STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC. FOR; (1) APPROVAL OF PETITIONER'S 6-YEAR PLAN FOR ELIGIBLE TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS, PURSUANT TO IND. CODE § 8-1-39-10; (2) APPROVAL OF A TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT COST RATE ADJUSTMENT AND DEFERRALS, PURSUANT TO IND. CODE §§ 8-1-2-10, 8-1-2-12, 8-1-2-14, AND 8-1-39-1 *ET SEQ*; AND (3) APPROVAL OF A TARGETED ECONOMIC DEVELOPMENT PROJECT AND RECOVERY OF COSTS ASSOCIATED WITH THE PROJECT, PURSUANT TO IND. CODE §§ 8-1-39-10 AND 8-1-39-11	)	**CAUSE NO. 45647**

VERIFIED DIRECT TESTIMONY
OF
JAMES W. SHIELDS

On Behalf of Petitioner,
DUKE ENERGY INDIANA, LLC

Petitioner's Exhibit 4

November 23, 2021

DIRECT TESTIMONY OF JAMES W. SHIELDS
PRINCIPAL CONSULTANT
BLACK & VEATCH MANAGEMENT CONSULTING LLC
ON BEHALF OF DUKE ENERGY INDIANA, LLC
BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James (Jim) William Shields. My business address is Black & Veatch Management Consulting LLC, 11401 Lamar Ave, Overland Park KS 66211

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Black & Veatch Management Consulting LLC (Black & Veatch). I hold the position of Principal Consultant.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I am a graduate of Purdue University – Indianapolis where I received a Bachelor of Science in Electrical Engineering Technology. I am also a graduate of the University of Indianapolis where I received a master's degree in Business Administration. I am a licensed professional engineer in Indiana, Ohio, and Wisconsin. I have 30 years of electric utility experience including prior positions with Wisconsin Public Service, Johnson County REMC, Eli Lilly & Co, Duke Energy Indiana, Northern Indiana Public Service Co., and AES Indiana.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION BEFORE?

A. Yes. In 2019, I testified for AES Indiana in Cause No. 45264. As an employee of AES Indiana, I directed the development of AES Indiana's TDSIC Plan. The purpose of my testimony was to explain how AES Indiana developed its plan, as well as supporting projects included in the plan, the cost estimates for the projects, plan development cost, plan implementation and plan update process.

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

A. The purpose of my testimony is 1) summarize the methodology Black & Veatch used in helping to develop the Duke Energy Indiana TDSIC 2.0 Investment Plan ("The Plan") and 2) summarize the process that Black & Veatch used to validate that the Duke Energy Indiana estimates meet the AACE Estimate Classification system definitions.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring the following exhibits:

1.) Petitioner's Exhibit 4-A (JWS): Duke Energy Indiana TDSIC 2.0 Investment Plan Report

2.) Petitioner's Confidential Exhibit 4-B (JWS): Independent Validation of Cost Estimate AACE Classification

II. <u>THE PLAN DEVELOPMENT</u>

Q. PLEASE SUMMARIZE HOW THE PLAN WAS DEVELOPED.

A. Duke Energy Indiana engaged Black & Veatch to help develop The Plan. The goal was to identify T&D system improvements and asset replacements that produce the greatest benefits to Duke Energy Indiana customers. Our approach to the investment plan analysis for TDSIC 2.0 differed from that in TDSIC 1.0 in that we combined the Copperleaf's decision analytics tool that provides a framework for quantifying benefits and optimizing investments with a Risk Adjusted Project Prioritization ("RAPP") modeling tool that identified high risk assets. Black & Veatch and Duke Energy Indiana collaboratively identified transmission line, substation, and distribution line programs that supported the objectives of The Plan. The objectives of The Plan were determined by Duke Energy Indiana and are described in section 1.1 of Petitioner's Exhibit 4-A (JWS).

Under each of the programs, more granular sub-programs were identified that provided system reinforcements contributable to the program. Then, financial, and non-financial benefit categories were identified across the sub-programs. Benefit categories were then mapped to each of the applicable sub-programs so that the benefits produced by project in each sub-programs could be quantified. Benefits categories were also mapped to a value model within Copperleaf. Within the value models, value measures were created to quantify the benefits of candidate projects. The value models allowed the Copperleaf tool to calculate the net benefit for each candidate project considered in The Plan development. Projects were grouped by transmission circuits, substations, and distribution circuits before optimizing the portfolio of projects modeled in Copperleaf. Optimizing the investments in this way helped ensure that high value projects were located in the areas on the system that produced the greatest value. Constraints were then applied at the sub-program level to determine which projects could be included in The Plan. Further discussion on The Plan development is described in Petitioner's Exhibit 4-A (JWS), Section 2.0.

Q. WHAT IS COPPERLEAF?

A. Copperleaf is a decision analytics software tool used for critical infrastructure investment planning. The tool provides a framework to quantify benefits associated with critical infrastructure investments in the electric, natural gas, water, wastewater, oil, and gas industries. Value models are developed for each investment type with specific value measures that quantify the benefits of the investments. Once the cost of each investment is paired with the benefits, the Copperleaf tool is able to run various investment scenarios to produce an optimized investment plan that aligns with the objectives of The Plan.

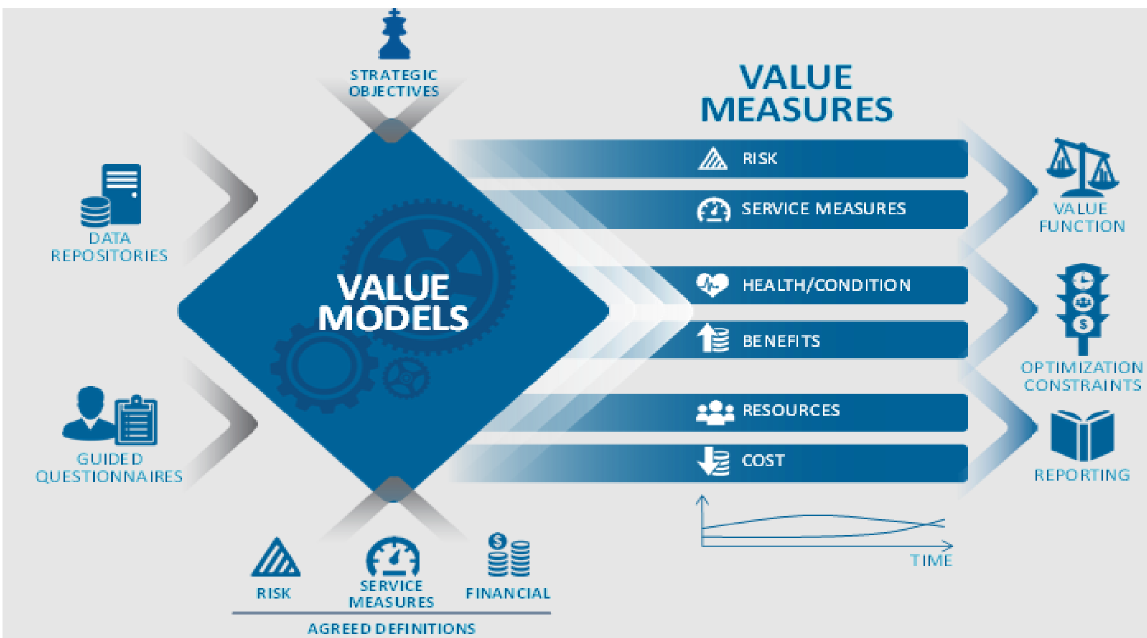
Q. WHAT IS THE RISK ADJUSTED PROJECT PRIORITIZATION ("RAPP") TOOL USED TO IDENTIFY HIGH RISK ASSETS?

A. The RAPP model is similar to risk models used in other Indiana TDSIC filings Black & Veatch has helped develop and is further described in Section 2.2.1.1 of Petitioner's Exhibit 4-A (JWS). The model calculates a risk score for assets included in the asset risk register. Risk is defined as the product of the Probability of Failure ("PoF") multiplied by the Consequence of Failure ("CoF"). Survivor curves combined with asset health data adjusts the actual age of assets to an effective age. The effective age of an asset is the age of the asset once the condition of the asset is taken into consideration. From this effective age a probability of failure is calculated from the remaining life of the asset of the survivor curves. Consequence of Failure is calculated from a criterion of consequences and scored based on the criticality of the consequence. The RAPP tool complimented the Copperleaf decision analytics tool by identifying high risk assets. High risk assets identified from the RAPP tool were input into the Copperleaf tool to compete for funding with other projects identified in the development of The Plan.

Q. WHAT IS A "VALUE MODEL"?

A. Value models combine all the benefits a project produces and calculates the value measures to quantify the benefits of the projects. The output of a value model is the project's net benefits, which is the net present value of the benefit stream minus the net present value of the cost. Inputs to a value model are data sets that are needed to calculate the net benefits. Figure 1 is a conceptual illustration of a value model. Value models are further discussed in Section 2.0 of Petitioner's Exhibit 4-A (JWS).

Figure 1: Value Model Concept



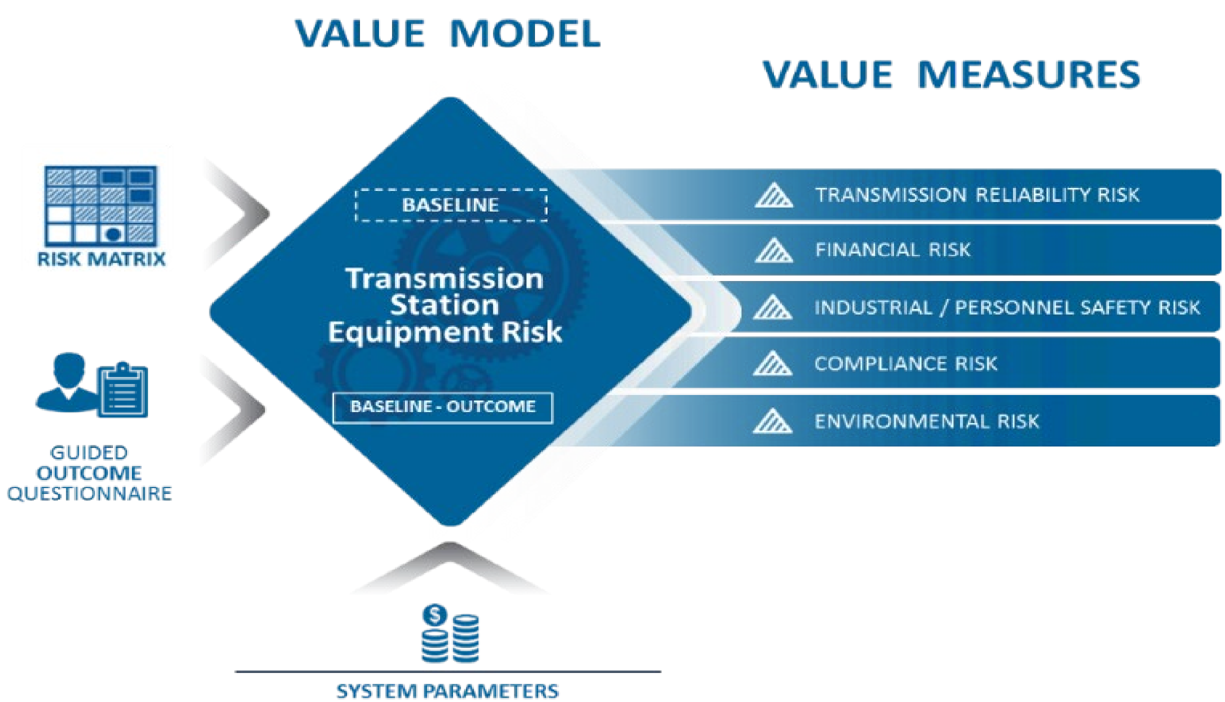
Q. WHAT IS A VALUE MEASURE?

A. Value measures capture the financial and non-financial benefits produced by a project. For projects that produce financial benefits, the benefits are measured in dollars. For projects that produce non-financial benefits, the benefits are measured in value units. A conversion factor of 1 value unit = $1,000 is used to normalize and monetize the non-financial benefits.

Q. WHICH VALUE MEASURES WERE USED IN THE INVESTMENT PLAN ANALYSIS?

A. The three different types of value measures used in the development of The Plan are risk mitigation, benefits, and cost. Risk mitigation captures the value in avoiding undesirable outcomes. Benefits capture the value of desirable outcomes. Cost is the dollars spent to construct a project. To illustrate, the value measures associated with the transmission station equipment risk value model is illustrated below in Figure 2.

Figure 2: Illustration of the Risk Value Model for Transmission



In this value model, the value measure captures the value of:

a) Transmission Reliability Risk: measures the societal impact of not delivering electricity to customers due to asset failure.

b) Financial Risk: measures the potential damage to Duke Energy equipment or property due to asset failure.

c) Industrial / Personnel Safety Risk: measures the potential harm to Duke Energy employees or the public due to asset failure.

d) Compliance Risk: measure the risk of being in non-compliance due to asset failure.

e) Environmental Risk: measures the risk to the environment due to asset failure.

Q. WHAT ARE VALUE UNITS?

A. Investment planning is based on determining the relative value of each investment under consideration for funding. Each investment brings different types of value to the organization. Value can be in the form of mitigated risk, cost savings, impacts to key performance indicators, or levels of service. For some projects the value produced can be quantified in dollars. For other projects, the value produced does not directly translate to dollars. To quantify the value of these projects, a uniform system of measurement can be established that scores projects on a common scale. For the risk mitigation value measure, used to capture the value of avoiding undesirable outcomes, a uniform risk matrix was developed to align the mitigation of risk to a common scale. Risk is defined as the Probability of Failure ("PoF") multiplied by the Consequence of Failure ("CoF"). Value units define consequence levels. A consequence scale defines the degree of consequence over a range of potential outcomes. Table 1 below, from Section 2.3.3 of Petitioner's Exhibit 4-A (JWS), depicts the common consequence scale used in calculating risk mitigation value units.

Table 1: Consequence Scale for Uniform Value Measures

CONSEQUENCE	MINIMAL	MODERATE	SIGNIFICANT	SEVERE	CRITICAL	CATASTROPHIC
Range (Value Units)	< 500	500 - 2,000	2,000 - 10,000	10,000 - 50,000	50,000 - 250,000	>250,000
Midpoint/ Representative Value	250	1,250	6,000	30,000	150,000	500,000

The probability of an event occurring, for any consequence level, can also have a common scale. Table 2 below is the probability levels used in calculating risk mitigation value units.

Table 2: Value Units Probability Levels

Level	Description	Range	Midpoint Representative Value
Almost Certain	Imminent (100% chance of occurring this year)	> 0.90	1.00
Once in 1 - 2 Years	Approximately 70% chance of consequence occurring this year (1 in every 1 to2 years)	0.5 - 0.90	0.70
Once in 2 - 5 Years	Approximately 35% chance of consequence occurring this year (1 in every 2 to 5 years)	0.2 – 0.5	0.35
Once in 5 - 10 Years	Approximately 15% chance of consequence occurring this year (1 in every 5 to 10 years)	0.1 – 0.2	0.15
Once in 10 - 20 Years	Approximately 7.5% chance of consequence occurring this year (1 in every 10 to 20 years)	0.05 - 0.1	0.075
Once in 20 -100 Years	Approximately 3% chance of consequence occurring this year (1 in every 20 to 100 years)	0.01 - 0.05	0.03
None	The consequence is unlikely to occur in the next 100 years	<0.007	0.00

As an example, if a project has a significant consequence (6,000) and a 1 in every 5 to 10 years probability of occurring (0.15), the risk mitigation value units would be 6,000 x 0.15, equating to 900 value units. This in turn, equates to $900,000 of benefits associated with avoiding the undesirable outcomes of completing the project. Risk mitigation and benefits have a positive value while costs have a negative value.

Q. DESCRIBE BENEFIT MAPPING.

A. Thirteen quantifiable benefit categories were identified for sub-programs. The benefits were mapped to the sub-program that produced the benefit. Table 3 below summarizes how the benefits were mapped.

Table 3: Quantifiable Benefits Mapping

	Sub-Programs	Benefit Categories: Reduce/Avoid Capital Cost	Reduce/Avoid O&M Cost	Reduce/Avoid Generation Capacity Cost	Reduce/Avoid Energy Costs	Reduce/Avoid Ancillary Services Cost	Reduce/Avoid T&D Losses	Avoid Restoration Costs	Compliance Risk	Public Property Risk	Safety Risk	Customer Outage Reduction Value	Increased Customer Satisfaction	Avoid Customer Fuel Cost
D	Self-Optimizing Grid (SOG)			✓	✓							✓	✓	
D	Circuit Visibility & Control							✓				✓		
D	Inaccessible ROW							✓				✓	✓	
D	Declared Circuits							✓				✓	✓	
D	IVVC		✓	✓	✓	✓	✓	✓						✓
D	Capacitor Automation		✓					✓					✓	
D	Circuit Segmentation							✓				✓	✓	
D	Ltd Access Road Crossing								✓					
D	Circuit Sectionalization											✓	✓	
D	Deteriorated Conductor							✓				✓	✓	
D	Automated Lateral Device							✓				✓	✓	

D	Targeted Undergrounding	✓	✓					✓				✓	✓	
D	UG Cable Rehabilitation											✓		
D	4kv Conversion	✓	✓	✓			✓					✓	✓	
D	GLT Pole Inspection & Replacement									✓	✓	✓	✓	
D	Surface Mount Equipment Inspection												✓	
D	Switchgear Inspection & Replacement												✓	
D	Recloser Replacements	✓											✓	
T	Wood to Non-Wood Replacement							✓			✓	✓	✓	
T	Cross Arm Replacement							✓			✓	✓	✓	
T	Cathodic Protection							✓			✓	✓	✓	
T	Tower Replacement							✓			✓	✓	✓	
T	345 Circuit Hardening							✓			✓	✓	✓	
T	SCADA to Switches					✓	✓	✓			✓	✓	✓	
T	Looping Short Radials Through Existing Substations							✓			✓	✓	✓	
T	OHG (OH Ground Wire)						✓	✓			✓	✓	✓	
T	T-Line Rebuilds						✓	✓			✓	✓	✓	
T	Transmission Relay Upgrades							✓			✓	✓	✓	
T	T&D Circuit Breakers Replacements							✓			✓	✓	✓	
T	T&D Transformers Replacements						✓	✓			✓	✓	✓	
T	Condition Based Monitoring - Transformers & Breakers							✓			✓	✓	✓	
T	Upgrade T&D Transformer							✓			✓	✓	✓	
T	Substation Reconfiguration for Improved Reliability							✓			✓	✓	✓	
T	SCADA Communications						✓	✓			✓	✓	✓	

The thirteen quantifiable benefits were also mapped to a value model in Copperleaf. Value models combine all the value measures a project can produce to calculate the net value of the project. Table 4 below illustrates the value model each benefit category is mapped to.

