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TECO’s Response to OPC's Third Set of Interrogatories Nos. 51-149

TAMPA ELECTRIC COMPANY
DOCKET NO. 20220048-EI
OPC'S THIRD SET OF INTERROGATORIES
INTERROGATORY NO. 51
BATES PAGE: 1
FILED: MAY 25, 2022

51. Referring to Exhibit DAP-1, Page 10 of 78, please confirm the CMI savings of the feeder automation program are not based on the 1898 & Co.'s Storm Resilience Model.

a. Why was the Storm Resilience Model not used to evaluate this program?

A. Feeder automation is a part of the Storm Resilience Model. The Storm Resilience Model employs two main calculation approaches for estimating benefits of hardening investments. The first approach develops a major storms event database, modeling of these storms in the Storm Impact Model, and then performing Monte Carlo simulation to 'trigger' storm probability over the next 50 years.

The second approach is applied for feeder automation. Feeder Automation Hardening Projects were evaluated based on historical outages and the expected decrease in historical outages if automation had been in place. While many of the other Storm Protection Programs provide resilience benefit by mitigating outages from the beginning, feeder automation projects provide resilience benefit by decreasing the impact of a storm event. Due to the nature of the projects and data available to calculate benefits, automation hardening projects benefits were evaluated based on historical outages and the expected decrease in historical outages if automation had been in place.

Please see Exhibit DAP-1, Appendix F, Page 66 of 82, section 5.4 for more details on the Feeder Hardening automation benefits assessment.

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INTERROGATORY NO. 52
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52. Referring to Exhibit DAP-1, Page 17 of 78, the Plan states that "all new lateral lines will be constructed underground if doing so will reduce storm restoration costs and outage times."

a. Does this mean all new laterals will be undergrounded since undergrounding reduces storm restoration costs? If this is not a true, explain why some new laterals will not be undergrounded.

b. Explain who pays for the undergrounding of the new lateral, the customer or TECO?

c. Identify all rules, instruction manuals, or guidelines used for determining when new laterals will be undergrounded.

A. a. No, in accordance with the Underground Residential Distribution ("URD") Tariff, not all new laterals are installed underground.

Pursuant to Commission Rule 25-6.078, Florida Administrative Code ("F.A.C."), each utility must file a written policy regarding installation of underground facilities in new subdivisions with the Commission. Once it is approved by the Commission, this written policy then becomes part of the utility's tariff. The policy must state the basis upon which the utility will provide underground service and its method for recovering the difference in cost, if any, between an underground system and an equivalent overhead system from the applicant, i.e. an underground differential charge. Rule 25-6.078 also sets out a specific methodology that the utility must use to calculate this differential.

In Tampa Electric's 2021 URD tariff filing in Docket 20210064-EI, the company followed the Commission methodology and determined that there would be a small positive differential in cost between underground and overhead service in a low density subdivision. As a result, the company's tariff currently requires developers to pay a small fee in order to receive underground service for a new low density subdivision. Some developers may decide not to pay the differential charge and instead receive overhead service. In those instances, the new laterals would not initially be constructed underground.

Rule 25-6.078(10) provides that the utility may waive the differential charge

if the Commission determines that there is a "quantifiable benefit to the general body of ratepayers commensurate with the waived differential." In the company's 2021 filing, Tampa Electric initially asked the Commission to waive the differential on the grounds that: (1) the general body of ratepayers would receive a financial benefit in the form of a reduction in storm restoration costs; (2) the general body of ratepayers may avoid the cost of converting overhead lines to underground via the SPP in the future; and (3) customers experience improved reliability from the performance of the underground facilities. Please see Tampa Electric's supplemental response to Staff's First Data Request No. 1, filed September 15, 2021 in Docket No. 20210064-EI for additional discussion of these benefits. The company was not, however, able to precisely quantify these benefits in a manner sufficient to satisfy the waiver provision of Rule 25-6.078(10). The company ultimately revised its petition to remove the request for a waiver of the differential. Tampa Electric still believes that customers would benefit from providing initial construction underground in low density subdivisions with no incremental charge, but the company must comply with the applicable Commission Rule.

b. See the response to Interrogatory 52.a, above. If the developer requests underground service for a new low-density subdivision they would be responsible for paying the cost differential.

c. See Rule 25-6.078, F.A.C., Rule 25-6.064 F.A.C, and Tampa Electric Tariff Sheet Nos. 5.210, 5.510, 5.515, 5.516. The website address to Tampa Electric's Tariff is provided below:

https://www.tampaelectric.com/company/ourpowersystem/tariff/

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53. Regarding undergrounding new construction, is the default service overhead?

A. Yes, with the exception of Tampa Electric designated geographical areas where electrical service is only available from an underground distribution system. Please refer to Tampa Electric's Tariff sheet number 5.250 section 3.3.3.1 for additional information.

The website address to Tampa Electric's Tariff is provided below:

https://www.tampaelectric.com/company/ourpowersystem/tariff/

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INTERROGATORY NO. 54
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54. Does the customer have to pay extra for underground service?

A. Yes, except in Tampa Electric designated geographical areas where electrical service is only available from an underground distribution system or high- density subdivisions. Please refer to Tampa Electric's Tariff sheet number 5.250 section 3.3.3.1 and sheet number 5.500 section 3.7.1.1 for additional information.

The website address to Tampa Electric's Tariff is provided below:

https://www.tampaelectric.com/company/ourpowersystem/tariff/

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55. If a new home is on a lateral to be undergrounded, explain if undergrounding the new service would be borne by the customer.

A. This is based on the customer's needs and timeframe.

Some customers are willing to wait until the SPP team plans to underground the lateral, then the underground service will be completed through the SPP program with the costs for undergrounding recovered through the SPP Cost Recovery Clause. In this scenario, the customer will not incur any other additional costs for the undergrounding of the service.

If the customer needs to have the service installed underground before the lateral conversion project would be completed as part of the SPP, then the customer is charged by the service just like any new customer that is installing a new service to a home that is not on a lateral scheduled for conversion under the SPP.

If the customer wants to have their service installed overhead and can't wait for the SPP program to get power to their home, then the company will install the service overhead at no charge to the customer (due to the investment allowance they get if going overhead) and SPP will then plan to underground that service when they work the project associated with this home.

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56 If borne by the customer, the SPP would convert the overhead service to underground. Explain the increased cost to the customer for this conversion after the overhead service is built.

A. Referring to the scenario provided in the answer to #55, if a customer needs to have service installed underground before the project would be completed as part of the SPP, the customer would be charged for Contribution in Aid of Construction in accordance with Rule 25-6.064 F.A.C. The increased cost stems from the fact that underground service is generally more expensive than overhead service.

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INTERROGATORY NO. 57
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57. For new subdivisions, what is the standard service: overhead service or underground service?

A. The standard service is overhead service except in Tampa Electric designated geographical areas where electrical service is only available from an underground distribution system. Please refer to Tampa Electric's Tariff sheet number 5.250 section 3.3.3.1 for additional information.

The website address to Tampa Electric's Tariff is provided below:

https://www.tampaelectric.com/company/ourpowersystem/tariff/

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INTERROGATORY NO. 58
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58. If undergrounding laterals is good for reliability, explain why overhead service for new subdivisions makes sense in light of the SPP?

A. Please see the Response No. 52a, this set.

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INTERROGATORY NO. 59
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59. In Mr. Pickles' opinion, should new services be initially installed underground or overhead based on his experience with the SPP?

A. I believe there is merit to making underground services the standard, where possible for new residential services. Overhead services routinely cause outage issues due to tree contacts, wildlife interference, vehicle accidents, etc. An underground service virtually eliminates many of our traditional outage causes, thus providing a higher degree of customer reliability. For the past three years, the approximate ratio of underground installations as compared to overhead installations is trending around three to one (3:1). It would not be a significant shift to capture the remaining one third recognizing that some portion of those customers would not be feasible for undergrounding.

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INTERROGATORY NO. 60
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60. Referring to Exhibit DAP-1, Page 18 of 78, please provide example calculations showing the Grade B Extreme Wind loading is 87% stronger than Grade C Extreme Wind Loading.

A. It should be noted that this statement refers to a safety loading factor under the National Electrical Safety Code ("NESC") Rule 250B (Combined Ice and Wind) and not Rule 250C (Extreme Wind). The referenced Safety Factor is value calculated as the Wind Load Factor divided by the Strength Factor (refer to NESC Tables 253-1 and 261-1 for these values).

For NESC Grade C the Safety Factor = 1.75 / 0.85 = 2.06
For NESC Grade B the Safety Factor = 2.50 / 0.65 = 3.85

NESC Grade B Safety Factor is stronger than Grade C Safety Factor 3.85/2.06 = 1.87 or 87 percent stronger.

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INTERROGATORY NO. 61
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61. Referring to Exhibit DAP-1 Page, 18 of 78 regarding the construction of triangular line using fiberglass brackets, please explain any experience regarding phase conductors slapping together in high winds when construction is a triangular line.

A. Tampa Electric has not had any experience with phase conductors slapping together during high wind conditions, including during events such as Hurricane Irma in 2017. This is supported by National Electrical Safety Code ("NESC") Table 235-3 which defines the minimum horizontal conductor spacing at the structure. For the company's 7,620V system with 336 ACSR Conductors, 300' Ruling Span and 300' horizontal span the calculated 37" final sag would require 16.3" of clearance at the structure which is much less than the approximate 54" of clearance found with triangular line construction.

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62. Referring to Exhibit DAP-1 Page, 18 of 78 regarding the construction of triangular line using fiberglass brackets, will the use of different construction types such as vertical or cross arm construction reduce outages from wire slap?

A. Tampa Electric has not had any experience with wire slap during high winds and does not believe it is an issue for the company's electrical system. Triangular construction provides multiple benefits such as being the most economical and suitability in restrictive clearance locations.

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63. Referring to Exhibit DAP-1 Page, 18 of 78 regarding the construction of triangular line using fiberglass brackets, why utilize a standard triangular configuration when Tampa Electric is improving its vegetation management practices to gain more clearance to conductors?

A. Triangular Construction reduces the clearance from the centerline of the pole to phase conductors from approximately 60" to 27" allowing the pole to be located 33" closer to the right-of-way/easement line. This would provide increased clearance from the traveled way and may reduce the amount of any required easements. The company follows a multi-pronged strategy when it comes to vegetation clearance and reducing harm caused by vegetation during large storms. This includes construction standards as well as vegetation management.

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64. Referring to Exhibit DAP-1, Page 21 of 78, regarding the submersible switchgear, are the electronic controls of the switchgear submersible?

A. The electronic controllers for submersible switchgear are not in themselves submersible. In case of immersion, switchgear will continue to be operable in a manual mode.

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65. Referring to Exhibit DAP-1, Page, 18 of 78 regarding the construction of triangular line using fiberglass brackets, please provide examples of the type and style of switchgear used (Trident, VFI, Vista, etc.).

A. Current switchgear includes S&C PME, Trayer Submersible, and Cooper VFI.

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INTERROGATORY NO. 66
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66. Referring to Exhibit DAP-1, Page, 18 of 78 regarding the construction of triangular line using fiberglass brackets, what grade of construction does Tampa Electric use when designing new overhead distribution line for NESC Extreme Wind?

A. Without regards to framing style, all new feeder construction and priority feeder hardening will utilize NESC Rule 250C (Extreme Wind) Grade B criteria.

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67. Referring to Exhibit DAP-1, Page 31 of 78, regarding the table with outage percentages, please confirm that the values are in percent of outages.

A. Yes, the values are in percent.

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68. Referring to Exhibit DAP-1, Page 31 of 78, how are the "outages" measured in this table (customers, events, CMI, duration, etc.)?

A. The outages calculation is based upon customer count.

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INTERROGATORY NO. 69
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69. Referring to Exhibit DAP-1, Page 31 and 32 of 78, regarding prioritizing undergrounding of laterals, is there any weight given to the relative location to other laterals to be undergrounded? (i.e. select several laterals on a single circuit)

A. Based on a lessons learned evaluation, the project definition for lateral projects was adjusted to include a collection of electrically connected protection zones, or 'branches' off the mainline feeder. Tampa Electric's undergrounding design standard includes looping for added resilience. While the project definition/scope has expanded for efficiencies, project prioritization is still based on the net benefit to customers. Additionally, the general approach is to underground all the beneficial laterals on a circuit in the same year.

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INTERROGATORY NO. 70
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70. Referring to Exhibit DAP-1, Page 31 and 32 of 78, regarding prioritizing undergrounding of laterals, is it less costly to underground all the laterals on a feeder rather than using a priority system where the laterals to be undergrounded are spread over a wider area? If so, why? If not, please explain.

A. Tampa Electric has not run that specific analysis so is unable to answer this question in its current form. The company has identified that it is more cost effective to do larger projects when compared to the smaller projects. It appears the ideal project size is around 1.5 miles, or greater, from the small sample set the company has performed to date. This data is supported by the cost per mile seen from the recent projects the company has completed. The company described the change in project definition and project scope size in the SPP and testimony and in the company's response to Interrogatory No. 69, above.

The company also incorporated geographic diversity into its prioritization for lateral undergrounding. At the core of the company's philosophy on the SPP is that it is a customer program, and all customers are sharing in the incremental cost. As such, all customers should benefit from the SPP and the programs. The company's projects, specifically in the Distribution Lateral Undergrounding Program, were intentionally grouped into four geographic buckets and then prioritized to ensure the projects and benefits were spread across the company's service territory.

In addition, in preparing the SPP, Tampa Electric and 1898 & Co. carefully considered the tradeoffs between approaches. It is important to note that a significant cost of lateral undergrounding is customer engagement. These costs will be significantly higher in an approach where lateral undergrounding is spread out across the entire system. To balance the cost efficiencies with benefit efficiencies, Tampa Electric took a hybrid approach. The modeling effort first identified all the laterals to underground for the 10 years. This factors in the benefit efficiencies. Then the model scheduled each of the laterals to execute all the laterals on a circuit in the same year. This approach allows for cost efficiencies and spread the work around the system over the 10 year horizon.

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71. For the number of laterals shown in the Table of Exhibit DAP-1, Page 32 of 78, what is the fewest number of customers on a single lateral?

A Please see Response No. 72, this set.

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INTERROGATORY NO. 72
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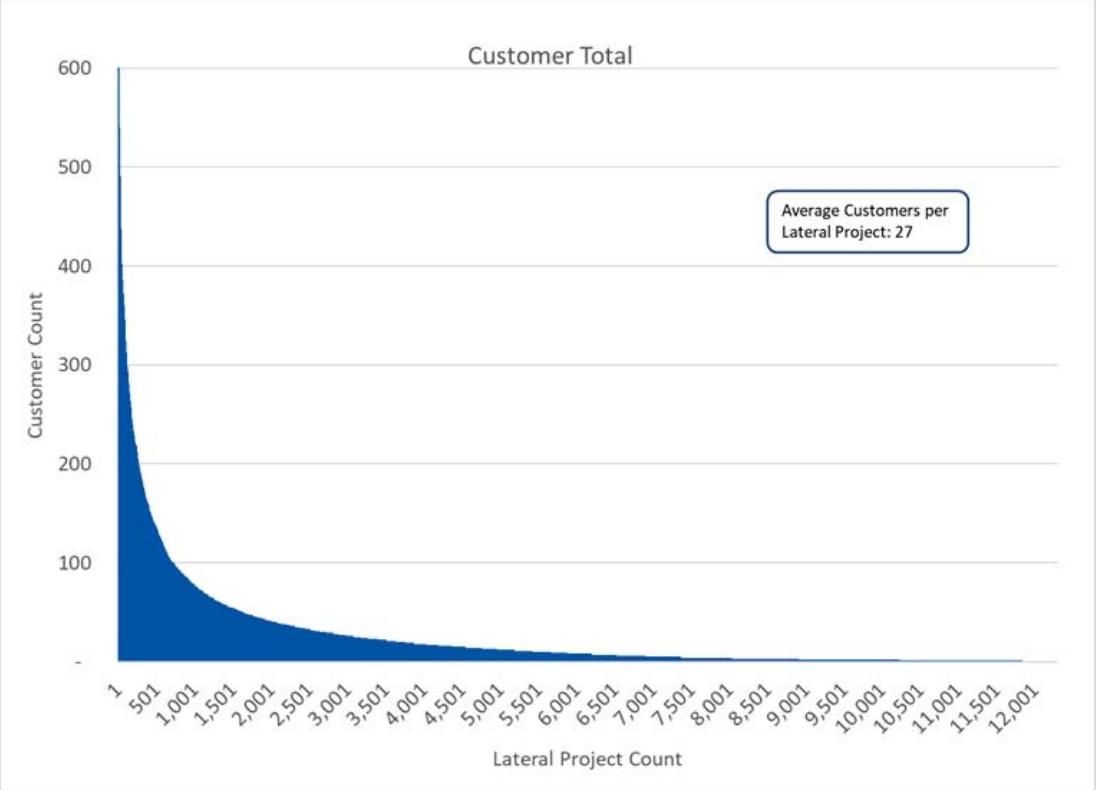
72. For the number of laterals shown in the Table of Exhibit DAP-1, Page32 of 78, what is the average number of customers on a lateral?

