



# Article Distribution Reliability Optimization Using Synthetic Feeders

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Received: 23 July 2019; Accepted: 9 September 2019; Published: 12 September 2019



**Abstract:** Historical distribution system reliability optimization approaches have relied on the creation of detailed feeder reliability models, which is extremely labor-intensive. This paper presents a reliability optimization approach using synthetic feeders that does not require creating a topologically-precise model, but can still perform an overall system assessment considering a wide range of reliability improvement options for far less modeling effort. The synthetic feeder approach is then applied to Hawaiian Electric's O'ahu distribution system, to identify (1) the lowest cost required to achieve various levels of reliability improvement, and (2) an approximate reliability project portfolio for each level of spending.

**Keywords:** distribution reliability; reliability indices; reliability risk; reliability improvement; reliability optimization

# 1. Introduction

Hawaiian Electric Company (Hawaiian Electric) and its subsidiaries, Maui Electric Company, and Hawai'i Electric Light Company (collectively the "Hawaiian Electric Companies"), serve 95 percent of the state's 1.4 million residents on the islands of O'ahu, Maui, Hawai'i Island, Lāna'i, and Moloka'i. The Hawaii Public Utilities Commission (Commission) established reliability performance incentive mechanisms (PIMs) for the Hawaiian Electric Companies based on customer interruption frequency and customer interruption duration. The frequency-based index used is SAIFI (system average interruption frequency index, the average number of sustained interruptions customers experience in a year). The duration-based index used is SAIDI (system average interruption duration index, the average number of interruption minutes customers experience in a year). These reliability indices are calculated according to IEEE Standard 1366 using the 2.5 Beta method for major event day identification [1].

The Commission sets reliability PIMs index targets based on ten years of historical data. Financial penalties begin at one standard deviation above the ten-year mean, linearly increase, and reach a maximum amount at two standard deviations above the ten-year mean.

To improve reliability and avoid incurring penalties, the Hawaiian Electric Companies are interested in determining the most cost-effective way to improve SAIFI and SAIDI. Specifically, they are interested in generating cost-versus-reliability curves that show how much investment is required to achieve various levels of reliability improvement. Each point on these curves should correspond to an optimal mix of reliability improvement projects that achieves the specified level of reliability for the lowest possible cost. To generate these curves, predictive reliability models are required.

In the same way that a power flow model can calculate voltages and currents, a predictive reliability model can calculate expected customer interruptions (CI) and customer minutes of interruption (CMI). Distribution reliability assessment models were initiated by the Electric Power Research Institute

(EPRI) in 1978 [2]. Since then, several major utilities have developed in-house reliability models [3–5] and the sophistication of these models has gradually increased [6,7]. Commercial reliability models are now available from several vendors that incorporate reliability assessment algorithms into their power flow models. These reliability models can be used to assess the financial risk associated with performance-based rates [8], and can be used in various reliability optimization approaches [9–20].

Traditional approaches to reliability optimization require detailed reliability models that reflect complete distribution circuit topology including routing, section lengths, circuit interconnection points, protection device locations, switching device locations, and so forth (the remainder of this paper refers to a distribution circuit as a "feeder"). A detailed description of how to develop this type of model for reliability optimization is provided in [21]. Creating good feeder reliability models is labor-intensive. This effort can be justified when examining the reliability characteristics of specific feeders but can be untenable when looking at the overall reliability characteristics of a distribution system consisting of hundreds or thousands of feeders.

The Hawaiian Electric distribution system for the island of O'ahu, for example, consists of more than 400 feeders. In order to estimate the lowest-cost way to achieve various levels of reliability improvement, all feeders need to be considered. However, the effort to create a detailed reliability model of each feeder is prohibitively labor-intensive for high-level budgeting purposes. Therefore, the authors have developed a new approach to distribution reliability optimization that uses the concept of a synthetic feeder.

