0	1/24/2020
Eaglehead	Summerfield	2.1	1/2/2020
East Hagerstown	Fairway Meadows	9.9	8/13/2020
East Hagerstown	Fox Deceived	8.5	7/2/2020
East Hagerstown	Hospital No 1	1.1	5/6/2020
East Hagerstown	Hospital No 2	1.0	6/4/2020
East Hagerstown	Mount Aetna	17.2	7/30/2020
East Hagerstown	Robinwood	1.6	5/7/2020
East Hagerstown	Youngstoun	1.6	6/18/2020
Frederick A	Carroll Street	3.9	3/27/2020
Frederick A	Frederick Iron & Steel	1.9	3/5/2020
Frederick A	Highs	4.4	3/26/2020
Frederick A	Hospital	1.8	3/19/2020
Frederick A	Northwest	2.7	3/27/2020
Frederick A	Southwest	4.5	2/5/2020
Frederick A	Wisner St	2.0	4/30/2020
Garrett	Hoyes Run Road	52.7	9/3/2020
Garrett	Marsh Hill Road	3.8	9/16/2020
Garrett	Rt 219 South	19.9	1/13/2020
General Office	Homewood	4.8	2/20/2020
General Office	Storeroom	12.4	7/9/2020
General Office	Downsville	52.4	9/24/2020
Halfway	Cedar Lawn	3.0	7/22/2020
Halfway	Elliott Parkway	0.8	7/9/2020
Halfway	Hopewell	1.6	8/13/2020
Halfway	Hunt Ridge	3.2	10/15/2020
Halfway	Kemps Mill	22.7	9/17/2020
Halfway	K-Mart	0.2	7/2/2020
Halfway	Lakeside	0.7	7/2/2020
Halfway	Newgate	0.1	6/17/2020
Halfway	Tandy	2.4	7/2/2020
Hazelton	Prison (MD Portion)	1.3	12/24/2020
Huyetts	South	0.03	12/31/2020
Key Mall	Grove Road	4.3	4/8/2020
Key Mall	Monocacy Battlefield	21.2	6/29/2020
Larkin	Largent (MD Portion)	0.3	12/31/2020
Lavale	Rt 40 East	14.6	7/7/2020
Lavale	Rt 40 West	5.3	9/17/2020
Lavale	Sunset View	5.1	9/22/2020
Mccain	Ballenger Creek	1.5	6/24/2020
Mccain	Brigadoon	7.0	7/9/2020

Substation Name	Feeder/Circuit	Overhead Mileage	Date Complete
Mccain	Center Park	1.3	6/25/2020
Mccain	Crestwood Village	3.1	7/14/2020
Mccain	Emerald Farm	0.6	7/22/2020
Mccain	Jefferson Street	5.2	7/29/2020
Mccain	Keys Stadium	3.3	7/9/2020
Mccain	Mccain Drive	0.1	7/21/2020
Mccain	Schaffer Drive	0.3	7/20/2020
Milnor	Mason Dixon (MD Portion)	1.8	9/11/2020
Monocacy	Community College	1.5	7/1/2020
Monocacy	Gov Johnson	8.9	7/21/2020
Monocacy	Mill Island	4.8	5/18/2020
Monocacy	North Crossing	1.5	5/21/2020
Monocacy	Opossumtown Pike	3.7	5/28/2020
Monocacy	Progress Hvd	0.04	6/18/2020
Monocacy	Riverside Hvd	0.01	6/18/2020
Monocacy	Wormans Mill	1.7	5/27/2020
Mt Airy	Long Corner	6.0	3/26/2020
Mt Airy	Village Gate	4.7	5/13/2020
Mt Airy	Twin Arch	9.1	6/18/2020
Mt Airy	Watersville Road	22.8	6/10/2020
Mt Airy	Bartholows	14.5	5/21/2020
Mt Airy	Main Street	6.3	3/26/2020
Myersville	Wolfsville	77.8	2/6/2020
Old Farm	Rock Creek	23.9	12/31/2020
Paramount No 1	West Longmeadow	12.3	6/4/2020
Petersville	Burkittsville	41.9	5/7/2020
Petersville	Landers	32.3	3/10/2020
Plaza	Braddock Run	10.5	5/7/2020
Plaza	Shopping Center	0.2	4/11/2020
PPG	Industrial Park	0.9	9/24/2020
PPG	Prison	0.5	9/24/2020
PPG	Super Fos	0.5	9/24/2020
Ridgeley	Main Street (MD Portion)	0.1	5/11/2020
Ridgeville	Rt 144	25.4	8/20/2020
Ridgeville	St Michaels Road	34.3	12/31/2020
Showalter	Maugansville	12.6	10/15/2020
Showalter	Orchard Hills	3.4	10/15/2020
Showalter	State Line	4.4	9/24/2020
South Frederick	Evergreen Point	3.0	10/21/2020
South Frederick	Linganore	14.2	9/17/2020
Thayerville	Mayhew Inn	41.7	12/9/2020
Thayerville	Turkeyneck	61.5	11/14/2020
Thomas Street	Shades Lane	15.3	3/11/2020
Thomas Street	Rt. 28 (MD Portion)	6.3	1/3/2020
Thomas Street	The Moose	1.5	1/3/2020
Tuscarora	Nolans Ferry	0.8	12/12/2020
West Frederick	7th Street	5.5	10/15/2020
West Frederick	Hillcrest	1.1	9/24/2020
West Frederick	Rosemont	6.0	11/5/2020
West Frederick	State Farm	0.6	9/22/2020
West Frederick	Westridge	1.3	9/24/2020
AT1 Tap-LK1-LK2 Tap (Hyattstown)	AD3	11.5	12/10/2020
B&O Shops-Canal Jct	BO1	0.3	9/10/2020
Boonsboro-Skycroft	O1	2.1	4/17/2020
Canal Jct-Thomas Street	BO2	1.0	9/10/2020
Carlos Jct-Chambers Landfill	CC	2.2	10/15/2020
Carlos Jct-Lonaconing	LW1	4.1	12/23/2020