A. The number of customers on a lateral varies significantly from a low of just a few customers, sometimes one, to hundreds. The following figure shows the range of customers on approximately 13,000 laterals. As the figure shows the average customer count is 27.



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INTERROGATORY NO. 73
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73. Referring to Exhibit DAP-1 Page 34 of 78 regarding supplemental trimming, please identify all studies, memos, presentations, etc., that support the statement that supplemental trimming would be justified.

A. The analysis performed by Accenture, LLP titled "Vegetation Management Storm Protection Program Analytic Support Report" describes the intent, process, and results of the study performed supporting the implementation of the Supplemental Distribution Circuit VM Initiative. This analysis was included in Tampa Electric's SPP filing in this docket as Exhibit DLP-1, Document No. 3.

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INTERROGATORY NO. 74
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74. Referring to Exhibit DAP-1, Pages 37 through 39 regarding the 69kV Vegetation Management Reclamation project, how many years will be required to reclaim the 69kV right-of-way as described in the SPP?

A. The 69kV Reclamation Initiative is projected to span years 2020 through 2023. The Initiative objectives are expected to be completed by the end of 2023.

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INTERROGATORY NO. 75
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75. What is the total cost of the 69kV Vegetation Management Reclamation project?

A. The total cost of the 69kV Reclamation Initiative is projected to be $2.2M.

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INTERROGATORY NO. 76
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76. When the reclamation project is complete, will the transmission Vegetation Management change? If so, describe how.

A. The primary intent of the 69kV Reclamation Initiative is not to alter the existing vegetation management program. This initiative is designed to provide benefits following extreme weather by improving access and reducing vegetation threats, such as hazard trees, and to speed storm restoration and provide additional protection against storm outages.

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INTERROGATORY NO. 77
BATES PAGE: 28 - 29
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77. Referring to Exhibit DAP-1 page 41 of 78 regarding transmission asset upgrades, please provide the following:

a. number of transmission poles replaced by this program for each of the last 3 years.

b. total cost associated with replacement of the transmission poles for each of the last 3 years.

c. number of poles budgeted to be replaced in next three years of the SPP

d. budget for transmission pole replacement

A. a. The table below provides the number of transmission poles replaced by this program for each of the last two years and the projected number of poles to be replaced in 2022:

	Transmission Asset Upgrades Number of Wood Poles Replaced
2020	171
2021	637
2022	474

b. The table below provides the total cost associated with replacement of the transmission poles replaced by this program for each of the last two years and the projected cost to replace poles in in 2022:

	Transmission Asset Upgrades Total Costs for Wood Poles Replaced
2020	$3,980,836
2021	$18,219,099
2022	$16,478,998

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c. The table below provides the number of transmission poles projected to be replaced in the next three years:

	Transmission Asset Upgrades Projected Number of Wood Poles to be Replaced
2022	474
2023	463
2024	472

d. The table below provides the projected cost associated with replacement of the transmission poles projected to be replaced in the next three years:

	Transmission Asset Upgrades Projected Costs for Wood Poles Projected to be Replaced
2022	$16,478,998
2023	$17,463,787
2024	$18,100,000

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78. Regarding Exhibit DAP-1, Appendix B Transmission Asset Upgrades, please explain the upgrades for Circuit 66048, which has 5 poles and a project cost of $50,000.

A. The upgrades for circuit 66048 are for the wood poles to be replaced with non-wood poles. The $50,000 represents the remaining costs for 66048 in 2022. Most of the costs for the conversion of these wood poles occurred in 2021.

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INTERROGATORY NO. 79
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79. Regarding Exhibit DAP-1, Appendix B, please explain the upgrades for Circuit 66020, which has 10 poles and a cost of $305,900.

A. The upgrades for circuit 66020 are for the wood poles to be replaced with non-wood poles. The $305,900 represents the projected spend in 2022 for the conversion of the 10 poles on this circuit.

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80. Regarding Exhibit DAP-1, Appendix b, please explain the upgrades for Circuit 66025, which has 105 poles and a cost of $2,324,840.

A. The upgrades for circuit 66025 are for the wood poles to be replaced with non-wood poles. The $2,324,840 represents the remaining projected costs for circuit 66025 in 2022. A portion of the costs for this conversion occurred in 2021.

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INTERROGATORY NO. 81
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81. Regarding Exhibit DAP-1, page 42 of 78, Substation Extreme Hardening, please identify the referenced study that further identifies and evaluates other potential hardening solutions.

A. The Substation Extreme Hardening Study that was referenced was the Substation Hardening Study that was prepared by HDR Engineering, Inc. on August 27, 2021, that was included as Exhibit No.1, Document No. 5, in the Direct Testimony of David L. Plusquellic that was filed on April 11, 2022, within the company's 2022-2031 SPP petition in this proceeding.

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82. Other vegetation management costs may include hot spot trimming, trimming/clearing required from storm damage. Are these vegetation management costs contained in the SPP? If so, provide separate estimates for these activities. If not, describe safeguards to prevent vegetation management costs from being captured in both rate base O&M charges and SPPCRC charges.

A. Hot spot and storm restoration trimming, while part of Tampa Electric's Vegetation Management Program ("VMP"), are excluded from recovery through the SPPCRC. These costs are tracked as part of the company's reactive initiative to ensure exclusion.

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INTERROGATORY NO. 83
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83. Please describe TECO's vegetation management protocol regarding:

i. Removal of overhanging tree limbs.

ii. Use of growth retardants.

iii. Management of vines on poles.

A. i. Tampa Electric does not allow for vegetation overhang on its transmission facilities. The specification for distribution is fifteen feet above; exceptions can be made for large, healthy trees where removal would be detrimental to the tree or pose little to no threat to the electric facilities.

ii. While Tampa Electric has utilized tree growth regulators in the past, the results were largely ineffective at controlling vegetation; therefore, are no longer in use.

iii. The company has several methods for managing vines on poles, most of which are captured by the various Program Initiatives, Four-Year Cycle, Supplemental, Mid-Cycle, and Transmission. Vines reported by internal or external customers that are outside of the Initiatives' plans are addressed via the Reactive Initiative.

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INTERROGATORY NO. 84
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84. Please describe any cost sharing between TECO and communication attachees regarding vegetation management.

A. Tampa Electric charges attachers a cost per attachment for their attaching their equipment to the company's poles. The attachees are responsible for any vegetation that affects their facilities.

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INTERROGATORY NO. 85
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85. Does TECO trim service drops to homes? If so, what is the clearance distance used for overhead services?

A. Tampa Electric evaluates service wires for vegetation conflicts; vegetative threats are either trimmed by Tampa Electric or made safe for the customer to trim. The vegetation-to-conductor, post-trim clearance is approximately three feet.

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INTERROGATORY NO. 86
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86. Does TECO trim for triplex secondary cables between poles? If so, what is the clearance distance used for overhead secondary?

A. Cabled or insulated secondary wires are trimmed when vegetative threats exist. The vegetation-to-conductor, post-trim clearance is approximately three feet.

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INTERROGATORY NO. 87
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87. For the last 3 years, how many miles of three-phase mainline were trimmed each year and at what cost?

A. Tampa Electric VM Program does not separate its Initiatives by feeder and lateral. The Mid-Cycle Distribution VM Initiative, to mitigate contractor supply and demand issues, focused on feeders for the first three years. The Initiative will encompass both feeder and lateral beginning in 2023.

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88. For the last 3 years, how many miles of laterals were trimmed and at what cost?

A. Tampa Electric VM Program does not separate its Initiatives by feeder and lateral. The following links below contain the reported data tables to the Commission for the company's vegetation management reports for the past three years.

2021 for 2020:
http://www.floridapsc.com/Files/PDF/Utilities/Electricgas/StormProtectionPlans/2020/2020%20Tampa%20Electric%20Company%20SPP%20Annual%20Status%20Report.pdf

2020 for 2019:
http://www.floridapsc.com/Files/PDF/Utilities/Electricgas/DistributionReliabilityReports/2019/2019%20Tampa%20Electric%20Company%20Distribution%20Reliability%20Report.pdf

2019 for 2018:
http://www.floridapsc.com/Files/PDF/Utilities/Electricgas/DistributionReliabilityReports/2018/2018%20Tampa%20Electric%20Company%20Distribution%20Reliability%20Report.pdf

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89. Referring to Exhibit DAP-1, Page 43 of 78, for each of the nine substations that must have flood mitigation improvements, please confirm that TECO had the sole discretion to purchase the land for use as a substation.

A. Tampa Electric did have sole discretion to purchase each of the nine substation sites. The company does not, however, site substations arbitrarily. Substations are sited based on load, proximity to transmission facilities, and system operating needs. This means that some substations must be placed in locations that may be vulnerable to flooding or storm surge. All substation sites are permitted in their local jurisdiction and go through civil engineering site designs that include station layout, stormwater design, utility planning, and the various other aspects of site development. For instance, one of the nine substations is the Maritime 69kV Substation, which feeds critical load at the Port of Tampa. This substation is located 0.3 miles from a canal that feeds into Tampa Bay.

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90. Referring to Exhibit DAP-1, Page 43 of 78, please identify documents showing the land for these substations was not subject to flooding at the time the decision was made to build or upgrade the existing stations.

A. The company does not have documentation showing whether or not the land for these substations was subject to flooding at the time the decision was made to build or upgrade the existing stations. See Response No. 89 this set.

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INTERROGATORY NO. 91
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91. For Substation Extreme Weather Hardening, provide the estimated reduction in cost for storm restoration. If no estimate has been made state such.

A. See Response No. 134, this set.

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INTERROGATORY NO. 92
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92. Referring to Exhibit DAP-1, Page 43 of 78, for the one project slated for 2024 with a budget of $4.3 million, please provide a description of the improvement(s) to be made and a kmz file of the substation location (alternately the latitude and longitude of the substation site).

A. The Substation Extreme Weather Hardening project scheduled for 2024 is the company's Maritime Substation. The Maritime 69 kV Substation is in the Federal Emergency Management Agency's "FEMA" 100-yr floodplain and 0.3 miles from a canal/drainage feature discharging into Tampa Bay. This substation feeds critical port fuel load. The scope of the $4.3M cost is to replace four (4)13.8 kV circuit breakers, install two (2) new 69/13kV medium power transformers with Spill Prevention, Control, and Countermeasure ("SPCC") Systems, and elevate the control house with new relaying. The latitude and longitude of the substation is 27°55'30.53"N / 82°26'29.51"W.

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93. Referring to Exhibit DAP-1, Page 43 of 78 and looking back for the last 10 years, for each of the nine substations slated for modification by the Substation Extreme Weather Hardening Program, please provide the dates each of the substations had to be de-energized due to high water.

a. For each date of de-energization, provide the duration that the substation was de-energized.

b. Provide the number of customers served by each substation at the time of de-energization.

A. Tampa Electric has not had to de-energize any of these nine substations over the last 10 years. These substations, however, have not experienced any extreme weather events in recent history.

a. Not applicable, see Response No. 93 above.

b. Not applicable, see Response No. 93 above.

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94. Referring to Appendix D of Exhibit DAP-1, for Circuit 13346, the budget is listed as $80,786 and the work includes upgrading 148 feeder poles, installing 2 new reclosers, and installing 51 trip savers and 74 fuses. Please provide detailed cost breakdowns for this circuit (cost for fuses, pole upgrades, etc.).

A. The $80,786 is the original project scope of four on-road poles at a cost of $8,900 per pole and three off-road poles at a cost of $13,500. The balance is for internal labor and overhead. The scope that is reflected in Appendix D of Exhibit DAP-1 for Circuit 13346 reflects a proposed scope increase that was identified during the design phase of this project. Tampa Electric is currently evaluating this increased scope that would increase the planned budget to approximately $1.6 million.

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95. Referring to Appendix D of Exhibit DAP-1, for Circuit 13770, the budget is listed as $5,898,017 and the work includes upgrading 103 feeder poles, installing 9 new recloser, and installing 3 trip savers and 52 fuses. Please provide detailed cost breakdowns for this circuit (cost for fuse, pole upgrades, etc.).

A. The table below provides the projected costs for Circuit 13770:

	Circuit 13770 - Projected Costs		
	Number of Units	**Cost per Unit**	**Total Cost**
TripSaver	3	$4,450	$13,350
Recloser	9	$41,400	$372,600
Fuse	52	$825	$42,900
Feeder Pole	103	$6,240	$642,720
Substation Upgrades			$3,240,000
Conductor Upgrades			$1,500,000
Engineering			$38,471
Internal Labor			$86,479
Projected Total			$5,936,520

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96. Regarding Exhibit DAP-1, Page 44 of 78 Distribution Feeder Sectionalizing and Automation, how many feeders were modified with automation for self-healing from 2017 through 2021?

A. The table below provides the number of feeders that were modified with self-healing automation equipment from 2017 through 2021:

	Feeders Modified with Self-Healing Automation
2017	0
2018	0
2019	0
2020	5
2021	8

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97. Regarding Exhibit DAP-1, Page 44 of 78 Distribution Feeder Sectionalizing and Automation, how many feeders are planned for automation for self-healing through the duration of the SPP?

A. The table below provides the number of feeders (133 in total) that are planned for automation for self-healing in the company's proposed 2022-2031 SPP:

Feeders Planned for Distribution Feeder Sectionalizing and Automation	
2022	10
2023	19
2024	17
2025	11
2026	18
2027	13
2028	15
2029	13
2030	10
2031	7

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98. Regarding Exhibit DAP-1, Page 44 of 78 Distribution Feeder Sectionalizing and Automation, identify all reports, memos, studies, or analysis describing or analyzing the success and shortcomings of the self-optimization system.

A. An analysis describing the success of the Fault Location Isolation and Restoration Service ("FLISR") system implemented through the end of 2021, is carried out monthly for internal tracking purposes. The reliability metrics SAIDI and MAIFIe are tracked. The tracking spreadsheet titles "OPC IRR 98 SPP FLISR" is being provided in the accompanying Production of Documents, Document No. 14. In addition, The company is providing the confidential Electric Power Research Institute ('EPRI") "Estimating Impact of Adverse Weather/Storms" via the confidential SharePoint site.

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INTERROGATORY NO. 99
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99. Regarding Exhibit DAP-1, Page 44 of 78 Distribution Feeder Sectionalizing and Automation, identify all documentation illustrating improvements in CAIDI or SAIDI as a direct result of the automation program.

A. See Response No. 98, this set.

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100. During a major storm event, what is the standard operating procedure for the automation of reclosers in terms of bypassing of the system if significant failures are expected along a feeder or group of feeders?