A synthetic feeder is a feeder model based on the characteristics of an actual feeder that captures the critical aspects of feeder reliability without having to create a topologically-precise model. This paper presents a method of creating synthetic feeders based on equipment and reliability characteristics of actual feeders and then applying a reliability optimization approach to identify the lowest-cost way to achieve various levels of reliability improvement. It then presents the results of using this approach for Hawaiian Electric's O'ahu distribution system.

## 2. Materials and Methods

Reliability optimization approaches must be able to quantify the benefits and costs of reliability improvement projects and project portfolios. Section 2.1 describes some potential reliability improvement options. Section 2.2 describes the synthetic feeder concept used for modeling the reliability characteristics of these reliability improvement options. Section 2.3 describes the specific algorithms used to assess the reliability of synthetic feeders in a manner capable of quantifying the benefits of these reliability improvement options.

## 2.1. Reliability Improvement Options

To improve SAIFI and SAIDI, some potential options to reduce CI and CMI include the following:

- Reducing failure rates
- Reducing the number of customers affected
  - o Adding protection devices
  - Using single-phase lockout
  - o Using fuse-saving instead of fuse-blowing protection schemes
  - Adding auto-transfer/auto-return (AT/AR) capability
- Reducing step-restoration times
  - Adding switching devices
  - o Adding back-feed capability
  - o Adding SCADA capabilities
- Reducing repair times.

- **Reducing failure rates.** Aggregate failure rates on a feeder are measured in the total number of failures per circuit mile (or km), typically separated into a three-phase overhead, three-phase underground, lateral overhead, and lateral underground. Overhead failure rates are typically reduced by more aggressive vegetation management; underground failure rates are typically reduced through aging cable replacement.
- **Reducing the number of customers affected.** When a fault occurs, protective devices deenergize the faulted equipment. Customers downstream from the protective device will experience an interruption of service. The number of customers affected by a fault can be reduced by adding protection devices, using single-phase lockout, using fuse-saving protection schemes, and/or adding AT/AR capability.
  - Adding protection devices. Adding protection devices results in fewer customers being impacted for faults in certain locations (i.e., increased protection selectivity). Protection devices can either be three-phase devices or lateral protection devices.
  - **Using single-phase lockout.** A significant percentage of faults on three-phase overhead sections do not involve all three phases. Most modern three-phase reclosers have the capability to only interrupt the faulted phases, preventing customers connected to the unfaulted phases from experiencing an interruption. Substation feeder breakers generally do not have this ability.
  - Using fuse-saving versus fuse-blowing protection schemes. Fuse saving occurs when the instantaneous trip setting of a recloser or feeder breaker is enabled. When a fault downstream of a fuse occurs, the upstream recloser or feeder breaker will operate before the fuse, allowing a self-clearing fault to clear itself. Fuse blowing occurs when the instantaneous trip setting of a recloser or feeder breaker is disabled. When a fault downstream of a fuse occurs, the fuse will operate regardless of whether the fault would have cleared itself. Fuse saving results in fewer sustained interruptions but more momentary interruptions. This is an option for overhead feeders only since underground faults are not typically self-clearing.
  - Adding AT/AR capability. AT/AR uses automated switching actions to quickly isolate faults and restore customers. The restored customers will, therefore, experience a momentary interruption rather than a sustained interruption, reducing the number of customers experiencing a sustained interruption and therefore benefiting SAIFI and SAIDI.
- **Reducing step-restoration times.** After a fault, it is often possible to isolate the fault location through switching and restore certain customers before repairs are complete. This includes upstream restoration, where customers are restored using the normal electrical route to the substation. This can also include downstream restoration, where customers are restored through alternate routes using normally-open tie switches. Step-restoration times can be reduced by adding switching devices, adding back-feed capability, and adding SCADA capabilities.
  - **Adding switching devices.** Adding switching devices allows more customers to be restored through the step-restoration process described above.
  - Adding back-feed capability. If a feeder does not have normally open switches connected to back-feed capacity, such a tie can be made, allowing for customers to be back-fed after downstream fault isolation.
  - Adding SCADA capabilities. From a reliability perspective, a SCADA-enabled device can be quickly operated by a dispatcher rather than requiring a crew to travel to the device location. For substations, SCADA-enabled feeder breakers can be remotely closed after a fault has been isolated in the upstream direction. SCADA-enabled tie-breakers can similarly be remotely closed after a fault has been isolated in the downstream direction.