1 **Table 4: Benefits Mapping by Category**

Benefit Category	Value Model	Value Model Description
Reduced/Avoided Capital Costs Reduced/Avoided Generation Capacity Costs Reduced/Avoided O&M Costs Reduced/Avoided Energy Costs Reduced/Avoided Ancillary Services Costs Reduced/Avoided T&D Losses Avoided Restoration Costs Avoided Customer Fuel Cost	Financial Impact	Calculates the total annual incurred savings or costs related to competing an investment. The Financial Impact Value Model has two Value Measures, Financial Impact – Capital and Financial Impact - O&M.
Customer Outage Reduction Value	Transmission Line Reliability (TLR) Transmission Substation Electric Reliability (TSER) Electric Reliability Risk - Distribution	Measures the mitigated risk associated with not being able to deliver electricity to customers. This model compares the value of Customer Minutes of Interruption (CMI) cost, Duration Cost, and Frequency Cost and choses the cost with the highest value.
Increased Customer Satisfaction	External Relations Impact	Measures the Impacts that affect Duke's interaction with external stakeholders (customers, legislators, regulators, community leaders, public and media) i.e. Tail Risk, public perception, Rate-Cases, NRC notifications, branding, etc.
Compliance Risk	Compliance Risk	Takes inputs from a user questionnaire and Risk Matrix, and outputs a single Value Measure calculated in risk units
Personal Property Risk	Personal Property Risk	Measures the risks associated with damage to public or third-party property
Improved Safety	Transmission Line Reliability (TLR) Transmission Substation Electric Reliability (TSER)	Takes inputs from a user questionnaire and Risk Matrix, and outputs a single Value Measure calculated in risk units
Improved Power Quality	Transmission Line Reliability (TLR) Transmission Substation Electric Reliability (TSER)	Takes inputs from a user questionnaire and Risk Matrix, and outputs a single Value Measure calculated in risk units

Q. DESCRIBE THE TWO FUNDING METHODS USED IN OPTIMIZING THE PLAN?

A. In developing The Plan, candidate projects were identified for potential inclusion. Benefits were quantified in terms of net value for each candidate project. From this portfolio of investments, an optimization analysis was performed to direct the funding of projects. The Plan utilized two funding mechanisms, reserved and optimized.

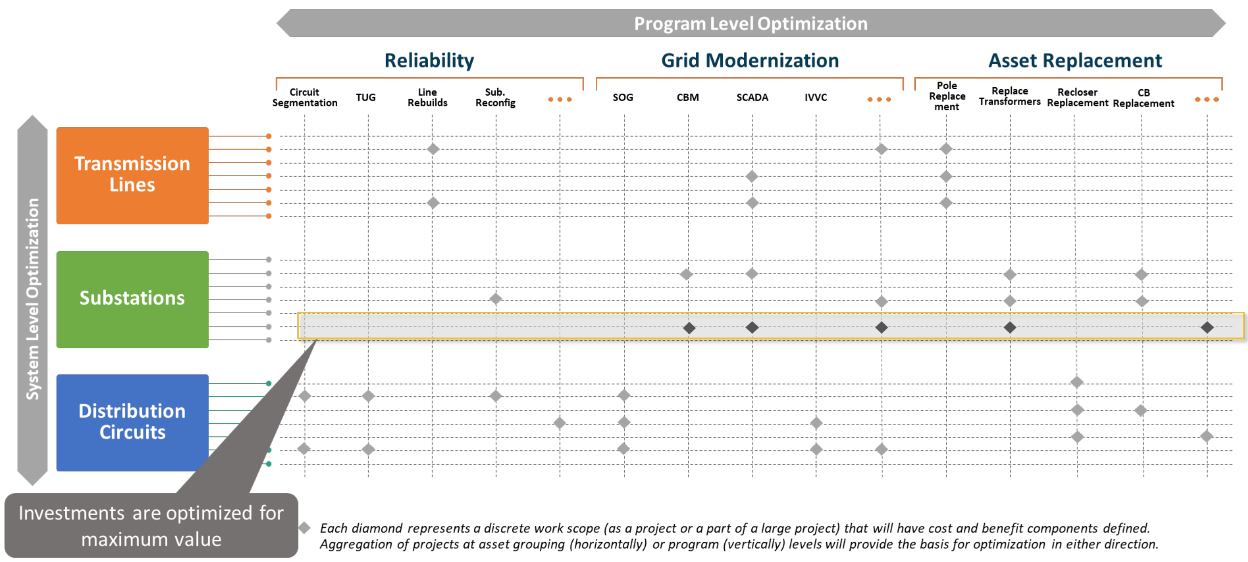
Reserved was used for sub-programs that are inspection based, where historical failure rates could be used to project future funding levels for replacing equipment that did not pass inspection. Reserved was also used for replacing assets with known poor performance and for projects that provided required minimum levels of redundancy or system intelligence on the system.

Optimized was used on projects that competed for funding based on the value they produced. The optimization analysis first grouped projects to their associated system component (i.e. Distribution Line, Substation or Transmission Line) and then optimized them based on the aggregation of benefits from each project. Grouping and optimizing projects in this fashion directs funding to areas on the system, that produce the most benefit. Also, construction efficiencies are realized during execution of the plan from concentrating resources in specific areas.

Q. DESCRIBE HOW THE PLAN WAS OPTIMIZED.

A. The investment plan was optimized using the approach depicted in Figure 3 below. The three investment groupings are shown on vertical axis - Transmission Lines, Substations and Distribution Circuits. Sub-programs are shown on the horizontal axis as the column headings.

Figure 3: Optimization Approach



Each diamond represents a discrete scope of work that will have cost and benefit defined. The discrete scopes of works were then combined to form candidate TDSIC projects at a system component level (distribution circuit, substation or transmission line). This structure groups projects at the system component level and aggregates benefits from the candidate projects, to be evaluated at the system component level. By doing this, funding is directed based on highest benefits generated, to specific areas on the system. This approach supersedes previous approaches in that it doesn't prioritize work only from a program view. Rather, it prioritizes and optimizes work based on all the benefits that are generated from all the programs to specific areas on the system.

Q. DESCRIBE THE CONSTRAINTS APPLIED DURING THE INVESTMENT PLAN ANALYSIS.

A. Constraints such as construction and engineering resource availability, required transmission system clearances and funding levels were applied to the investment plan modeling. The main constraint applied in The Plan development was funding levels. Funding levels for transmission and distribution systems were set by Duke Energy Indiana. For transmission, an additional funding split between substations and transmission lines was made. Sub programs, where reserved funding was applied, established the second constraint. Projects designated as "subject to optimization" then competed for the remaining funding, based on the benefits they produced.

Q. WERE THE TRANSMISSION PROJECTS EVALUATED UTILIZING THE SAME METHODOLOGY AS THE DISTRIBUTION PROJECTS?

A. Yes, in general. However, due to the inherent differences between Transmission and Distribution systems, benefits needed to be assessed slightly differently. Distribution systems are typically radial, segmented, and have more frequent outages that impact fewer customers than transmission systems. Transmission systems are designed to be redundant to minimize impacts on large numbers of customers and to transport power long distances reliably. In addition, high voltage transmission substation equipment failures can take months and cost hundreds of thousands of dollars to replace or repair. This redundancy, that has been established over several decades, has provided reliable electric service across the entire transmission grid. When evaluating benefits on the transmission system, the emphasis is on maintaining this high reliability performance that customers have become accustomed to. In this light, benefits on the Transmission system are focused less on the value of loss load and more on maintaining and reinforcing the redundancy that currently exists.

Distribution substation and line project benefits were valued based on the reduction in future outages compared to historical system performance. When these assets fail, customers see an interruption of electric service. Quantifying benefits on the distribution system relies more on avoided customer outage costs.

Table 5 below summarizes the key differences in the reliability risk approach for Transmission and Distribution.

Table 5: Comparison of Transmission and Distribution Risk Approach

Area	Transmission	Distribution
Key Driver	Strengthening and maintaining built-in redundancy by replacing high risk assets prior to failure	Implement projects that reduce SAIDI and SAIFI.
Approach	Perform relative risk assessment to identify projects with maximum value - risk reduction potential	Quantify reliability improvement to determine projects that can provide maximum benefit to the customers
Rating basis	Projects are independently evaluated based on the potential risk mitigation	Project are evaluated based on improvements in reliability

Q. PLEASE SUMMARIZE THE CMI AND CI IMPROVEMENTS AS A RESULT OF THE PLAN.

A. Table 6 below summarizes the improvement in Customer Interruptions and Customer Minutes of Interruption associated with the proposed distribution project by Program.

Table 6: CI and CMI Improvements by Distribution Programs

Program	CI Improvement	CMI Improvement
Overhead Lateral Uplift	33,184	5,809,593
Circuit Backbone Uplift	240,668	47,097,671
Inspection Based	-	-
4 KV Conversion	1,974	212,695
Underground System Uplift	2,143	388,408
Total	**277,969**	**53,508,367**

Q. PLEASE SUMMARIZE THE RESULTS OF THE ANALYSIS BLACK & VEATCH PERFORMED.

A. The summary results of the investment plan analysis shows that the estimated cost of The Plan is justified by the incremental benefits attributable to The Plan. Table 6 below shows that The Plan, as a whole, has a 2.8 benefit to cost ratio.

Table 7: Benefit to Cost Ratio Summary

Program	Benefit	Cost	Benefit/Cost Ratio
Transmission			
Line Hardening and Resiliency	$ 1,474,854,161	$ 498,972,419	3.0
Substation Hardening and Resiliency	$ 1,318,960,413	$ 300,695,373	4.4
Sub Total	**$ 2,793,814,574**	**$ 799,667,792**	**3.5**
Distribution			
Circuit Backbone Uplift	$ 1,005,459,622	$ 406,791,333	2.5
Inspection Based	$ 309,041,687	$ 160,831,806	1.9
OH Lateral Uplift	$ 208,412,225	$ 104,297,652	2.0
Underground System Uplift	$ 50,592,886	$ 35,709,735	1.4
4 KV Conversion	$ 41,285,100	$ 67,630,648	0.6
Sub Total	**$1,614,791,520**	**$ 775,261,174**	**2.1**
Totals	**$ 4,408,606,094**	**$ 1,574,928,966**	**2.8**

III. VALIDATION OF AACE CLASSIFICATION

Q. PLEASE DESCRIBE BLACK & VEATCH EXPERIENCE VALIDATING ESTIMATES FOR AACE CLASSIFICATION.

A. As a leading engineering, construction and procurement consulting firm in the United States, Black & Veatch has used the AACE classification system for estimating projects on many projects. We also have performed independent estimate reviews for other TDSIC filings in Indiana.

Q. WHAT DID BLACK & VEATCH DO TO VALIDATE DUKE ENERGY INDIANA COST ESTIMATES?

A. Black & Veatch reviewed a sample of Duke Energy Indiana cost estimates for reasonableness. The report is found in Petitioner's Confidential Exhibit 4-B (JWS). The estimate sample included both AACE Class 2 and Class 4 type estimates used in The Plan. For Class 2 estimates, Black & Veatch reviewed the scope of work and site-specific detailed engineering drawings with Duke Energy Indiana engineering, project management and construction labor contractors. The reviews included detailed line item material and labor estimates including quantities needed for the specific project. For Class 4 estimates, Duke Energy Indiana developed cost estimates based on a typical unitized project scope. While these estimates did not contain the site-specific detailed engineering as with the Class 2 estimates, line item costs for a typical project scope were provide to Black & Veatch for review. These estimates were reviewed in a similar fashion with line item material and labor estimates including quantities.

Q. DO YOU BELIEVE THE ASSUMPTIONS AND METHODOLOGY DUKE ENERGY INDIANA USED TO DEVELOP ESTIMATES ARE REASONABLE?

A. Yes. Based on the review of Duke Energy Indiana engineering and estimating processes, Duke Energy Indiana has well established engineering processes and estimating tools that are in alignment with industry best practices and AACE Estimate Classification guidelines.

Q. IS IT REASONABLE TO UTILIZE CLASS 2 ESTIMATES FOR THE FIRST TWO YEARS OF THE PLAN AND CLASS 4 ESTIMATES FOR THE REMAINING YEARS?

A. Yes. This approach is reasonable for two reasons: First, performing the detailed engineering required for AACE Class 2 estimate classification on projects further than two years out could introduce additional cost to the projects. The Duke Energy Indiana T&D system is a dynamic system that changes on a regular basis. Projects identified in The Plan potentially may not be necessary or the scope could change significantly in five years, rendering the detailed engineering obsolete. Secondly, while AACE Class 4 estimates are parametric in nature, the type of work is typical and familiar to Duke Energy Indiana. Duke Energy Indiana has historical average actual costs for similar completed projects that helped guide the development of the Class 4 estimates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes

PETITIONER'S EXHIBIT 4-A (JWS)
DEI TDSIC 2.0

TDSIC 2.0 INVESTMENT PLAN

BLACK & VEATCH PROJECT NO. 406509

PREPARED FOR

DUKE ENERGY.

Duke Energy Indiana

19 NOVEMBER 2021

BLACK & VEATCH

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Key Terms and Acronyms

AACE	American Association of Cost Engineering
AHI	Asset Health Index
ALD	Automated Lateral Device
Black & Veatch MC	Black & Veatch Management Consulting
CBM	Condition-Based Monitoring
CI	Customer Interruptions
CMI	Customer Minutes of Interruption
CoF	Consequence of Failure
Constraint	Limits in terms of time, budget, or specific condition implemented to the inputs in Copperleaf Portfolio Model to derive the output in terms of Net Benefits for a specific scenario.
Copperleaf	Copperleaf Technologies software, Copperleaf Asset and Copperleaf Portfolio, were used to develop the net benefit values and optimize project selection.
CY	Calendar Years
DEI	Duke Energy Indiana
DER	Distributed Energy Resources
EDSH	Enterprise Distribution System Health
ERR	Electric Reliability Risk
Hardening	Hardening applies to projects that prevent outages
ICE	Interruption Cost Estimator
IOWA Curve	Asset class-specific Survivor Curves developed[1] by the University of IOWA
IURC	Indiana Utility Regulatory Commission
IVVC	Integrated Volt VAR Controls Systems
kV	Kilovolt
M	Million
MED	Major Event Days
Non-MED	Non-Major Event Days
OHG	Overhead Ground
PoF	Probability of Failure
Program	High level initiatives of the Duke Energy Indiana TDSIC 2.0 Investment Plan
Project	Project designated by Duke Energy Indiana in specific substation or on a line combing a singular or multiple asset class.

[1] "Reconciliation of Iowa Survivor Curves", by J.G. Russo and H.A. Cowles, Iowa State University, The Engineering Economist, Vol. 26, Issue 1 (1980).

RAPP	Black & Veatch Risk Adjusted Project Prioritization Model for determining risk scores for assets. It is determined by Probability of Failure (PoF) X Consequence of Failure (CoF).
Resiliency	The ability to recover from outage events on a T&D system.
Reserved Projects	High-priority Transmission and Distribution sub-programs that are primarily inspection-based replacement projects such as pole replacements.
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SMEI	Surface Mount Equipment Inspection
SOG	Self-Optimizing Grid
Sub-program	Projects are further categorized by Duke Energy Indiana based on specific asset class or specific initiative as sub-programs.
Optimized	Projects that competed for funding
T&D	Transmission and Distribution
TDSIC 1.0	The existing approved Duke Energy Indiana TDSIC 1.0 Plan
TDSIC 2.0	Duke Energy Indiana TDSIC 2.0 Investment Plan
The Plan	Duke Energy Indiana TDSIC 2.0 Investment Plan
TUG	Targeted Undergrounding
Unconstrained	Output of Copperleaf Portfolio Model without any limits or conditions
Uplift	Improvement or upgrade
USD	US Dollar
Value Score	The Value-Score is the net present value of the benefit stream minus the net present value of the Cost.
VoLL	Value of Lost Load

1.0 Executive Summary

1.1 Plan Objectives

This report presents the Duke Energy Indiana Transmission, Distribution and Storage System Improvement Charge Investment Plan (The Plan). The investment plan analysis included $1.57 billion of investments over a 6-year period between 2023-2028. The investments are nearly equally divided between Transmission ($800 million) and Distribution ($775 million) programs. Not included in the investment plan analysis was project contingency for the T&D projects at $278 million and targeted economic development projects at $158 million.

The Plan was developed to meet key objectives for the Duke Energy Indiana T&D system that are in alignment with the TDSIC Statute codified in Indiana Code Ch. 8-1-39. The Plan is focused on cost-effective improvements in safety, reliability, grid modernization, and economic development, as established in the TDSIC statute. The Plan addresses these objectives through a program and project evaluation process that optimizes benefits to cost. The Plan was developed in light of three Duke Energy Indiana objectives that provide customer benefits in the following areas:

- Improved Reliability for Indiana Customers – Maximize the reduction in total customer minutes of interruption (CMI) for the optimal cost for both MED and non-MED CMI. Reduce total outage events, costs and number of customers impacted when outages occur.
- Advanced Grid Hardening and Resiliency – Eliminate outdated grid architecture such as 4kv distribution and electromechanical relays. Target vulnerable assets with high consequence of failure, such as 69kv Transmission
- Enable expansion of renewable and distributed generation - Advance smart grid architecture that supports a two-way smart thinking grid that supports the expansion of distributed energy resources and electric vehicles. Modernize and expands system intelligence and control.

1.2 Investment Plan Summary

The Plan is made up of seven programs that support the objectives of The Plan. Unique to The Plan is each project has quantifiable benefits and costs. This allowed for an investment plan analysis that was optimized to deliver the highest benefits to customers. This was accomplished through the work that Duke Energy Indiana and Black & Veatch completed while developing The Plan. Table 1-1 summarizes The Plan by the seven cornerstone programs. A summary of The Plan shows that the estimated cost of The Plan is justified by the incremental benefits attributable to The Plan. The Plan, as a whole, produces a $4.4 billion in benefits, cost of $1.6 billion with a benefit to cost ratio of 2.8.