A. Advanced field devices, including fault indicators, relays, tripsavers and automated feeder switches, can be monitored and manually controlled at the device or remotely controlled via a communications network (if capable). Some of these devices can also be programmed to operate autonomously. The control and performance of these individual advanced field devices and their successful remote or programmed operation relies heavily on the system for that device. If significant failures are expected along a feeder or groups of feeders, the reclosers can be left in normal operation in that they would operate as intended to prevent the potential damage from faults to upstream electrical systems components in addition to isolating the fault. The amount of oversight of these devices by a Distribution System Operator ("DSO") will greatly increase during extreme weather events as they monitor for potential issues. If the DSO determines that additional protection is needed from the advanced field device, the DSO can place the device in Hot-Line Mode which will block the reclosing and enable the instantaneous trip for a faster trip curve. The company is currently testing a few circuits to determine what would be the appropriate standard operating procedure to enable the FLSIR which will enable automatic switching modes.

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101. After a major event, what is the standard operating procedure for re-constituting the automation of the self-healing system (i.e., returning it normal operation)?

A. The company is currently testing a few circuits to determine what would be the appropriate standard operating procedure to enable the FLISR which will enable automatic switching modes, which would include the restoration of the system to its normal configuration following a self-healing event.

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102. Regarding Exhibit DAP-1, Page 45 of 78 Distribution Feeder Sectionalizing and Automation, provide the budgets for upgrading additional transformer capacity at strategic substations that are contained in the SPP.

A. The table below provides the budgets for upgrading transformer capacity in the strategic substations that will support distribution feeder sectionalizing and automation in the company's proposed 2022-2031 SPP. The projected costs of each transformer upgrade was projected to be $1,750,000 in the study that was conducted by 1898 & Co..

Transformer Capacity Additions for Distribution Feeder Sectionalizing and Automation		
Year Planned	**Substation**	**Projected Costs**
2022	South Eloise, Transformer Upgrade	$1,750,000
2022	Lucerne Park, Transformer Upgrade	$1,750,000
2022	Dairy Road, Transformer Upgrade	$1,750,000
2022	Pebble Creek, Transformer Upgrade	$1,750,000
2022	Lake Alfred, Transformer Upgrade	$1,750,000
2024	Trout Creek N, Transformer Upgrade	$1,750,000
2025	Caloosa S, Transformer Upgrade	$1,750,000
2028	McFarland, Transformer Upgrade	$1,750,000

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103. Regarding Exhibit DAP-1, Page 45 of 78 Distribution Feeder Sectionalizing and Automation, provide the location (latitude and longitude), substation name, transformer size, and upgraded transformer capacity.

A. The table below provides the location (latitude and longitude), substation name, transformer size, and upgraded transformer capacity for the substations that will support distribution feeder sectionalizing and automation in the company's proposed 2022-2031 SPP.

Transformer Capacity Additions for Distribution Feeder Sectionalizing and Automation

Substation	Location Latitude and Longitude	Transformer Size (MVA)	Upgraded Transformer Capacity (MVA)
South Eloise, Transformer Upgrade	27°59'14.57"N, 81°44'39.75"W	37	9
Lucerne Park, Transformer Upgrade	28° 4'13.16"N, 81°41'10.34"W	37	9
Dairy Road, Transformer Upgrade	28° 4'16.26"N, 81°46'36.85"W	37	9
Pebble Creek, Transformer Upgrade	28° 9'10.15"N, 82°21'15.07"W	37	9
Lake Alfred, Transformer Upgrade	28° 5'15.86"N, 81°43'52.90"W	37	9
Trout Creek N, Transformer Upgrade	28°10'48.32"N, 82°21'9.35"W	37	9
Caloosa S, Transformer Upgrade	27°45'25.76"N, 82°20'4.14"W	37	9
McFarland, Transformer Upgrade	28° 3'55.14"N, 82°27'12.03"W	37	9

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104. Regarding Exhibit DAP-1, Page 45 of 78 Distribution Feeder Sectionalizing and Automation, identify all maps of all proposed upgraded conductors included in the SPP.

A. The precise locations for conductor upgrades are identified through the design process. As such, the company does not have a full set of maps like those requested. For those projects that have been designed, the company is providing the construction maps with these locations. The company is providing the construction maps for the following 7 circuits in the accompanying Production of Documents, Document No. 14, which shows the proposed upgraded conductors that will support the Distribution Sectionalizing and Automation:

13118 – Construction print provided
13148 – Construction print provided
13296 – Construction print provided
13308 – Construction print provided
13433 – Construction print provided
13770 – Construction print provided
13309 – Construction print provided

The following 10 circuits do not have upgraded conductor as part of their design:

13048 – Construction print provided
13312 – Construction print provided
13227 – Construction print provided
13314 – Construction print provided
13346 – Construction print provided
13651 – Construction print provided
13984 – Construction print provided
13989 – Construction print provided
14094 – Construction print provided
14123 – Construction print provided

The company does not have maps for the following 12 circuits due to the design being unfinished at this time:

13008 – Design not yet complete

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13028 – Design not yet complete
13039 – Design not yet complete
13040 – Design not yet complete
13077 – Design not yet complete
13094 – Design not yet complete
13187 – Design not yet complete
13230 - Design not yet complete
13292 – Design not yet complete
13299 – Design not yet complete
13313 – Design not yet complete
13687 – Design not yet complete

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105. Regarding Exhibit DAP-1, Page 45 of 78 Distribution Feeder Sectionalizing and Automation, provide budgets for all proposed upgraded conductors.

A. The table below provides the projected reconductoring costs for the Overhead Feeder Hardening projects to support distribution sectionalizing and automation:

Project ID	Circuit ID	Studied conductor upgrade (miles)	OH Upgrades (miles)	Reconductor Cost
FLISR-13187	13187	0.783	0.783	$235,131
FLISR-13230	13230	0.351	0.027	$112,312
FLISR-13299	13299	0.484	0.000	$156,308
FLISR-13312	13312	0.653	0.653	$185,768
FLISR-13029	13029	0.292	0.292	$82,971
FLISR-13024	13024	0.491	0.446	$141,429
FLISR-13082	13082	0.044	0.044	$12,446
FLISR-13181	13181	0.121	0.103	$35,192
FLISR-13370	13370	0.080	0.080	$22,844
FLISR-13042	13042	0.723	0.334	$220,621
FLISR-13072	13072	0.678	0.632	$194,689
FLISR-13754	13754	0.105	0.105	$29,956
FLISR-13948	13948	0.059	0.059	$16,810
FLISR-13303	13303	0.993	0.993	$282,531
FLISR-13236	13236	0.222	0.222	$63,036
FLISR-13511	13511	0.043	0.000	$13,815
FLISR-13117	13117	1.323	1.075	$398,181
FLISR-13290	13290	0.038	0.038	$10,883
FLISR-13243	13243	0.058	0.028	$17,578
FLISR-13293	13293	0.602	0.602	$183,570
FLISR-13152	13152	0.482	0.000	$155,514
FLISR-13458	13458	0.462	0.462	$131,406
FLISR-13909	13909	0.400	0.067	$126,607
FLISR-13493	13493	0.134	0.134	$50,494
FLISR-13593	13593	0.060	0.000	$19,256
FLISR-13045	13045	0.241	0.241	$68,693
FLISR-13331	13331	0.145	0.145	$41,324

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106. Referring to Exhibit DAP-1, Page 46 of 78, provide vendor information regarding the three new applications to the Overhead Feeder Hardening Program.

A. Tampa Electric has chosen Itron as the vendor which will develop the three new applications to leverage the company's advanced metering infrastructure information in the Overhead Feeder Hardening program.

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107. Referring to Exhibit DAP-1, Page 46 of 78, describe how TECO's Outage Management Systems will be modified with the addition of localization.

A. Tampa Electric's current Outage Management System ("OMS") does have the capability to communicate to the company's electric advanced metering infrastructure meters. This communication is mainly for detecting the status of the electrical conditions at the customer's premise. This communication does not include the actual relationship of electrical infrastructure/facilities between the meter and the company's OMS system. The company at this time, has not developed how the company's distribution management systems (i.e., OMS, Advanced Distribution Management System, SCADA, or other supporting potential systems or reports) will be modified to leverage the localization data during and after an extreme weather event.

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108. Referring to Exhibit DAP-1, Page 46 of 78, does TECO's current OMS communicate with electric meters without the localization enhancement? If so, describe the communication and data exchange relating to extreme storm restoration.

A. As described in Response No. 107, this set, Tampa Electric's current Outage Management System ("OMS") does have the capability to communicate to the company's electric advanced metering infrastructure meters. This communication is mainly for detecting w the status of electrical conditions at the customer's premise. This communication ignores the actual relationship of electrical infrastructure/facilities between the meter and the company's OMS system. Please see Response No. 109 for how the data from the storm mode is used during an extreme weather event.

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INTERROGATORY NO. 109
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109. Referring to Exhibit DAP-1, Page 46 of 78, identify all reports, memos, or analysis of pilot programs regarding the Vegetation Contact Detection system.

A. Tampa Electric is providing the confidential and proprietary document entitled, "TECO-Itron DI Recommendation for SPP-Grid Mod," which will be produced to OPC via the confidential SharePoint site and subject to a Motion for Temporary Protective Order.

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INTERROGATORY NO. 110
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110. Referring to Exhibit DAP-1, Page 46 of 78, provide the estimated cost for deployment of the Vegetation Contact Detection system on a feeder basis.

A. Tampa Electric projects the cost of the deployment of the Vegetation Contact Detection application across the company's entire electrical distribution system to be $2,000,000. The company is still negotiating the agreement for this development, which includes the cost of this application.

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INTERROGATORY NO. 111
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111. Referring to Exhibit DAP-1, Page 46 of 78, identify all reports, memos, or analysis of "Storm Mode."

A. See Response No. 109, this set.

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INTERROGATORY NO. 112
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112. Referring to Exhibit DAP-1, Page 46 of 78, provide costs for deployment of Storm Mode on a feeder basis.

A. Tampa Electric projects the cost of the deployment of the Storm Mode Application across the company's entire electrical distribution system to be $2,000,000. The company is still negotiating the agreement for this development, which includes the cost of this application.

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INTERROGATORY NO. 113
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113. Referring to Exhibit DAP-1, Page 46 of 78, identify all reports, memo, or analysis on the cost effectiveness of Storm Mode.

A. See Response No. 109, this set.

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INTERROGATORY NO. 114
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114. Referring to Exhibit DAP-1 Page 47 of 78, describe how vegetation management is conducted in areas without access roads, bridges and culverts.

A. Tampa Electric currently deploys several means in areas with compromised access. Temporary matting and bridges and specialized equipment or workforce are two examples; both are slow to deploy, resource limited, and expensive. The Transmission Access Enhancement Program will significantly enhance access to critical routes throughout the company's transmission corridors providing immediate and permanent access to these facilities thus reducing restoration times and restoration costs.

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115. Referring to Exhibit DAP-1, Page 47 of 78, identify documents that state that bridges are necessary to comply with FAC-003-4 rather than other means such as boats, helicopters, etc.

A. Bridges are not specifically required as part of the FAC-003-4 standard; however, maintaining required clearances during all operating conditions is a requirement and is the primary driver for establishing permanent access.

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INTERROGATORY NO. 116
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116. Referring to Exhibit DAP-1, Page 47 of 78, is it TECO's position that FERC requires all transmission poles must be accessible by a road? If so, provide documentation support such a position.

A. Road access is not specifically required as part of the FAC-003-4 standard; however, maintaining required clearances during all operating conditions is a requirement and is the primary driver for establishing permanent access. The Transmission Access Enhancement Program will provide permanent access to critical routes throughout the company's transmission corridors thus bolstering the company's VM Program.

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117. Referring to Exhibit DAP-1, Page 47 of 78, identify all studies or analysis by TECO to purchase the necessary equipment to access the areas in question rather building bridges and roads.

A. The analysis performed by 1898&Co. titled "2022-2031 Storm Protection Plan Resilience Benefits Report" outlines the costs and benefits associated with establishing permanent bridge and road access for the company's transmission system. Please see Exhibit No. DAP-1, Appendix F of the company's April 11, 2022 SPP filing.

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118. Referring to Exhibit DAP-1, Page 47 of 78, what is the cost for track vehicles necessary to work in rugged transmission right of ways?

A. Track vehicles are not specifically addressed in the report, as they are already in use on the Tampa Electric system. Their application does not resolve all access issues.

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119. Referring to Exhibit DAP-1, Page 47 of 78, what is the cost for large tire vehicles to work in rugged transmission right of ways?

A. Large tire vehicles are not specifically addressed in the report, as they are already in use on the Tampa Electric system. Their application does not resolve all access issues.

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INTERROGATORY NO. 120
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120. Referring to Exhibit DAP-1, Page 47 of 78, what is the cost for floating equipment necessary for restoring power in rugged transmission right of ways?

A. Tampa Electric has not explored procuring floating equipment necessary for restoring power in rugged transmission right of ways.

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121. Referring to Exhibit DAP-1, Page 47 of 78, what is the cost for setting poles using helicopters if roads are not available?

A. Tampa Electric has not explored procuring helicopter services for setting poles if a road was not available.

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122. Referring to Exhibit DAP-1, Page 47 of 78, provide details of additional mats for transmission access described on in Exhibit DAP-1 page 77 of 78.

A. The analysis performed by 1898&Co. titled "2022-2031 Storm Protection Plan Resilience Benefits Report" accounts for the costs and availability of temporary matting. Please see Exhibit No. DAP-1, Appendix F of the company's April 11, 2022 SPP filing.

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123. Referring to Exhibit DAP-1, Page 47 of 78, for the roads in the transmission right of way, who has the responsibility to maintain the roads?

A. Access roads constructed by the company in the transmission right-of-way are maintained by Tampa Electric.

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124. Referring to Exhibit DAP-1, Page 47 of 78, why has TECO not maintained the roads that were originally installed to build the transmission line that now need a road to access improvements?

A. Tampa Electric has an existing network of roads that are regularly maintained. The Transmission Access Enhancement Program current list of projects are all new roads in areas where topography and/or hydrology changes have negatively impacted access.

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125. Referring to Exhibit DAP-1, Page 47 of 78, provide TECO's actual cost for transmission access maintenance for each of the last 10 years.

A. The table below shows the 10-year cost for transmission access maintenance:

Transmission Access Maintenance Costs (in thousands)	
2012	N/A
2013	$384
2014	$487
2015	$396
2016	$608
2017	$291
2018	$284
2019	$251
2020	$282
2021	$211

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126. Referring to Exhibit DAP-1 Page 47 of 78, provide an analysis of cost savings for restoration after an extreme weather event.

A. See Response No. 134, this set.

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INTERROGATORY NO. 127
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127. Referring to Exhibit DAP-1 Page 47 of 78, provide an analysis of restoration cost savings for the application of the proposed program.

A. See Response No. 134, this set.

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128. Referring to Exhibit DAP-1 Page 47 of 78, provide an analysis of cost benefit for this program.

A. The analysis performed by 1898&Co. titled "2022-2031 Storm Protection Plan Resilience Benefits Report" provides an analysis of cost benefit for this program. Please see Exhibit No. DAP-1, Appendix F of the company's April 11, 2022 SPP filing.

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129. Regarding Distribution pole inspections, provide the actual number of poles inspected in the last 3 years. Include all types of inspection methods

A. The table below provides the number of Tampa Electric's distribution wood poles that were inspected in the last three years:

	Distribution Pole Inspections (Inspections Completed)
2019	38,940
2020	24,962
2021	19,861

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130. Please provide the failure rate of poles inspected in the last 3 years.

A. The table below provides the failure rate for Tampa Electric's distribution wood poles that were inspected in the last three years:

	Distribution Pole Inspections (Inspection Failure Rates)
2019	4.43%
2020	3.98%
2021	4.02%

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131. Are the inspection criteria for pole replacement as defined in NESC Table 261-1 based on extreme wind loading (Rule 250C) or based on ice and wind loading (Rule 250B) for the loading criteria? Why was this criterion selected by TECO?