SCADA-enabled switches that are normally-closed can be remotely operated to perform upstream and downstream fault isolation.

• **Reducing repair times.** The time from failure to complete repair can be reduced in a variety of ways, such as increased off-shift staffing, automatic fault location inference, and the use of faulted circuit indicators (FCIs).

#### 2.2. Synthetic Feeder

Recent research has shown that synthetic feeders can be useful for obtaining general results that are appropriate for being used at a high-level decision process [22–29]. A representation of the synthetic feeder used in this paper is shown in Figure 1. The synthetic feeder is divided into four parts: the substation, the three-phase main trunk, single-phase lateral taps, and a back-feed source.



**Figure 1.** Representation of a synthetic feeder. The feeder begins at a substation circuit breaker and consists of a three-phase main trunk, single-phase overhead lateral taps, single-phase underground lateral taps, and a three-phase normally-open connection to a back-feed source.

**Substation.** The substation consists of an infinite source bus that supplies power to a main feeder circuit breaker. The breaker has (1) a reclosing relay that can have its instantaneous trip setting as either enabled or disabled, and (2) a time-overcurrent relay that is assumed to properly coordinate with all downstream protection devices. The substation can either be equipped with SCADA or not. If equipped with SCADA, a tripped substation feeder breaker can be remotely closed by dispatchers after upstream fault isolation occurs. If not, it takes longer since a troubleman must drive to the substation to close the breaker.

Main trunk. The main trunk consists of all three-phase overhead and underground circuit miles. It also contains all three-phase switching devices (SCADA and non-SCADA) and all three-phase protection devices (SCADA and non-SCADA). The main trunk is divided into switchable sections of equal length, with protection devices being spaced as evenly as possible. Underground faults are assumed to be three-phase (three-phase underground protection schemes almost always trip all three phases), whereas overhead faults have the possibility of being either three-phase or single-phase. Line reclosers can be set for either three-phase lockout or single-phase lockout (thereby only interrupting a single phase for faults that are only a single-phase).

**Lateral taps.** The number of lateral taps is assumed to be the number of single-phase protection devices, with all taps being the same length. Underground taps are protected by a fuse, and have faults that do not have the possibility of being self-clearing. Overhead taps are protected by either a fuse or a single-phase recloser, and have faults that can either be self-clearing or not self-clearing.

## 2.3. Reliability Assessment

enough capacity to backfeed the entire synthetic feeder.

The synthetic feeder reliability assessment consists of an underground lateral analysis, an overhead lateral analysis, and a main trunk analysis. It is assumed that the laterals are protected at their connection to the main trunk, and that these protection devices always operate properly. With these assumptions, the lateral analyses can be decoupled from the main trunk analysis. It is also assumed that customers are evenly distributed over all circuit miles, with lateral customer density equal to main trunk customer density. Customer density is measured in customers per circuit mile. Failure rate is measured in failures per circuit mile. The analyses for the synthetic reliability assessment are now described.

**Underground lateral analysis.** The number of underground laterals is assumed to be the number of underground fuses, with each lateral length equal to the total underground lateral length divided by the number of assumed laterals. This approach results in each underground lateral representing the actual average lateral protection zone length.