Table 1-1 Investment Plan Summary

Program	Benefit	Cost	Benefit/Cost Ratio
Transmission			
Line Hardening and Resiliency	$ 1,474,854,161	$ 498,972,419	3.0
Substation Hardening and Resiliency	$ 1,318,960,413	$ 300,695,373	4.4
Sub Total	**$ 2,793,814,574**	**$ 799,667,792**	**3.5**

Distribution			
Circuit Backbone Uplift	$ 1,005,459,622	$ 406,791,333	2.5
Inspection Based	$ 309,041,687	$ 160,831,806	1.9
OH Lateral Uplift	$ 208,412,225	$ 104,297,652	2.0
Underground System Uplift	$ 50,592,886	$ 35,709,735	1.4
4 KV Conversion	$ 41,285,100	$ 67,630,648	0.6
Sub Total	**$1,614,791,520**	**$ 775,261,174**	**2.1**
Totals	**$ 4,408,606,094**	**$ 1,574,928,966**	**2.8**

1.3 Black & Veatch Infrastructure Investment Planning

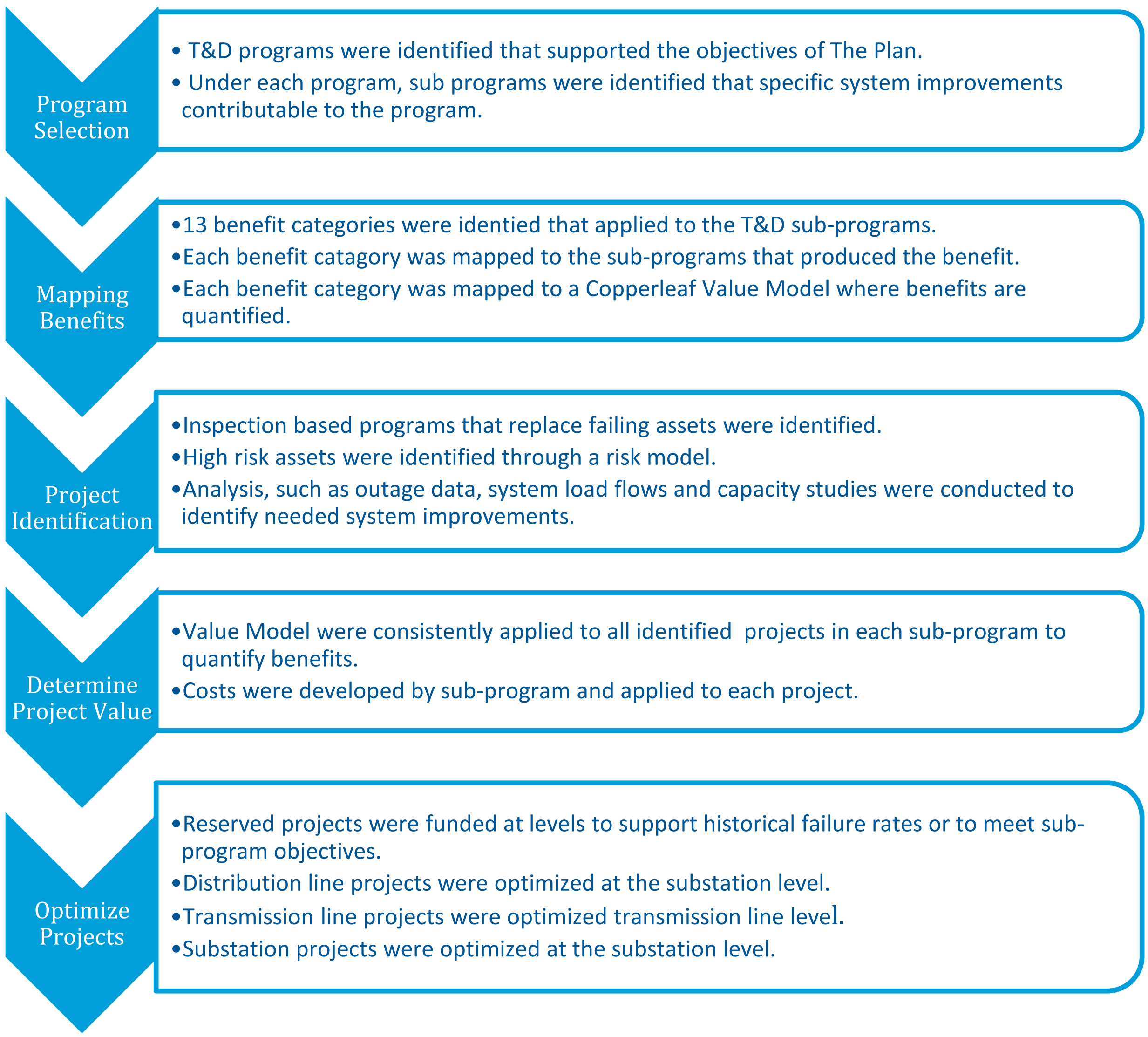
Black & Veatch is an industry leader in infrastructure investment planning in critical power, water, and communication industries. The Plan was developed through a partnership between Duke Energy Indiana, Black & Veatch, and Copperleaf. The Plan combines Duke Energy Indiana's expertise along with the knowledge Black & Veatch has acquired over 100 years through engineering and constructing critical infrastructure and Copperleaf's decision analytics tool for critical infrastructure investment planning. The combination of the three has resulted in an investment plan that produced strategic infrastructure investments yielding maximum benefit for each dollar proposed in The Plan.

2.0 Investment Plan Development

The Black & Veatch investment plan analysis quantified costs and benefits for each project. The analysis was enabled by the use of Copperleaf's decision analytics software tool. This tool is used for critical infrastructure investment planning by the utility, oil, and gas industries. The analysis produced an optimized portfolio of projects over the plan period of 2023 through 2028

The Plan was developed in 5 progressive steps as illustrated in Figure 2-1.

Figure 2-1 Project Identification Process



2.1 Program Selection

The first step in the development of The Plan was to identify programs and sub-programs that supported the objectives of the plan. The portfolio was separated between transmission and distribution and is described below.

2.1.1 Transmission

The Transmission system investments are organized within two programs:

1. Line Hardening and Resiliency
2. Substation Hardening and Resiliency

These two programs are further divided into 17 sub-programs. Sub-programs T01 through T09 support the Transmission Line Hardening and Resiliency objectives. Sub-programs T10 through T17 support the Substation Hardening and Resiliency objectives. Each sub-program provides system reinforcements contributable to the program and support the Plan objectives. Table 2-1 below provides a summary of the two programs with a description of the sub-programs.

Table 2-1 Transmission Program Organization

Program	ID	Sub-program	Description	Category
Line Hardening and Resiliency	T01	Wood to Non-Wood Replacements	Replacement of wood poles with non-wood poles	Reserved
	T02	Cross Arm Replacements	Proactive replacement of cross-arms observed in poor condition	Reserved
	T03	Cathodic Protection	Install cathodic protection on towers to mitigate the corrosion	Reserved
	T04	Tower Replacements	Identification and replacement of the vulnerable Steel towers	Reserved
	T05	Install Intermediate Dead-End Structures	installation of self-supporting steel dead-end structures to limit cascading failure	Optimized
	T06	SCADA to Switches	Extension of Supervisory Control and Data Acquisition System (SCADA) to Switches which were not connected to SCADA	Reserved
	T07	Looping Short Radial Through Existing Substations	Looping short radials through the substations	Reserved
	T08	Overhead Ground Wires	Installing overhead ground wires where needed for safety	Optimized
	T09	Line Rebuild	Rebuilding lines with old and deteriorated conductor	Optimized
Substation Hardening and Resiliency	T10	Transmission Relay Upgrade	Replacing outdated or under-performing relays to reduce the risk of relay miss-operations	Optimized
	T11	T&D Circuit Breaker Replacements	Replacing outdated breakers with modern circuit breaker	Optimized
	T12	T&D Transformer Replacements	Replace transmission transformers which have been identified to have condition issues that put them at risk of failure.	Optimized
	T13	Condition Based Monitoring - Transformers and Circuit Breakers	Add condition-based monitoring to substation transformers and circuit breakers	Reserved
	T14	Upgrade T&D Transformers	This program upgrades existing transformers to improve their performance and extend the life of the transformer	Optimized
	T15	Substation Reconfiguration for Improved Reliability	Change the configuration of an existing substation to improve reliability and/or operating flexibility	Optimized
	T16	SCADA Communications	Installs and/or upgrades the SCADA system	Optimized
	T17	Ancillary Substation Equipment Replacement	Replaces ancillary substation equipment such as transformer bushings, arrestors, potential transformers and current transformers	Optimized

The two Transmission programs are further described below

*Transmission Line - Line Hardening & Resiliency -*There are 9 sub-programs in this program. Six of the nine sub-programs are designated as Reserved Funding while the remaining three are Optimized. Sub-programs (T01, T02, T03, T04) are field inspection based where assets are assessed against a standard ability to perform criteria. If the assets do not meet the criteria, they are replaced. Sub-programs (T06, T07) are modernization projects that bring a minimum required level of redundancy or system intelligence on the system for safety and reliability. Sub-programs (T05, T08, T09) are system improvement projects that address known transmission line deficiencies and are meant to bring the facilities up to current construction standards to improve reliability and to avoid costly outages.

Substation - Hardening & Resiliency – There are 8 sub-programs in this program. One sub-program is designated as Reserved Funding while the remaining seven are designated Optimized. Sub-program (T13) is designed to increase Duke Energy Indiana’s ability to monitor the health of substation transformers so that the condition-based asset management practice may be enhanced across the Duke Energy Indiana fleet of substation transformers. Two of the sub-programs (T11, T12) are derived from the asset risk model. The projects under these two sub-programs were filtered through the Risk Adjusted Project Prioritization (RAPP) tool to identify the high-risk assets. The RAPP tool is further described in section 2.2.1.1 of this report. The remaining five sub-programs (T10, T14, T15, T16, T17) are system improvement projects meant to modernize or upgrade substation designs and equipment that improve Duke Energy Indiana’s ability to monitor, operate and maintain substation equipment effectively.

2.1.2 Distribution

The Distribution system investments have the following five programs:

1. Circuit Backbone Uplift
2. Overhead Lateral Uplift
3. Underground Cable
4. 4 kV Conversion
5. Inspection Based

Three of the five programs are comprised of sub-programs. Underground Cable Rehabilitation and 4 kV Conversion stand as their own single program investment with no sub-programs under them.

The sub-programs associated with each of the five programs are shown in Table 2-2.

Table 2-2 Distribution Program Organization

Program	ID	Sub-program Name	Description	Category
Circuit Backbone Uplift	D-01	Self-Optimizing Grid (SOG)	Dynamic Self-Healing Network	Optimized
	D-02	Circuit Visibility & Control	Provide Remote Visibility, Operation, and Control	Optimized
	D-03	Inaccessible R/W	Relocate Lines to Road Right of Way	Optimized
	D-04	Declared Circuits	Correct Probable Outage Causes for Declared Circuits with Above Average Number of Outages	Reserved
	D-05	IVVC	Optimize Voltage and VARs	Optimized
	D-06	Capacitor Automation	Replace Existing Capacitor Bank Controls with a Digital Control	Reserved
	D-07	Circuit Segmentation	Installation of Protection Devices to Isolate Faults on Circuits	Optimized
	D-08	Ltd Access Road Crossing	Reassess Overhead Distribution Circuits that Cross Limited Access Roadways	Optimized
OH Lateral Uplift	D-09	Circuit Sectionalization	Installation of Protection Devices to Isolate Faults on Circuits	Optimized
	D-10	Deteriorated Conductor	Replace Primary Voltage Conductors Likely to Fail	Optimized
	D-11	Automated Lateral Device (ALD)	Replace One-Time Use Fuses with Automatic Operating Reclosing Devices	Optimized
	D-12	Targeted Undergrounding (TUG)	Relocate Outage Prone Overhead Power Line Sections Underground	Optimized
Underground Cable Uplift	D-13	UG Cable Rehabilitation	Replace Medium Voltage Underground Cables Nearing End-of-Life	Reserved
4 KV Conversion	D-14	4 kV Conversion	Convert the 4 kV Distribution System to 12 kV	Reserved

Program	ID	Sub-program Name	Description	Category
Inspection Based	D-15	GLT Pole Inspection & Replacement	Replace or Modify Defective Distribution Poles	Reserved
	D-16	Surface Mount Equipment Inspection (SMEI)	Examine the Integrity and Safe Operations of Pad Mounted Equipment	Reserved
	D-17	Switchgear Inspection & Replacement	Inspect and Replace Aged Switchgear	Reserved
	D-18	Recloser Replacements	Replace Aging Oil Filled Reclosers	Reserved

The five Distribution programs are further described below.

Circuit Backbone Uplift – There are 8 sub-programs in this program. Two of the sub-programs are designated as Reserved Funding while the remaining six are designated as Optimized. Sub-programs (D01, D02, D05, D06,) are projects that modernizes the distribution system enabling self-optimizing capabilities, integrated volt-var control and additional visibility and control of the distribution system. These modernization investments reduce outage impacts with respect to their frequency, size, recovery time. Such improvements also have the added value of enhancing capability to integrate DER's on to the distribution system. Sub-programs (D03, D04, D07, D08) target system upgrades that improve reliability and integrity in specific areas on the distribution system.

Overhead Lateral Uplift – There are 4 sub-programs in this program. All four of the sub-programs are designated as Optimized. These sub - programs (D9, D10, D11, D12) were chosen to improve the reliability performance of overhead lateral lines off the main line of distribution circuits. The sub-programs are designed to improve hardening and resiliency, notably in avoiding outages and enabling more rapid recovery in response to outages.

Underground Cable – This program (D13) contains no sub-programs and is designated as Reserved Funding. It targets known poor performing cable for replacement or rehabilitation to prevent future outages associated with underground cable failures.

4 kV Conversion - This program (D14) contains no sub- programs and is designated as Reserved Funding. Conversion of the remaining 4kv distribution system to the standard 12.5kv distribution system will eliminate an increasing obsolete system that is difficult and expensive to operate and maintain. By converting the remaining 4kv system to the Duke Energy Indiana standard operating voltage of 12.5kv, Duke Energy Indiana will be able to use standard distribution equipment across its entire service territory while eliminating an "island" system prone to failures.

Inspection-Based – There are 4 sub-programs in this program. All four of the sub-programs are designated as Reserved Funding. These sub-programs (D15, D16, D17, D18) are field inspection based where assets are assessed against an ability to perform criteria standard. If the assets do not meet the criteria, they are scheduled for replacement or rehabilitation. Field inspections are geared towards proactively replacing distribution hardware and equipment based on field verification of the health and condition of the assets being inspected.

2.2 Mapping Benefits

The second step in the process was to determine the benefits of candidate projects considered for inclusion in The Plan. This was accomplished through the use of the Copperleaf Value Framework. The Copperleaf Value Framework modeling system is an infrastructure investment planning tool that performs risk-based valuations utilizing a consistent framework to quantify benefits and optimize investment portfolios. A summary description of the Copperleaf Value Framework is provided in Appendix A.

2.2.1 Mapping of Benefits to Sub-Programs

Thirteen quantifiable benefit categories were identified for sub-programs. The benefits were mapped to the sub-program that produced them. This is done to identify all the benefits attributable to the projects under the sub-programs. Table 2-6 summarizes how the benefits were mapped.

Table 2-3 Mapping Benefits to Sub-programs

		Benefit Categories												
	Sub-Programs	Reduce/Avoid Capital Cost	Reduce/Avoid O&M Cost	Reduce/Avoid Generation Capacity Cost	Reduce/Avoid Energy Costs	Reduce/Avoid Ancillary Services Cost	Reduce/Avoid T&D Losses	Avoid Restoration Costs	Compliance Risk	Public Property Risk	Safety Risk	Customer Outage Reduction Value	Increased Customer Satisfaction	Avoid Customer Fuel Cost
D	Self-Optimizing Grid (SOG)			✓	✓							✓	✓	
D	Circuit Visibility & Control							✓				✓		
D	Inaccessible ROW							✓				✓	✓	
D	Declared Circuits							✓				✓	✓	
D	IVVC		✓	✓	✓	✓	✓	✓						✓
D	Capacitor Automation		✓					✓					✓	
D	Circuit Segmentation							✓				✓	✓	
D	Ltd Access Road Crossing								✓					
D	Circuit Sectionalization											✓	✓	
D	Deteriorated Conductor							✓				✓	✓	
D	Automated Lateral Device							✓				✓	✓	
D	Targeted Undergrounding	✓	✓					✓				✓	✓	
D	UG Cable Rehabilitation											✓		
D	4kv Conversion	✓	✓	✓			✓					✓	✓	
D	GLT Pole Inspection & Replacement									✓	✓	✓	✓	

	Sub-Programs	Benefit Categories												
		Reduce/Avoid Capital Cost	Reduce/Avoid O&M Cost	Reduce/Avoid Generation Capacity Cost	Reduce/Avoid Energy Costs	Reduce/Avoid Ancillary Services Cost	Reduce/Avoid T&D Losses	Avoid Restoration Costs	Compliance Risk	Public Property Risk	Safety Risk	Customer Outage Reduction Value	Increased Customer Satisfaction	Avoid Customer Fuel Cost
D	Surface Mount Equipment Inspection												✓	
D	Switchgear Inspection & Replacement												✓	
D	Recloser Replacements	✓											✓	
T	Wood to Non-Wood Replacement							✓			✓	✓	✓	
T	Cross Arm Replacement							✓			✓	✓	✓	
T	Cathodic Protection							✓			✓	✓	✓	
T	Tower Replacement							✓			✓	✓	✓	
T	345 Circuit Hardening							✓			✓	✓	✓	
T	SCADA to Switches					✓	✓	✓			✓	✓	✓	
T	Looping Short Radials Through Existing Substations							✓			✓	✓	✓	
T	OHG (OH Ground Wire)						✓	✓			✓	✓	✓	
T	T-Line Rebuilds						✓	✓			✓	✓	✓	
T	Transmission Relay Upgrades							✓			✓	✓	✓	
T	T&D Circuit Breakers Replacements							✓			✓	✓	✓	
T	T&D Transformers Replacements						✓	✓			✓	✓	✓	
T	Condition Based Monitoring - Transformers & Breakers							✓			✓	✓	✓	
T	Upgrade T&D Transformer							✓			✓	✓	✓	
T	Substation Reconfiguration for Improved Reliability							✓			✓	✓	✓	
T	SCADA Communications						✓	✓			✓	✓	✓	

2.2.2 Mapping of Benefits to Value Models

The thirteen quantifiable benefits were also mapped to value models in Copperleaf. Value models combine all the benefits a project produces to calculate the net benefit of the project. Table 2-7 below shows how the benefit categories were mapped to Value Models.