Substation Name	Feeder/Circuit	Overhead Mileage	Date Complete
Catoctin-Thurmont & Raven Rock (MD Portion)	WT4	7.3	4/2/2020
Chambers Landfill-Cresaptown	CC1	4.3	12/17/2020
Coverwood-Plaza	CF3	1.2	4/23/2020
Cumberland - Lavale	CV	3.5	1/30/2020
Cumberland-Ridgeley (MD Portion)	RX	0.1	9/5/2020
Cumberland-Thomas Street (MD Portion)	CT	0.9	1/23/2020
Cumberland-Wills Mtn Jct	RN	3.9	10/1/2020
Fairchild Plant - Showalter	RA2	3.5	12/31/2020
Fort Detrick-Old Farm	DF2	2.1	7/2/2020
Fountain Head-Paramount	FR1	1.9	2/5/2020
Frederick A-Fort Detrick	DF1	2.6	7/2/2020
Frederick A-Frederick B	M1	0.8	3/26/2020
Frederick A-South Frederick	FK	0.7	2/5/2020
Ft Richie Tap-Blue Ridge Summit	WT2	0.8	12/31/2020
Garrett-Cablentertainment & Thayerville	GT	5.6	12/9/2020
Huyetts - Milnor (MD Portion)	WD3	5.3	12/10/2020
IP Tap-General	SM2	3.3	12/19/2020
Jefferson - Petersville	BF2	5.0	1/8/2020
Key Mall-Balleger Sewage	AL3	1.5	4/1/2020
Legore-Carroll	TL2	7.5	3/24/2020
Lonaconing-Westernport	LW2	6.1	12/3/2020
Marlowe-Ip Tap (MD Portion)	SM1	1.7	4/15/2020
Marlowe-Williamsport	WH0	0.8	12/24/2020
Mt Airy-Ridgeville	AD1	4.3	8/13/2020
Oldtown-Donaldson (MD Portion)	GR0/GR1	0.1	5/11/2020
Paramount-Reid	FR2	1.9	12/26/2020
Penna Glass & Sand-Hancock	H4	0.7	11/14/2020
Petersville - Brunswick	BF3	2.4	1/9/2020
Plaza-Frostburg No 2	CF4	4.2	10/8/2020
Park Head Jct-Cherry Run (MD Portion)	PR	0.6	11/28/2020
Reid - Bushtown	RG1	0.4	12/31/2020
Reid-Fairchild Plant2	RA1	2.6	11/14/2020
Reid-West Waynesboro (MD Portion)	REI-WWN	1.4	12/24/2020
Ridgeley-Ca3 Deadended (MD Portion)	CA3	2.2	11/25/2020
Ridgeley-Cumberland (MD Portion)	RR	0.1	9/3/2020
Ridgeville-AT1 Tap	AD2	1.6	10/28/2020
Skycroft-Myersville/Middletown	O2	8.8	4/17/2020
SM1-SM2 Bus-Rustoleum	IP	1.5	11/26/2020
South Frederick-Lime Kiln	FK1	4.5	7/27/2020
Swan Pond-Bg-Bg1 Bus (MELP) Tap (MD Portion)	BG	0.3	9/24/2020
Swan Pond-Cumb Sewage-B&O Shops (MD Portion)	BO	0.5	9/11/2020
Swan Pond-Pitts Plate Glass (MD Portion)	OP	1.2	9/24/2020
Swan Pond-Pitts Plate Glass-Sewage Plant (MD Portion)	MP	1.2	9/16/2020
Troutville Bus-Legore	TL1	1.2	3/24/2020
Tuscarora-Canam Steel	NT	3.1	12/30/2020