The CI contribution of an underground lateral is equal to the product of length, failure rate, and customer density. The total CI contribution of all underground laterals is simply this amount multiplied by the number of underground laterals. The CMI contribution of all underground laterals is equal to the CI contribution of all underground laterals multiplied by the average time to restore. The equation for CI contribution from underground laterals is:

$$CI_{UGL} = # UG Laterals \times Length \times UG Failure Rate \times Customer Density.$$
 (1)

**Overhead lateral analysis.** The overhead analysis is similar to the underground lateral analysis. The number of overhead laterals is assumed to be the number of overhead fuses, with each lateral length equal to the total overhead lateral length divided by the number of assumed laterals. This approach results in each overhead lateral representing the actual average lateral protection zone length.

The CI contribution of an overhead lateral is similar to an underground lateral but must account for whether fuse saving is being used or not. If fuse saving is not enabled, the failure rate used is equal to the full failure rate of overhead laterals. If fuse saving is enabled, the failure rate used is multiplied by the probability that overhead lateral faults are not self-clearing. Other than this treatment of failure rate, the CI and CMI calculations for overhead laterals are identical to underground laterals. The equation for CI contribution from overhead laterals is:

$$CI_{OHL} = \# UG Laterals \times Length \times FR_{OH} \times Customer Density.$$
 (2)

 $FR_{OH} = OH$  Failure Rate; no fuse saving.

 $FR_{OH}$  = OH Failure Rate × P (OH faults do not self-clear); fuse saving.

Main trunk base analysis. The main trunk analysis divides the main trunk into equal-length switchable sections, with the number of switchable sections being equal to the number of protection devices plus the number of normally-closed switching devices.

The analysis algorithm sequentially assesses the CI and CMI contribution for faults in each section, starting with the section connected to the substation. When moving to each subsequent section, the analysis keeps track of the nearest upstream protection device (starting with the substation feeder breaker), the nearest upstream SCADA switch (if any), and the nearest downstream SCADA switch (if any).

Each section is treated as a composite section of both overhead and underground in the same proportion as total main trunk overhead and underground. If single-phase lockout is not enabled, the failure rate is equal to the weighted average of overhead and underground failure rates. If single-phase lockout is enabled and the upstream protection device is not the substation breaker (substation breakers do not have this capability), the failure rate is equal to the weighted average of the underground failure rate and a modified overhead failure rate that accounts for the probability that overhead failure rates might only involve a single phase. The repair time is equal to the weighted average of overhead and underground repair times.

The base CI contribution of a main trunk section fault is equal to the product of section length, failure rate, customer density, and the number of switchable sections downstream of the nearest upstream protection device. The base CMI contribution is equal to the base CI impact multiplied by the repair time. The equation for base CI contribution from a main trunk section is:

$$CI_{MT\_Section\_Base}$$
 = Failure Rate × Length × Customer Density × Affected Sections. (3)

Both the base CI and CMI contributions are then adjusted for manual and/or automated step restoration as follows.

Main trunk upstream automated restoration. If the substation is SCADA-enabled and there is a SCADA switch between the faulted section and the nearest upstream protection device, upstream automated restoration is assumed to occur. This is done by rebating the CI and CMI of these sections that were assigned during the base main trunk analysis.

Main trunk upstream manual restoration. If upstream automated restoration did not occur, upstream manual restoration is assumed to occur. This is done by rebating the CMI of all customers in upstream sections to the nearest upstream protection device. The CMI rebate amount is equal to the repair time minus the switching time.

Main trunk downstream automated restoration. If there are a SCADA-enabled tie switch and a normally-closed SCADA switch downstream of the faulted section, downstream automated restoration is assumed to occur. This is done by rebating the CI and CMI of these sections that were assigned during the base main trunk analysis.

Main trunk downstream manual restoration. If a manual tie switch exists, downstream manual restoration is assumed to occur. This is done by rebating the CMI of all customers in all downstream sections. The rebate amount is equal to the repair time minus the switching time.