A. As defined in NESC Table 261-1, foot notes 2 & 3, the minimum allowable remaining structural capacity of a Rule 250B (wind and ice) Grade B pole is 67 percent and for Rule 250C (extreme wind) Grade B is 75 percent. Non-feeder poles are evaluated against the Rule 250B criteria and feeder poles are evaluated against the Rule 250C criteria.

Tampa Electric follows the criteria as provided in the NESC. This was committed to by the company in the development of meeting the Commission storm hardening requirements in 2006.

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132. For the last three years provide the following for poles that failed inspection:

i. Remedy (pole replacement, truss, etc.).

ii. Total cost by remedy used.

iii. Number of poles remedied per year separated by remedy used.

A. i. The table below shows the remedy for poles that failed inspection in the last three years:

	Distribution Pole Inspection Failure Remedy	
	Poles Replaced	Poles Restored (trussed)
2019	3,376	915
2020	1,435	935
2021	417	0
Total	5,228	1,850

ii. The table below shows the total cost by remedy used for poles that failed inspection in the last three years:

	Distribution Pole Inspection Failure Total Cost by Remedy	
	Poles Replaced	Poles Restored (trussed)
2019	$19,949,764	$365,860
2020	$11,097,673	$434,299
2021	$4,752,341	$0
Total	$35,799,778	$800,159

iii. See Response No. 132.i. above.

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133. Referring to Exhibit DAP-1 page 70 of 78, is it TECO's intention to include unplanned vegetation management in the SPPCRC? If so, explain the rationale for inclusion.

a. Provide historical costs for unplanned vegetation management for the last 3 years.

b. In detail describe what is included in unplanned vegetation management.

A. No, Tampa Electric does not intend to seek recovery of unplanned vegetation management through the Storm Protection Plan Cost Recovery Clause

a. The table below provides the historical costs for Tampa Electric's unplanned vegetation management for the last three years:

	Unplanned (Reactionary) Vegetation Management Costs
2019	$2,222,800
2020	$2,026,699
2021	$1,672,323

b. Reactive VM includes customer requested work that is not captured by an existing proactive VM Initiative and storm restoration support.

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134. Referring to Exhibit DAP-1 page 71 of 78:

a. Provide actual costs in reduction in restoration costs for storm protection program.

b. Describe the term of reduction costs (annual, ten years, life of the assets, etc)

c. Provided projected annual cost reduction for the next ten years.

d. Provide actual customer minutes of interruption before improvements and after improvements.

e. Describe the term of reduction costs (annual, ten years, life of the assets, etc)

f. Provided projected annual cost reduction for the next ten years.

A. a. Assuming 'actual cost' is the modeled status quo for the percentage reduction calculation. For each of the programs, the following figures shows:

1. Range of the Status Quo 50-year storm restoration costs (blue bars)
2. Range in the 50-year storm restoration costs after the 10 years of investment in hardening projects (orange bars)
3. Difference and percent difference between each of the range values (grey area)

The percentage in the grey areas map to the values in the table on page 71 of 78 references in the question. Adding all these figures together produces the results for the entire plan.

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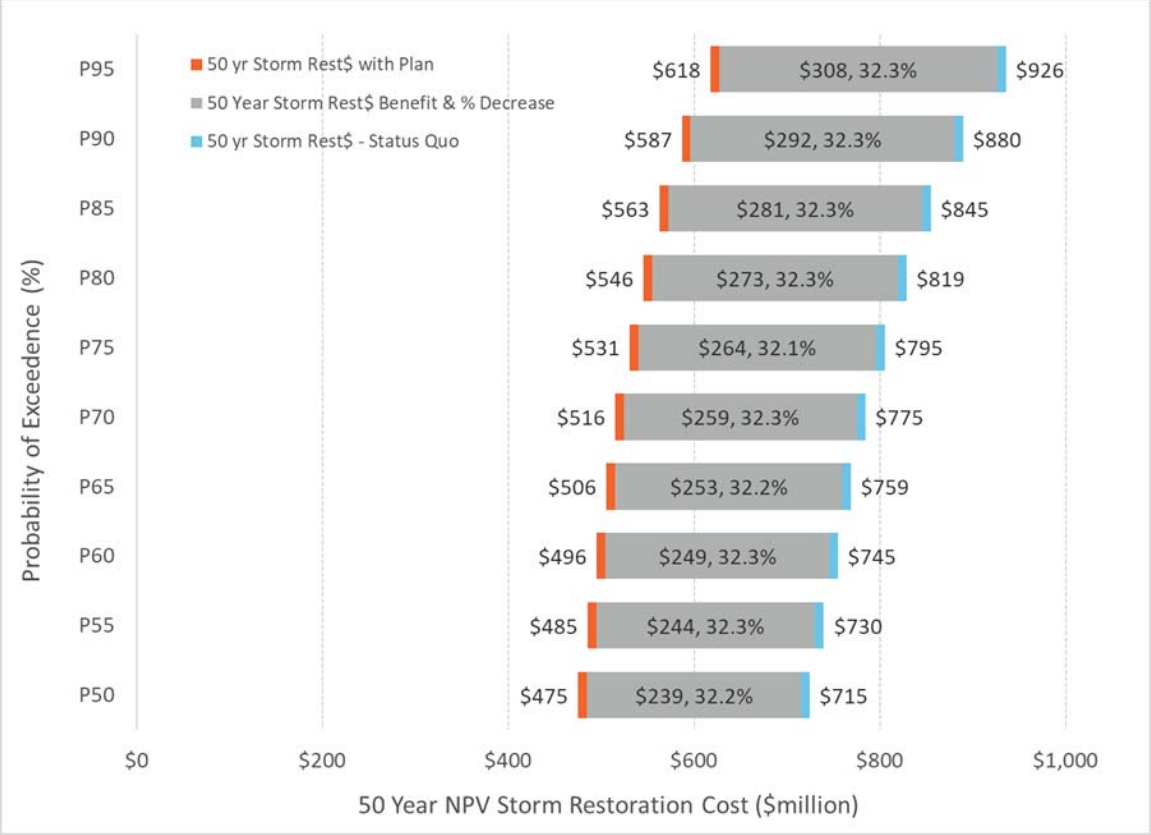
Lateral Undergrounding



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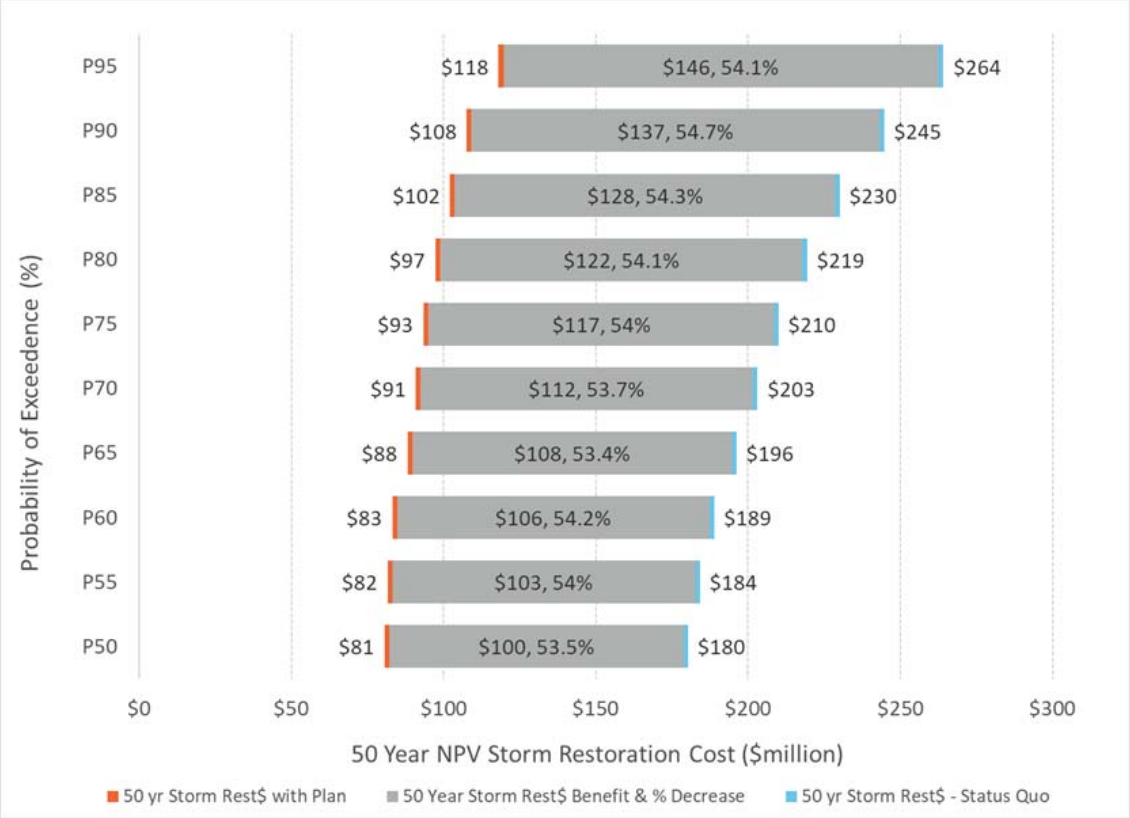
Distribution Feeder Hardening



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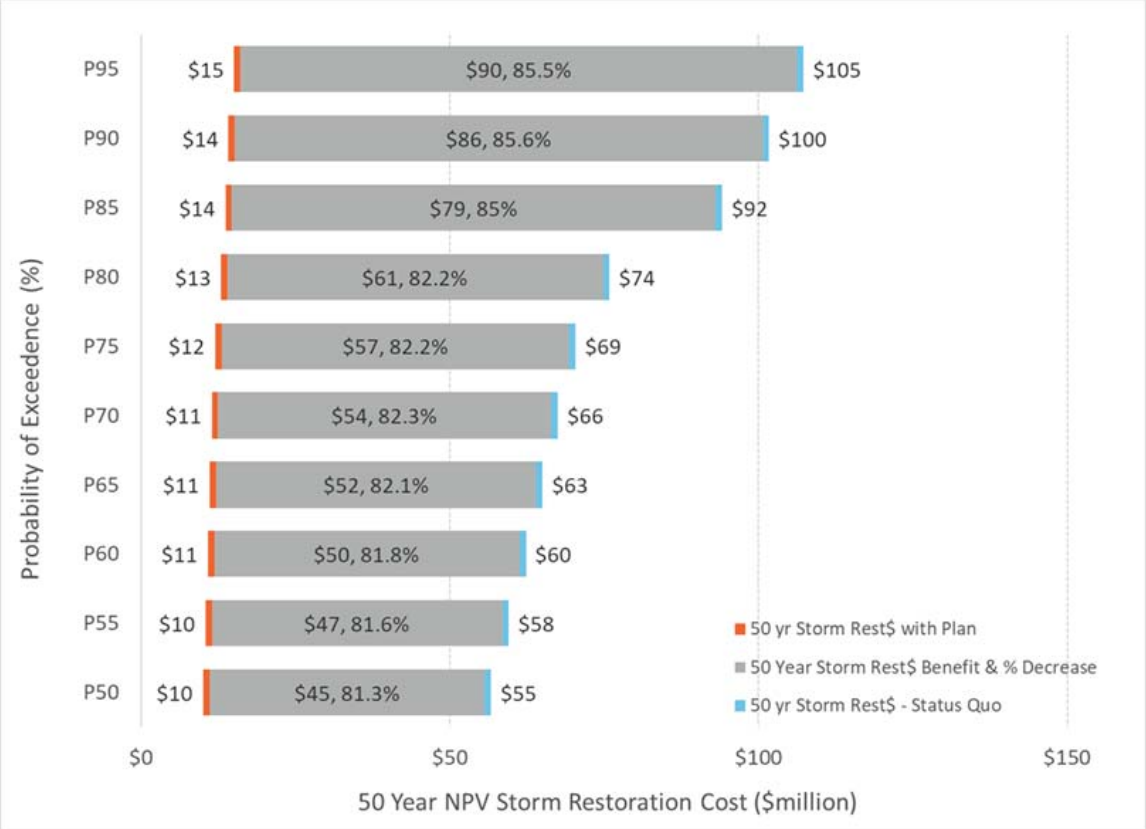
Transmission Asset Upgrades



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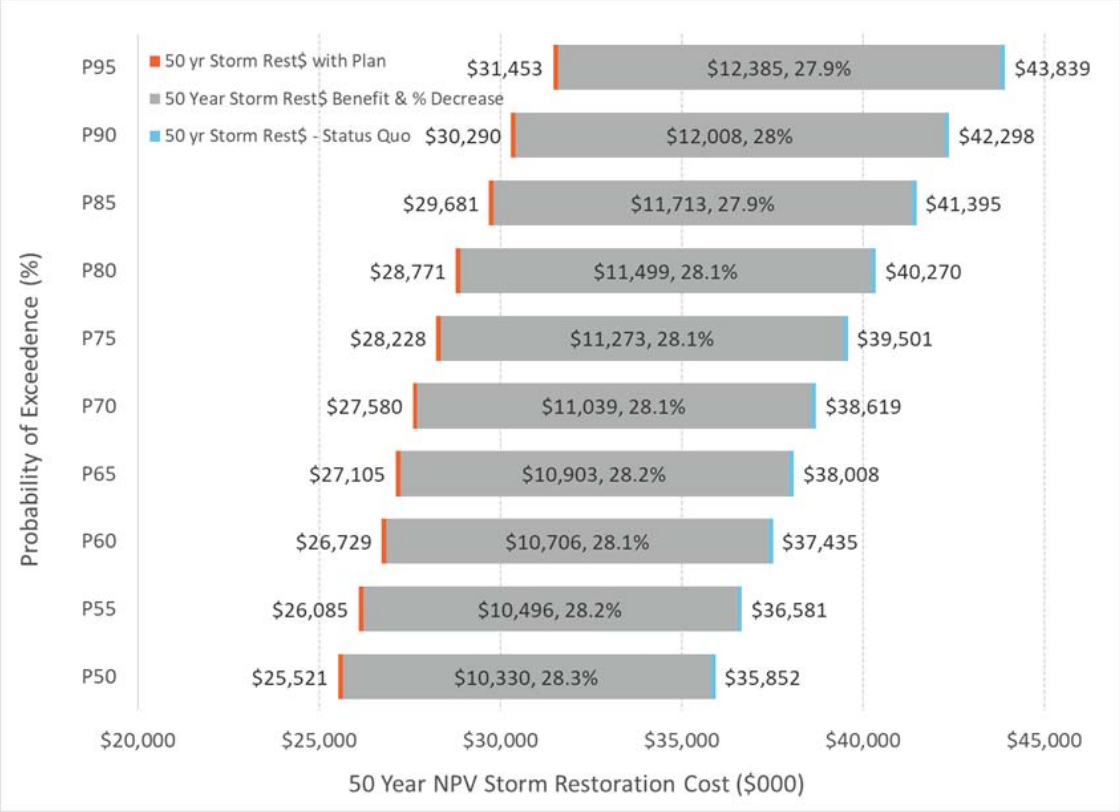
Transmission Access Enhancement