Table 2-4 Benefit Mapping to Value Models

Benefit Category	Value Model	Value Model Description
Reduced/Avoided Capital Costs	Financial Impact	Calculates the total annual incurred savings or costs related to competing an investment. The Financial Impact Value Model has two Value Measures, Financial Impact – Capital and Financial Impact - O&M.
Reduced/Avoided Generation Capacity Costs		
Reduced/Avoided O&M Costs		
Reduced/Avoided Energy Costs		
Reduced/Avoided Ancillary Services Costs		
Reduced/Avoided T&D Losses		
Avoided Restoration Costs		
Avoided Customer Fuel Cost		
Customer Outage Reduction Value	Transmission Line Reliability (TLR) Transmission Substation Electric Reliability (TSER) Electric Reliability Risk - Distribution	Measures the mitigated risk associated with not being able to deliver electricity to customers. This model compares the value of Customer Minutes of Interruption (CMI) cost, Duration Cost, and Frequency Cost and choses the cost with the highest value.
Increased Customer Satisfaction	External Relations Impact	Measures the Impacts that affect Duke's interaction with external stakeholders (customers, legislators, regulators, community leaders, public and media) i.e. Tail Risk, public perception, Rate-Cases, NRC notifications, branding, etc.
Compliance Risk	Compliance Risk	Takes inputs from a user questionnaire and Risk Matrix, and outputs a single Value Measure calculated in risk units
Personal Property Risk	Personal Property Risk	Measures the risks associated with damage to public or third-party property
Improved Safety	Transmission Line Reliability (TLR) Transmission Substation Electric Reliability (TSER)	Takes inputs from a user questionnaire and Risk Matrix, and outputs a single Value Measure calculated in risk units
Improved Power Quality	Transmission Line Reliability (TLR) Transmission Substation Electric Reliability (TSER)	Takes inputs from a user questionnaire and Risk Matrix, and outputs a single Value Measure calculated in risk units

2.3 Project Identification

The third step in the development of the Investment Plan was to identify candidate projects in each of the sub-programs. As shown in Figure 2-2 there were two processes used for identifying projects:

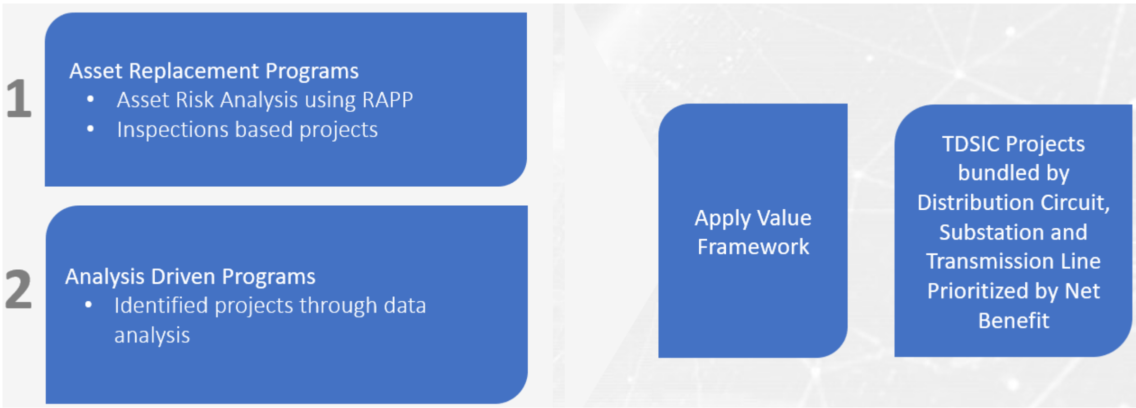


Figure 2-2 Project Identification Strategies

2.3.1 Asset Replacement Programs

Duke Energy Indiana has implemented inspection programs for asset reliability and integrity. The assets identified during these inspection, as needing replaced, are included in The Plan with Reserved Funding. Also, Duke Energy Indiana provided substation transformers, breakers, and distribution switchgear and surface mounted equipment inspection (SMEI) to Black & Veatch to conduct a risk analysis. The high-risk assets identified in the analysis competed for funding for inclusion in the plan.

2.3.1.1 Asset Risk Analysis

Duke Energy Indiana asset management practices enable them to manage their fleet of T&D assets using the risk management principle of “risk modeling” to help guide investment plans. The use of risk models in investment planning is a best practice not only in the utility industry but across other industries with large numbers of physical assets. As part of The Plan development, Black & Veatch utilized our RAPP tool to identify and prioritize high risk assets. Risk is defined as Probability of Failure (PoF) x Consequence of Failure (CoF) and can be depicted in the form of a heat map as the one in Figure 2-3.

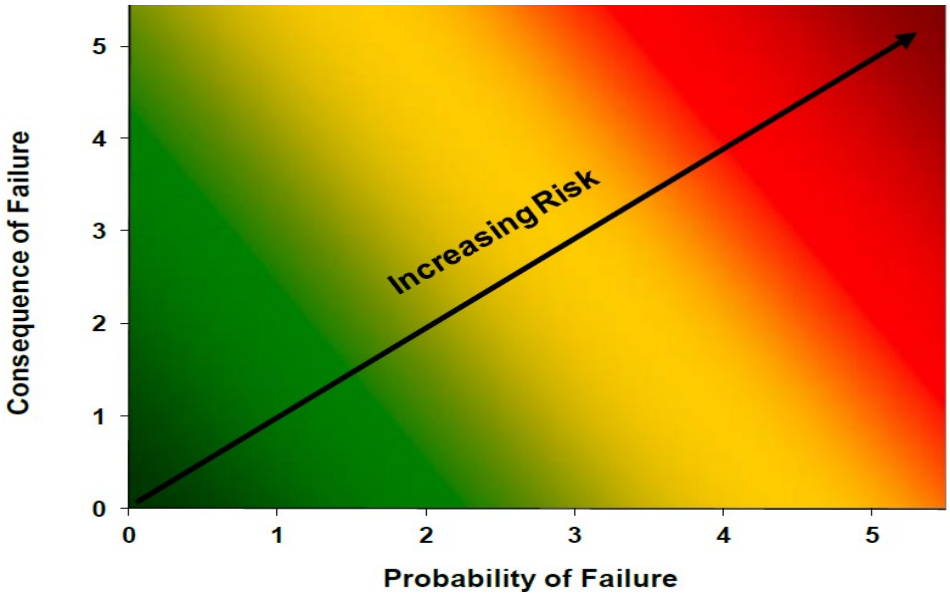


Figure 2-3 Heat Map

First, the RAPP model determines the PoF for each asset in the model. The asset's PoF is determined, in part, by its associated survivor (or Iowa) curve. Survivor curves are used by utilities in depreciation studies to forecast the average service life of assets. Iowa curves are asset class-specific survivor curves developed by the University of Iowa. The survivor curve is used as a tool to determine average remaining life of an asset. Figure 2-4 is a typical survivor curve for an electric utility asset.

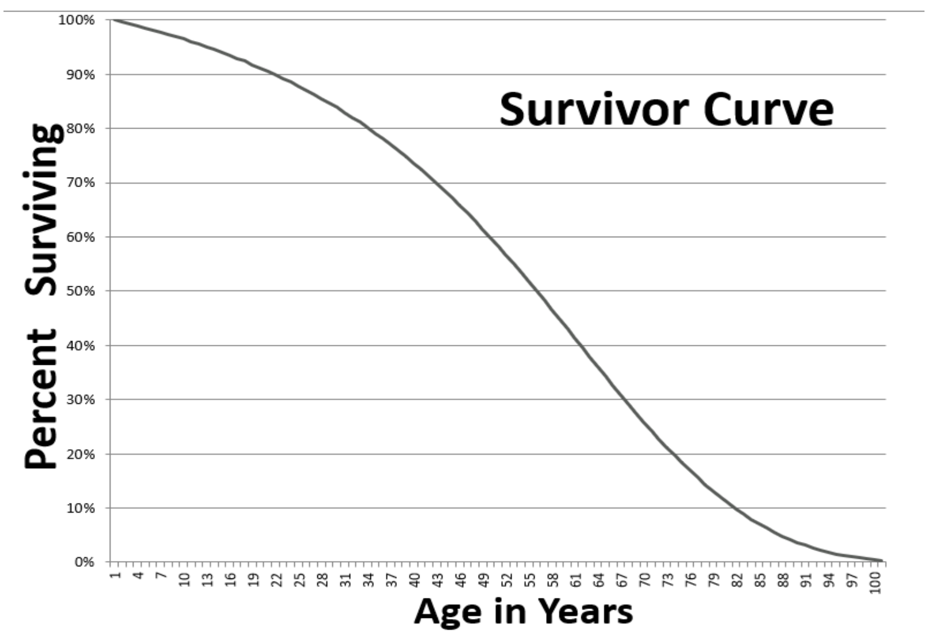


Figure 2-4 Survivor Curve Example

The RAPP tool further quantifies the average remaining life of an asset by considering the health of the asset. Through Duke Energy Indiana testing and inspecting programs, asset health data is gathered for each asset and recorded in an asset management database. Black & Veatch incorporated this health data to adjust the actual age of the asset to an effective age of the asset. Asset health data is scored to create an index to the actual age of the asset to determine the effective age. The effective age of an asset can be younger or older than the actual age depending on the health of the asset. This is depicted in Figure 2-5.

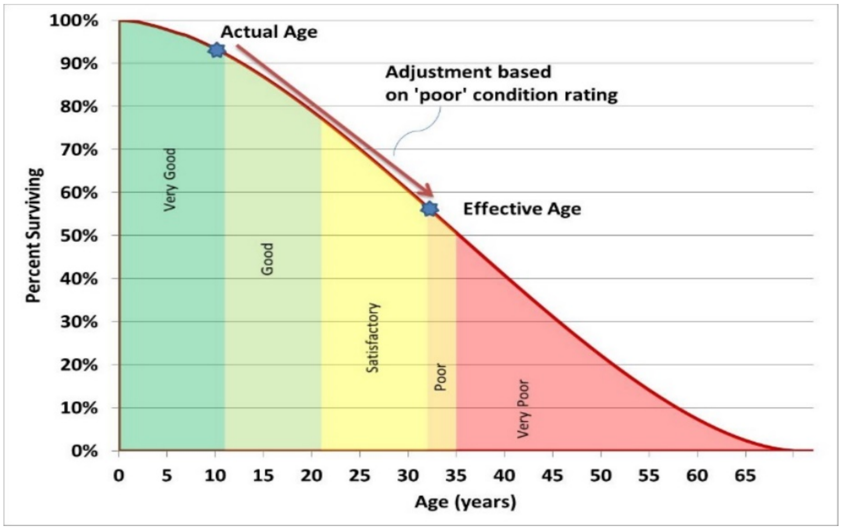


Figure 2-5 Effective Age of Asset

Once the effective age of the asset is determined, the RAPP tool calculates the probability of failure based on the remaining life of the asset relative to the effective age and its associated survivor curve. The probability of failure is based on a forward-looking forecast on the survivor curve from the effective age. This is illustrated below in Figure 2-6.

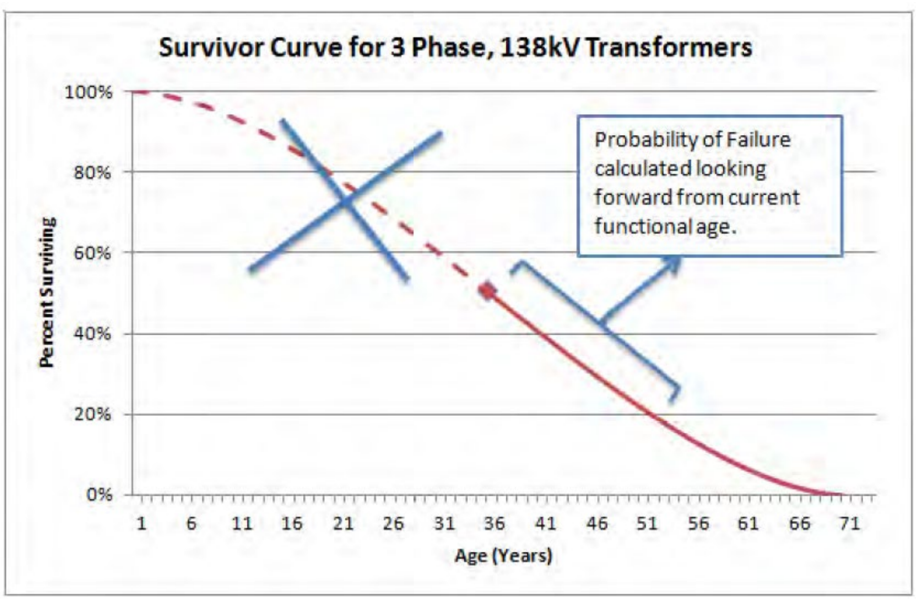


Figure 2-6 Probability of Failure

Secondly, the RAPP model determines the CoF. The CoF was determined by identifying the potential consequences of the asset failing and applying a significance score of the consequence occurring. Subject matter experts from both Duke Energy Indiana and Black & Veatch in the areas of engineering, operations and maintenance collaboratively identified the criteria within the transmission and distribution systems. The criteria considered a range of potential consequences. Figure 2-7 is a list of criteria used in developing the CoF score. The subject matter experts then scored each of the consequences based on their knowledge of the Duke Energy Indiana system and other available data to determine the CoF score.

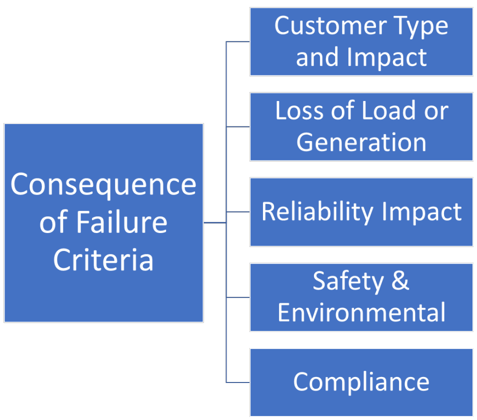


Figure 2-7 Consequence of Failure Criteria

2.3.2 Analysis Driven Projects

Identifying candidate projects to be considered for inclusion in the plan also included projects that are identified through system data analysis. Examples of projects that originate from system data analysis is Substation Reconfiguration for improved reliability and Self Optimizing Grid sub-program. In this case power flows and capacity studies are completed to identify system reinforcements that would reduce the number of transmission elements taken offline for system faults. These projects deliver value by limiting lost redundancy on the transmission.

2.4 Project Value

2.4.1 Value Models

Value models combine all the benefits a project produces and calculates value measures to quantify the benefits of the project. The output of a value model is the project's net benefits, which is the net present value of the benefit stream minus the net present value of the cost. Inputs to a value model are data sets that are needed to calculate the net benefits. The Value Model has an optimization module, which enables a consistent net benefit calculation and investment optimization over the investment horizon. Reliability improvements are a dominant contributor to the value streams generated within the Value Models used in developing The Plan. Copperleaf 's use of the Department of Energy (DOE) / Lawrence Berkley Lab's Interruption Cost Estimate (ICE) Model. The method in which the Value of Lost Load was implemented is documented in Appendix B. A conceptual Value Model is depicted in Figure 2-8.

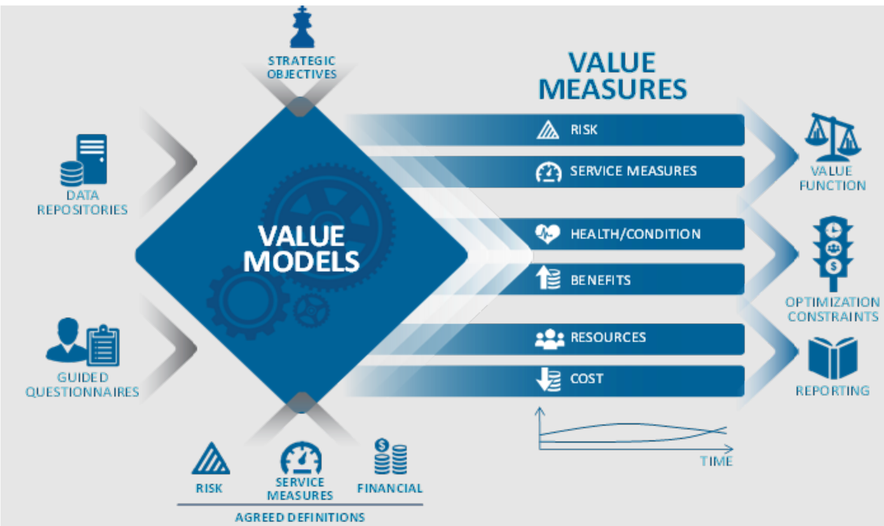


Figure 2-8 Copperleaf Value Framework

The optimization module utilizes the net benefit calculation to optimize around the anchor asset (i.e. transmission lines, substations, and distribution circuits) and reflects any imposed constraints. This functionality provides the optimized investment rank, timing, and sequencing of project. The associated net benefit streams over the investment horizon are all inflated and discounted back to a consistent net present value using inflation and discount rates provided by Duke Energy Indiana.

2.4.2 Value Measures

There are three types of Value Measures produced by Value Models:

- Risk Mitigation
- Benefits
- Cost

Risk mitigation captures the value in avoiding undesirable outcomes. They are typically configured with a baseline and a mitigated outcome. For example, substation breaker relays protect the public by automatically de-energizing faulted circuits and protects nearby T&D assets from the damaging effects of high fault currents. Relays nearing end of life have an increased risk of mis-operation. Replacing the relays with modern micro-processor based technology reduces the risk of mis-operation. The risk mitigation baseline would be to not replace the relays and accept the increasing risk of mis-operation and the mitigated outcome would be to replace the relays and reduce the risk of mis-operation. Risk mitigation is represented as a positive value stream based on the difference between the mitigated vs. baseline performance forecast.

For the risk mitigation value measure a uniform risk matrix was developed to align the mitigation of risk to a common scale. Risk is defined as the Probability of Failure ("PoF") multiplied by the Consequence of Failure ("CoF"). Value units define consequence levels. A consequence scale defines the degree of consequence over a range of potential outcomes. Table 2-8 below, depicts the common consequence scale used in calculating risk mitigation value units.

Table 2-5 Common Consequence Scale

Consequence	Minimal	Moderate	Significant	Severe	Critical	Catastrophic
Range (Value Units)	< 500	500 to 1,999	2,000 to 9,999	10,000 to 49,999	50,000 to 249,999	>250,000
Midpoint/Representative Value	250	1,250	6,000	30,000	150,000	500,000

A set of Consequence Level Definitions were developed for each of the risk's categories of:

1.) Collateral Damage Risk (Financial Risk)
2.) Public Property Risk
3.) Industrial/Personal Safety Risk
4.) Compliance Risk
5.) Environmental Risk
6.) External Stakeholder Risk

These definitions provided guidance to Duke Energy Indiana subject matter experts that have knowledge of the T&D system that enabled them to gauge the consequence level. The Duke Energy Indiana subject matter experts used this guide to score each candidate project considered in the development of The Plan.

Table 2-6 Consequence Level Definitions - Environmental

Consequence	Minimal	Moderate	Significant	Severe	Critical	Catastrophic
Environmental Risk	• On-site impact: quickly mitigated • Inability to perform environmental monitoring: quickly mitigated	• On-site impact: legal or permit violation • Inability to perform environmental monitoring: legal or permit violation	• On-site impact: possible to mitigate in long-term (> 3 years)	• Off-site impact: civil penalties or regulatory violations, possible to mitigate for $10M - $50M	• Off-site impact: civil penalties or regulatory violations/intervention, possible to mitigate for $50M - $250M	• Off-site impact: civil penalties or regulatory violations or intervention, possible to mitigate for > $250M

The probability of an event occurring, for any consequence level, can also have a common scale. Table 2 below is the probability levels used in calculating risk mitigation value units.