#### 2.4. Comparison with Branched Feeders

From a reliability perspective, the largest difference between a synthetic feeder and an actual feeder is the lack of branching on the main trunk and the lack of branching on laterals. This is because switching and protection devices on branches will generally result in fewer customer interruptions and better fault isolation when compared to a synthetic feeder with no branching.

Consider Figure 2, which shows an actual feeder with a branch after the first main trunk section and the corresponding synthetic feeder, which has no branching. If each branch has a failure rate of 1 per year and a single customer, the actual branched feeder will have 5 customer interruptions per year (three for a fault on the first section and one for a fault on each branch) but the corresponding synthetic feeder will have 6 customer interruptions per year (three for the initial section, two for the middle section, and one for the last section). This example represents the most disparate case, and reliability calculation results will become more similar when manual switching, automated switching, and back-feeding are introduced.



**Figure 2.** Representation of a branched feeder and the corresponding synthetic feeder, which has no branching.

For this paper, failure rates and repair times are adjusted so that calculated reliability indices are equal to historical reliability indices (discussed in the next section). In the case of Figure 2, this would result in lower failure rates for the calibrated synthetic feeder when compared to the calibrated failure rated for the branched feeder. This calibration process further reduces the reliability calculation differences between actual branched feeders and corresponding synthetic feeders.

#### 2.5. Reliability Calibration

Reliability calibration is performed so that calculated feeder SAIFI and SAIDI is equal to a target SAIFI and SAIDI [30]. This is done by first calibrating SAIFI, and then calibrating SAIDI. Calibration is done by modifying a failure rate multiplier (FRM), a repair time multiplier (RTM), and a switching time multiplier (STM).

The reliability assessment assumes specific values for the following failure rates and repair times: overhead main, underground main, overhead lateral, and underground lateral. FRM proportionally adjusts each of the failure rate values, and RTM proportionally adjusts each of the repair time values.

Two switching time values are assumed in the reliability assessment: the time required to isolate a fault by opening manual switches, and the additional time required to restore customers by closing normally-open switches. STM proportionally adjusts each of these switching time values.

Since SAIFI is proportional to FRM, SAIFI calibration is straightforward, with FRM calculated as follows:

$$FRM = (Target SAIFI) / (Calculated SAIFI).$$
(4)

Once SAIFI is calibrated, SAIDI is calibrated based on the sensitivity of SAIDI to RTM (dSAIDI/dRTM). RTM is then calculated as follows:

$$RTM = RTM + (Target SAIDI - Calculated SAIDI) \div (dSAIDI/dRTM).$$
(5)

Equation (5) will properly calibrate SAIDI, but may result in repair times that are too low when compared to realistic repair times. Therefore, the SAIDI calibration procedure tests whether the adjusted RTM is below a specified threshold. If so, STM is lowered slightly and the SAIDI calibration is redone. The process continues until RTM is above the specified threshold.

#### 2.6. Reliability Optimization

Reliability optimization is performed by examining the cost and reliability impact of reliability improvement projects examined on each feeder. This is done by using the ratio of the project cost to CMI reduction (\$/CMI). CI is not used since some projects do not result in CI improvement.

Reliability optimization is achieved by incrementally choosing projects with the highest \$/CMI value, which is equivalent to a gradient ascent methodology. However, reliability improvement

projects may not be independent. It is, therefore, necessary to perform a sequential assessment of improvement options since the reliability benefits of a project may change based on previous projects that have been implemented. Discrete optimization methods such as genetic algorithms and simulated annealing can be used to account for reliability project interactions, but are computationally intensive and cannot guarantee a globally-optimal solution [18]. The issue is examined in [21], which determines that sequentially examining reliability improvement projects based on which projects typically have the lowest \$/CMI values produces results similar to discrete optimization methods. Reliability improvement projects for this paper are therefore assessed in the following order:

- 1. **Convert an overhead lateral fuse to a smart recloser (e.g., a TripSaver or a FuseSaver).** This is done by incrementing the number of smart lateral reclosers on the feeder and decrementing the number of overhead lateral fuses on the feeder. The process is repeated until all overhead lateral fuses are converted.
- 2. Add a smart recloser to a lateral. This is done by incrementing the number of smart lateral reclosers on the feeder, resulting in a shorter overhead lateral length. The process is repeated until \$/CMI rises above a specified threshold.
- 3. Add a manual switch to the main trunk. This is done by incrementing the number of manual switches on the main trunk, resulting in a shorter switchable section length. The process is repeated until \$/CMI rises above a specified threshold.
- 4. **Convert a non-SCADA recloser to a SCADA recloser.** This is done by incrementing the number of SCADA reclosers on the feeder and decrementing the number of non-SCADA reclosers on the feeder. The process is repeated until all non-SCADA reclosers are converted.
- 5. Add a SCADA recloser. This is done by incrementing the number of SCADA reclosers on the main trunk, resulting in a shorter average protection zone lengths and shorter switchable section lengths. The process is repeated until \$/CMI rises above a specified threshold.

A flow diagram showing the reliability optimization process for a single feeder is shown in Figure 3.



Figure 3. Flow diagram for reliability optimization of a single feeder.

The above process will result in a large number of reliability projects for each feeder, each with an associated \$/CMI value. These projects are then sorted with the lowest \$/CMI project ranked first and the highest \$/CMI project ranked last. The optimal (i.e., lowest cost) way to achieve a specified level of reliability improvement is determined by choosing projects, starting with the lowest \$/CMI project, until the desired reliability improvement is attained. Additional reliability improvement projects (e.g., enhanced vegetation management, installing tree wire/spacer cable, replacing high failure rate underground cable) can also be modeled, but require models that link the projects to model parameters such as failure rates, and are therefore not addressed in this paper.

## 3. Results

The methodology of Section 2 has been applied to Hawaiian Electric's O'ahu distribution system (based on equipment and reliability data provided by Hawaiian Electric for 363 feeders). All algorithms were implemented in Microsoft Excel VBA code.

A specific synthetic feeder has been created for each feeder, resulting in 363 synthetic feeders. The synthetic feeder is based on characteristics of the actual feeder such as the lengths (overhead main, underground main, overhead lateral, and underground lateral), number of devices (reclosers, manual switches, underground switches, and fuses), and other characteristics (ties to other feeders and use of fuse saving).

Default reliability parameters are shown in Table 1 (failure rates are in failures per circuit mile; all times are in minutes), and were chosen based on the experience of Hawaiian Electric. The important factor for these default parameters are the proportions of failure rates, the proportions of repair times, and the proportions of switching times. Calibration will change these values, but will change them in proportion. A summary of system characteristics is shown in Table 2. Cost assumptions are shown in Table 3.

All synthetic feeders were calibrated to their corresponding historical SAIFI and SAIDI averages for the most recent five years. This was done by adjusting the failure rate multiplier, repair time multiplier, and switching time multiplier for each feeder as described in Section 2.4. This results in unique reliability parameters for each feeder, but with proportional failure rates, proportional repair times, and proportional switching times.

A reliability assessment has been performed for each calibrated feeder (base case), which assumes SCADA in all substations, no fuse saving, and no single-phase lockout. Assessments were also performed for modifications to the base synthetic feeders. SAIFI and SAIDI results for these assessments are shown in Table 4.