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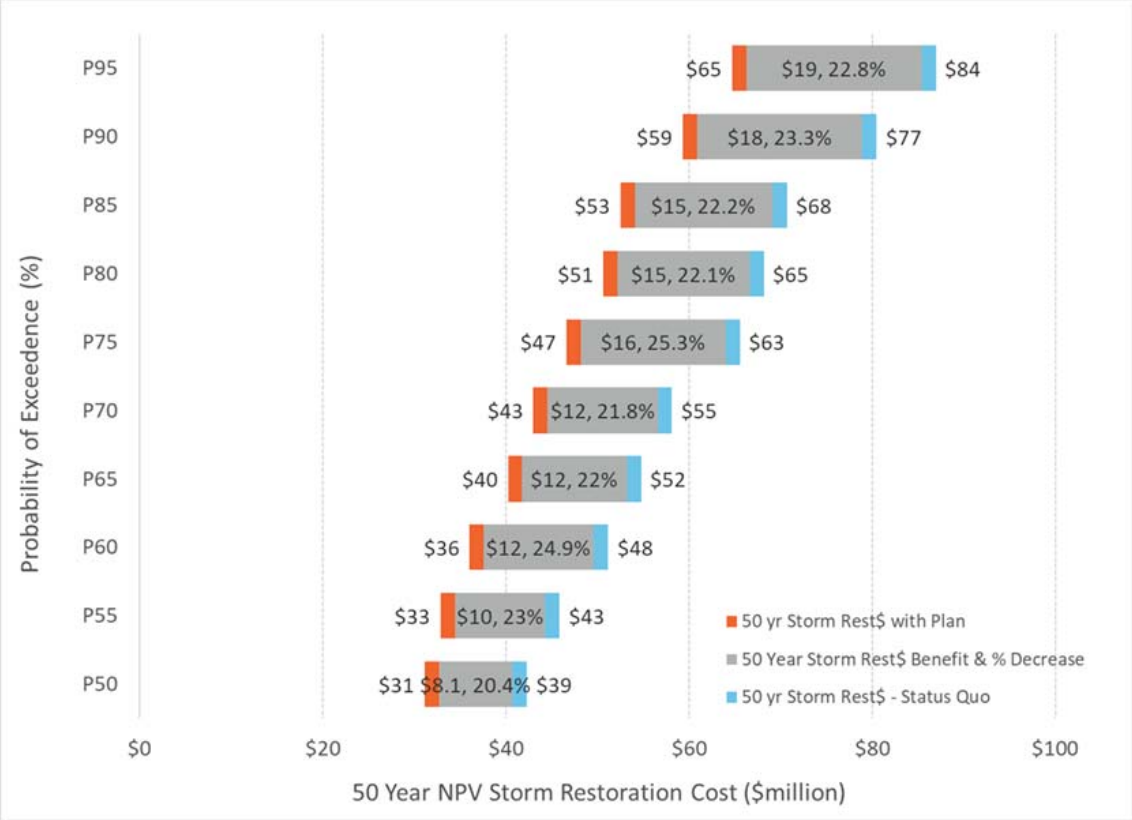
Substation Extreme Weather Hardening



b. The reduction percentage is based on the assumption that the entire plan has been executed. It is the reduction in storm costs for the following 50 years. It should be noted that the values are in Net Present Value terms (2022). Since storm activities vary from year to year, the reduction should be seen from the 50 year lifecycle perspective.

c. As discussed above in Response No. 134.b. and in the technical conference session, the model assumes all investments are completed 'overnight' as a conservative assumption. The value for the next 10 years

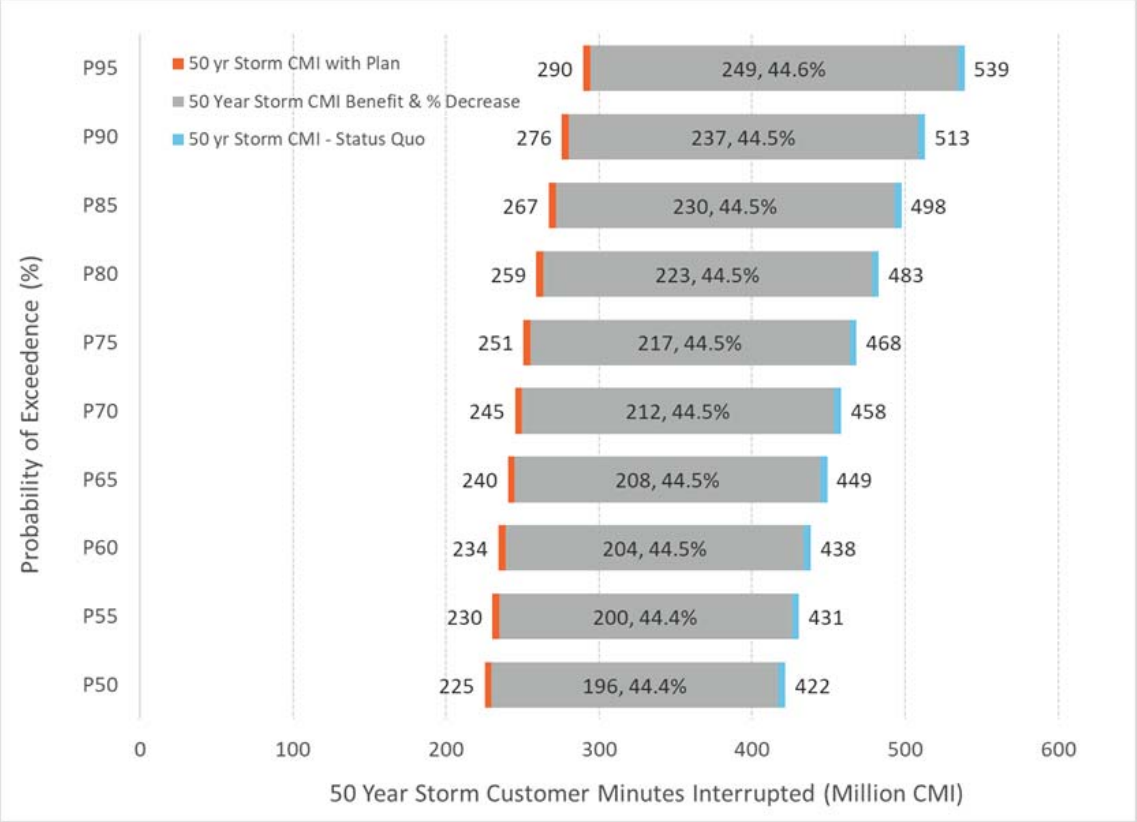
has not been calculated. However, the percent reduction will increase the values in the figures shown above in part a) each year.

d. For each of the programs, the following figures shows:

1. Range of the Status Quo 50-year storm CMI (blue bars)
2. Range in the 50-year storm CMI costs after the 10 years of investment in hardening projects (orange bars)
3. Difference and percent difference between each of the range values (grey area)

The percentage in the grey areas map to the values in the table on page 71 of 78 references in the question. Adding all these figures together produces the results for the entire plan.

Lateral Undergrounding



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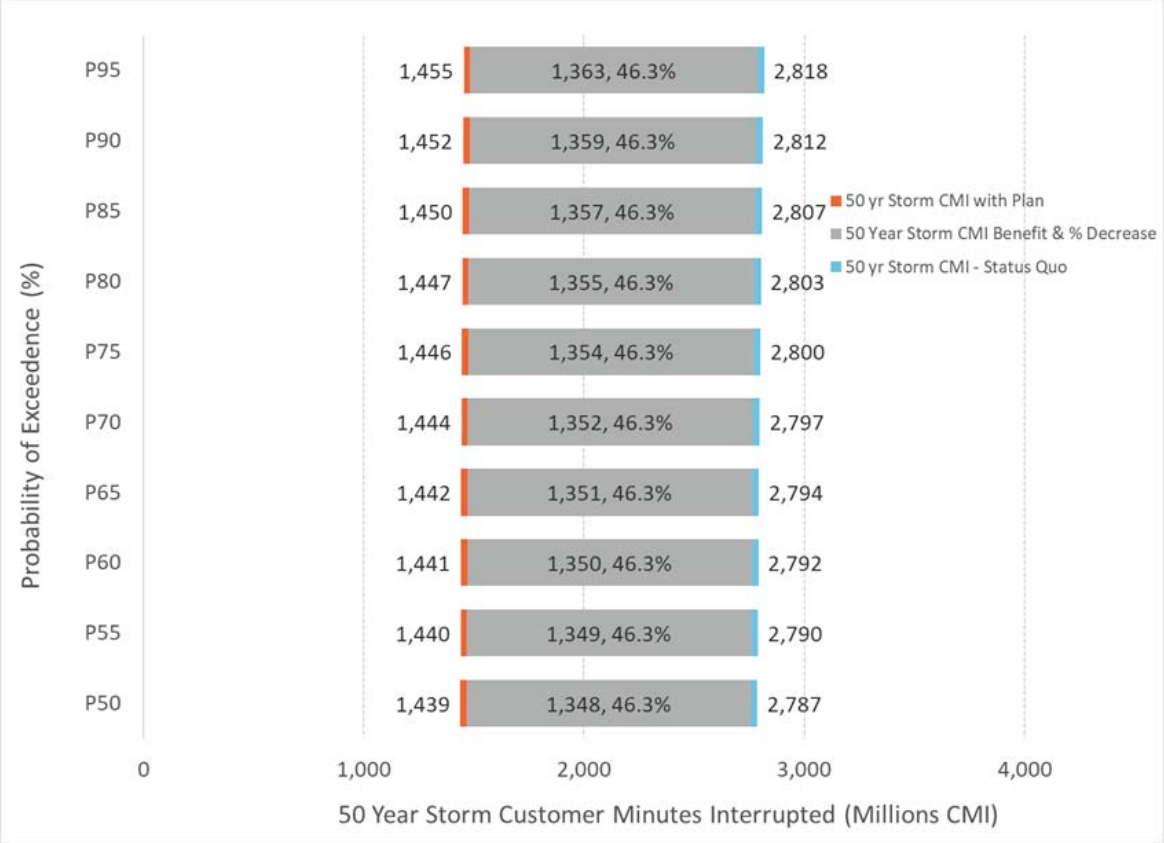
Distribution Feeder Hardening



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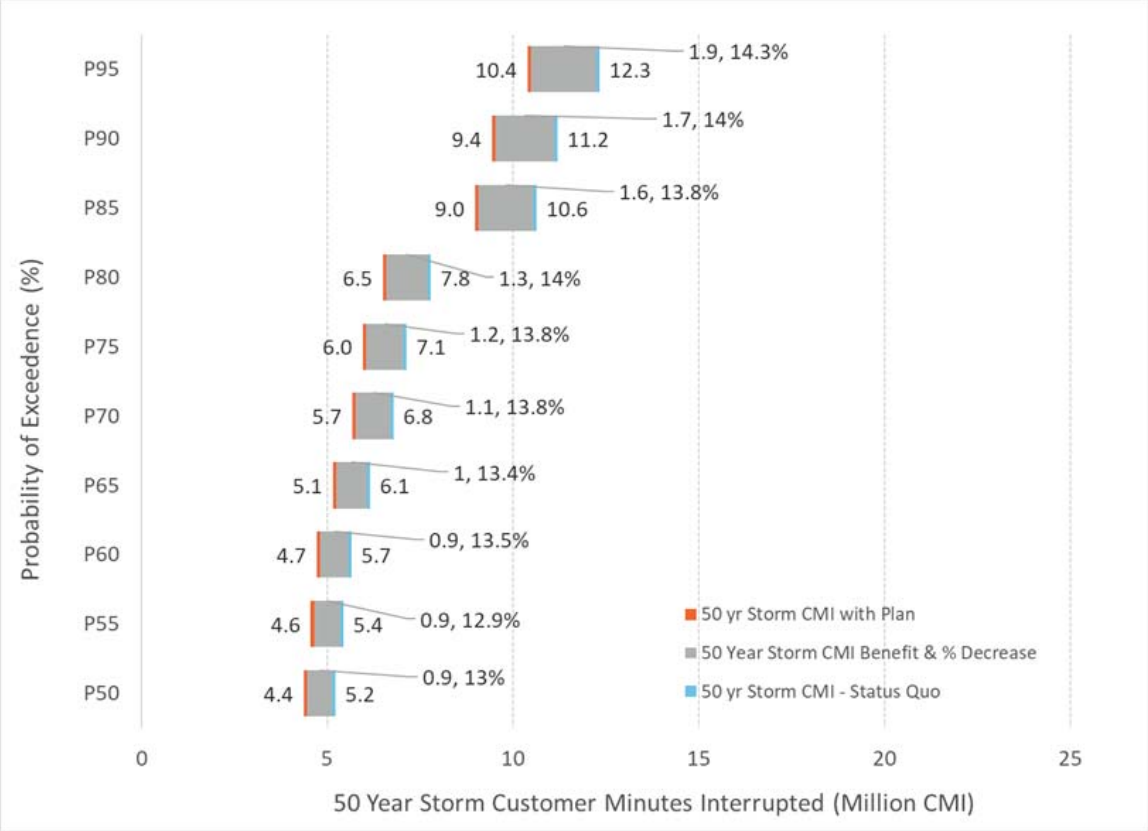
Transmission Asset Upgrades



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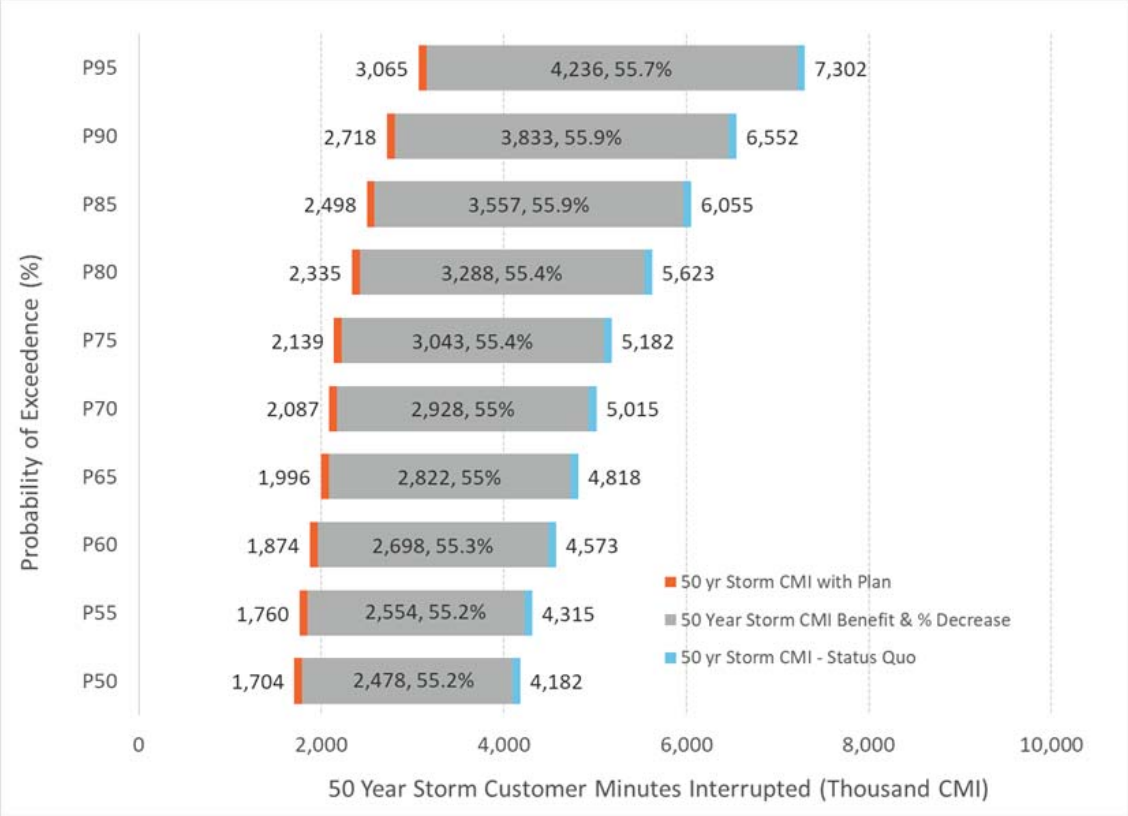
Transmission Access Enhancement