Table 2-7 Probability Levels

Level	Description	Range	Midpoint Representative Value
Almost Certain	Imminent (100% chance of occurring this year)	> 0.90	1.00
Once in 1 - 2 Years	Approximately 70% chance of consequence occurring this year (1 in every 1 to2 years)	0.5 - 0.90	0.70
Once in 2 - 5 Years	Approximately 35% chance of consequence occurring this year (1 in every 2 to 5 years)	0.2 – 0.5	0.35
Once in 5 - 10 Years	Approximately 15% chance of consequence occurring this year (1 in every 5 to 10 years)	0.1 – 0.2	0.15
Once in 10 - 20 Years	Approximately 7.5% chance of consequence occurring this year (1 in every 10 to 20 years)	0.05 - 0.1	0.075
Once in 20 -100 Years	Approximately 3% chance of consequence occurring this year (1 in every 20 to 100 years)	0.01 - 0.05	0.03
None	The consequence is unlikely to occur in the next 100 years	<0.007	0.00

To illustrate, if a project has a significant consequence (6,000) and a 1 in every 5 to 10 years probability of occurring (0.15), the risk mitigation value units would be 6,000 x 0.15, equating to 900 value units. This in turn, equates to $900,000 of benefits associated with avoiding the undesirable outcomes when the project is completed. Risk mitigations value measures have a positive net present value streams.

Benefits capture desirable outcomes that are created by a project such as reduction reducing duration of outages that occur on the distribution system. Similar to Risk Mitigation, benefits typically have both a baseline and a mitigated outcome. For example, if distribution automation is deployed enabling distribution circuits to locate faults on the system, isolate them and automatically restore service this would produce a desirable outcome of reducing the duration of outages on the system. The benefit baseline would be the historical outage performance of the distribution circuits and the mitigated outcome would be future performance of the distribution system with distribution automation. In this case, the value measure would be calculated by using the I.C.E calculator, where the reduction in outage duration would be monetized based on reduced outage durations once the distribution automation project is completed.

Cost represents project cost and is a negative contributor to benefits. Investment costs are broken down into individual Cost Account Types, which can be used as constraints in the investment optimization process and for reporting (e.g., Capital Spend or O&M Spend). The cost accounts for a given investment typically include capital, O&M and overhead elements, in addition to other cost categories, as listed below:

- Capital
- O&M
- AFUDC
- Third-Party Services
- Removal Costs
- Other Costs

2.5 Optimize Projects

The fifth and last step in the process was to optimize the portfolio of candidate projects in Copperleaf to select the projects that make up The Plan. The Plan was optimized using the approach depicted in Figure 2-11. The three investment groupings are shown on vertical axis and the sub-programs on the horizontal axis as the column headings.

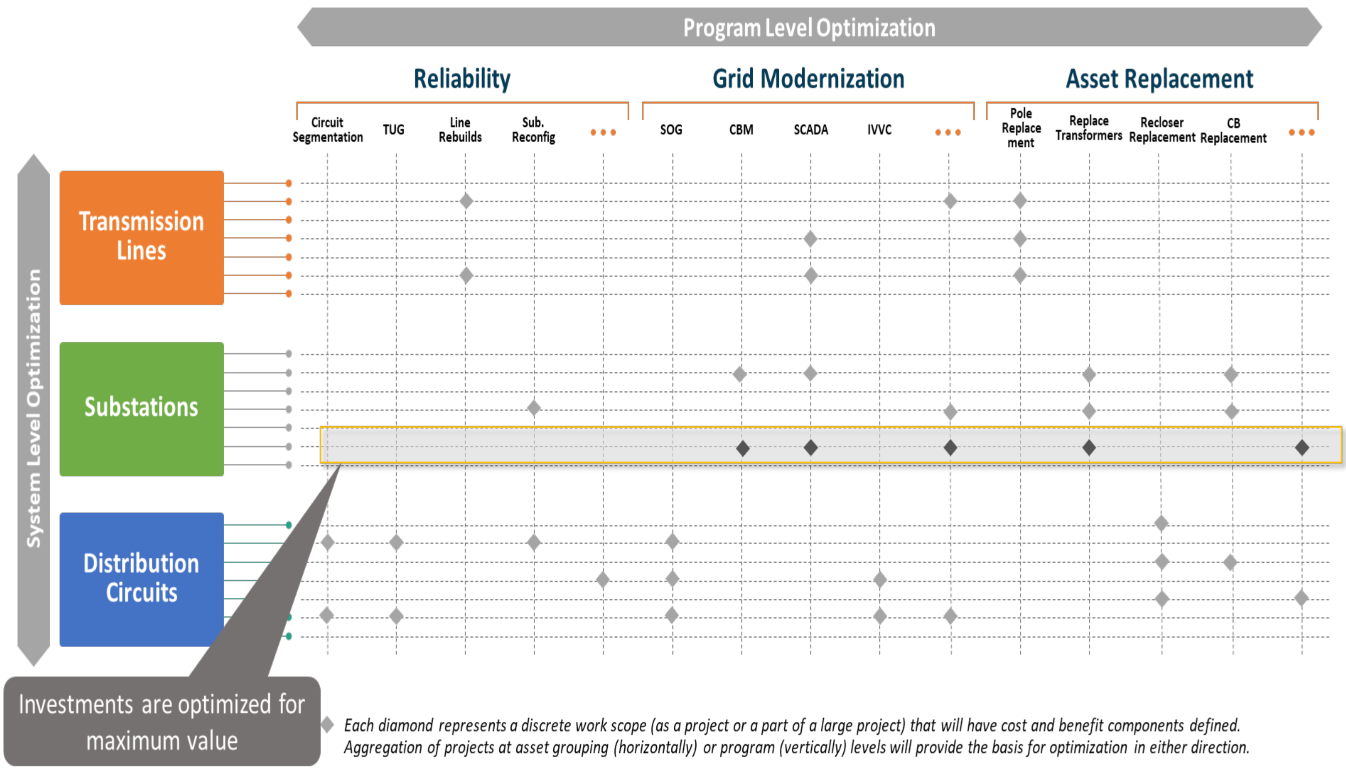


Figure 2-9 Illustrative Investment Optimization Approach

Each diamond represents a discrete scope of work that will have cost and benefit defined. The discrete scopes of works were then combined to form candidate TDSIC project, represented as a row. The candidate TDSIC projects that were designated as Optimized competed for funding. The funding level for Reserved projects were set by historical failure rates or levels required to meet the objectives of the Reserved funded sub-program. This optimization structure supports the evaluation and presentation of net benefit rankings and optimized investments both from a T&D system and a plan objective perspective.

A summary of the two funding types is described below.

1. Reserved Funding
   - Projects that are inspection based, where funding levels are determined by historical failure rates (T01, T02, T03, T04, D15, D16, D17, D18).
   - Projects that are required, to provide a minimum level of redundancy or system intelligence on the system (T06, T07, D06).
   - Projects that replace known poor performing assets or systems (D04, D13, D14).
2. Optimized Funding
   - Projects that compete for funding through a benefit/cost optimization process.

2.5.1 Investment Plan Reference Cases

The project identification and optimization phases of the project resulted in a reference case for Transmission and one for Distribution. The reference cases are comprised of a list of optimized projects that can be sorted by highest benefit to lowest. These lists were the source of the projects identified for AACE cost estimation and The Plan.

- The **Transmission Reference Case** limited investment to $797M for the 6-year term and split the budget between Transmission Lines and Substation in a ratio of 62% to 38% respectively.
- The **Distribution Reference Case** limited investment to $920M for the 6-year term. The $920M case was chosen to provide an alternate list of projects.

Class 2 project costs for 2023 and 2024 and Class 4 project costs for years 2025- 2028 were developed by Duke Energy Indiana and Duke Energy Indiana subcontractors drawing from the highest value projects in the reference case. These costs were applied to the reference case projects making the cut for The Plan. Projects not in The Plan were moved to 2029 and beyond and will become Alternate projects based on their value.

Figure 2-10 shows how the Copperleaf Value Models were applied to the Transmission sub-programs.

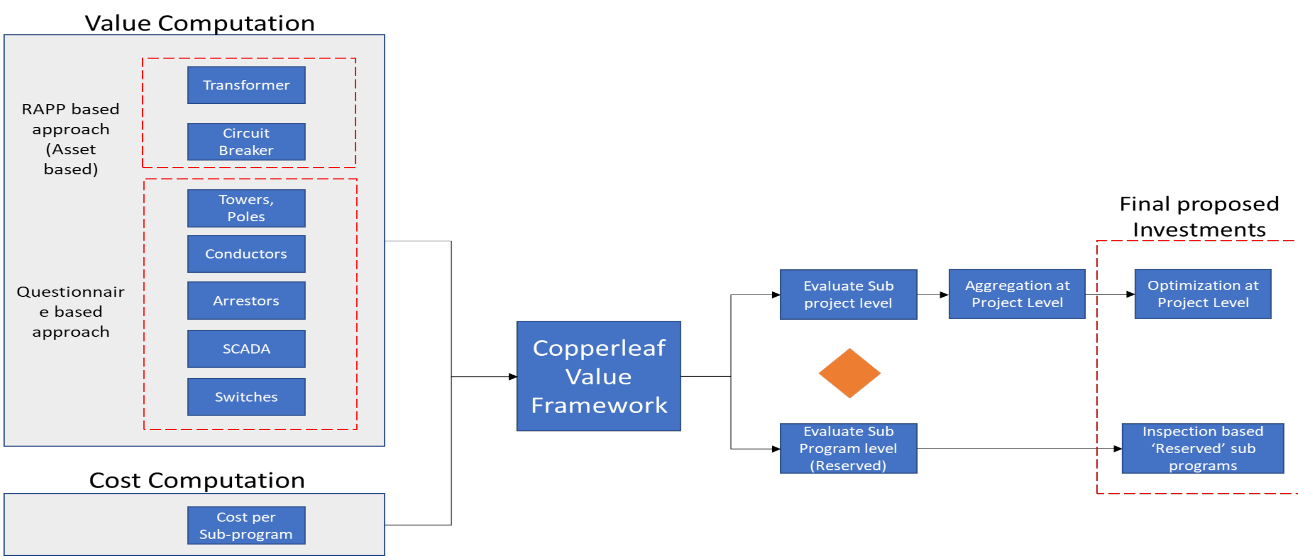


Figure 2-10 Transmission Investment Optimization Approach

Figure 2-11 shows how the Copperleaf Value Models were applied to the Distribution sub-programs.

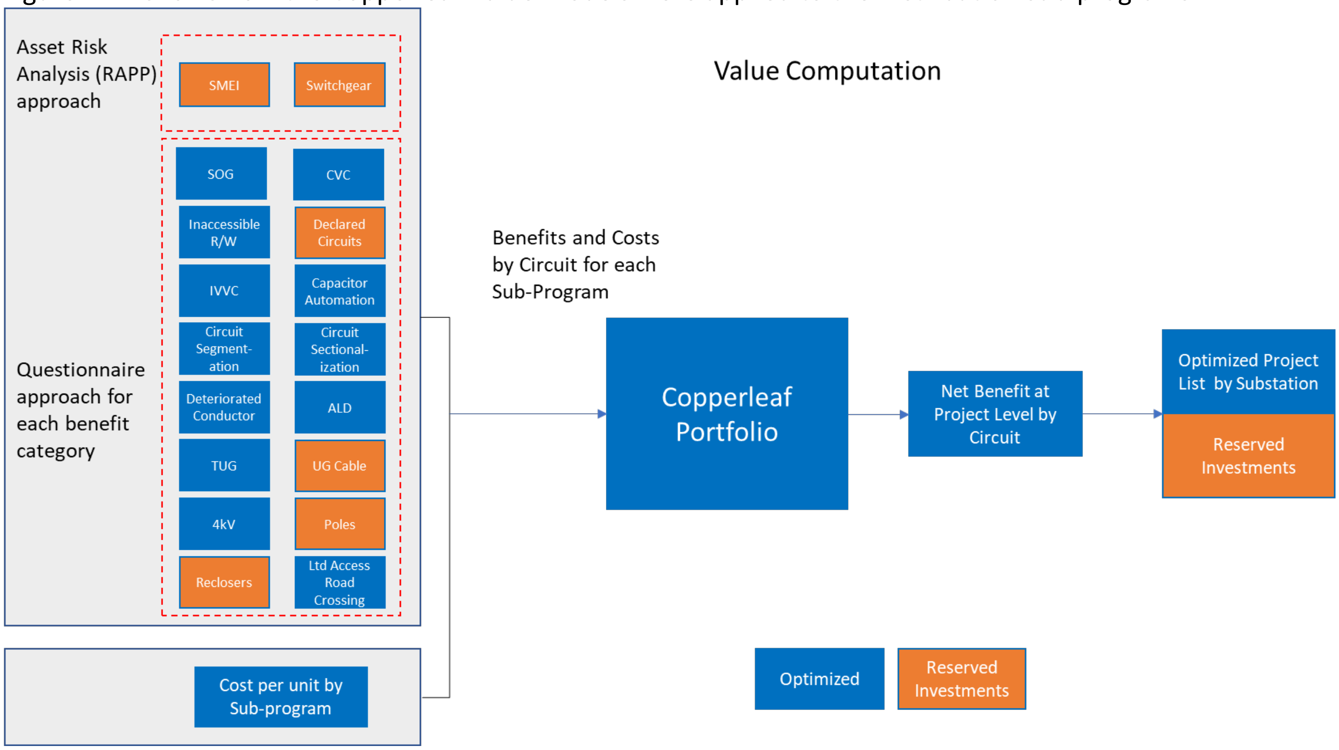


Figure 2-11 Distribution Investment Optimization Approach

3.0 Transmission Benefits and Costs Summary

Table 3-1 summarizes the benefits, costs, and benefit cost ratio of the transmission investment plan

Table 3-1 Transmission Investment Plan Summary by Program

Program	Benefit	Cost	Benefit/Cost Ratio
Transmission			
Line Hardening and Resiliency	$ 1,474,854,161	$ 498,972,419	3.0
Substation Hardening and Resiliency	$ 1,318,960,413	$ 300,695,373	4.4
Sub Total	**$ 2,793,814,574**	**$ 799,667,792**	**3.5**

3.1 Transmission Line Sub-Program Descriptions

3.1.1 T01 Wood Structures - Wood to Non-Wood Replacement

This program will involve the replacement of wood poles with the non-wood poles. Around 4,000+ poles are identified which is 5.6% of the total pole population. Additionally, there are approximately 630 poles already identified through inspection. Program scale and budget does not allow the structurally overloaded poles to be included in the program.

3.1.2 T02 Wood Structures - Cross Arm Replacement

This program will replace identified deteriorated or under-performing wood or fiberglass cross-arms or horizontal structure elements on transmission lines.

3.1.3 T03 Towers - Cathodic Protection

Cathodic protection of towers is one of the standard industry practices to mitigate the corrosion of the towers. All towers are to be considered under the Cathodic protection and installation of anodes to every leg to approximately 1180 towers.

3.1.4 T04 Towers – Tower Replacement

This program will involve identification and replacement of the vulnerable Steel towers based on condition assessment. Towers under consideration: 6 steel towers will be addressed per year, resulting in a total of 36 steel towers over the 6 years of TDSIC 2.0 program.

3.1.5 T05 Towers – Install Intermediate Dead-End Structure

This program will involve installation of approximately 13 intermediate self-supporting steel dead-end structures on circuit 34507 to complete the mitigation plan of limiting cascading failure to 2.5 mile interval.

3.1.6 T06 – Remote Line Sectionalizing- SCADA to Switches

This is an automation program which involves extension of Supervisory Control and Data Acquisition System (SCADA) to Switches which were not connected to the SCADA. Switches having short distances to the substations and the ones under the requests have been considered.

3.1.7 T07 – Remote Line Sectionalizing - Looping Short Radials Through Existing Substations

The project will involve looping short radials through the substations. Adding SCADA to substations which do not have it already.

3.1.8 T08 – OHG – Overhead Ground Wire

This program will replace identified deteriorated or under-performing overhead ground wire on transmission lines.

3.1.9 T09 – Line Rebuilds

This program consists of replacing transmission line assets on circuits that contain multiple components that are poor performing, obsolete, or at the end of productively useful life.

3.1.10 Substation Sub Program Descriptions

3.1.11 T10 – Transmission Relay Upgrades

This project involves replacing outdated or under-performing relays to reduce the risk of relay miss operations leading to customer outage and/or disruption to the electrical systems.

3.1.12 T11 – Upgrade T&D Circuit Breakers

This project will assess the condition assessment of the existing circuit breakers and replace the o circuit breakers which have a higher likelihood of failure or have experienced failure in the recent past. This will also involve replacing the outdated Oil circuit breakers and Type SFA gas circuit breakers with modern SF6 or Vacuum circuit breaker.

3.1.13 T12 – T&D Transformers - Replacements

This program will proactively replace transmission transformers that supply power at transmission voltages (69kV and above) which have been identified to have condition issues that put them at risk of failure. The replacement criteria for the transformer will be based on condition assessment and performance of the transformer. The condition of the transformers was provided by Duke Energy Indiana.

3.1.14 T13 - Condition Based Monitoring – Transformers and Circuit Breakers

The program adds condition-based monitoring to substation transformers and circuit breakers to remotely monitor the condition of the asset and allow corrective action to be taken in a planned manner prior to an event or unplanned outage.

3.1.15 T14 – Upgrade T&D Transformer

This program includes targeted replacement or upgrades existing transformers to improve their performance and reduce the risk of failure or mis-operation.

3.1.16 T15 – Substation Reconfiguration for Improved Reliability

This program includes projects that change the configuration of an existing substation to improve reliability, resiliency and/or operating flexibility. This includes changes such as reconfiguring substation transmission buses from “straight bus” to “ring bus” configuration, and installing circuit switching devices capable of interrupting fault current on the high-voltage side of the transformer to eliminate "ground switch" transformer fault interruption schemes.

3.1.17 T16 – SCADA Communications

This program involves installing or upgrading Remote Terminal Units and associated data communications and capability to allow the transmission and distribution grid operators to remotely monitor and control substation equipment. It also includes installing motorized operation and the capability to remotely and/or automatically operate the transmission switches to allow rapid sectionalizing and restoration when faults occur.

3.1.18 T17 – Replacement of Ancillary Substation Equipment

This program replaces ancillary substation equipment such as circuit switchers, arrestors, Capacitive Voltage Transformers (CVT), and control cabinets.

4.0 Distribution

4.1 Distribution Benefits and Costs Summary

Table 4-1 summarizes the Distribution benefits, costs, and benefit cost ratios

Table 4-1 Distribution Investment Plan Summary by Program

Program	Benefit	Cost	Benefit/Cost Ratio
Circuit Backbone Uplift	$ 1,005,459,622	$ 406,791,333	2.5
Inspection Based	$ 309,041,687	$ 160,831,806	1.9
OH Lateral Uplift	$ 208,412,225	$ 104,297,652	2.0
Underground System Uplift	$ 50,592,886	$ 35,709,735	1.4
4 KV Conversion	$ 41,285,100	$ 67,630,648	0.6
Total	**$ 1,614,791,520**	**$ 775,261,174**	**2.1**

4.2 Distribution CI and CMI Improvement Summary

A summary of the expected CI and CMI improvement by sub-program for The Plan shown in Table 4-3. The following programs do not have a significant impact on CI and CMI Improvement and are not shown in the table below.