Default Parameter	Value
Failure Rate: Overhead 3-Phase	0.1
Failure Rate: Underground 3-Phase	0.05
Failure Rate: Overhead 1-Phase	0.2
Failure Rate: Underground 1-Phase	0.1
Repair Time: Overhead 3-Phase	500
Repair Time: Underground 3-Phase	600
Repair Time: Overhead 1-Phase	250
Repair Time:Underground 1-Phase	300
Manual Switching Time to Isolate	60
Incremental Manual Switching Time to Restore	30
Overhead main trunk faults that are single-phase	50%
Overhead lateral faults that are self clearing	50%

Table 1.	Default	reliability	parameters.
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Category	#	Per Feeder
Feeders	363	
Customers	348082	959
Overhead 3-Phase (mi)	762	2.10
Underground 3-Phase (mi)	1100	3.03
Overhead 1-Phase (mi)	468	1.29
Underground 1-Phase (mi)	1165	3.21
SCADA Switches	7	0.02
Non-SCADA Switches	1577	4.34
Reclosers	261	0.72
Overhead Fuses	5896	16.24
Underground Fuses	3386	9.33
Feeders with Ties	324	0.89

Table 2. System summary.

**Table 3.** Cost assumptions.

Improvement Project	Cost
Convert Fuse to Smart Recloser	\$1000
Add Smart Recloser (use existing structure)	\$2000
Add Manual Switch (replace structure)	\$10,000
Upgrade Manual Recloser (use existing structure)	\$40,000
Add Automated Recloser (replace structure)	\$50,000

Table 4. Results without optimization.

	SAIFI	SAIDI	%SAIFI	%SAIDI
Base Model	0.683	63.7	100.0%	100.0%
Base + Fuse Saving	0.679	63.3	99.4%	99.4%
Base + Single Phase Lockout	0.66	61.1	96.6%	95.9%
Base + Fuse Saving + Single Phase Lockout	0.655	60.8	95.9%	95.4%
Base – Substation SCADA	0.686	68.7	100.4%	107.8%

As can be seen from Table 4, the benefits of fuse saving when compared to the base model are only about 0.6 percent. This is due to the relatively low amount of overhead lateral exposure on most O'ahu feeders (average main trunk length of 5.1 miles versus average overhead lateral length of 1.3 miles).

The benefits of single-phase lockout are significant when compared to the base model, resulting in SAIDI improvement of over 4 percent. This large benefit is due to the high percentage of main trunk exposure. The benefits of substation SCADA are also significant, with SAIDI increasing by almost 8 percent when all substation SCADA capability is disabled.

A reliability optimization was performed for each feeder using the process shown in Figure 3. This results in a large number of potential reliability improvement projects for each synthetic feeder, with each project having an associated cost and an associated CMI improvement. Optimal system reliability improvement is then determined by ranking each project from the lowest \$/CMI improvement to the highest \$/CMI improvement. This allows the most CMI improvement for each budget level to be determined.

A graph of cost versus system reliability improvement is shown in Figure 4 (i.e., reliability improvement of all 363 feeders, weighted by customer count). The optimization metric is based on SAIDI (SAIDI is proportional to CMI), but SAIFI improvement tracks SAIDI improvement closely. Reliability improves quickly for the first \$10 million in spending, and then has diminishing returns and little marginal benefit after about \$60 million in spending.



Figure 4. Cost versus reliability improvement without single-phase lockout.

A reliability optimization was also performed for the base case, but with single-phase lockout enabled. A graph of cost versus reliability improvement with single-phase lockout enabled is shown in Figure 5. Reliability improvements are significantly increased for similar spending levels. For example, \$10 million in spending improves SAIDI by about 20 percent in the base case, but by 24 percent if single-phase lockout is enabled (a 20 percent increase in the overall benefit-to-cost ratio). Reliability improvement tops out at about 32 percent for the base case as compared to 37 percent if single-phase lockout is enabled.



Figure 5. Cost versus reliability improvement with single-phase lockout.

A spending breakdown for base-case reliability results is shown in Figure 6. Spending is broken down into the first \$10 M spent for the first column, the next incremental \$10 M spent in the second column, and so forth. Color breakdown in each column corresponds to the amount of spending in each project category. As can be seen, spending in each bin is dominated by adding main smart reclosers. This is due to the high importance of main trunk reliability for the O'ahu distribution system, and the relatively small number of reclosers in the base case.