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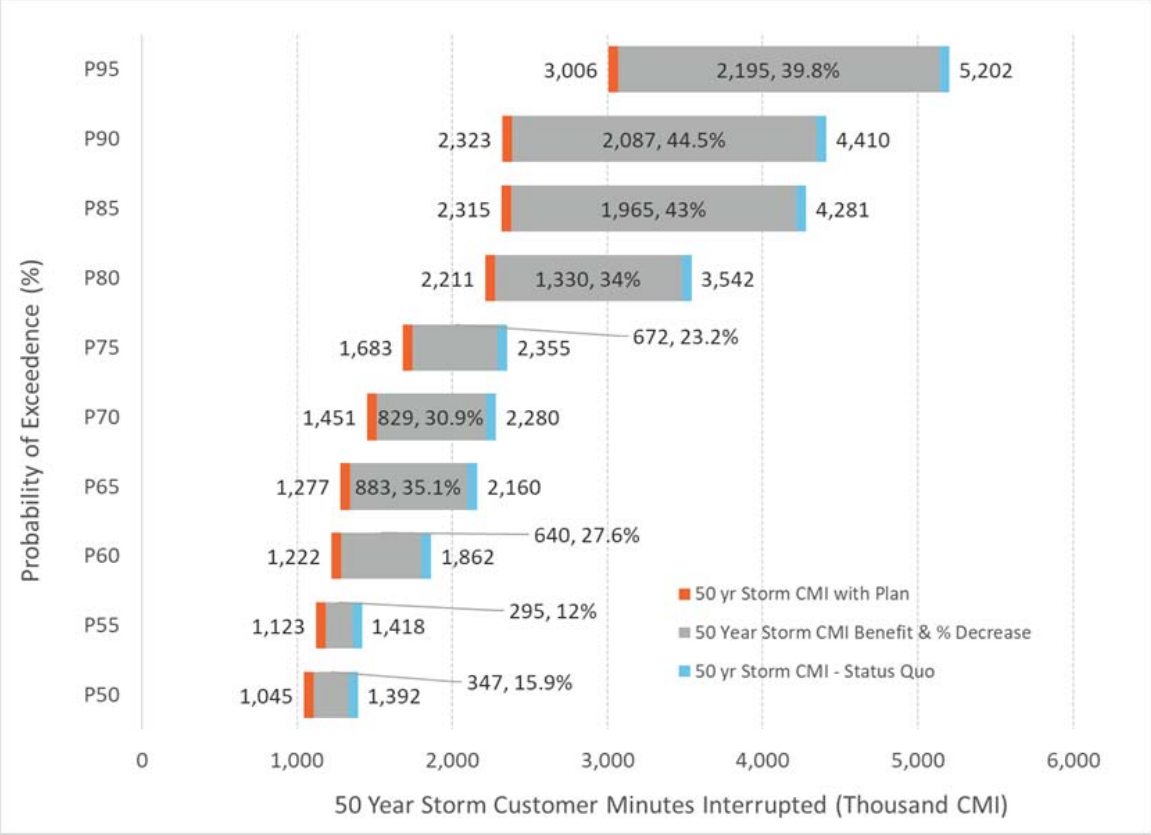

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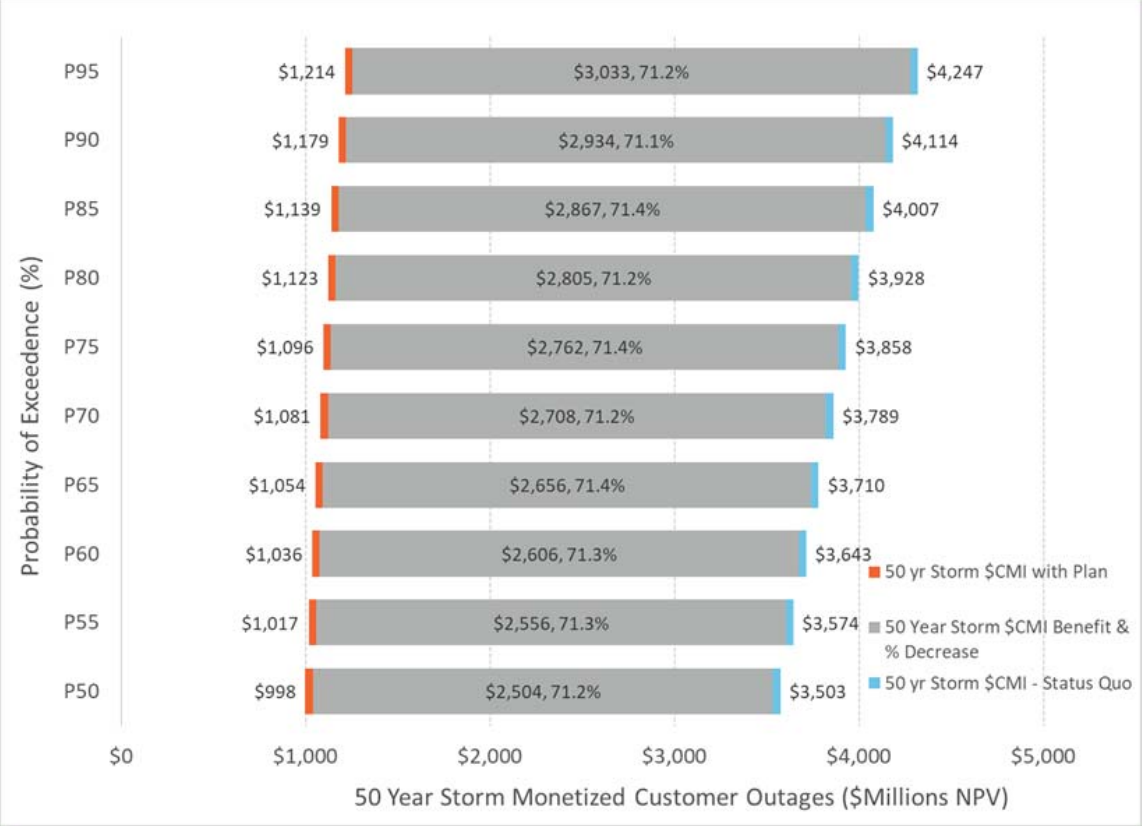
The following figures convert the CMI values to dollars using the DOE ICE Calculator and described in the plan.

Lateral Undergrounding



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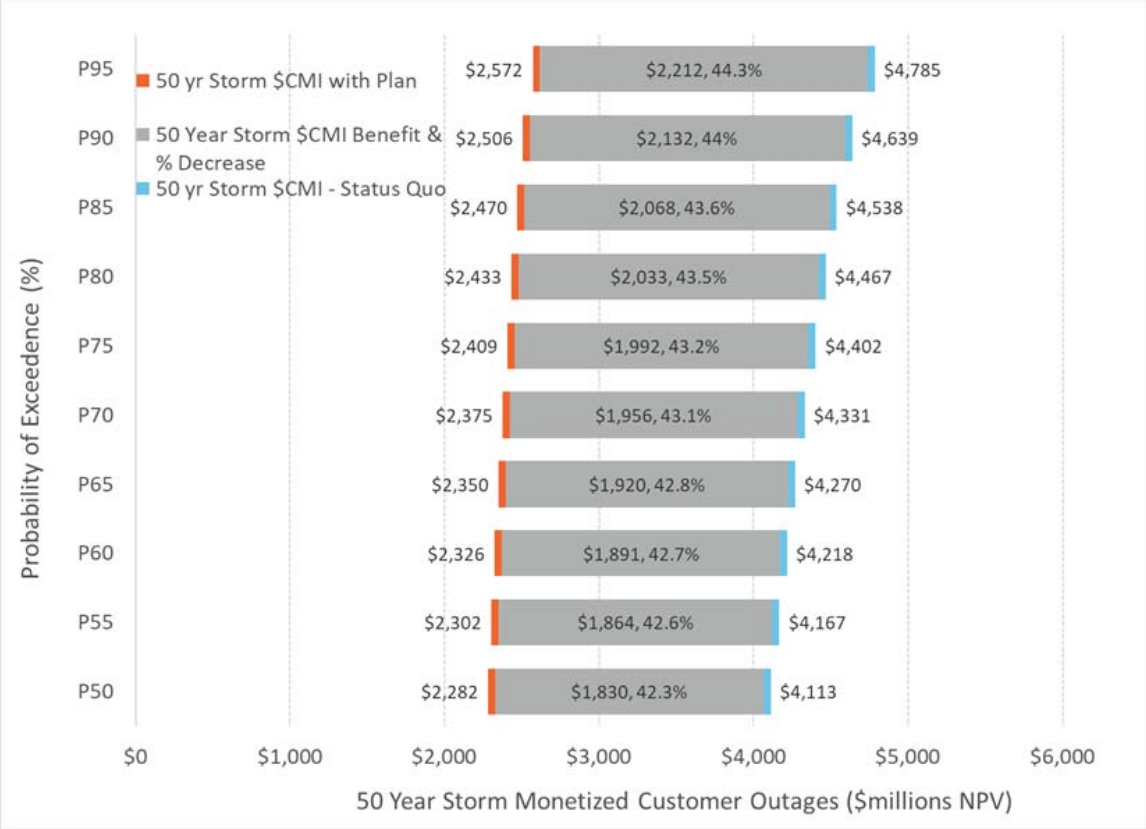
Distribution Feeder Hardening



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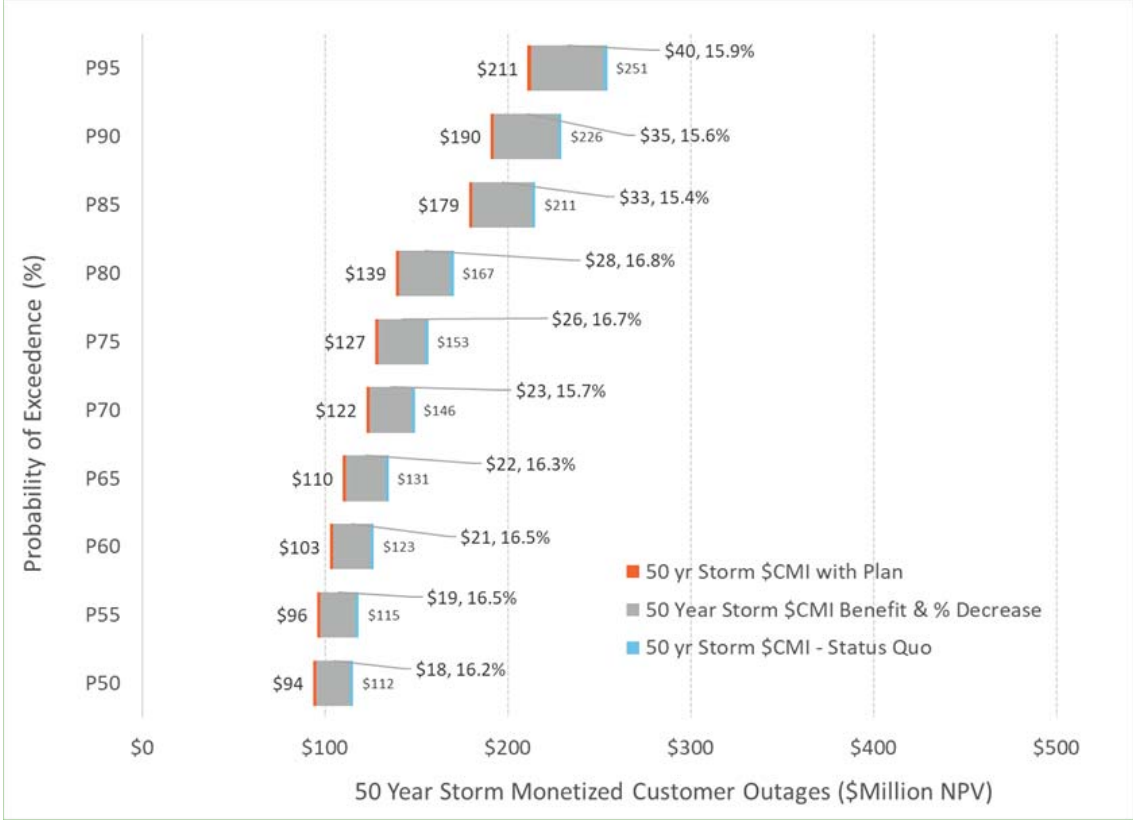
Transmission Asset Upgrades



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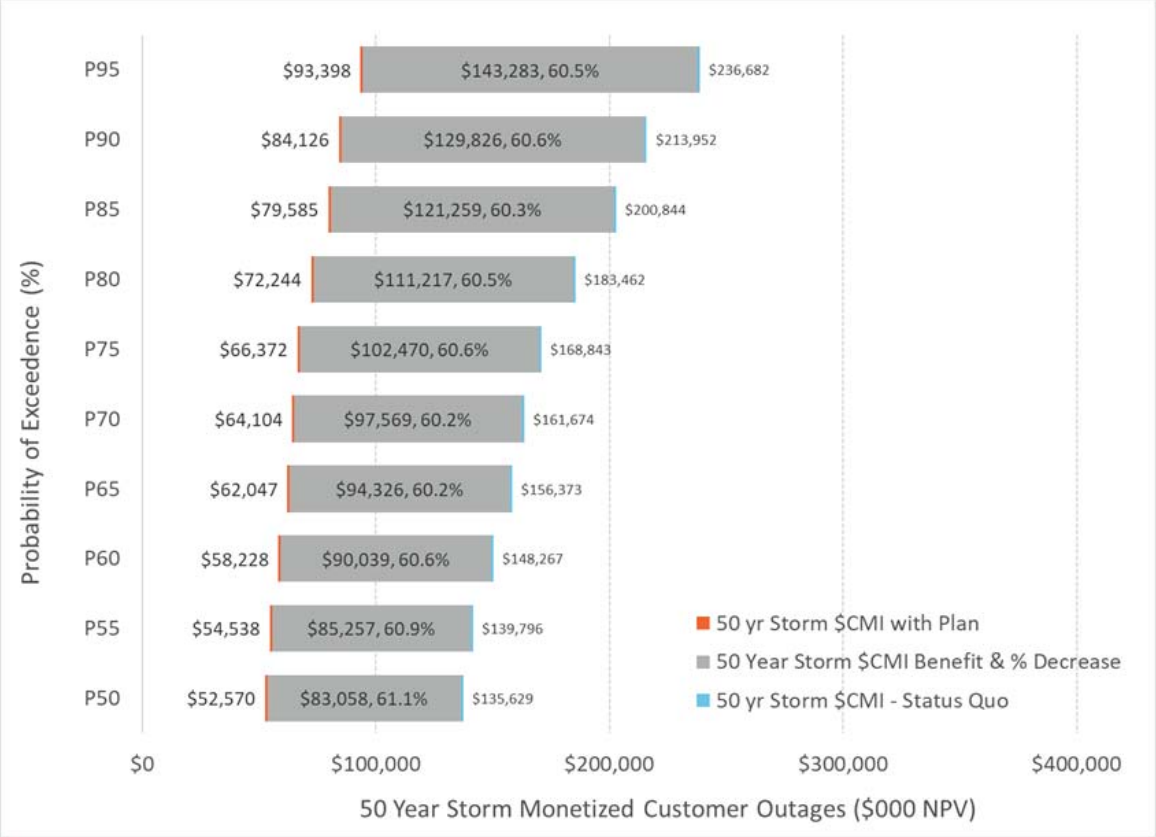
Transmission Access Enhancement



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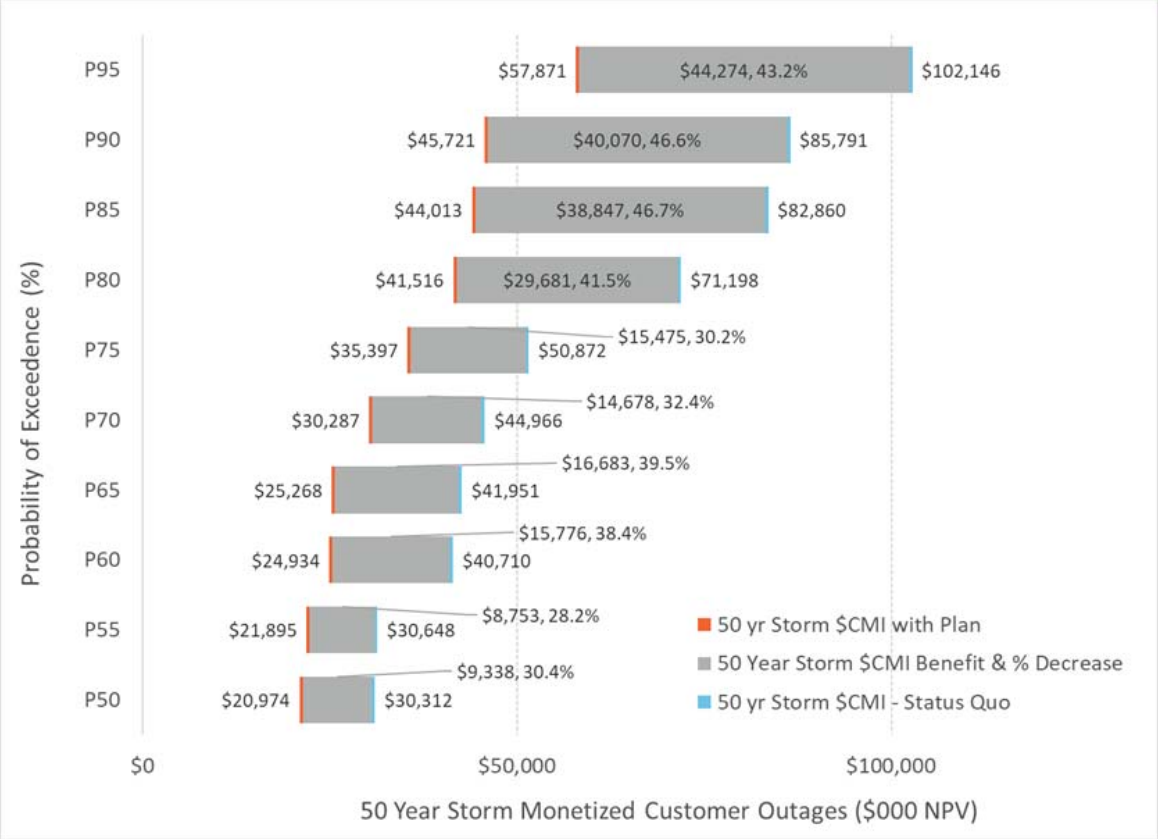
Substation Extreme Weather Hardening



e. See Response No. 134.b, this set.

f. See Response No. 134.c, this set.