- IVVC
- Limited Access Road Crossing
- Inspection-Based Programs
  - GLT Pole Replacement
  - SMEI
  - Switchgear
  - Reclosers

Table 4-2 Summary of Reliability Metric Improvement for The Plan

Program	CI Improvement	CMI Improvement
Overhead Lateral Uplift	33,184	5,809,593
Circuit Backbone Uplift	240,668	47,097,671
Inspection Based	-	-
4 KV Conversion	1,974	212,695
Underground System Uplift	2,143	388,408
Total	**277,969**	**53,508,367**

*Duke Energy's table may show a different value as described in testimony of Jeremy Lewis due to mitigated SOG benefits from TDSIC 1.0 reclosers.

4.3 Program and Sub-programs

To achieve the goals established for The Plan, Duke Energy Indiana has laid out resiliency and reliability initiatives under the five distribution investment program categories, which are further divided into 18 sub-programs, as elaborated below.

4.3.1 Descriptions of Programs and Sub-programs

The 5 programs and 18 sub-programs were carefully designed to provide the highest value to Duke Energy Indiana's customers by increasing grid reliability and resiliency with initiatives that modernize and expand system intelligence and control, eliminate outdated grid architectures, and replace aging infrastructure. Grid modernization will provide more operational awareness enabling 2-way power flow and automatic fault detection and restoration where possible. The four programs are:

- **Circuit Backbone Uplift** – Primarily comprised of projects that add segmentation and automation of the circuit backbone to reduce the number of outages and customers impacted as well as reducing the duration of the outages. The sub-programs associated with this program are:
  - Self-Optimizing Grid (SOG)
  - Circuit Visibility & Control
  - Inaccessible Right of Way
  - Declared Circuits
  - IVVC
  - Capacitor Automation
  - Circuit Segmentation
  - Ltd Access Road Crossing

- **OH Lateral Uplift** - Primarily comprised of projects that add segmentation and automation of the circuit laterals to reduce the number of outages and customers impacted as well as reducing the duration of the outages themselves. The sub-programs associated with this program are:
  - Circuit Sectionalization
  - Deteriorated Conductor
  - Automated Lateral Device (ALD)
  - Targeted Undergrounding (TUG)
- **UG System Uplift** – The cable assessment/cable replacement project identifies medium voltage underground cables nearing end of life, at least 25 years or older. When the cable assessment results show the cable or cable splice is in pre-failure condition the cable or components will be replaced to restore reliability to the circuit.
- **4 kV Conversion** - This program is comprised of 1 sub-program – The sub-program converts an outdated 4kV system to a modern 12kV system.
- **Inspection Based** – These programs are inspection-based programs where assets are assessed against an ability to perform criteria. These sub-programs are a pro-active approach to maintain the reliability and the resiliency of the grid. The sub-programs associated with this program are:
  - GLT Pole Inspection & Replacement
  - Surface Mount Equipment Inspection (SMEI)
  - Switchgear Inspection & Replacement
  - Recloser Replacements

4.3.2 Circuit Backbone Uplift

The projects in the following sub-programs improve the reliability of the Circuit Backbone.

4.3.2.1 Self-Optimizing Grid (SOG)

The SOG program redesigns key portions of the distribution system and transforms it into a dynamic smart-thinking, self-healing grid. The grid will have the ability to automatically reroute power around trouble areas, like a tree on a power line, to quickly restore power to the maximum number of customers and rapidly dispatch line crews directly to the source of the outage. Self-healing technologies can reduce outage impacts by as much as 75 percent. Circuit ties and self-healing grid automation enable safe 2-way power flow which in turn supports customer installed DER installations.

4.3.2.2 Circuit Visibility and Control

This program modernizes the protection, operation, and control of distribution circuits where physical space inside the substation is limited and costly to install within the fenced area of the substation. At these substation locations Automated Switching Devices will be installed outside the substations fence to enable remote monitoring, control, data acquisition, and improved fault location.

4.3.2.3 Inaccessible Right of Way

The Inaccessible Right of Way project relocates overhead distribution circuits currently located in difficult to reach rights-of-way to more readily accessible rights-of-way. Distribution lines located in difficult right-of-way increases safety risk and repair costs while at the same time causes longer duration outages when outages occur.

4.3.2.4 Declared Protection Zone

When a specific distribution circuit (or section of a circuit) overall reliability is underperforming a detailed inspection of the circuit is performed. At Duke Energy this is called a “Declared Circuit”. Declared Circuit inspections mitigate potential future outages by identifying and correcting probable outage causes. The inspection looks at all aspects of the construction on the circuit from a per pole and per span of wire review. Probable outage causes can include, but is not limited to, connections, arresters, switches, jumpers, system grounds, any damaged equipment, and inadequate Basic Insulation Level (BIL).

4.3.2.5 IVVC

IVVC allows the distribution system to optimize voltage and reactive power needs. The program employs remotely operated substation and distribution circuit devices such as voltage regulators and capacitors. The settings for thousands of these controllable field devices are optimized and dispatched via an Advanced Distribution Management System (ADMS). The IVVC functionality within the ADMS system can perform several functions including, conservation voltage reduction, peak demand reduction, voltage, and VAR support during system events. This functionality reduces the need to generate or purchase additional power at peak prices or protecting the system from exceeding its load limitations.

4.3.2.6 Capacitor Automation

The Capacitor Automation project replaces existing capacitor bank controls with a digital control that is capable of two-way communications to an Advanced Distribution Management System. Sensors are installed at each capacitor bank to measure current, voltage and power factor through the digital control. This communication capability enables the ADMS functionality of Integrated Volt/Var Control (“IVVC”) to control the distribution system voltage profile across the circuit, while the current and voltage sensors permit Duke Energy Indiana to capture system condition data for load management and service restoration plans.

4.3.2.7 Circuit Segmentation

Circuit Segmentation is applied to circuits that are currently not part of the ADMS Fault Location and Service Restoration (FLISR) functionality. Its purpose is to provide improved circuit reliability and is using the same criteria as SOG circuits for location of segmentation devices. Improved reliability performance, on these circuits, will be derived from fewer customer interruptions. Examples of interruptions include outages caused by cars hitting poles, trees falling into lines, and outages caused by storms. This reduction of exposure is accomplished by adding and/or re-configuring several protective devices on mainlines, circuit backbones, and branch circuits. The settings for these protective devices are coordinated to cause the devices to operate in a manner that isolates only the faulted section of a circuit.

4.3.2.8 Limited Access Road Crossing

Limited Access road right-of way situations occur along Interstates and on other non-Interstate roads and highways as classified by the Indiana Department of Transportation (INDOT). INDOT road classifications change annually as INDOT projects are constructed or as road right-of-way is re-classified as “limited access”.

4.3.3 OH Lateral Uplift

The projects in the following Sub-programs improve the reliability to customers by reducing the frequency of outages and/or outage durations on the laterals from which they are fed.

4.3.3.1 Circuit Sectionalization

Circuit Sectionalization is a power outage mitigation project designed to improve the reliability of distribution circuits by reducing the number of customers exposed to power outages associated with circuit faults. Examples of interruptions include outages caused by cars hitting poles, trees falling into lines, and outages caused by storms. This reduction of exposure is accomplished by adding and/or re-configuring a number of protective devices on circuit laterals. The settings for these protective devices are coordinated to cause the devices to operate in a manner that isolates only the faulted section of a circuit.

4.3.3.2 Deteriorated Conductor

The Duke Energy Indiana distribution system has many overhead laterals off the main backbone circuits. In many cases, these overhead laterals have been in service over 50 years. Most of these conductors are small diameter Copper Wire (CW) or small diameter ACSR wire that have higher failure rates than other conductors.

4.3.3.3 Automated Lateral Device (ALD)

This program focuses on strategically replacing overhead lateral fuses with a modern electronic reclosing device. Many of the faults that occur on overhead laterals from the mainline are temporary in nature. By strategically replacing fuses with ALD’s with reclosing capabilities, that fits in a standard fuse holder, Duke Energy Indiana will be able to cost effectively, reduce the number permanent outages on the system. The electronic reclosing device temporary de-energizes the section of circuit, that it is protecting, where the fault occurred, allowing time for the temporary fault to clear the line. This results in a momentary interruption instead of a sustained outage.

4.3.3.4 Targeted Undergrounding (TUG)

The goal of the TUG program is to significantly reduce future outages by strategically replacing overhead distribution circuit segments with underground facilities. Duke Energy Indiana reviews outage data across the distribution system to identify re-occurring outages at the interrupting device level. The causes of outages are reviewed to determine if future outages can be avoided by replacing the overhead facilities with underground facilities. Reducing future outages improves service while lowering maintenance and restoration costs.

4.3.4 UG Cable Replacement/Rehabilitation

Duke Energy Indiana currently has an estimated 8,471 miles of underground cable installed. Cable technology used during the 1970’s was non-jacketed, concentric neutral using high molecular weight insulation. Cable technology has improved through the years and life expectancy continues to increase. This cable is now beyond its anticipated life span and experiences increased failure rates. These failures result in an increased number of customer interruptions that, depending upon the installation configuration, can have an extended duration.

4.3.5 4kV Conversion

Only 3.5 percent of our distribution circuits supply customers at the 4kV voltage level. These 4kV circuits are in areas where they are surrounded by 12kV, which severely limits the number of available circuit ties. The optimal system configuration enables customers' supply to be transferred between circuits via a tie switches in the event of a circuit fault. System reliability and resiliency is improved by enabling such transfers. Transferring load between circuits could also be automated by acquiring more power flow data and using that data to determine how to autonomously operate the grid. Ultimately, customers who were originally supplied from the 4kV system would experience fewer outages and the outages they experience would be shorter in duration.

4.3.6 Inspection Based

The following inspection based sub-programs are critical to maintaining system integrity. These sub-programs are field inspection based where assets are assessed against an ability to perform criteria standard. If the assets do not meet the criteria, they are scheduled for replacement. Field inspections are geared towards proactively replacing grid hardware and equipment based on field verification of the health and condition of the assets being inspected. All Inspection Based sub-programs were determined to be Reserved Investments and were not included in the project optimization.

4.3.6.1 GLT Pole Inspection and Replacement

Ground Line Treatment (GLT) is an ongoing wood pole life extension and replacement project. Wood pole inspection is a long-standing practice used by utilities to manage the very large wood pole asset base. The project involves the inspection of distribution wood poles for ground line decay, above ground decay, pole top damage, or other defects that threaten the structural integrity of the pole. Mitigation plans are developed to replace or structurally modify poles to address identified issues. Poles nearing end of life are identified and replacement plans are developed.

4.3.6.2 Surface Mount Equipment Inspection (SMEI)

The Surface Mounted Equipment Inspection sub-program is specifically focused on examining the external enclosure integrity, pad integrity, safety/clearance signage, locking mechanism integrity, and general safe operations of pad mounted equipment. The equipment includes pad mounted transformers, switchgear, meter panels, and switching cabinets.

4.3.6.3 Switchgear Inspection and Replacement

The Switchgear Inspection and Replacement project proactively inspects and replaces aged equipment, prior to failure. The work is performed in a planned manner to minimize customer impact and extensive outages.

4.3.6.4 Recloser Replacements

This sub-program replaces aging oil-filled reclosers with new, refurbished units, or electronic reclosers to ensure proper operation of equipment. Over time, as recloser operate while in service, their gaskets can degrade and allow moisture and other pollutants to contaminate the oil inside. Climate, use, and operating conditions also impact hydraulic reclosers' electrical and mechanical components and its rate of decline. Proactively replacing hydraulic reclosers enhances the system by ensuring devices perform properly to effectively clear faults.

Appendix A. Introduction to Copperleaf Value Framework Overview

PETITIONER'S APPENDIX "A" IS CONFIDENTIAL

Appendix B. ICE Value of Lost Load (VOLL) Briefing Paper

APPENDIX B

DUKE ENERGY INDIANA
TDSIC 2.0 Plan Development
Value of Lost Load (VoLL)
Concept, Derivation and Application

INTRODUCTION

As an integral part of the TDSIC 2.0 Investment Plan Development Project being conducted by Black & Veatch Management Consulting, LLC (Black & Veatch) for Duke Energy Indiana (DEI), a comprehensive set of value measures (i.e., benefits) are being derived for each of DEI's potential TDSIC 2.0 programs to serve as the basis to evaluate, optimize and select the most beneficial programs for inclusion in DEI's TDSIC 2.0 Plan.

One of the primary value measures used in this process directly addresses the benefits DEI's customers derive from the utility's improved reliability, system hardening and resiliency. From a customer's perspective, whether it is for a residential, small commercial and industrial (C&I) or medium/large C&I customer, avoidance of an electric system outage has tangible and long-lasting value to the customer and should be implicitly recognized in the cost-benefit analysis (CBA) accompanying the utility's infrastructure investment plan.

Value of Lost Load ("VoLL") is the concept used in the electric utility industry to monetize this customer-related value based on the benefits that customers receive from the avoidance of electric utility outages. This briefing paper provides a high-level discussion of the VoLL concept and explains how the VoLL factors are derived for electric utilities, in general, and specifically for DEI. Further, it describes how these factors can be applied to DEI's infrastructure investments to identify the value its customers associate with improvements to its reliability and resiliency on a systemwide basis as well as by individual circuit or system component basis.

CONCEPTUAL BACKGROUND

The Value of Lost Load or VoLL is a measure of how customers and businesses value improved reliability, hardening, and resiliency. VoLL is intended to capture the direct, private costs that are borne by market participants in relation to the hazards, damages, and inconveniences related to outage events. For example, with a reduction in a utility's SAIDI metric due to the implementation of a grid modernization initiative, the durations of future outages will be reduced which means that the utility's customers will value this operational benefit from the avoidance of the loss of electric service for the reduced amount of time reflected by the improvement in the SAIDI metric and the associated reduction in the Customer Minutes of Interruption (CMI).

Unlike in a purely competitive market, improving the reliability and resiliency of a utility's electric delivery system is challenging since there is no referenceable market for reliability. It is difficult to observe the price consumers would be willing to pay to avoid outages because there are not easily available substitutes consumers can select under short notices and uncertain outage events. Over time they will adapt but understanding how customers value sustained improvements to the overall reliability of the electric grid is an important area of policy research.

Economists agree that the value customers perceive in reliability is tied to the outage costs (and harm and inconveniences) they avoid, but outage costs are not always easy to identify. When power is not available residential customers and businesses incur many direct and indirect impacts. In a resiliency-scale event, for example, there would be wide-ranging impacts encompassing worker productivity, direct customer costs for supplies, delays to projects under construction, emergency-related costs to local governments, accidents and injuries, and lower tax and fee revenues (due to a decline in economic activity), just to name a few.

Customers and businesses face additional costs both in the short-term and long-term. Short-term costs are often understood as damage costs. Some customers might seek out long-term alternatives (e.g., consider moving or back-up supply sources if service is very poor during reliability-scale events and/or resiliency-scale events). The long-term costs are often a form of adaptive behaviors to avoid the outage risk in the future (such as installing a backup generator for an electricity customer who determines losing power is no longer acceptable). These can also be considered mitigation costs that help avoid the damage in the future. For outages, it is also relevant to expand the impacts to beyond just observable costs. Some of the impacts are quantifiable in monetary terms, and hence, economic in nature; whereas, others reflect social impacts tied to convenience, personal safety, pain and suffering, security, and other less tangible, but very real, values to the customer. Outage impacts are also characterized by externalities, which can be either

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positive or negative. For example, an outage event may disrupt an airport and cause supply chain disruptions for manufacturers far outside the immediate region. The structure of many of the outage cost types and attributes are summarized in Table 1 below.

Table 1 Structure of Damage and Mitigation Costs[1]

PRIVATE INDIVIDUALS			ECONOMY (INDUSTRY, COMMERCIAL USERS)		
Damage Costs		Mitigation Costs	Damage Costs		Mitigation Costs
Direct	Indirect	Direct	Direct	Indirect	Direct
• Restrictions on activities • Lost leisure, stress • Financial costs • Damage to premises and real estate • Food spoilage • Data loss • Health and safety aspects.	• Restrictions on acquisition of goods • Costs for other private individuals and companies	• Procurement of standby generators, batteries, etc. • Investments in grid construction via charges (network tariffs)	• Opportunity costs of idle resources. Lost profits. • Production holdups and restart times. • Adverse effects and damage to capital goods • Data loss	• Delayed deliveries along value chain. • Damage for consumers if the company produces end - use product. • Cost/benefits for some manufacturers. • Health and safety aspects.	• Procurement of standby generators, batteries, etc. • Investments in grid construction via charges (network tariffs)

The foregoing information is provided to set a context for why assessing a monetary value to electric reliability improvements requires care. This information is taken from the literature on power system disruptions. It represents one of the many ways that economists describe outage costs.

VOLL RELIABILITY FACTORS

To translate an electric utility's reliability improvements into value (i.e., benefits), practitioners in the electric utility industry apply a set of factors that relate customer class, outage durations, and load assumptions to economic value. These factors – which pertain to reliability-scale events -- have been developed for the specific purpose of estimating the value to customers of avoiding or reducing the extent of power outages. The economic losses associated with these factors are referred to as the Value of Lost Load ("VoLL").

These factors were originally published in the "Updated Value of Service Reliability Estimate for Electric Utility Customers in the United States." The Lawrence Berkeley National Laboratory (LBNL)

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[1] Schroder, T. and W. Kuckshinrichs, "Value of Lost Load: An Efficient Economic Indicator for Power Supply Security?", Frontiers in Energy Research, Cross Mark. December 24, 2015. Page 3.

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under contract with the Department of Energy developed this report.[2] Black & Veatch finds that these factors have been widely cited and often applied in the electric utility industry. The 2015 Report was built on and superseded a prior study published in 2009.[3] It is instructive to cite from the 2015 LBNL Report's abstract explaining the study effort:

> "This report updates the 2009 meta-analysis that provides estimates of the value of service reliability for electricity customers in the United States (U.S.). The meta-dataset now includes 34 different datasets from surveys fielded by 10 different utility companies between 1989 and 2012. Because these studies used nearly identical interruption cost estimation or willingness-to- pay/accept methods, it was possible to integrate their results into a single meta-dataset describing the value of electric service reliability observed in all of them. Once the datasets from the various studies were combined, a two-part regression model was used to estimate customer damage functions that can be generally applied to calculate customer interruption costs per event by season, time of day, day of week, and geographical regions within the U.S. for industrial, commercial, and residential customer."