Figure 6. Spending breakdown by \$10 M bins.

A project breakdown for base-case reliability results is shown in Figure 7. Color breakdown in each column corresponds to the number of projects in each project category. The number of added SCADA reclosers (also referred to as "main smart reclosers") stays roughly constant in each spending bin, while the number of added manual switches ramps down and this money is largely shifted to OH lateral fuse to smart recloser conversions.



Figure 7. Project breakdown by \$10 M bins.

Figures 6 and 7 show the optimization results for the first \$60 million in spending, corresponding to 3486 projects (an average of about 10 projects per feeder). The entire optimization results examined 8750 projects with a total cost of \$101.8 million. Results in Figures 6 and 7 are limited to the first \$60 million due to very small additional reliability improvements.

### 4. Discussion

The project portfolio mix generated by synthetic feeder optimization is somewhat surprising. For typical U.S. distribution systems, the lowest \$/CMI projects tend to be lateral fusing and/or the deployment of single-phase smart reclosers. In the results for Hawaiian Electric, projects are weighted towards main-trunk improvements, which are smaller in number but much higher in cost. Upon investigation, there are two reasons for this.

First, Hawaiian Electric's O'ahu distribution system has a much higher percentage of main trunk circuit miles when compared to mainland utilities. On the mainland, it is common for laterals to travel many miles away from the main trunk. On O'ahu, this is not the case. Consider Table 2, which indicates that the average feeder has 1.29 miles of overhead laterals and 16.24 overhead fuses. On average, this corresponds to an overhead lateral length of fewer than 0.1 miles. It is therefore understandable that additional lateral protection only results in a small reliability benefit. There is a certain percentage of feeders where overhead lateral lengths are significantly higher than the system average; these are the feeders that the optimization algorithm assigns lateral protection projects.

Second, the synthetic feeder approach assumes that all overhead laterals on a feeder are equal. This assumption is conservative in that actual feeders are likely to have some relatively short laterals and some relatively long laterals. Differences in lateral lengths for a specific feeder would result in a higher \$/CMI score for longer laterals, resulting in earlier assignments of projects on these longer laterals.

In terms of overall value, consider the results of the most cost-effective projects representing the first \$10 million in spending. The total CMI reduction for these projects is about 4.3 million, resulting in an overall \$/CMI for these projects of about \$2.33. This is quite reasonable in terms of value, and also corresponds to a significant SAIDI reduction of 20 percent.

#### 5. Conclusions

This paper has presented a distribution system reliability optimization approach using synthetic feeders. The approach does not require creating a topologically-precise model, but can perform an overall system assessment considering a wide range of reliability improvement options for far less modeling effort when compared to previous predictive reliability assessment approaches.

The synthetic feeder optimization approach has been applied to Hawaiian Electric's O'ahu distribution system. The results of this optimization effort are comparable to results from other efforts based on detailed topological reliability models or detailed feeder reliability engineering. They are reasonable in terms of overall cost-versus-reliability results and average project portfolio value. Notable differences in the typical project portfolio mix are appropriate given the differences between O'ahu's and mainland distribution systems. The synthetic feeder approach is appropriate for utilities to quickly perform a high-level system analysis resulting in (1) the lowest cost required to achieve various levels of reliability improvement, and (2) an approximate reliability project portfolio for each level of spending.

The synthetic feeder optimization approach is not intended to replace detailed feeder reliability engineering. Once a utility sets overall reliability improvement goals and budgets, the specific topology of each feeder being addressed should be considered.

Author Contributions: Conceptualization and methodology, R.E.B and R.P.; software, formal analysis, and original draft preparation, R.E.B.; review and editing, R.P.

**Funding:** This research was funded by the Hawaiian Electric Company as part of a reliability improvement strategy development project.

Conflicts of Interest: The authors declare no conflict of interest.

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