APPENDIX B

Substation	Circuit Name	Overhead Miles
Adamstown	Christian Brothers	16.8
Adamstown	Town	23.7
Bayard	#3 North Branch (MD Portion)	1.2
Beallsville	Barnesville	25.9
Beallsville	BH-12	38.6
Beallsville	Cattail Road	12.1
Beallsville	Poolesville	30.8
Boonsboro	Zittlestown	19.7
Carroll	CW-12	52.6
Carroll	Bark Hill Road	38.5
Carroll	Pfoutz Mill	48.6
Corriganville	Barrelville (MD Portion)	16.6
Cresaptown	Winchester Road	11.0
Cresaptown	Potomac Park	20.8
Damascus	Cedar Grove	2.9
Damascus	Etchison	24.2
Damascus	Hawkes Road	16.1
Damascus	Hawkins Creamery	8.2
Damascus	Kemptown	17.8
Damascus	Lewis Drive	10.7
Damascus	Plantations	3.2
Damascus	Sweepstakes Road	1.7
Damascus	Town	4.5
Damascus	Woodfield	11.2
Davis Mill	Brink Road	5.9
Flintstone	Chaneysville (MD Portion)	25.8
Frostburg #1	College Avenue	2.3
Frostburg #1	Midlothian	21.0
Frostburg #1	Northtown	8.2
Frostburg #1	Centertown	72.8
Frostburg #1	Victoria Lane	4.8
General Office	Friendship	10.3
Hancock	Town Hill	85.2
Hancock	Town	44.1
Hoyes	Accident	90.4
Huyetts	North	2.8
Jefferson	Town	20.1
Jennings	Closetmaid	2.5
Jennings	Grantsville	33.3
Legore	New Midway	62.0
Middletown	Bidle Hill	14.9
Middletown	Cone Branch Road	3.0
Middletown	Town	14.8
Mt Airy	Woodville	0.8
OakPark	Loch Lynn	44.8
Oldtown	Paw Paw	36.4
Oldtown	Green Spring (MD Portion)	0.3
Oldtown	Brice Hollow	43.7
Paramount	Marsh Pike	6.4

Substation	Circuit Name	Overhead Miles
Paramount No 1	Shawley Drive	11.2
Ridgeville	Tall Oaks	6.0
Sharpsburg	Dargan	54.7
Sharpsburg	Keedysville	53.4
Sharpsburg	Antietam (MD Portion)	29.3
Tuscarora	Point Of Rocks	5.0
Tuscarora	Licksville	39.1
Urbana	Rt 355	27.3
Urbana	Carriage Hill	0.7
Urbana	Urbana	11.5
Warfordsburg	Big Cove (MD Portion)	0.7
Warfordsburg	Buck Valley (MD Portion)	1.3
Yellow Springs	Whittier	5.4
Wb Tap(Wills Mtn)-Corriganville	NK2	1.9
West Frederick - DF1 Tap	DF	1.1
Wt4-Wt5 Tap-Raven Rock	UA	1.0
Adamstown-Tuscarora (NT Tap) & HA	FA2	4.1
Alleghany Ballistics-Cresaptown (MD Portion)	SG4	1.7
Aqueduct-Beallsville	AB3	3.9
Ballenger Sewage-Thomas Bakery	AL5-1	0.6
Bedford Road-M&M Quarries	WB1	4.7
BG-BG1 Bus-Oldtown(MELP) Tap	BG1	9.8
Braddock Heights-Mccain	O4	4.0
Carroll-Taneytown	L	7.2
Catoctin-Yellow Springs	TF1	11.4
Corriganville-Hyndman (MD Portion)	NK3	9.4
Cumberland-Coverwood	CF2	4.4
East Waynesboro-Catoctin (MD Portion)	EW-CTC	2.2
Emmitsburg-Worthington Pump	TT2	8.1
Flintkote-Key Mall Frederick	AL2	1.5
Frederick A-South Frederick & Flintkote	AL1	1.8
Frostburg No 2-Carlos Jct	FL	0.5
Georgia Pacific & Toys-R-Us-Tamko	AL6	0.7
Halfway Pump-HG1 Tap	WH2	2.3
Hancock-Mercersburg (MD Portion)	HE1	1.5
HG1 Tap-HG Tap	WH3	1.0
Lavale-Corriganville	CV1	4.1
Mack Truck-Fountain Head	RA4	1.3
Maidstone-Dam 5	S4	5.3
Middletown-Braddock Heights	O3	3.2
NK1-NK2 Bus(Wills Mtn)-Bedford	WB	4.2
Reid-Milnor	REI-MLN	0.1
Sharpsburg-Boonsboro	SA2	7.8
Shepherdstown-Sharpsburg	SA1	5.8
Swan Pond-Flintstone (MD Portion)	OF	12.3
Thomas Bakery - Georgia Pacific Toys R Us	AL5-2	2.0
Tuscarora-Aqueduct	FA3	3.6