DERIVATION OF VOLL FACTORS FOR DEI

DEI's Current Use of VoLL Factors

Black & Veatch understands that DEI currently utilizes VoLL factors derived by LBNL as described above. These VoLL factors are presented in Table ES-1 below (which is an excerpt from the referenced 2015 LBNL document). It is important to note LBNL points out in its report that the interruption costs in Table ES-1 are for the "average-sized customer in the meta-database" (which is a nationwide database of customer survey results that served as the basis to derive the VoLL factors in the Table). As a point of reference, the annual average use per customer values in the database are 13, 351 kWh for residential customers, 19,214 kWh for small C&I customers and 7,140,501 kWh for medium and large C&I customers. In contrast, the average annual usage in 2018 for DEI's average residential customer was 12,173 kWh and its industrial class was at an annual level of 3,934,971 kWh per customer. We would expect if DEI's customer database was reconfigured to conform with the three customer class categories in Table ES-1 that its average annual use per customer figures for small and medium/large C&I customers would be significantly less than those used as input in creating this Table.

[2] Michael J. Sullivan, Josh Schellenberg, and Marshall Blundell in collaboration with Nexant. Lawrence Berkeley National Laboratory (LBNL-6941E). Performed as part of DOE Contract No. DE-AC02-05CH11231. January 2015.

[3] Michael J. Sullivan, Ph.D., Matthew Mercurio, Ph.D., Josh Schellenberg, M.A, Freeman, Sullivan & Co., Estimated Value of Service Reliability for Electric Utility Customers in the United States, Prepared for Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy, LBNL-2132E, June 2009.

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Table ES-1: Estimated Interuption Cost per Event, Average kW and Unserved kWh (US 2013$) by Duration and Customer Class							
Interruption Cost	Interruption Duration						
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours	24 Hours
Cost per Event	0.0	0.5	1.0	4.0	8.0	16.0	24.0
Medium and Large C&I (Over 50,000 Annual kWh)							
Cost per Event	$12,952.00	$15,241.00	$17,804.00	$39,458.00	$84,083.00	$165,482.00	$246,881.00
Cost per Average kW	$15.90	$18.70	$21.80	$48.40	$103.20	$203.00	
Cost per Unserved kWh	$190.70	$37.40	$21.80	$12.10	$12.90	$12.70	
Small C&I (Under 50,000 Annual kWh)							
Cost per Event	$412.00	$520.00	$647.00	$1,880.00	$4,690.00	$9,055.00	$13,420.00
Cost per Average kW	$187.90	$237.00	$295.00	$857.10	$2,138.10	$4,128.30	
Cost per Unserved kWh	$2,254.60	$474.10	$295.00	$214.30	$267.30	$258.00	
Residential							
Cost per Event	$3.90	$4.50	$5.10	$9.50	$17.20	$32.40	$47.60
Cost per Average kW	$2.60	$2.90	$3.30	$6.20	$11.30	$21.20	
Cost per Unserved kWh	$30.90	$5.90	$3.30	$1.60	$1.40	$1.30	

In addition, the VoLL factors in Table ES-1 also are a function of household income, the times of the day when power interruptions occur, the mix of industries and the availability of backup generation, not on a state-by-state basis, but on a nationwide basis. For these reasons, Black & Veatch believes that the VoLL factors presented in Table ES-1 are not reasonably reflective of DEI's current reliability characteristics of its electric system and the load characteristics of its retail customers.

Our Recommended Approach

VoLL factors can be derived for a specific electric utility using the Interruption Cost Estimate (ICE) Calculator which is an electric reliability, on-line planning tool developed by LBNL and Nexant, Inc. This tool is designed for electric reliability planners at utilities, government organizations, and other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States.

Based on our understanding of the LBNL/Nexant work on this topic and our ongoing use of the ICE Calculator on grid modernization and reliability improvement projects, we recommend that DEI employ VoLL factors that are derived on a utility-specific basis using the ICE Calculator to value customer-related reliability benefits for DEI's future infrastructure investment plans. Based on how the ICE Calculator is structured, these utility-specific VoLL factors can be derived on a systemwide utility basis, separately for the utility's transmission or distribution system, or by individual circuit, if the input data for running the ICE Calculator are available (e.g., the mix of utility customers and its reliability metrics) for each circuit being analyzed.

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Attachment A to this document provides a detailed description of the data inputs required to run the ICE Calculator and a step-by-step procedure for deriving VoLL factors that are specific to DEI's electric system and customer characteristics. The process described in **Attachment A** will allow DEI to replicate the VoLL factors presented in Table ES-1 using the ICE Calculator,[4] but the resulting factors will be reflective of Duke's specific characteristics if the defined inputs are used for each of its state jurisdictions.

Table DEI-1 below presents the VoLL values applicable to DEI's electric system derived by Black & Veatch using the ICE calculator with DEI's reliability and customer input data for 2019.[5]

Table DEI-1: Estimated Interruption Cost per Event, Average kW and Unserved kWh (US 2016$) by Duration and Customer Class[6]

	Interruption Duration					
Interruption Cost	**Momentary**	**30 Minutes**	**1 Hour**	**4 Hours**	**8 Hours**	**16 Hours**
Medium and Large C&I (Over 50,000 Annual kWh)						
Cost per Event	$3,340.75	$4,007.38	$4,784.39	$11,449.49	$24,594.43	$41,939.88
Cost per Average kW	$32.48	$38.96	$46.52	$111.32	$239.12	$407.76
Cost per Unserved kWh	$2,165.37	$77.92	$46.52	$27.83	$29.89	$25.49
Small C&I (Under 50,000 Annual kWh)						
Cost per Event	$489.50	$613.16	$762.78	$2,194.55	$5,380.46	$10,256.15
Cost per Average kW	$130.33	$163.26	$203.10	$584.32	$1,432.61	$2,730.82
Cost per Unserved kWh	$2,165.37	$326.52	$203.10	$146.08	$179.08	$170.68
Residential						
Cost per Event	$4.79	$5.30	$5.86	$9.91	$16.86	$30.86
Cost per Average kW	$3.50	$3.87	$4.28	$7.24	$12.31	$22.53
Cost per Unserved kWh	$233.24	$7.74	$4.28	$1.81	$1.54	$1.41

Comparing the VoLL factors in Table DEI-1 to those in Table ES-1, it is readily observed that the VoLL factors derived on a Cost per Event basis for residential customers are higher for DEI compared to the nationwide results, with higher VoLL factors for DEI's small C&I customers and lower VoLL factors for its medium/large C&I customers compared to the nationwide results across all of the measured interruption durations. These differences are driven primarily by the differences in the annual average use per customer for DEI operating as a utility in Indiana compared to the nationwide customer characteristics as well as by differences between the other Indiana-specific and the nationwide data

[4] The maximum interruptible duration that is computed by the ICE Calculator is 16 hours.
[5] If DEI adopts this approach to derive its VoLL factors, we recommend that the ICE Calculator be run using the reliability metrics (SAIFI and SAIDI) that DEI designates as its "baseline" level of reliability and the number of customers for the chosen time period over which DEI's system reliability is measured.
[6] Using reliability data excluding MEDs.

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sources assumed in deriving the VoLL factors.

Table DEI-1 can be used to derive the value (benefits) for each of DEI's programs by selecting the VoLL factor that corresponds to the appropriate interruption duration based on the specific reliability metrics for the program. If necessary, interpolation can be used to derive a VoLL factor for the specific interruptible duration between the two available durations.[7]

For each reliability program, the improvements in SAIFI and SAIDI (i.e., CI and CMI) that will result from the program compared to the baseline level (i.e., without the program) are required to determine the customer-related value (benefits) associated with the program. The improvements measured by the changes in these reliability metrics when applied against the interruption cost per customer outage and per momentary outage in Table DEI-1 derives the estimated value to customers of improving (reducing) the frequency and duration of outages.

In addition to this Table, Tables DEI-2 and DEI-3 below present DEI's "Total Interruption Cost" for its transmission grid[8] and distribution systems, respectively, based on the 5-year average (2015 through 2019) of its systemwide reliability metrics and customer counts as of December 2019. For purposes of this discussion, we can characterize these results as DEI's "baseline" or "business as usual" (BAU) reliability conditions which are used to determine the value its customers associate with the avoidance of outages experienced at DEI's 5-year reliability levels.[9] In other words, the value DEI's customers will derive from a reduction in the level of outages from its baseline levels through the deployment of its TDSIC 2.0 Plan investments can be quantified on a unit basis using the VoLL factors derived from the ICE Calculator.

Table DEI-2: Transmission Grid Systemwide Interruption Cost (in US 2016$)
by Customer Class for Baseline Reliability[10]

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[7] For example, a reliability-based program being evaluated by DEI with circuits that have an average outage duration in Year 1 of 45 minutes would utilize a VoLL factor for the Cost per Event of $687.97 for DEI's small C&I customers (based on the average of $613.16 and $762.78) to monetize the operational benefits associated with the program.
[8] The *Transmission Grid* designation refers to DEI's retail and wholesale customers served from its transmission system.
[9] The Systemwide Interruption Cost in the base year (i.e., 2019) presented in Tables DEI-2 and DEI-3 for DEI's transmission and distribution systems, respectively, is based on DEI's most recent 5-year average reliability metrics (2015-2019) and does not reflect the increase in Total Interruption Costs in future years caused by the expected deterioration in system reliability without additional reliability-related investments made by DEI.
[10] Results generated from the ICE Calculator using DEI reliability data excluding MEDs.

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Sector	# of Customers	Cost Per Event	Cost Per Avg kW	Cost Per Unserved kWh	Total Cost
Residential	1,115,674	$6.47	$4.72	$3.11	$1,443,932.55
Small C&I	112,326	$942.62	$250.98	$165.48	$21,176,257.73
Medium and Large C&I	28,780	$5,686.34	$55.29	$36.45	$32,730,588.08
Total	**1,256,780**	**$220.21**	**$56.36**	**$37.16**	**$55,350,778.36**
	At December 2019				
	SAIFI	0.20	Average 2015-2019		
	SAIDI	18.2	Average 2015-2019		
	CAIDI	91.0	Average 2015-2019		
	Cost/CMI	$2.42	(Total Interruption Cost/Total Customers/SAIDI)		
	CMI	22,873,396	(SAIDI x Total Customers)		
	Customer Interruptions (CI)	251,356	(CMI/CAIDI)		

To illustrate how these tables would be used, a 20% reduction in DEI's Transmission Grid SAIDI metric caused by infrastructure investments designed to improve its system reliability would result in a reduction in the "baseline" or current CMI of 4,574,679 (a SAIDI reduction of about 3.64 x 1,256,780 customers) which equates to an annual customer value (i.e., level of monetized benefits) of approximately $11.1 million (4,574,679 CMI x $2.42/CMI).[11]

Table DEI-3: Distribution Systemwide Interruption Cost (in US 2016$) by Customer Class for Baseline Reliability[12]

Sector	# of Customers	Cost Per Event	Cost Per Avg kW	Cost Per Unserved kWh	Total Cost
Residential	740,711	$7.63	$5.57	$2.30	$5,603,783.71
Small C&I	84,816	$1,324.05	$352.54	$145.48	$111,290,167.41
Medium and Large C&I	21,731	$7,521.74	$73.09	$30.16	$161,904,990.07
Total	**847,258**	**$332.05**	**$78.84**	**$32.53**	**$278,798,941.19**
	At December 2019				
	SAIFI	0.99	Average 2015-2019		
	SAIDI	144.129	Average 2015-2019		
	CAIDI	145.4	Average 2015-2019		
	Cost/CMI	$2.28	(Total Interruption Cost/Total Customers/SAIDI)		
	CMI	122,114,448	(SAIDI x Total Customers)		
	Customer Interruptions (CI)	839,852	(CMI/CAIDI)		

It is important to note that Tables DEI-2 and DEI-3 can also be derived on an individual circuit basis using the mix of customers, CI and CMI (i.e., SAIFI and SAIDI metrics) for the specific circuit, which also

[11] It should be recognized that the economic value customers associate with a reduction in the level of power outages, which is estimated using the VoLL factors, represents only one of several value streams (i.e., benefits) that will be experienced by DEI and its customers with the expected improvements in electric system reliability under its TDSIC 2.0 Plan.
[12] Results generated from the ICE Calculator using DEI reliability data excluding MEDs.

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can be characterized as the "baseline" reliability conditions for that circuit. This computational ability will allow the proper recognition of the value received by customers from reductions in the frequency and duration of outages achieved through DEI's TDSIC 2.0 investments and will enable the program and circuit optimization through Copperleaf's C55 modeling process.

APPLICATION OF VOLL FACTORS TO DEI'S TDSIC 2.0 PLAN

On a going-forward basis, Black & Veatch recommends that Duke derive separate sets of VoLL factors for each of its jurisdictions. We also recommend that two sets of VoLL factors be derived for its transmission and distribution systems, with individual VoLL factors derived for each distribution circuit where feasible.[13] This approach is consistent with the intent and capabilities of the ICE calculator to derive utility-specific VoLL factors and will properly reflect the different "baseline" reliability conditions across and within Duke's service areas. For DEI, we specifically recommend that separate VoLL Factors be derived for transmission grid and distribution, and by individual circuit where feasible, to be applied to the specific programs and individual circuits that will be included in DEI's proposed TDSIC 2.0 Plan.

Escalation of the VoLL Factors

Because the VoLL factors in Tables DEI-1 and DEI-2 derived using the ICE Calculator are stated in 2016$, these amounts must be adjusted to each year of DEI's TDSIC 2.0 Plan using an appropriate escalation or inflation factor. DEI currently makes this type of adjustment in the preliminary cost-benefit analyses (CBAs) associated with the TDSIC 2.0 distribution programs that we have reviewed to date.

Updating of the VoLL Factors

We recommend that DEI update its VoLL factors on a periodic basis whenever its baseline level of reliability changes for each of Duke's jurisdictions. However, we believe that DEI should consider changing its baseline level of reliability only when evaluating future infrastructure investment programs. The baseline reliability levels used to evaluate the value (benefits) for DEI's TDSIC 2.0 programs should be preserved throughout the term of the Plan to maintain a realistic basis for measuring the annual level of reliability improvements realized from the Plan's investments.

[13] If circuit-specific customer mix and reliability data is readily available.

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Inclusion of the VoLL Factors in Copperleaf's C55 Model

The VoLL factors described above for DEI were compiled in an Excel-based spreadsheet for direct input into the Copperleaf C55 model.

Transmission-Related VoLL Factors

We understand that the VoLL factors for DEI's transmission system were previously derived using the ICE Calculator and have been utilized in the Copperleaf C55 model for internal purposes by DEI. The transmission-related reliability metrics (SAIDI and SAIFI) and customer counts (residential, commercial and industrial customer groups) used in the VoLL factor calculation were for calendar year 2018. Black & Veatch has updated DEI's transmission grid VoLL factors using average SAIDI and SAIFI metrics for the latest 5-year period (calendar 2015 through 2019) and customer counts at December 2019.[14] This updated data was utilized by Black & Veatch in conjunction with the value measures and models contained in Copperleaf's C55 model for DEI's transmission system projects.[15] The values derived from Copperleaf's value models are used for the relative ranking of projects for reliability benefits.

These VoLL factors were used to compute the value (benefits) associated with the Electric Reliability Risk (ERR) and Transmission Reliability Risk (TRR) component of the C55 model based on the algorithms detailed in **Appendix A** to Black & Veatch's TDSIC 2.0 Investment Plan – Phase 1 report. The ERR Model estimates the reliability benefits for planning projects that would potentially add redundancy to DEI's transmission system while the TRR Model estimates reliability benefits for asset replacement or improvement interventions.

Distribution-Related VoLL Factors

The VoLL factors for DEI's distribution system were derived on an individual circuit basis using average reliability metrics (SAIDI and SAIFI) for the latest 5-year period (calendar 2015 through 2019) and customer counts (residential, commercial and industrial) at December 2019. This data was provided by Duke Energy from multiple sources including its Enterprise Distribution System Health (EDSH) data analytics platform. Where data was not available, reasonable assumptions were made such as using

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[14] The customer counts are based upon DEI's total number of retail and wholesale customers served at December 2019, where the wholesale customer count reflects the number of end-use customers served by Wabash Valley Power Association, Hoosier Energy and Indiana Municipal Power Agency (IMPA).

[15] Tables 44 through 49 in Copperleaf's Value Framework Definition Document (VFDD) were updated to reflect DEI's VoLL factors described above.

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DEI's average SAIDI, SAIFI and average percentage customer counts for its distribution system. This data was utilized by Black & Veatch in conjunction with the Electric DX Reliability Risk (applied to 13 sub-programs) and the Transmission Line Risk (applied for GLT Pole Inspect & Replace sub-program) value models contained in Copperleaf's C55 model for DEI's distribution system projects.

These VoLL factors by individual circuit were used to compute the value (benefits) associated with the DX Electric Reliability Risk component of the C55 model based on the following algorithms:

- **Customer Minutes of Interruption Cost (applied to 12 sub-programs)**
    - Failures Avoided Per Year * Duration (Hours) * 60 (minutes/hour) * Average Number of Customers Affected * *CMI Cost ($/minute)*[16]
- **Frequency Cost (not applied to any sub-programs)**
    - Failures Avoided Per Year * Peak Load Lost (MW) * 1,000 (kW/MW) * Duration (Hours) * *Frequency Cost of Customer Mix ($/minute)*[17]
- **Duration Cost (applied to Circuit Visibility and Control sub-programs)**
    - Failures Avoided Per Year * Peak Load Lost (MW) * 1,000 (kW/MW) * Duration (Hours) * *Duration Cost of Customer Mix ($/kWh)*[18]

The system-wide average SAIDI and SAIFI factors for DEI were used in the Transmission Line Risk Model for the GLT Pole Inspect and Replace sub-program.

[16] Copperleaf Distribution VFDD – Table __.
[17] Copperleaf Distribution VFDD – Table __.
[18] Copperleaf Distribution VFDD – Table __.

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ATTACHMENT A

ICE CALCULATOR
Estimating Interruption Costs
Data Inputs and Outputs

ICE CALCULATOR WEBSITE - https://icecalculator.com/home

Choose "Estimate Interruption Costs" option

Inputs

- Select a State
- Number of Customers
  - Non-Residential
  - Residential
- Reliability Inputs: Enter values for two of the three index values[19]
  - SAIFI
  - SAIDI
  - CAIDI

Run the Model

After the Model is run for the first time, you can modify the initial input values so that they are more specific to the utility and then rerun the Model.

Scroll to top of page to update model parameters (optional)[20]

Updated Inputs *(Optional)*

- Number of Customers
  - Small C&I
  - Medium/Large C&I (over 50,000 annual kWh)
  - Residential
- Annual Usage (MWh)
  - Residential
  - Small C&I
  - Medium and Large C&I
- Household Income
- Power Interruptions – Distribution of Outages
  - By Time of Day

[19] For the systemwide, baseline (without TDSIC improvements) reliability conditions.

[20] While the most recent version of the ICE Calculator has been updated to generate reasonable results for a specific utility using the initial data inputs indicated under the "Inputs" section above, to the extent the additional data is available in the other categories listed in the "Updated Inputs" section above, the utility should consider using such additional utility-specific data to refine, customize and strengthen its VoLL results.