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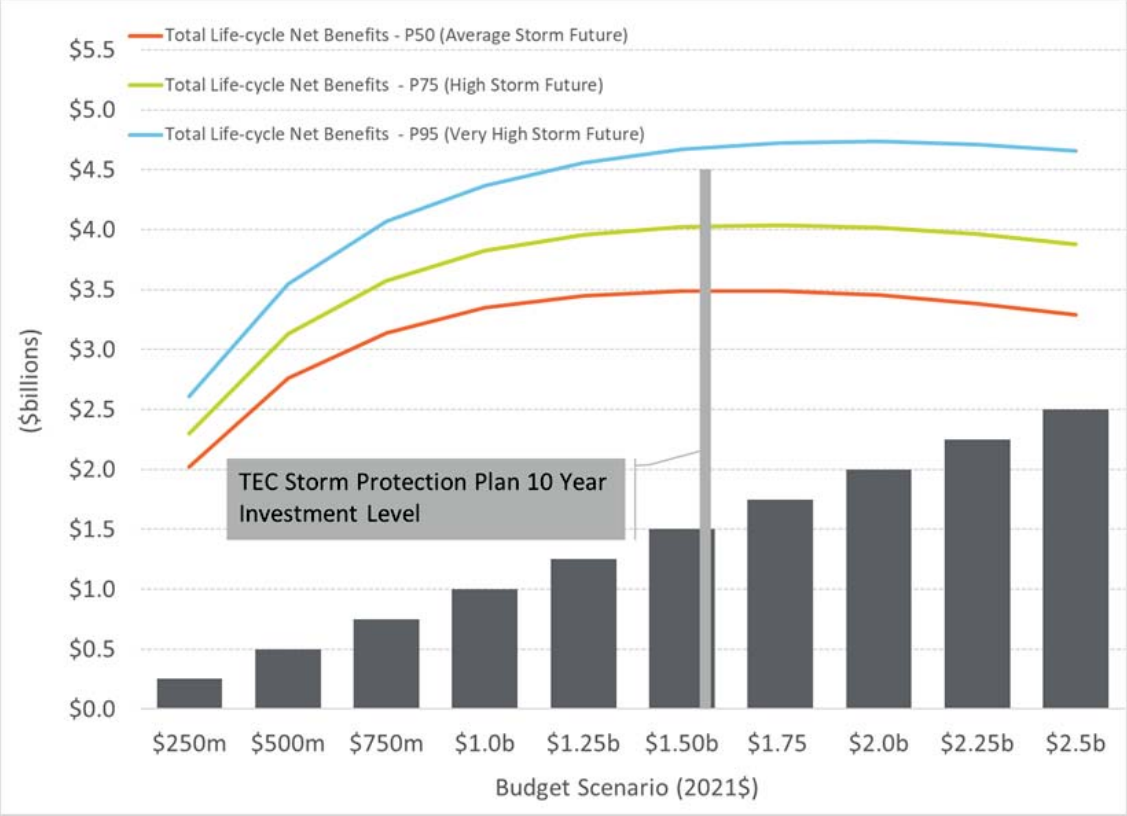
135. Referring to Exhibit DAP-1, page 77 of 78, provide detail results of the budget optimization analysis.

A. The 1898 & Co. Report includes additional information on the budget optimization analysis. Please see Exhibit DAP-1, Appendix F, page 70 of 82, section 6.0 Budget Optimization and Project Selection. Please note that the first figure includes the Net Benefits while the second figure includes the Gross Benefits. Net Benefits = Gross Benefits – Invested Capital



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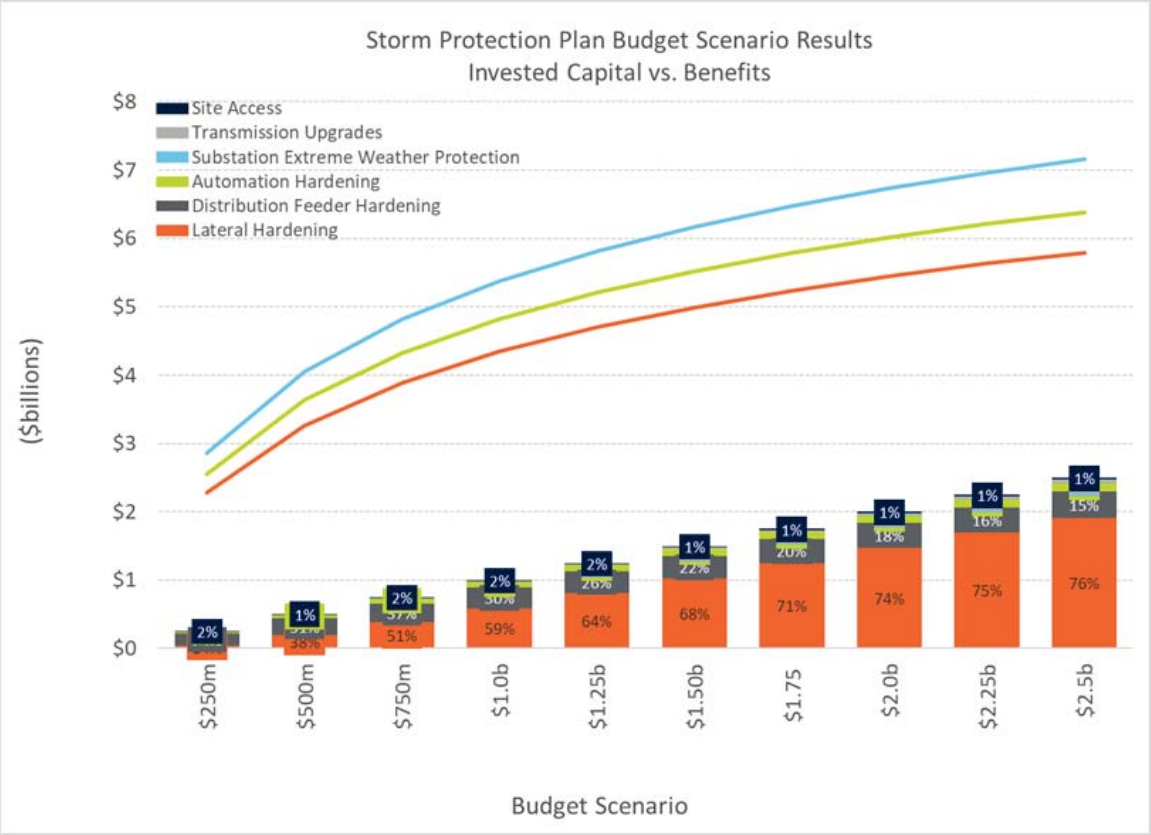

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136. Referring to Exhibit DAP-1, page 77 of 78, provide benefit levels from each budget optimization scenario ($250 million to $2.5 billion)

A. See Response No. 135, this set.

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137. Referring to Exhibit DAP-1, Appendix F Page 23 of 82, the discussion of the trip saver implies that hardening a lateral does not reduce outages during a major. Further a fuse or trip saver also does not reduce the number of outages. Explain why Trip Savers are necessary for resiliency of major storms.

A. Trip Savers, as opposed to fuses, have two operations before the final open operation that gives any momentary vegetation or animal disturbance to clear. During a major storm with high winds, such momentary disturbances are numerous and if there were fuses protecting the lateral, the disturbances would result in many outages that would require field resources to make a field visit, do an investigation to ensure the fault is clear, and then close in the fuse. By replacing the fuses with Trip Savers many of these outages and resulting field visits would be eliminated.

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138. Referring to Exhibit DAP-1, Appendix F Page 23 of 82, automation hardening generally can help on blue sky days. Provide evidence that automation reduces storm recovery costs when multiple feeders of a protection area are de-energized due to vegetation contact?

A. Not all de-energizations will be as a result of downed wire or conductor on all the related feeders in a protection area. Many vegetation contacts are momentary in nature. If one feeder has downed conductor while the adjacent feeder is still energized, having an automation scheme between the two feeders will dramatically reduce outage time. By isolating the section with the downed wire, then reenergizing the remaining feeder section with the adjacent feeder reduces restoration minutes to customers and isolates the fault to the affected portion of the system which will reduce the overall outage time and the overall storm recovery costs. Having these capabilities more areas of the company's system will have a large positive effect during a major storm.

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139. Regarding Exhibit DAP-1, Appendix F page 24 of 82:

a. Please identify the 9 substations

b. Provide the specific scenarios (storm levels) that resulted in "risk to the level that could justify investment"

c. Provide the elevation of each of the 9 substation sites, elevation of critical equipment, and elevation of water levels due to storms.

A. a. The nine substations are:

- MacDill
- Maritime
- Jackson Road
- Skyway
- South Gibsonton
- El Prado
- Desal
- Hookers Point
- Estuary.

b. There is not one specific scenario (storm level) that will result in "risk to the level that could justify investment" as these substations are not in one specific area. Each substation is unique as it depends on the strength of the extreme weather event, location of the storm landfall, and how quickly the storm moves. Each of these nine substations were evaluated by the FEMA 100 and 500 year floodplain maps, evacuation zone categories, existing wetlands within or adjacent to the substation, and hydric soil presence.

c. The following table are the elevations of the substations above mean sea level. To be specific with elevation of critical equipment and the elevation of water levels due to storms, a survey would need to be taken by a third-party contractor to obtain this information.

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Substation Name	Elevation Above Mean Sea Level (MSL)	Evacuation Zone Category
MacDill	5	A
Maritime	5	A
Jackson Road	6	A
Skyway	11	B
South Gibsonton	12	B
El Prado	7	A
Desal	10	A
Hookers Point	10	A
Estuary	12.7	A

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140. Regarding Exhibit DAP-1, Appendix F, page 28 of 82:

a. Provide the annual frequency of storms

b. Provide values used to input in the ICE calculator

c. Provide individual results from the ICE calculator for the scenarios investigated.

A. a. The 1898 & Co. Report includes the 13 unique storm types that have historically impacted the Tampa Electric service territory. The report included a table of the frequencies as well as the high-level impacts of each of these storm types. Please see Exhibit No. DAP-1, Appendix F, Page 47 of 82, table 3-4 Storm Event Database for the table of storm frequencies. For ease of reference that table has been included below.

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Storm Type No	Scenario Name	Annual Probability	Restoration Costs (Millions)	System Impact (Laterals)	Total Duration (Days)
1	Cat 3+ Direct Hit - Gulf	1.0% - 2.0%	$306 - $1,224	60% - 70%	17.4 - 34.5
2	Cat 1 & 2 Direct Hit – Florida	5% - 8%	$76.5 - $153	35% - 55%	6.0 - 8.8
3	Cat 1 & 2 Direct Hit – Gulf	2% - 4%	$153 - $306	45% - 60%	8.7 - 12.9
4	TS Direct Hit	16.5%	$25.5 - $76.5	12.5% - 31.3%	2.6 - 5.3
5	TD Direct Hit	14.5%	$5.1 - $15.3	6.3% - 15.6%	2.0 - 3.6
6	Localized Event Direct Hit	50.0%	$0.5 - $1.5	1.3% - 3.1%	0.3 - 0.6
7	Cat 3+ Partial Hit	3% - 4%	$91.8 - $184	36% - 48%	6.4 - 9.2
8	Cat 1 & 2 Partial Hit	7.0%	$15.3 - $91.8	8.5% - 28%	2.3 - 6.9
9	TS Partial Hit	17% - 18%	$11.5 - $30.6	8% - 15%	2.0 - 3.6
10	TD Partial Hit	12% - 15%	$0.4 - $3.1	2% - 3.8%	1.5 - 2.7
11	Cat 3+ Peripheral Hit	2% - 3%	$0.8 - $ 22.2	1.2% - 14.1%	1.0 - 3.0
12	Cat 1 & 2 Peripheral Hit	10% - 11%	$0.6 - $8.9	0.9% - 6.5%	0.9 - 2.3
13	TS Peripheral Hit	11% - 12%	$0.5 - $3.8	0.7% - 3.4%	0.9 - 1.3

b. Tampa Electric is including the excel spreadsheet titled, "OPC IRR 140 ICE.xlsx" in the accompanying Production of Documents, Document No. 14, for the values of interruption costs for various customer types and outage durations.

c. As discussed in the technical conference session, the Storm Resilience Model is foundationally project centric. While the Storm Resilience Model includes modeling and assumptions at both the whole system level (Major Storms Event Database) and assets (poles, substations), its base denomination is potential hardening projects. The model includes approximately 13,350 projects (see Table 4-2, Page 50 of 82). The ICE

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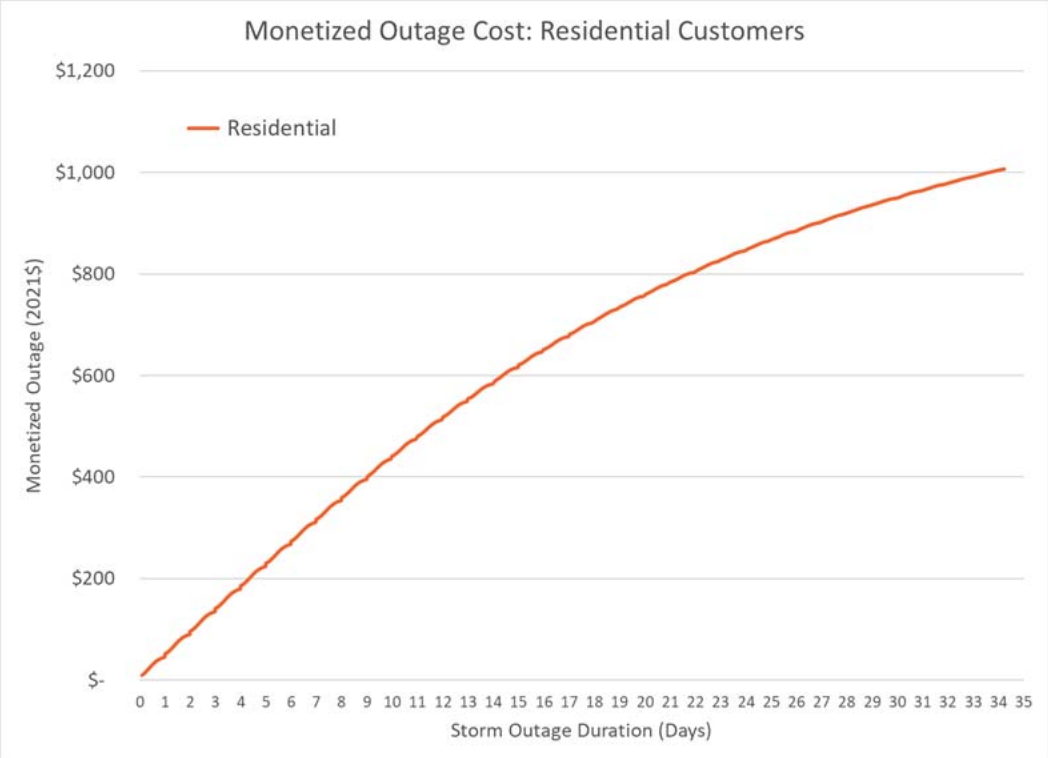
Calculator results are done for each of the 13,350 for 99 different storm scenarios (~1,335,000 calculations). The approach also factors in customer counts and types (residential, Small C&I, Large C&I, critical) for each of the projects.

Monetized Outage Costs: Residential Customers



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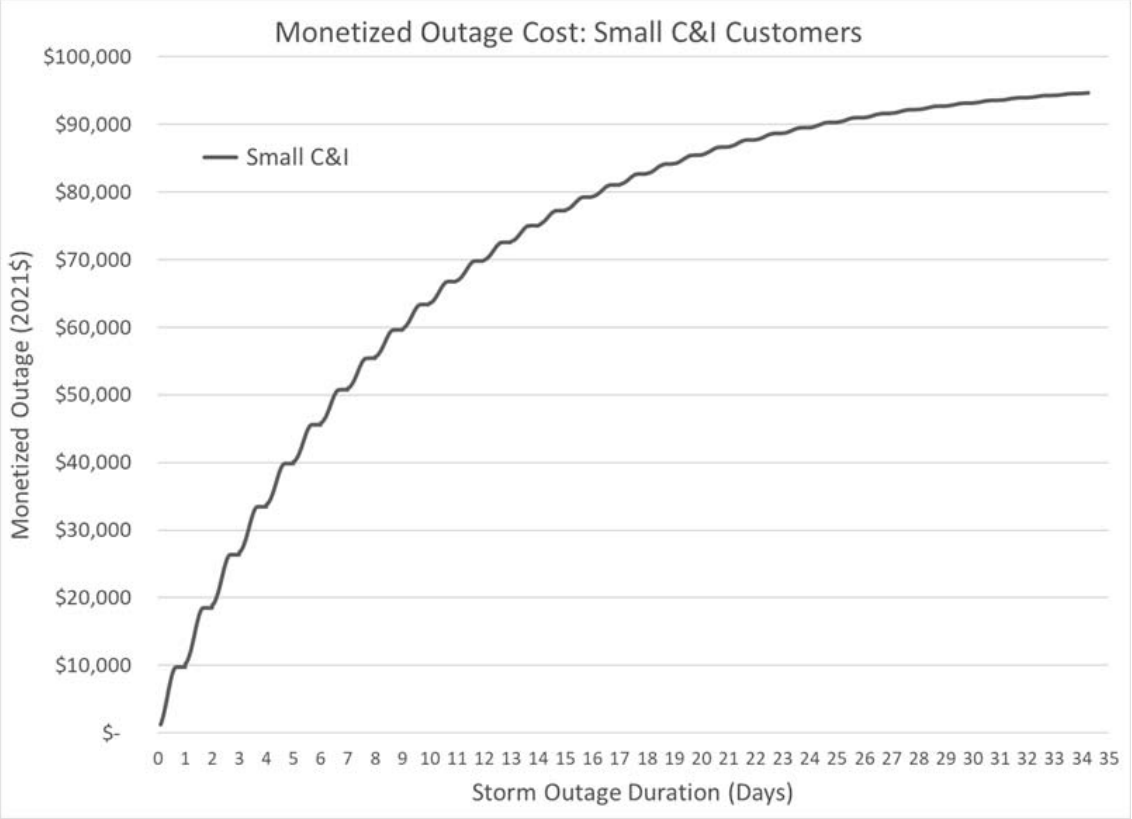
Monetized Outage Costs: Small C&I Customers



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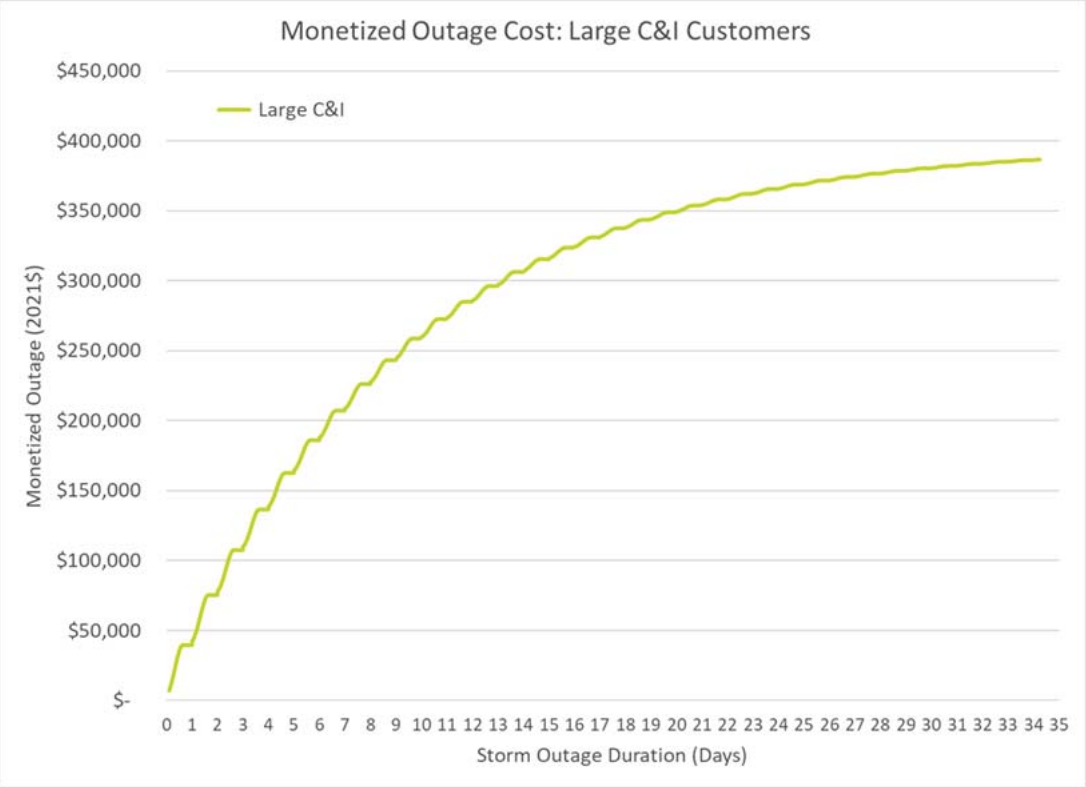
Monetized Outage Costs: Large C&I Customers



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141. Regarding Exhibit DAP-1, Appendix F page 31 of 82:

a. Provide the units for the X-axis. CMI is different than restoration costs and therefore cannot be the same value.

b. CMI and restoration costs do not have a linear relationship. Explain how these two distinctly different costs can both be represented by the X-axis.

c. Provide an explanation of the value "5,000".

d. Provide the annual frequency of storms

A. a. The figure in question on page 31 of 82 is illustrative. The evaluation performed by 1898 & Co. shows similar type of 'S-Curves" for three main result types:

1. CMI
2. $CMI or monetized CMI
3. Restoration Dollars

The figure was developed to show how these types of results would be displayed within the 1898 & Co. Report how those results should be interpreted.

b. See Response No. 141.a above.

c. See Response No. 141.a above.

d. See Response No. 140.a, this set

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142. Regarding Exhibit DAP-1, Appendix F page 67 of 82, the resilience benefit calculation assumes that a four hour outage is reduced from a storm event because an adjacent feeder is available. Identify documentation that shows that this is assumption is true.

A. The quote in question for a four (4) hour outage is an illustrative example. For clarity, the approach estimates the benefits of automation hardening by recalculating each historical Major Event Day ("MED") outage assuming the devices and load transfer schemes would have been in place. The referenced quote of 4 hours was for one of those example historical outages. The historical outage records include ranges from a few minutes to days in some cases.

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143. Regarding Exhibit DAP-1, Appendix F page 67 of 82, did the storm model adjust this load transfer if the adjacent feeders or substations were also out of power? If not, why not?

A. For the larger storm events, category storms, we are not including any benefit from feeder automation hardening. Feeder automation hardening benefit is only for MED outages as designated by the Outage Management System ("OMS"). The large hurricane event outages are not included in the OMS.

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144. Regarding Exhibit DAP-1, Appendix F page 75 of 82, for a P70, the status quo would cost $1.063 Billion to restore power and only $0.645 billion to restore power if the full plan is implemented at a cost of $1.594 billion, saving roughly $0.418 billion in restoration costs. Please confirm this interpretation of the graph.

A. The interpretation is correct for the restoration cost benefit. However, the investment of $1.594 billion would also produce a decrease in CMI which is shown in figure on the following page, Appendix F page 76 of 82. Using the P70 value, the investment of $1,594 billion would provide benefits of:

1. $0.481 billion in avoided restoration costs
2. 1,570 million in avoided CMI

Put another way, the cost to buy down 1,570 million CMI is $1.113 billion ($1.594 - $0.481). As discussed in the SPP filing and the 1898 & Co. report, the business justification is the avoided restoration costs and CMI shown above. The report also includes the monetization of the CMI using the DOE ICE Calculator modified for longer outage times. The figure below shows an alternative business justification using that outage monetization approach. As this figure shows, the benefits outweigh the costs of the plan.

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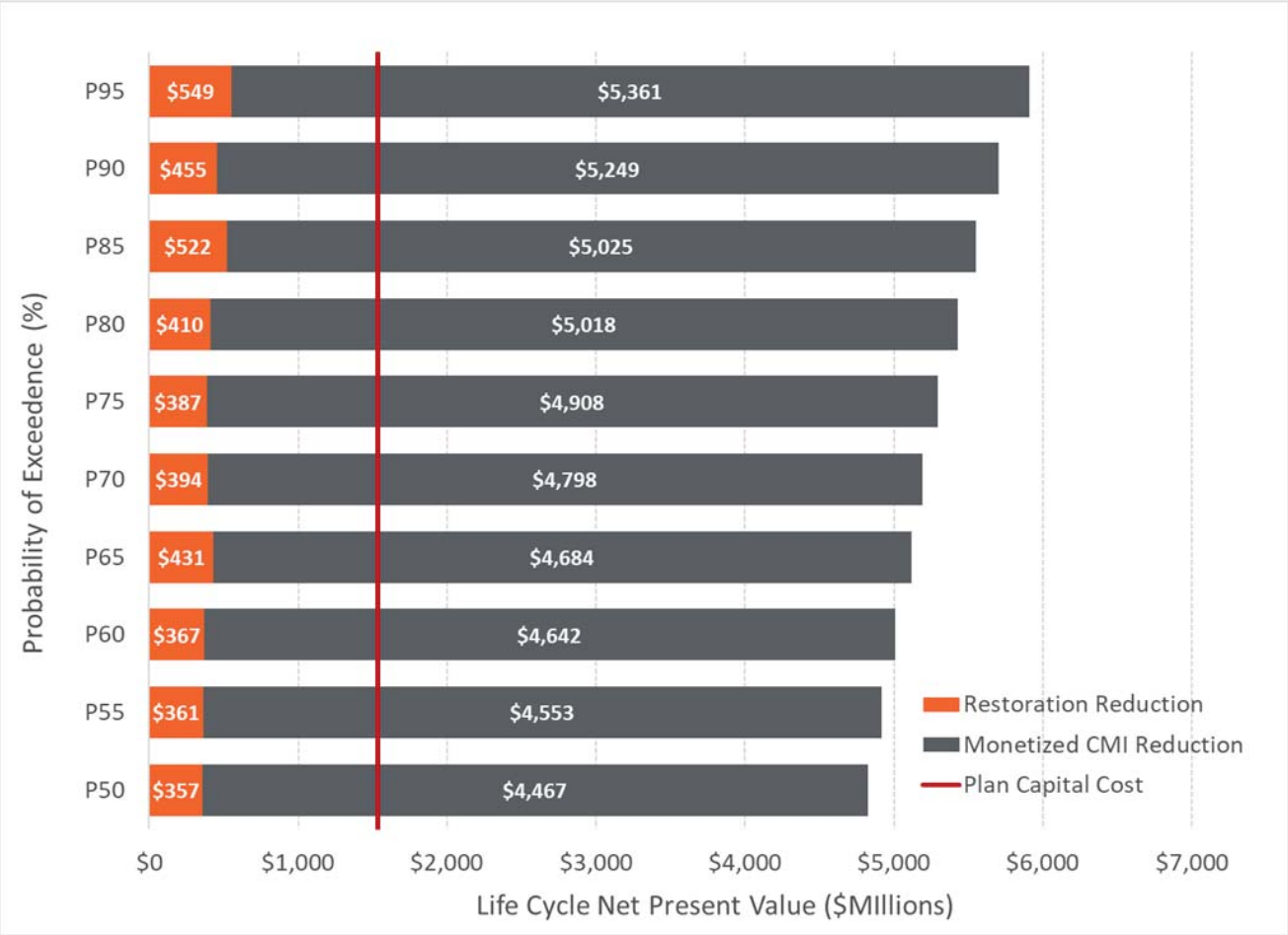

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145. Regarding Exhibit DAP-1, Appendix F page 75 of 82, please confirm that model does not include legacy programs which are described in Exhibit DAP-1.

A. The 1898 & Co. Storm Resilience Model does not include legacy initiatives and programs. Please see Exhibit DAP-1 Section 6.8 Titled Legacy Storm Hardening Initiative page 59 of 78.

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146. Regarding Exhibit DAP-1, Appendix F page 75 of 82, please confirm that the resilience benefit calculation assumes that a four hour outage is reduced from a storm.

A. The resilience benefit is calculated in terms of: 1. Decrease in Storm Restoration Costs 2. Decrease in the customers impacted and the duration of the overall outage, calculated as CMI. Durations of multiple lengths, including four hours, are reduced as result of storm hardening.

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147. Referring to Exhibit DLP-1, Document No. 5, Page 39 of 55, please explain the Flood Hazard zone of 1% annual chance of Flood hazard.

i. What is the elevation of this 1% hazard?

ii. Is this a 100 year flood plain or 500 year flood plain?

A. i. Referring to Exhibit DLP-1, Document No. 5, Page 39 of 55, this map shows two substations: Gannon and Port Sutton. The elevations for these two substations are 14.5 feet for Gannon and 3.0 feet for Port Sutton.

ii. These two sites are in the 100 year flood plain as shown on the graph in Exhibit DLP-1, Document No. 5, Page 39 of 55. The 500 year flood plain is captured in the orange/rust color toward the bottom left of the graph and does not include the substation property of Gannon or Port Sutton.

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148. Referring to Exhibit DLP-1, Document No. 5, Page 39 of 55, what is the elevation of the Gannon and Port Sutton Substation?

A. See Response No. 147.i, this set.

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149. Referring to Exhibit DLP-1, Document No. 5, Page 39 of 55, what is the elevation of the floor of the control house in these substations?

A. Referring to Exhibit DLP-1, Document No. 5, Page 39 of 55, the two substations in this question are Hookers Point and Harbour Island. To be specific with the elevation of the control house, a survey will need to be taken by a third-party contractor to obtain this information.