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        - Morning (5 am to 12 pm)
        - Afternoon (12 pm to 5 pm)
        - Evening (5 pm to 10 pm)
        - Night (10 pm to 5 am)
    - By Time of Year
        - Summer (June through September)
- Industry Percentage
    - Small C&I (equal to 100%)
        - Construction (%)
        - Manufacturing (%)
        - All Other Industries (%)
    - Medium and Large C&I (100%)
        - Construction (%)
        - Manufacturing (%)
        - All Other Industries (%)
- Backup Generation (equal to 100%)
    - Small C&I
        - No or Unknown Backup Equipment (%)
        - Backup Generation or Power Conditioning (%)
        - Backup Generation and Power Conditioning (%)
    - Medium and Large C&I (equal to 100%)
        - No or Unknown Backup Equipment (%)
        - Backup Generation or Power Conditioning (%)
        - Backup Generation and Power Conditioning (%)

Outputs by Customer Class[21]

- By customer sector (Residential, Small C&I, Medium and Large C&I)
    - Cost per Event
    - Cost per Average kW
    - Cost per Unserved kWh
    - Total Cost of Interruption

Outputs by Outage Duration and Customer Class

- Rerun the ICE Calculator for each desired outage duration using the same inputs as above except for the following changes:
    - Momentary: set SAIDI at 1.00.
    - 30 Minutes: set SAIFI at 1.00 and SAIDI at 30.
    - 1 Hour: set SAIFI at 1.00 and SAIDI at 60.
    - 4 Hours: set SAIFI at 1.00 and SAIDI at 240.
    - 8 Hours: set SAIFI at 1.00 and SAIDI at 480.
    - 16 Hours: set SAIFI at 1.00 and SAIDI at 960.
    - 24 Hours: set SAIFI at 1.00 and SAIDI at 1,440.

[21] Calculated for the utility system's average outage duration in hours (CAIDI/60 minutes).

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Sample Output from the ICE Calculator

- DEI Momentary Outage Duration for 2019 (Excel file downloaded from the ICE Calculator)

Sector	# of Customers	Cost Per Event	Cost Per Avg kW	Cost Per Unserved kWh	Total Cost
Residential	733944	$4.79	$3.50	$233.24	$3,763,781.29
Small C&I	84517	$489.50	$130.33	$8,688.97	$44,266,899.35
Medium and Large C&I	21655	$3,340.75	$32.48	$2,165.37	$77,408,070.89
Total	**840116**	**$139.54**	**$33.02**	**$2,201.47**	**$125,438,751.54**

- DEI 4 Hour Outage Duration 2019 (Excel file downloaded from the ICE Calculator)

Sector	# of Customers	Cost Per Event	Cost Per Avg kW	Cost Per Unserved kWh	Total Cost
Residential	733944	$9.91	$7.24	$1.81	$7,275,172.04
Small C&I	84517	$2,194.55	$584.32	$146.08	$185,476,753.39
Medium and Large C&I	21655	$11,449.49	$111.32	$27.83	$247,938,724.88
Total	**840116**	**$524.56**	**$124.13**	**$31.03**	**$440,690,650.31**

In addition, the cost per CMI for each ICE Calculator run can easily be computed from the model's output data (Total Interruption Cost/Number of Customers/Baseline SAIDI). For example, DEI's Cost per CMI for a 4-hour outage duration in 2019 is $2.19 per CMI ($440,690,650/840,116 customers/240 minutes/customer).

INDEPENDENT COST ESTIMATE REVIEW

BLACK & VEATCH PROJECT NO. 406509

PREPARED BY
THOMAS WHITE, CERTIFIED AACE ESTIMATOR

PREPARED FOR

Duke Energy Indiana

18 NOVEMBER 2021

BLACK & VEATCH

Table of Contents

LIST OF TABLES

1.0 Duke Energy Indiana TDSIC 2.0 – Cost Estimate Review

Duke Energy Indiana engaged Black & Veatch to review its TDSIC 2.0 Investment Plan (The Plan) project cost estimates and estimating methodology. The purpose of the review was to test estimates for reasonableness based on Black & Veatch's experience estimating similar T&D projects in the electric utility industry.

1.1 Company Overview - Black & Veatch Corporation

The independent cost review was completed by cost estimating, engineering, and consulting professionals from Black & Veatch. Founded in 1915, Black & Veatch is a leading global engineering, consulting, and construction company. Black & Veatch specializes in the following major markets:

- Energy.
- Water.
- Telecommunications.
- Federal.
- Management Consulting.

Black & Veatch Holding Company is an employee-owned, global company that delivers sustainable infrastructure solutions across the Power, Oil & Gas, Water, Telecommunications, and Federal markets. Since 1915, we help clients improve the lives of people in communities worldwide through consulting, engineering, construction, operations, and program management services.

2.0 Cost Estimate Review Approach

First, Black & Veatch met with Duke Energy Indiana's engineering and project management teams to review the processes and tools to develop cost estimates. Secondly, a sampling of Duke Energy Indiana's project cost estimates was selected for review by Black & Veatch for reasonableness. Finally, Duke Energy Indiana provided Black & Veatch cost estimating documents and workbooks of the projects selected for review. These included transmission and distribution substations, transmission lines, and distribution lines included in The Plan.

2.1 Duke Energy Indiana Cost Estimating Approach

Duke Energy Indiana developed project cost estimates by utilizing detailed estimation workbooks and engineering design tools. These tools allow Duke Energy Indiana's cost estimators to create estimates using a consistent set of base cost assumptions such as labor rates and material costs, among others. The cost estimates reviewed by Black & Veatch include Duke Energy Indiana's overhead costs. Duke Energy Indiana developed project cost estimates for The Plan based on a combination of factors, including:

- Actual costs of recently completed projects of similar scope.
- Material cost estimates from Duke Energy's inventory management system and price quotes from vendors that supply electrical equipment to Duke Energy Indiana, all in 2021 terms.
- For substation and transmission line projects, Class 2 estimates: construction labor quotes were provided by construction contractors based on a review of the scope of work, all in 2021 terms.

For distribution line Class 2 estimates: construction labor estimates were developed from labor costs currently under contract. An inflation rate of 3% for both labor and material over the life of The Plan.

Duke Energy Indiana developed Class 2 estimates for projects scheduled for 2023 and 2024. Class 4 estimates were developed for projects scheduled from 2025 through 2028 projects. Table 1 below list the America Association of Cost Engineers (AACE) estimate classifications applicable for the projects in The Plan.

Table 1 AACE Cost Estimate Classification System

	Primary Characteristic	Secondary Characteristic		
ESTIMATE CLASS	MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES Expressed as % of complete definition	END USAGE Typical purpose of estimate	METHODOLOGY Typical estimating method	EXPECTED ACCURACY RANGE The typical variation in low and high ranges
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed takeoff	L: -5% to -15% H: +5% to +20%
Note: The above table has been re-produced using data from "AACE International Recommended Practice No.18R-97: COST ESTIMATE CLASSIFICATION SYSTEM - AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES, Rev. November 29,2011; http://www.aacei.org/toc/toc_18R-97.pdf"				

2.2 Black & Veatch Approach for Review of Cost Estimates

The approach for reviewing The Plan cost estimates was based on taking a sampling of project estimates from The Plan to review for reasonableness. Therefore, the review did not include adjustments for the salvage value of retired equipment or any removal costs. The sample of projects included Class 2 and Class 4 estimates. Table 1 of section 1.3.1 below lists the projects chosen for review.

Class 2 estimates were used for years 2023 and 2024 of The Plan. For Class 2 estimates, reviews were conducted by gathering project data from Duke Energy Indiana that included a site-specific scope of work, project schedule, scope of procurement, detailed engineering drawings, bill of materials, unit man-hour rates, unit material rates, and indirect costs cost, contingency, and escalation. Costs were reviewed at the line item level and included a review of quantities for both material and labor. The labor costs were quotes from construction contractors or labor costs currently under contract with Duke Energy Indiana. Additionally, any special equipment or material needed to construct the project was reviewed a withnd estimated project duration. After the data was gathered, project cost estimate review meetings were conducted by Black & Veatch professionals with Duke Energy Indiana engineering and project management teams. The purpose of the reviews was to validate consistency in project cost estimate assumptions and methodologies across the sampling of projects

Class 4 estimates were used for projects in the years 2025 through 2028. For Class 4 estimates, the same level of project detail has not been established for Class 2 estimates. This is reasonable because the projects being scheduled for construction later in The Plan and Duke Energy Indiana has historical average actual costs for similar completed projects. The review of the Class 4 estimates was conducted similarly as the Class 2 estimates. However, the scope of work was defined as a typical installation of a specific asset or set of assets. Examples would be a substation 138kv breaker or a 1-mile section of the distribution line. Line item unit labor and material cost were identified, along with the quantities needed to complete the work. Labor costs for Class 4 estimates were compared to quoted labor costs used in the Class 2 estimates for similar work. Where Duke Energy Indiana is currently under the labor contract, those labor costs were used. Indirect costs, contingency, and escalation were reviewed as well. As in Class 2 estimates, cost estimate review meetings were conducted to validate consistency in assumptions and methodologies.

The approach for reviewing Duke Energy Indiana's estimating methodology was to use the project estimate review sessions to understand Duke Energy Indiana's estimating tools and processes. During the review sessions, Duke Energy Indiana presented engineering design and estimating tools along with estimating excel pricing workbooks. This allowed Black & Veatch to understand Duke Energy Indiana's level of detail, cost basis, and assumptions in developing project costs.

Some factors can cause changes in material and labor costs throughout The Plan. In today's global economy, market forces impact significant equipment suppliers and their costs. These cost impacts are passed on to equipment suppliers' customers. Similarly, contract construction labor costs can fluctuate based on local supply of labor.

BV's review shows that the Duke Energy cost estimates and cost estimating process are reasonable. Based on the review of the process and documentation developed to support each of the project estimates, Duke Energy Indiana has utilized the correct AACE class level. The level of detail Duke Energy Indiana has used to estimate the projects in The Plan is consistent with common practice within the industry.

2.3 T&D Project Estimates

Table 2below summarizes the cost review results for distribution and transmission projects. In addition, Black & Veatch reviewed the project cost estimate workbooks and documentation to validate that the class level indicated by Duke Energy Indiana meets the AACE class-level definition.

Table 2 Summary of Projects Black & Veatch Reviewed

T or D	Sub-Program	Project Name	Year Planned In-Service	AACE Class Level	Reviewed by BV
D	Targeted Undergrounding (TUG)	BLM NORTHWEST (770) 1271	2023	2	✓
D	SOG	LAFAYETTE SHADELAND (461) 1281	2023	2	✓
D	SOG	AVON SOUTH (603) 1254	2023	2	✓
D	Circuit Segmentation	GEORGETOWN (467) 1201	2023	2	✓
D	Circuit Segmentation	HOPE (417) 1261	2023	2	✓
D	IVVC	N1141641213	2023	2	✓
D	IVVC	N1141641215	2023	2	✓
D	4kV Conversion	THORNBURG ST (335) 411	2023	2	✓

T or D	Sub-Program	Project Name	Year Planned In-Service	AACE Class Level	Reviewed by BV
D	Circuit Visibility & Control	HE DILLSBORO (86) 1202	2023	2	✓
D	Declared Circuits	VINCENNES 138 (257) 1210	2023	2	✓
D	Circuit Sectionalization	ZIONSVL TURKEY FOOT (576) 1264	2023	2	✓
T	GLT Pole Inspect Repl.	TRANSMISSION POLE REPLACEMENTS	[redacted]	2	✓
T	Substation	Toad Hop Reliability Upgrade TDSIC	[redacted]	2	✓
T	Substation	Westwood 138kV CB-Rel Repl.	[redacted]	2	✓
T	Transmission Line	Lines M20038901	[redacted]	2	✓
T	Transmission Line	Greencastle-Morton	[redacted]	2	✓
D	Automated Lateral Device (ALD)	WORTHINGTON 34 (447) 1201	2024	2	✓
D	Limited Access	ALLENDALE (333) 1282	2024	2	✓
D	Limited Access	ALLENDALE (333) 1283	2024	2	✓
D	Limited Access	CINCINNATI ST (314) 1218	2024	2	✓
D	Switchgear Insp & Repl.	GREENWOOD N (543) 1211	2024	2	✓
D	Targeted Undergrounding (TUG)	HAGERSTOWN (221) 1210	2024	2	✓
D	Targeted Undergrounding (TUG)	HUNTINGTON STATE ST (695) 1203	2024	2	✓
D	SOG	ALLENDALE (333) 1281	2024	2	✓
D	SOG	NOBLESVILLE NE (768) 1245	2024	2	✓
D	Circuit Segmentation	WHITEHALL PIKE (601) 1264	2024	2	✓
D	IVVC	N1307681244	2024	2	✓
D	4kV Conversion	NEW CASTLE 138 (241) 401	2024	2	✓
D	Circuit Visibility & Control	RIVER RIDGE NORTH (299) 1213	2024	2	✓
T	Substation	Huntington CB Rel. Repl.	[redacted]	2	✓
T	Economic Development	River Ridge New 138kV Ring Bus	[redacted]	2	✓
D	SOG	Danville DA	2025	4	✓
D	IVVC	Cicero Add Voltage Regulation BK1	2025	4	✓
T	Substation	Kokomo Webster 69kV CB Rel. Repl.	[redacted]	4	✓
T	Substation	New Albany CB Rel. Repl.	[redacted]	4	✓

T or D	Sub-Program	Project Name	Year Planned In-Service	AACE Class Level	Reviewed by BV
T	Substation	Rochester 69 CB Rel. Repl.	[redacted]	4	✓
T	Substation	Kokomo East Relay Repl.	[redacted]	4	✓
T	Substation	New Washington Repl. 3 phase VR	[redacted]	4	✓
T	Substation	St Paul	[redacted]	4	✓
D	IVVC	Carmel 1st Ave BK1 Add volt Reg	2026	4	✓
D	IVVC	COL Commerce Park DA	2026	4	✓
T	Substation	Shelbyville Northeast CB Rel Repl.	[redacted]	4	✓
T	Substation	Osgood Wood Structure Rebuild-VCR	[redacted]	4	✓
T	Substation	Bedford Boyd 69 CB Rel. Repl.	[redacted]	4	✓
T	Substation	Crawfordsville Reliability Upgrade	[redacted]	4	✓
T	Substation	Roseburg Switch Sta. CB Rel. Repl.	[redacted]	4	✓
T	Substation	Central Foundry Reliability Upgrade	[redacted]	4	✓
T	Substation	Vincennes Transrupter Replace	[redacted]	4	✓
T	Substation	TH Water ST	[redacted]	4	✓
D	IVVC	Madison 2nd St DA	2027	4	✓
D	IVVC	COL Cliffty Creek	2027	4	✓
D	IVVC	Noblesville Marilyn BK1 Add VR DA I	2027	4	✓
T	Substation	Kokomo Webster 230kV CB Rel. Repl.	[redacted]	4	✓
T	Substation	Greencastle CB Rel. Repl.	[redacted]	4	✓
T	Substation	Carmel Spring Mill Rd Reliability Upg.	[redacted]	4	✓
T	Substation	Prestwick Transrupter Repl.	[redacted]	4	✓
T	Substation	Columbus 345 Repl. Station Serv	[redacted]	4	✓
T	Substation	Rockville 138 Rel Repl.	[redacted]	4	✓
T	Substation	Veedersburg 8th	[redacted]	4	✓
T	Substation	Camp Atterbury	[redacted]	4	✓
D	IVVC	French Lick South DA	2028	4	✓
D	IVVC	Westfield Ditch BK2 Add VR DA	2028	4	✓
D	IVVC	Zionsville 121st Add Volt Reg DA	2028	4	✓

T or D	Sub-Program	Project Name	Year Planned In-Service	AACE Class Level	Reviewed by BV
D	IVVC	Carmel Guilford Rd BK1 Add VR DA I	2028	4	✓
D	IVVC	Fishers 106th St	2028	4	✓
T	Substation	Franklin_230 230kV Ring Bus	[redacted]	4	✓
T	Substation	Nucor Steel Relay Replacement	[redacted]	4	✓
T	Substation	Noblesville Wellington Reliability Upgrade	[redacted]	4	✓
T	Substation	Greentown 230kV CB Rel. Repl.	[redacted]	4	✓
T	Substation	Terre Haute East CB Rel. Repl.	[redacted]	4	✓
D	Automated Lateral Device (ALD)	To be identified later in the plan	2025-2028	4	✓
D	Limited Access	To be identified later in the plan	2025-2028	4	✓
D	Switchgear Insp & Repl.	To be identified later in the plan	2025-2028	4	✓
D	Surface Mount Equipment Inspection (SMEI)	To be identified later in the plan	2025-2028	4	✓
D	Targeted Undergrounding (TUG)	To be identified later in the plan	2025-2028	4	✓
D	Recloser Replacements	To be identified later in the plan	2025-2028	4	✓
D	SOG	To be identified later in the plan	2025-2028	4	✓
D	Circuit Segmentation	To be identified later in the plan	2025-2028	4	✓
D	Inaccessible R/W	To be identified later in the plan	2025-2028	4	✓
D	IVVC	To be identified later in the plan	2025-2028	4	✓
D	4kV Conversion	To be identified later in the plan	2025-2028	4	✓
D	GLT Pole Inspect Repl.	To be identified later in the plan	2025-2028	4	✓
D	Circuit Visibility & Control	To be identified later in the plan	2025-2028	4	✓
D	Declared Circuits	To be identified later in the plan	2025-2028	4	✓
D	Deteriorated Conductor	To be identified later in the plan	2025-2028	4	✓
D	Capacitor Automation	To be identified later in the plan	2025-2028	4	✓
D	UG Cable Rehabilitation	To be identified later in the plan	2025-2028	4	✓
T	Substation	Henry County Switching Station Reliability Upgrade	[redacted]	4	✓
T	Substation	Fishers North Reliability Upgrade	[redacted]	4	✓
T	Substation	Fishers Olio Rd	[redacted]	4	✓

3.0 Conclusions

Based on the data Duke Energy Indiana provided and Black & Veatch's knowledge and experience with project costs similar to the above projects, Black & Veatch concludes that the cost estimates Duke Energy Indiana has developed for The Plan are reasonable. Furthermore, based on the review of cost estimating processes and the level of detail Duke Energy Indiana has provided, Black & Veatch can validate the cost estimates developed by Duke Energy Indiana are appropriate and consistent with AACE class level of the estimate. In some cases, Black & Veatch found that Duke Energy Indiana was conservative in its AACE class level assignment. For example, some of the project estimates given a 'Class 4' level are based on the most recent actual costs that Duke Energy has experienced for the scope of work. In addition, these estimates have a defined quantity for their scope. Having these two characteristics would justify a 'Class 3' level estimate.

VERIFICATION

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

Signed: James W Shields
James W. Shields

Dated: November 23, 2021